RELION® PROTECTION AND CONTROL

615 series ANSI
Technical Manual

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Disclaimer

The data, examples and diagrams in this manual are included solely for the concept or product description and are not to be deemed as a statement of guaranteed properties. All persons responsible for applying the equipment addressed in this manual must satisfy themselves that each intended application is suitable and acceptable, including that any applicable safety or other operational requirements are complied with. In particular, any risks in applications where a system failure and/or product failure would create a risk for harm to property or persons (including but not limited to personal injuries or death) shall be the sole responsibility of the person or entity applying the equipment, and those so responsible are hereby requested to ensure that all measures are taken to exclude or mitigate such risks.

This product has been designed to be connected and communicate data and information via a network interface which should be connected to a secure network. It is the sole responsibility of the person or entity responsible for network administration to ensure a secure connection to the network and to take the necessary measures (such as, but not limited to, installation of firewalls, application of authentication measures, encryption of data, installation of anti virus programs, etc.) to protect the product and the network, its system and interface included, against any kind of security breaches, unauthorized access, interference, intrusion, leakage and/or theft of data or information. ABB is not liable for any such damages and/or losses.

This document has been carefully checked by ABB but deviations cannot be completely ruled out. In case any errors are detected, the reader is kindly requested to notify the manufacturer. Other than under explicit contractual commitments, in no event shall ABB be responsible or liable for any loss or damage resulting from the use of this manual or the application of the equipment.

Conformity

This product complies with the directive of the Council of the European Communities on the approximation of the laws of the Member States relating to electromagnetic compatibility (EMC Directive 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC). This conformity is the result of tests conducted by ABB in accordance with the product standards EN 50263 and EN 60255-26 for the EMC directive, and with the product standards EN 60255-1 and EN 60255-27 for the low voltage directive. The product is designed in accordance with the international standards of the IEC 60255 series and ANSI C37.90. This product complies with the UL 508 certification.

Table of contents

Section 1 Introduction

1.1 This manual

The technical manual contains application and functionality descriptions and lists function blocks, logic diagrams, input and output signals, setting parameters and technical data sorted per function. The manual can be used as a technical reference during the engineering phase, installation and commissioning phase, and during normal service.

1.2 Intended audience

This manual addresses system engineers and installation and commissioning personnel, who use technical data during engineering, installation and commissioning, and in normal service.

The system engineer must have a thorough knowledge of protection systems, protection equipment, protection functions and the configured functional logic in the protection relays. The installation and commissioning personnel must have a basic knowledge in handling electronic equipment.

1.3 Product documentation

1.3.1 Product documentation set

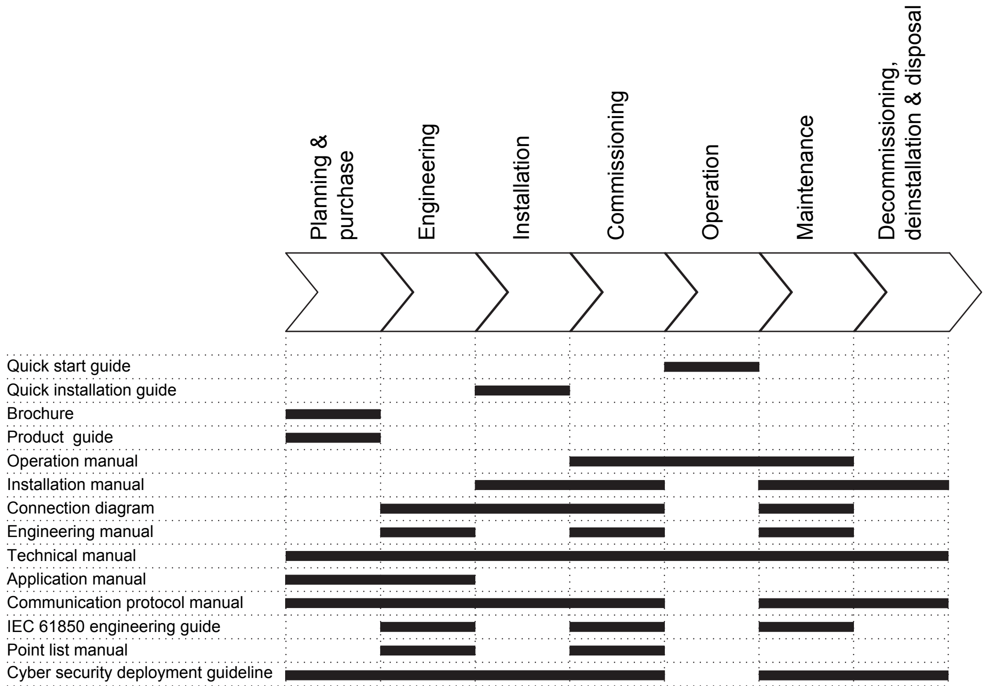

Figure 1: The intended use of documents during the product life cycle

Product series- and product-specific manuals can be downloaded from the ABB Web site http://www.abb.com/relion.

1.3.2 Document revision history

Document revision/date	Product series version	History
A/2018-04-23	5.0 FP1	First release

Download the latest documents from the ABB Web site http://www.abb.com/substationautomation.

1.3.3 Related documentation

Product series- and product-specific manuals can be downloaded from the ABB Web site http://www.abb.com/substationautomation.

1.4 Symbols and conventions

1.4.1 Symbols

The electrical warning icon indicates the presence of a hazard which could result in electrical shock.

The warning icon indicates the presence of a hazard which could result in personal injury.

The caution icon indicates important information or warning related to the concept discussed in the text. It might indicate the presence of a hazard which could result in corruption of software or damage to equipment or property.

The information icon alerts the reader of important facts and conditions.

The tip icon indicates advice on, for example, how to design your project or how to use a certain function.

Although warning hazards are related to personal injury, it is necessary to understand that under certain operational conditions, operation of damaged equipment may result in degraded process performance leading to personal injury or death. Therefore, comply fully with all warning and caution notices.

1.4.2 Document conventions

A particular convention may not be used in this manual.

- Abbreviations and acronyms are spelled out in the glossary. The glossary also contains definitions of important terms.
- Push button navigation in the LHMI menu structure is presented by using the push button icons.

  To navigate between the options, use and .
- Menu paths are presented in bold.

  Select **Main menu/Settings**.
- LHMI messages are shown in Courier font.

  To save the changes in nonvolatile memory, select `Yes` and press .
- Parameter names are shown in italics.

  The function can be enabled and disabled with the *Operation* setting.
- Parameter values are indicated with quotation marks.

  The corresponding parameter values are "Enabled" and "Disabled".
- Input/output messages and monitored data names are shown in Courier font.

  When the function picks up, the `PICKUP` output is set to TRUE.
- Dimensions are provided both in inches and mm. If it is not specifically mentioned, the dimension is in mm.
- This document assumes that the parameter setting visibility is "Advanced".

1.4.3 Functions, codes and symbols

All available functions are listed in the table. All of them may not be applicable to all products.

Table 1: Functions included in the relays

Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
Protection							
Three-phase non-directional overcurrent protection, low stage	PHLPTOC1	3I> (1)		51P-1	51P-1	51P	51P (1)
	PHLPTOC2	3I> (2)		51P-2			51P (2)
Three-phase non-directional overcurrent protection, high stage	PHHPTOC1	3I>> (1)		50P-1	50P-1	50P-1	50P-1 (1)
	PHHPTOC2	3I>> (2)		50P-2		50P-2	50P-1 (2)
Three-phase non-directional overcurrent protection, instantaneous stage	PHIPTOC1	3I>>> (1)	50P-3	50P-3	50P-3	50P-3	50P-3 (1)
	PHIPTOC2	3I>>> (2)					50P-3 (2)
Three-phase directional overcurrent protection, low stage	DPHLPDOC1	3I> -> (1)	67/51P-1	67/51P-1	67/51P-1		67/51P-1(2)
	DPHLPDOC2	3I> -> (2)	67/51P-2	67/51P-2			67/51P-2(2)
Three-phase directional overcurrent protection, high stage	DPHHPDOC1	3I>> -> (1)	67/50P-1	67/50P-1	67/50P-1		
	DPHHPDOC2	3I>> -> (2)		67/50P-2			
Three-phase voltage-dependent overcurrent protection	PHPVOC1	3I(U)> (1)			51V		
Non-directional ground-fault protection, low stage	EFLPTOC1	Io> (1)		51G		51G	

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
	EFLPTOC2	Io> (2)		51N-1			51N (2)
Non-directional ground-fault protection, high stage	EFHPTOC1	Io>> (1)	50G-1	50G-1	50G-1	50G-1	
	EFHPTOC2	Io>> (2)		50G-2		50G-2	50G-2 (2)
	EFHPTOC3	Io>> (3)		50N-1			
	EFHPTOC4	Io>> (4)		50N-2			
Non-directional ground-fault protection, instantaneous stage	EFIPTOC1	Io>>> (1)		50G-3			
	EFIPTOC2	Io>>> (2)		50N-3			
Directional ground-fault protection, low stage	DEFLPDEF1	Io> -> (1)	67/51N-1	67/51N-1	67/51N-1	67/51N	67/51N-1 (2)
	DEFLPDEF2	Io> -> (2)	67/51N-2	67/51N-2	67/51N-2		67/51N-2 (2)
Directional ground-fault protection, high stage	DEFHPDEF1	Io>> -> (1)	67/50N-1	67/50N-1	67/50N-1		
	DEFHPDEF2	Io>> -> (2)		67/50N-2			
Admittance-based ground-fault protection	EFPADM1	Yo> -> (1)	21YN-1	21YN-1			
	EFPADM2	Yo> -> (2)	21YN-2	21YN-2			
	EFPADM3	Yo> -> (3)	21YN-3	21YN-3			
Wattmetric-based ground-fault protection	WPWDE1	Po> -> (1)	32N-1	32N-1			
	WPWDE2	Po> -> (2)	32N-2	32N-2			
	WPWDE3	Po> -> (3)	32N-3	32N-3			
Transient/intermittent ground-fault protection	INTRPTEF1	Io> -> IEF (1)	67NIEF	67NIEF			
Harmonics-based ground-fault protection	HAEFPTOC1	Io>HA (1)	51NHA	51NHA			
Negative-sequence overcurrent protection	NSPTOC1	I2> (1)	46-1	46-1			46 (1)
	NSPTOC2	I2> (2)	46-2	46-2			46 (2)
Phase discontinuity protection	PDNSPTOC1	I2/I1> (1)	46PD	46PD			
Residual overvoltage protection	ROVPTOV1	Uo> (1)	59G	59G	59G	59G-1	59G (1)
	ROVPTOV2	Uo> (2)	59N-1	59N-1	59N-1	59N-1	59N (1)
	ROVPTOV3	Uo> (3)	59N-2	59N-2			59N (2)
Three-phase undervoltage protection	PHPTUV1	3U< (1)	27-1	27-1	27-1	27-1	27-1 (2)
	PHPTUV2	3U< (2)	27-2	27-2	27-2	27-2	27-2 (2)
	PHPTUV3	3U< (3)	27-3	27-3			
Three-phase overvoltage protection	PHPTOV1	3U> (1)	59-1	59-1	59-1	59-1	59-1 (2)
	PHPTOV2	3U> (2)	59-2	59-2	59-2	59-2	59-2 (2)
	PHPTOV3	3U> (3)	59-3	59-3			
Positive-sequence undervoltage protection	PSPTUV1	U1< (1)	47U-1	47U-1	47U-1	27PS	
	PSPTUV2	U1< (2)		47U-2	47U-2		
Negative-sequence overvoltage protection	NSPTOV1	U2> (1)	47-1	47-1	47-1	47-1	
	NSPTOV2	U2> (2)		47-2	47-2	47-2	
Three-phase remnant undervoltage protection	MSVPR1	3U< (1)		27R-1		27R	
	MSVPR2	3U< (2)		27R-2			
Frequency protection	FRPFRQ1	f>/f<,df/dt (1)	81-1	81-1	81-1	81-1	81-1 (2)
	FRPFRQ2	f>/f<,df/dt (2)	81-2	81-2	81-2	81-2	81-2 (2)
	FRPFRQ3	f>/f<,df/dt (3)	81-3	81-3	81-3		
	FRPFRQ4	f>/f<,df/dt (4)	81-4	81-4	81-4		
	FRPFRQ5	f>/f<,df/dt (5)		81-5	81-5		
	FRPFRQ6	f>/f<,df/dt (6)		81-6	81-6		
Overexcitation protection	OEPVPH1	U/f> (1)			24	24-1	24-1 (2)
	OEPVPH2	U/f> (2)				24-2	24-2 (2)

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
Three-phase thermal protection for feeders, cables and distribution transformers	T1PTTR1	3Ith>F (1)	49F-1	49F-1			
Three-phase thermal overload protection, two time constants	T2PTTR1	3Ith>T/G/C (1)	49T-1		49T-1		49T (1)
Negative-sequence overcurrent protection for machines	MNSPTOC1	I2>M (1)			46M-1	46M-1	
	MNSPTOC2	I2>M (2)			46M-2	46M-2	
Loss of load supervision	LOFLPTUC1	3I< (1)				37M-1	
	LOFLPTUC2	3I< (2)				37M-2	
Motor load jam protection	JAMPTOC1	Ist> (1)				51LR-1	
	JAMPTOC2	Ist> (2)				51LR-2	
Motor start-up supervision	STTPMSU1	Is2t n< (1)				66/51LRS	
Phase reversal protection	PREVPTOC1	I2>> (1)				46R	
Thermal overload protection for motors	MPTTR1	3Ith>M (1)				49M	
Binary signal transfer	BSTGGIO1	BST (1)	BST-1				
Motor differential protection	MPDIF1	3dI>M			87G-1	87M	
High-impedance differential protection for phase A	HIAPDIF1	dHi_A>(1)		87A		87A	
High-impedance differential protection for phase B	HIBPDIF1	dHi_B>(1)		87B		87B	
High-impedance differential protection for phase C	HICPDIF1	dHi_C>(1)		87C		87C	
Stabilized and instantaneous differential protection for two-winding transformers	TR2PTDF1	3dI>T (1)					87T
Numerically stabilized low-impedance restricted ground-fault protection	LREFPNDF1	dIoLo> (1)			87LOZREF		87LOZREF (2)
Circuit breaker failure protection	CCBRBRF1	3I>/Io>BF (1)	50BF-1	50BF-1	50BF-1	50BF	50BF (1)
	CCBRBRF2	3I>/Io>BF (2)		50BF-2			50BF (2)
Three-phase inrush detector	INRPHAR1	3I2f> (1)	INR-1	INR-1	INR-1		
Switch onto fault	CBPSOF1	SOTF (1)	SOTF-1	SOTF-1			
Master trip	TRPPTRC1	Master Trip (1)	86/94-1	86/94-1	86/94-1	86/94-1	86/94-1
	TRPPTRC2	Master Trip (2)	86/94-2	86/94-2	86/94-2	86/94-2	86/94-2
	TRPPTRC3	Master Trip (3)		86/94-3	86/94-3	86/94-3	86/94-3
	TRPPTRC4	Master Trip (4)		86/94-4	86/94-4	86/94-4	86/94-4
	TRPPTRC5	Master Trip (5)		86/94-5	86/94-5	86/94-5	86/94-5
	TRPPTRC6	Master Trip (6)			86/94-6		
Arc protection	ARCSARC1	ARC (1)		AFD-1	AFD-1	AFD-1	AFD-1 (2)
	ARCSARC2	ARC (2)		AFD-2	AFD-2	AFD-2	AFD-2 (2)
	ARCSARC3	ARC (3)		AFD-3	AFD-3	AFD-3	AFD-3 (2)
Multipurpose protection	MAPGAPC1	MAP (1)	MAP-1	MAP-1	MAP-1	MAP-1	MAP-1
	MAPGAPC2	MAP (2)	MAP-2	MAP-2	MAP-2	MAP-2	MAP-2
	MAPGAPC3	MAP (3)	MAP-3	MAP-3	MAP-3	MAP-3	MAP-3

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Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
	MAPGAPC4	MAP (4)	MAP-4	MAP-4	MAP-4	MAP-4	MAP-4
	MAPGAPC5	MAP (5)	MAP-5	MAP-5	MAP-5	MAP-5	MAP-5
	MAPGAPC6	MAP (6)	MAP-6	MAP-6	MAP-6	MAP-6	MAP-6
	MAPGAPC7	MAP (7)	MAP-7	MAP-7	MAP-7	MAP-7	MAP-7
	MAPGAPC8	MAP (8)	MAP-8	MAP-8	MAP-8	MAP-8	MAP-8
	MAPGAPC9	MAP (9)	MAP-9	MAP-9	MAP-9	MAP-9	MAP-9
	MAPGAPC10	MAP (10)	MAP-10	MAP-10	MAP-10	MAP-10	MAP-10
	MAPGAPC11	MAP (11)	MAP-11	MAP-11	MAP-11	MAP-11	MAP-11
	MAPGAPC12	MAP (12)	MAP-12	MAP-12	MAP-12	MAP-12	MAP-12
	MAPGAPC13	MAP (13)	MAP-13	MAP-13	MAP-13	MAP-13	MAP-13
	MAPGAPC14	MAP (14)	MAP-14	MAP-14	MAP-14	MAP-14	MAP-14
	MAPGAPC15	MAP (15)	MAP-15	MAP-15	MAP-15	MAP-15	MAP-15
	MAPGAPC16	MAP (16)	MAP-16	MAP-16	MAP-16	MAP-16	MAP-16
	MAPGAPC17	MAP (17)	MAP-17	MAP-17	MAP-17	MAP-17	MAP-17
	MAPGAPC18	MAP (18)	MAP-18	MAP-18	MAP-18	MAP-18	MAP-18
Fault locator	SCEFRFLO1	FLOC (1)	21FL-1	21FL-1			
Loss of phase	PHPTUC1	3I< (1)		37-1			
Line differential protection with in-zone power transformer	LNPLDF1	3Id/I> (1)	87L-1				
High-impedance fault detection	PHIZ1	HIF (1)	HIZ-1	HIZ-1			
Third harmonic-based stator ground-fault protection	H3EFPSEF1	dUo>/Uo3H (1)			27/59THN		
Underpower protection	DUPPDPR1	P< (1)		32U-1	32U-1	32U-1	
	DUPPDPR2	P< (2)		32U-2	32U-2	32U-2	
Reverse power/directional overpower protection	DOPPDPR1	P>/Q> (1)		32R/32O-1	32R-32	32O-1	
	DOPPDPR2	P>/Q> (2)		32R/32O-2	32R-32	32O-2	
	DOPPDPR3	P>/Q> (3)			32R-32	32O-3	
Three-phase underexcitation protection	UEXPDIS1	X< (1)			40-1		
Three-phase underimpedance protection	UZPDIS1	Z<G (1)			21G-1		
Out-of-step protection	OOSRPSB1	OOS (1)			78-1		
Multifrequency admittance-based ground-fault protection	MFADPSDE1	Io> ->Y (1)		67YN-1			
Interconnection functions							
Directional reactive power undervoltage protection	DQPTUV1	Q> ->,3U< (1)		32Q-27			
Low-voltage ride-through protection	LVRTPTUV1	U<RT (1)		27RT-1			
	LVRTPTUV2	U<RT (2)		27RT-2			
	LVRTPTUV3	U<RT (3)		27RT-3			
Voltage vector shift protection	VVSPPAM1	VS (1)		78V-1			
Power quality							
Current total demand distortion	CMHAI1	PQM3I (1)	PQI-1	PQI-1	PQI-1		
	CMHAI2	PQM3I(B)					

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Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
Voltage total harmonic distortion	VMHAI1	PQM3U (1)	PQVPH-1	PQVPH-1	PQVPH-1		
	VMHAI2	PQM3U(B)		PQVPH-2			
Voltage variation	PHQVVR1	PQMU (1)	PQSS-1	PQSS-1	PQSS-1		
	PHQVVR2	PQ 3U<>(B)		PQSS-2			
Voltage unbalance	VSQVUB1	PQUUB (1)	PQVUB-1	PQVUB-1	PQVUB-1		
Control							
Circuit-breaker control	CBXCBR1	I <-> O CB (1)	52-1	52-1	52-1	52	52 (1)
	CBXCBR2	I <-> O CB (2)		52-2			52 (2)
Disconnector control	DCXSWI1	I <-> O DCC (1)	29DS-1	29DS-1	29DS-1	29DS-1	29DS-1
	DCXSWI2	I <-> O DCC (2)	29DS-2	29DS-2	29DS-2	29DS-2	29DS-2
Grounding switch control	ESXSWI1	I <-> O ESC (1)	29GS-1	29GS-1	29GS-1	29GS-1	29GS-1
Disconnector position indication	DCSXSWI1	I <-> O DC (1)	52-TOC	52-TOC	52-TOC	52-TOC	52-TOC
	DCSXSWI2	I <-> O DC (2)	29DS-1	29DS-1	29DS-1	29DS-1	29DS-1
	DCSXSWI3	I <-> O DC (3)	29DS-2	29DS-2	29DS-2	29DS-2	29DS-2
Grounding switch indication	ESSXSWI1	I <-> O ES (1)	29GS-1	29GS-1	29GS-1	29GS-1	29GS-1
	ESSXSWI2	I <-> O ES (2)	29GS-2	29GS-2	29GS-2	29GS-2	29GS-2
Emergency startup	ESMGAPC1	ESTART (1)				62EST	
Autoreclosing	DARREC1	O -> I (1)	79	79			
Tap changer position indication	TPOSYLTC1	TPOSM (1)					84T
Synchronism and energizing check	SECRSYN1	SYNC (1)	25	25	25		25 (2)
Condition monitoring							
Circuit-breaker condition monitoring	SSCBR1	CBCM (1)	52CM-1	52CM-1	52CM-1	52CM	52CM (1)
	SSCBR2	CBCM (2)		52CM-2			52CM (2)
Trip circuit supervision	TCSSCBR1	TCS (1)	TCM-1	TCM-1	TCM-1	TCM-1	TCM-1
	TCSSCBR2	TCS (2)	TCM-2	TCM-2	TCM-2	TCM-2	TCM-2
Current circuit supervision	CCSPVC1	MCS 3I (1)	CCM	CCM		CCM	
Current transformer supervision for high-impedance protection scheme for phase A	HZCCASPVC1	MCS I_A(1)		MCS-A			
Current transformer supervision for high-impedance protection scheme for phase B	HZCCBSPVC1	MCS I_B(1)		MCS-B			
Current transformer supervision for high-impedance protection scheme for phase C	HZCCCSPVC1	MCS I_C(1)		MCS-C			
Fuse failure supervision	SEQSPVC1	FUSEF (1)	60-1	60-1	60-1	60	60 (1)
	SEQSPVC2	FUSEF (2)		60-2			
Protection communication supervision	PCSITPC1	PCS (1)	PCS-1				
Runtime counter for machines and devices	MDSOPT1	OPTS (1)	OPTM-1	OPTM-1	OPTM-1	OPTM-1	OPTM-1
Measurement							
Load profile record	LDPRLRC1	LOADPROF (1)	LoadProf	LoadProf	LoadProf	LoadProf	LoadProf
Three-phase current measurement	CMMXU1	3I (1)	IA, IB, IC	IA, IB, IC	IA, IB, IC	IA, IB, IC	IA, IB, IC (1)
	CMMXU2	3I (2)			IA, IB, IC (2)	IA, IB, IC (2)	IA, IB, IC (2)
Sequence current measurement	CSMSQI1	I1, I2, I0 (1)	I1, I2, I0	I1, I2, I0	I1, I2, I0	I1, I2, I0	I1, I2, I0 (1)

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Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
Residual current measurement	RESCMMXU1	Io (1)	IG	IG	IG	IG	
	RESCMMXU2	Io (2)					IG (2)
Three-phase voltage measurement	VMMXU1	3U (1)	VA, VB, VC	VA, VB, VC	VA, VB, VC	VA, VB, VC	VA, VB, VC (2)
	VMMXU2	3U (2)	VA, VB, VC (2)	VA, VB, VC (2)	VA, VB, VC (2)		
Residual voltage measurement	RESVMMXU1	Uo (1)	VG-1	VG	VG-1	VG	VG (2)
	RESVMMXU2	Uo (2)			VG-2		
Sequence voltage measurement	VSMSQI1	U1, U2, U0 (1)	V1, V2, V0	V1, V2, V0	V1, V2, V0	V1, V2, V0	V1, V2, V0 (2)
	VSMSQI2	U1, U2, U0(B)		V1, V2, V0 (2)			
Single-phase power and energy measurement	SPEMMXU1	SP, SE	SP, SE-1	SP, SE-1	SP, SE-1	SP, SE-1	SP, SE (2)
Three-phase power and energy measurement	PEMMXU1	P, E (1)	P, E-1	P, E-1	P, E-1	P, E-1	P, E (2)
RTD/mA measurement	XRGGIO130	X130 (RTD) (1)	X130 (RTD) (1)	X130 (RTD) (1)	X130 (RTD) (1)	X130 (RTD) (1)	X130 (RTD) (1)
Frequency measurement	FMMXU1	f (1)	f	f	f	f	f
IEC 61850-9-2 LE sampled value sending	SMVSENDER	SMVSENDER	SMVSENDER	SMVSENDER	SMVSENDER	SMVSENDER	SMVSENDER
IEC 61850-9-2 LE sampled value receiving (voltage sharing)	SMVRECEIVER	SMVRECEIVER	SMVRECEIVER	SMVRECEIVER	SMVRECEIVER	SMVRECEIVER	SMVRECEIVER
Other							
Minimum pulse timer (2 pcs)	TPGAPC1	TP (1)	62TP-1	62TP-1	62TP-1	62TP-1	62TP-1
	TPGAPC2	TP (2)	62TP-2	62TP-2	62TP-2	62TP-2	62TP-2
	TPGAPC3	TP (3)	62TP-3	62TP-3	62TP-3	62TP-3	62TP-3
	TPGAPC4	TP (4)	62TP-4	62TP-4	62TP-4	62TP-4	62TP-4
Minimum pulse timer (2 pcs, second resolution)	TPSGAPC1	TPS (1)	62TPS-1	62TPS-1	62TPS-1	62TPS-1	62TPS-1
Minimum pulse timer (2 pcs, minute resolution)	TPMGAPC1	TPM (1)	62TPM-1	62TPM-1	62TPM-1	62TPM-1	62TPM-1
Pulse timer (8 pcs)	PTGAPC1	PT (1)	62PT-1	62PT-1	62PT-1	62PT-1	62PT-1
	PTGAPC2	PT (2)	62PT-2	62PT-2	62PT-2	62PT-2	62PT-2
Time delay off (8 pcs)	TOFGAPC1	TOF (1)	62TOF-1	62TOF-1	62TOF-1	62TOF-1	62TOF-1
	TOFGAPC2	TOF (2)	62TOF-2	62TOF-2	62TOF-2	62TOF-2	62TOF-2
	TOFGAPC3	TOF (3)	62TOF-3	62TOF-3	62TOF-3	62TOF-3	62TOF-3
	TOFGAPC4	TOF (4)	62TOF-4	62TOF-4	62TOF-4	62TOF-4	62TOF-4
Time delay on (8 pcs)	TONGAPC1	TON (1)	62TON-1	62TON-1	62TON-1	62TON-1	62TON-1
	TONGAPC2	TON (2)	62TON-2	62TON-2	62TON-2	62TON-2	62TON-2
	TONGAPC3	TON (3)	62TON-3	62TON-3	62TON-3	62TON-3	62TON-3
	TONGAPC4	TON (4)	62TON-4	62TON-4	62TON-4	62TON-4	62TON-4
Set-reset (8 pcs)	SRGAPC1	SR (1)	SR-1	SR-1	SR-1	SR-1	SR-1
	SRGAPC2	SR (2)	SR-2	SR-2	SR-2	SR-2	SR-2
	SRGAPC3	SR (3)	SR-3	SR-3	SR-3	SR-3	SR-3
	SRGAPC4	SR (4)	SR-4	SR-4	SR-4	SR-4	SR-4
Move (8 pcs)	MVGAPC1	MV (1)	MV-1	MV-1	MV-1	MV-1	MV-1
	MVGAPC2	MV (2)	MV-2	MV-2	MV-2	MV-2	MV-2
Generic control point (16 pcs)	SPCGAPC1	SPC (1)	SPC-1	SPC-1	SPC-1	SPC-1	SPC-1
	SPCGAPC2	SPC (2)	SPC-2	SPC-2	SPC-2	SPC-2	SPC-2
Analog value scaling	SCA4GAPC1	SCA4 (1)	SCA4-1	SCA4-1	SCA4-1	SCA4-1	SCA4-1
	SCA4GAPC2	SCA4 (2)	SCA4-2	SCA4-2	SCA4-2	SCA4-2	SCA4-2
	SCA4GAPC3	SCA4 (3)	SCA4-3	SCA4-3	SCA4-3	SCA4-3	SCA4-3
	SCA4GAPC4	SCA4 (4)	SCA4-4	SCA4-4	SCA4-4	SCA4-4	SCA4-4

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI/C37.2-2008				
			RED615	REF615	REG615	REM615	RET615
Integer value move	MVI4GAPC1	MVI4 (1)	MVI4-1	MVI4-1	MVI4-1	MVI4-1	MVI4-1
Generic up-down counters	UDFCNT1	UDCNT (1)	CTR-1	CTR-1	CTR-1	CTR-1	CTR-1
	UDFCNT2	UDCNT (2)	CTR-2	CTR-2	CTR-2	CTR-2	CTR-2
	UDFCNT3	UDCNT (3)	CTR-3	CTR-3	CTR-3	CTR-3	CTR-3
	UDFCNT4	UDCNT (4)	CTR-4	CTR-4	CTR-4	CTR-4	CTR-4

Section 2 615 series overview

2.1 Overview

615 series is a product family of relays designed for protection, control, measurement and supervision of utility substations and industrial switchgear and equipment. The design of the relay has been guided by the IEC 61850 standard for communication and interoperability of substation automation devices.

The relays feature a draw-out-type design with a variety of mounting methods, compact size and ease of use. Depending on the product, optional functionality is available at the time of order for both software and hardware, for example, autoreclosing and additional I/Os.

The 615 series relays support a range of communication protocols including IEC 61850 with Edition 2 support, process bus according to IEC 61850-9-2 LE, Modbus® and DNP3.

2.1.1 Product series version history

Product series version	Product series history
1.0.1	First product from 615 series REF615 released
1.1	• Circuit breaker condition monitoring • Replaced EFIPTOC3 with EFLPTOC3 • New communication modules COMB11A, COMB12A, COMB13A and COMB14A • IRIG-B • CB interlocking functionality enhanced • TCS functionality in HW enhanced • Non-volatile memory added • Serial communications
2.0	New products: • REM615 • RET615 Platform enhancements • Support for DNP3 serial or TCP/IP • Voltage measurement and protection • Power and energy measurement • Disturbance recorder upload via WHMI • Fuse failure supervision
Table continues on next page	

Product series version	Product series history
4.0	• User programming through Application Configuration tool • Frequency measurement protection • Load shedding and restoration • Single phase power and energy measurement • Load profile recorder
4.2	• HSR/PRP functionality • 320 and 32U over- and underpower protection • 27R remnant undervoltage protection • High-impedance differential protection
5.0 FP1	New products: • RED615 • REG615 New standard configurations: • RED615: D and E • REF615: D, F, L, N and P • REG615: C and D • REM615: A, B, D, E • RET615: B and F Platform enhancements • Support for IEC 61850-9-2 LE • IEEE 1588 v2 time synchronization • Fault locator • Line differential protection with in-zone transformer • Load profile recorder • High-speed binary outputs • Profibus adapter support • Support for multiple SLD pages • Import/export of settings via WHMI • Setting usability improvements • HMI event filtering tool • IEC 61850 Edition 2 • Currents sending support with IEC 61850-9-2 LE • Support for synchronism and energizing check with IEC 61850-9-2 LE • Software closable Ethernet ports • Report summary via WHMI • Multifrequency admittance-based ground-fault protection • Support for high-impedance differential protection • Voltage unbalance power quality option • Additional timer, set-reset and analog value scaling functions

2.1.2 PCM600 and relay connectivity package version

- Protection and Control IED Manager PCM600 2.8 or later
- RED615 Connectivity Package Ver.5.1 or later
- REF615 Connectivity Package Ver.5.1 or later

- REG615 Connectivity Package Ver.5.1 or later
- REM615 Connectivity Package Ver.5.1 or later
- RET615 Connectivity Package Ver.5.1 or later

Download connectivity packages from the ABB Web site http://www.abb.com/substationautomation or directly with Update Manager in PCM600.

2.2 Local HMI

The LHMI is used for setting, monitoring and controlling the protection relay. The LHMI comprises the display, buttons, LED indicators and communication port.

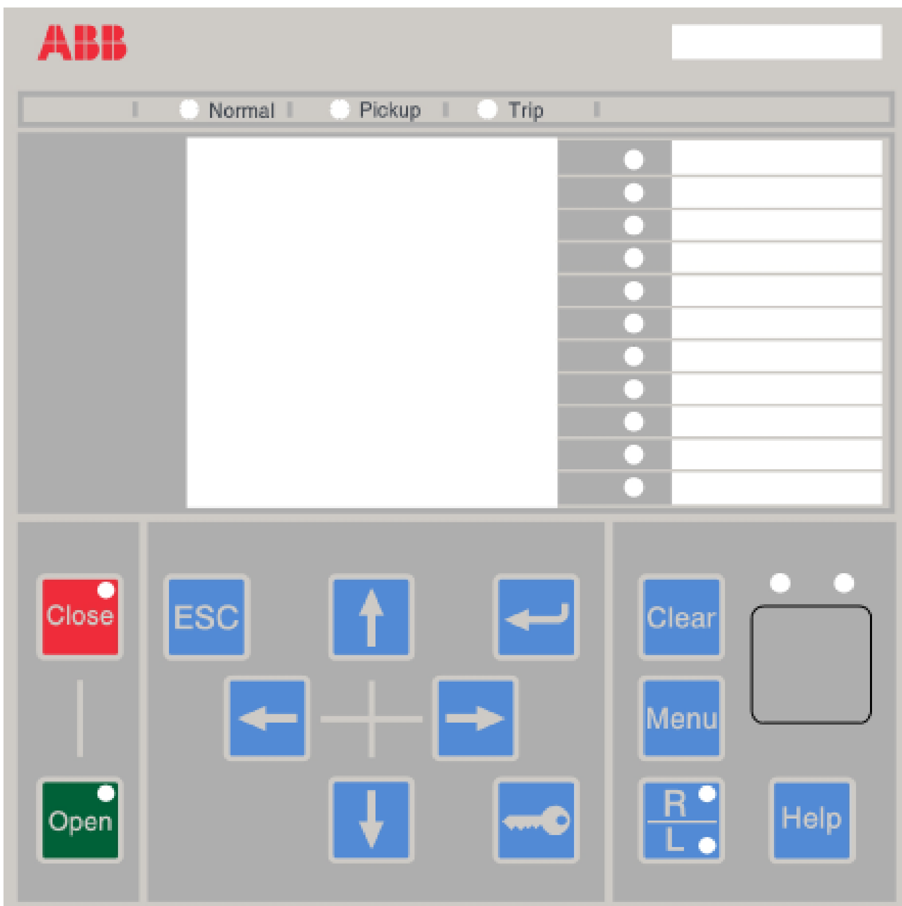


Figure 2: Example of the LHMI

2.2.1 Display

The LHMI includes a graphical display that supports one character size. The character size depends on the selected language. The amount of characters and rows fitting the view depends on the character size.

Table 2: Large display

Character size[1)]	Rows in the view	Characters per row
Small, mono-spaced (6 × 12 pixels)	10	20

1) Depending on the selected language

The display view is divided into four basic areas.

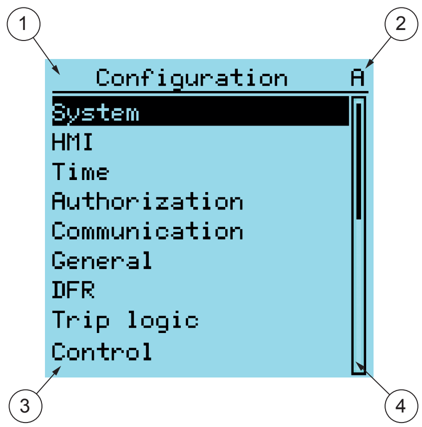


Figure 3: Display layout

1 Header

2 Icon

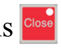
3 Content

4 Scroll bar (displayed when needed)

2.2.2 LEDs

The LHMI includes three protection indicators above the display: Normal, Pickup and Trip.

There are 11 matrix programmable LEDs on front of the LHMI. The LEDs can be configured with PCM600 and the operation mode can be selected with the LHMI, WHMI or PCM600.

There are two additional LEDs which are embedded into the control buttons  and . They represent the status of breaker 1 (CBXCBR1).

2.2.3 Keypad

The LHMI keypad contains push buttons which are used to navigate in different views or menus. With the push buttons you can give open or close commands to objects in the primary circuit, for example, a circuit breaker, a contactor or a disconnector. The push buttons are also used to acknowledge alarms, reset indications, provide help and switch between local and remote control mode.

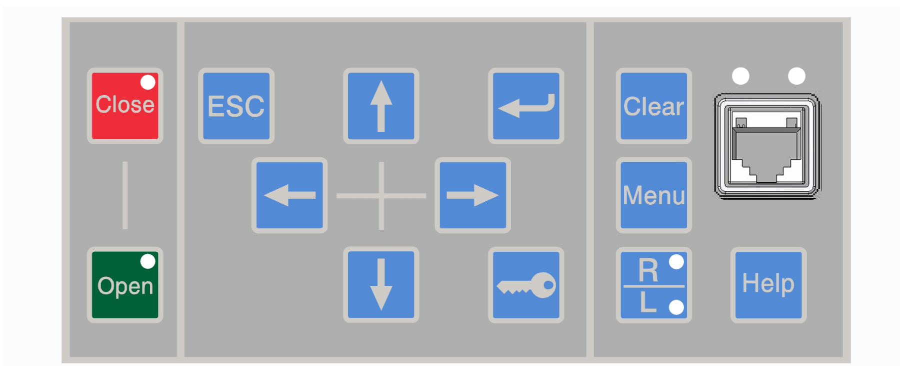


Figure 4: LHMI keypad with object control, navigation and command push buttons and RJ-45 communication port

2.3 Web HMI

The WHMI allows secure access to the protection relay via a Web browser. The supported Web browser versions are Internet Explorer 9.0, 10.0 and 11.0. When the *Secure Communication* parameter in the protection relay is activated, the Web server is forced to take a secured (HTTPS) connection to WHMI using TLS encryption.The WHMI is verified with Internet Explorer 11.0.

WHMI is disabled by default.WHMI is enabled by default.

WHMI offers several functions.

- Programmable LEDs and event lists
- System supervision
- Parameter settings
- Measurement display
- DFR records
- Fault records
- Load profile record
- Phasor diagram
- Single-line diagram
- Importing/Exporting parameters
- Report summary

The menu tree structure on the WHMI is almost identical to the one on the LHMI.

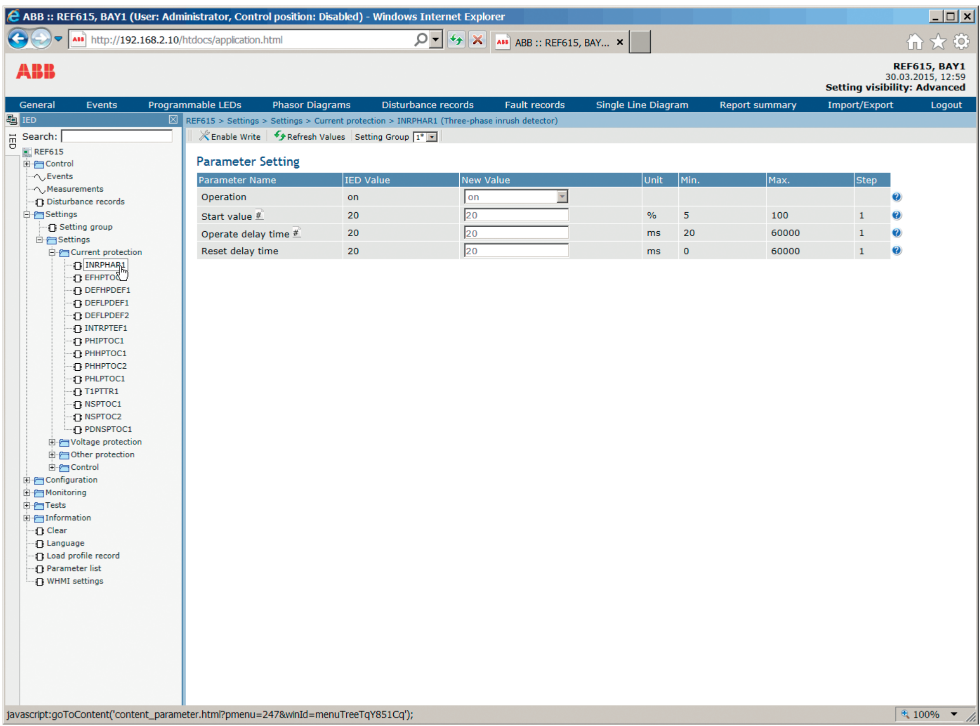


Figure 5: Example view of the WHMI

The WHMI can be accessed locally and remotely.

- Locally by connecting the laptop to the protection relay via the front communication port.
- Remotely over LAN/WAN.

2.4 Authorization

Four user categories have been predefined for the LHMI and the WHMI, each with different rights and default passwords.

The default passwords in the protection relay delivered from the factory can be changed with Administrator user rights.

User authorization is disabled by default for LHMI but WHMI always uses authorization.

Table 3: Predefined user categories

Username	User rights
VIEWER	Read only access
OPERATOR	• Selecting remote or local state with (only locally) • Changing setting groups • Controlling • Clearing indications
ENGINEER	• Changing settings • Clearing event list • Clearing DFRs and load profile record • Changing system settings such as IP address, serial baud rate or DFR settings • Setting the protection relay to test mode • Selecting language
ADMINISTRATOR	• All listed above • Changing password • Factory default activation

For user authorization for PCM600, see PCM600 documentation.

2.5 Communication

The protection relay supports a range of communication protocols including IEC 61850, IEC 61850-9-2 LE, Modbus® and DNP3. Operational information and controls are available through these protocols. However, some communication functionality, for example, horizontal communication between the protection relays, is only enabled by the IEC 61850 communication protocol.

The protection relay utilizes Ethernet communication extensively for different purposes. The exact services depend on the ordered product variant and enabled functionality. HSR/PRP is available in 615 series Ver.5.0 FP1 ANSI.

HSR/PRP availability depends on the product ordering information. See the Rear communication modules chapter for information on HSR/PRP supported COM cards.

Table 4: TCP and UDP ports used for different services

Service	Port
File Transfer Protocol (FTP and FTPS)	20, 21
IEC 61850	102
Web Server HTTP	80
Web Server HTTPS	443
Simple Network Time Protocol (SNTP)	123
Modbus TCP	502
DNP TCP	20000

The IEC 61850 communication implementation supports all monitoring and control functions. Additionally, parameter setting and DFR records can be accessed using the IEC 61850 protocol. Oscillographic files are available to any Ethernet-based application in the standard COMTRADE format. The protection relay can send and receive binary signals from other devices (so-called horizontal communication) using the IEC 61850-8-1 GOOSE profile, where the highest performance class with a total transmission time of 3 ms is supported. Furthermore, the protection relay supports sending and receiving of analog values using GOOSE messaging. The protection relay meets the GOOSE performance requirements for tripping applications in distribution substations, as defined by the IEC 61850 standard. The protection relay can simultaneously report events to five different clients on the station bus.

The protection relay can support five simultaneous clients. If PCM600 reserves one client connection, only four client connections are left, for example, for IEC 61850 and Modbus.

All communication connectors, except for the front port connector, are placed on integrated optional communication modules. The protection relay can be connected to Ethernet-based communication systems via the RJ-45 connector (100Base-TX) or the fiber optic LC connector (100Base-FX).

2.5.1 Self-healing Ethernet ring

For the correct operation of self-healing loop topology, it is essential that the external switches in the network support the RSTP protocol and that it is enabled in the switches. Otherwise, connecting the loop topology can cause problems to the network. The protection relay itself does not support link-down detection or RSTP. The ring recovery process is based on the aging of the MAC addresses, and the link-up/link-down events can cause temporary breaks in communication. For a better performance of the self-healing loop, it is recommended that the external switch furthest from the protection relay loop is assigned as the root switch (bridge priority = 0) and the bridge priority increases towards the protection relay loop. The end links of the protection relay loop can be attached to the same external switch or to two adjacent external switches. A self-healing Ethernet ring requires a communication module with at least two Ethernet interfaces for all protection relays.

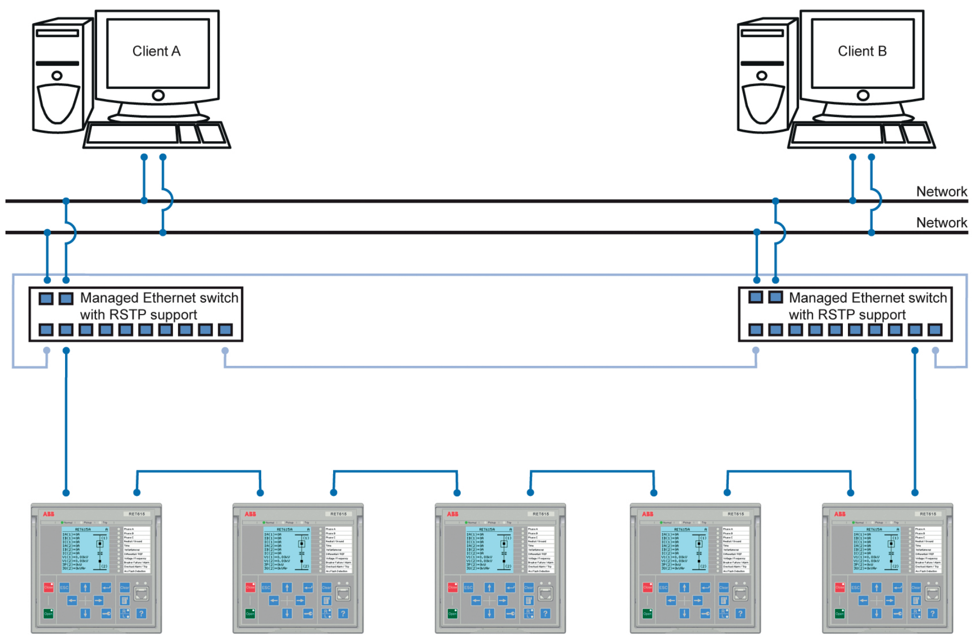


Figure 6: Self-healing Ethernet ring solution

The Ethernet ring solution supports the connection of up to 30 protection relays. If more than 30 protection relays are to be connected, it is recommended that the network is split into several rings with no more than 30 protection relays per ring. Each protection relay has a 50-µs store-and-forward delay, and to fulfil the performance requirements for fast horizontal communication, the ring size is limited to 30 protection relays.

2.5.2 Ethernet redundancy

IEC 61850 specifies a network redundancy scheme that improves the system availability for substation communication. It is based on two complementary protocols defined in the IEC 62439-3:2012 standard: parallel redundancy protocol PRP and high-availability seamless redundancy HSR protocol. Both protocols rely on the duplication of all transmitted information via two Ethernet ports for one logical network connection. Therefore, both are able to overcome the failure of a link or switch with a zero-switchover time, thus fulfilling the stringent real-time requirements for the substation automation horizontal communication and time synchronization.

PRP specifies that each device is connected in parallel to two local area networks. HSR applies the PRP principle to rings and to the rings of rings to achieve cost-effective redundancy. Thus, each device incorporates a switch element that forwards frames from port to port. The HSR/PRP option is available for all 615 series protection relays. However, RED615 supports this option only over fiber optics.

IEC 62439-3:2012 cancels and replaces the first edition published in 2010. These standard versions are also referred to as IEC 62439-3 Edition 1 and IEC 62439-3 Edition 2. The protection relay supports IEC 62439-3:2012 and it is not compatible with IEC 62439-3:2010.

PRP

Each PRP node, called a double attached node with PRP (DAN), is attached to two independent LANs operated in parallel. These parallel networks in PRP are called LAN A and LAN B. The networks are completely separated to ensure failure independence, and they can have different topologies. Both networks operate in parallel, thus providing zero-time recovery and continuous checking of redundancy to avoid communication failures. Non-PRP nodes, called single attached nodes (SANs), are either attached to one network only (and can therefore communicate only with DANs and SANs attached to the same network), or are attached through a redundancy box, a device that behaves like a DAN.

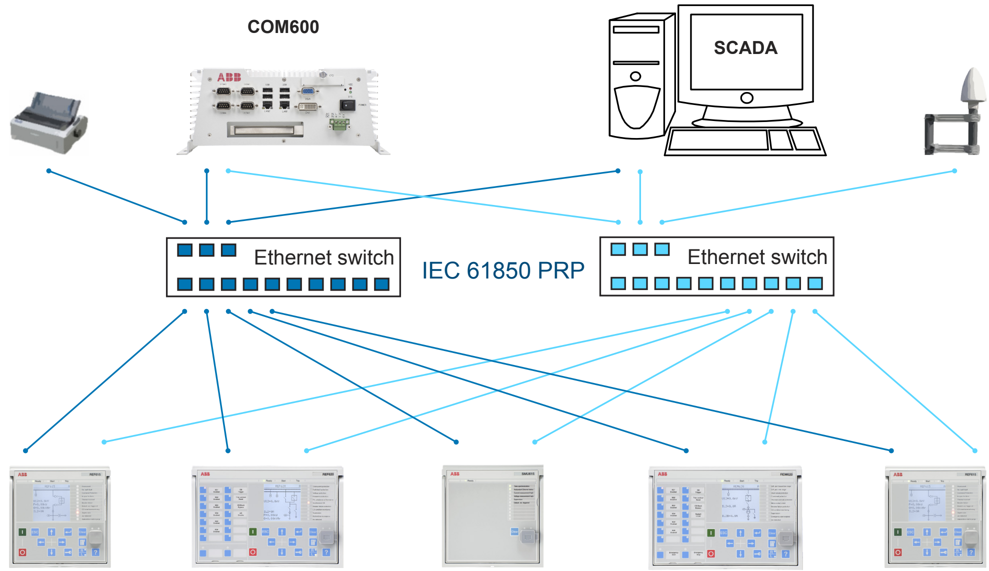


Figure 7: PRP solution

In case a laptop or a PC workstation is connected as a non-PRP node to one of the PRP networks, LAN A or LAN B, it is recommended to use a redundancy box device or an Ethernet switch with similar functionality between the PRP network and SAN to remove additional PRP information from the Ethernet frames. In some cases, default PC workstation adapters are not able to handle the maximum-length Ethernet frames with the PRP trailer.

There are different alternative ways to connect a laptop or a workstation as SAN to a PRP network.

- Via an external redundancy box (RedBox) or a switch capable of connecting to PRP and normal networks
- By connecting the node directly to LAN A or LAN B as SAN
- By connecting the node to the protection relay's interlink port

HSR

HSR applies the PRP principle of parallel operation to a single ring, treating the two directions as two virtual LANs. For each frame sent, a node, DAN, sends two frames, one over each port. Both frames circulate in opposite directions over the ring and each node forwards the frames it receives, from one port to the other. When the originating node receives a frame sent to itself, it discards that to avoid loops; therefore, no ring protocol is needed. Individually attached nodes, SANs, such as laptops and printers, must be attached through a “redundancy box” that acts as a ring element. For example, a 615 or 620 series protection relay with HSR support can be used as a redundancy box.

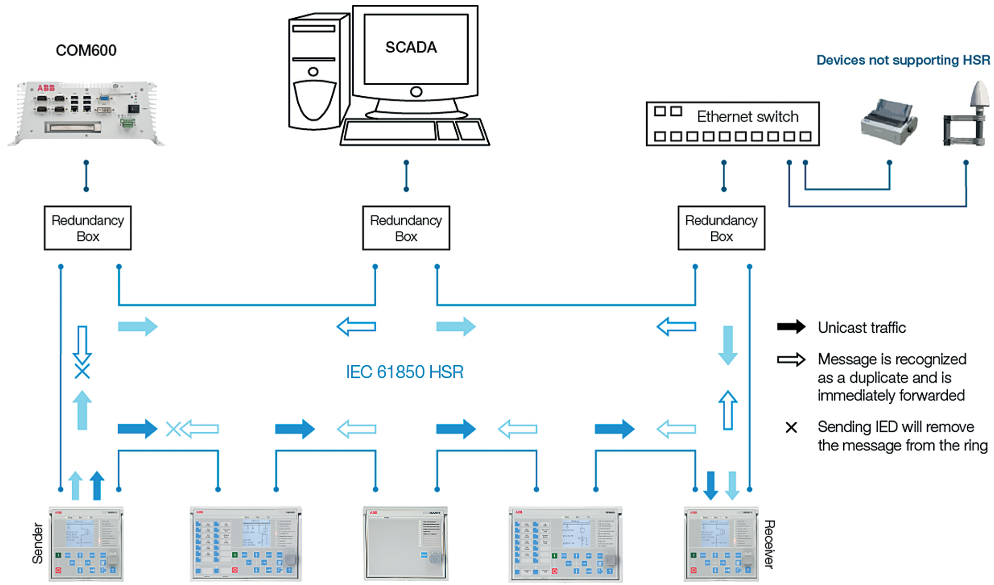


Figure 8: HSR solution

Section 3 Basic functions

3.1 General parameters

Table 5: Analog input settings, phase currents

Parameter	Values (Range)	Unit	Step	Default	Description
Primary current	1.0...6000.0	A	0.1	100.0	Rated primary current
Secondary current	2=1A 3=5A			2=1A	Rated secondary current
Amplitude corr. A	0.9000...1.1000		0.0001	1.0000	Phase A amplitude correction factor
Amplitude corr. B	0.9000...1.1000		0.0001	1.0000	Phase B amplitude correction factor
Amplitude corr. C	0.9000...1.1000		0.0001	1.0000	Phase C amplitude correction factor
Nominal Current[1)]	39...4000	A	1	1300	Network Nominal Current (In)
Rated secondary Val[1)]	1.000...150.000	mV/Hz	0.001	3.000	Rated Secondary Value (RSV) ratio
Reverse polarity	0=False 1=True			0=False	Reverse the polarity of the phase CTs
Angle Corr A	-20.0000...20.0000	deg	0.0001	0.0000	Phase A angle correction factor
Angle Corr B	-20.0000...20.0000	deg	0.0001	0.0000	Phase B angle correction factor
Angle Corr C	-20.0000...20.0000	deg	0.0001	0.0000	Phase C angle correction factor

1) Available for sensor analog inputs only

Table 6: Analog input settings, residual current

Parameter	Values (Range)	Unit	Step	Default	Description
Primary current	1.0...6000.0	A	0.1	100.0	Primary current
Secondary current	1=0.2A 2=1A 3=5A			2=1A	Secondary current
Amplitude corr.	0.9000...1.1000		0.0001	1.0000	Amplitude correction
Reverse polarity	0=False 1=True			0=False	Reverse the polarity of the residual CT
Angle correction	-20.0000...20.0000	deg	0.0001	0.0000	Angle correction factor

Table 7: Analog input settings, phase voltages

Parameter	Values (Range)	Unit	Step	Default	Description
Primary voltage	0.100...440.000	kV	0.001	20.000	Primary rated voltage
Secondary voltage	60...210	V	1	100	Secondary rated voltage
VT connection	1=Wye 2=Delta 3=VAB 4=VA			2=Delta	Voltage transducer measurement connection
Amplitude corr. A	0.9000...1.1000		0.0001	1.0000	Phase A Voltage phasor magnitude correction of an external voltage transformer
Amplitude corr. B	0.9000...1.1000		0.0001	1.0000	Phase B Voltage phasor magnitude correction of an external voltage transformer
Amplitude corr. C	0.9000...1.1000		0.0001	1.0000	Phase C Voltage phasor magnitude correction of an external voltage transformer
Division ratio	1000...20000		1	10000	Voltage sensor division ratio
Voltage input type	1=Voltage trafo 3=CVD sensor			1=Voltage trafo	Type of the voltage input
Angle Corr A	-20.0000...20.0000	deg	0.0001	0.0000	Phase A Voltage phasor angle correction of an external voltage transformer
Angle Corr B	-20.0000...20.0000	deg	0.0001	0.0000	Phase B Voltage phasor angle correction of an external voltage transformer
Angle Corr C	-20.0000...20.0000	deg	0.0001	0.0000	Phase C Voltage phasor angle correction of an external voltage transformer

Table 8: Analog input settings, residual voltage

Parameter	Values (Range)	Unit	Step	Default	Description
Primary voltage	0.100...440.000[1)]	kV	0.001	11.547	Primary voltage
Secondary voltage	60...210	V	1	100	Secondary voltage
Amplitude corr.	0.9000...1.1000		0.0001	1.0000	Amplitude correction
Angle correction	-20.0000...20.0000	deg	0.0001	0.0000	Angle correction factor

1) In 9-2 applications, Primary voltage maximum is limited to 126 kV.

Table 9: Authorization settings

Parameter	Values (Range)	Unit	Step	Default	Description
Remote Update	0=Disable 1=Enable			0=Disable	Remote update
Secure Communication	0=False 1=True			1=True	Secure Communication
Authority logging	1=None 2=Configuration change 3=Setting group 4=Setting group, control 5=Settings edit 6=All			1=None	Authority logging level
Remote override	0=False[1)] 1=True[2)]			1=True	Disable authority
Remote viewer (9-20 chars)				0	Set password (9-20 chars)
Remote operator (9-20 chars)				0	Set password (9-20 chars)
Remote engineer (9-20 chars)				0	Set password (9-20 chars)
Remote admin (9-20 chars)				0	Set password (9-20 chars)
Local override	0=False[3)] 1=True[4)]			1=True	Disable authority
Local viewer (4-8 chars)				0	Set password (4-8 chars)
Local operator (4-8 chars)				0	Set password (4-8 chars)
Local engineer (4-8 chars)				0	Set password (4-8 chars)
Local admin (4-8 chars)				0	Set password (4-8 chars)

1) Authorization override disabled, communication tools ask password to enter the protection relay
2) Authorization override enabled, communication tools do not need password to enter the protection relay, except for WHMI which always requires it
3) Authorization override disabled, LHMI password must be entered
4) Authorization override enabled, LHMI password is not asked

Table 10: Binary input settings

Parameter	Values (Range)	Unit	Step	Default	Description
Threshold voltage	16...176	Vdc	2	16	Digital input threshold voltage
Input osc. level	2...50	events/s	1	30	Digital input oscillation suppression threshold
Input osc. hyst	2...50	events/s	1	10	Digital input oscillation suppression hysteresis

Adjust the binary input threshold voltage correctly. The threshold voltage should be comparable to the nominal value instead of the default minimum value. The factory default is 16 V to ensure the binary inputs' operation regardless of the auxiliary voltage used (24, 48, 60, 110, 125, 220 or 250 V DC). However, the default value is not optimal for the higher auxiliary voltages. The binary input threshold voltage should be set as high as possible to prevent any inadvertent activation of the binary inputs due to possible external disturbances. At the same time, the threshold should be set so that the correct operation is not jeopardized in case of undervoltage of the auxiliary voltage.

Table 11: Binary input signals in card location Xnnn

Name	Type	Description
Xnnn-Input m [1)2)]	BOOLEAN	See the application manual for standard configuration specific terminal connections

1) Xnnn = Slot ID, for example, X100, X110, as applicable
2) m =For example, 1, 2, depending on the serial number of the binary input in a particular BIO or AIM card

Table 12: Binary output signals in card location Xnnn

Name	Type	Default	Description
Xnnn-Pmm[1)2)]	BOOLEAN	0=False	See the application manual for standard configuration specific terminal connections

1) Xnnn = Slot ID, for example, X100, X110, as applicable
2) Pmm = For example, PO1, PO2, SO1, SO2, as applicable

Table 13: Binary input settings in card location Xnnn

Name [1)]	Value	Unit	Step	Default
Input m[2)] filter time	5…1000	ms		5
Input m inversion	0= False 1= True			0=False

1) Xnnn = Slot ID, for example, X100, X110, as applicable
2) m = For example, 1, 2, depending on the serial number of the binary input in a particular BIO or AIM card

Table 14: Ethernet front port settings

Parameter	Values (Range)	Unit	Step	Default	Description
IP address				192.168.0.254	IP address for front port (fixed)
Mac address				XX-XX-XX-XX-XX-XX	Mac address for front port

Table 15: Ethernet rear port settings

Parameter	Values (Range)	Unit	Step	Default	Description
IP address				192.168.2.10	IP address for rear port(s)
Subnet mask				255.255.255.0	Subnet mask for rear port(s)
Default gateway				192.168.2.1	Default gateway for rear port(s)
Mac address				XX-XX-XX-XX-XX-XX	Mac address for rear port(s)

Table 16: General system settings

Parameter	Values (Range)	Unit	Step	Default	Description
Rated frequency	1=50Hz 2=60Hz			1=50Hz	Rated frequency of the network
Phase rotation	1=ABC 2=ACB			1=ABC	Phase rotation order
Blocking mode	1=Freeze timer 2=Block all 3=Block TRIP output			1=Freeze timer	Behavior for function BLOCK inputs
Bay name 1)				REF615 2)	Bay name in system
IDMT Sat point	10...50	I/I>	1	50	Overcurrent IDMT saturation point
Frequency adaptivity 3)	0=Disable 1=Enable			0=Disable	Enabling frequency adaptivity
SMV Max Delay	0=1.90 1.58 ms 1=3.15 2.62 ms 2=4.40 3.67 ms 3=5.65 4.71 ms 4=6.90 5.75 ms			1=3.15 2.62 ms	SMV Maximum allowed delay

1) Used in the protection relay main menu header and as part of the disturbance recording identification
2) Depending on the product variant
3) Available only in REG615

Table 17: HMI settings

Parameter	Values (Range)	Unit	Step	Default	Description
FB naming convention	1=IEC61850 2=IEC60617 3=IEC-ANSI			1=IEC61850	FB naming convention used in IED
Default view	1=Measurements 2=Main menu 3=SLD page 1			1=Measurements	LHMI default view
Backlight timeout	1...60	min	1	3	LHMI backlight timeout
Web HMI mode	1=Active read only 2=Active 3=Disabled			3=Disabled	Web HMI functionality
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Web HMI timeout	1...60	min	1	3	Web HMI login timeout
SLD symbol format	1=IEC 2=ANSI			1=IEC	Single Line Diagram symbol format
Autoscroll delay	0...30	s	1	0	Autoscroll delay for Measurements view
Setting visibility	1=Basic 2=Advanced			1=Basic	Setting visibility for HMI

Table 18: IEC 61850-8-1 MMS settings

Parameter	Values (Range)	Unit	Step	Default	Description
Unit mode	1=Primary[1)] 0=Nominal[2)] 2=Primary-Nominal[3)]			0=Nominal	IEC 61850-8-1 unit mode

1) MMS client expects primary values from event reporting and data attribute reads
2) MMS client expects nominal values from event reporting and data attribute reads; this is the default for PCM600
3) For PCM600 use only, When Unit mode is set to "Primary", the PCM600 client can force its session to "Nominal" by selecting "Primary-Nominal" and thus parameterizing in native form. The selection is not stored and is therefore effective only for one session. This value has no effect if selected via the LHMI.

Table 19: Modbus settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			5=disable	Enable or disable this protocol instance
Port	1=COM 1 2=COM 2 3=Ethernet - TCP 1			3=Ethernet - TCP 1	Port selection for this protocol instance. Select between serial and Ethernet based communication.
Mapping selection	1...2		1	1	Chooses which mapping scheme will be used for this protocol instance.
Address	1...254		1	1	Unit address
Link mode	1=RTU 2=ASCII			1=RTU	Selects between ASCII and RTU mode. For TCP, this should always be RTU.
TCP port	1...65535		1	502	Defines the listening port for the Modbus TCP server. Default = 502.
Parity	0=none 1=odd 2=even			2=even	Parity for the serial connection.
Start delay	0...20		1	4	Start delay in character times for serial connection
End delay	0...20		1	4	End delay in character times for serial connections
CRC order	0=Hi-Lo 1=Lo-Hi			0=Hi-Lo	Selects between normal or swapped byte order for checksum for serial connection. Default: Hi-Lo.
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Client IP				0.0.0.0	Sets the IP address of the client. If set to zero, connection from any client is accepted.
Write authority	0=Read only 1=Disable 0x write 2=Full access			2=Full access	Selects the control authority scheme
Time format	0=UTC 1=Local			1=Local	Selects between UTC and local time for events and timestamps.
Event ID selection	0=Address 1=UID			0=Address	Selects whether the events are reported using the MB address or the UID number.
Event buffering	0=Keep oldest 1=Keep newest			0=Keep oldest	Selects whether the oldest or newest events are kept in the case of event buffer overflow.
Event backoff	1...500		1	200	Defines how many events have to be read after event buffer overflow to allow new events to be buffered. Applicable in "Keep oldest" mode only.
ControlStructPWd 1				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 2				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 3				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 4				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 5				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 6				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 7				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.
ControlStructPWd 8				****	Password for control operations using Control Struct mechanism, which is available on 4x memory area.

Table 20: DNP3 settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			5=disable	Operation Disable / Enable
Port	1=COM 1 2=COM 2 3=Ethernet - TCP 1 4=Ethernet TCP +UDP 1			3=Ethernet - TCP 1	Communication interface selection
Unit address	1...65519		1	1	DNP unit address
Master address	1...65519		1	3	DNP master and UR address
Mapping select	1...2		1	1	Mapping select
ClientIP				0.0.0.0	IP address of client
TCP port	20000...65535		1	20000	TCP Port used on ethernet communication
TCP write authority	0=No clients 1=Reg. clients 2=All clients			2=All clients	0=no client controls allowed; 1=Controls allowed by registered clients; 2=Controls allowed by all clients
Link keep-alive	0...65535	s	1	0	Link keep-alive interval for DNP
Validate master addr	1=Disable 2=Enable			1=Disable	Validate master address on receive
Self address	1=Disable 2=Enable			2=Enable	Support self address query function
Need time interval	0...65535	min	1	30	Period to set IIN need time bit
Time format	0=UTC 1=Local			1=Local	UTC or local. Coordinate with master.
CROB select timeout	1...65535	s	1	10	Control Relay Output Block select timeout
Data link confirm	0=Never 1=Only Multiframe 2=Always			0=Never	Data link confirm mode
Data link confirm TO	100...65535	ms	1	3000	Data link confirm timeout
Data link retries	0...65535		1	3	Data link retries count
Data link Rx to Tx delay	0...255	ms	1	0	Turnaround transmission delay
Data link inter char delay	0...20	char	1	4	Inter character delay for incoming messages
App layer confirm	1=Disable 2=Enable			1=Disable	Application layer confirm mode
App confirm TO	100...65535	ms	1	5000	Application layer confirm and UR timeout
App layer fragment	256...2048	bytes	1	2048	Application layer fragment size
UR mode	1=Disable 2=Enable			1=Disable	Unsolicited responses mode
UR retries	0...65535		1	3	Unsolicited retries before switching to UR offline mode
UR TO	0...65535	ms	1	5000	Unsolicited response timeout
UR offline interval	0...65535	min	1	15	Unsolicited offline interval
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
UR Class 1 Min events	0...999		1	2	Min number of class 1 events to generate UR
UR Class 1 TO	0...65535	ms	1	50	Max holding time for class 1 events to generate UR
UR Class 2 Min events	0...999		1	2	Min number of class 2 events to generate UR
UR Class 2 TO	0...65535	ms	1	50	Max holding time for class 2 events to generate UR
UR Class 3 Min events	0...999		1	2	Min number of class 3 events to generate UR
UR Class 3 TO	0...65535	ms	1	50	Max holding time for class 3 events to generate UR
Legacy master UR	1=Disable 2=Enable			1=Disable	Legacy DNP master unsolicited mode support. When enabled relay does not send initial unsolicited message.
Legacy master SBO	1=Disable 2=Enable			1=Disable	Legacy DNP Master SBO sequence number relax enable
Default Var Obj 01	1=1:BI 2=2:BI&status			1=1:BI	1=BI; 2=BI with status.
Default Var Obj 02	1=1:BI event 2=2:BI event&time			2=2:BI event&time	1=BI event; 2=BI event with time.
Default Var Obj 03	1=1:DBI 2=2:DBI&status			1=1:DBI	1=DBI; 2=DBI with status.
Default Var Obj 04	1=1:DBI event 2=2:DBI event&time			2=2:DBI event&time	1=DBI event; 2=DBI event with time.
Default Var Obj 20	1=1:32bit Cnt 2=2:16bit Cnt 5=5:32bit Cnt noflag 6=6:16bit Cnt noflag			2=2:16bit Cnt	1=32 bit counter; 2=16 bit counter; 5=32 bit counter without flag; 6=16 bit counter without flag.
Default Var Obj 21	1=1:32bit FrzCnt 2=2:16bit FrzCnt 5=5:32bit FrzCnt&time 6=6:16bit FrzCnt&time 9=9:32bit FrzCnt noflag 10=10:16bit FrzCnt noflag			6=6:16bit FrzCnt&time	1=32 bit frz counter; 2=16 bit frz counter; 5=32 bit frz counter with time; 6=16 bit frz counter with time; 9=32 bit frz counter without flag; 10=16 bit frz counter without flag.
Default Var Obj 22	1=1:32bit Cnt evt 2=2:16bit Cnt evt 5=5:32bit Cnt evt&time 6=6:16bit Cnt evt&time			6=6:16bit Cnt evt&time	1=32 bit counter event; 2=16 bit counter event; 5=32 bit counter event with time; 6=16 bit counter event with time.

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Default Var Obj 23	1=1:32bit FrzCnt evt 2=2:16bit FrzCnt evt 5=5:32bit FrzCnt evt&time 6=6:16bit FrzCnt evt&time			6=6:16bit FrzCnt evt&time	1=32 bit frz counter event; 2=16 bit frz counter event; 5=32 bit frz counter event with time; 6=16 bit frz counter event with time.
Default Var Obj 30	1=1:32bit AI 2=2:16bit AI 3=3:32bit AI noflag 4=4:16bit AI noflag 5=5:AI float 6=6:AI double			5=5:AI float	1=32 bit AI; 2=16 bit AI; 3=32 bit AI without flag; 4=16 bit AI without flag; 5=AI float; 6=AI double.
Default Var Obj 32	1=1:32bit AI evt 2=2:16bit AI evt 3=3:32bit AI evt&time 4=4:16bit AI evt&time 5=5: float AI evt 6=6:double AI evt 7=7:float AI evt&time 8=8:double AI evt&time			7=7:float AI evt&time	1=32 bit AI event; 2=16 bit AI event; 3=32 bit AI event with time; 4=16 bit AI event with time; 5=float AI event; 6=double AI event; 7=float AI event with time; 8=double AI event with time.
Default Var Obj 40	1=1:32bit AO 2=2:16bit AO 3=3:AO float 4=4:AO double			2=2:16bit AO	1=32 bit AO; 2=16 bit AO; 3=AO float; 4=AO double.
Default Var Obj 42	1=1:32bit AO evt 2=2:16bit AO evt 3=3:32bit AO evt&time 4=4:16bit AO evt&time 5=5:float AO evt 6=6:double AO evt 7=7:float AO evt&time 8=8:double AO evt&time			4=4:16bit AO evt&time	1=32 bit AO event; 2=16 bit AO event; 3=32 bit AO event with time; 4=16 bit AO event with time; 5=float AO event; 6=double AO event; 7=float AO event with time; 8=double AO event with time.

Table 21: COM1 serial communication settings

Parameter	Values (Range)	Unit	Step	Default	Description
Fiber mode	0=No fiber 2=Fiber light OFF loop			0=No fiber	Fiber mode
Serial mode	1=RS485 2Wire 2=RS485 4Wire 3=RS232 no handshake 4=RS232 with handshake			1=RS485 2Wire	Serial mode
CTS delay	0...60000	ms	1	0	CTS delay
RTS delay	0...60000	ms	1	0	RTS delay
Baudrate	1=300 2=600 3=1200 4=2400 5=4800 6=9600 7=19200 8=38400 9=57600 10=115200			6=9600	Baudrate

Table 22: COM2 serial communication settings

Parameter	Values (Range)	Unit	Step	Default	Description
Fiber mode	0=No fiber 2=Fiber light OFF loop			0=No fiber	Fiber mode
Serial mode	1=RS485 2Wire 2=RS485 4Wire 3=RS232 no handshake 4=RS232 with handshake			1=RS485 2Wire	Serial mode
CTS delay	0...60000	ms	1	0	CTS delay
RTS delay	0...60000	ms	1	0	RTS delay
Baudrate	1=300 2=600 3=1200 4=2400 5=4800 6=9600 7=19200 8=38400 9=57600 10=115200			6=9600	Baudrate

3.2 Self-supervision

The protection relay's extensive self-supervision system continuously supervises the software and the electronics. It handles run-time fault situation and informs the user about a fault via the LHMI and through the communication channels.

There are two types of fault indications.

- Internal faults
- Warnings

3.2.1 Internal faults

When an internal relay fault is detected, the green Normal LED begins to flash and the self-supervision output contact is activated.

Internal fault indications have the highest priority on the LHMI. None of the other LHMI indications can override the internal fault indication.

An indication about the fault is shown as a message on the LHMI. The text `Internal Fault` with an additional text message, a code, date and time, is shown to indicate the fault type.

Different actions are taken depending on the severity of the fault. The protection relay tries to eliminate the fault by restarting. After the fault is found to be permanent, the protection relay stays in the internal fault mode. All other output contacts are released and locked for the internal fault. The protection relay continues to perform internal tests during the fault situation.

If an internal fault disappears, the green Normal LED stops flashing and the protection relay returns to the normal service state. The fault indication message remains on the display until manually cleared.

The self-supervision signal output operates on the closed-circuit principle. Under normal conditions, the protection relay is energized and the contact gaps 3-5 in slot X100 is closed. If the auxiliary power supply fails or an internal fault is detected, the contact gaps 3-5 are opened.

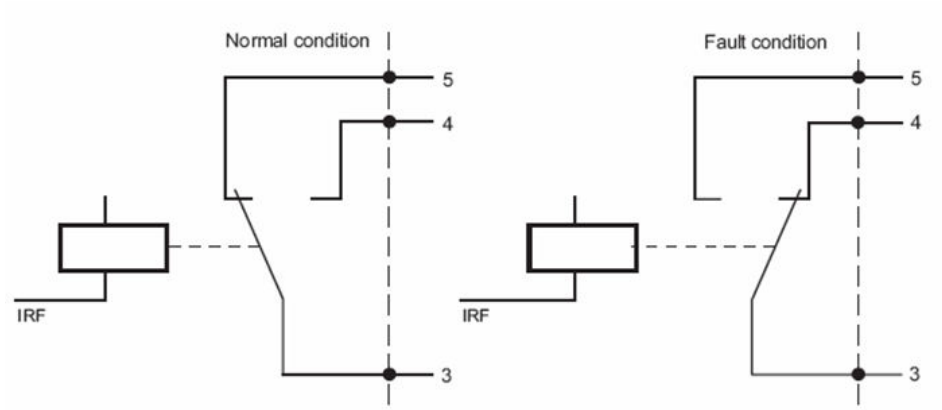


Figure 9: Output contact

The internal fault code indicates the type of internal relay fault. When a fault appears, the code must be recorded so that it can be reported to ABB customer service.

Table 23: Internal fault indications and codes

Fault indication	Fault code	Additional information
Internal Fault System error	2	An internal system error has occurred.
Internal Fault File system error	7	A file system error has occurred.
Internal Fault Test	8	Internal fault test activated manually by the user.
Internal Fault SW watchdog error	10	Watchdog reset has occurred too many times within an hour.
Internal Fault SO-relay(s),X100	43	Faulty Signal Output relay(s) in card located in slot X100.
Internal Fault SO-relay(s),X110	44	Faulty Signal Output relay(s) in card located in slot X110.
Internal Fault SO-relay(s),X120	45	Faulty Signal Output relay(s) in card located in slot X120.
Internal Fault SO-relay(s),X130	46	Faulty Signal Output relay(s) in card located in slot X130.
Internal Fault PO-relay(s),X100	53	Faulty Power Output relay(s) in card located in slot X100.
Internal Fault PO-relay(s),X110	54	Faulty Power Output relay(s) in card located in slot X110.
Internal Fault PO-relay(s),X120	55	Faulty Power Output relay(s) in card located in slot X120.
Internal Fault PO-relay(s),X130	56	Faulty Power Output relay(s) in card located in slot X130.
Internal Fault Light sensor error	57	Faulty ARC light sensor input(s).

Table continues on next page

Fault indication	Fault code	Additional information
Internal Fault Conf. error,X000	62	Card in slot X000 is wrong type, is missing, does not belong to original configuration or card firmware is faulty.
Internal Fault Conf. error,X100	63	Card in slot X100 is wrong type or does not belong to the original composition.
Internal Fault Conf. error,X110	64	Card in slot X110 is wrong type, is missing or does not belong to the original composition.
Internal Fault Conf. error,X120	65	Card in slot X120 is wrong type, is missing or does not belong to the original composition.
Internal Fault Conf.error,X130	66	Card in slot X130 is wrong type, is missing or does not belong to the original composition.
Internal Fault Card error,X000	72	Card in slot X000 is faulty.
Internal Fault Card error,X100	73	Card in slot X100 is faulty.
Internal Fault Card error,X110	74	Card in slot X110 is faulty.
Internal Fault Card error,X120	75	Card in slot X120 is faulty.
Internal Fault Card error,X130	76	Card in slot X130 is faulty.
Internal Fault LHMI module	79	LHMI module is faulty. The fault indication may not be seen on the LHMI during the fault.
Internal Fault RAM error	80	Error in the RAM memory on the CPU card.
Internal Fault ROM error	81	Error in the ROM memory on the CPU card.
Internal Fault EEPROM error	82	Error in the EEPROM memory on the CPU card.
Internal Fault FPGA error	83	Error in the FPGA on the CPU card.
Internal Fault RTC error	84	Error in the RTC on the CPU card.
Internal Fault RTD card error,X130	96	RTD card located in slot X130 may have permanent fault. Temporary error has occurred too many times within a short time.
Internal Fault COM card error	116	Error in the COM card.

For further information on internal fault indications, see the operation manual.

3.2.2 Warnings

In case of a warning, the protection relay continues to operate except for those protection functions possibly affected by the fault, and the green Normal LED remains lit as during normal operation.

Warnings are indicated with the text `Warning` additionally provided with the name of the warning, a numeric code and the date and time on the LHMI. The warning indication message can be manually cleared.

If a warning appears, record the name and code so that it can be provided to ABB customer service.

Table 24: Warning indications and codes

Warning indication	Warning code	Additional information
Warning Watchdog reset	10	A watchdog reset has occurred.
Warning Power down det.	11	The auxiliary supply voltage has dropped too low.
Warning IEC61850 error	20	Error when building the IEC 61850 data model.
Warning Modbus error	21	Error in the Modbus communication.
Warning DNP3 error	22	Error in the DNP3 communication.
Warning Dataset error	24	Error in the Data set(s).
Warning Report cont. error	25	Error in the Report control block(s).
Warning GOOSE contr. error	26	Error in the GOOSE control block(s).
Warning SCL config error	27	Error in the SCL configuration file or the file is missing.
Warning Logic error	28	Too many connections in the configuration.
Warning SMT logic error	29	Error in the SMT connections.
Warning GOOSE input error	30	Error in the GOOSE connections.
ACT error	31	Error in the ACT connections.
Warning GOOSE Rx. error	32	Error in the GOOSE message receiving.

Table continues on next page

Warning indication	Warning code	Additional information
Warning AFL error	33	Analog channel configuration error.
Warning SMV config error	34	Error in the SMV configuration.
Warning Comm. channel down	35	Redundant Ethernet (HSR/PRP) communication interrupted.
Warning Unack card comp.	40	A new composition has not been acknowledged/accepted.
Warning Protection comm.	50	Error in protection communication.
Warning ARC1 cont. light	85	A continuous light has been detected on the ARC light input 1.
Warning ARC2 cont. light	86	A continuous light has been detected on the ARC light input 2.
Warning ARC3 cont. light	87	A continuous light has been detected on the ARC light input 3.
Warning RTD card error,X130	96	Temporary error occurred in RTD card located in slot X130.
Warning RTD meas. error,X130	106	Measurement error in RTD card located in slot X130.

For further information on warning indications, see the operation manual.

3.3 LED indication control

3.3.1 Function block

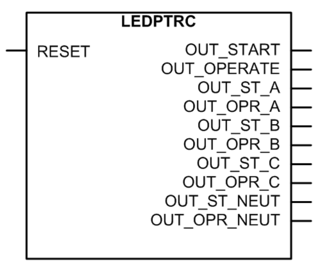


Figure 10: Function block

3.3.2 Functionality

The protection relay includes a global conditioning function LEDPTRC that is used with the protection indication LEDs.

LED indication control should never be used for tripping purposes. There is a separate trip logic function 86/94 available in the relay configuration.

LED indication control is preconfigured in a such way that all the protection function general pickup and trip signals are combined with this function (available as output signals `OUT_START` and `OUT_OPERATE`). These signals are always internally connected to Pickup and Trip LEDs. LEDPTRC collects and combines phase information from different protection functions (available as output signals `OUT_ST_A /_B /_C` and `OUT_OPR_A /_B /_C`). There is also combined ground fault information collected from all the ground-fault functions available in the relay configuration (available as output signals `OUT_ST_NEUT` and `OUT_OPR_NEUT`).

3.4 Programmable LEDs

3.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE identification
Programmable LEDs	LED	LED	LED

3.4.2 Function block

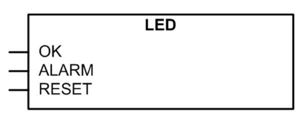


Figure 11: Function block

3.4.3 Functionality

The programmable LEDs reside on the right side of the display on the LHMI.

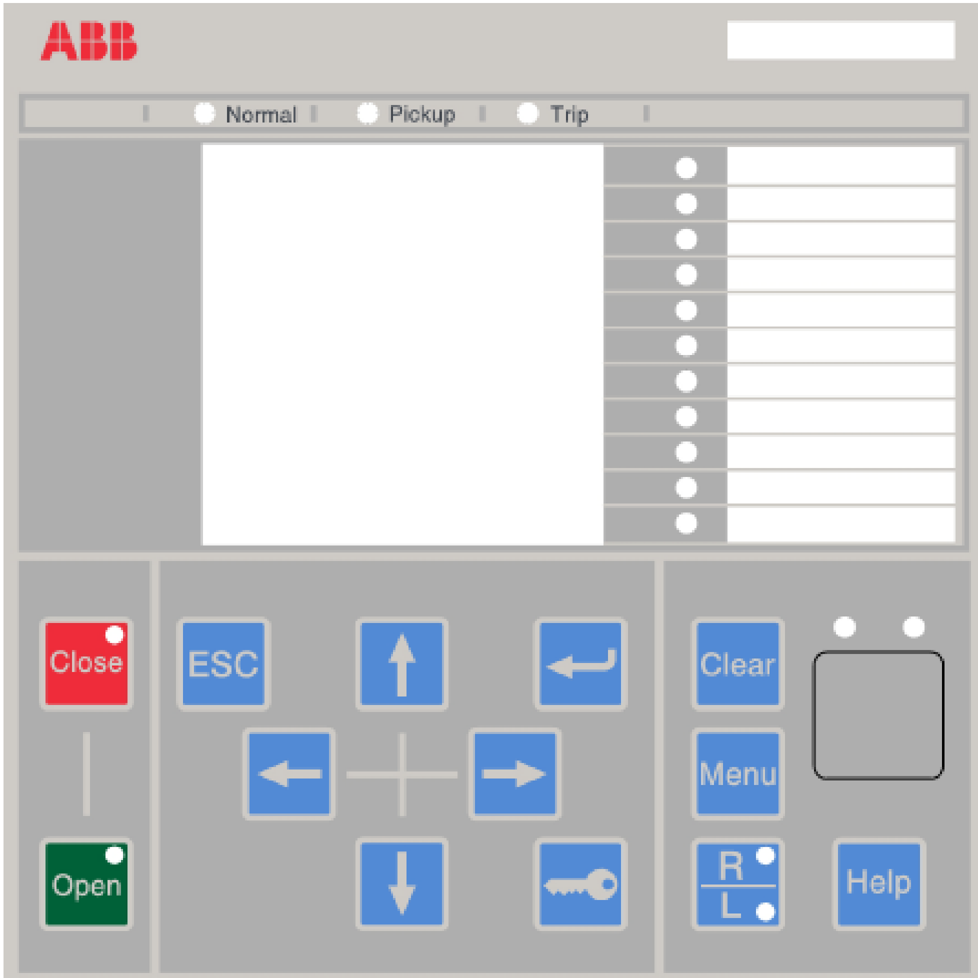


Figure 12: Programmable LEDs on the right side of the display

All the programmable LEDs in the HMI of the protection relay have two colors, green and red. For each LED, the different colors are individually controllable.

Each LED has two control inputs, `ALARM` and `OK`. The color setting is common for all the LEDs. It is controlled with the *Alarm colour* setting, the default value being "Red". The `OK` input corresponds to the color that is available, with the default value being "Green".

Changing the *Alarm colour* setting to "Green" changes the color behavior of the `OK` inputs to red.

The `ALARM` input has a higher priority than the `OK` input.

Each LED is seen in the Application Configuration tool as an individual function block. Each LED has user-editable description text for event description. The state ("None", "OK", "Alarm") of each LED can also be read under a common monitored data view for programmable LEDs.

The LED status also provides a means for resetting the individual LED via communication. The LED can also be reset from configuration with the RESET input.

The resetting and clearing function for all LEDs is under the **Clear** menu.

The menu structure for the programmable LEDs is presented in Figure 13. The common color selection setting *Alarm colour* for all ALARM inputs is in the **General** menu, while the LED-specific settings are under the LED-specific menu nodes.

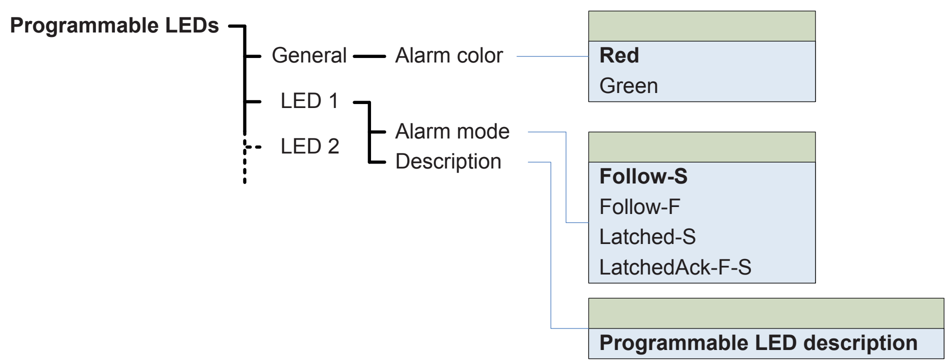


Figure 13: Menu structure

Alarm mode alternatives

The ALARM input behavior can be selected with the alarm mode settings from the alternatives "Follow-S", "Follow-F", "Latched-S" and "LatchedAck-F-S". The OK input behavior is always according to "Follow-S". The alarm input latched modes can be cleared with the reset input in the application logic.

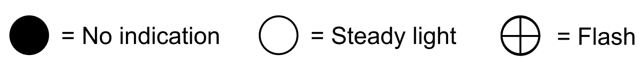


Figure 14: Symbols used in the sequence diagrams

"Follow-S": Follow Signal, ON

In this mode ALARM follows the input signal value, Non-latched.

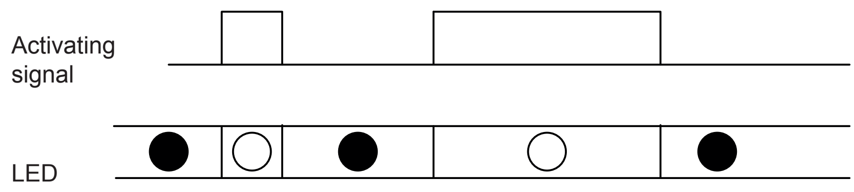


Figure 15: Operating sequence "Follow-S"

"Follow-F": Follow Signal, Flashing

Similar to "Follow-S", but instead the LED is flashing when the input is active, Non-latched.

"Latched-S": Latched, ON

This mode is a latched function. At the activation of the input signal, the alarm shows a steady light. After acknowledgement by the local operator pressing any key on the keypad, the alarm disappears.

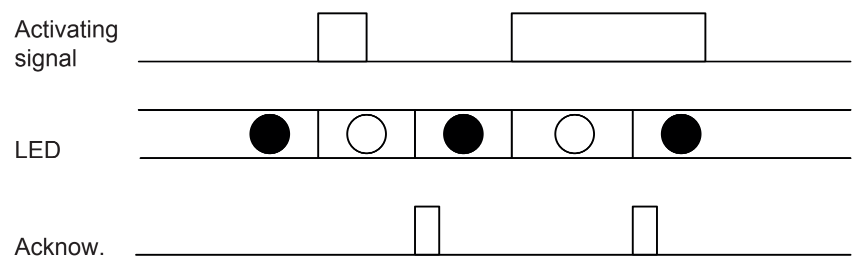


Figure 16: Operating sequence "Latched-S"

"LatchedAck-F-S": Latched, Flashing-ON

This mode is a latched function. At the activation of the input signal, the alarm starts flashing. After acknowledgement, the alarm disappears if the signal is not present and gives a steady light if the signal is present.

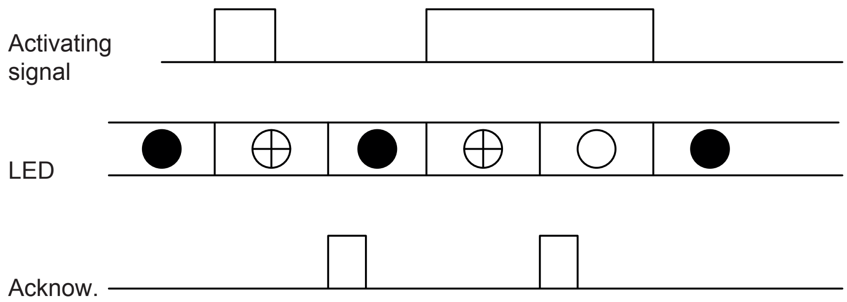


Figure 17: Operating sequence "LatchedAck-F-S"

3.4.4 Signals

Table 25: LED Input signals

Name	Type	Default	Description
OK	BOOLEAN	0=False	Ok input for LED 1
ALARM	BOOLEAN	0=False	Alarm input for LED 1
RESET	BOOLEAN	0=False	Reset input for LED 1
OK	BOOLEAN	0=False	Ok input for LED 2
ALARM	BOOLEAN	0=False	Alarm input for LED 2
RESET	BOOLEAN	0=False	Reset input for LED 2
OK	BOOLEAN	0=False	Ok input for LED 3
ALARM	BOOLEAN	0=False	Alarm input for LED 3
RESET	BOOLEAN	0=False	Reset input for LED 3
OK	BOOLEAN	0=False	Ok input for LED 4
ALARM	BOOLEAN	0=False	Alarm input for LED 4
RESET	BOOLEAN	0=False	Reset input for LED 4
OK	BOOLEAN	0=False	Ok input for LED 5
ALARM	BOOLEAN	0=False	Alarm input for LED 5
RESET	BOOLEAN	0=False	Reset input for LED 5
OK	BOOLEAN	0=False	Ok input for LED 6
ALARM	BOOLEAN	0=False	Alarm input for LED 6
RESET	BOOLEAN	0=False	Reset input for LED 6
OK	BOOLEAN	0=False	Ok input for LED 7
ALARM	BOOLEAN	0=False	Alarm input for LED 7
RESET	BOOLEAN	0=False	Reset input for LED 7
OK	BOOLEAN	0=False	Ok input for LED 8

Table continues on next page

Name	Type	Default	Description
ALARM	BOOLEAN	0=False	Alarm input for LED 8
RESET	BOOLEAN	0=False	Reset input for LED 8
OK	BOOLEAN	0=False	Ok input for LED 9
ALARM	BOOLEAN	0=False	Alarm input for LED 9
RESET	BOOLEAN	0=False	Reset input for LED 9
OK	BOOLEAN	0=False	Ok input for LED 10
ALARM	BOOLEAN	0=False	Alarm input for LED 10
RESET	BOOLEAN	0=False	Reset input for LED 10
OK	BOOLEAN	0=False	Ok input for LED 11
ALARM	BOOLEAN	0=False	Alarm input for LED 11
RESET	BOOLEAN	0=False	Reset input for LED 11

3.4.5 Settings

Table 26: LED settings

Parameter	Values (Range)	Unit	Step	Default	Description
Alarm color	1=Green 2=Red			2=Red	Color for the alarm state of the LED
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 1
Description				Programmable LEDs LED 1	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 2
Description				Programmable LEDs LED 2	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 3
Description				Programmable LEDs LED 3	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 4
Description				Programmable LEDs LED 4	Programmable LED description

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 5
Description				Programmable LEDs LED 5	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 6
Description				Programmable LEDs LED 6	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 7
Description				Programmable LEDs LED 7	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 8
Description				Programmable LEDs LED 8	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 9
Description				Programmable LEDs LED 9	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 10
Description				Programmable LEDs LED 10	Programmable LED description
Alarm mode	0=Follow-S 1=Follow-F 2=Latched-S 3=LatchedAck-F-S			0=Follow-S	Alarm mode for programmable LED 11
Description				Programmable LEDs LED 11	Programmable LED description

3.4.6 Monitored data

Table 27: LED Monitored data

Name	Type	Values (Range)	Unit	Description
Programmable LED 1	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 1
Programmable LED 2	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 2
Programmable LED 3	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 3
Programmable LED 4	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 4
Programmable LED 5	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 5
Programmable LED 6	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 6
Programmable LED 7	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 7
Programmable LED 8	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 8
Programmable LED 9	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 9
Programmable LED 10	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 10
Programmable LED 11	Enum	0=None 1=Ok 3=Alarm		Status of programmable LED 11

3.5 Time synchronization

3.5.1 Time master supervision GNRLLTMS

3.5.1.1 Function block

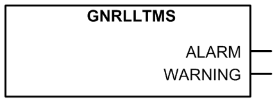


Figure 18: Function block

3.5.1.2 Functionality

The protection relay has an internal real-time clock which can be either free-running or synchronized from an external source. The real-time clock is used for time stamping events, recorded data and disturbance recordings.

The protection relay is provided with a 48 hour capacitor backup that enables the real-time clock to keep time in case of an auxiliary power failure.

The setting *Synch source* determines the method to synchronize the real-time clock. If it is set to “None”, the clock is free-running and the settings *Date* and *Time* can be used to set the time manually. Other setting values activate a communication protocol that provides the time synchronization. Only one synchronization method can be active at a time but SNTP provides time master redundancy.

The protection relay supports SNTP, IRIG-B, IEEE 1588 v2, DNP3 and Modbus to update the real-time clock. IEEE 1588 v2 with GPS grandmaster clock provides the best accuracy ±1 µs. The accuracy using IRIG-B and SNTP is ±1 ms.

The protection relay's 1588 time synchronization complies with the IEEE C37.238-2011 Power Profile, interoperable with IEEE 1588 v2. According to the power profile, the frame format used is IEEE 802.3 Ethernet frames with 88F7 Ethertype as communication service and the delay mechanism is P2P. *PTP announce mode* determines the format of PTP announce frames sent by the protection relay when acting as 1588 master, with options “Basic IEEE1588” and “Power Profile”. In the “Power Profile” mode, the TLVs required by the IEEE C37.238-2011 Power Profile are included in announce frames.

IEEE 1588 v2 time synchronization requires a communication card with redundancy support (COM0031...COM0037).

When Modbus TCP or DNP3 over TCP/IP is used, SNTP or IRIG-B time synchronization should be used for better synchronization accuracy.

With the legacy protocols, the synchronization message must be received within four minutes from the previous synchronization. Otherwise bad synchronization status is raised for the protection relay. With SNTP, it is required that the SNTP server responds to a request within 12 ms, otherwise the response is considered invalid.

The relay can use one of two SNTP servers, the primary or the secondary server. The primary server is mainly in use, whereas the secondary server is used if the primary server cannot be reached. While using the secondary SNTP server, the relay tries to switch back to the primary server on every third SNTP request attempt. If both the SNTP servers are offline, event time stamps have the time invalid status. The time is requested from the SNTP server every 60 seconds. Supported SNTP versions are 3 and 4.

IRIG-B time synchronization requires the IRIG-B format B004/B005 according to the 200-04 IRIG-B standard. Older IRIG-B standards refer to these as B000/B001 with IEEE-1344 extensions. The synchronization time can be either UTC time or local time. As no reboot is necessary, the time synchronization starts immediately after the IRIG-B sync source is selected and the IRIG-B signal source is connected.

IRIG-B time synchronization requires a COM card with an IRIG-B input.

When using line differential communication between RED615 protection relays, the time synchronization messages can be received from the other line end protection relay within the protection telegrams. The protection relay begins to synchronize its real-time clock with the remote end protection relay's time if the Line differential time synchronization source is selected. This does not affect the protection synchronization used in the line differential protection or the selection of the remote end protection relay's time synchronization method. [1]

3.5.1.3 Signals

Table 28: GNRLLTMS output signals

Name	Type	Description
ALARM	BOOLEAN	Time synchronization alarm
WARNING	BOOLEAN	Time synchronization warning

[1] The line differential protection is available only in RED615.

3.5.1.4 Settings

Table 29: Time format

Parameter	Values (Range)	Unit	Step	Default	Description
Time format	1=24H:MM:SS:MS 2=12H:MM:SS:MS			1=24H:MM:SS:MS	Time format
Date format	1=DD.MM.YYYY 2=DD/MM/YYYY 3=DD-MM-YYYY 4=MM.DD.YYYY 5=MM/DD/YYYY 6=YYYY-MM-DD 7=YYYY-DD-MM 8=YYYY/DD/MM			1=DD.MM.YYYY	Date format

Table 30: Time settings

Parameter	Values (Range)	Unit	Step	Default	Description
Synch source	0=None 1=SNTP 2=Modbus 3=IEEE 1588 5=IRIG-B 9=DNP			1=SNTP	Time synchronization source
PTP domain ID	0...255		1	0	The domain is identified by an integer, the domainNumber, in the range of 0 to 255.
PTP priority 1	0...255		1	128	PTP priority 1, in the range of 0 to 255.
PTP priority 2	0...255		1	128	PTP priority 2, in the range of 0 to 255.
PTP announce mode	1=Basic IEEE1588 2=Power Profile			1=Basic IEEE1588	PTP announce frame mode

Table 31: Time settings

Parameter	Values (Range)	Unit	Step	Default	Description
Date				0	Date
Time				0	Time
Local time offset	-840...840	min	1	0	Local time offset in minutes

Table 32: Time settings

Parameter	Values (Range)	Unit	Step	Default	Description
IP SNTP primary				10.58.125.165	IP address for SNTP primary server
IP SNTP secondary				192.168.2.165	IP address for SNTP secondary server

Table 33: Time settings

Parameter	Values (Range)	Unit	Step	Default	Description
DST in use	0=False 1=True			1=True	DST in use setting
DST on time (hours)	0...23	h		2	Daylight saving time on, time (hh)
DST on time (minutes)	0...59	min		0	Daylight saving time on, time (mm)
DST on date (day)	1...31			1	Daylight saving time on, date (dd:mm)
DST on date (month)	1=January 2=February 3=March 4=April 5=May 6=June 7=July 8=August 9=September 10=October 11=November 12=December			5=May	Daylight saving time on, date (dd:mm)
DST on day (weekday)	0=reserved 1=Monday 2=Tuesday 3=Wednesday 4=Thursday 5=Friday 6=Saturday 7=Sunday			0=reserved	Daylight saving time on, day of week
DST off time (hours)	0...23	h		2	Daylight saving time off, time (hh)
DST off time (minutes)	0...59	min		0	Daylight saving time off, time (mm)
DST off date (day)	1...31			25	Daylight saving time off, date (dd:mm)
DST off date (month)	1=January 2=February 3=March 4=April 5=May 6=June 7=July 8=August 9=September 10=October 11=November 12=December			9=September	Daylight saving time off, date (dd:mm)
DST off day (weekday)	0=reserved 1=Monday 2=Tuesday 3=Wednesday 4=Thursday 5=Friday 6=Saturday 7=Sunday			0=reserved	Daylight saving time off, day of week
DST offset	-720...720	min	1	60	Daylight saving time offset

3.6 Parameter setting groups

3.6.1 Function block

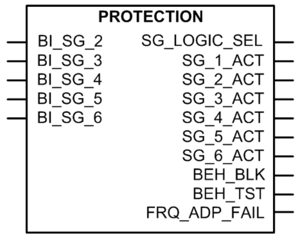


Figure 19: Function block

3.6.2 Functionality

The protection relay supports six setting groups. Each setting group contains parameters categorized as group settings inside application functions. The customer can change the active setting group at run time.

The active setting group can be changed by a parameter or via binary inputs depending on the mode selected with the **Configuration/Setting Group/SG operation mode** setting.

The default value of all inputs is FALSE, which makes it possible to use only the required number of inputs and leave the rest disconnected. The setting group selection is not dependent on the `SG_x_ACT` outputs.

Table 34: Optional operation modes for setting group selection

SG operation mode	Description
Operator (Default)	Setting group can be changed with the setting **Settings/Setting group/Active group**. Value of the `SG_LOGIC_SEL` output is FALSE.
Logic mode 1	Setting group can be changed with binary inputs (`BI_SG_2...BI_SG_6`). The highest `TRUE` binary input defines the active setting group. Value of the `SG_LOGIC_SEL` output is TRUE.
Logic mode 2	Setting group can be changed with binary inputs where `BI_SG_4` is used for selecting setting groups 1-3 or 4-6. When binary input `BI_SG_4` is `FALSE`, setting groups 1-3 are selected with binary inputs `BI_SG_2` and `BI_SG_3`. When binary input `BI_SG_4` is `TRUE`, setting groups 4-6 are selected with binary inputs `BI_SG_5` and `BI_SG_6`. Value of the `SG_LOGIC_SEL` output is TRUE.

For example, six setting groups can be controlled with three binary inputs. The *SG operation mode* is set to “Logic mode 2” and inputs BI_SG_2 and BI_SG_5 are connected together the same way as inputs BI_SG_3 and BI_SG_6.

Table 35: SG operation mode = “Logic mode 1”

Input					
BI_SG_2	BI_SG_3	BI_SG_4	BI_SG_5	BI_SG_6	Active group
FALSE	FALSE	FALSE	FALSE	FALSE	1
TRUE	FALSE	FALSE	FALSE	FALSE	2
any	TRUE	FALSE	FALSE	FALSE	3
any	any	TRUE	FALSE	FALSE	4
any	any	any	TRUE	FALSE	5
any	any	any	any	TRUE	6

Table 36: SG operation mode = “Logic mode 2”

Input					
BI_SG_2	BI_SG_3	BI_SG_4	BI_SG_5	BI_SG_6	Active group
FALSE	FALSE	FALSE	any	any	1
TRUE	FALSE	FALSE	any	any	2
any	TRUE	FALSE	any	any	3
any	any	TRUE	FALSE	FALSE	4
any	any	TRUE	TRUE	FALSE	5
any	any	TRUE	any	TRUE	6

The setting group 1 can be copied to any other or all groups from HMI (Copy group 1).

3.7 Test mode

3.7.1 Function blocks

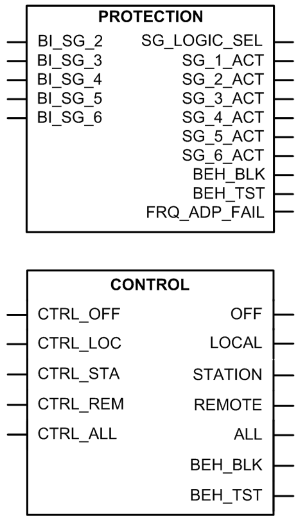


Figure 20: Function blocks

3.7.2 Functionality

The mode of all the logical nodes in the relay's IEC 61850 data model can be set with *Test mode*. *Test mode* is selected through one common parameter via the WHMI path **Tests/IED test**. By default, *Test mode* can only be set locally through LHMI. *Test mode* is also available via IEC 61850 communication (LD0.LLN0.Mod).

Table 37: Test mode

Test mode	Description	Protection BEH_BLK
Normal mode	Normal operation	FALSE
IED blocked	Protection working as in “Normal mode” but ACT configuration can be used to block physical outputs to process. Control function commands blocked.	TRUE
IED test	Protection working as in “Normal mode” but protection functions are working in parallel with test parameters.	FALSE
IED test and blocked	Protection working as in “Normal mode” but protection functions are working in parallel with test parameters. ACT configuration can be used to block physical outputs to process. Control function commands blocked.	TRUE

Behavior data objects in all logical nodes follow LD0.LLN0.Mod value. If "Normal mode" is selected, behaviour data objects follow mode (.Mod) data object of the corresponding logical device.

Vertical and horizontal communication is not blocked by the “IED blocked” or “IED test and blocked” modes.

3.7.3 Application configuration and Test mode

The physical outputs from control commands to process are blocked with ”IED blocked” and “IED test and blocked” modes. If physical outputs need to be blocked from the protection, the application configuration must be used to block these signals. Blocking scheme needs to use `BEH_BLK` output of PROTECTION function block.

3.7.4 Control mode

The mode of all logical nodes located under CTRL logical device can be set with *Control mode*. The *Control mode* parameter is available via the HMI or PCM600 path **Configuration/Control/General**. By default, *Control mode* can only be set locally through LHMI.*Control mode* inherits its value from *Test mode* but *Control mode* ”On”, “Blocked” and “Off” can also be set independently. *Control mode* is also available via IEC 61850 communication (CTRL.LLN0.Mod).

Table 38: Control mode

Control mode	Description	Control BEH_BLK
On	Normal operation	FALSE
Blocked	Control function commands blocked	TRUE
Off	Control functions disabled	FALSE

Behavior data objects under CTRL logical device follow CTRL.LLN0.Mod value. If "On" is selected, behavior data objects follow the mode of the corresponding logical device.

3.7.5 Application configuration and Control mode

The physical outputs from commands to process are blocked with “Blocked“ mode. If physical outputs need to be blocked totally, meaning also commands from the binary inputs, the application configuration must be used to block these signals. Blocking scheme uses `BEH_BLK` output of CONTROL function block.

3.7.6 Authorization

By default, *Test mode* and *Control mode* can only be changed from LHMI. It is possible to write test mode by remote client, if it is needed in configuration. This is done via LHMI only by setting the *Remote test mode* parameter via **Tests/IED test/Test mode**. Remote operation is possible only when control position of the relay is in remote position. Local and remote control can be selected with R/L button or via Control function block in application configuration.

When using the Signal Monitoring tool to force online values, the following conditions need to be met.

- *Remote force* is set to “All levels”
- *Test mode* is enabled
- Control position of the relay is in remote position

Table 39: Remote test mode

Remote test mode	61850-8-1-MMS	WHMI/PCM600
Off	No access	No access
Maintenance	Command originator category maintenance	No access
All levels	All originator categories	Yes

3.7.7 LHMI indications

The yellow Start LED flashes when the relay is in “IED blocked” or “IED test and blocked” mode. The green Ready LED flashes to indicate that the “IED test and blocked” mode or "IED test" mode is activated.

3.7.8 Signals

Table 40: PROTECTION input signals

Name	Type	Default	Description
BI_SG_2	BOOLEAN	0	Setting group 2 is active
BI_SG_3	BOOLEAN	0	Setting group 3 is active
BI_SG_4	BOOLEAN	0	Setting group 4 is active
BI_SG_5	BOOLEAN	0	Setting group 5 is active
BI_SG_6	BOOLEAN	0	Setting group 6 is active

Table 41: CONTROL input signals

Name	Type	Default	Description
CTRL_OFF	BOOLEAN	0	Control OFF
CTRL_LOC	BOOLEAN	0	Control local
CTRL_STA	BOOLEAN	0	Control station
CTRL_REM	BOOLEAN	0	Control remote
CTRL_ALL	BOOLEAN	0	Control all

Table 42: PROTECTION output signals

Name	Type	Description
SG_LOGIC_SEL	BOOLEAN	Logic selection for setting group
SG_1_ACT	BOOLEAN	Setting group 1 is active
SG_2_ACT	BOOLEAN	Setting group 2 is active
SG_3_ACT	BOOLEAN	Setting group 3 is active
SG_4_ACT	BOOLEAN	Setting group 4 is active
SG_5_ACT	BOOLEAN	Setting group 5 is active
SG_6_ACT	BOOLEAN	Setting group 6 is active
BEH_BLK	BOOLEAN	Logical device LD0 block status
BEH_TST	BOOLEAN	Logical device LD0 test status
FRQ_ADP_FAIL	BOOLEAN	Frequency adaptivity status fail

Table 43: CONTROL output signals

Name	Type	Description
OFF	BOOLEAN	Control OFF
LOCAL	BOOLEAN	Control local
STATION	BOOLEAN	Control station
REMOTE	BOOLEAN	Control remote
ALL	BOOLEAN	Control all
BEH_BLK	BOOLEAN	Logical device LD0 block status
BEH_TST	BOOLEAN	Logical device LD0 test status

3.8 Fault recorder FLR

3.8.1 Function block

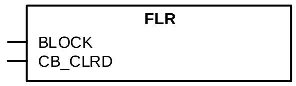


Figure 21: Function block

3.8.2 Functionality

The protection relay has the capacity to store the records of 128 latest fault events. Fault records include fundamental or RMS current values. The records enable the user to analyze recent power system events. Each fault record (FLTRFRC) is marked with an up-counting fault number and a time stamp that is taken from the beginning of the fault.

The fault recording period begins from the pickup event of any protection function and ends if any protection function trips or the pickup(s) is restored before the trip event. If a pickup is restored without a trip event, the pickup duration shows the protection function that has picked up first.

Pickup duration that has the value of 100% indicates that a protection function has tripped during the fault and if none of the protection functions has been tripped, Pickup duration shows always values less than 100%.

The Fault recorded data Protection and Pickup duration is from the same protection function. The Fault recorded data trip time shows the time of the actual fault period. This value is the time difference between the activation of the internal pickup and trip signals. The actual trip time also includes the pickup time and the delay of the output relay. The Fault recorded data *Breaker clear time* is the time difference between internal trip signal and activation of `CB_CLRD` input.

If some functions in relay application are sensitive to start frequently it might be advisable to set the setting parameter *Trig mode* to “From trip”. Then only faults that cause an trip event trigger a new fault recording.

The fault-related current, voltage, frequency, angle values, shot pointer and the active setting group number are taken from the moment of the operate event, or from the beginning of the fault if only a pickup event occurs during the fault. The maximum current value collects the maximum fault currents during the fault. In case frequency cannot be measured, nominal frequency is used for frequency and zero for Frequency gradient and validity is set accordingly.

Measuring mode for phase current and residual current values can be selected with the *Measurement mode* setting parameter.

3.8.3 Settings

Table 44: FLR settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Trig mode	0=Trip or Pickup 1=Trip only 2=Pickup only			0=Trip or Pickup	Triggering mode

Table 45: FLR settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode

3.8.4 Monitored data

Table 46: FLR Monitored data

Name	Type	Values (Range)	Unit	Description
Fault number	INT32	0...999999		Fault record number
Time and date	Timestamp			Fault record time stamp
Protection	Enum	0=Unknown 1=PHLPTOC1 2=PHLPTOC2 6=PHHPTOC1 7=PHHPTOC2 8=PHHPTOC3 9=PHHPTOC4 12=PHIPTOC1 13=PHIPTOC2 17=EFLPTOC1 18=EFLPTOC2 19=EFLPTOC3 22=EFHPTOC1 23=EFHPTOC2 24=EFHPTOC3 25=EFHPTOC4 30=EFIPTOC1 31=EFIPTOC2 32=EFIPTOC3 35=NSPTOC1 36=NSPTOC2 -7=INTRPTEF1 -5=STTPMSU1 -3=JAMPTOC1 41=PDNSPTOC1 44=T1PTTR1 46=T2PTTR1 48=MPTTR1 50=DEFLPDEF1 51=DEFLPDEF2 53=DEFHPDEF1 56=EFPADM1 57=EFPADM2 58=EFPADM3 59=FRPFRQ1 60=FRPFRQ2 61=FRPFRQ3 62=FRPFRQ4 63=FRPFRQ5 64=FRPFRQ6		Protection function
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
		65=LSHDPFRQ1 66=LSHDPFRQ2 67=LSHDPFRQ3 68=LSHDPFRQ4 69=LSHDPFRQ5 71=DPHLPDOC1 72=DPHLPDOC2 74=DPHHPDOC1 77=MAPGAPC1 78=MAPGAPC2 79=MAPGAPC3 85=MNSPTOC1 86=MNSPTOC2 88=LOFLPTUC1 90=TR2PTDF1 91=LNPLDF1 92=LREFPNDF1 94=MPDIF1 96=HREFPDIF1 100=ROVPTOV1 101=ROVPTOV2 102=ROVPTOV3 104=PHPTOV1 105=PHPTOV2 106=PHPTOV3 108=PHPTUV1 109=PHPTUV2 110=PHPTUV3 112=NSPTOV1 113=NSPTOV2 116=PSPTUV1 118=ARCSARC1 119=ARCSARC2 120=ARCSARC3 -96=SPHIPTOC1 -93=SPHLPTOC2 -92=SPHLPTOC1 -89=SPHHPTOC2 -88=SPHHPTOC1 -87=SPHPTUV4 -86=SPHPTUV3 -85=SPHPTUV2 -84=SPHPTUV1		

Table continues on next page

Name	Type	Values (Range)	Unit	Description
		-83=SPHPTOV4 -82=SPHPTOV3 -81=SPHPTOV2 -80=SPHPTOV1 -25=OEPVPH4 -24=OEPVPH3 -23=OEPVPH2 -22=OEPVPH1 -19=PSPTOV2 -18=PSPTOV1 -15=PREVPTOC1 -12=PHPTUC2 -11=PHPTUC1 -9=PHIZ1 5=PHLTPTOC1 20=EFLPTOC4 26=EFHPTOC5 27=EFHPTOC6 37=NSPTOC3 38=NSPTOC4 45=T1PTTR2 54=DEFHPDEF2 75=DPHHPDOC2 89=LOFLPTUC2 103=ROVPTOV4 117=PSPTUV2 -13=PHPTUC3 3=PHLPTOC3 10=PHHPTOC5 11=PHHPTOC6 28=EFHPTOC7 29=EFHPTOC8 107=PHPTOV4 111=PHPTUV4 114=NSPTOV3 115=NSPTOV4 -30=PHDSTPDIS1 -29=TR3PTDF1 -28=HICPDIF1 -27=HIBPDIF1 -26=HIAPDIF1 -32=LSHDPFRQ8 -31=LSHDPFRQ7 70=LSHDPFRQ6 80=MAPGAPC4 81=MAPGAPC5 82=MAPGAPC6		

Table continues on next page

Name	Type	Values (Range)	Unit	Description
		83=MAPGAPC7 -102=MAPGAPC12 -101=MAPGAPC11 -100=MAPGAPC10 -99=MAPGAPC9 -98=RESCPSCH1 -57=FDEFLPDEF2 -56=FDEFLPDEF1 -54=FEFLPTOC1 -53=FDPHLPDOC2 -52=FDPHLPDOC1 -50=FPHLPTOC1 -47=MAP12GAPC8 -46=MAP12GAPC7 -45=MAP12GAPC6 -44=MAP12GAPC5 -43=MAP12GAPC4 -42=MAP12GAPC3 -41=MAP12GAPC2 -40=MAP12GAPC1 -37=HAEFPTOC1 -35=WPWDE3 -34=WPWDE2 -33=WPWDE1 52=DEFLPDEF3 84=MAPGAPC8 93=LREFPNDF2 97=HREFPDIF2 -117=XDEFLPDEF2 -116=XDEFLPDEF1		

Table continues on next page

Name	Type	Values (Range)	Unit	Description
		-115=SDPHLPD OC2 -114=SDPHLPD OC1 -113=XNSPTOC 2 -112=XNSPTOC 1 -111=XEFIPTOC 2 -110=XEFHPTO C4 -109=XEFHPTO C3 -108=XEFLPTO C3 -107=XEFLPTO C2 -66=DQPTUV1 -65=VVSPPAM1 -64=PHPVOC1 -63=H3EFPSEF 1 -60=HCUBPTO C1 -59=CUBPTOC1 -72=DOPPDPR1 -69=DUPPDPR1 -61=COLPTOC1 -106=MAPGAPC 16 -105=MAPGAPC 15 -104=MAPGAPC 14 -103=MAPGAPC 13 -76=MAPGAPC1 8 -75=MAPGAPC1 7 -62=SRCPTOC1 -74=DOPPDPR3 -73=DOPPDPR2 -70=DUPPDPR2 -58=UZPDIS1 -36=UEXPDIS1 14=MFADPSDE 1 -10=LVRTPTUV 1 -8=LVRTPTUV2 -6=LVRTPTUV3		

Table continues on next page

Name	Type	Values (Range)	Unit	Description
		-122=DPH3LPDOC1 -121=DPH3HPDOC2 -120=DPH3HPDOC1 -119=PH3LPTOC2 -118=PH3LPTOC1 -79=PH3HPTOC2 -78=PH3HPTOC1 -77=PH3IPTOC1 -127=PHAPTUV1 -124=PHAPTOV1 -123=DPH3LPDOC2 -68=PHPVOC2 -67=DQPTUV2 -39=UEXPDIS2 98=MHZPDIF1 -4=MREFPTOC1 -21=JAMPTOC2		
Pickup duration	FLOAT32	0.00...100.00	%	Maximum pickup duration of all stages during the fault
Trip time	FLOAT32	0.000...999999.999	s	Trip time
Breaker clear time	FLOAT32	0.000...3.000	s	Breaker clear time
Fault distance	FLOAT32	0.00...3000.00	pu	Distance to fault measured in pu
Fault resistance	FLOAT32	0.00...1000000.00	ohm	Fault resistance
Fault loop resistance	FLOAT32	-1000.00...1000.00	ohm	Resistance of fault loop
Fault loop reactance	FLOAT32	-1000.00...1000.00	ohm	Reactance of fault loop
Setting group	INT32	1...6		Active setting group
Shot pointer	INT32	1...7		Autoreclosing shot pointer value
Max diff current IA	FLOAT32	0.000...80.000	pu	Maximum phase A differential current
Max diff current IB	FLOAT32	0.000...80.000	pu	Maximum phase B differential current
Max diff current IC	FLOAT32	0.000...80.000	pu	Maximum phase C differential current
Diff current IA	FLOAT32	0.000...80.000	pu	Differential current phase A

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Diff current IB	FLOAT32	0.000...80.000	pu	Differential current phase B
Diff current IC	FLOAT32	0.000...80.000	pu	Differential current phase C
Max bias current IA	FLOAT32	0.000...50.000	pu	Maximum phase A bias current
Max bias current IB	FLOAT32	0.000...50.000	pu	Maximum phase B bias current
Max bias current IC	FLOAT32	0.000...50.000	pu	Maximum phase C bias current
Bias current IA	FLOAT32	0.000...50.000	pu	Bias current phase A
Bias current IB	FLOAT32	0.000...50.000	pu	Bias current phase B
Bias current IC	FLOAT32	0.000...50.000	pu	Bias current phase C
Diff current IG	FLOAT32	0.000...80.000	pu	Differential current residual
Bias current IG	FLOAT32	0.000...50.000	pu	Bias current residual
Max current IA	FLOAT32	0.000...50.000	xIn	Maximum phase A current
Max current IB	FLOAT32	0.000...50.000	xIn	Maximum phase B current
Max current IC	FLOAT32	0.000...50.000	xIn	Maximum phase C current
Max current IG	FLOAT32	0.000...50.000	xIn	Maximum residual current
Current IA	FLOAT32	0.000...50.000	xIn	Phase A current
Current IB	FLOAT32	0.000...50.000	xIn	Phase B current
Current IC	FLOAT32	0.000...50.000	xIn	Phase C current
Current IG	FLOAT32	0.000...50.000	xIn	Residual current
Current IN	FLOAT32	0.000...50.000	xIn	Calculated residual current
Current I1	FLOAT32	0.000...50.000	xIn	Positive sequence current
Current I2	FLOAT32	0.000...50.000	xIn	Negative sequence current
Max current IA2	FLOAT32	0.000...50.000	xIn	Maximum phase A current (b)
Max current IB2	FLOAT32	0.000...50.000	xIn	Maximum phase B current (b)
Max current IC2	FLOAT32	0.000...50.000	xIn	Maximum phase C current (b)
Max current IG2	FLOAT32	0.000...50.000	xIn	Maximum residual current (b)
Current IA2	FLOAT32	0.000...50.000	xIn	Maximum phase A current (b)
Current IB2	FLOAT32	0.000...50.000	xIn	Maximum phase B current (b)
Current IC2	FLOAT32	0.000...50.000	xIn	Maximum phase C current (b)
Current IG2	FLOAT32	0.000...50.000	xIn	Residual current (b)
Current I0B	FLOAT32	0.000...50.000	xIn	Calculated residual current (b)
Current I1B	FLOAT32	0.000...50.000	xIn	Positive sequence current (b)
Current I2B	FLOAT32	0.000...50.000	xIn	Negative sequence current (b)
Max current IA3	FLOAT32	0.000...50.000	xIn	Maximum phase A current (c)
Max current IB3	FLOAT32	0.000...50.000	xIn	Maximum phase B current (c)

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Max current IC3	FLOAT32	0.000...50.000	xIn	Maximum phase C current (c)
Max current IG3	FLOAT32	0.000...50.000	xIn	Maximum residual current (c)
Current IA3	FLOAT32	0.000...50.000	xIn	Phase A current (c)
Current IB3	FLOAT32	0.000...50.000	xIn	Phase B current (c)
Current IC3	FLOAT32	0.000...50.000	xIn	Phase C current (c)
Current IG3	FLOAT32	0.000...50.000	xIn	Residual current (c)
Current I0C	FLOAT32	0.000...50.000	xIn	Calculated residual current (c)
Current I1C	FLOAT32	0.000...50.000	xIn	Positive sequence current (c)
Current I2C	FLOAT32	0.000...50.000	xIn	Negative sequence current (c)
Voltage VA	FLOAT32	0.000...4.000	xUn	Phase A voltage
Voltage VB	FLOAT32	0.000...4.000	xUn	Phase B voltage
Voltage VC	FLOAT32	0.000...4.000	xUn	Phase C voltage
Voltage VAB	FLOAT32	0.000...4.000	xUn	Phase A to phase B voltage
Voltage VBC	FLOAT32	0.000...4.000	xUn	Phase B to phase C voltage
Voltage VCA	FLOAT32	0.000...4.000	xUn	Phase C to phase A voltage
Voltage VG	FLOAT32	0.000...4.000	xUn	Residual voltage
Voltage V0	FLOAT32	0.000...4.000	xUn	Zero sequence voltage
Voltage V1	FLOAT32	0.000...4.000	xUn	Positive sequence voltage
Voltage V2	FLOAT32	0.000...4.000	xUn	Negative sequence voltage
Voltage VA2	FLOAT32	0.000...4.000	xUn	Phase A voltage (b)
Voltage VB2	FLOAT32	0.000...4.000	xUn	Phase B voltage (b)
Voltage VC2	FLOAT32	0.000...4.000	xUn	Phase B voltage (b)
Voltage VAB2	FLOAT32	0.000...4.000	xUn	Phase A to phase B voltage (b)
VoltageVBC2	FLOAT32	0.000...4.000	xUn	Phase B to phase C voltage (b)
Voltage VCA2	FLOAT32	0.000...4.000	xUn	Phase C to phase A voltage (b)
Voltage VG2	FLOAT32	0.000...4.000	xUn	Residual voltage (b)
Voltage Zro-SeqB	FLOAT32	0.000...4.000	xUn	Zero sequence voltage (b)
Voltage Ps-SeqB	FLOAT32	0.000...4.000	xUn	Positive sequence voltage (b)
Voltage Ng-SeqB	FLOAT32	0.000...4.000	xUn	Negative sequence voltage (b)
49 thermal level	FLOAT32	0.00...99.99		49 calculated temperature of the protected object relative to the trip level
PDNSPTOC1 rat. I2/I1	FLOAT32	0.00...999.99	%	46PD ratio I2/I1
Frequency	FLOAT32	30.00...80.00	Hz	Frequency

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Frequency gradient	FLOAT32	-10.00...10.00	Hz/s	Frequency gradient
Conductance Yo	FLOAT32	-1000.00...1000.00	mS	Conductance Yo
Susceptance Yo	FLOAT32	-1000.00...1000.00	mS	Susceptance Yo
Angle VG - IG	FLOAT32	-180.00...180.00	deg	Angle residual voltage - residual current
Angle VBC - IA	FLOAT32	-180.00...180.00	deg	Angle phase B to phase C voltage - phase A current
Angle VCA - IB	FLOAT32	-180.00...180.00	deg	Angle phase C to phase A voltage - phase B current
Angle VAB - IC	FLOAT32	-180.00...180.00	deg	Angle phase A to phase B voltage - phase C current
Angle VG2 - IG2	FLOAT32	-180.00...180.00	deg	Angle residual voltage - residual current (b)
Angle VBC2 - IA2	FLOAT32	-180.00...180.00	deg	Angle phase B to phase C voltage - phase A current (b)
Angle VCA2 - IB2	FLOAT32	-180.00...180.00	deg	Angle phase C to phase A voltage - phase B current (b)
Angle VAB2 - IC2	FLOAT32	-180.00...180.00	deg	Angle phase A to phase B voltage - phase C current (b)

3.9 Non-volatile memory

The relay does not include any battery backup power. If the auxiliary power is lost, critical information such as relay configuration and settings, events, disturbance recordings and other critical data are saved to the relay’s non-volatile memory. The relay’s real-time clock keeps running via a 48-hour capacitor backup.

- Up to 1024 events are stored. The stored events are visible in LHMI and WHMI only
- Recorded data
    - Fault records (up to 128)
    - Maximum demands
- Circuit breaker condition monitoring
- Latched alarm and trip LEDs' statuses
- Trip circuit lockout
- Counter values
- Load profile

3.10 Sensor inputs for currents and voltages

This chapter gives short examples on how to define the correct parameters for sensors.

Sensors have corrections factors, measured and verified by the sensor manufacturer, to increase the measurement accuracy of primary values. Correction factors are recommended to be set. Two types of correction factors are available for voltage and rogowski sensors. The Amplitude correction factor is named *Amplitude corr. A(B/C)* and Angle correction factor is named *Angle corr A(B/C)*. These correction factors can be found on the Sensor's rating plate. If the correction factors are not available, contact the sensor manufacturer for more information.

Rogowski sensor setting example

In this example, an 80 A/0.150 V at 50 Hz sensor is used and the application has a 150 A nominal current (In). As the Rogowski sensor is linear and does not saturate, the 80 A/ 0.150 V at 50 Hz sensor also works as a 150 A/0.28125 V at 50 Hz sensor. When defining another primary value for the sensor, also the nominal voltage has to be redefined to maintain the same transformation ratio. However, the setting in the protection relay (*Rated Secondary Value*) is not in V but in mV/Hz, which makes the same setting value valid for both 50 and 60 Hz nominal frequency.

$$RSV = \frac{\frac{I_n}{I_{pr}} \times K_r}{f_n}$$

(Equation 1)

RSV	*Rated Secondary Value* in mV/Hz
I_n	Application nominal current
I_{pr}	Sensor-rated primary current
f_n	Network nominal frequency
K_r	Sensor-rated voltage at the rated current in mV

In this example, the value is as calculated using the equation.

$$\frac{\frac{150A}{80A} \times 150mV}{50Hz} = 5.625\frac{mV}{Hz}$$

(Equation 2)

With this information, the protection relay's Rogowski sensor settings can be set.

Table 47: Example setting values for rogowski sensor

Setting	Value
Primary current	150 A
Rated secondary value	5.625 mV/Hz
Nominal current	150 A

Unless otherwise specified, the *Nominal Current* setting should always be the same as the *Primary Current* setting.

Voltage sensor setting example

The voltage sensor is based on the resistive divider or capacitive divider principle. Therefore, the voltage is linear throughout the whole measuring range. The output signal is a voltage, directly proportional to the primary voltage. For the voltage sensor all parameters are readable directly from its rating plate and conversions are not needed.

In this example the system phase-to-phase voltage rating is 10 kV. Thus, the *Primary voltage* parameter is set to 10 kV. For protection relays with sensor measurement support the *Voltage input type* is always set to “CVD sensor” and it cannot be changed. The same applies for the *VT connection* parameter which is always set to “WYE” type. The division ratio for ABB voltage sensors is most often 10000:1. Thus, the *Division ratio* parameter is usually set to “10000”. The primary voltage is proportionally divided by this division ratio.

Table 48: Example setting values for voltage sensor

Setting	Value
Primary voltage	10 kV
VT connection	Wye
Voltage input type	3=CVD sensor
Division ratio	10000

3.11 Binary input

3.11.1 Binary input filter time

The filter time eliminates debounces and short disturbances on a binary input. The filter time is set for each binary input of the protection relay.

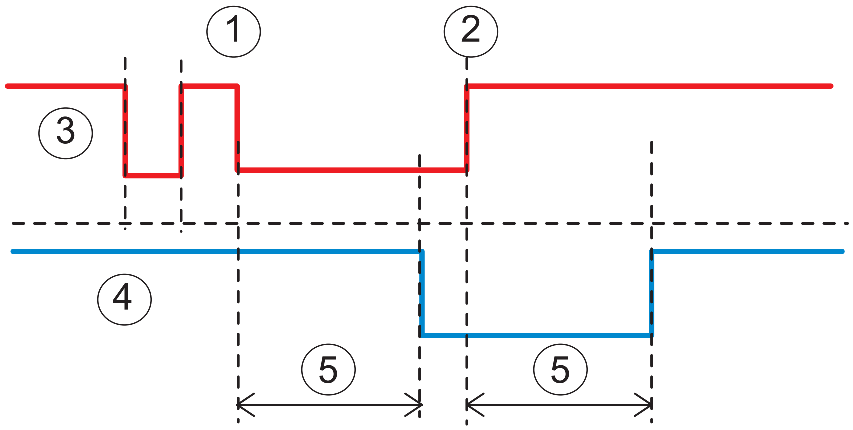


Figure 22: Binary input filtering

1 t_0

2 t_1

3 Input signal

4 Filtered input signal

5 Filter time

At the beginning, the input signal is at the high state, the short low state is filtered and no input state change is detected. The low state starting from the time t_0 exceeds the filter time, which means that the change in the input state is detected and the time tag attached to the input change is t_0. The high state starting from t_1 is detected and the time tag t_1 is attached.

Each binary input has a filter time parameter *Input # filter*, where # is the number of the binary input of the module in question (for example *Input 1 filter*).

Table 49: Input filter parameter values

Parameter	Values	Default
Input # filter time	5...1000 ms	5 ms

3.11.2 Binary input inversion

The parameter *Input # invert* is used to invert a binary input.

Table 50: Binary input states

Control voltage	Input # invert	State of binary input
No	0	FALSE (0)
Yes	0	TRUE (1)
No	1	TRUE (1)
Yes	1	FALSE (0)

When a binary input is inverted, the state of the input is TRUE (1) when no control voltage is applied to its terminals. Accordingly, the input state is FALSE (0) when a control voltage is applied to the terminals of the binary input.

3.11.3 Oscillation suppression

Oscillation suppression is used to reduce the load from the system when a binary input starts oscillating. A binary input is regarded as oscillating if the number of valid state changes (= number of events after filtering) during one second is equal to or greater than the set oscillation level value. During oscillation, the binary input is blocked (the status is invalid) and an event is generated. The state of the input will not change when it is blocked, that is, its state depends on the condition before blocking.

The binary input is regarded as non-oscillating if the number of valid state changes during one second is less than the set oscillation level value minus the set oscillation hysteresis value. Note that the oscillation hysteresis must be set lower than the oscillation level to enable the input to be restored from oscillation. When the input returns to a non-oscillating state, the binary input is deblocked (the status is valid) and an event is generated.

Table 51: Oscillation parameter values

Parameter	Values	Default
Input osc. level	2...50 events/s	30 events/s
Input osc. hyst	2...50 events/s	10 events/s

3.12 Binary outputs

The protection relay provides a number of binary outputs used for tripping, executing local or remote control actions of a breaker or a disconnector, and for connecting the protection relay to external annunciation equipment for indicating, signalling and recording.

Power output contacts are used when the current rating requirements of the contacts are high, for example, for controlling a breaker, such as energizing the breaker trip and closing coils.

The contacts used for external signalling, recording and indicating, the signal outputs, need to adjust to smaller currents, but they can require a minimum current (burden) to ensure a guaranteed operation.

The protection relay provides both power output and signal output contacts. To guarantee proper operation, the type of the contacts used are chosen based on the operating and reset time, continuous current rating, make and carry for short time, breaking rate and minimum connected burden. A combination of series or parallel contacts can also be used for special applications. When appropriate, a signal output can also be used to energize an external trip relay, which in turn can be confiugred to energize the breaker trip or close coils.

Using an external trip relay can require an external trip circuit supervision relay. It can also require wiring a separate trip relay contact back to the protection relay for breaker failure protection function.

All contacts are freely programmable, except the internal fault output IRF.

3.12.1 Power output contacts

Power output contacts are normally used for energizing the breaker closing coil and trip coil, external high burden lockout or trip relays.

3.12.1.1 Dual single-pole power outputs PO1 and PO2 in power supply module

Dual (series-connected) single-pole (normally open/form A) power output contacts PO1 and PO2 are rated for continuous current of 8 A. The contacts are normally used for closing circuit breakers and energizing high burden trip relays. They can be arranged to trip the circuit breakers when the trip circuit supervision is not available or when external trip circuit supervision relay is provided.

The power outputs are included in slot X100 of the power supply module.

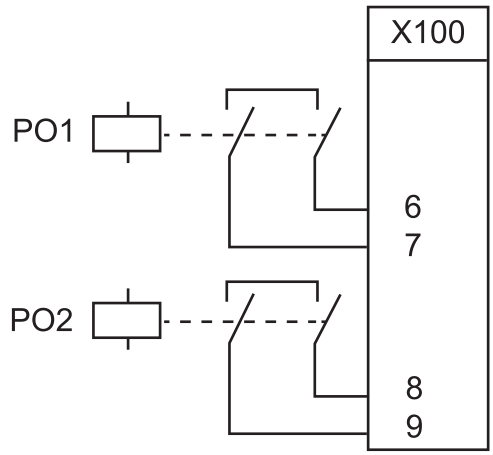


Figure 23: Dual single-pole power output contacts PO1 and PO2

3.12.1.2 Double-pole power outputs PO3 and PO4 with trip circuit supervision in power supply module

The power outputs PO3 and PO4 are double-pole normally open/form A power outputs with trip circuit supervision.

When the two poles of the contacts are connected in series, they have the same technical specification as PO1 for breaking duty. The trip circuit supervision hardware and associated functionality which can supervise the breaker coil both during closing and opening condition are also provided. Contacts PO3 and PO4 are almost always used for energizing the breaker trip coils.

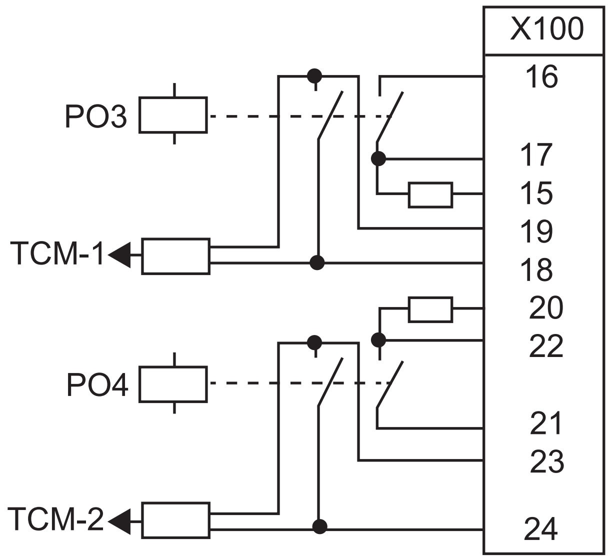


Figure 24: Double-pole power outputs PO3 and PO4 with trip circuit supervision

Power outputs PO3 and PO4 are included in the power supply module located in slot X100 of the protection relay.

3.12.1.3 Dual single-pole high-speed power outputs HSO1, HSO2 and HSO3 in BIO0007

HSO1, HSO2 and HSO3 are dual parallel connected, single-pole, normally open/form A high-speed power outputs. The high-speed power output is a hybrid discrete and electromechanical output that is rated as a power output.

The outputs are normally used in applications that require fast relay output contact activation time to achieve fast opening of a breaker, such as, arc-protection or breaker failure protection, where fast operation is required either to minimize fault effects to the equipment or to avoid a fault to expand to a larger area. With the high-speed outputs, the total time from the application to the relay output contact activation is 5...6 ms shorter than when using output contacts with conventional mechanical output relays. The high-speed power outputs have a continuous rating of 6 A.

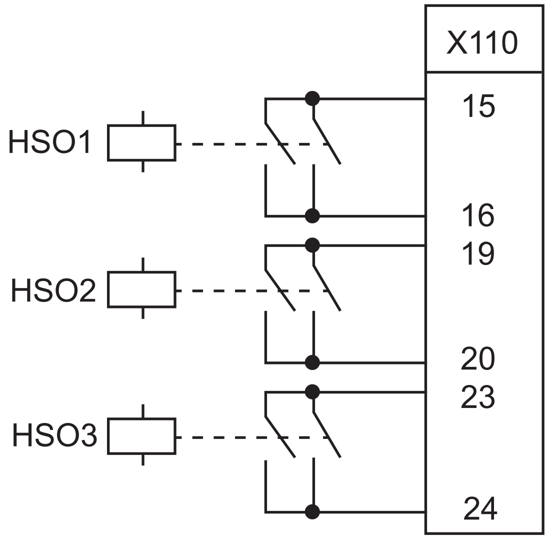


Figure 25: High-speed power outputs HSO1, HSO2 and HSO3

The reset time of the high-speed output contacts is longer than that of the conventional output contacts.

High-speed power contacts are part of the card BIO0007 with eight binary inputs and three HSOs. They are optional alternatives to conventional BIO cards of the protection relay.

3.12.2 Signal output contacts

Signal output contacts are single-pole, single (normally open/form A or change-over/form C) signal output contacts (SO1, SO2,...) or parallel connected dual contacts.

The signal output contacts are used for energizing, for example, external low burden trip relays, auxiliary relays, annunciators and LEDs.

A single signal contact is rated for a continuous current of 5 A. It has a make and carry for 0.5 seconds at 15 A.

When two contacts are connected in parallel, the relay is of a different design. It has the make and carry rating of 30 A for 0.5 seconds. This can be applied for energizing breaker close coil and tripping coil. Due to the limited breaking capacity, a breaker auxiliary contact can be required to break the circuit.

3.12.2.1 Internal fault signal output IRF

The internal fault signal output (change-over/form C) IRF is a single contact included in the power supply module of the protection relay.

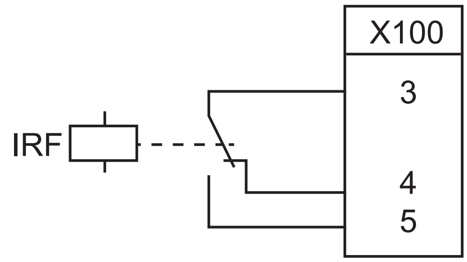


Figure 26: Internal fault signal output IRF

3.12.2.2 Signal outputs SO1 and SO2 in power supply module

Signal outputs (normally open/form A or change-over/form C) SO1 (dual parallel form C) and SO2 (single contact/form A) are part of the power supply module of the protection relay.

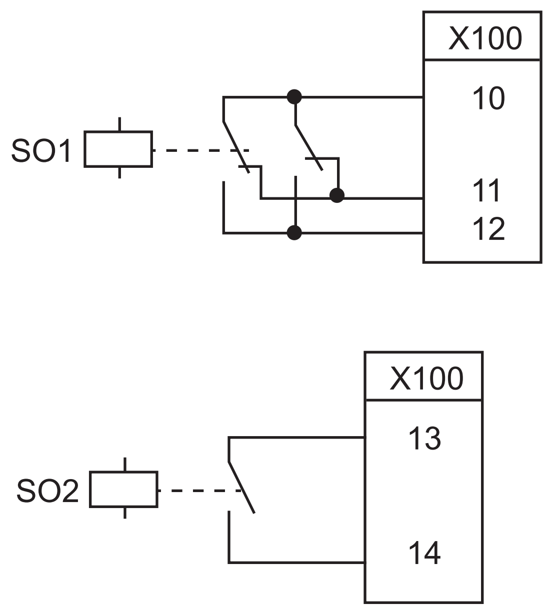


Figure 27: Signal outputs SO1 and SO2 in power supply module

3.12.2.3 Signal outputs SO1, SO2, SO3 and SO4 in BIO0005

The optional card BIO0005 provides the signal outputs SO1, SO2 SO3 and SO4. Signal outputs SO1 and SO2 are dual, parallel form C contacts; SO3 is a single form C contact, and SO4 is a single form A contact.

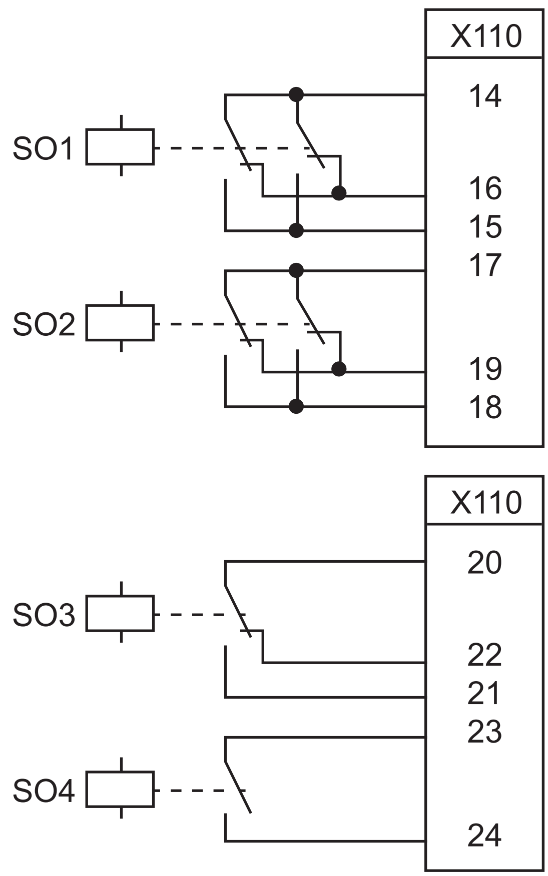


Figure 28: Signal output in BIO0005

3.12.2.4 Signal outputs SO1, SO2 and SO3 in BIO0006

The optional card BIO0006 provides the signal outputs SO1, SO2 and SO3. Signal outputs SO1 and SO2 are dual, parallel form C contacts; SO3 is a single form C contact.

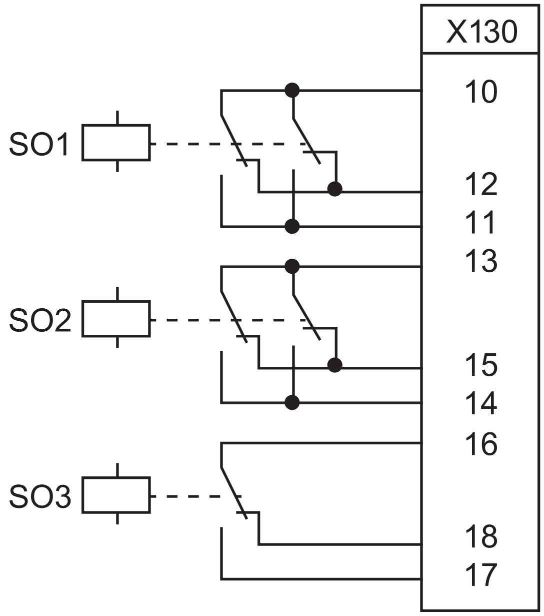


Figure 29: Signal output in BIO0006

3.13 RTD/mA inputs

3.13.1 Functionality

The RTD and mA analog input module is used for monitoring and metering current (mA), temperature (°C) and resistance (Ω). Each input can be linearly scaled for various applications, for example, transformer's tap changer position indication. Each input has independent limit value supervision and deadband supervision functions, including warning and alarm signals.

3.13.2 Operation principle

All the inputs of the module are independent RTD and mA channels with individual protection, reference and optical isolation for each input, making them galvanically isolated from each other and from the rest of the module. However, the RTD inputs share a common ground.

3.13.2.1 Selection of input signal type

The function module inputs accept current or resistance type signals. The inputs are configured for a particular type of input type by the channel-specific *Input mode* setting.

The default value for all inputs is “Not in use”, which means that the channel is not sampled at all, and the output value quality is set accordingly.

Table 52: Limits for the RTD/mA inputs

Input mode	Description
Not in use	Default selection. Used when the corresponding input is not used.
0...20 mA	Selection for analog DC milliampere current inputs in the input range of 0...20 mA.
Resistance	Selection for RTD inputs in the input range of 0...2000 Ω.
Pt100 Pt250 Ni100 Ni120 Ni250 Cu10	Selection for RTD inputs, when temperature sensor is used. All the selectable sensor types have their resistance vs. temperature characteristics stored in the module; default measuring range is -40...200°C.

3.13.2.2 Selection of output value format

Each input has independent *Value unit* settings that are used to select the unit for the channel output. The default value for the *Value unit* setting is “Dimensionless”. *Input minimum* and *Input maximum*, and *Value maximum* and *Value minimum* settings have to be adjusted according to the input channel. The default values for these settings are set to their maximum and minimum setting values.

When the channel is used for temperature sensor type, set the *Value unit* setting to “Degrees celsius”. When *Value unit* is set to “Degrees celsius”, the linear scaling is not possible, but the default range (-40…200 °C) can be set smaller with the *Value maximum* and *Value minimum* settings.

When the channel is used for DC milliampere signal and the application requires a linear scaling of the input range, the *Value unit* setting value has to be "Dimensionless”, where the input range can be linearly scaled with settings *Input minimum* and *Input maximum* to *Value minimum* and *Value maximum*. When milliampere is used as an output unit, *Value unit* has to be "Ampere”. When *Value unit* is set to “Ampere”, the linear scaling is not possible, but the default range (0…20 mA) can be set smaller with the *Value maximum* and *Value minimum* settings.

When the channel is used for resistance type signals and the application requires a linear scaling of the input range, the *Value unit* setting value has to be "Dimensionless”, where the input range can be linearly scaled with the setting *Input minimum* and *Input maximum* to *Value minimum* and *Value maximum*. When resistance is used as an output unit, *Value unit* has to be "Ohm". When *Value unit* is set to “Ohm”, the linear scaling is not possible, but the default range (0…2000 Ω) can be set smaller with the *Value maximum* and *Value minimum* settings.

3.13.2.3 Input linear scaling

Each RTD/mA input can be scaled linearly by the construction of a linear output function in respect to the input. The curve consists of two points, where the y-axis (*Input minimum* and *Input maximum*) defines the input range and the x-axis (*Value minimum* and *Value maximum*) is the range of the scaled value of the input.

The input scaling can be bypassed by selecting *Value unit* = "Ohm" when *Input mode* = "Resistance" is used and by selecting *Value unit* = "Ampere" when *Input mode* = "0...20 mA" is used.

Example for linear scaling

Milliampere input is used as tap changer position information. The sensor information is from 4 mA to 20 mA that is equivalent to the tap changer position from -36 to 36, respectively.

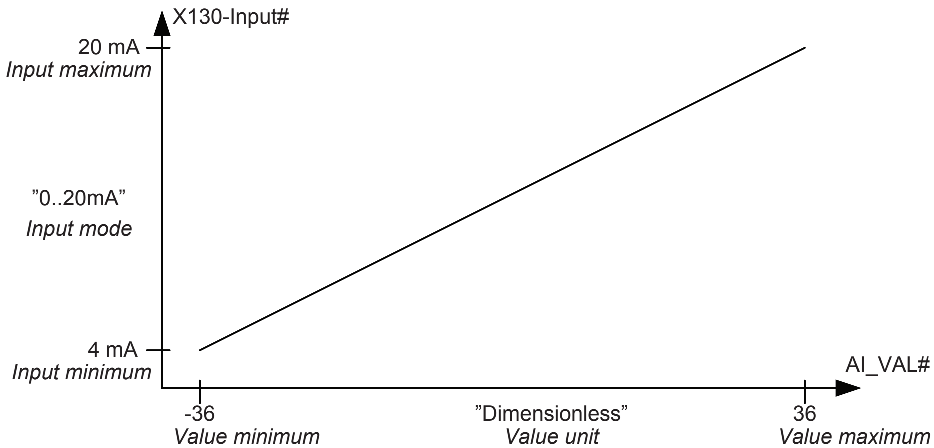


Figure 30: Milliampere input scaled to tap changer position information

3.13.2.4 Measurement chain supervision

Each input contains a functionality to monitor the input measurement chain. The circuitry monitors the RTD channels continuously and reports a circuitry break of any enabled input channel. If the measured input value is outside the limits, minimum/maximum value is shown in the corresponding output. The quality of the corresponding output is set accordingly to indicate misbehavior in the RTD/mA input.

Table 53: Function identification, limits for the RTD/mA inputs

Input	Limit value
RTD temperature, high	> 200 °C
RTD temperature, low	< -40 °C
mA current, high	> 23 mA
Resistance, high	> 2000 Ω

3.13.2.5 Self-supervision

Each input sample is validated before it is fed into the filter algorithm. The samples are validated by measuring an internally set reference current immediately after the inputs are sampled. Each RTD sensor type has expected current based on the sensor type. If the measured offset current deviates from the reference current more than 20%, the sample is discarded and the output is set to invalid. The invalid measure status deactivates as soon as the measured input signal is within the measurement offset.

3.13.2.6 Calibration

RTD and mA inputs are calibrated at the factory. The calibration circuitry monitors the RTD channels continuously and reports a circuitry break of any channel.

3.13.2.7 Limit value supervision

The limit value supervision function indicates whether the measured value of AI_INST# exceeds or falls below the set limits. All the measuring channels have an individual limit value supervision function. The measured value contains the corresponding range information AI_RANGE# and has a value in the range of 0 to 4:

- 0: “normal”
- 1: “high”
- 2: “low”
- 3: “high-high”
- 4: “low-low”

The range information changes and the new values are reported.

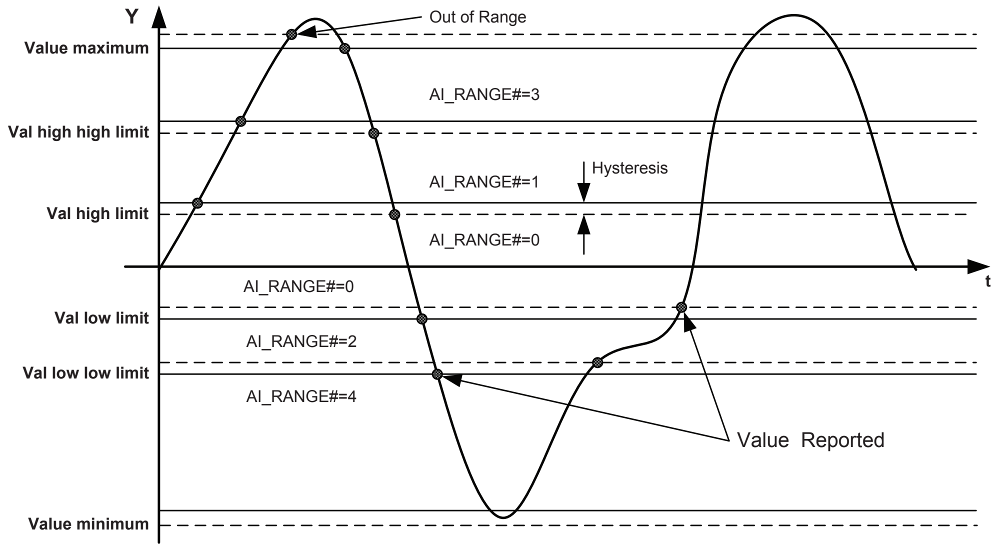


Figure 31: Limit value supervision for RTD

The range information of “High-high limit” and “Low-low limit” is combined from all measurement channels to the Boolean ALARM output. The range information of “High limit” and “Low limit” is combined from all measurement channels to the Boolean WARNING output.

Table 54: Settings for RTD analog input limit value supervision

Function	Settings for limit value supervision	
RTD analog input	Out of range	Value maximum
	High-high limit	Val high high limit
	High limit	Val high limit
	Low limit	Val low limit
	Low-low limit	Val low low limit
	Out of range	Value minimum

When the measured value exceeds either the *Value maximum* setting or the *Value minimum* setting, the corresponding quality is set to out of range and a maximum or minimum value is shown when the measured value exceeds the added hysteresis, respectively. The hysteresis is added to the extreme value of the range limit to allow the measurement slightly to exceed the limit value before it is considered out of range.

3.13.2.8 Deadband supervision

Each input has an independent deadband supervision. The deadband supervision function reports the measured value according to integrated changes over a time period.

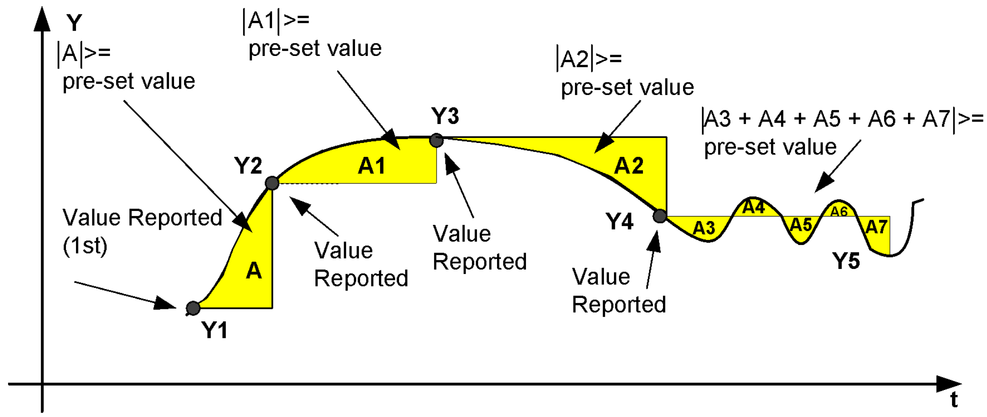


Figure 32: Integral deadband supervision

The deadband value used in the integral calculation is configured with the *Value deadband* setting. The value represents the percentage of the difference between the maximum and minimum limits in the units of 0.001 percent * seconds. The reporting delay of the integral algorithms in seconds is calculated with the formula:

$$t(s) = \frac{(Value\ maximum - Value\ minimum) \cdot \frac{deadband}{100000} s}{\Delta Y}$$

(Equation 3)

Example of X130 (RTD) analog input deadband supervision

Temperature sensor Pt100 is used in the temperature range of 15...180 °C. *Value unit* “Degrees Celsius” is used and the set values *Value minimum* and *Value maximum* are set to 15 and 180, respectively.

Value deadband = 7500 (7.5% of the total measuring range 165)

AI_VAL# = AI_DB# = 85

If AI_VAL# changes to 90, the reporting delay is:

$$t(s) = \frac{(180°C - 15°C) \cdot \frac{7500\,\%s}{100000} s}{90°C - 85°C} \approx 2.5s$$

(Equation 4)

Table 55: Settings for RTD analog deadband supervision

Function	Setting	Maximum/minimum (=range)
RTD analog input	Value deadband	Value maximum / Value minimum (=20000)

Since the function can be utilized in various measurement modes, the default values are set to the extremes; thus, it is very important to set correct limit values to suit the application before the deadband supervision works properly.

3.13.2.9 RTD temperature vs. resistance

Table 56: Temperature vs. resistance

Temp °C	Platinum TCR 0.00385		Nickel TCR 0.00618			Copper TCR 0.00427
	Pt 100	Pt 250	Ni 100	Ni 120	Ni 250	Cu 10
-40	84.27	210.675	79.1	94.92	197.75	7.49
-30	88.22	220.55	84.1	100.92	210.25	-
-20	92.16	230.4	89.3	107.16	223.25	8.263
-10	96.09	240.225	94.6	113.52	236.5	-
0	100	250	100	120	250	9.035
10	103.9	259.75	105.6	126.72	264	-
20	107.79	269.475	111.2	133.44	278	9.807
30	111.67	279.175	117.1	140.52	292.75	-
40	115.54	288.85	123	147.6	307.5	10.58
50	119.4	298.5	129.1	154.92	322.75	-
60	123.24	308.1	135.3	162.36	338.25	11.352
70	127.07	317.675	141.7	170.04	354.25	-
80	130.89	327.225	148.3	177.96	370.75	12.124
90	134.7	336.75	154.9	185.88	387.25	-
100	138.5	346.25	161.8	194.16	404.5	12.897
120	146.06	365.15	176	211.2	440	13.669
140	153.58	383.95	190.9	229.08	477.25	14.442
150	-	-	198.6	238.32	496.5	-
160	161.04	402.6	206.6	247.92	516.5	15.217
180	168.46	421.15	223.2	267.84	558	-
200	175.84	439.6	240.7	288.84	601.75	-

3.13.2.10 RTD/mA input connection

RTD inputs can be used with a 2-wire or 3-wire connection with common ground. When using the 3-wire connection, it is important that all three wires connecting the sensor are symmetrical, that is, the wires are of the same type and length. Thus the wire resistance is automatically compensated.

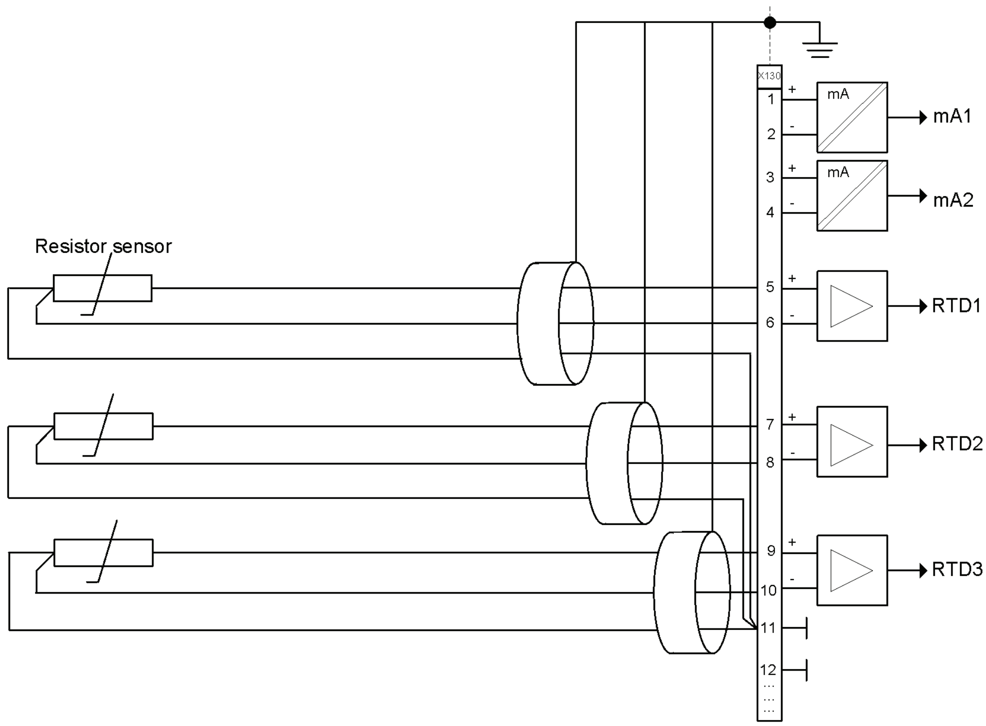


Figure 33: Three RTD/resistance sensors connected according to the 3-wire connection

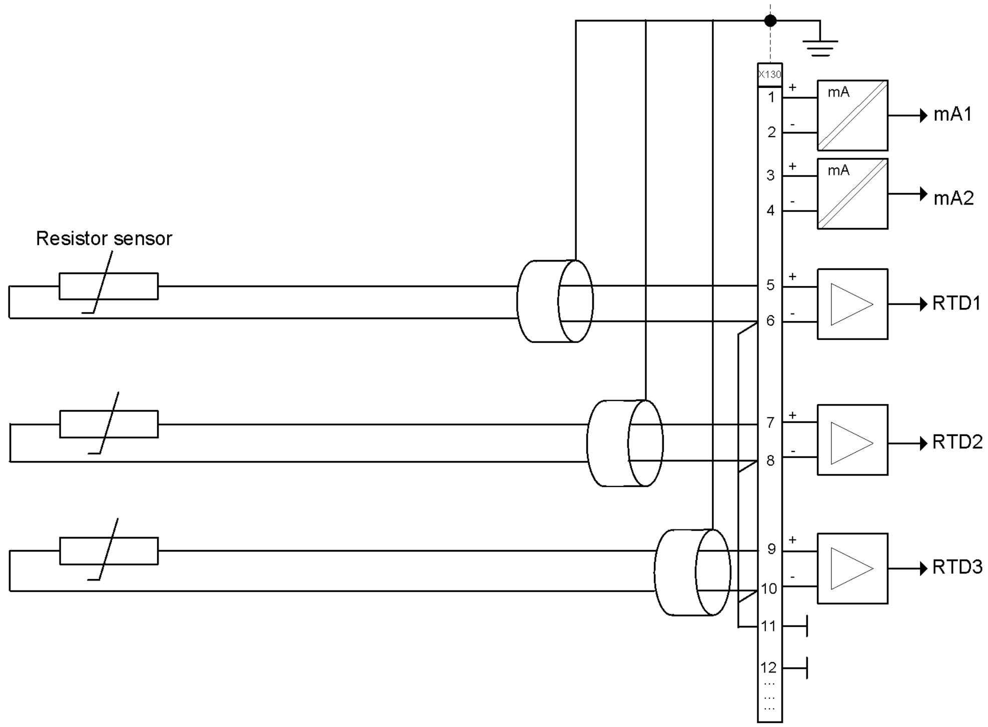


Figure 34: Three RTD/resistance sensors connected according to the 2-wire connection

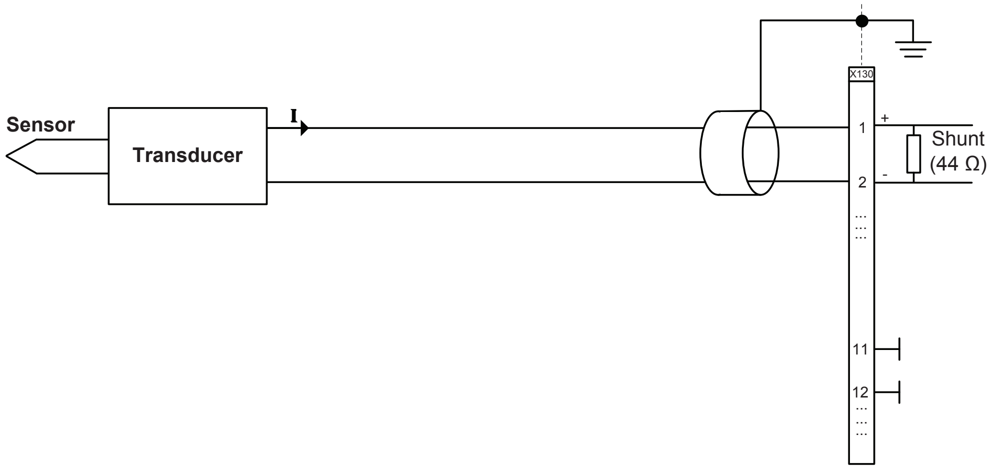


Figure 35: mA wiring connection

3.13.2.11 RTD/mA card variants

The available variants of RTD cards are 6RTD/2mA and 2RTD/1mA. The features are similar in both cards.

6RTD/2mA card

This card accepts two milliampere inputs and six inputs from the RTD sensors. The inputs `1` and `2` are used for current measurement, whereas inputs from `3` to `8` are used for resistance type of measurements.

RTD/mA input connection

Resistance and temperature sensors can be connected to the 6RTD/2mA board with 3-wire and 2-wire connections.

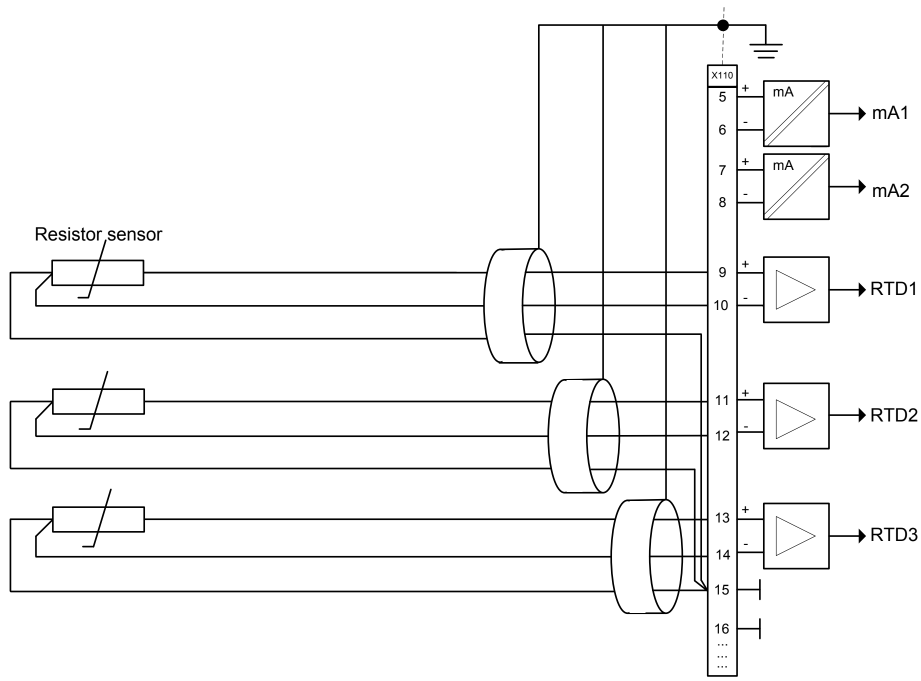


Figure 36: Three RTD sensors and two resistance sensors connected according to the 3-wire connection for 6RTD/2mA card

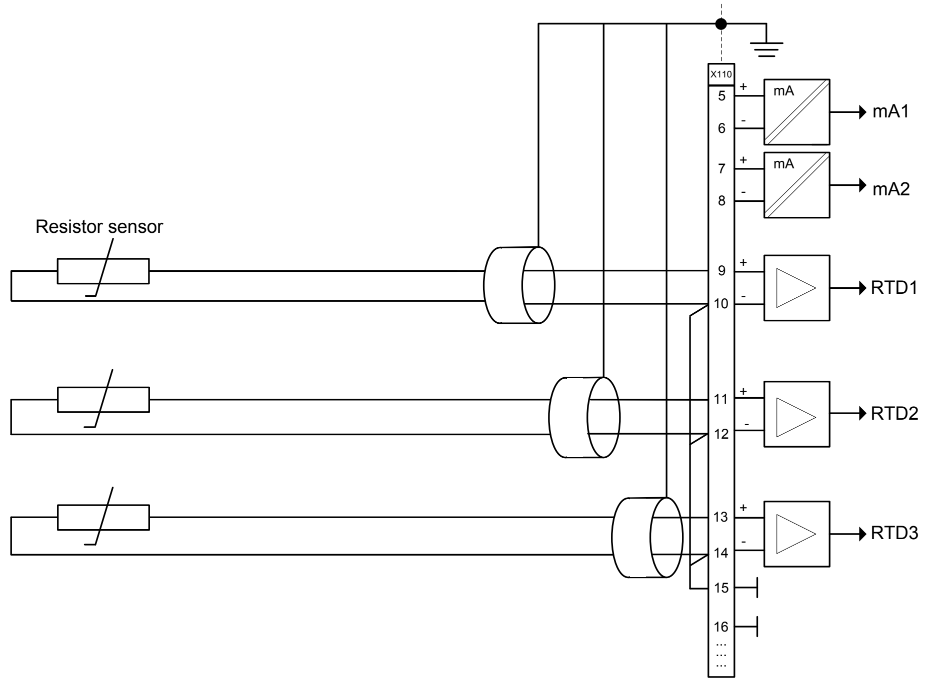


Figure 37: Three RTD sensors and two resistance sensors connected according to the 2-wire connection for 6RTD/2mA card

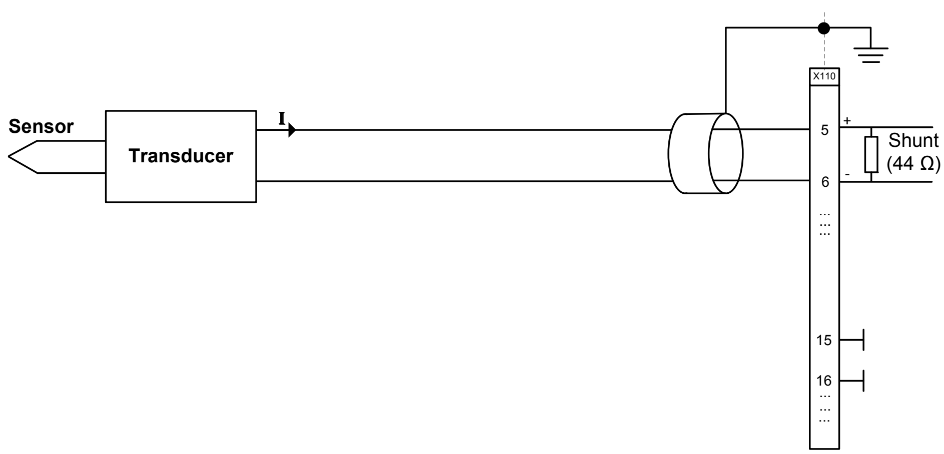


Figure 38: mA wiring connection for 6RTD/2mA card

2RTD/1mA card

This type of card accepts one milliampere input, two inputs from RTD sensors and five inputs from VTs. The Input `1` is assigned for current measurements, inputs `2` and `3` are for RTD sensors and inputs `4` to `8` are used for measuring input data from VT.

RTD/mA input connections

The examples of 3-wire and 2-wire connections of resistance and temperature sensors to the 2RTD/1mA board are as shown:

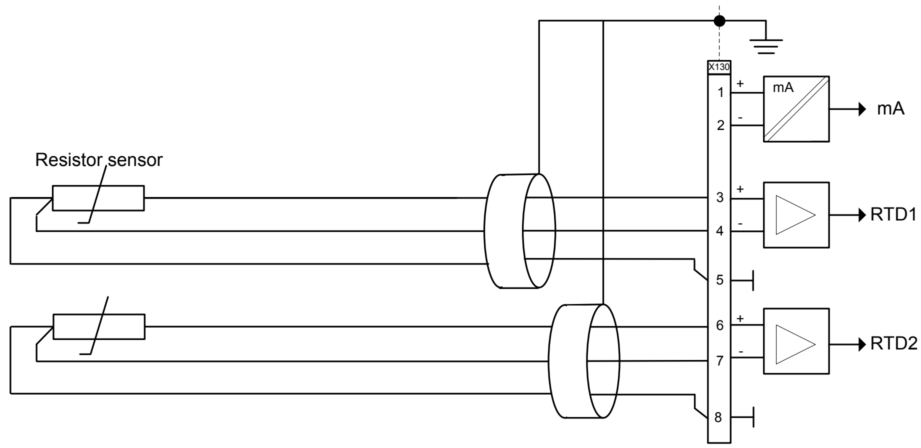


Figure 39: Two RTD and resistance sensors connected according to the 3-wire connection for RTD/mA card

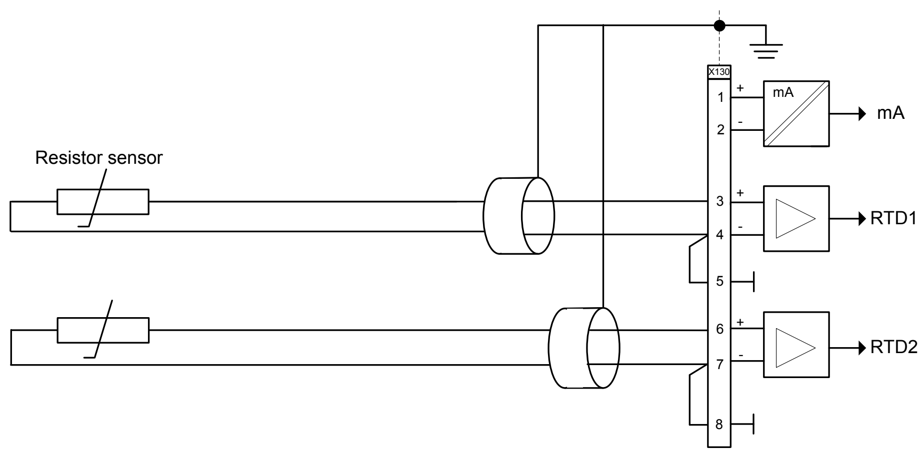


Figure 40: Two RTD and resistance sensors connected according to the 2-wire connection for RTD/mA card

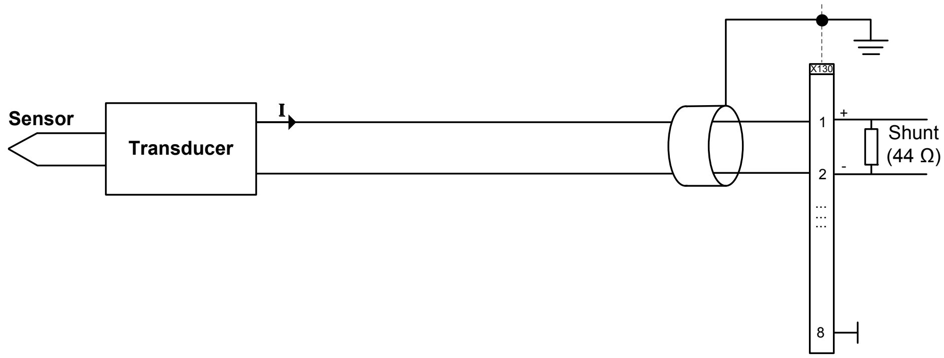


Figure 41: mA wiring connection for RTD/mA card

3.13.3 Signals

Table 57: RTD Output signals

Name	Type	Description
ALARM	BOOLEAN	General alarm
WARNING	BOOLEAN	General warning
AI_VAL1	FLOAT32	mA input, Connectors 1-2, instantaneous value
AI_VAL2	FLOAT32	mA input, Connectors 3-4, instantaneous value
AI_VAL3	FLOAT32	RTD input, Connectors 5-6-11c, instantaneous value
AI_VAL4	FLOAT32	RTD input, Connectors 7-8-11c, instantaneous value
AI_VAL5	FLOAT32	RTD input, Connectors 9-10-11c, instantaneous value
AI_VAL6	FLOAT32	RTD input, Connectors 13-14-12c, instantaneous value
AI_VAL7	FLOAT32	RTD input, Connectors 15-16-12c, instantaneous value
AI_VAL8	FLOAT32	RTD input, Connectors 17-18-12c, instantaneous value

3.13.4 Settings

Table 58: RTD input settings

Parameter	Values (Range)	Unit	Step	Default	Description
Input mode	1=Not in use 2=Resistance 10=Pt100 11=Pt250 20=Ni100 21=Ni120 22=Ni250 30=Cu10			1=Not in use	Analogue input mode
Input maximum	0...2000	Ω	1	2000	Maximum analogue input value for mA or resistance scaling
Input minimum	0...2000	Ω	1	0	Minimum analogue input value for mA or resistance scaling
Value unit	1=Dimensionless 5=Ampere 23=Degrees celsius 30=Ohm			1=Dimensionless	Selected unit for output value format
Value maximum	-10000.0...10000.0		1	10000.0	Maximum output value for scaling and supervision
Value minimum	-10000.0...10000.0		1	-10000.0	Minimum output value for scaling and supervision
Val high high limit	-10000.0...10000.0		1	10000.0	Output value high alarm limit for supervision
Value high limit	-10000.0...10000.0		1	10000.0	Output value high warning limit for supervision
Value low limit	-10000.0...10000.0		1	-10000.0	Output value low warning limit for supervision
Value low low limit	-10000.0...10000.0		1	-10000.0	Output value low alarm limit for supervision
Value deadband	100...100000		1	1000	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 59: mA input settings

Parameter	Values (Range)	Unit	Step	Default	Description
Input mode	1=Not in use 5=0..20mA			1=Not in use	Analogue input mode
Input maximum	0...20	mA	1	20	Maximum analogue input value for mA or resistance scaling
Input minimum	0...20	mA	1	0	Minimum analogue input value for mA or resistance scaling
Value unit	1=Dimensionless 5=Ampere 23=Degrees celsius 30=Ohm			1=Dimensionless	Selected unit for output value format

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Value maximum	-10000.0...10000.0		1	10000.0	Maximum output value for scaling and supervision
Value minimum	-10000.0...10000.0		1	-10000.0	Minimum output value for scaling and supervision
Val high high limit	-10000.0...10000.0		1	10000.0	Output value high alarm limit for supervision
Value high limit	-10000.0...10000.0		1	10000.0	Output value high warning limit for supervision
Value low limit	-10000.0...10000.0		1	-10000.0	Output value low warning limit for supervision
Value low low limit	-10000.0...10000.0		1	-10000.0	Output value low alarm limit for supervision
Value deadband	100...100000		1	1000	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

3.13.5 Monitored data

Table 60: Monitored data

Name	Type	Values (Range)	Unit	Description
AI_DB1	FLOAT32	-10000.0...10000.0		mA input, Connectors 1-2, reported value
AI_RANGE1	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		mA input, Connectors 1-2, range
AI_DB2	FLOAT32	-10000.0...10000.0		mA input, Connectors 3-4, reported value
AI_RANGE2	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		mA input, Connectors 3-4, range
AI_DB3	FLOAT32	-10000.0...10000.0		RTD input, Connectors 5-6-11c, reported value
AI_RANGE3	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 5-6-11c, range
AI_DB4	FLOAT32	-10000.0...10000.0		RTD input, Connectors 7-8-11c, reported value
AI_RANGE4	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 7-8-11c, range
AI_DB5	FLOAT32	-10000.0...10000.0		RTD input, Connectors 9-10-11c, reported value

Table continues on next page

Name	Type	Values (Range)	Unit	Description
AI_RANGE5	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 9-10-11c, range
AI_DB6	FLOAT32	-10000.0...10000.0		RTD input, Connectors 13-14-12c, reported value
AI_RANGE6	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 13-14-12c, range
AI_DB7	FLOAT32	-10000.0...10000.0		RTD input, Connectors 15-16-12c, reported value
AI_RANGE7	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 15-16-12c, range
AI_DB8	FLOAT32	-10000.0...10000.0		RTD input, Connectors 17-18-12c, reported value
AI_RANGE8	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		RTD input, Connectors 17-18-12c, range

3.14 SMV function blocks

SMV function blocks are used in the process bus applications with the sending of the sampled values of analog currents and voltages and with the receiving of the sampled values of voltages.

3.14.1 IEC 61850-9-2 LE sampled values sending SMVSENDER

3.14.1.1 Function block

Figure 42: Function block

3.14.1.2 Functionality

The SMVSENDER function block is used for activating the SMV sending functionality. It adds/removes the sampled value control block and the related data set into/from the sending device's configuration. It has no input or output signals.

SMVSENDER can be disabled with the *Operation* setting value "off". If the SMVSENDER is disabled from the LHMI, it can only be enabled from the LHMI. When disabled, the sending of the samples values is disabled.

3.14.1.3 Settings

Table 61: SMVSENDER Settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=on 5=off			1=on	Operation

3.14.2 IEC 61850-9-2 LE sampled values receiving SMVRECEIVER

3.14.2.1 Function block

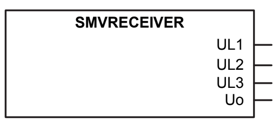


Figure 43: Function block

3.14.2.2 Functionality

The SMVRECEIVER function block is used for activating the SMV receiving functionality.

3.14.2.3 Signals

Table 62: SMVRECEIVER Output signals

Name	Type	Description
UL1	INT32-UL1	IEC61850-9-2 phase 1 voltage
UL2	INT32-UL2	IEC61850-9-2 phase 2 voltage
UL3	INT32-UL3	IEC61850-9-2 phase 3 voltage
U0	INT32-Uo	IEC61850-9-2 residual voltage

3.14.3 ULTVTR function block

3.14.3.1 Function block

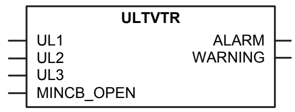


Figure 44: Function block

3.14.3.2 Functionality

The ULTVTR function is used in the receiver application to perform the supervision for the sampled values and to connect the received analog phase voltage inputs to the application. Synchronization accuracy, sampled value frame transfer delays and missing frames are being supervised.

The typical additional operate time increase is +2 ms for all the receiver application functions (using either local or remote samples) when SMV is used.

3.14.3.3 Operation principle

The `ALARM` in the receiver is activated if the synchronization accuracy of the sender or the receiver is either unknown or worse than 100 ms. The output is held on for 10 seconds after the synchronization accuracy returns within limits.

`ALARM` is activated when two or more consecutive SMV frames are lost or late. A single loss of frame is corrected with a zero-order hold scheme. In this case the effect on protection is considered negligible and the `WARNING` or `ALARM` outputs are not activated. The output is held on for 10 seconds after the conditions return to normal.

The *SMV Max Delay* parameter defines how long the receiver waits for the SMV frames before activating the `ALARM` output. This parameter can be accessed via **Configuration/ System/Common**. Waiting of the SMV frames also delays the local measurements of the receiver to keep them correctly time aligned. The *SMV Max Delay* values include sampling, processing and network delay.

The `MINCB_OPEN` input signal is supposed to be connected through a protection relay's binary input to the NC auxiliary contact of the miniature circuit breaker protecting the VT secondary circuit. The MINCB_OPEN signal sets the FUSEF_U output signal to block all the voltage-related functions when MCB is in the open state.

The WARNING output in the receiver is activated if the synchronization accuracy of the sender or the receiver is worse than 4 µs. The output is held on for 10 seconds after the synchronization accuracy returns within limits. If the protection relay supports frequency adaptivity and it is enabled, the WARNING output is also activated when the adaptivity is not ready.

The WARNING output is always internally active whenever the ALARM output is active.

The receiver activates the WARNING and ALARM outputs if any of the quality bits, except for the derived bit, is activated. When the receiver is in the test mode, it accepts SMV frames with test bit without activating the WARNING and ALARM outputs.

3.14.3.4 Signals

Table 63: ULTVTR Input signals

Name	Type	Default	Description
UL1	INT32-UL1	0	IEC 61850-9-2 phase 1 voltage
UL2	INT32-UL2	0	IEC 61850-9-2 phase 2 voltage
UL3	INT32-UL3	0	IEC 61850-9-2 phase 3 voltage
MINCB_OPEN	BOOLEAN	0=False	Active when external MCB opens protected voltage circuit

Table 64: ULTVTR Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm
WARNING	BOOLEAN	Warning

3.14.3.5 Settings

Table 65: ULTVTR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Primary voltage	0.100...440.000	kV	0.001	20.000	Primary rated voltage
Secondary voltage	60...210	V	1	100	Secondary rated voltage
VT connection	1=Wye 2=Delta 3=VAB 4=VA			2=Delta	Voltage transducer measurement connection

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Amplitude corr. A	0.9000...1.1000		0.0001	1.0000	Phase A Voltage phasor magnitude correction of an external voltage transformer
Amplitude corr. B	0.9000...1.1000		0.0001	1.0000	Phase B Voltage phasor magnitude correction of an external voltage transformer
Amplitude corr. C	0.9000...1.1000		0.0001	1.0000	Phase C Voltage phasor magnitude correction of an external voltage transformer
Division ratio	1000...20000		1	10000	Voltage sensor division ratio
Voltage input type	1=Voltage trafo 3=CVD sensor			1=Voltage trafo	Type of the voltage input
Angle Corr A	-20.0000...20.0000	deg	0.0001	0.0000	Phase A Voltage phasor angle correction of an external voltage transformer
Angle Corr B	-20.0000...20.0000	deg	0.0001	0.0000	Phase B Voltage phasor angle correction of an external voltage transformer
Angle Corr C	-20.0000...20.0000	deg	0.0001	0.0000	Phase C Voltage phasor angle correction of an external voltage transformer

3.14.3.6 Monitored data

Monitored data is available in three locations.

- **Monitoring/I/O status/Analog inputs**
- **Monitoring/IED status/SMV traffic**
- **Monitoring/IED status/SMV accuracy**

3.14.4 RESTVTR function block

3.14.4.1 Function block

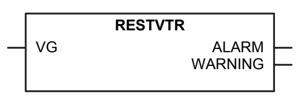


Figure 45: Function block

3.14.4.2 Functionality

The RESTVTR function is used in the receiver application to perform the supervision for the sampled values of analog residual voltage and to connect the received analog residual voltage input to the application. Synchronization accuracy, sampled value frame transfer delays and missing frames are being supervised.

The typical additional operate time increase is +2 ms for all the receiver application functions (using either local or remote samples) when SMV is used.

3.14.4.3 Operation principle

The ALARM in the receiver is activated if the synchronization accuracy of the sender or the receiver is either unknown or worse than 100 ms. The output is held on for 10 seconds after the synchronization accuracy returns within limits.

ALARM is activated when two or more consecutive SMV frames are lost or late. A single loss of frame is corrected with a zero-order hold scheme. In this case, the effect on protection is considered negligible and the WARNING or ALARM outputs are not activated. The output is held on for 10 seconds after the conditions return to normal.

The *SMV Max Delay* parameter defines how long the receiver waits for the SMV frames before activating the ALARM output. This parameter can be accessed via **Configuration/ System/Common**. Waiting of the SMV frames also delays the local measurements of the receiver to keep them correctly time aligned. The *SMV Max Delay* values include sampling, processing and network delay.

The WARNING output in the receiver is activated if the synchronization accuracy of the sender or the receiver is worse than 4 µs. The output is held on for 10 seconds after the synchronization accuracy returns within limits.

The WARNING output is always internally active whenever the ALARM output is active.

3.14.4.4 Signals

Table 66: RESTVTR Input signals

Name	Type	Default	Description
VG	INT32-UL0	0	IEC 61850-9-2 residual voltage

Table 67: RESTVTR Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm
WARNING	BOOLEAN	Warning

3.14.4.5 Settings

Table 68: RESTVTR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Primary voltage	0.100...440.000	kV	0.001	11.547	Primary voltage
Secondary voltage	60...210	V	1	100	Secondary voltage
Amplitude corr.	0.9000...1.1000		0.0001	1.0000	Amplitude correction
Angle correction	-20.0000...20.0000	deg	0.0001	0.0000	Angle correction factor

3.14.4.6 Monitored data

Monitored data is available in three locations.

- **Monitoring/I/O status/Analog inputs**
- **Monitoring/IED status/SMV traffic**
- **Monitoring/IED status/SMV accuracy**

3.15 GOOSE function blocks

GOOSE function blocks are used for connecting incoming GOOSE data to application. They support BOOLEAN, Dbpos, Enum, FLOAT32, INT8 and INT32 data types.

Common signals

The VALID output indicates the validity of received GOOSE data, which means in case of valid, that the GOOSE communication is working and received data quality bits (if configured) indicate good process data. Invalid status is caused either by bad data quality bits or GOOSE communication failure. See IEC 61850 engineering guide for details.

The OUT output passes the received GOOSE value for the application. Default value (0) is used if VALID output indicates invalid status. The IN input is defined in the GOOSE configuration and can always be seen in SMT sheet.

Settings

The GOOSE function blocks do not have any parameters available in LHMI or PCM600.

3.15.1 GOOSERCV_BIN function block

3.15.1.1 Function block

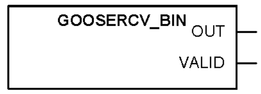


Figure 46: Function block

3.15.1.2 Functionality

The GOOSERCV_BIN function is used to connect the GOOSE binary inputs to the application.

3.15.1.3 Signals

Table 69: GOOSERCV_BIN Output signals

Name	Type	Description
OUT	BOOLEAN	Output signal
VALID	BOOLEAN	Output signal

3.15.2 GOOSERCV_DP function block

3.15.2.1 Function block

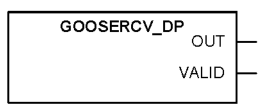


Figure 47: Function block

3.15.2.2 Functionality

The GOOSERCV_DP function is used to connect the GOOSE double binary inputs to the application.

3.15.2.3 Signals

Table 70: GOOSERCV_DP Output signals

Name	Type	Description
OUT	Dbpos	Output signal
VALID	BOOLEAN	Output signal

3.15.3 GOOSERCV_MV function block

3.15.3.1 Function block

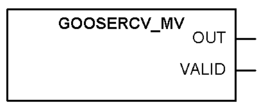


Figure 48: Function block

3.15.3.2 Functionality

The GOOSERCV_MV function is used to connect the GOOSE measured value inputs to the application.

3.15.3.3 Signals

Table 71: GOOSERCV_MV Output signals

Name	Type	Description
OUT	FLOAT32	Output signal
VALID	BOOLEAN	Output signal

3.15.4 GOOSERCV_INT8 function block

3.15.4.1 Function block

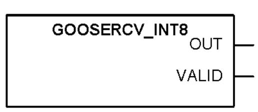


Figure 49: Function block

3.15.4.2 Functionality

The GOOSERCV_INT8 function is used to connect the GOOSE 8 bit integer inputs to the application.

3.15.4.3 Signals

Table 72: GOOSERCV_INT8 Output signals

Name	Type	Description
OUT	INT8	Output signal
VALID	BOOLEAN	Output signal

3.15.5 GOOSERCV_INTL function block

3.15.5.1 Function block

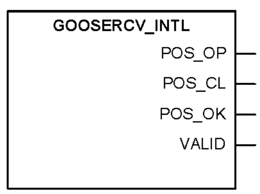


Figure 50: Function block

3.15.5.2 Functionality

The GOOSERCV_INTL function is used to connect the GOOSE double binary input to the application and extracting single binary position signals from the double binary position signal.

The OP output signal indicates that the position is open. Default value (0) is used if VALID output indicates invalid status.

The CL output signal indicates that the position is closed. Default value (0) is used if VALID output indicates invalid status.

The OK output signal indicates that the position is neither in faulty or intermediate state. The default value (0) is used if VALID output indicates invalid status.

3.15.5.3 Signals

Table 73: GOOSERCV_INTL Output signals

Name	Type	Description
POS_OP	BOOLEAN	Position open output signal
POS_CL	BOOLEAN	Position closed output signal
POS_OK	BOOLEAN	Position OK output signal
VALID	BOOLEAN	Output signal

3.15.6 GOOSERCV_CMV function block

3.15.6.1 Function block

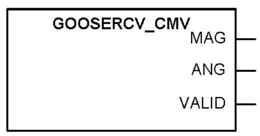


Figure 51: Function block

3.15.6.2 Functionality

The GOOSERCV_CMV function is used to connect GOOSE measured value inputs to the application. The MAG_IN (amplitude) and ANG_IN (angle) inputs are defined in the GOOSE configuration (PCM600).

The MAG output passes the received GOOSE (amplitude) value for the application. Default value (0) is used if VALID output indicates invalid status.

The ANG output passes the received GOOSE (angle) value for the application. Default value (0) is used if VALID output indicates invalid status.

3.15.6.3 Signals

Table 74: GOOSERCV_CMV Output signals

Name	Type	Description
MAG	FLOAT32	Output signal (amplitude)
ANG	FLOAT32	Output signal (angle)
VALID	BOOLEAN	Output signal

3.15.7 GOOSERCV_ENUM function block

3.15.7.1 Function block

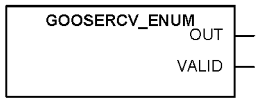


Figure 52: Function block

3.15.7.2 Functionality

The GOOSERCV_ENUM function block is used to connect GOOSE enumerator inputs to the application.

3.15.7.3 Signals

Table 75: GOOSERCV_ENUM Output signals

Name	Type	Description
OUT	Enum	Output signal
VALID	BOOLEAN	Output signal

3.15.8 GOOSERCV_INT32 function block

3.15.8.1 Function block

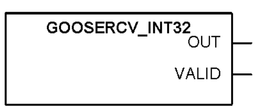


Figure 53: Function block

3.15.8.2 Functionality

The GOOSERCV_INT32 function block is used to connect GOOSE 32 bit integer inputs to the application.

3.15.8.3 Signals

Table 76: GOOSERCV_INT32 Output signals

Name	Type	Description
OUT	INT32	Output signal
VALID	BOOLEAN	Output signal

3.16 Type conversion function blocks

3.16.1 QTY_GOOD function block

3.16.1.1 Function block

Figure 54: Function block

3.16.1.2 Functionality

The QTY_GOOD function block evaluates the quality bits of the input signal and passes it as a Boolean signal for the application.

The IN input can be connected to any logic application signal (logic function output, binary input, application function output or received GOOSE signal). Due to application logic quality bit propagation, each (simple and even combined) signal has quality which can be evaluated.

The `OUT` output indicates quality good of the input signal. Input signals that have no quality bits set or only test bit is set, will indicate quality good status.

3.16.1.3 Signals

Table 77: QTY_GOOD Input signals

Name	Type	Default	Description
IN	Any	0	Input signal

Table 78: QTY_GOOD Output signals

Name	Type	Description
OUT	BOOLEAN	Output signal

3.16.2 QTY_BAD function block

3.16.2.1 Function block

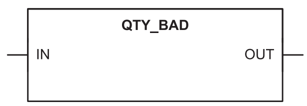


Figure 55: Function block

3.16.2.2 Functionality

The QTY_BAD function block evaluates the quality bits of the input signal and passes it as a Boolean signal for the application.

The IN input can be connected to any logic application signal (logic function output, binary input, application function output or received GOOSE signal). Due to application logic quality bit propagation, each (simple and even combined) signal has quality which can be evaluated.

The `OUT` output indicates quality bad of the input signal. Input signals that have any other than test bit set, will indicate quality bad status.

3.16.2.3 Signals

Table 79: QTY_BAD Input signals

Name	Type	Default	Description
IN	Any	0	Input signal

Table 80: QTY_BAD Output signals

Name	Type	Description
OUT	BOOLEAN	Output signal

3.16.3 QTY_GOOSE_COMM function block

3.16.3.1 Function block

Figure 56: Function block

3.16.3.2 Functionality

The QTY_GOOSE_COMM function block evaluates the peer device communication status from the quality bits of the input signal and passes it as a Boolean signal to the application.

The `IN` input can be connected to any GOOSE application logic output signal, for example, GOOSERCV_BIN.

The `OUT` output indicates the communication status of the GOOSE function block. When the output is in the true (1) state, the GOOSE communication is active. The value false (0) indicates communication timeout.

3.16.3.3 Signals

Table 81: QTY_GOOSE_COMM Input signals

Name	Type	Default	Description
IN	Any	0	Input signal

Table 82: QTY_GOOSE_COMM Output signals

Name	Type	Description
COMMVALID	BOOLEAN	Output signal

3.16.4 T_HEALTH function block

3.16.4.1 Function block

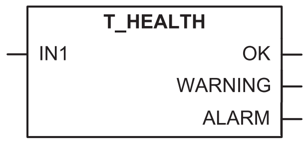


Figure 57: Function block

3.16.4.2 Functionality

The T_HEALTH function evaluates enumerated data of “Health” data attribute. This function block can only be used with GOOSE.

The IN input can be connected to GOOSERCV_ENUM function block, which is receiving the LD0.LLN0.Health.stVal data attribute sent by another device.

The outputs `OK`, `WARNING` and `ALARM` are extracted from the enumerated input value. Only one of the outputs can be active at a time. In case the GOOSERCV_ENUM function block does not receive the value from the sending device or it is invalid, the default value (0) is used and the `ALARM` is activated in the T_HEALTH function block.

3.16.4.3 Signals

Table 83: T_HEALTH Input signals

Name	Type	Default	Description
IN1	Any	0	Input signal

Table 84: T_HEALTH Output signals

Name	Type	Description
OK	BOOLEAN	Output signal
WARNING	BOOLEAN	Output signal
ALARM	BOOLEAN	Output signal

3.16.5 T_F32_INT8 function block

3.16.5.1 Function block

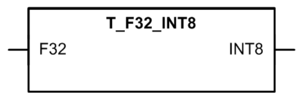


Figure 58: Function block

3.16.5.2 Functionality

The T_F32_INT8 function is used to convert 32-bit floating type values to 8-bit integer type. The rounding operation is included. Output value saturates if the input value is below the minimum or above the maximum value. .

3.16.5.3 Signals

Table 85: T_F32_INT8 Input signals

Name	Type	Default	Description
F32	FLOAT32	0.0	Input signal

Table 86: T_F32_INT8 Output signal

Name	Type	Description
INT8	INT8	Output signal

3.16.6 T_DIR function block

3.16.6.1 Function block

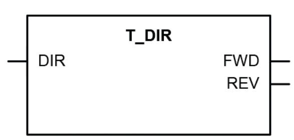


Figure 59: Function block

3.16.6.2 Functionality

The T_DIR function evaluates enumerated data of the FAULT_DIR data attribute of the directional functions. T_DIR can only be used with GOOSE. The `DIR` input can be connected to the GOOSERCV_ENUM function block, which is receiving the LD0.<function>.Str.dirGeneral or LD0.<function>.Dir.dirGeneral data attribute sent by another device.

In case the GOOSERCV_ENUM function block does not receive the value from the sending device or it is invalid, the default value (0) is used in function outputs.

The outputs `FWD` and `REV` are extracted from the enumerated input value.

3.16.6.3 Signals

Table 87: T_DIR Input signals

Name	Type	Default	Description
DIR	Enum	0	Input signal

Table 88: T_DIR Output signals

Name	Type	Default	Description
FWD	BOOLEAN	0	Direction forward
REV	BOOLEAN	0	Direction backward

3.16.7 T_TCMD function block

3.16.7.1 Function block

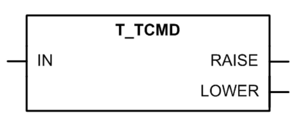


Figure 60: Function block

3.16.7.2 Functionality

The T_TCMD function is used to convert enumerated input signal to Boolean output signals.

Table 89: Conversion from enumerated to Boolean

IN	RAISE	LOWER
0	FALSE	FALSE
1	FALSE	TRUE
2	TRUE	FALSE
x	FALSE	FALSE

3.16.7.3 Signals

Table 90: T_TCMD input signals

Name	Type	Default	Description
IN	Enum	0	Input signal

Table 91: T_TCMD output signals

Name	Type	Description
RAISE	BOOLEAN	Raise command
LOWER	BOOLEAN	Lower command

3.16.8 T_TCMD_BIN function block

3.16.8.1 Function block

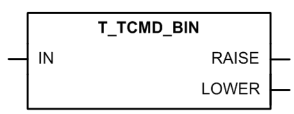


Figure 61: Function block

3.16.8.2 Functionality

The T_TCMD_BIN function is used to convert 32 bit integer input signal to Boolean output signals.

Table 92: Conversion from integer to Boolean

IN	RAISE	LOWER
0	FALSE	FALSE
1	FALSE	TRUE
2	TRUE	FALSE
x	FALSE	FALSE

3.16.8.3 Signals

Table 93: T_TCMD_BIN input signals

Name	Type	Default	Description
IN	INT32	0	Input signal

Table 94: T_TCMD_BIN output signals

Name	Type	Description
RAISE	BOOLEAN	Raise command
LOWER	BOOLEAN	Lower command

3.16.9 T_BIN_TCMD function block

3.16.9.1 Function block

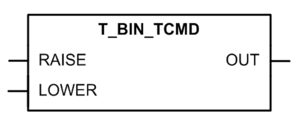


Figure 62: Function block

3.16.9.2 Functionality

The T_BIN_TCMD function is used to convert Boolean input signals to 32 bit integer output signals.

Table 95: Conversion from Boolean to integer

RAISE	LOWER	OUT
FALSE	FALSE	0
FALSE	TRUE	1
TRUE	FALSE	2

3.16.9.3 Signals

Table 96: T_BIN_TCMD input signals

Name	Type	Default	Description
RAISE	BOOLEAN	0	Raise command
LOWER	BOOLEAN	0	Lower command

Table 97: T_BIN_TCMD output signals

Name	Type	Description
OUT	INT32	Output signal

3.17 Configurable logic blocks

3.17.1 Standard configurable logic blocks

3.17.1.1 OR function block

Function block

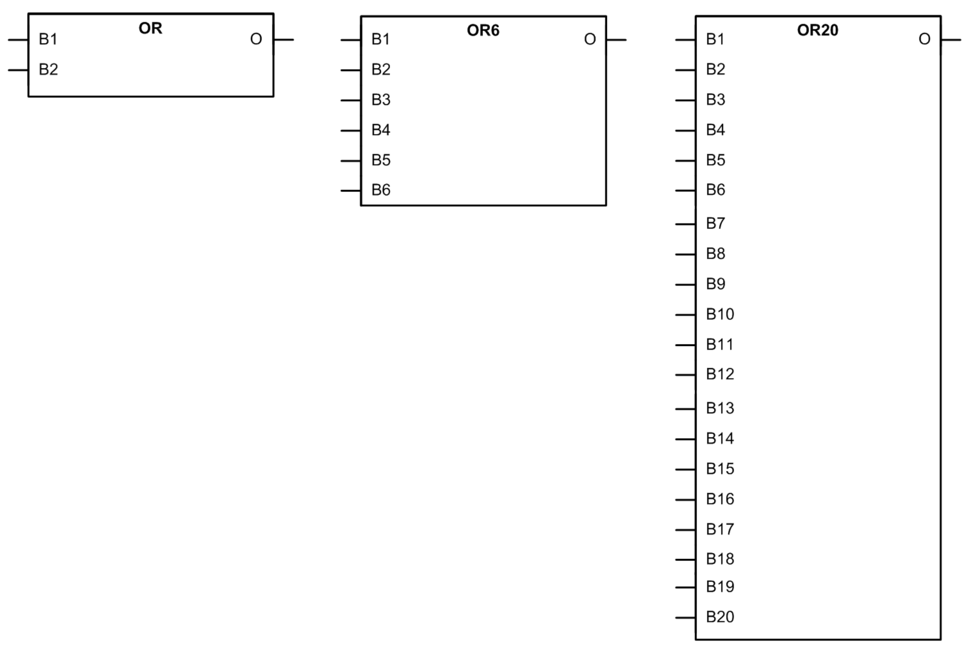


Figure 63: Function blocks

Functionality

OR, OR6 and OR20 are used to form general combinatory expressions with Boolean variables.

The O output is activated when at least one input has the value TRUE. The default value of all inputs is FALSE, which makes it possible to use only the required number of inputs and leave the rest disconnected.

OR has two inputs, OR6 six and OR20 twenty inputs.

Signals

Table 98: OR Input signals

Name	Type	Default	Description
B1	BOOLEAN	0	Input signal 1
B2	BOOLEAN	0	Input signal 2

Table 99: OR6 Input signals

Name	Type	Default	Description
B1	BOOLEAN	0	Input signal 1
B2	BOOLEAN	0	Input signal 2
B3	BOOLEAN	0	Input signal 3
B4	BOOLEAN	0	Input signal 4
B5	BOOLEAN	0	Input signal 5
B6	BOOLEAN	0	Input signal 6

Table 100: OR20 Input signals

Name	Type	Default	Description
B1	BOOLEAN	0	Input signal 1
B2	BOOLEAN	0	Input signal 2
B3	BOOLEAN	0	Input signal 3
B4	BOOLEAN	0	Input signal 4
B5	BOOLEAN	0	Input signal 5
B6	BOOLEAN	0	Input signal 6
B7	BOOLEAN	0	Input signal 7
B8	BOOLEAN	0	Input signal 8
B9	BOOLEAN	0	Input signal 9
B10	BOOLEAN	0	Input signal 10
Table continues on next page			

Name	Type	Default	Description
B11	BOOLEAN	0	Input signal 11
B12	BOOLEAN	0	Input signal 12
B13	BOOLEAN	0	Input signal 13
B14	BOOLEAN	0	Input signal 14
B15	BOOLEAN	0	Input signal 15
B16	BOOLEAN	0	Input signal 16
B17	BOOLEAN	0	Input signal 17
B18	BOOLEAN	0	Input signal 18
B19	BOOLEAN	0	Input signal 19
B20	BOOLEAN	0	Input signal 20

Table 101: OR Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Table 102: OR6 Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Table 103: OR20 Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.2 AND function block

Function block

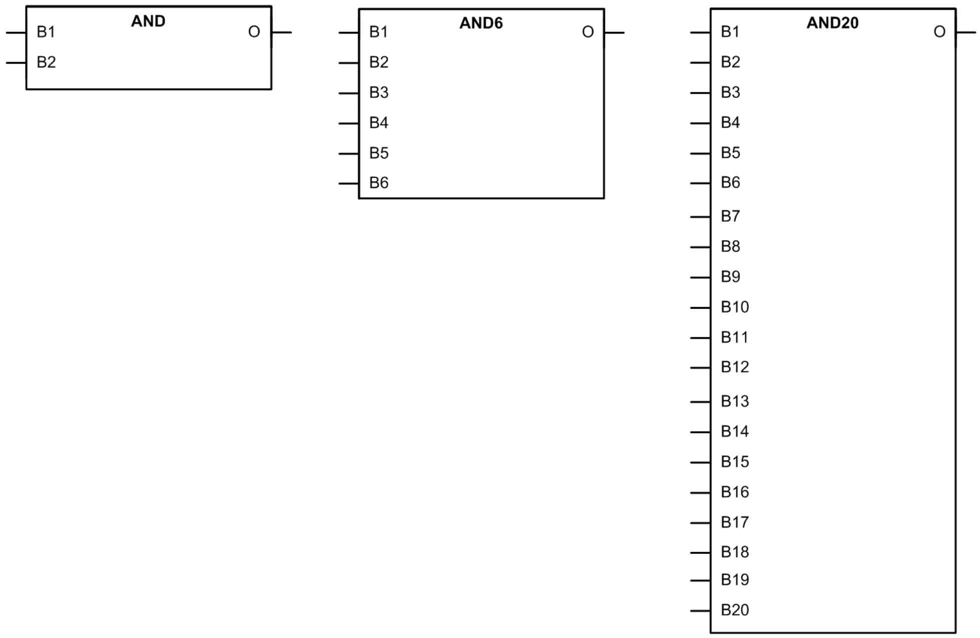


Figure 64: Function blocks

Functionality

AND, AND6 and AND20 are used to form general combinatory expressions with Boolean variables.

The default value in all inputs is logical true, which makes it possible to use only the required number of inputs and leave the rest disconnected.

AND has two inputs, AND6 six inputs and AND20 twenty inputs.

Signals

Table 104: AND Input signals

Name	Type	Default	Description
B1	BOOLEAN	1	Input signal 1
B2	BOOLEAN	1	Input signal 2

Table 105: AND6 Input signals

Name	Type	Default	Description
B1	BOOLEAN	1	Input signal 1
B2	BOOLEAN	1	Input signal 2
B3	BOOLEAN	1	Input signal 3
B4	BOOLEAN	1	Input signal 4
B5	BOOLEAN	1	Input signal 5
B6	BOOLEAN	1	Input signal 6

Table 106: AND20 Input signals

Name	Type	Default	Description
B1	BOOLEAN	0	Input signal 1
B2	BOOLEAN	0	Input signal 2
B3	BOOLEAN	0	Input signal 3
B4	BOOLEAN	0	Input signal 4
B5	BOOLEAN	0	Input signal 5
B6	BOOLEAN	0	Input signal 6
B7	BOOLEAN	0	Input signal 7
B8	BOOLEAN	0	Input signal 8
B9	BOOLEAN	0	Input signal 9
B10	BOOLEAN	0	Input signal 10
B11	BOOLEAN	0	Input signal 11
B12	BOOLEAN	0	Input signal 12
B13	BOOLEAN	0	Input signal 13
B14	BOOLEAN	0	Input signal 14
B15	BOOLEAN	0	Input signal 15
B16	BOOLEAN	0	Input signal 16
B17	BOOLEAN	0	Input signal 17
B18	BOOLEAN	0	Input signal 18
B19	BOOLEAN	0	Input signal 19
B20	BOOLEAN	0	Input signal 20

Table 107: AND Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Table 108: AND6 Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Table 109: AND20 Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.3 XOR function block

Function block

Figure 65: Function block

Functionality

The exclusive OR function XOR is used to generate combinatory expressions with Boolean variables.

The output signal is TRUE if the input signals are different and FALSE if they are equal.

Signals

Table 110: XOR Input signals

Name	Type	Default	Description
B1	BOOLEAN	0	Input signal 1
B2	BOOLEAN	0	Input signal 2

Table 111: XOR Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.4 NOT function block

Function block

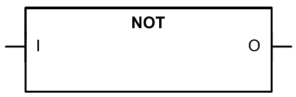


Figure 66: Function block

Functionality

NOT is used to generate combinatory expressions with Boolean variables.

NOT inverts the input signal.

Signals

Table 112: NOT Input signal

Name	Type	Default	Description
I	BOOLEAN	0	Input signal

Table 113: NOT Output signal

Name	Type	Description
O	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.5 MAX3 function block

Function block

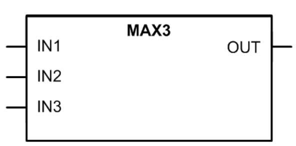


Figure 67: Function block

Functionality

The maximum function MAX3 selects the maximum value from three analog values. Disconnected inputs and inputs whose quality is bad are ignored. If all inputs are disconnected or the quality is bad, MAX3 output value is set to -2^21.

Signals

Table 114: MAX3 Input signals

Name	Type	Default	Description
IN1	FLOAT32	0	Input signal 1
IN2	FLOAT32	0	Input signal 2
IN3	FLOAT32	0	Input signal 3

Table 115: MAX3 Output signal

Name	Type	Description
OUT	FLOAT32	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.6 MIN3 function block

Function block

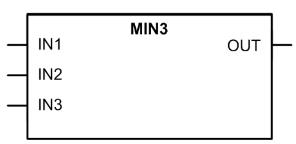


Figure 68: Function block

Functionality

The minimum function MIN3 selects the minimum value from three analog values. Disconnected inputs and inputs whose quality is bad are ignored. If all inputs are disconnected or the quality is bad, MIN3 output value is set to 2^21.

Signals

Table 116: MIN3 Input signals

Name	Type	Default	Description
IN1	FLOAT32	0	Input signal 1
IN2	FLOAT32	0	Input signal 2
IN3	FLOAT32	0	Input signal 3

Table 117: MIN3 Output signal

Name	Type	Description
OUT	FLOAT32	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.7 R_TRIG function block

Function block

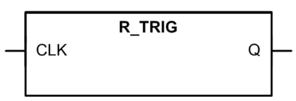


Figure 69: Function block

Functionality

R_TRIGTrig is used as a rising edge detector.

R_TRIG detects the transition from FALSE to TRUE at the `CLK` input. When the rising edge is detected, the element assigns the output to TRUE. At the next execution round, the output is returned to FALSE despite the state of the input.

Signals

Table 118: R_TRIG Input signals

Name	Type	Default	Description
CLK	BOOLEAN	0	Input signal

Table 119: R_TRIG Output signal

Name	Type	Description
Q	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.8 F_TRIG function block

Function block

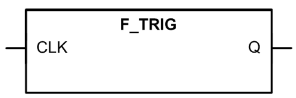


Figure 70: Function block

Functionality

F_TRIG is used as a falling edge detector.

The function detects the transition from TRUE to FALSE at the `CLK` input. When the falling edge is detected, the element assigns the `Q` output to TRUE. At the next execution round, the output is returned to FALSE despite the state of the input.

Signals

Table 120: F_TRIG Input signals

Name	Type	Default	Description
CLK	BOOLEAN	0	Input signal

Table 121: F_TRIG Output signal

Name	Type	Description
Q	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.9 T_POS_XX function blocks

Function block

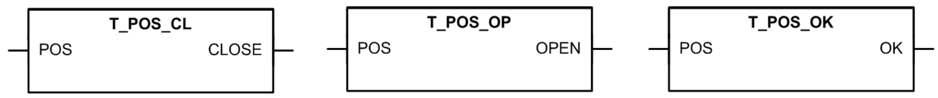


Figure 71: Function blocks

Functionality

The circuit breaker position information can be communicated with the IEC 61850 GOOSE messages. The position information is a double binary data type which is fed to the POS input.

T_POS_CL and T_POS_OP are used for extracting the circuit breaker status information. Respectively, T_POS_OK is used to validate the intermediate or faulty breaker position.

Table 122: Cross reference between circuit breaker position and the output of the function block

Circuit breaker position	Output of the function block		
	T_POS_CL	T_POS_OP	T_POS_OK
Intermediate '00'	FALSE	FALSE	FALSE
Close '01'	TRUE	FALSE	TRUE
Open '10'	FALSE	TRUE	TRUE
Faulty '11'	TRUE	TRUE	FALSE

Signals

Table 123: T_POS_CL Input signals

Name	Type	Default	Description
POS	Double binary	0	Input signal

Table 124: T_POS_OP Input signals

Name	Type	Default	Description
POS	Double binary	0	Input signal

Table 125: T_POS_OK Input signals

Name	Type	Default	Description
POS	Double binary	0	Input signal

Table 126: T_POS_CL Output signal

Name	Type	Description
CLOSE	BOOLEAN	Output signal

Table 127: T_POS_OP Output signal

Name	Type	Description
OPEN	BOOLEAN	Output signal

Table 128: T_POS_OK Output signal

Name	Type	Description
OK	BOOLEAN	Output signal

Settings

The function does not have any parameters available in LHMI or PCM600.

3.17.1.10 SWITCHR function block

Function block

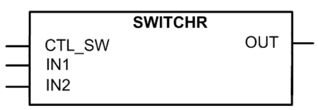


Figure 72: Function block

Functionality

SWITCHR switching block for REAL data type is operated by the `CTL_SW` input, selects the output value `OUT` between the `IN1` and `IN2` inputs.

CTL_SW	OUT
FALSE	IN2
TRUE	IN1

Signals

Table 129: SWITCHR Input signals

Name	Type	Default	Description
CTL_SW	BOOLEAN	1	Control Switch
IN1	REAL	0.0	Real input 1
IN2	REAL	0.0	Real input 2

Table 130: SWITCHR Output signals

Name	Type	Description
OUT	REAL	Real switch output

3.17.1.11 SWITCHI32 function block

Function block

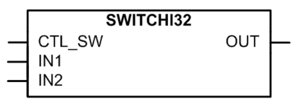


Figure 73: Function block

Functionality

SWITCHI32 switching block for 32-bit integer data type is operated by the `CTL_SW` input, which selects the output value `OUT` between the `IN1` and `IN2` inputs.

Table 131: SWITCHI32

CTL_SW	OUT
FALSE	IN2
TRUE	IN1

Signals

Table 132: SWITCHI32 input signals

Name	Type	Default	Description
CTL_SW	BOOLEAN	1	Control Switch
IN1	INT32	0	Input signal 1
IN2	INT32	0	Input signal 2

Table 133: SWITCHI32 output signals

Name	Type	Description
OUT	INT32	Output signal

3.17.1.12 SR function block

Function block

Figure 74: Function block

Functionality

The SR flip-flop output `Q` can be set or reset from the `S` or `R` inputs. `S` input has a higher priority over the `R` input. Output `NOTQ` is the negation of output `Q`.

The statuses of outputs `Q` and `NOTQ` are not retained in the nonvolatile memory.

Table 134: Truth table for SR flip-flop

S	R	Q
0	0	0[1)]
0	1	0
1	0	1
1	1	1

1) Keep state/no change

Signals

Table 135: SR Input signals

Name	Type	Default	Description
S	BOOLEAN	0=False	Set Q output when set
R	BOOLEAN	0=False	Resets Q output when set

Table 136: SR Output signals

Name	Type	Description
Q	BOOLEAN	Q status
NOTQ	BOOLEAN	NOTQ status

3.17.1.13 RS function block

Function block

Figure 75: Function block

Functionality

The RS flip-flop output Q can be set or reset from the S or R inputs. R input has a higher priority over the S input. Output NOTQ is the negation of output Q.

The statuses of outputs Q and NOTQ are not retained in the nonvolatile memory.

Table 137: Truth table for RS flip-flop

S	R	Q
0	0	0[1)]
0	1	0
1	0	1
1	1	0

1) Keep state/no change

Signals

Table 138: RS Input signals

Name	Type	Default	Description
S	BOOLEAN	0=False	Set Q output when set
R	BOOLEAN	0=False	Resets Q output when set

Table 139: RS Output signals

Name	Type	Description
Q	BOOLEAN	Q status
NOTQ	BOOLEAN	NOTQ status

Technical revision history

Table 140: RS Technical revision history

Technical revision	Change
L	The name of the function has been changed from SR to RS.

3.17.2 Minimum pulse timer

3.17.2.1 Minimum pulse timer 62TP

Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Minimum pulse timer (2 pcs)	TPGAPC	TP	62TP

Function block

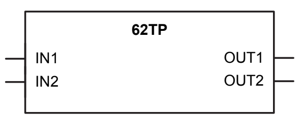


Figure 76: Function block

Functionality

The Minimum pulse timer function TP contains two independent timers. The function has a settable pulse length (in milliseconds). The timers are used for setting the minimum pulse length for example, the signal outputs. Once the input is activated, the output is set for a specific duration using the *Pulse time* setting. Both timers use the same setting parameter.

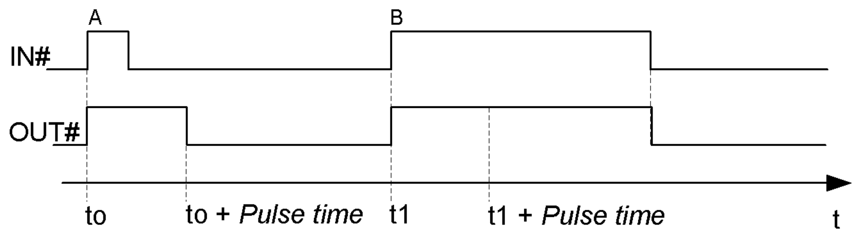


Figure 77: A = Trip pulse is shorter than Pulse time setting, B = Trip pulse is longer than Pulse time setting

Signals

Table 141: 62TP Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1
IN2	BOOLEAN	0=False	Input 2

Table 142: 62TP Output signals

Name	Type	Description
OUT1	BOOLEAN	Output 1 status
OUT2	BOOLEAN	Output 2 status

Settings

Table 143: 62TP Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pulse time	0...60000	ms	1	150	Minimum pulse time

Technical revision history

Table 144: 62TP Technical revision history

Technical revision	Change
B	Outputs now visible in menu
C	Internal improvement

3.17.2.2 Minimum pulse timer 62TPS

Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Minimum second pulse timer (2 pcs)	TPSGAPC	TPS	62TPS

Function block

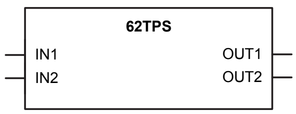


Figure 78: Function block

Functionality

The Minimum second pulse timer function 62TPS contains two independent timers. The function has a settable pulse length (in seconds). The timers are used for setting the minimum pulse length for example, the signal outputs. Once the input is activated, the output is set for a specific duration using the *Pulse time* setting. Both timers use the same setting parameter.

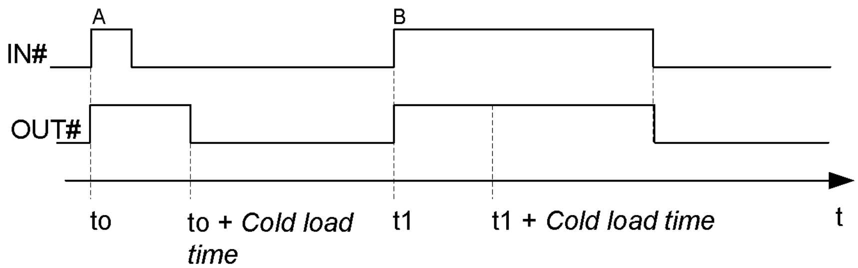


Figure 79: A = Trip pulse is shorter than Cold load time setting, B = Trip pulse is longer than Cold load time setting

Signals

Table 145: 62TPS Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1
IN2	BOOLEAN	0=False	Input 2

Table 146: 62TPS Output signals

Name	Type	Description
OUT1	BOOLEAN	Output 1 status
OUT2	BOOLEAN	Output 2 status

Settings

Table 147: 62TPS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Cold load time	0...300	s	1	0	Cold load time

Technical revision history

Table 148: 67TPS Technical revision history

Technical revision	Change
B	Outputs now visible in menu
C	Internal improvement

3.17.2.3 Minimum pulse timer 62TPM

Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Minimum minute pulse timer (2 pcs)	TPMGAPC	TPM	62TPM

Function block

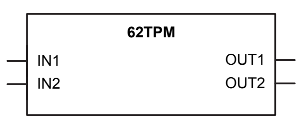


Figure 80: Function block

Functionality

The Minimum minute pulse timer function 62TPM contains two independent timers. The function has a settable pulse length (in minutes). The timers are used for setting the minimum pulse length for example, the signal outputs. Once the input is activated, the output is set for a specific duration using the *Pulse time* setting. Both timers use the same setting parameter.

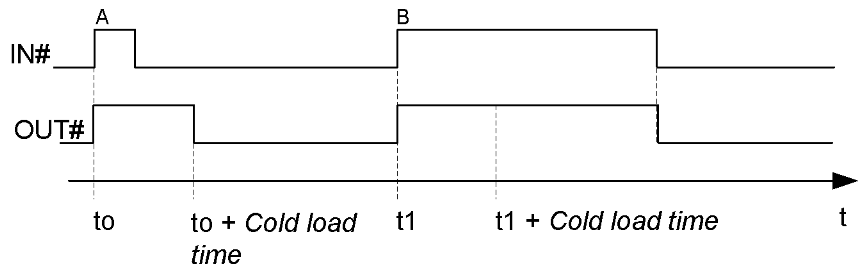


Figure 81: A = Trip pulse is shorter than Cold load time setting, B = Trip pulse is longer than Cold load time setting

Signals

Table 149: 62TPM Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1
IN2	BOOLEAN	0=False	Input 2

Table 150: 62TPM Output signals

Name	Type	Description
OUT1	BOOLEAN	Output 1 status
OUT2	BOOLEAN	Output 2 status

Settings

Table 151: 62TPM Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Cold load time	0...300	min	1	0	Cold load time

3.17.3 Pulse timer function block 62PT

3.17.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse timer (8 pcs)	PTGAPC	PT	62PT

3.17.3.2 Function block

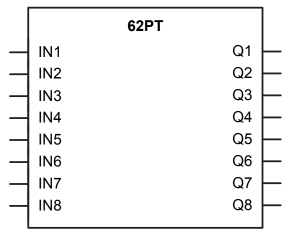


Figure 82: Function block

3.17.3.3 Functionality

The pulse timer function 62PT contains eight independent timers. The function has a settable pulse length. Once the input is activated, the output is set for a specific duration using the *Pulse delay time* setting.

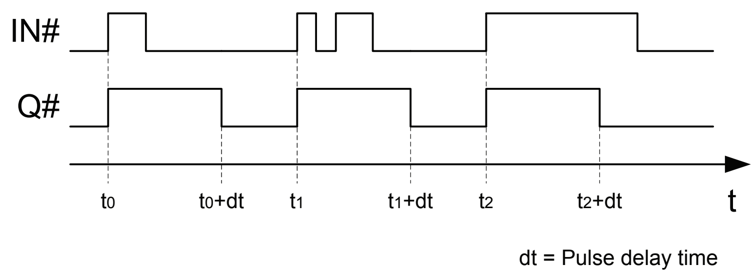


Figure 83: Timer operation

3.17.3.4 Signals

Table 152: 62PT Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1 status
IN2	BOOLEAN	0=False	Input 2 status
IN3	BOOLEAN	0=False	Input 3 status
IN4	BOOLEAN	0=False	Input 4 status
IN5	BOOLEAN	0=False	Input 5 status
IN6	BOOLEAN	0=False	Input 6 status
IN7	BOOLEAN	0=False	Input 7 status
IN8	BOOLEAN	0=False	Input 8 status

Table 153: 62PT Output signals

Name	Type	Description
Q1	BOOLEAN	Output 1 status
Q2	BOOLEAN	Output 2 status
Q3	BOOLEAN	Output 3 status
Q4	BOOLEAN	Output 4 status
Q5	BOOLEAN	Output 5 status
Q6	BOOLEAN	Output 6 status
Q7	BOOLEAN	Output 7 status
Q8	BOOLEAN	Output 8 status

3.17.3.5 Settings

Table 154: 62PT Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pulse delay time 1	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 2	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 3	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 4	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 5	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 6	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 7	0...3600000	ms	10	0	Pulse delay time
Pulse delay time 8	0...3600000	ms	10	0	Pulse delay time

3.17.3.6 Technical data

Table 155: 62PT Technical data

Characteristic	Value
Operate time accuracy	±1.0% of the set value or ±20 ms

3.17.4 Time delay off (8 pcs) 62TOF

3.17.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time delay off (8 pcs)	TOFGAPC	TOF	62TOF

3.17.4.2 Function block

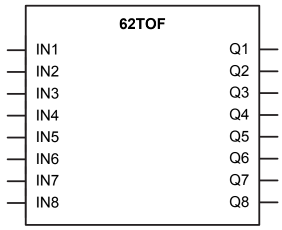


Figure 84: Function block

3.17.4.3 Functionality

The time delay off (8 pcs) function 62TOF can be used, for example, for a drop-off-delayed output related to the input signal. The function contains eight independent timers. There is a settable delay in the timer. Once the input is activated, the output is set immediately. When the input is cleared, the output stays on until the time set with the *Off delay time* setting has elapsed.

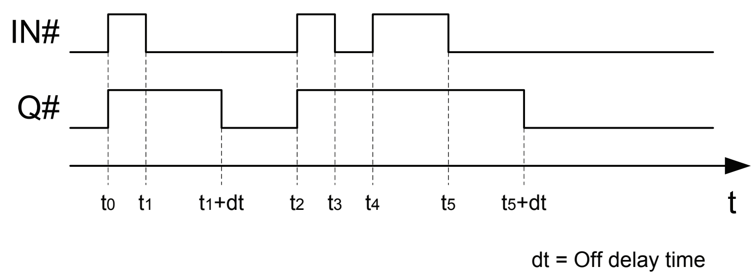


Figure 85: Timer operation

3.17.4.4 Signals

Table 156: 62TOF Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1 status
IN2	BOOLEAN	0=False	Input 2 status
IN3	BOOLEAN	0=False	Input 3 status
IN4	BOOLEAN	0=False	Input 4 status
IN5	BOOLEAN	0=False	Input 5 status
Table continues on next page			

Name	Type	Default	Description
IN6	BOOLEAN	0=False	Input 6 status
IN7	BOOLEAN	0=False	Input 7 status
IN8	BOOLEAN	0=False	Input 8 status

Table 157: 62TOF Output signals

Name	Type	Description
Q1	BOOLEAN	Output 1 status
Q2	BOOLEAN	Output 2 status
Q3	BOOLEAN	Output 3 status
Q4	BOOLEAN	Output 4 status
Q5	BOOLEAN	Output 5 status
Q6	BOOLEAN	Output 6 status
Q7	BOOLEAN	Output 7 status
Q8	BOOLEAN	Output 8 status

3.17.4.5 Settings

Table 158: 62TOF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Off delay time 1	0...3600000	ms	10	0	Off delay time
Off delay time 2	0...3600000	ms	10	0	Off delay time
Off delay time 3	0...3600000	ms	10	0	Off delay time
Off delay time 4	0...3600000	ms	10	0	Off delay time
Off delay time 5	0...3600000	ms	10	0	Off delay time
Off delay time 6	0...3600000	ms	10	0	Off delay time
Off delay time 7	0...3600000	ms	10	0	Off delay time
Off delay time 8	0...3600000	ms	10	0	Off delay time

3.17.4.6 Technical data

Table 159: 62TOF Technical data

Characteristic	Value
Operate time accuracy	±1.0% of the set value or ±20 ms

3.17.5 Time delay on (8 pcs) 62TON

3.17.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time delay on (8 pcs)	TONGAPC	TON	62TON

3.17.5.2 Function block

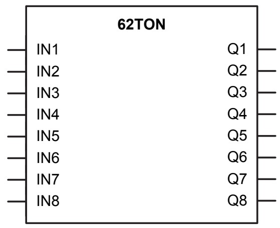


Figure 86: Function block

3.17.5.3 Functionality

The time delay on (8 pcs) function 62TON can be used, for example, for time-delaying the output related to the input signal. 62TON contains eight independent timers. The timer has a settable time delay. Once the input is activated, the output is set after the time set by the *On delay time* setting has elapsed.

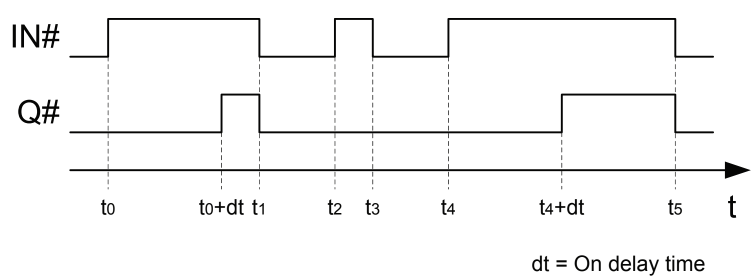


Figure 87: Timer operation

3.17.5.4 Signals

Table 160: 62TON Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	Input 1
IN2	BOOLEAN	0=False	Input 2
IN3	BOOLEAN	0=False	Input 3
IN4	BOOLEAN	0=False	Input 4
IN5	BOOLEAN	0=False	Input 5
IN6	BOOLEAN	0=False	Input 6
IN7	BOOLEAN	0=False	Input 7
IN8	BOOLEAN	0=False	Input 8

Table 161: 62TON Output signals

Name	Type	Description
Q1	BOOLEAN	Output 1
Q2	BOOLEAN	Output 2
Q3	BOOLEAN	Output 3
Q4	BOOLEAN	Output 4
Q5	BOOLEAN	Output 5
Q6	BOOLEAN	Output 6
Q7	BOOLEAN	Output 7
Q8	BOOLEAN	Output 8

3.17.5.5 Settings

Table 162: 62TON Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
On delay time 1	0...3600000	ms	10	0	On delay time
On delay time 2	0...3600000	ms	10	0	On delay time
On delay time 3	0...3600000	ms	10	0	On delay time
On delay time 4	0...3600000	ms	10	0	On delay time
On delay time 5	0...3600000	ms	10	0	On delay time
On delay time 6	0...3600000	ms	10	0	On delay time
On delay time 7	0...3600000	ms	10	0	On delay time
On delay time 8	0...3600000	ms	10	0	On delay time

3.17.5.6 Technical data

Table 163: 62TON Technical data

Characteristic	Value
Operate time accuracy	±1.0% of the set value or ±20 ms

3.17.6 Set reset (8 pcs) SR

3.17.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Set reset (8 pcs)	SRGAPC	SR	SR

3.17.6.2 Function block

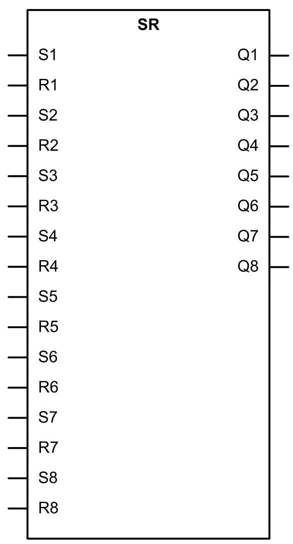


Figure 88: Function block

3.17.6.3 Functionality

The set-reset (8 pcs) function SR is a simple SR flip-flop with a memory that can be set or that can reset an output from the `S#` or `R#` inputs, respectively. The function contains eight independent set-reset flip-flop latches where the `SET` input has the higher priority over the `RESET` input. The status of each `Q#` output is retained in the nonvolatile memory. The individual reset for each `Q#` output is available on the LHMI or through tool via communication.

Table 164: Truth table for SR

S#	R#	Q#
0	0	0[1)]
0	1	0
1	0	1
1	1	1

1) Keep state/no change

3.17.6.4 Signals

Table 165: SR Input signals

Name	Type	Default	Description
S1	BOOLEAN	0=False	Set Q1 output when set
R1	BOOLEAN	0=False	Resets Q1 output when set
S2	BOOLEAN	0=False	Set Q2 output when set
R2	BOOLEAN	0=False	Resets Q2 output when set
S3	BOOLEAN	0=False	Set Q3 output when set
R3	BOOLEAN	0=False	Resets Q3 output when set
S4	BOOLEAN	0=False	Set Q4 output when set
R4	BOOLEAN	0=False	Resets Q4 output when set
S5	BOOLEAN	0=False	Set Q5 output when set
R5	BOOLEAN	0=False	Resets Q5 output when set
S6	BOOLEAN	0=False	Set Q6 output when set
R6	BOOLEAN	0=False	Resets Q6 output when set
S7	BOOLEAN	0=False	Set Q7 output when set
R7	BOOLEAN	0=False	Resets Q7 output when set
S8	BOOLEAN	0=False	Set Q8 output when set
R8	BOOLEAN	0=False	Resets Q8 output when set

Table 166: SR Output signals

Name	Type	Description
Q1	BOOLEAN	Q1 status
Q2	BOOLEAN	Q2 status
Q3	BOOLEAN	Q3 status

Table continues on next page

Name	Type	Description
Q4	BOOLEAN	Q4 status
Q5	BOOLEAN	Q5 status
Q6	BOOLEAN	Q6 status
Q7	BOOLEAN	Q7 status
Q8	BOOLEAN	Q8 status

3.17.6.5 Settings

Table 167: SR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset Q1	0=Cancel 1=Reset			0=Cancel	Resets Q1 output when set
Reset Q2	0=Cancel 1=Reset			0=Cancel	Resets Q2 output when set
Reset Q3	0=Cancel 1=Reset			0=Cancel	Resets Q3 output when set
Reset Q4	0=Cancel 1=Reset			0=Cancel	Resets Q4 output when set
Reset Q5	0=Cancel 1=Reset			0=Cancel	Resets Q5 output when set
Reset Q6	0=Cancel 1=Reset			0=Cancel	Resets Q6 output when set
Reset Q7	0=Cancel 1=Reset			0=Cancel	Resets Q7 output when set
Reset Q8	0=Cancel 1=Reset			0=Cancel	Resets Q8 output when set

3.17.7 Move (8 pcs) MV

3.17.7.1 Function block

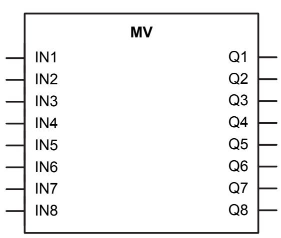


Figure 89: Function block

3.17.7.2 Functionality

The move (8 pcs) function MV is used for user logic bits. Each input state is directly copied to the output state. This allows the creating of events from advanced logic combinations.

3.17.7.3 Signals

Table 168: MV Input signals

Name	Type	Default	Description
IN1	BOOLEAN	0=False	IN1 status
IN2	BOOLEAN	0=False	IN2 status
IN3	BOOLEAN	0=False	IN3 status
IN4	BOOLEAN	0=False	IN4 status
IN5	BOOLEAN	0=False	IN5 status
IN6	BOOLEAN	0=False	IN6 status
IN7	BOOLEAN	0=False	IN7 status
IN8	BOOLEAN	0=False	IN8 status

Table 169: MV Output signals

Name	Type	Description
Q1	BOOLEAN	Q1 status
Q2	BOOLEAN	Q2 status
Q3	BOOLEAN	Q3 status
Q4	BOOLEAN	Q4 status
Q5	BOOLEAN	Q5 status
Q6	BOOLEAN	Q6 status
Q7	BOOLEAN	Q7 status
Q8	BOOLEAN	Q8 status

3.17.7.4 Settings

Table 170: MV Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Description				MVGAPC1 Q1	Output description
Description				MVGAPC1 Q2	Output description
Description				MVGAPC1 Q3	Output description
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Description				MVGAPC1 Q4	Output description
Description				MVGAPC1 Q5	Output description
Description				MVGAPC1 Q6	Output description
Description				MVGAPC1 Q7	Output description
Description				MVGAPC1 Q8	Output description

3.17.8 Integer value move MVI4

3.17.8.1 Function block

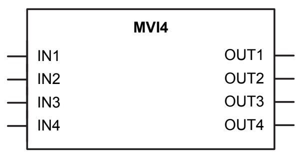


Figure 90: Function block

3.17.8.2 Functionality

The integer value move function MVI4 is used for creation of the events from the integer values. The integer input value is received via `IN1...4` input. The integer output value is available on `OUT1...4` output.

The integer input range is from -2147483648 to 2147483647.

3.17.8.3 Signals

Table 171: MVI4 Input signals

Name	Type	Default	Description
IN1	INT32	0	Integer input value 1
IN2	INT32	0	Integer input value 2
IN3	INT32	0	Integer input value 3
IN4	INT32	0	Integer input value 4

Table 172: MVI4 Output signals

Name	Type	Description
OUT1	INT32	Integer output value 1
OUT2	INT32	Integer output value 2
OUT3	INT32	Integer output value 3
OUT4	INT32	Integer output value 4

3.17.9 Analog value scaling SCA4

3.17.9.1 Function block

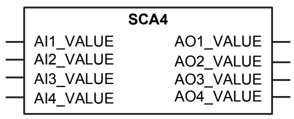


Figure 91: Function block

3.17.9.2 Functionality

The analog value scaling function SCA4 is used for scaling the analog value. It allows creating events from analog values.

The analog value received via the `AIn_VALUE` input is scaled with the *Scale ratio n* setting. The scaled value is available on the `AOn_VALUE` output.

Analog input range is from -10000.0 to 10000.0.

Analog output range is from -2000000.0 to 2000000.0.

If the value of the `AIn_VALUE` input exceeds the analog input range, `AOn_VALUE` is set to 0.0.

If the result of `AIn_VALUE` multiplied by the *Scale ratio n* setting exceeds the analog output range, `AOn_VALUE` shows the minimum or maximum value, according to analog value range.

3.17.9.3 Signals

Table 173: SCA4 Input signals

Name	Type	Default	Description
AI1_VALUE	FLOAT32	0.0	Analog input value of channel 1
AI2_VALUE	FLOAT32	0.0	Analog input value of channel 2
AI3_VALUE	FLOAT32	0.0	Analog input value of channel 3
AI4_VALUE	FLOAT32	0.0	Analog input value of channel 4

Table 174: SCA4 Output signals

Name	Type	Description
AO1_VALUE	FLOAT32	Analog value 1 after scaling
AO2_VALUE	FLOAT32	Analog value 2 after scaling
AO3_VALUE	FLOAT32	Analog value 3 after scaling
AO4_VALUE	FLOAT32	Analog value 4 after scaling

3.17.9.4 Settings

Table 175: SCA4 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Scale ratio 1	0.001...1000.000		0.001	1.000	Scale ratio for analog value 1
Scale ratio 2	0.001...1000.000		0.001	1.000	Scale ratio for analog value 2
Scale ratio 3	0.001...1000.000		0.001	1.000	Scale ratio for analog value 3
Scale ratio 4	0.001...1000.000		0.001	1.000	Scale ratio for analog value 4

3.17.10 Local/remote control function block CONTROL

3.17.10.1 Function block

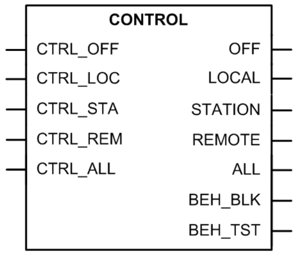


Figure 92: Function block

3.17.10.2 Functionality

Local/Remote control is by default realized through the R/L button on the front panel. The control via binary input can be enabled by setting the value of the *LR control* setting to "Binary input". The binary input control requires that the CONTROL function is instantiated in the product configuration.

Local/Remote control supports multilevel access for control operations in substations according to the IEC 61850 standard. Multilevel control access with separate station control access level is not supported by other protocols than IEC 61850.

The actual Local/Remote control state is evaluated by the priority scheme on the function block inputs. If more than one input is active, the input with the highest priority is selected. The priority order is “off”, “local”, “station”, “remote”, “all”.

The actual state is reflected on the CONTROL function outputs. Only one output is active at a time.

Table 176: Truth table for CONTROL

Input					Output
CTRL_OFF	CTRL_LOC	CTRL_STA	CTRL_REM	CTRL_ALL	
TRUE	N/A	N/A	N/A	N/A	OFF = TRUE
FALSE	TRUE	N/A	N/A	N/A	LOCAL = TRUE
FALSE	FALSE	TRUE	N/A	N/A	STATION = TRUE
FALSE	FALSE	FALSE	TRUE	TRUE	REMOTE = TRUE
FALSE	FALSE	FALSE	FALSE	TRUE	ALL = TRUE
FALSE	FALSE	FALSE	FALSE	FALSE	OFF = TRUE

3.17.10.3 L/R control access

Four different Local/Remote control access scenarios are possible depending on the selected station authority level: “L,R”, “L,R,L+R”, “L,S,R” and “L, S, S+R, L+S, L+S+R”. If control commands need to be allowed from multiple levels, multilevel access can be used. Multilevel access is possible only by using the station authority levels “L,R,L+R” and “L, S, S+R, L+S, L+S+R”. Multilevel access status is available from IEC 61850 data object CTRL.LLN0.MltLev.

Control access selection is made with R/L button or CONTROL function block and IEC 61850 data object CTRL.LLN0.LocSta. When writing CTRL.LLN0.LocSta IEC 61850 data object, IEC 61850 command originator category station must be used by the client, and remote IEC 61850 control access must be allowed by the relay station authority. CTRL.LLN0.LocSta data object value is retained in the nonvolatile memory. The present control status can be monitored in the HMI or PCM600 via **Monitoring/Control command** with the *LR state* parameter or from the IEC 61850 data object CTRL.LLN0. LocKeyHMI.

IEC 61850 command originator category is always set by the IEC 61850 client. The relay supports station and remote IEC 61850 command originator categories, depending on the selected station authority level.

3.17.10.4 Station authority level “L,R”

Relay's default station authority level is “L,R”. In this scenario only local or remote control access is allowed. Control access with IEC 61850 command originator category station is interpreted as remote access. There is no multilevel access.

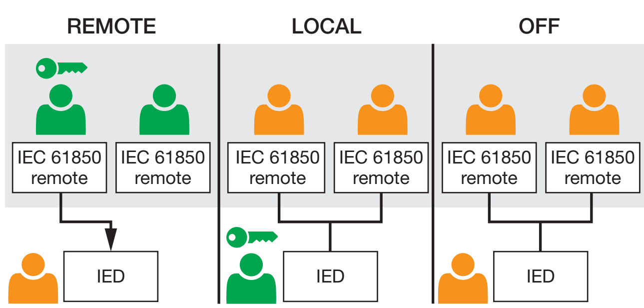


Figure 93: Station authority is “L,R”

When station authority level “L,R” is used, control access can be selected using R/L button or CONTROL function block. IEC 61850 data object CTRL.LLN0.LocSta and CONTROL function block inputs `CTRL_STA` and `CTRL_ALL` are not applicable for this station authority level.

Table 177: Station authority level "L,R" using R/L button

L/R control		L/R control status		Control access	
R/L button	CTRL.LLN0.LocSta	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client 1)
Local	N/A	FALSE	1	x	
Remote	N/A	FALSE	2		x
Off	N/A	FALSE	0		

1) Client IEC 61850 command originator category check is not performed.

Table 178: Station authority "L,R" using CONTROL function block

L/R control		L/R control status		Control access	
Control FB input	CTRL.LLN0.LocSta	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client 1)
CTRL_OFF	N/A	FALSE	0		
CTRL_LOC	N/A	FALSE	1	x	
CTRL_STA	N/A	FALSE	0		
CTRL_REM	N/A	FALSE	2		x
CTRL_ALL	N/A	FALSE	0		

1) Client IEC 61850 command originator category check is not performed.

3.17.10.5 Station authority level "L,R,L+R"

Station authority level "L,R, L+R" adds multilevel access support. Control access can also be simultaneously permitted from local or remote location. Simultaneous local or remote control operation is not allowed as one client and location at time can access controllable objects and they remain reserved until the previously started control operation is first completed by the client. Control access with IEC 61850 originator category station is interpreted as remote access.

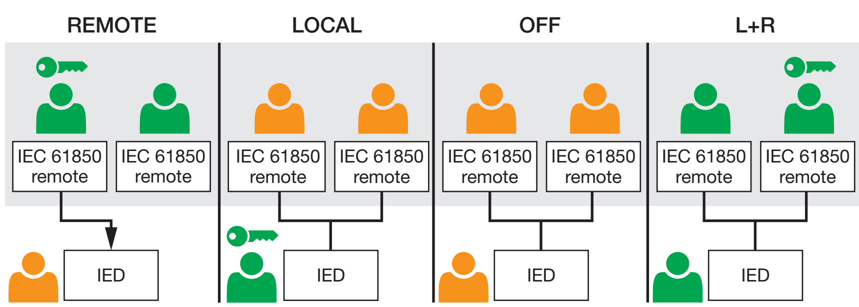


Figure 94: Station authority is "L,R,L+R"

When station authority level "L,R, L+R" is used, the control access can be selected using R/L button or CONTROL function block. IEC 61850 data object CTRL.LLN0.LocSta and CONTROL function block input CTRL_STA are not applicable for this station authority level.

Table 179: Station authority level "L,R,L+R" using R/L button

L/R Control		L/R Control status		Control access	
R/L button	CTRL.LLN0.LocSta	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client [1)]
Local	N/A	FALSE	1	x	
Remote	N/A	FALSE	2		x
Local + Remote	N/A	TRUE	4	x	x
Off	N/A	FALSE	0		

1) Client IEC 61850 command originator category check is not performed.

Table 180: Station authority "L,R,L+R" using CONTROL function block

L/R Control		L/R Control status		Control access	
Control FB input	CTRL.LLN0.LocSta	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client [1)]
CTRL_OFF	N/A	FALSE	0		
CTRL_LOC	N/A	FALSE	1	x	
CTRL_STA	N/A	FALSE	0		
CTRL_REM	N/A	FALSE	2		x
CTRL_ALL	N/A	TRUE	4	x	x

1) Client IEC 61850 command originator category check is not performed.

3.17.10.6 Station authority level "L,S,R"

Station authority level "L,S,R" adds station control access. In this level IEC 61850 command originator category validation is performed to distinguish control commands with IEC 61850 command originator category set to "Remote" or "Station". There is no multilevel access.

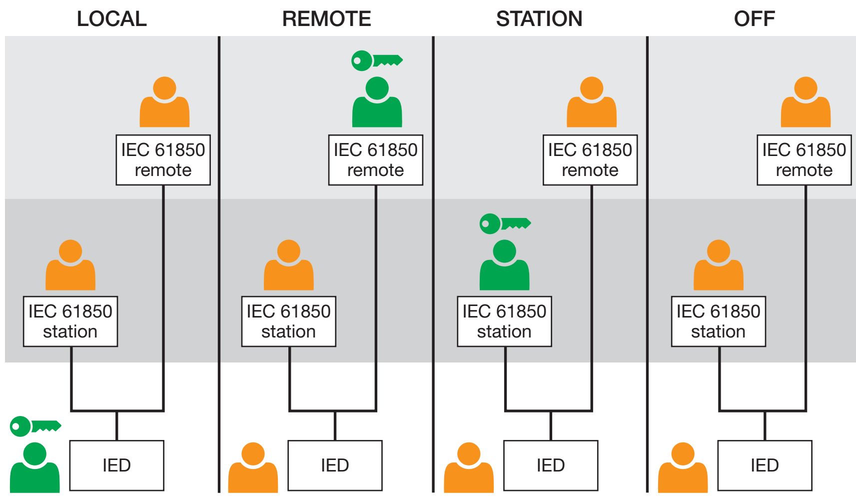


Figure 95: Station authority is "L,S,R"

When the station authority level "L,S,R" is used, the control access can be selected using R/L button or CONTROL function block. IEC 61850 data object CTRL.LLN0.LocSta and CONTROL function block input `CTRL_STA` are applicable for this station authority level.

Station control access can be reserved by using R/L button or CONTROL function block together with IEC 61850 data object CTRL.LLN0.LocSta.

Table 181: Station authority level "L,S,R" using R/L button

L/R Control		L/R Control status		Control access		
R/L button	CTRL.LLN0.LocSta 1)	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client 2)	IEC 61850 client 3)
Local	FALSE	FALSE	1	x		
Remote	FALSE	FALSE	2		x	
Remote	TRUE	FALSE	3			x
Off	FALSE	FALSE	0			

1) Station client reserves the control operating by writing controllable point LocSta.
2) Client IEC 61850 command originator category is remote.
3) Client IEC 61850 command originator category is station.

Table 182: Station authority level “L,S,R” using CONTROL function block

L/R Control		L/R Control status		Control access		
Control FB input	CTRL.LLN0.LocSta [1)]	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client [2)]	IEC 61850 client [3)]
CTRL_OFF	FALSE	FALSE	0			
CTRL_LOC	FALSE	FALSE	1	x		
CTRL_STA	TRUE	FALSE	3			x
CTRL_REM [4)]	TRUE	FALSE	3			x
CTRL_REM	FALSE	FALSE	2		x	
CTRL_ALL	FALSE	FALSE	0			

1) Station client reserves the control operating by writing controllable point LocSta.
2) Client IEC 61850 command originator category is remote.
3) Client IEC 61850 command originator category is station.
4) CTRL_STA unconnected in application configuration. Station client reserves the control operating by writing controllable point LocSta.

3.17.10.7 Station authority level “L,S,S+R,L+S,L+S+R”

Station authority level “L,S,S+R,L+S,L+S+R” adds station control access together with several different multilevel access scenarios. Control access can also be simultaneously permitted from local, station or remote location. Simultaneous local, station or remote control operation is not allowed as one client and location at time can access controllable objects and they remain reserved until the previously started control operation is first completed by the client.

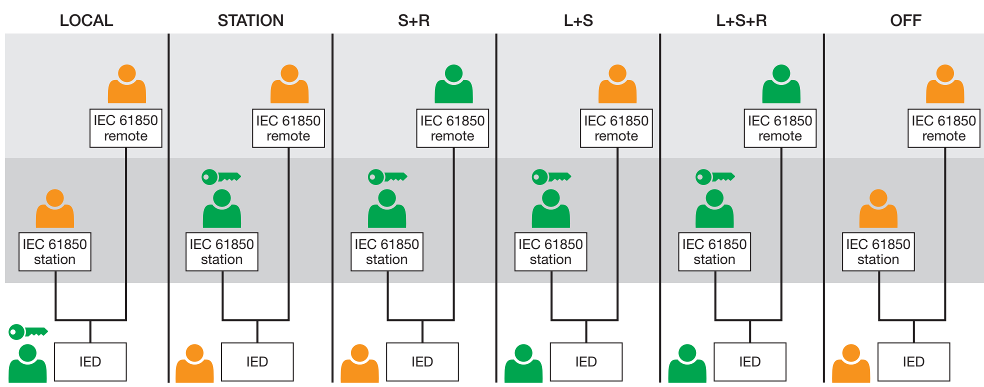


Figure 96: Station authority is “L,S,S+R,L+S,L+S+R”

When station authority level “L,S,S+R,L+S,L+S+R” is used, control access can be selected using R/L button or CONTROL function block. IEC 61850 data object CTRL.LLN0.LocSta and CONTROL function block input `CTRL_STA` are applicable for this station authority level.

"Station" and "Local + Station" control access can be reserved by using R/L button or CONTROL function block in combination with IEC 61850 data object CTRL.LLN0.LocSta.

Table 183: Station authority level "L,S,S+R,L+S,L+S+R" using R/L button

L/R Control		L/R Control status		Control access		
R/L button	CTRL.LLN0.LocSta 1)	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client 2)	IEC 61850 client 3)
Local	FALSE	FALSE	1	x		
Remote	FALSE	TRUE	7		x	x
Remote	TRUE	FALSE	3			x
Local + Remote	FALSE	TRUE	6	x	x	x
Local + Remote	TRUE	TRUE	5	x		x
Off	FALSE	FALSE	0			

1) Station client reserves the control operating by writing controllable point LocSta.
2) Client IEC61850 command originator category is remote.
3) Client IEC61850 command originator category is station.

Table 184: Station authority level "L,S,S+R,L+S,L+S+R" using CONTROL function block

L/R Control		L/R Control status		Control access		
Control FB input	CTRL.LLN0.LocSta 1)	CTRL.LLN0.MltLev	L/R state CTRL.LLN0.LocKeyHMI	Local user	IEC 61850 client 2)	IEC 61850 client 3)
CTRL_OFF	FALSE	FALSE	0			
CTRL_LOC	FALSE	FALSE	1	x		
CTRL_STA	FALSE	FALSE	3			x
CTRL_REM 4)	TRUE	TRUE	3			x
CTRL_REM	FALSE	TRUE	7		x	x
CTRL_ALL	FALSE	TRUE	6	x	x	x
CTRL_ALL 4)	TRUE	TRUE	5	x		x

1) Station client reserves the control operating by writing controllable point LocSta.
2) Client IEC61850 command originator category is remote.
3) Client IEC61850 command originator category is station.
4) CTRL_STA unconnected in application configuration. Station client reserves the control operating by writing controllable point LocSta.

3.17.10.8 Signals

Table 185: CONTROL input signals

Name	Type	Default	Description
CTRL_OFF	BOOLEAN	0	Control input OFF
CTRL_LOC	BOOLEAN	0	Control input Local
CTRL_STA	BOOLEAN	0	Control input Station
CTRL_REM	BOOLEAN	0	Control input Remote
CTRL_ALL	BOOLEAN	0	Control input All

Table 186: CONTROL output signals

Name	Type	Description
OFF	BOOLEAN	Control output OFF
LOCAL	BOOLEAN	Control output Local
STATION	BOOLEAN	Control output Station
REMOTE	BOOLEAN	Control output Remote
ALL	BOOLEAN	Control output All
BEH_BLK	BOOLEAN	Logical device CTRL block status
BEH_TST	BOOLEAN	Logical device CTRL test status

3.17.10.9 Settings

Table 187: Control settings

Parameter	Values (Range)	Unit	Step	Default	Description
LR control	1=LR key 2=Binary input			1=LR key	LR control through LR key or binary input
Station authority	1=L,R 2=L,S,R 3=L,R,L+R 4=L,S,S+R,L+S,L+S+R			1=L,R	Control command originator category usage
Control mode	1=Enable 2=Blocked 5=Disable			1=Enable	Enabling and disabling control

3.17.10.10 Monitored data

Table 188: Monitored data

Name	Type	Values (Range)	Unit	Description
Command response	Enum	0=No commands 1=Select open 2=Select close 3=Trip open 4=Trip close 5=Direct open 6=Direct close 7=Cancel 8=Position reached 9=Position timeout 10=Object status only 11=Object direct 12=Object select 13=RL local allowed 14=RL remote allowed 15=RL off 16=Function off 17=Function blocked 18=Command progress 19=Select timeout 20=Missing authority 21=Close not enabled 22=Open not enabled 23=Device in IRF 24=Already close 25=Wrong client 26=RL station allowed 27=RL change 28=Maximum 3 seconds unbalance voltage		Latest command response
LR state	Enum	0=Disable 1=Local 2=Remote 3=Station 4=L+R 5=L+S 6=L+S+R 7=S+R		LR state monitoring for PCM

3.17.11 Generic control point (16 pcs) SPC

3.17.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/ IEEEidentification
Generic control point (16 pcs)	SPCGAPC	SPC	SPC

3.17.11.2 Function block

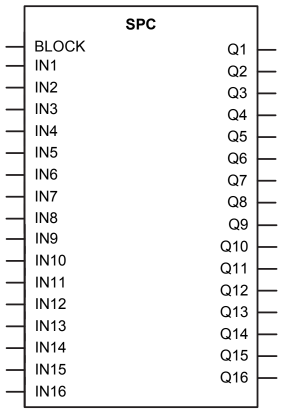


Figure 97: Function block

3.17.11.3 Functionality

The generic control points function SPC contains 16 independent control points. SPC offers the capability to activate its outputs through a local or remote control. The local control request can be issued through the buttons in the single-line diagram or via inputs and the remote control request through communication. The rising edge of the input signal is interpreted as a control request, and the output operation is triggered. When remote control requests are used, the control points behave as persistent.

The *Loc Rem restriction* setting is used for enabling or disabling the restriction for SPC to follow the R/L button state. If *Loc Rem restriction* is "True", as it is by default, the local or remote control operations are accepted according to the R/L button state.

Each of the 16 generic control point outputs has the *Operation mode*, *Pulse length* and *Description* setting. If *Operation mode* is "Toggle", the output state is toggled for every control request received. If *Operation mode* is "Pulsed", the output pulse of a preset duration (the *Pulse length* setting) is generated for every control request received. The

Description setting can be used for storing information on the actual use of the control point in application, for instance.

For example, if the *Operation mode* is "Toggle", the output O# is initially “False”. The rising edge in IN# sets O# to “True”. The falling edge of IN# has no effect. Next rising edge of IN# sets O# to “False”.

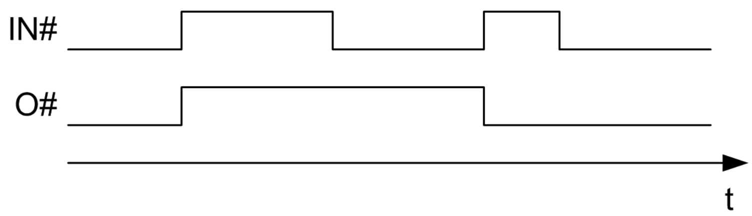


Figure 98: Operation in "Toggle" mode

The BLOCK input can be used for blocking the functionality of the outputs. The operation of the BLOCK input depends on the *Operation mode* setting. If *Operation mode* is "Toggle", the output state freezes and cannot be changed while the BLOCK input is active. If *Operation mode* is "Pulsed", the activation of the BLOCK input resets the outputs to the "False" state and further control requests are ignored while the BLOCK input is active.

From the remote communication point of view SPC toggled operation mode is always working as persistent mode. The output O# follows the value written to the input IN#.

3.17.11.4 Signals

Table 189: SPC Input signals

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
IN1	BOOLEAN	0=False	Input of control point 1
IN2	BOOLEAN	0=False	Input of control point 2
IN3	BOOLEAN	0=False	Input of control point 3
IN4	BOOLEAN	0=False	Input of control point 4
IN5	BOOLEAN	0=False	Input of control point 5
IN6	BOOLEAN	0=False	Input of control point 6
IN7	BOOLEAN	0=False	Input of control point 7
IN8	BOOLEAN	0=False	Input of control point 8

Table continues on next page

Name	Type	Default	Description
IN9	BOOLEAN	0=False	Input of control point 9
IN10	BOOLEAN	0=False	Input of control point 10
IN11	BOOLEAN	0=False	Input of control point 11
IN12	BOOLEAN	0=False	Input of control point 12
IN13	BOOLEAN	0=False	Input of control point 13
IN14	BOOLEAN	0=False	Input of control point 14
IN15	BOOLEAN	0=False	Input of control point 15
IN16	BOOLEAN	0=False	Input of control point 16

Table 190: SPC Output signals

Name	Type	Description
O1	BOOLEAN	Output 1 status
O2	BOOLEAN	Output 2 status
O3	BOOLEAN	Output 3 status
O4	BOOLEAN	Output 4 status
O5	BOOLEAN	Output 5 status
O6	BOOLEAN	Output 6 status
O7	BOOLEAN	Output 7 status
O8	BOOLEAN	Output 8 status
O9	BOOLEAN	Output 9 status
O10	BOOLEAN	Output 10 status
O11	BOOLEAN	Output 11 status
O12	BOOLEAN	Output 12 status
O13	BOOLEAN	Output 13 status
O14	BOOLEAN	Output 14 status
O15	BOOLEAN	Output 15 status
O16	BOOLEAN	Output 16 status

3.17.11.5 Settings

Table 191: SPC Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Loc Rem restriction	0=False 1=True			1=True	Local remote switch restriction
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 1	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 2	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 3	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 4	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 5	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 6	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Description				SPCGAPC1 Output 7	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 8	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 9	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 10	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 11	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 12	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 13	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 14	Generic control point description

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 15	Generic control point description
Operation mode	0=Pulsed 1=Toggle -1=Off			-1=Off	Operation mode for generic control point
Pulse length	10...3600000	ms	10	1000	Pulse length for pulsed operation mode
Description				SPCGAPC1 Output 16	Generic control point description

3.17.12 Generic up-down counter CTR

3.17.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Generic up-down counter	UDFCNT	UDCNT	CTR

3.17.12.2 Function block

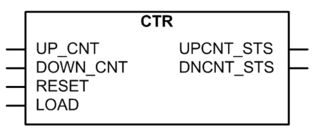


Figure 99: Function block

3.17.12.3 Functionality

The multipurpose generic up-down counter function CTR counts up or down for each positive edge of the corresponding inputs. The counter value output can be reset to zero or preset to some other value if required.

The function provides up-count and down-count status outputs, which specify the relation of the counter value to a loaded preset value and to zero respectively.

3.17.12.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of CTR can be described with a module diagram. All the modules in the diagram are explained in the next sections.

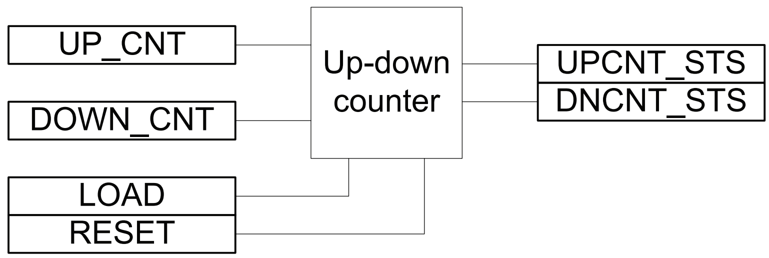


Figure 100: Functional module diagram

Up-down counter

Each rising edge of the UP_CNT input increments the counter value CNT_VAL by one and each rising edge of the DOWN_CNT input decrements the CNT_VAL by one. If there is a rising edge at both the inputs UP_CNT and DOWN_CNT, the counter value CNT_VAL is unchanged. The CNT_VAL is available in the monitored data view.

The counter value CNT_VAL is stored in a nonvolatile memory. The range of the counter is 0...+2147483647. The count of CNT_VAL saturates at the final value of 2147483647, that is, no further increment is possible.

The value of the setting *Counter load value* is loaded into counter value CNT_VAL either when the LOAD input is set to "True" or when the *Load Counter* is set to "Load" in the LHMI. Until the LOAD input is "True", it prevents all further counting.

The function also provides status outputs UPCNT_STS and DNCNT_STS. The UPCNT_STS is set to "True" when the CNT_VAL is greater than or equal to the setting *Counter load value*. DNCNT_STS is set to "True" when the CNT_VAL is zero.

The RESET input is used for resetting the function. When this input is set to "True" or when *Reset counter* is set to "reset", the CNT_VAL is forced to zero.

3.17.12.5 Signals

Table 192: CTR Input signals

Name	Type	Default	Description
UP_CNT	BOOLEAN	0=False	Input for up counting
DOWN_CNT	BOOLEAN	0=False	Input for down counting
RESET	BOOLEAN	0=False	Reset input for counter
LOAD	BOOLEAN	0=False	Load input for counter

Table 193: CTR Output signals

Name	Type	Description
UPCNT_STS	BOOLEAN	Status of the up counting
DNCNT_STS	BOOLEAN	Status of the down counting

3.17.12.6 Settings

Table 194: CTR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Counter load value	0...2147483647		1	10000	Preset counter value
Reset counter	0=Cancel 1=Reset			0=Cancel	Resets counter value
Load counter	0=Cancel 1=Load			0=Cancel	Loads the counter to preset value

3.17.12.7 Monitored data

Table 195: CTR Monitored data

Name	Type	Values (Range)	Unit	Description
CNT_VAL	INT64	0...2147483647		Output counter value

3.18 Factory settings restoration

In case of configuration data loss or any other file system error that prevents the protection relay from working properly, the whole file system can be restored to the original factory state. All default settings and configuration files stored in the factory are restored. For further information on restoring factory settings, see the operation manual.

3.19 Load profile record LOADPROF

3.19.1 Functionality

The protection relay is provided with a load profile recorder. The load profile feature stores the historical load data captured at a periodical time interval (demand interval). Up to 12 load quantities can be selected for recording and storing in a nonvolatile memory. The value range for the recorded load quantities is about eight times the nominal value, and values larger than that saturate. The recording time depends on a settable demand interval parameter and the amount of quantities selected. The record output is in the COMTRADE format.

3.19.1.1 Quantities

Selectable quantities are product-dependent.

Table 196: Quantity Description

Quantity Sel x	Description
Disabled	Quantity not selected
IA	Phase A current
IB	Phase B current
IC	Phase C current
IG	Neutral/ground/residual current
IA2	Phase A current, B side
IB2	Phase B current, B side
IC2	Phase C current, B side
IG2	Neutral/ground/residual current, B side
VAB	Phase-to-phase AB voltage
VBC	Phase-to-phase BC voltage
VCA	Phase-to-phase CA voltage
VA	Phase-to-ground A voltage
VB	Phase-to-ground B voltage
VC	Phase-to-ground C voltage
VAB2	Phase-to-phase AB voltage, B side
VBC2	Phase-to-phase BC voltage, B side

Table continues on next page

Quantity Sel x	Description
VCA2	Phase-to-phase CA voltage, B side
VA2	Phase-to-ground A voltage, B side
VB2	Phase-to-ground B voltage, B side
VC2	Phase-to-ground C voltage, B side
S	Apparent power
P	Real power
Q	Reactive power
PF	Power factor
S2	Apparent power, B side
P2	Real power, B side
Q2	Reactive power, B side
PF2	Power factor, B side
SA	Apparent power, phase A
SB	Apparent power, phase B
SC	Apparent power, phase C
PA	Real power, phase A
PB	Real power, phase B
PC	Real power, phase C
QA	Reactive power, phase A
QB	Reactive power, phase B
QC	Reactive power, phase C
PFA	Power factor, phase A
PFB	Power factor, phase B
PFC	Power factor, phase C
SA2	Apparent power, phase A, B side
SB2	Apparent power, phase B, B side
SC2	Apparent power, phase C, B side
PA2	Real power, phase A, B side
PB2	Real power, phase B, B side
PC2	Real power, phase C, B side
QA2	Reactive power, phase A, B side
QB2	Reactive power, phase B, B side
QC2	Reactive power, phase C, B side
PFA2	Power factor, phase A, B side
PFB2	Power factor, phase B, B side
PFC2	Power factor, phase C, B side

If the data source for the selected quantity is removed, for example, with Application Configuration in PCM600, the load profile recorder stops recording it and the previously collected data are cleared.

3.19.1.2 Length of record

The recording capability is about 7.4 years when one quantity is recorded and the demand interval is set to 180 minutes. The recording time scales down proportionally when a shorter demand time is selected or more quantities are recorded. The recording lengths in days with different settings used are presented in Table 197. When the recording buffer is fully occupied, the oldest data are overwritten by the newest data.

Table 197: Recording capability in days with different settings

	Demand interval						
	1 minute	5 minutes	10 minutes	15 minutes	30 minutes	60 minutes	180 minutes
Amount of quantities	Recording capability in days						
1	15.2	75.8	151.6	227.4	454.9	909.7	2729.2
2	11.4	56.9	113.7	170.6	341.1	682.3	2046.9
3	9.1	45.5	91.0	136.5	272.9	545.8	1637.5
4	7.6	37.9	75.8	113.7	227.4	454.9	1364.6
5	6.5	32.5	65.0	97.5	194.9	389.9	1169.6
6	5.7	28.4	56.9	85.3	170.6	341.1	1023.4
7	5.1	25.3	50.5	75.8	151.6	303.2	909.7
8	4.5	22.7	45.5	68.2	136.5	272.9	818.8
9	4.1	20.7	41.4	62.0	124.1	248.1	744.3
10	3.8	19.0	37.9	56.9	113.7	227.4	682.3
11	3.5	17.5	35.0	52.5	105.0	209.9	629.8
12	3.2	16.2	32.5	48.7	97.5	194.9	584.8

3.19.1.3 Uploading of record

The protection relay stores the load profile COMTRADE files to the C:\LDP \COMTRADE folder. The files can be uploaded with the PCM600 tool or any appropriate computer software that can access the C:\LDP\COMTRADE folder.

The load profile record consists of two COMTRADE file types: the configuration file (.CFG) and the data file (.DAT). The file name is same for both file types.

To ensure that both the uploaded file types are generated from the same data content, the files need to be uploaded successively. Once either of the files is uploaded, the recording buffer is halted to give time to upload the other file.

Data content of the load profile record is sequentially updated. Therefore, the size attribute for both COMTRADE files is "0".

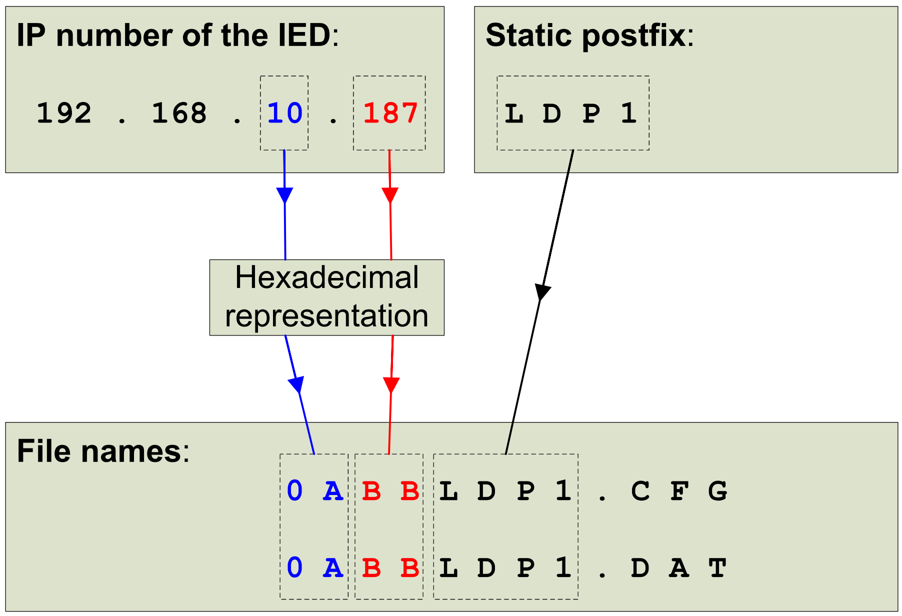


Figure 101: Load profile record file naming

3.19.1.4 Clearing of record

The load profile record can be cleared with *Reset load profile rec* via HMI, communication or the ACT input in PCM600. Clearing of the record is allowed only on the engineer and administrator authorization levels.

The load profile record is automatically cleared if the quantity selection parameters are changed or any other parameter which affects the content of the COMTRADE configuration file is changed. Also, if data source for selected quantity is removed, for example, with ACT, the load profile recorder stops recording and previously collected data are cleared.

3.19.2 Configuration

The load profile record can be configured with the PCM600 tool or any tool supporting the IEC 61850 standard.

The load profile record can be enabled or disabled with the *Operation* setting under the **Configuration/Load Profile Record** menu.

Each protection relay can be mapped to each of the quantity channels of the load profile record. The mapping is done with the *Quantity selection* setting of the corresponding quantity channel.

The IP number of the protection relay and the content of the *Bay name* setting are both included in the COMTRADE configuration file for identification purposes.

The memory consumption of load profile record is supervised, and indicated with two signals `MEM_WARN` and `MEM_ALARM`, which could be used to notify the customer that recording should be backlogged by reading the recorded data from the protection relay. The levels for MEM_WARN and MEM_ALARM are set by two parameters *Mem.warn level* and *Mem. Alarm level*.

3.19.3 Signals

Table 198: LOADPROF Output signals

Name	Type	Description
MEM_WARN	BOOLEAN	Recording memory warning status
MEM_ALARM	BOOLEAN	Recording memory alarm status

3.19.4 Settings

Table 199: LOADPROF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=disable	Operation Disable / Enable
Quantity Sel x (1...12)	0=Disabled 1=IA 2=IB 3=IC 4=IG 5=IA2 6=IB2 7=IC2 8=IG2 9=VAB 10=VBC 11=VCA 12=VA 13=VB 14=VC 15=VAB2 16=VBC2 17=VCA2 18=VA2 19=VB2 20=VC2 21=S 22=P 23=Q 24=PF 25=S2 26=P2 27=Q2 28=PF2 29=SA 30=SB 31=SC 32=PA 33=PB 34=PC 35=QA 36=QB 37=QC 38=PFA 39=PFB 40=PFC 41=SA2 42=SB2 43=SC2 44=PA2 45=PB2 46=PC2 47=QA2 48=QB2 49=QC2 50=PFA2 51=PFB2 52=PFC2			0=Disabled	Select quantity to be recorded
Mem. warning level	0...100	%	1	0	Set memory warning level

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Mem. alarm level	0...100	%	1	0	Set memory alarm level

3.19.5 Monitored data

Table 200: LOADPROF Monitored data

Name	Type	Values (Range)	Unit	Description
Rec. memory used	INT32	0...100	%	How much recording memory is currently used

3.20 ETHERNET channel supervision function blocks

3.20.1 Redundant Ethernet channel supervision RCHLCCH

3.20.1.1 Function block

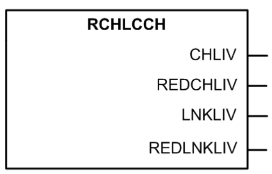


Figure 102: Function block

3.20.1.2 Functionality

Redundant Ethernet channel supervision RCHLCCH represents LAN A and LAN B redundant Ethernet channels.

3.20.1.3 Signals

Table 201: RCHLCCH output signals

Parameter	Values (Range)	Unit	Step	Default	Description
CHLIV	True False				Status of redundant Ethernet channel LAN A. When *Redundant mode* is set to "HSR" or "PRP", value is "True" if the protection relay is receiving redundancy supervision frames. Otherwise value is "False".
REDCHLIV	True False				Status of redundant Ethernet channel LAN B. When *Redundant mode* is set to "HSR" or "PRP", value is "True" if the protection relay is receiving redundancy supervision frames. Otherwise value is "False".
LNKLIV	Up Down				Link status of redundant port LAN A. Valid only when *Redundant mode* is set to "HSR" or "PRP".
REDLNKLIV	Up Down				Link status of redundant port LAN B. Valid only when *Redundant mode* is set to "HSR" or "PRP".

3.20.1.4 Settings

Table 202: Redundancy settings

Parameter	Values (Range)	Unit	Step	Default	Description
Redundant mode	None PRP HSR			None	Mode selection for Ethernet switch on redundant communication modules. The "None" mode is used with normal and Self-healing Ethernet topologies.

3.20.1.5 Monitored data

Monitored data is available in four locations.

- **Monitoring/Communication/Ethernet/Activity/CHLIV_A**
- **Monitoring/Communication/Ethernet/Activity/REDCHLIV_B**
- **Monitoring/Communication/Ethernet/Link statuses/LNKLIV_A**
- **Monitoring/Communication/Ethernet/Link statuses/REDLNKLIV_B**

3.20.2 Ethernet channel supervision SCHLCCH

3.20.2.1 Function block

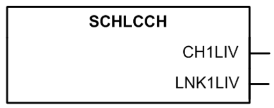


Figure 103: Function block

3.20.2.2 Functionality

Ethernet channel supervision SCHLCCH represents X1/LAN, X2/LAN and X3/LAN Ethernet channels.

An unused Ethernet port can be set "Off" with the setting **Configuration/ Communication/Ethernet/Rear port(s)/Port x Mode**. This setting closes the port from software, disabling the Ethernet communication in that port. Closing an unused Ethernet port enhances the cyber security of the relay.

3.20.2.3 Signals

Table 203: SCHLCCH1 output signals

Parameter	Values (Range)	Unit	Step	Default	Description
CH1LIV	True False				Status of Ethernet channel X1/LAN. Value is "True" if the port is receiving Ethernet frames. Valid only when *Redundant mode* is set to "None" or port is not one of the redundant ports (LAN A or LAN B).
LNK1LIV	Up Down				Link status of Ethernet port X1/LAN.

Table 204: SCHLCCH2 output signals

Parameter	Values (Range)	Unit	Step	Default	Description
CH2LIV	True False				Status of Ethernet channel X2/LAN. Value is "True" if the port is receiving Ethernet frames. Valid only when *Redundant mode* is set to "None" or port is not one of the redundant ports (LAN A or LAN B).
LNK2LIV	Up Down				Link status of Ethernet port X2/LAN.

Table 205: SCHLCCH3 output signals

Parameter	Values (Range)	Unit	Step	Default	Description
CH3LIV	True False				Status of Ethernet channel X3/LAN. Value is "True" if the port is receiving Ethernet frames. Valid only when *Redundant mode* is set to "None" or port is not one of the redundant ports (LAN A or LAN B).
LNK3LIV	Up Down				Link status of Ethernet port X3/LAN.

3.20.2.4 Settings

Table 206: Port mode settings

Parameter	Values (Range)	Unit	Step	Default	Description
Port 1 Mode	Off On			On	Mode selection for rear port(s). If port is not used, it can be set to “Off”. Port cannot be set to “Off” when *Redundant mode* is “HSR” or “PRP” and port is one of the redundant ports (LAN A or LAN B) or when port is used for line differential communication.
Port 2 Mode	Off On			On	Mode selection for rear port(s). If port is not used, it can be set to “Off”. Port cannot be set to “Off” when *Redundant mode* is “HSR” or “PRP” and port is one of the redundant ports (LAN A or LAN B).
Port 3 Mode	Off On			On	Mode selection for rear port(s). If port is not used, it can be set to “Off”. Port cannot be set to “Off” when *Redundant mode* is “HSR” or “PRP” and port is one of the redundant ports (LAN A or LAN B).

3.20.2.5 Monitored data

Monitored data is available in six locations.

- **Monitoring/Communication/Ethernet/Activity/CH1LIV**
- **Monitoring/Communication/Ethernet/Activity/CH2LIV**
- **Monitoring/Communication/Ethernet/Activity/CH3LIV**
- **Monitoring/Communication/Ethernet/Link statuses/LNK1LIV**
- **Monitoring/Communication/Ethernet/Link statuses/LNK2LIV**
- **Monitoring/Communication/Ethernet/Link statuses/LNK3LIV**

Section 4 Protection functions

4.1 Three-phase current protection

4.1.1 Three-phase non-directional overcurrent protection 51P, 50P, 50P-3

4.1.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase non-directional overcurrent protection, low stage	PHLPTOC	3I>	51P
Three-phase non-directional overcurrent protection, high stage	PHHPTOC	3I>>	50P
Three-phase non-directional overcurrent protection, instantaneous stage	PHIPTOC	3I>>>	50P-3

4.1.1.2 Function block

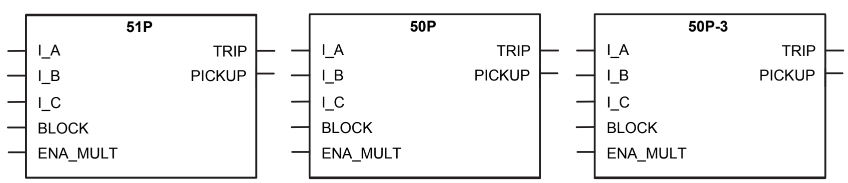


Figure 104: Function block

4.1.1.3 Functionality

The three-phase non-directional overcurrent protection function 51P, 50P, 50P-3 is used as one-phase, two-phase or three-phase non-directional overcurrent and short-circuit protection.

The function picks up when the current exceeds the set limit. The trip time characteristics for low stage 51P and high stage 50P can be selected to be either definite time (DT) or inverse definite minimum time (IDMT). The instantaneous stage 50P-3 always trips with the DT characteristic.

In the DT mode, the function trips after a predefined trip time and resets when the fault current disappears. The IDMT mode provides current-dependent timer characteristics.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.1.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 51P, 50P, 50P-3 can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

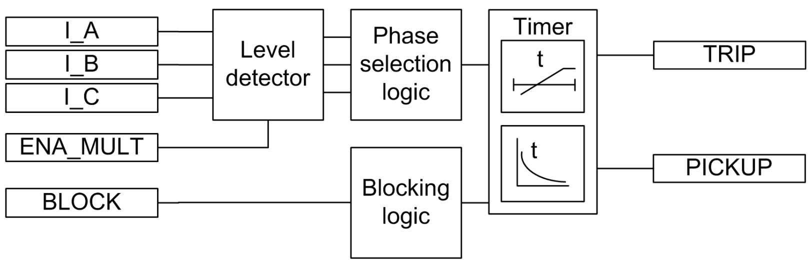


Figure 105: Functional module diagram

Level detector

The measured phase currents are compared phasewise to the set *Pickup value*. If the measured value exceeds the set *Pickup value*, the level detector reports the exceeding of the value to the phase selection logic. If the ENA_MULT input is active, the *Pickup value* setting is multiplied by the *Pickup value Mult* setting.

The protection relay does not accept the *Pickup value* or *Pickup value Mult* setting if the product of these settings exceeds the *Pickup value* setting range.

The pickup value multiplication is normally done when the inrush detection function (INR) is connected to the ENA_MULT input.

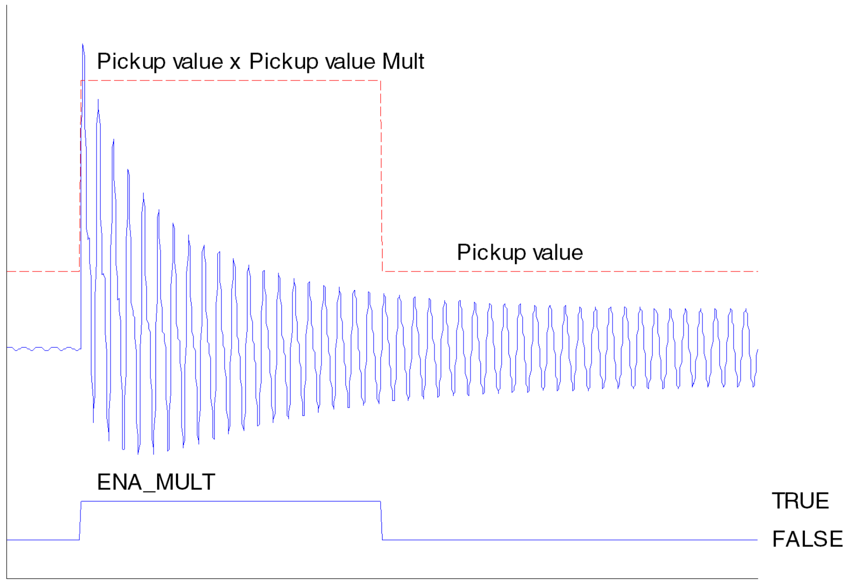


Figure 106: Pickup value behavior with `ENA_MULT` *input activated*

Phase selection logic

If the fault criteria are fulfilled in the level detector, the phase selection logic detects the phase or phases in which the measured current exceeds the setting. If the phase information matches the *Num of pickup phases* setting, the phase selection logic activates the timer module.

Timer

Once activated, the timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated.

When the user-programmable IDMT curve is selected, the operation time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set

Reset delay time value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The `PICKUP` output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT trip and reset times.

The setting parameter *Minimum trip time* defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.1.1.5 Measurement modes

The function operates on four alternative measurement modes: "RMS", "DFT", "Peak-to-Peak" and "P-to-P + backup". Additionally, there is “Wide P-to-P” measurement mode in some products variants. The measurement mode is selected with the setting *Measurement mode*.

Table 207: Measurement modes supported by 51P/50P stages

Measurement mode	51P	50P	50P-3
RMS	x	x	
DFT	x	x	
Peak-to-Peak	x	x	
P-to-P + backup			x
Wide P-to-P	x [1]		

1) Available only in REG615 standard configurations C and D

For a detailed description of the measurement modes, see the Measurement modes section in this manual.

4.1.1.6 Timer characteristics

51P, 50P, 50P-3 supports both DT and IDMT characteristics. The user can select the timer characteristics with the *Operating curve type* and *Type of reset curve* settings. When the DT characteristic is selected, it is only affected by the *Trip delay time* and *Reset delay time* settings.

The protection relay provides 16 IDMT characteristics curves, of which seven comply with the IEEE C37.112 and six with the IEC 60255-3 standard. Two curves follow the special characteristics of ABB praxis and are referred to as RI and RD. In addition to this, a user programmable curve can be used if none of the standard curves are applicable. The DT characteristics can be chosen by selecting the *Operating curve type* values "ANSI Def. Time" or "IEC Def. Time". The functionality is identical in both cases.

The timer characteristics supported by different stages comply with the list in the IEC 61850-7-4 specification, indicate the characteristics supported by different stages:

Table 208: Timer characteristics supported by different stages

Operating curve type	51P	50P
(1) ANSI Extremely Inverse	x	x
(2) ANSI Very Inverse	x	
(3) ANSI Normal Inverse	x	x
(4) ANSI Moderately Inverse	x	
(5) ANSI Definite Time	x	x
(6) Long Time Extremely Inverse	x	
(7) Long Time Very Inverse	x	
(8) Long Time Inverse	x	
(9) IEC Normal Inverse	x	x
(10) IEC Very Inverse	x	x
(11) IEC Inverse	x	
(12) IEC Extremely Inverse	x	x
(13) IEC Short Time Inverse	x	
(14) IEC Long Time Inverse	x	
(15) IEC Definite Time	x	x
(17) User programmable	x	x
(18) RI type	x	
(19) RD type	x	

50P-3 supports only definite time characteristic.

For a detailed description of timers, see the General function block features section in this manual.

Table 209: Reset time characteristics supported by different stages

Reset curve type	51P	50P	Note
(1) Immediate	x	x	Available for all reset time curves
(2) Def time reset	x	x	Available for all reset time curves
(3) Inverse reset	x	x	Available only for ANSI and user programmable curves

The *Type of reset curve* setting does not apply to 50P-3 or when the DT operation is selected. The reset is purely defined by the *Reset delay time* setting.

4.1.1.7 Application

51P, 50P, 50P-3 is used in several applications in the power system. The applications include but are not limited to:

- Selective overcurrent and short-circuit protection of feeders in distribution and subtransmission systems
- Backup overcurrent and short-circuit protection of power transformers and generators
- Overcurrent and short-circuit protection of various devices connected to the power system, for example shunt capacitor banks, shunt reactors and motors
- General backup protection

51P, 50P, 50P-3 is used for single-phase, two-phase and three-phase non-directional overcurrent and short-circuit protection. Typically, overcurrent protection is used for clearing two and three-phase short circuits. Therefore, the user can choose how many phases, at minimum, must have currents above the pickup level for the function to trip. When the number of pickup-phase settings is set to "1 out of 3", the operation of 51P, 50P, 50P-3 is enabled with the presence of high current in one-phase.

When the setting is "2 out of 3" or "3 out of 3", single-phase faults are not detected. The setting "3 out of 3" requires the fault to be present in all three phases.

Many applications require several steps using different current pickup levels and time delays. 51P/50P consists of three protection stages:

- Low 51P
- High 50P
- Instantaneous 50P-3

51P is used for overcurrent protection. The function contains several types of time-delay characteristics. 50P and 50P-3 are used for fast clearance of very high overcurrent situations.

Transformer overcurrent protection

The purpose of transformer overcurrent protection is to operate as main protection, when differential protection is not used. It can also be used as coarse back-up protection for differential protection in faults inside the zone of protection, that is, faults occurring in incoming or outgoing feeders, in the region of transformer terminals and tank cover. This means that the magnitude range of the fault current can be very wide. The range varies from $6xI_n$ to several hundred times I_n, depending on the impedance of the transformer and the source impedance of the feeding network. From this point of view, it is clear that the operation must be both very fast and selective, which is usually achieved by using coarse current settings.

The purpose is also to protect the transformer from short circuits occurring outside the protection zone, that is through-faults. Transformer overcurrent protection also provides protection for the LV-side busbars. In this case the magnitude of the fault current is typically lower than $12xI_n$ depending on the fault location and transformer impedance. Consequently, the protection must operate as fast as possible taking into account the selectivity requirements, switching-in currents, and the thermal and mechanical withstand of the transformer and outgoing feeders.

Traditionally, overcurrent protection of the transformer has been arranged as shown in Figure 107. The low-set stage 51P operates time-selectively both in transformer and LV-side busbar faults. The high-set stage 50P operates instantaneously making use of current selectivity only in transformer HV-side faults. If there is a possibility, that the fault current can also be fed from the LV-side up to the HV-side, the transformer must also be equipped with LV-side overcurrent protection. Inrush current detectors are used in start-up situations to multiply the current pickup value setting in each particular protection relay where the inrush current can occur. The overcurrent and contact based circuit breaker failure protection 50BF is used to confirm the protection scheme in case of circuit breaker malfunction.

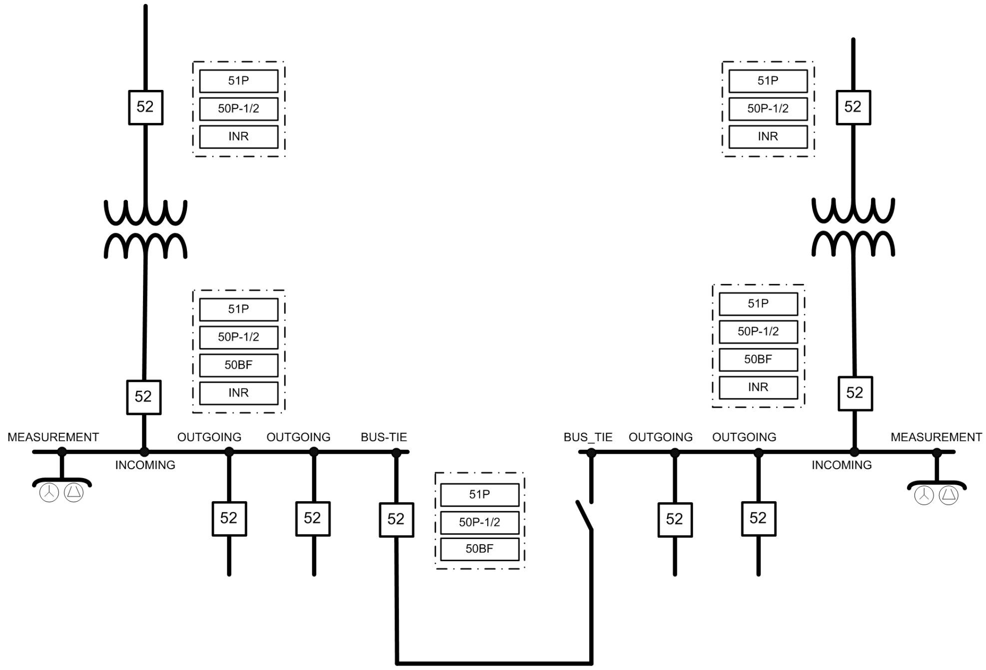


Figure 107: Example of traditional time selective transformer overcurrent protection

The operating times of the main and backup overcurrent protection of the above scheme become quite long, this applies especially in the busbar faults and also in the transformer LV-terminal faults. In order to improve the performance of the above scheme, a multiple-stage overcurrent protection with reverse blocking is proposed. Figure 108 shows this arrangement.

Transformer and busbar overcurrent protection with reverse blocking principle

By implementing a full set of overcurrent protection stages and blocking channels between the protection stages of the incoming feeders, bus-tie and outgoing feeders, it is possible to speed up the operation of overcurrent protection in the busbar and transformer LV-side faults without impairing the selectivity. Also, the security degree of busbar protection is increased, because there is now a dedicated, selective and fast busbar protection functionality which is based on the blockable overcurrent protection principle. The additional time selective stages on the transformer HV and LV-sides provide increased security of backup protection for the transformer, busbar and also for the outgoing feeders.

Depending on the overcurrent stage in question, the selectivity of the scheme in Figure 108 is based on the operating current, operating time or blockings between successive overcurrent stages. With blocking channels, the operating time of the protection can be drastically shortened if compared to the simple time selective protection. In addition to the busbar protection, this blocking principle is applicable for the protection of transformer

LV terminals and short lines. The functionality and performance of the proposed overcurrent protections can be summarized as seen in the table.

Table 210: Proposed functionality of numerical transformer and busbar overcurrent protection. DT = definite time, IDMT = inverse definite minimum time

O/C-stage	Operating char.	Selectivity mode	Operation speed	Sensitivity
HV/51P	DT/IDMT	time selective	low	very high
HV/50PHV/ 50P-1/2	DT	blockable/time selective	high/low	high
HV/50P-3	DT	current selective	very high	low
LV/51P	DT/IDMT	time selective	low	very high
LV/50P	DT	time selective	low	high
LV/50P-3	DT	blockable	high	high

In case the bus-tie breaker is open, the operating time of the blockable overcurrent protection is approximately 100 ms (relaying time). When the bus-tie breaker is closed, that is, the fault current flows to the faulted section of the busbar from two directions, the operation time becomes as follows: first the bus-tie relay unit trips the tie breaker in the above 100 ms, which reduces the fault current to a half. After this the incoming feeder relay unit of the faulted bus section trips the breaker in approximately 250 ms (relaying time), which becomes the total fault clearing time in this case.

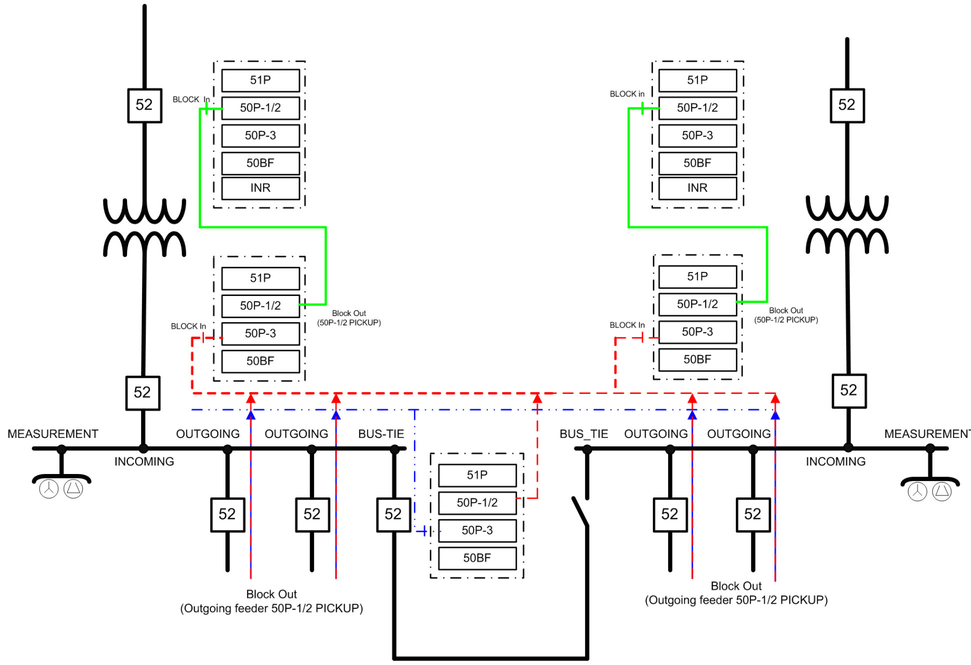


Figure 108: Numerical overcurrent protection functionality for a typical sub-transmission/distribution substation (feeder protection not shown).Blocking output = digital output signal from the pickup of a protection stage, Blocking in = digital input signal to block the operation of a protection stage

The operating times of the time selective stages are very short, because the grading margins between successive protection stages can be kept short. This is mainly due to the advanced measuring principle allowing a certain degree of CT saturation, good operating accuracy and short retardation times of the numerical units. So, for example, a grading margin of 150 ms in the DT mode of operation can be used, provided that the circuit breaker interrupting time is shorter than 60 ms.

The sensitivity and speed of the current-selective stages become as good as possible due to the fact that the transient overreach is very low. Also, the effects of switching inrush currents on the setting values can be reduced by using the protection relay's logic, which recognizes the transformer energizing inrush current and blocks the operation or multiplies the current pickup value setting of the selected overcurrent stage with a predefined multiplier setting.

Finally, a dependable trip of the overcurrent protection is secured by both a proper selection of the settings and an adequate ability of the measuring transformers to reproduce the fault current. This is important in order to maintain selectivity and also for the protection to operate without additional time delays. For additional information about available measuring modes and current transformer requirements, see the Measurement modes chapter in this manual.

Radial outgoing feeder overcurrent protection

The basic requirements for feeder overcurrent protection are adequate sensitivity and operation speed taking into account the minimum and maximum fault current levels along the protected line, selectivity requirements, inrush currents and the thermal and mechanical withstand of the lines to be protected.

In many cases the above requirements can be best fulfilled by using multiple-stage overcurrent units. Figure 109 shows an example of this. A brief coordination study has been carried out between the incoming and outgoing feeders.

The protection scheme is implemented with three-stage numerical overcurrent protection where the low-set stage 51P operates in IDMT-mode and the two higher stages 50P and 50P-3 in DT-mode. Also the thermal withstand of the line types along the feeder and maximum expected inrush currents of the feeders are shown. Faults occurring near the station, where the fault current levels are the highest, are cleared rapidly by the instantaneous stage in order to minimize the effects of severe short circuit faults. The influence of the inrush current is taken into consideration by connecting the inrush current detector to the pickup value multiplying input of the instantaneous stage. In this way, the pickup value is multiplied with a predefined setting during the inrush situation and nuisance tripping can be avoided.

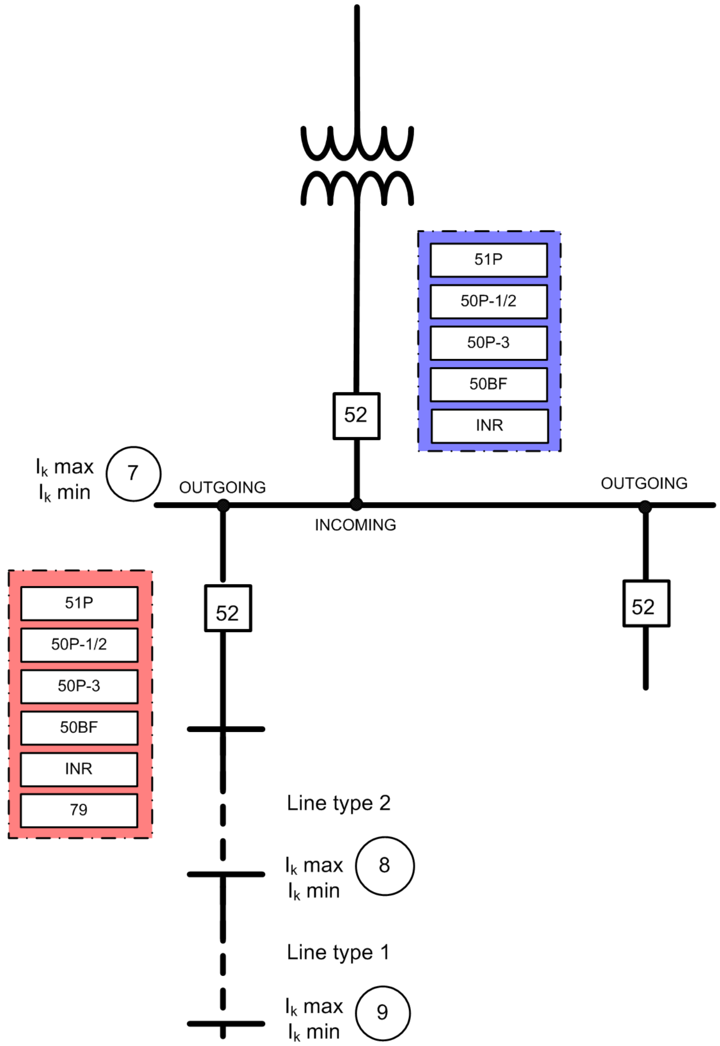


Figure 109: Functionality of numerical multiple-stage overcurrent protection

The coordination plan is an effective tool to study the operation of time selective operation characteristics. All the points mentioned earlier, required to define the overcurrent protection parameters, can be expressed simultaneously in a coordination plan. In Figure 110, the coordination plan shows an example of operation characteristics in the LV-side incoming feeder and radial outgoing feeder.

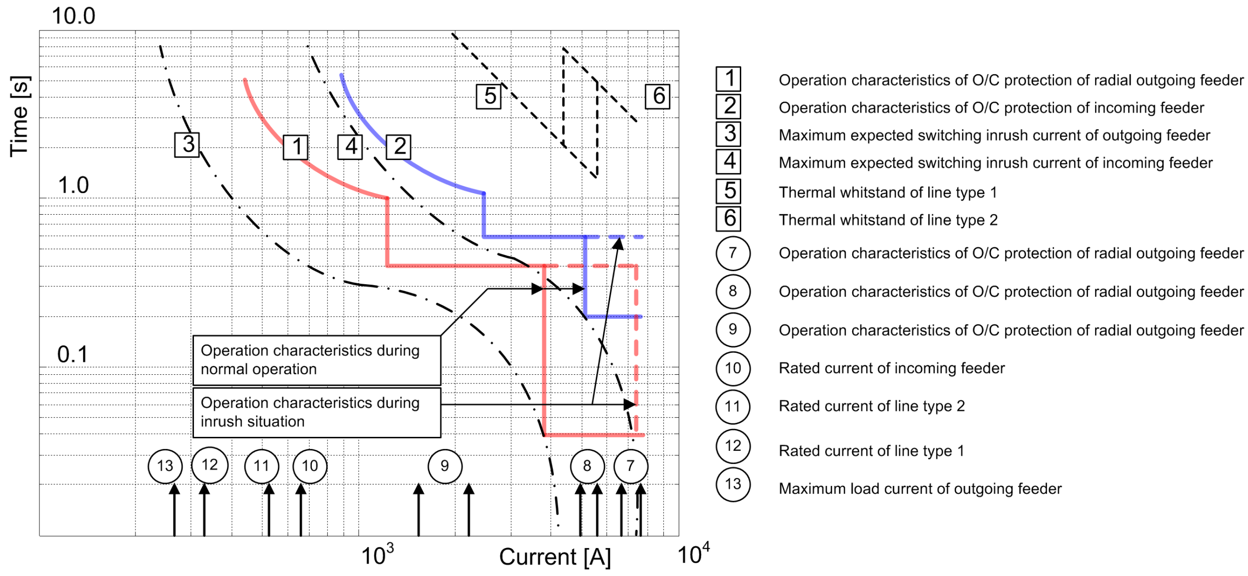


Figure 110: Example coordination of numerical multiple-stage overcurrent protection

4.1.1.8 Signals

Table 211: 51P Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 212: 50P Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 213: 50P-3 Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 214: 51P Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 215: 50P Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 216: 50P-3 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.1.1.9 Settings

Table 217: 51P Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...5.00	xIn	0.01	0.05	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type

Table 218: 51P Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 219: 51P Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 220: 51P Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak 5=IL1-unb			2=DFT	Selects used measurement mode

Table 221: 50P Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.10...40.00	xIn	0.01	0.10	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Operating curve type	1=ANSI Ext Inv 3=ANSI Norm Inv 5=ANSI DT 9=IEC Norm Inv 10=IEC Very Inv 12=IEC Ext Inv 15=IEC DT 17=Programmable			15=IEC DT	Selection of time delay curve type

Table 222: 50P Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 223: 50P Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 224: 50P Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode

Table 225: 50P-3 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	1.00...40.00	xIn	0.01	1.00	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Trip delay time	20...200000	ms	10	20	Trip delay time

Table 226: 50P-3 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation

Table 227: 50P-3 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.1.1.10 Monitored data

Table 228: 51P Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
51P	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 229: 50P Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
50P	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 230: 50P-3 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
50P-3	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.1.11 Technical data

Table 231: 51P, 50P, 50P-3 Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n ±2 Hz		
	51P	±1.5% of the set value or ±0.002 × I_n		
	50P and 50P-3	±1.5% of set value or ±0.002 × I_n (at currents in the range of 0.1…10 × I_n) ±5.0% of the set value (at currents in the range of 10…40 × I_n)		
Pickup time 1)2)		Minimum	Typical	Maximum
	50P-3: I_{Fault} = 2 × set *Pickup value* I_{Fault} = 10 × set *Pickup value*	16 ms 11 ms	19 ms 12 ms	23 ms 14 ms
	50P and 51P: I_{Fault} = 2 × set *Pickup value*	23 ms	26 ms	29 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<30 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode		±5.0% of the theoretical value or ±20 ms 3)		
Suppression of harmonics		RMS: No suppression DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,… Peak-to-Peak: No suppression P-to-P+backup: No suppression		

1) *Measurement mode* = default (depends on stage), current before fault = 0.0 × I_n, f_n = 50 Hz, fault current in one phase with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 2.5 × I_n, *Pickup value* multiples in range of 1.5...20

4.1.1.12 Technical revision history

Table 232: 50P-3 Technical revision history

Technical revision	Change
B	Minimum and default values changed to 40 ms for the *Trip delay time* setting
C	Minimum and default values changed to 20 ms for the *Trip delay time* setting Minimum value changed to 1.00 x I_n for the *Pickup value* setting
D	Internal improvement
E	Internal improvement

Table 233: 50P Technical revision history

Technical revision	Change
C	*Measurement mode* "P-to-P + backup" replaced with "Peak-to-Peak"
D	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting
E	Internal improvement
F	Internal improvement

Table 234: 51P Technical revision history

Technical revision	Change
B	Minimum and default values changed to 40 ms for the *Trip delay time* setting
C	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting
D	Internal improvement
E	Internal improvement

4.1.2 Three-phase directional overcurrent protection 67/51P, 67/50P

4.1.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase directional overcurrent protection, low stage	DPHLPDOC	3I> ->	67/51P
Three-phase directional overcurrent protection, high stage	DPHHPDOC	3I>> ->	67/50P

4.1.2.2 Function block

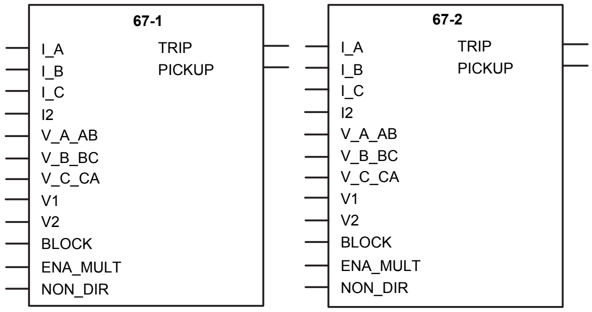


Figure 111: Function block

4.1.2.3 Functionality

The three-phase directional overcurrent protection function 67/51P, 67/50P is used as one-phase, two-phase or three-phase directional overcurrent and short-circuit protection for feeders.

67/51P, 67/50P picks up when the value of the current exceeds the set limit and directional criterion is fulfilled. The trip time characteristics for low stage 67/51P and high stage 67/50P can be selected to be either definite time (DT) or inverse definite minimum time (IDMT).

In the DT mode, the function trips after a predefined trip time and resets when the fault current disappears. The IDMT mode provides current-dependent timer characteristics.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.1.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 67/51P, 67/50P can be described using a module diagram. All the modules in the diagram are explained in the next sections.

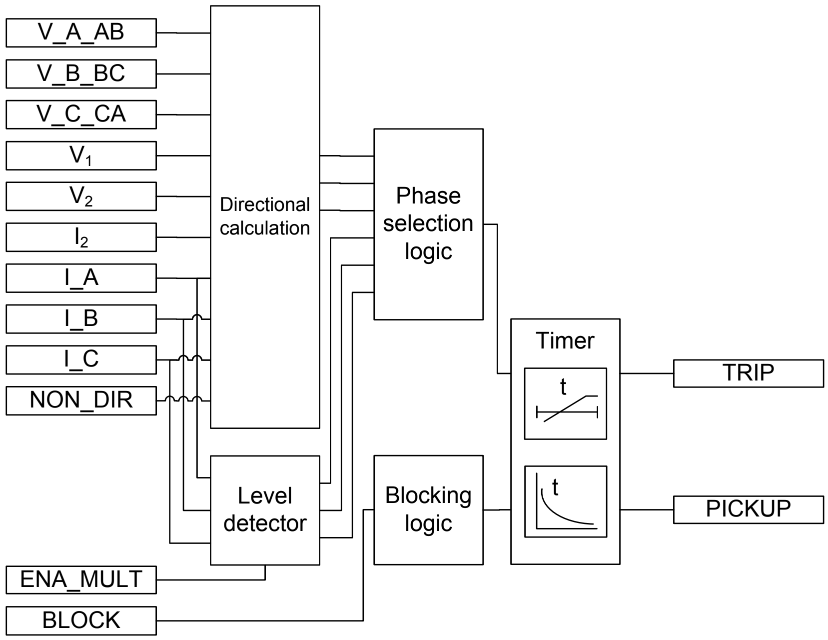


Figure 112: Functional module diagram

Directional calculation

The directional calculation compares the current phasors to the polarizing phasor. A suitable polarization quantity can be selected from the different polarization quantities, which are the positive sequence voltage, negative sequence voltage, self-polarizing (faulted) voltage and cross-polarizing voltages (healthy voltages). The polarizing method is defined with the *Pol quantity* setting.

Table 235: Polarizing quantities

Polarizing quantity	Description
Pos. seq. volt	Positive sequence voltage
Neg. seq. volt	Negative sequence voltage
Self pol	Self polarization
Cross pol	Cross polarization

The directional operation can be selected with the *Directional mode* setting. The user can select either "Non-directional", "Forward" or "Reverse" operation. By setting the value of *Allow Non Dir* to "True", the non-directional operation is allowed when the directional information is invalid.

The *Characteristic angle* setting is used to turn the directional characteristic. The value of *Characteristic angle* should be chosen in such a way that all the faults in the operating direction are seen in the operating zone and all the faults in the opposite direction are seen in the non-operating zone. The value of *Characteristic angle* depends on the network configuration.

Reliable operation requires both the operating and polarizing quantities to exceed certain minimum amplitude levels. The minimum amplitude level for the operating quantity (current) is set with the *Min trip current* setting. The minimum amplitude level for the polarizing quantity (voltage) is set with the *Min trip voltage* setting. If the amplitude level of the operating quantity or polarizing quantity is below the set level, the direction information of the corresponding phase is set to "Unknown".

The polarizing quantity validity can remain valid even if the amplitude of the polarizing quantity falls below the value of the *Min trip voltage* setting. In this case, the directional information is provided by a special memory function for a time defined with the *Voltage Mem time* setting.

67/51P, 67/50P is provided with a memory function to secure a reliable and correct directional protection relay operation in case of a close short circuit or a ground fault characterized by an extremely low voltage. At sudden loss of the polarization quantity, the angle difference is calculated on the basis of a fictive voltage. The fictive voltage is calculated using the positive phase sequence voltage measured before the fault occurred, assuming that the voltage is not affected by the fault. The memory function enables the function to trip up to a maximum of three seconds after a total loss of voltage. This time can be set with the *Voltage Mem time* setting. The voltage memory cannot be used for the "Negative sequence voltage" polarization because it is not possible to substitute the positive sequence voltage for negative sequence voltage without knowing the network unsymmetry level. This is the reason why the fictive voltage angle and corresponding direction information are frozen immediately for this polarization mode when the need for a voltage memory arises and these are kept frozen until the time set with *Voltage Mem time* elapses.

The value for the *Min trip voltage* setting should be carefully selected since the accuracy in low signal levels is strongly affected by the measuring device accuracy.

When the voltage falls below *Min trip voltage* at a close fault, the fictive voltage is used to determine the phase angle. The measured voltage is applied again as soon as the voltage rises above *Min trip voltage* and hysteresis. The fictive voltage is also discarded if the measured voltage stays below *Min trip voltage*and hysteresis for longer than *Voltage Mem time* or if the fault current disappears while the fictive voltage is in use. When the voltage is below *Min trip voltage* and hysteresis and the fictive voltage is unusable, the fault direction cannot be determined. The fictive voltage can be unusable for two reasons:

- The fictive voltage is discarded after *Voltage Mem time*
- The phase angle cannot be reliably measured before the fault situation.

67/51P, 67/50P can be forced to the non-directional operation with the NON_DIR input. When the NON_DIR input is active, 67/51P, 67/50P operates as a non-directional overcurrent protection, regardless of the *Directional mode* setting.

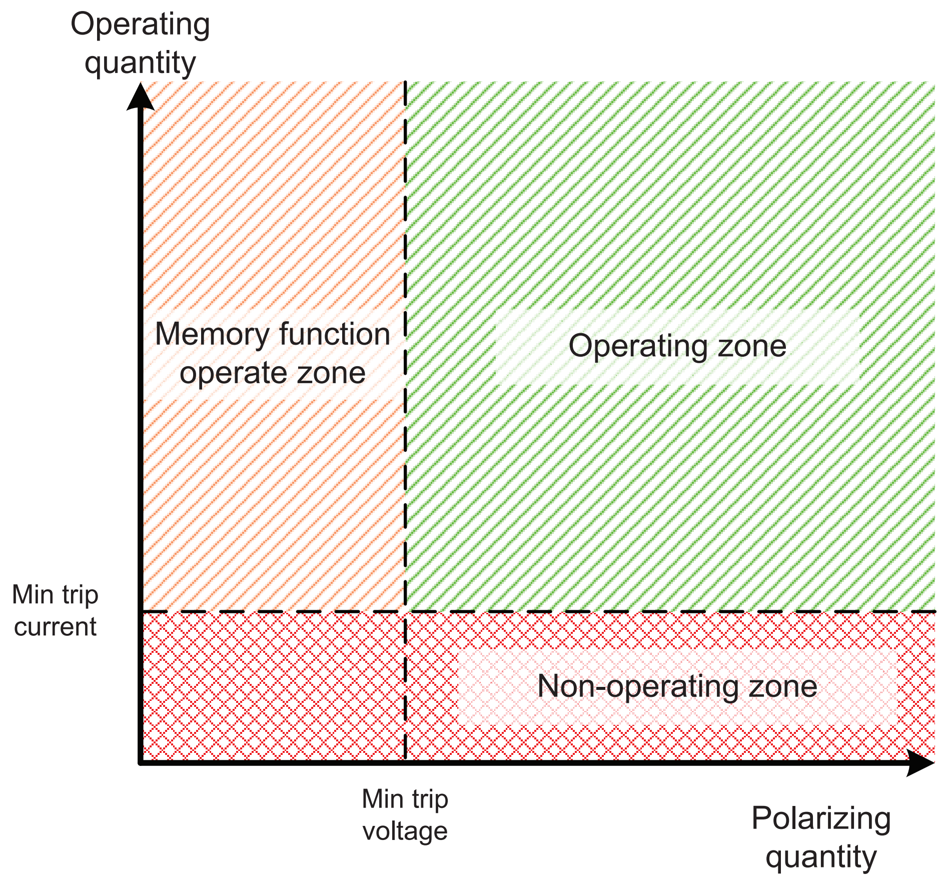


Figure 113: Operating zones at minimum magnitude levels

Level detector

The measured phase currents are compared phasewise to the set *Pickup value*. If the measured value exceeds the set *Pickup value*, the level detector reports the exceeding of the value to the phase selection logic. If the ENA_MULT input is active, the *Pickup value* setting is multiplied by the *Pickup value Mult* setting.

The protection relay does not accept the *Pickup value* or *Pickup value Mult* setting if the product of these settings exceeds the *Pickup value* setting range.

The pickup value multiplication is normally done when the inrush detection function (INR) is connected to the ENA_MULT input.

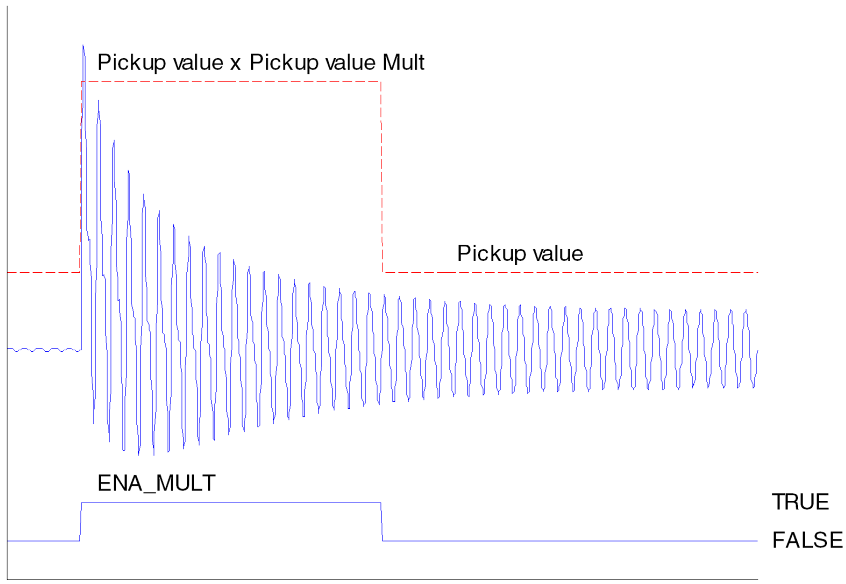


Figure 114: Pickup value behavior with ENA_MULT *input activated*

Phase selection logic

If the fault criteria are fulfilled in the level detector and the directional calculation, the phase selection logic detects the phase or phases in which the measured current exceeds the setting. If the phase information matches the *Num of pickup phases* setting, the phase selection logic activates the timer module.

Timer

Once activated, the timer activates the PICKUP output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the TRIP output is activated.

When the user-programmable IDMT curve is selected, the operation time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set *Reset delay time* value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The `PICKUP` output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT trip and reset times.

The setting parameter *Minimum trip time* defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.1.2.5 Measurement modes

The function operates on three alternative measurement modes: “RMS”, “DFT” and “Peak-to-Peak” . The measurement mode is selected with the *Measurement mode* setting.

Table 236: Measurement modes supported by 67/51P, 67/50P stagesMeasurement modes supported by 67/51P and 67/50P stages

Measurement mode	67/51P	67/50P
RMS	x	x
DFT	x	x
Peak-to-Peak	x	x

4.1.2.6 Directional overcurrent characteristics

The forward and reverse sectors are defined separately. The forward operation area is limited with the *Min forward angle* and *Max forward angle* settings. The reverse operation area is limited with the *Min reverse angle* and *Max reverse angle* settings.

The sector limits are always given as positive degree values.

In the forward operation area, the *Max forward angle* setting gives the counterclockwise sector and the *Min forward angle* setting gives the corresponding clockwise sector, measured from the *Characteristic angle* setting.

In the backward operation area, the *Max reverse angle* setting gives the counterclockwise sector and the *Min reverse angle* setting gives the corresponding clockwise sector, a measurement from the *Characteristic angle* setting that has been rotated 180 degrees.

Relay characteristic angle (RCA) is set positive if the operating current lags the polarizing quantity and negative if the operating current leads the polarizing quantity.

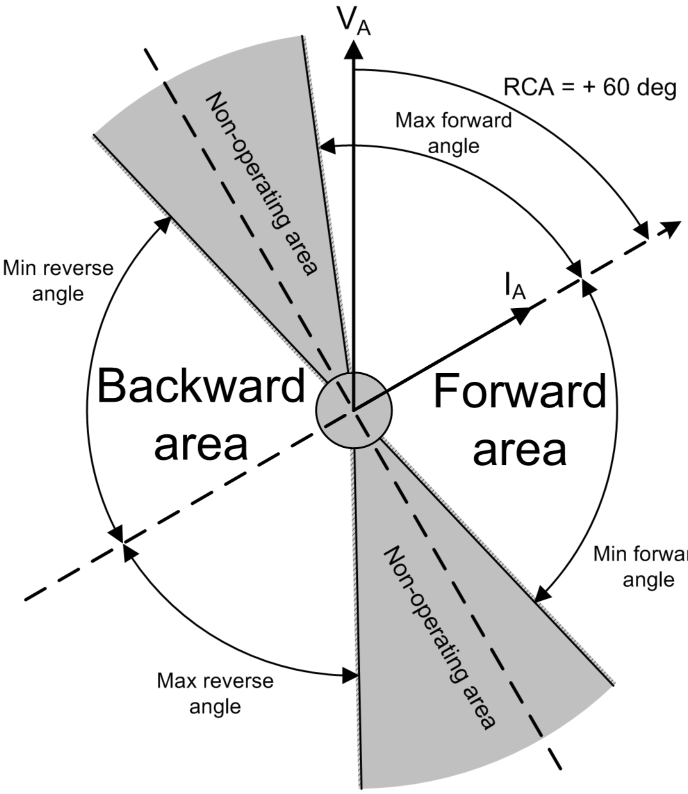


Figure 115: Configurable operating sectors

Table 237: Momentary per phase direction value for monitored data view

Criterion for per phase direction information	The value for DIR_A/_B/_C
The ANGLE_X is not in any of the defined sectors, or the direction cannot be defined due too low amplitude	0 = unknown
The ANGLE_X is in the forward sector	1 = forward
The ANGLE_X is in the reverse sector	2 = backward
(The ANGLE_X is in both forward and reverse sectors, that is, when the sectors are overlapping)	3 = both

Table 238: Momentary phase combined direction value for monitored data view

Criterion for phase combined direction information	The value for DIRECTION
The direction information (DIR_X) for all phases is unknown	0 = unknown
The direction information (DIR_X) for at least one phase is forward, none being in reverse	1 = forward
The direction information (DIR_X) for at least one phase is reverse, none being in forward	2 = backward
The direction information (DIR_X) for some phase is forward and for some phase is reverse	3 = both

FAULT_DIR gives the detected direction of the fault during fault situations, that is, when the PICKUP output is active.

Self-polarizing as polarizing method

Table 239: Equations for calculating angle difference for self-polarizing method

Faulted phases	Used fault current	Used polarizing voltage	Angle difference
A	$\underline{I}_A$	$\underline{V}_A$	$ANGLE\_A = \varphi(\underline{V}_A) - \varphi(\underline{I}_A) - \varphi_{RCA}$
B	$\underline{I}_B$	$\underline{V}_B$	$ANGLE\_B = \varphi(\underline{V}_B) - \varphi(\underline{I}_B) - \varphi_{RCA}$
C	$\underline{I}_C$	$\underline{V}_C$	$ANGLE\_C = \varphi(\underline{V}_C) - \varphi(\underline{I}_C) - \varphi_{RCA}$
A - B	$\underline{I}_A - \underline{I}_B$	$\underline{V}_{AB}$	$ANGLE\_A = \varphi(\underline{V}_{AB}) - \varphi(\underline{I}_A - \underline{I}_B) - \varphi_{RCA}$
B - C	$\underline{I}_B - \underline{I}_C$	$\underline{V}_{BC}$	$ANGLE\_B = \varphi(\underline{V}_{BC}) - \varphi(\underline{I}_B - \underline{I}_C) - \varphi_{RCA}$
C - A	$\underline{I}_C - \underline{I}_A$	$\underline{V}_{CA}$	$ANGLE\_C = \varphi(\underline{V}_{CA}) - \varphi(\underline{I}_C - \underline{I}_A) - \varphi_{RCA}$

In an example case of the phasors in a single-phase ground fault where the faulted phase is phase A, the angle difference between the polarizing quantity V_A and operating quantity I_A is marked as φ. In the self-polarization method, there is no need to rotate the polarizing quantity.

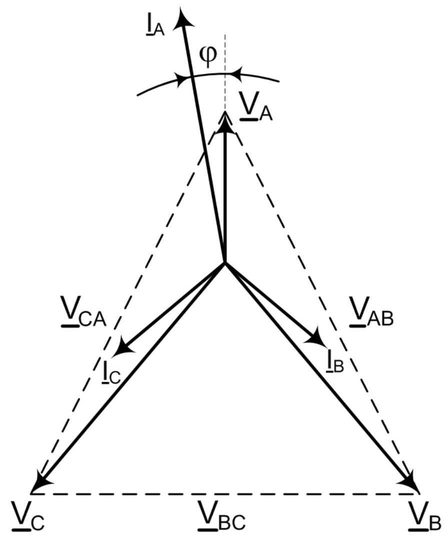


Figure 116: Single-phase ground fault, phase A

In an example case of a two-phase short-circuit failure where the fault is between phases B and C, the angle difference is measured between the polarizing quantity V_{BC} and operating quantity $\underline{I}_B$ - $\underline{I}_C$ in the self-polarizing method.

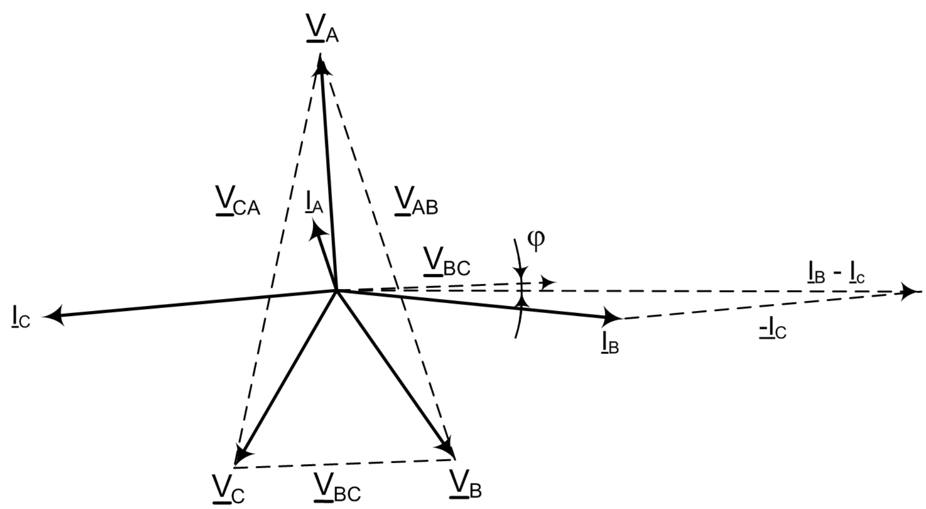


Figure 117: Two-phase short circuit, short circuit is between phases B and C

Cross-polarizing as polarizing quantity

Table 240: Equations for calculating angle difference for cross-polarizing method

Faulted phases	Used fault current	Used polarizing voltage	Angle difference
A	$\underline{I}_A$	$\underline{V}_{BC}$	$ANGLE\_A = \varphi(\underline{V}_{BC}) - \varphi(\underline{I}_A) - \varphi_{RCA} + 90^o$
B	$\underline{I}_B$	$\underline{V}_{CA}$	$ANGLE\_B = \varphi(\underline{V}_{CA}) - \varphi(\underline{I}_B) - \varphi_{RCA} + 90^o$
C	$\underline{I}_C$	$\underline{V}_{AB}$	$ANGLE\_C = \varphi(\underline{V}_{AB}) - \varphi(\underline{I}_C) - \varphi_{RCA} + 90^o$
A - B	$\underline{I}_A - \underline{I}_B$	$\underline{V}_{BC} - \underline{V}_{CA}$	$ANGLE\_A = \varphi(\underline{V}_{BC} - \underline{V}_{CA}) - \varphi(\underline{I}_A - \underline{I}_B) - \varphi_{RCA} + 90^o$
B - C	$\underline{I}_B - \underline{I}_C$	$\underline{V}_{CA} - \underline{V}_{AB}$	$ANGLE\_B = \varphi(\underline{V}_{CA} - \underline{V}_{AB}) - \varphi(\underline{I}_B - \underline{I}_C) - \varphi_{RCA} + 90^o$
C - A	$\underline{I}_C - \underline{I}_A$	$\underline{V}_{AB} - \underline{V}_{BC}$	$ANGLE\_C = \varphi(\underline{V}_{AB} - \underline{V}_{BC}) - \varphi(\underline{I}_C - \underline{I}_A) - \varphi_{RCA} + 90^o$

The angle difference between the polarizing quantity V_{BC} and operating quantity I_A is marked as φ in an example of the phasors in a single-phase ground fault where the faulted phase is phase A. The polarizing quantity is rotated with 90 degrees. The characteristic angle is assumed to be ~ 0 degrees.

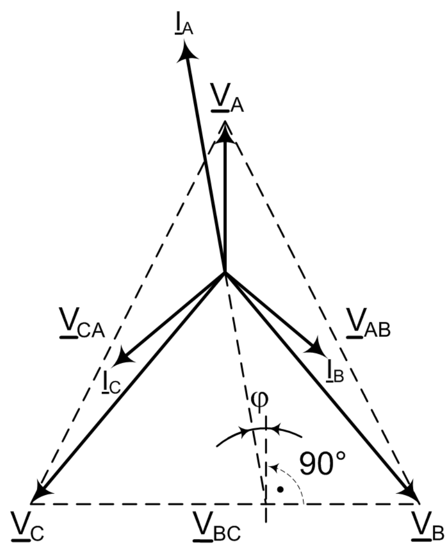


Figure 118: Single-phase ground fault, phase A

In an example of the phasors in a two-phase short-circuit failure where the fault is between the phases B and C, the angle difference is measured between the polarizing quantity $\underline{V}_{AB}$ and operating quantity $\underline{I}_B$ - $\underline{I}_C$ marked as φ.

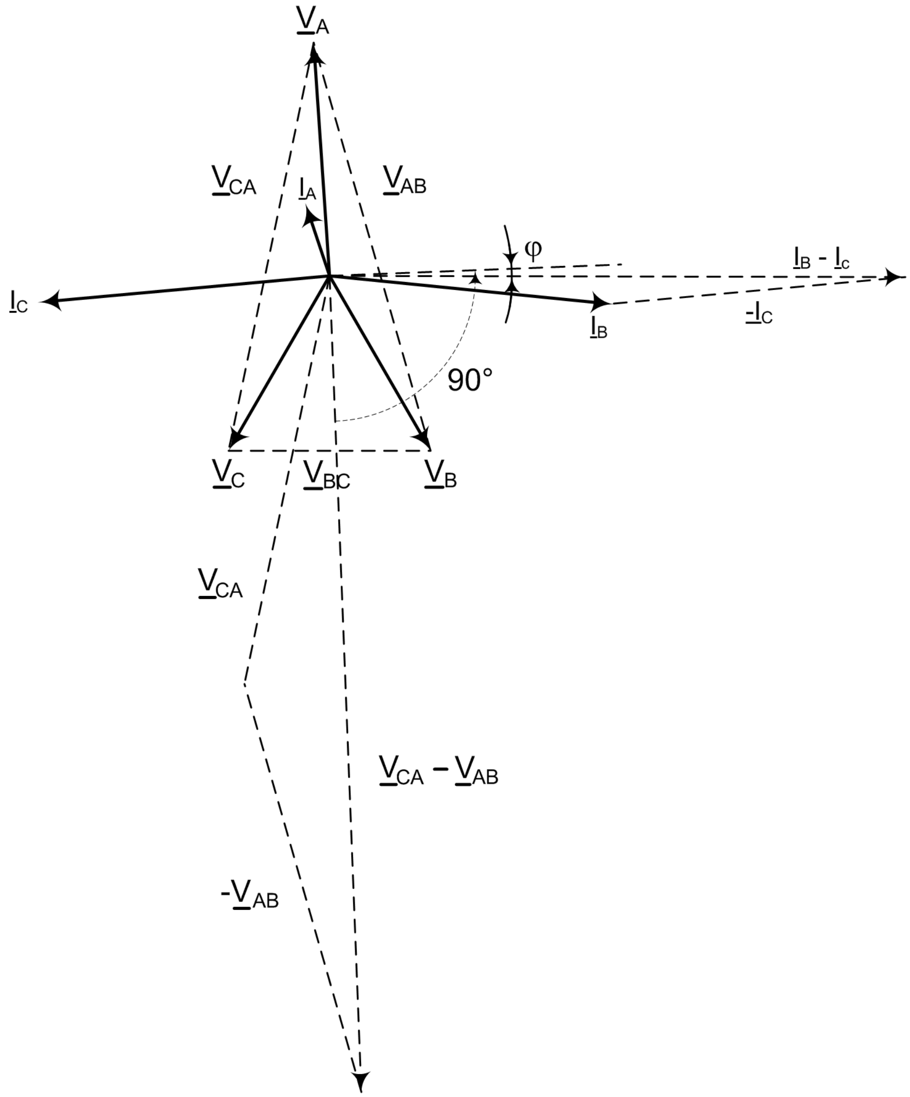


Figure 119: Two-phase short circuit, short circuit is between phases B and C

The equations are valid when network rotating direction is counter-clockwise, that is, ABC. If the network rotating direction is reversed, 180 degrees is added to the calculated angle difference. This is done automatically with a system parameter *Phase rotation*.

Negative sequence voltage as polarizing quantity

When the negative voltage is used as the polarizing quantity, the angle difference between the operating and polarizing quantity is calculated with the same formula for all fault types:

$$ANGLE\_X = \varphi(-\underline{V}2) - \varphi(\underline{I}2) - \varphi_{RCA}$$

(Equation 5)

This means that the actuating polarizing quantity is -V2.

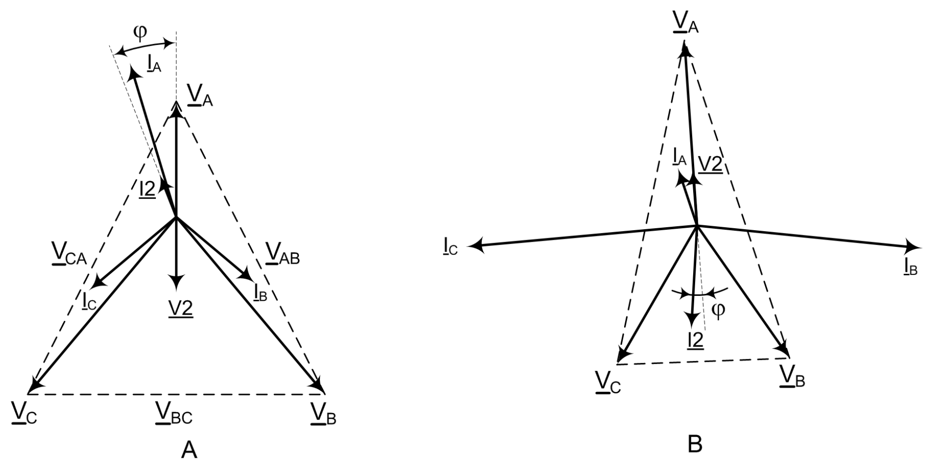


Figure 120: Phasors in a single-phase ground fault, phases A-N, and two-phase short circuit, phases B and C, when the actuating polarizing quantity is the negative-sequence voltage -V2

Positive sequence voltage as polarizing quantity

Table 241: Equations for calculating angle difference for positive-sequence quantity polarizing method

Faulted phases	Used fault current	Used polarizing voltage	Angle difference
A	$\underline{I}_A$	V1	$ANGLE\_A = \varphi(\underline{V}1) - \varphi(\underline{I}_A) - \varphi_{RCA}$
B	$\underline{I}_B$	V1	$ANGLE\_B = \varphi(\underline{V}1) - \varphi(\underline{I}_B) - \varphi_{RCA} - 120^{\circ}$
C	$\underline{I}_C$	V1	$ANGLE\_C = \varphi(\underline{V}1) - \varphi(\underline{I}_C) - \varphi_{RCA} + 120^{\circ}$
Table continues on next page			

Faulted phases	Used fault current	Used polarizing voltage	Angle difference
A - B	$\underline{I}_A$ - $\underline{I}_B$	$\underline{V1}$	$ANGLE\_A = \varphi(\underline{V1}) - \varphi(\underline{I}_A - \underline{I}_B) - \varphi_{RCA} + 30^\circ$
B - C	$\underline{I}_B$ - $\underline{I}_C$	$\underline{V1}$	$ANGLE\_B = \varphi(\underline{V1}) - \varphi(\underline{I}_B - \underline{I}_C) - \varphi_{RCA} - 90^\circ$
C - A	$\underline{I}_C$ - $\underline{I}_A$	$\underline{V1}$	$ANGLE\_C = \varphi(\underline{V1}) - \varphi(\underline{I}_C - \underline{I}_A) - \varphi_{RCA} + 150^\circ$

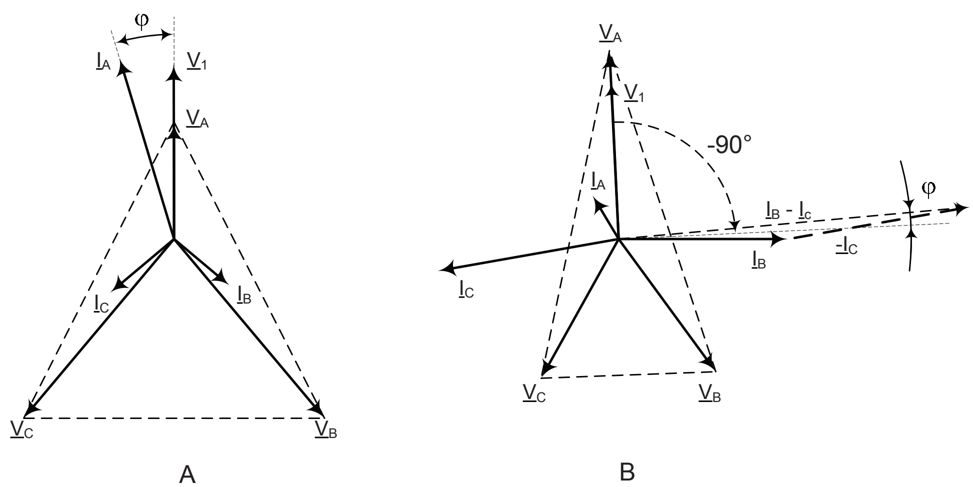


Figure 121: Phasors in a single-phase ground fault, phase A to ground, and a two-phase short circuit, phases B-C, are short-circuited when the polarizing quantity is the positive-sequence voltage V_1

Network rotation direction

Typically, the network rotating direction is counter-clockwise and defined as "ABC". If the network rotating direction is reversed, meaning clockwise, that is, "ACB", the equations for calculating the angle difference needs to be changed. The network rotating direction is defined with a system parameter *Phase rotation*. The change in the network rotating direction affects the phase-to-phase voltages polarization method where the calculated angle difference needs to be rotated 180 degrees. Also, when the sequence components are used, which are, the positive sequence voltage or negative sequence voltage components, the calculation of the components are affected but the angle difference calculation remains the same. When the phase-to-ground voltages are used as the polarizing method, the network rotating direction change has no effect on the direction calculation.

The network rotating direction is set in the protection relay using the parameter in the HMI menu **Configuration/System/Phase rotation**. The default parameter value is "ABC".

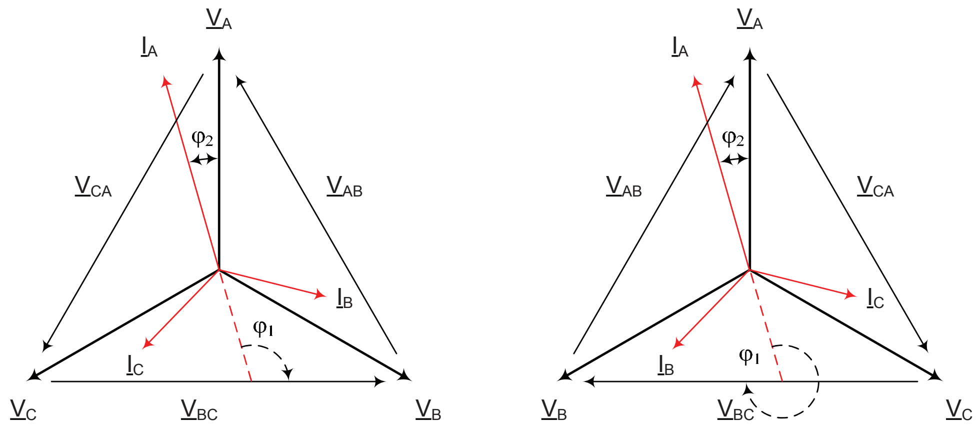


Figure 122: Examples of network rotating direction

4.1.2.7 Application

67/51P, 67/50P is used as short-circuit protection in three-phase distribution or sub transmission networks operating at 50 or 60 Hz.

In radial networks, phase overcurrent protection relays are often sufficient for the short circuit protection of lines, transformers and other equipment. The current-time characteristic should be chosen according to the common practice in the network. It is recommended to use the same current-time characteristic for all overcurrent protection relays in the network. This includes the overcurrent protection of transformers and other equipment.

The phase overcurrent protection can also be used in closed ring systems as short circuit protection. Because the setting of a phase overcurrent protection system in closed ring networks can be complicated, a large number of fault current calculations are needed. There are situations with no possibility to have the selectivity with a protection system based on overcurrent protection relays in a closed ring system.

In some applications, the possibility of obtaining the selectivity can be improved significantly if 67/51P, 67/50P is used. This can also be done in the closed ring networks and radial networks with the generation connected to the remote in the system thus giving fault current infeed in reverse direction. Directional overcurrent protection relays are also used to have a selective protection scheme, for example in case of parallel distribution lines or power transformers fed by the same single source.In ring connected supply feeders between substations or feeders with two feeding sources, 67/51P, 67/50P is also used.

Parallel lines or transformers

When the lines are connected in parallel and if a fault occurs in one of the lines, it is practical to have 67/51P, 67/50P to detect the direction of the fault. Otherwise, there is a risk that the fault situation in one part of the feeding system can de-energize the whole system connected to the LV side.

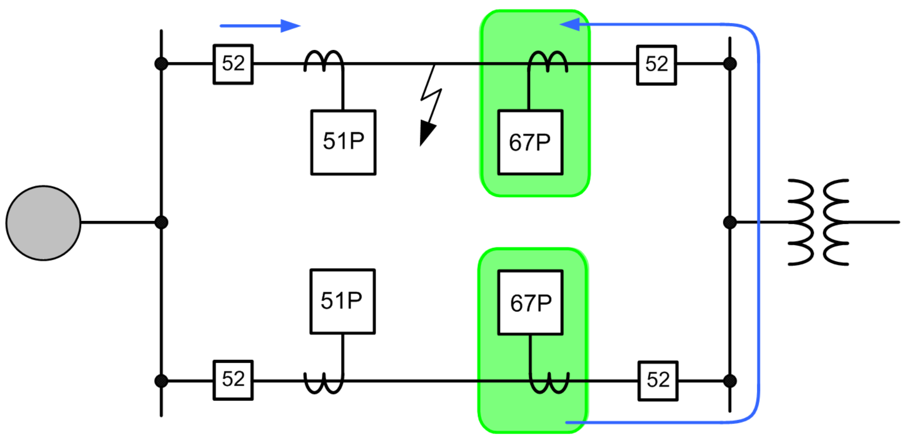


Figure 123: Overcurrent protection of parallel lines using directional protection relays

67/51P, 67/50P can be used for parallel operating transformer applications. In these applications, there is a possibility that the fault current can also be fed from the LV-side up to the HV-side. Therefore, the transformer is also equipped with directional overcurrent protection.

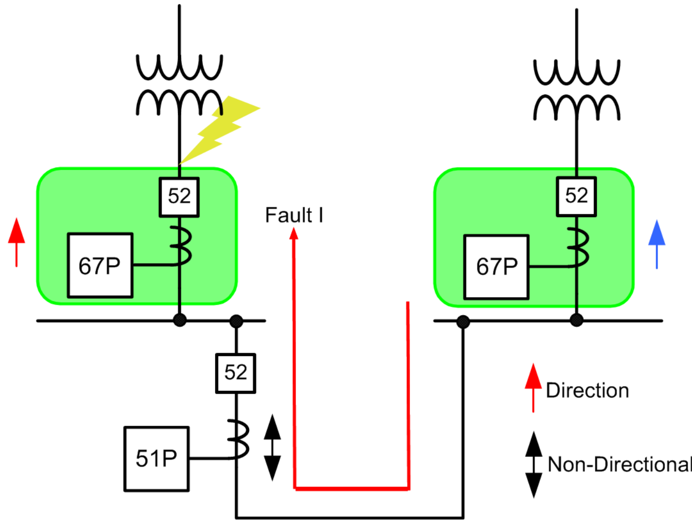


Figure 124: Overcurrent protection of parallel operating transformers

Closed ring network topology

The closed ring network topology is used in applications where electricity distribution for the consumers is secured during network fault situations. The power is fed at least from two directions which means that the current direction can be varied. The time grading between the network level stages is challenging without unnecessary delays in the time settings. In this case, it is practical to use the directional overcurrent protection relays to achieve a selective protection scheme. Directional overcurrent functions can be used in closed ring applications. The arrows define the operating direction of the directional functionality. The double arrows define the non-directional functionality where faults can be detected in both directions.

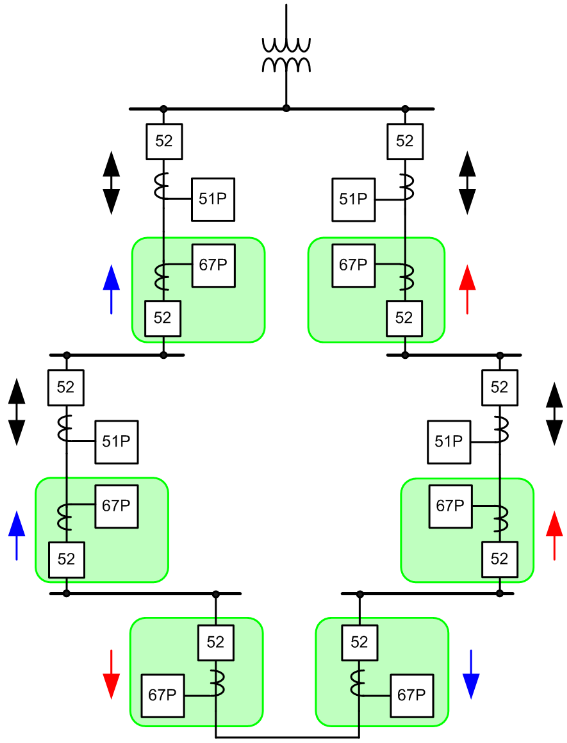


Figure 125: Closed ring network topology where feeding lines are protected with directional overcurrent protection relays

4.1.2.8 Signals

Table 242: 67/51P Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_2	SIGNAL	0	Negative phase sequence current
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
V_1	SIGNAL	0	Positive phase sequence voltage
V_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier
NON_DIR	BOOLEAN	0=False	Forces protection to non-directional

Table 243: 67/50P Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_2	SIGNAL	0	Negative phase sequence current
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
V_1	SIGNAL	0	Positive phase sequence voltage
V_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier
NON_DIR	BOOLEAN	0=False	Forces protection to non-directional

Table 244: 67/51P Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 245: 67/50P Output signals

Name	Type	Description
PICKUP	BOOLEAN	Pickup
TRIP	BOOLEAN	Trip

4.1.2.9 Settings

Table 246: 67/51P Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...5.00	xIn	0.01	0.05	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode
Characteristic angle	-179...180	deg	1	60	Characteristic angle
Max forward angle	0...90	deg	1	80	Maximum phase angle in forward direction
Max reverse angle	0...90	deg	1	80	Maximum phase angle in reverse direction
Min forward angle	0...90	deg	1	80	Minimum phase angle in forward direction
Min reverse angle	0...90	deg	1	80	Minimum phase angle in reverse direction

Table 247: 67/51P Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type
Voltage Mem time	0...3000	ms	1	40	Voltage memory time
Pol quantity	1=Self pol 4=Neg. seq. volt. 5=Cross pol 7=Pos. seq. volt.			5=Cross pol	Reference quantity used to determine fault direction

Table 248: 67/51P Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 249: 67/51P Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Allow Non Dir	0=False 1=True			0=False	Allows prot activation as non-dir when dir info is invalid
Min trip current	0.01...1.00	xIn	0.01	0.01	Minimum trip current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum trip voltage

Table 250: 67/50P Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.10...40.00	xIn	0.01	0.10	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Operating curve type	1=ANSI Ext Inv 3=ANSI Norm Inv 5=ANSI DT 9=IEC Norm Inv 10=IEC Very Inv 12=IEC Ext Inv 15=IEC DT 17=Programmable			15=IEC DT	Selection of time delay curve type
Trip delay time	40...200000	ms	10	40	Trip delay time
Characteristic angle	-179...180	deg	1	60	Characteristic angle
Max forward angle	0...90	deg	1	80	Maximum phase angle in forward direction
Max reverse angle	0...90	deg	1	80	Maximum phase angle in reverse direction
Min forward angle	0...90	deg	1	80	Minimum phase angle in forward direction
Min reverse angle	0...90	deg	1	80	Minimum phase angle in reverse direction

Table 251: 67/50P Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type
Voltage Mem time	0...3000	ms	1	40	Voltage memory time
Pol quantity	1=Self pol 4=Neg. seq. volt. 5=Cross pol 7=Pos. seq. volt.			5=Cross pol	Reference quantity used to determine fault direction

Table 252: 67/50P Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation

Table 253: 67/50P Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Allow Non Dir	0=False 1=True			0=False	Allows prot activation as non-dir when dir info is invalid
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Min trip current	0.01...1.00	xIn	0.01	0.01	Minimum trip current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum trip voltage

4.1.2.10 Monitored data

Table 254: 67/51P Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information
DIR_A	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase A
DIR_B	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase B
DIR_C	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase C
ANGLE_A	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase A
ANGLE_B	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase B
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
ANGLE_C	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase C
VMEM_USED	BOOLEAN	0=False 1=True		Voltage memory in use status
67/51P	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 255: 67/50P Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information
DIR_A	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase A
DIR_B	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase B
DIR_C	Enum	0=unknown 1=forward 2=backward -1=both		Direction phase C
ANGLE_A	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase A
ANGLE_B	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase B
ANGLE_C	FLOAT32	-180.00...180.00	deg	Calculated angle difference, Phase C
VMEM_USED	BOOLEAN	0=False 1=True		Voltage memory in use status
67/50P	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.2.11 Technical data

Table 256: 67/51P, 67/50P Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the current/voltage measured: f_n ±2 Hz		
	67/51P	Current: ±1.5% of the set value or ±0.002 × I_n Voltage: ±1.5% of the set value or ±0.002 × V_n Phase angle: ±2°		
	67/50P	Current: ±1.5% of the set value or ±0.002 × I_n (at currents in the range of 0.1…10 × I_n) ±5.0% of the set value (at currents in the range of 10…40 × I_n) Voltage: ±1.5% of the set value or ±0.002 × V_n Phase angle: ±2°		
Pickup time[1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 2.0 × set *Pickup value*	39 ms	43 ms	47 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<35 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode		±5.0% of the theoretical value or ±20 ms[3)]		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…		

1) *Measurement mode* and *Pol quantity* = default, current before fault = 0.0 × I_n, voltage before fault = 1.0 × V_n, f_n = 50 Hz, fault current in one phase with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 2.5 × I_n,*Pickup value* multiples in range of 1.5...20

4.1.2.12 Technical revision history

Table 257: 67/50P Technical revision history

Technical revision	Change
B	Added a new input `NON_DIR`
C	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
D	Monitored data VMEM_USED indicating voltage memory use.
E	Internal improvement.

Table 258: 67/51P Technical revision history

Technical revision	Change
B	Added a new input `NON_DIR`
C	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
D	Monitored data VMEM_USED indicating voltage memory use.
E	Internal improvement.

4.1.3 Three-phase voltage-dependent overcurrent protection 51V

4.1.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase voltage-dependent overcurrent protection	PHPVOC	3I(U)>	51V

4.1.3.2 Function block

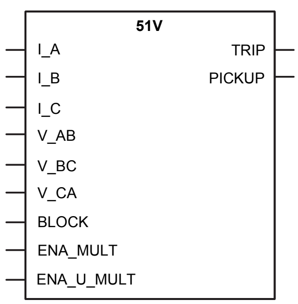


Figure 126: Function block

4.1.3.3 Functionality

The three-phase voltage-dependent overcurrent protection function 51V is used for single-phase, two-phase or three-phase voltage-dependent time overcurrent protection of generators against overcurrent and short circuit conditions.

The function picks up when the input phase current exceeds a limit which is dynamically calculated based on the measured terminal voltages. The operating characteristics can be selected to be either inverse definite minimum time IDMT or definite time DT.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.1.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 51V can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

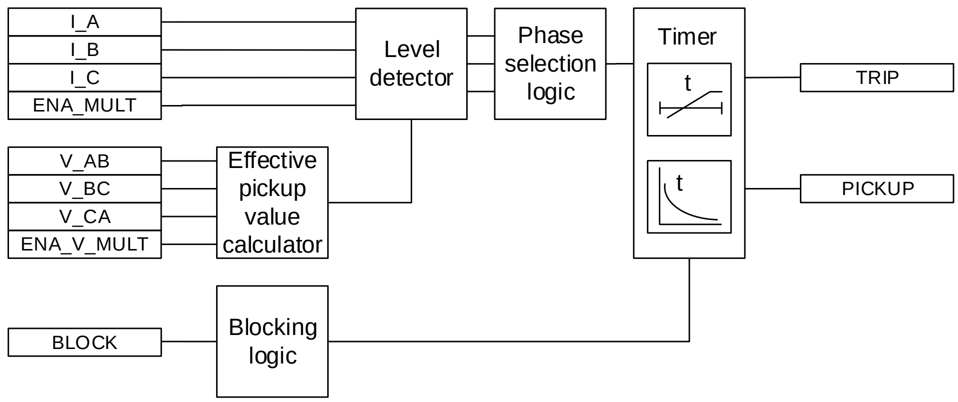


Figure 127: Functional module diagram

Effective pickup value calculator

The normal pickup current above which the overcurrent protection picks up is set through the *Pickup value* setting. The Effective pickup value of the current may need to be changed during certain conditions like magnetizing inrush or when the terminal voltages drop due to a fault. Hence, the effective pickup value calculator module dynamically calculates the effective pickup value above which the overcurrent protection picks up.

Four methods of calculating the effective pickup value are provided in 51V. These can be chosen with the *Control mode* setting to be either "Voltage control", "Input control", "Volt & Input Ctrl" or "No Volt dependency".

The calculated effective pickup value per phase, `EFF_ST_VAL_A`, `EFF_ST_VAL_B`, `EFF_ST_VAL_C`, is available in the Monitored data view and is used by the Level detector module.

All three phase-to-phase voltages should be available for the function to operate properly.

Voltage control mode

In the Voltage control mode, the Effective pickup value is calculated based on the magnitude of input voltages `V_AB`, `V_BC` and `V_CA`. The voltage dependency is phase sensitive, which means that the magnitude of one input voltage controls the pickup value of only the corresponding phase, that is, the magnitude of voltage inputs `V_AB`, `V_BC` and `V_CA` independently control the current pickup values of phases A, B and C.

Two voltage control characteristics, voltage step and voltage slope, can be achieved with the *Voltage high limit* and *Voltage low limit* settings.

The voltage step characteristic is achieved when the *Voltage high limit* setting is equal to the *Voltage low limit* setting. The effective pickup value is calculated based on the equations.

Voltage level	Effective pickup value (I> effective)
V < *Voltage high limit*	*Pickup value low*
V ≥ *Voltage high limit*	*Pickup value*

In this example, V represents the measured input voltage. This voltage step characteristic is graphically represented in Figure.

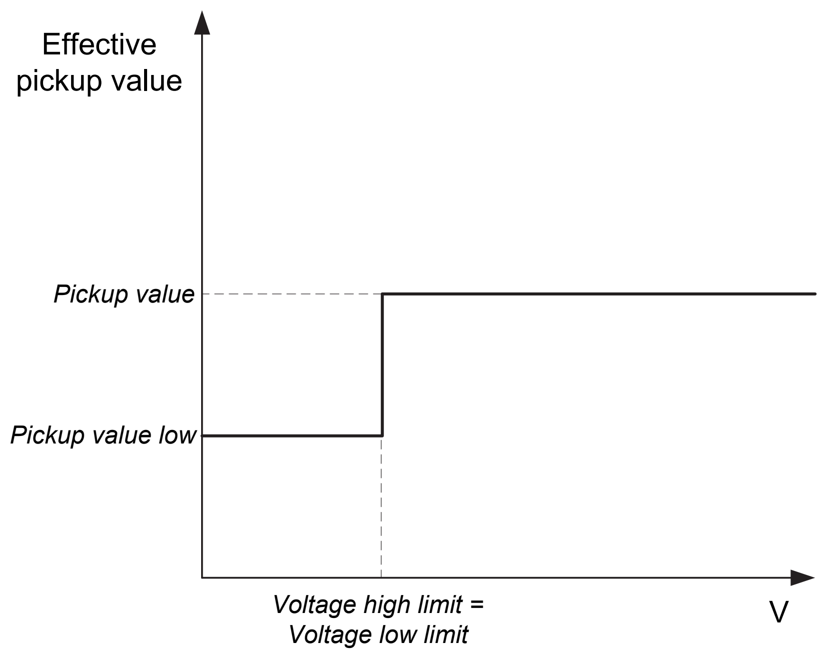


Figure 128: Effective pickup value for voltage step characteristic

The voltage slope characteristic is achieved by assigning different values to *Voltage high limit* and *Voltage low limit*. The effective pickup value calculation is based on the equations.

Voltage level	Effective pickup value (I> effective)
V < *Voltage low limit*	*Pickup value low*
V ≥ *Voltage high limit*	*Pickup value*

If *Voltage low limit* ≤ V < *Voltage high limit*,

$$I > (effective) = A - \left[\left(\frac{A - I>}{C - D} \right) \cdot (C - V) \right]$$

(Equation 6)

A set *Pickup value low*

I> set *Pickup value*

C set *Voltage high limit*

D set *Voltage low limit*

Here V represents the measured input voltage. The voltage slope characteristic is graphically represented.

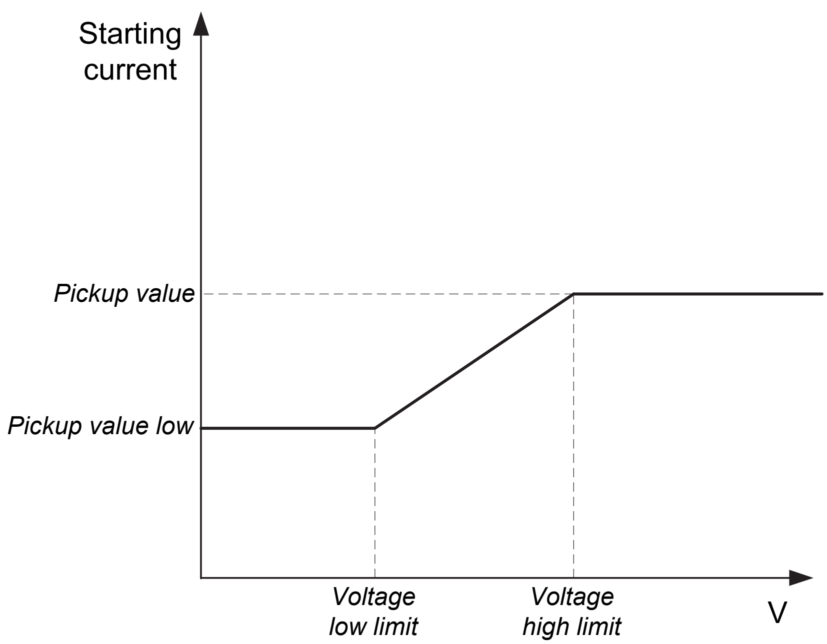


Figure 129: Effective pickup value or voltage slope characteristic

To achieve the voltage slope characteristics, *Voltage high limit* must always be set to a value greater than *Voltage low limit*.
If *Voltage high limit* is lower than *Voltage low limit*, the voltage step characteristic is active with *Voltage low limit* being the cutoff value.

The value of the setting *Pickup value* should always be greater than the setting *Pickup value low*. Otherwise, *Pickup value low* is used as the effective pickup value.

External input control mode

The External input control mode is used to enable voltage control from an external application. If *Control mode* is set to the "Input Control" mode, the effective pickup value for all phases is influenced by the status of the binary input ENA_V_MULT.

If ENA_V_MULT is TRUE:
Effective pickup value = Pickup value low

(Equation 7)

If ENA_V_MULT is FALSE:
Effective pickup value = Pickup value

(Equation 8)

Voltage and input control mode

If *Control mode* is set to "Voltage and input Ctrl", both the "Voltage control" and "Input control" modes are used. However, the “Input control” functionality is dominant over the “Voltage control” mode when ENA_V_MULT is active.

No voltage dependency mode

When *Control mode* is set to "No Volt dependency", the effective pickup value has no voltage dependency and the function acts as a normal time overcurrent function with effective pickup value being equal to the *Pickup value* setting.

Level detector

The measured phase currents are compared phasewise to the calculated effective pickup value. If the measured value exceeds the calculated effective pickup value, the Level detector reports the exceeding value to the phase selection logic. If the ENA_MULT input is active, the effective pickup value is multiplied by the *Pickup value Mult* setting.

Do not set the multiplier *Pickup value Mult* setting higher than necessary. If the value is too high, the function may not trip at all during an inrush followed by a fault, no matter how severe the fault is.

The pickup value multiplication is normally done when the inrush detection function INR is connected to the ENA_MULT input.

Phase selection logic

If the fault criteria are fulfilled in the level detector, the phase selection logic detects the phase or phases in which the measured current exceeds the setting. If the phase information matches the *Num of pickup phases* setting, the phase selection logic activates the Timer module.

Timer

Once activated, the Timer module activates the PICKUP output.

Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the TRIP output is activated.

When the user programmable IDMT curve is selected, the operation time characteristics are defined by the settings *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

In a drop-off situation, that is, when a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the Timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set *Reset delay time* value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The PICKUP output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The *Time multiplier* is used for scaling the IDMT trip and reset times.

The *Minimum trip time* setting defines the minimum desired trip time for IDMT operation. The setting is applicable only when the IDMT curves are used.

Though the *Time multiplier* and *Minimum trip time* settings are common for different IDMT curves, the trip time essentially depends upon the type of IDMT curve chosen.

The Timer calculates the pickup duration value PICKUP_DUR which indicates the percentage ratio of the pickup situation and the set trip time. This output is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.1.3.5 Application

The three-phase voltage-dependent overcurrent protection is used as a backup protection for the generators and system from damage due to the phase faults which are not cleared by primary protection and associated breakers.

In case of a short circuit, the sustained fault current of the generator, determined by the machine synchronous reactance, could be below the full-load current. If the generator excitation power is fed from the generator terminals, a voltage drop caused by a short circuit also leads to low fault current. The primary protection, like normal overcurrent protection, might not detect this kind of fault situation. In some cases, the automatic voltage regulator AVR can help to maintain high fault currents by controlling the generator excitation system. If the AVR is out of service or if there is an internal fault in the operation of AVR, the low fault currents can go unnoticed and therefore a voltage-depended overcurrent protection should be used for backup.

Two voltage control characteristics, voltage step and voltage slope, are available in 51V. The choice is made based on the system conditions and the level of protection to be provided.

Voltage step characteristic is applied to generators used in industrial systems. Under close-up fault conditions when the generator terminal voltages drop below the settable threshold value, a new pickup value of the current, well below the normal load current, is selected. The control voltage setting should ensure that 51V does not trip under the highest loading conditions to which the system can be subjected. Choosing too high a value for the control voltage may allow an undesired tripping of the function during wide-area disturbances. When the terminal voltage of the generator is above the control voltage value, the normal pickup value is used. This ensures that 51V does not trip during normal overloads when the generator terminal voltages are maintained near the normal levels.

Voltage slope characteristic is often used as an alternative to impedance protection on small to medium (5...150 MVA) size generators to provide backup to the differential protection. Other applications of the voltage slope characteristic protection exist in networks to provide better coordination and fault detection than plain overcurrent protection. The voltage slope method provides an improved sensitivity of overcurrent operation by making the overcurrent pickup value proportional to the terminal voltage. The current pickup value varies correspondingly with the generator terminal voltages between the set voltage high limit and voltage low limit, ensuring the operation of 51V despite the drop in fault current value.

The operation of 51V should be time-graded with respect to the main protection scheme to ensure that 51V does not trip before the main protection.

4.1.3.6 Signals

Table 259: 51V Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
V_AB	SIGNAL	0	Phase-to-phase voltage AB
V_BC	SIGNAL	0	Phase-to-phase voltage BC
V_CA	SIGNAL	0	Phase-to-phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier
ENA_LOW_LIM	BOOLEAN	0=False	Enable signal for voltage dependent lower pickup value

Table 260: 51V Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.1.3.7 Settings

Table 261: 51V Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...5.00	xIn	0.01	0.05	Pickup value
Pickup value low	0.05...1.00	xIn	0.01	0.05	Lower pickup value based on voltage control
Voltage high limit	0.01...1.00	xUn	0.01	1.00	Voltage high limit for voltage control
Voltage low limit	0.01...1.00	xUn	0.01	1.00	Voltage low limit for voltage control
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type
Trip delay time	40...200000	ms	10	40	Trip delay time

Table 262: 51V Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 263: 51V Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 264: 51V Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Control mode	1=Voltage control 2=Input control 3=Voltage and input Ctl 4=No Volt dependency			1=Voltage control	Type of control
Minimum trip time	40...60000	ms	1	40	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time

4.1.3.8 Monitored data

Table 265: 51V Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
EFF_ST_VAL_A	FLOAT32	0.00...50.00	xIn	Effective pickup value for phase A
EFF_ST_VAL_B	FLOAT32	0.00...50.00	xIn	Effective pickup value for phase B
EFF_ST_VAL_C	FLOAT32	0.00...50.00	xIn	Effective pickup value for phase C
51V	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.3.9 Technical data

Table 266: 51V Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current and voltage: f_n ±2 Hz
	Current: ±1.5% of the set value or ± 0.002 × I_n Voltage: ±1.5% of the set value or ±0.002 × V_n
Pickup time[1)2)]	Typically 26 ms
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Trip time accuracy in inverse time mode	±5.0% of the set value or ±20 ms
Suppression of harmonics	-50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) *Measurement mode* = default, current before fault = 0.0 × I_n, f_n = 50 Hz, fault current in one phase with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.1.4 Three-phase thermal protection for feeders, cables and distribution transformers 49F

4.1.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase thermal protection for feeders, cables and distribution transformers	T1PTTR	3Ith>F	49F

4.1.4.2 Function block

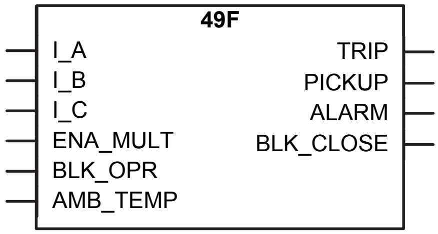


Figure 130: Function block

4.1.4.3 Functionality

The increased utilization of power systems closer to the thermal limits has generated a need for a thermal overload function for power lines as well.

A thermal overload is in some cases not detected by other protection functions, and the introduction of the three-phase thermal protection for feeders, cables and distribution transformers function 49F allows the protected circuit to operate closer to the thermal limits.

An alarm level gives an early warning to allow operators to take action before the line trips. The early warning is based on the three-phase current measuring function using a thermal model with first order thermal loss with the settable time constant. If the temperature rise continues the function operates based on the thermal model of the line.

Re-energizing of the line after the thermal overload operation can be inhibited during the time the cooling of the line is in progress. The cooling of the line is estimated by the thermal model.

4.1.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 49F can be described using a module diagram. All the modules in the diagram are explained in the next sections.

The function uses ambient temperature which can be measured locally or remotely. Local measurement is done by the protection relay. Remote measurement uses analog GOOSE to connect `AMB_TEMP` input.

If the quality of remotely measured temperature is invalid or communication channel fails the function uses ambient temperature set in *Env temperature Set*.

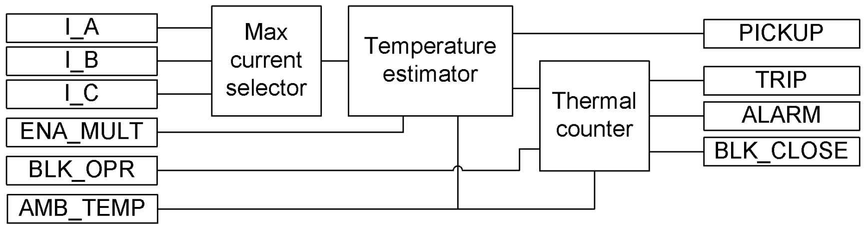


Figure 131: Functional module diagram

Max current selector

The max current selector of the function continuously checks the highest measured TRMS phase current value. The selector reports the highest value to the temperature estimator.

Temperature estimator

The final temperature rise is calculated from the highest of the three-phase currents according to the expression:

$$\Theta_{final} = \left(\frac{I}{I_{ref}}\right)^2 \cdot T_{ref}$$

(Equation 9)

I	the largest phase current
I_{ref}	set *Current reference*
T_{ref}	set *Temperature rise*

The ambient temperature is added to the calculated final temperature rise estimation, and the ambient temperature value used in the calculation is also available in the monitored data as TEMP_AMB in degrees. If the final temperature estimation is larger than the set *Maximum temperature*, the PICKUP output is activated.

Current reference and *Temperature raise* setting values are used in the final temperature estimation together with the ambient temperature. It is suggested to set these values to the maximum steady state current allowed for the line or cable under emergency operation for a few hours per years. Current values with the corresponding conductor temperatures are given in cable manuals. These values are given for conditions such as ground temperatures, ambient air temperature, the way of cable laying and ground thermal resistivity.

Thermal counter

The actual temperature at the actual execution cycle is calculated as:

$$\Theta_n = \Theta_{n-1} + \left(\Theta_{final} - \Theta_{n-1}\right) \cdot \left(1 - e^{-\frac{\Delta t}{\tau}}\right)$$

(Equation 10)

Θ_n	calculated present temperature
Θ_{n-1}	calculated temperature at previous time step
Θ_{final}	calculated final temperature with actual current
Δt	time step between calculation of actual temperature
τ	thermal time constant for the protected device (line or cable), set *Time constant*

The actual temperature of the protected component (line or cable) is calculated by adding the ambient temperature to the calculated temperature, as shown above. The ambient temperature can be given a constant value or it can be measured. The calculated component temperature can be monitored as it is exported from the function as a real figure.

When the component temperature reaches the set alarm level *Alarm value*, the output signal `ALARM` is set. When the component temperature reaches the set trip level *Maximum temperature*, the `TRIP` output is activated. The `TRIP` signal pulse length is fixed to 100 ms.

There is also a calculation of the present time to operation with the present current. This calculation is only performed if the final temperature is calculated to be above the operation temperature:

$$t_{trip} = -\tau \cdot \ln\left(\frac{\Theta_{final} - \Theta_{trip}}{\Theta_{final} - \Theta_n}\right)$$

(Equation 11)

Caused by the thermal overload protection function, there can be a lockout to reconnect the tripped circuit after operating. The lockout output `BLK_CLOSE` is activated at the same time when the `TRIP` output is activated and is not reset until the device temperature has cooled down below the set value of the *Reclose temperature* setting. The *Maximum temperature* value must be set at least two degrees above the set value of *Reclose temperature*.

The time to lockout release is calculated, that is, the calculation of the cooling time to a set value. The calculated temperature can be reset to its initial value (the *Initial temperature* setting) via a control parameter that is located under the clear menu. This is useful during testing when secondary injected current has given a calculated false temperature level.

$$t_{lockout\_release} = -\tau \cdot \ln\left(\frac{\Theta_{final} - \Theta_{lockout\_release}}{\Theta_{final} - \Theta_{n}}\right)$$

(Equation 12)

Here the final temperature is equal to the set or measured ambient temperature.

In some applications, the measured current can involve a number of parallel lines. This is often used for cable lines where one bay connects several parallel cables. By setting the *Current multiplier* parameter to the number of parallel lines (cables), the actual current on one line is used in the protection algorithm. To activate this option, the `ENA_MULT` input must be activated.

The ambient temperature can be measured with the RTD measurement. The measured temperature value is then connected, for example, from the `AI_VAL3` output of the X130 (RTD) function to the `AMB_TEMP` input of 49F.

The *Env temperature set* setting is used to define the ambient temperature if the ambient temperature measurement value is not connected to the `AMB_TEMP` input. The *Env temperature set* setting is also used when the ambient temperature measurement connected to 49F is set to “Not in use” in the X130 (RTD) function.

The temperature calculation is initiated from the value defined with the *Initial temperature* setting parameter. This is done in case the protection relay is powered up, the function is disabled and enabled back or reset through the Clear menu. The temperature is also stored in the nonvolatile memory and restored in case the protection relay is restarted.

The thermal time constant of the protected circuit is given in seconds with the *Time constant* setting. Please see cable manufacturers manuals for further details.

49F thermal model complies with the IEC 60255-149 standard.

4.1.4.5 Application

The lines and cables in the power system are constructed for a certain maximum load current level. If the current exceeds this level, the losses will be higher than expected. As a consequence, the temperature of the conductors will increase. If the temperature of the lines and cables reaches too high values, it can cause a risk of damages by, for example, the following ways:

- The sag of overhead lines can reach an unacceptable value.
- If the temperature of conductors, for example aluminium conductors, becomes too high, the material will be destroyed.
- Overheating can damage the insulation on cables which in turn increases the risk of phase-to-phase or phase-to-ground faults.

In stressed situations in the power system, the lines and cables may be required to be overloaded for a limited time. This should be done without any risk for the above-mentioned risks.

The thermal overload protection provides information that makes temporary overloading of cables and lines possible. The thermal overload protection estimates the conductor temperature continuously. This estimation is made by using a thermal model of the line/cable that is based on the current measurement.

If the temperature of the protected object reaches a set warning level, a signal is given to the operator. This enables actions in the power system to be done before dangerous temperatures are reached. If the temperature continues to increase to the maximum allowed temperature value, the protection initiates a trip of the protected line.

4.1.4.6 Signals

Table 267: 49F Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
ENA_MULT	BOOLEAN	0=False	Enable Current multiplier
BLK_OPR	BOOLEAN	0=False	Block signal for trip outputs
AMB_TEMP	FLOAT32	0	The ambient temperature used in the calculation

Table 268: 49F Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
ALARM	BOOLEAN	Thermal Alarm
BLK_CLOSE	BOOLEAN	Thermal overload indicator. To inhibite reclose.

4.1.4.7 Settings

Table 269: 49F Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Env temperature set	-50...100	°C	1	40	Ambient temperature used when AmbiSens is set to Off
Current reference	0.05...4.00	xIn	0.01	1.00	The load current leading to Temperature raise temperature
Temperature raise	0.0...200.0	°C	0.1	75.0	End temperature rise above ambient
Time constant	60...60000	s	1	2700	Time constant of the line in seconds.
Maximum temperature	20.0...200.0	°C	0.1	90.0	Temperature level for trip
Alarm value	20.0...150.0	°C	0.1	80.0	Temperature level for pickup (alarm)
Reclose temperature	20.0...150.0	°C	0.1	70.0	Temperature for reset of block reclose after trip

Table 270: 49F Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Current multiplier	1...5		1	1	Current multiplier when function is used for parallel lines

Table 271: 49F Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 272: 49F Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Initial temperature	-50.0...100.0	°C	0.1	0.0	Temperature raise above ambient temperature at startup

4.1.4.8 Monitored data

Table 273: 49F Monitored data

Name	Type	Values (Range)	Unit	Description
TEMP	FLOAT32	-100.0...9999.9	°C	The calculated temperature of the protected object
TEMP_RL	FLOAT32	0.00...99.99		The calculated temperature of the protected object relative to the trip level
T_TRIP	INT32	0...60000	s	Estimated time to trip
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
T_ENA_CLOSE	INT32	0...60000	s	Estimated time to deactivate BLK_CLOSE
TEMP_AMB	FLOAT32	-99...999	°C	The ambient temperature used in the calculation
49F	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.4.9 Technical data

Table 274: 49F Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	Current measurement: ±1.5% of the set value or ±0.002 × I_n (at currents in the range of 0.01...4.00 × I_n)
Trip time accuracy1)	±2.0% of the theoretical value or ±0.50 s

1) Overload current > 1.2 × Trip level temperature

4.1.4.10 Technical revision history

Table 275: 49F Technical revision history

Technical revision	Change
C	Removed the *Sensor available* setting parameter
D	Added the `AMB_TEMP` input
E	Internal improvement.
F	Internal improvement.

4.1.5 Three-phase thermal overload protection, two time constants 49T

4.1.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase thermal overload protection, two time constants	T2PTTR	3Ith>T/G/C	49T

4.1.5.2 Function block

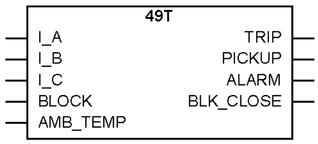


Figure 132: Function block

4.1.5.3 Functionality

The three-phase thermal overload, two time constants, protection function 49T protects the transformer mainly from short-time overloads. The transformer is protected from long-time overloads with the oil temperature detector included in its equipment.

The alarm signal gives an early warning to allow the operators to take action before the transformer trips. The early warning is based on the three-phase current measuring function using a thermal model with two settable time constants. If the temperature rise continues, 49T operates based on the thermal model of the transformer.

After a thermal overload operation, the re-energizing of the transformer is inhibited during the transformer cooling time. The transformer cooling is estimated with a thermal model.

4.1.5.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 49T can be described using a module diagram. All the modules in the diagram are explained in the next sections.

The function uses ambient temperature which can be measured locally or remotely. Local measurement is done by the protection relay. Remote measurement uses analog GOOSE to connect `AMB_TEMP` input.

If the quality of remotely measured temperature is invalid or communication channel fails the function uses ambient temperature set in *Env temperature Set*.

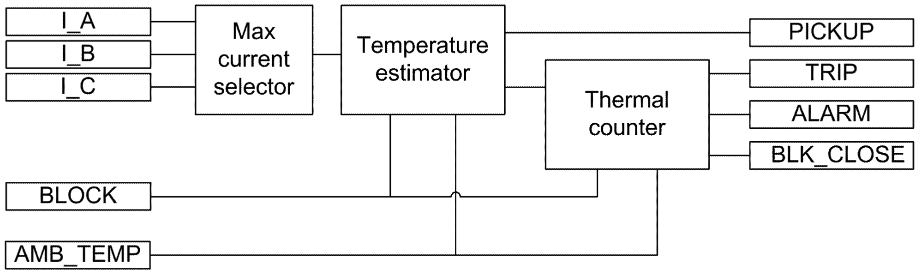


Figure 133: Functional module diagram

Max current selector

The max current selector of the function continuously checks the highest measured TRMS phase current value. The selector reports the highest value to the thermal estimator.

Temperature estimator

The final temperature rise is calculated from the highest of the three-phase currents according to the expression:

$$\Theta_{final} = \left(\frac{I}{I_{ref}} \right)^2 \cdot T_{ref}$$

(Equation 13)

I	highest measured phase current
I_{ref}	the set value of the *Current reference* setting
T_{ref}	the set value of the *Temperature rise* setting (temperature rise (°C) with the steady-state current I_{ref}

The ambient temperature value is added to the calculated final temperature rise estimation. If the total value of temperature is higher than the set trip temperature level, the `PICKUP` output is activated.

The *Current reference* setting is a steady-state current that gives the steady-state end temperature value *Temperature rise*. It gives a setting value corresponding to the rated power of the transformer.

The *Temperature rise* setting is used when the value of the reference temperature rise corresponds to the *Current reference* value. The temperature values with the corresponding transformer load currents are usually given by transformer manufacturers.

Thermal counter

49T applies the thermal model of two time constants for temperature measurement. The temperature rise in degrees Celsius (°C) is calculated from the highest of the three-phase currents according to the expression:

$$\Delta\Theta = \left[p * \left(\frac{I}{I_{ref}} \right)^2 * T_{ref} \right] \cdot \left(1 - e^{-\frac{\Delta t}{\tau 1}} \right) + \left[(1-p) \cdot \left(\frac{I}{I_{ref}} \right)^2 \cdot T_{ref} \right] \cdot \left(1 - e^{-\frac{\Delta t}{\tau 2}} \right)$$

(Equation 14)

ΔΘ	calculated temperature rise (°C) in transformer
I	measured phase current with the highest TRMS value
Iref	the set value of the *Current reference* setting (rated current of the protected object)
Tref	the set value of the *Temperature rise* setting (temperature rise setting (°C) with the steady-state current I_{ref})
p	the set value of the *Weighting factor p* setting (weighting factor for the short time constant)
Δt	time step between the calculation of the actual temperature
τ_1	the set value of the *Short time constant* setting (the short heating / cooling time constant)
τ_2	the set value of the *Long time constant* setting (the long heating / cooling time constant)

The warming and cooling following the two time-constant thermal curve is a characteristic of transformers. The thermal time constants of the protected transformer are given in seconds with the *Short time constant* and *Long time constant* settings. The *Short time constant* setting describes the warming of the transformer with respect to windings. The *Long time constant* setting describes the warming of the transformer with respect to the oil. Using the two time-constant model, the protection relay is able to follow both fast and slow changes in the temperature of the protected object.

The *Weighting factor p* setting is the weighting factor between *Short time constant* τ_1 and *Long time constant* τ_2. The higher the value of the *Weighting factor p* setting, the larger is the share of the steep part of the heating curve. When *Weighting factor p* =1, only *Short-time constant* is used. When *Weighting factor p* = 0, only *Long time constant* is used.

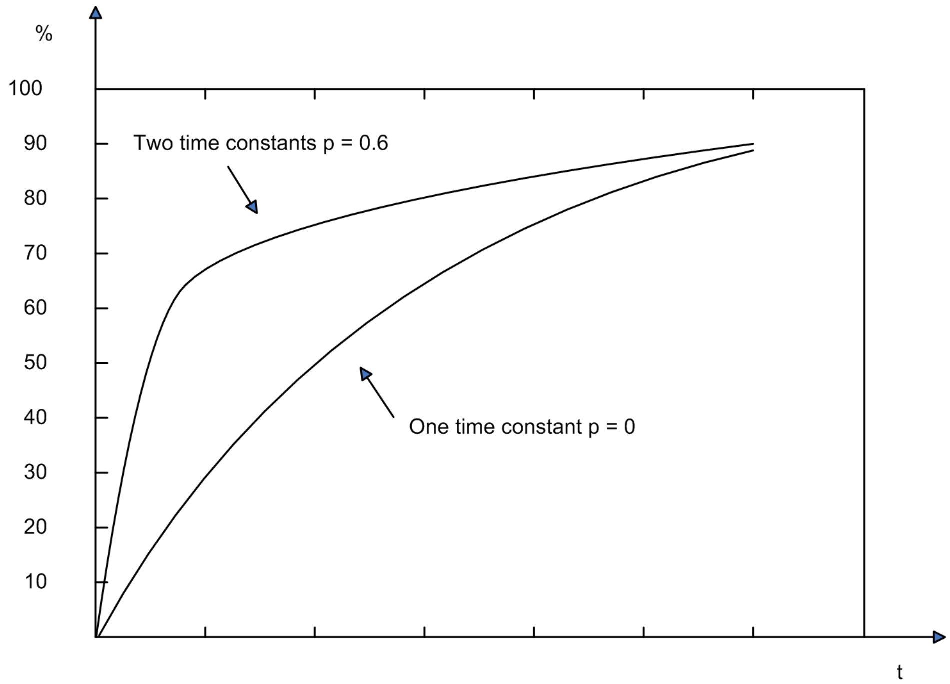


Figure 134: Effect of the Weighting factor p factor and the difference between the two time constants and one time constant models

The actual temperature of the transformer is calculated by adding the ambient temperature to the calculated temperature.

$$\Theta = \Delta\Theta + \Theta_{amb}$$

(Equation 15)

Θ	temperature in transformer (°C)
$\Delta\Theta$	calculated temperature rise (°C) in transformer
Θ_{amb}	set value of the *Env temperature Set* setting or measured ambient temperature

The ambient temperature can be measured with RTD measurement. The measured temperature value is connected, for example, from the `AI_VAL3` output of the X130 (RTD) function to the `AMB_TEMP` input of 49T.

The *Env temperature Set* setting is used to define the ambient temperature if the ambient temperature measurement value is not connected to the `AMB_TEMP` input. The *Env temperature Set* setting is also used when the ambient temperature measurement connected to 49T is set to “Not in use” in the X130 (RTD) function.

The temperature calculation is initiated from the value defined with the *Initial temperature* and *Max temperature* setting parameters. The initial value is a percentage of *Max temperature* defined by *Initial temperature*. This is done when the protection relay is powered up or the function is disabled and then enabled or reset through the Clear menu. The temperature is stored in a nonvolatile memory and restored if the protection relay is restarted.

The *Max temperature* setting defines the maximum temperature of the transformer in degrees Celsius (°C). The value of the *Max temperature* setting is usually given by transformer manufacturers. The actual alarm, trip and lockout temperatures for 49T are given as a percentage value of the *Max temperature* setting.

When the transformer temperature reaches the alarm level defined with the *Alarm temperature* setting, the `ALARM` output signal is set. When the transformer temperature reaches the trip level value defined with the *Trip temperature* setting, the `TRIP` output is activated. The `TRIP` output is deactivated when the value of the measured current falls below 10 percent of the *Current Reference* value or the calculated temperature value falls below *Trip temperature*.

There is also a calculation of the present time to trip with the present current. `T_TRIP` calculation is only monitored if the final temperature is calculated to be above the trip temperature. The value is available in the monitored data view.

After tripping, there can be a lockout to reconnect the tripped circuit due to the thermal overload protection function. The `BLK_CLOSE` lockout output is activated when the device temperature is above the *Reclose temperature* lockout release temperature setting value. The time to lockout release `T_ENA_CLOSE` is also calculated. The value is available in the monitored data view.

4.1.5.5 Application

The transformers in a power system are constructed for a certain maximum load current level. If the current exceeds this level, the losses are higher than expected. This results in a rise in transformer temperature. If the temperature rise is too high, the equipment is damaged:

- Insulation within the transformer ages faster, which in turn increases the risk of internal phase-to-phase or phase-to-ground faults.
- Possible hotspots forming within the transformer degrade the quality of the transformer oil.

During stressed situations in power systems, it is required to overload the transformers for a limited time without any risks. The thermal overload protection provides information and makes temporary overloading of transformers possible.

The permissible load level of a power transformer is highly dependent on the transformer cooling system. The two main principles are:

- ONAN: The air is naturally circulated to the coolers without fans, and the oil is naturally circulated without pumps.
- OFAF: The coolers have fans to force air for cooling, and pumps to force the circulation of the transformer oil.

The protection has several parameter sets located in the setting groups, for example one for a non-forced cooling and one for a forced cooling situation. Both the permissive steady-state loading level as well as the thermal time constant are influenced by the transformer cooling system. The active setting group can be changed by a parameter, or through a binary input if the binary input is enabled for it. This feature can be used for transformers where forced cooling is taken out of operation or extra cooling is switched on. The parameters can also be changed when a fan or pump fails to operate.

The thermal overload protection continuously estimates the internal heat content, that is, the temperature of the transformer. This estimation is made by using a thermal model of the transformer which is based on the current measurement.

If the heat content of the protected transformer reaches the set alarm level, a signal is given to the operator. This enables the action that needs to be taken in the power systems before the temperature reaches a high value. If the temperature continues to rise to the trip value, the protection initiates the trip of the protected transformer.

After the trip, the transformer needs to cool down to a temperature level where the transformer can be taken into service again. 49T continues to estimate the heat content of the transformer during this cooling period using a set cooling time constant. The energizing of the transformer is blocked until the heat content is reduced to the set level.

The thermal curve of two time constants is typical for a transformer. The thermal time constants of the protected transformer are given in seconds with the *Short time constant* and *Long time constant* settings. If the manufacturer does not state any other value, the *Long time constant* can be set to 4920 s (82 minutes) for a distribution transformer and 7260 s (121 minutes) for a supply transformer. The corresponding *Short time constants* are 306 s (5.1 minutes) and 456 s (7.6 minutes).

If the manufacturer of the power transformer has stated only one, that is, a single time constant, it can be converted to two time constants. The single time constant is also used by itself if the p-factor *Weighting factor p* setting is set to zero and the time constant value is set to the value of the *Long time constant* setting. The thermal image corresponds to the one time constant model in that case.

Table 276: Conversion table between one and two time constants

Single time constant (min)	*Short time constant* (min)	*Long time constant* (min)	*Weighting factor p*
10	1.1	17	0.4
15	1.6	25	0.4
20	2.1	33	0.4
25	2.6	41	0.4
30	3.1	49	0.4
35	3.6	58	0.4
40	4.1	60	0.4
45	4.8	75	0.4
50	5.1	82	0.4
55	5.6	90	0.4
60	6.1	98	0.4
65	6.7	107	0.4
70	7.2	115	0.4
75	7.8	124	0.4

The default *Max temperature* setting is 105°C. This value is chosen since even though the IEC 60076-7 standard recommends 98°C as the maximum allowable temperature in long-time loading, the standard also states that a transformer can withstand the emergency loading for weeks or even months, which may produce the winding temperature of 140°C. Therefore, 105°C is a safe maximum temperature value for a transformer if the *Max temperature* setting value is not given by the transformer manufacturer.

4.1.5.6 Signals

Table 277: 49T Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
AMB_TEMP	FLOAT32	0	The ambient temperature used in the calculation

Table 278: 49T Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
ALARM	BOOLEAN	Thermal Alarm
BLK_CLOSE	BOOLEAN	Thermal overload indicator. To inhibite reclose.

4.1.5.7 Settings

Table 279: 49T Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Env temperature Set	-50...100	°C	1	40	Ambient temperature used when no external temperature measurement available
Temperature rise	0.0...200.0	°C	0.1	78.0	End temperature rise above ambient
Maximum temperature	0.0...200.0	°C	0.1	105.0	Temperature level for trip
Trip temperature	80.0...120.0	%	0.1	100.0	Trip temperature, percent value
Alarm temperature	40.0...100.0	%	0.1	90.0	Alarm temperature, percent value
Reclose temperature	40.0...100.0	%	0.1	60.0	Temperature for reset of block reclose after trip
Short time constant	6...60000	s	1	450	Short time constant in seconds
Long time constant	60...60000	s	1	7200	Long time constant in seconds
Weighting factor p	0.00...1.00		0.01	0.40	Weighting factor of the short time constant

Table 280: 49T Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Current reference	0.05...4.00	xIn	0.01	1.00	The load current leading to Temperature raise temperature

Table 281: 49T Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 282: 49T Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Initial temperature, percent value	0.0...100.0	%	0.1	80.0	Temperature raise at startup

4.1.5.8 Monitored data

Table 283: 49T Monitored data

Name	Type	Values (Range)	Unit	Description
TEMP	FLOAT32	-100.0...9999.9	°C	The calculated temperature of the protected object
TEMP_RL	FLOAT32	0.00...99.99		The calculated temperature of the protected object relative to the trip level
T_TRIP	INT32	0...60000	s	Estimated time to trip
T_ENA_CLOSE	INT32	0...60000	s	Estimated time to deactivate BLK_CLOSE in seconds
TEMP_AMB	FLOAT32	-99...999	°C	The ambient temperature used in the calculation
49T	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.5.9 Technical data

Table 284: 49T Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	Current measurement: ±1.5% of the set value or ±0.002 x I_n (at currents in the range of 0.01...4.00 x I_n)
Trip time accuracy[1)]	±2.0% of the theoretical value or ±0.50 s

1) Overload current > 1.2 x Trip level temperature

4.1.5.10 Technical revision history

Table 285: 49T Technical revision history

Technical revision	Change
B	Added the `AMB_TEMP` input
C	Internal improvement.
D	Internal improvement.

4.1.6 Motor load jam protection 51LR

4.1.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Motor load jam protection	JAMPTOC	Ist>	51LR

4.1.6.2 Function block

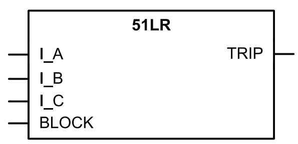


Figure 135: Function block

4.1.6.3 Functionality

The motor load jam protection function 51LR is used for protecting the motor in stall or mechanical jam situations during the running state.

When the motor is started, a separate function is used for the startup protection, and 51LR is normally blocked during the startup period. When the motor has passed the starting phase, 51LR monitors the magnitude of phase currents. The function picks up when the measured current exceeds the breakdown torque level, that is, above the set limit. The operation characteristic is definite time.

The function contains a blocking functionality. It is possible to block the function outputs.

4.1.6.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 51LR can be described with a module diagram. All the modules in the diagram are explained in the next sections.

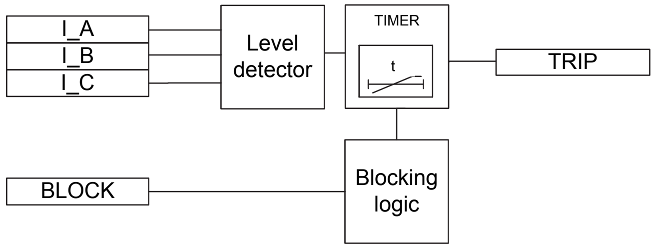


Figure 136: Functional module diagram

Level detector

The measured phase currents are compared to the set *Pickup value*. The TRMS values of the phase currents are considered for the level detection. The timer module is enabled if at least two of the measured phase currents exceed the set *Pickup value*.

Timer

Once activated, the internal `PICKUP` signal is activated. The value is available only through the Monitored data view. The time characteristic is according to DT. When the operation timer has reached the *Trip delay time* value, the `TRIP` output is activated.

When the timer has elapsed but the motor stall condition still exists, the `TRIP` output remains active until the phase currents values drop below the *Pickup value*, that is, until the stall condition persists. If the drop-off situation occurs while the trip time is still counting, the reset timer is activated. If the drop-off time exceeds the set *Reset delay time*, the operation timer is reset.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.1.6.5 Application

The motor protection during stall is primarily needed to protect the motor from excessive temperature rise, as the motor draws large currents during the stall phase. This condition causes a temperature rise in the stator windings. Due to reduced speed, the temperature also rises in the rotor. The rotor temperature rise is more critical when the motor stops.

The physical and dielectric insulations of the system deteriorate with age and the deterioration is accelerated by the temperature increase. Insulation life is related to the time interval during which the insulation is maintained at a given temperature.

An induction motor stalls when the load torque value exceeds the breakdown torque value, causing the speed to decrease to zero or to some stable operating point well below the rated speed. This occurs, for example, when the applied shaft load is suddenly increased and is greater than the producing motor torque due to the bearing failures. This condition develops a motor current almost equal to the value of the locked-rotor current.

51LR is designed to protect the motor in stall or mechanical jam situations during the running state. To provide a good and reliable protection for motors in a stall situation, the temperature effects on the motor have to be kept within the allowed limits.

4.1.6.6 Signals

Table 286: 51LR Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 287: 51LR Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip

4.1.6.7 Settings

Table 288: 51LR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Pickup value	0.10...10.00	xIn	0.01	2.50	Pickup value
Trip delay time	100...120000	ms	10	2000	Trip delay time

Table 289: 51LR Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	100	Reset delay time

4.1.6.8 Monitored data

Table 290: 51LR Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP	BOOLEAN	0=False 1=True		Pickup
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
51LR	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.6.9 Technical data

Table 291: 51LR Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × I_n
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms

4.1.6.10 Technical revision history

Table 292: 51LR Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

4.1.7 Loss of load supervision 37M

4.1.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of load supervision	LOFLPTUC	3I<	37M

4.1.7.2 Function block

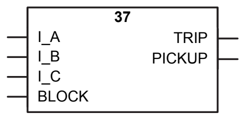


Figure 137: Function block

4.1.7.3 Functionality

The loss of load supervision function 37M is used to detect a sudden load loss which is considered as a fault condition.

37M picks up when the current is less than the set limit. It operates with the definite time (DT) characteristics, which means that the function operates after a predefined trip time and resets when the fault current disappears.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.1.7.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 37M can be described using a module diagram. All the modules in the diagram are explained in the next sections.

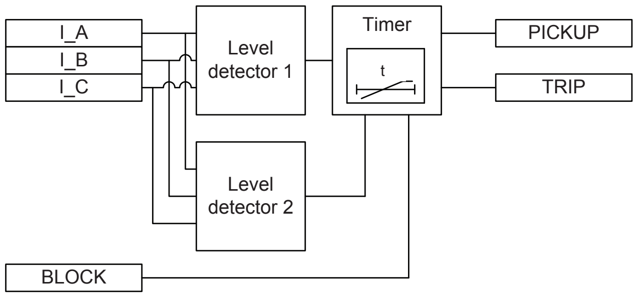


Figure 138: Functional module diagram

Level detector 1

This module compares the phase currents (RMS value) to the set *Pickup value high* setting. If all the phase current values are less than the set *Pickup value high* value, the loss of load condition is detected and an enable signal is sent to the timer. This signal is disabled after one or several phase currents have exceeded the set *Pickup value high* value of the element.

Level detector 2

This is a low-current detection module, which monitors the de-energized condition of the motor. It compares the phase currents (RMS value) to the set *Pickup value low* setting. If any of the phase current values is less than the set *Pickup value low*, a signal is sent to block the operation of the timer.

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated. If the fault disappears before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

The `BLOCK` signal blocks the operation of the function and resets the timer.

4.1.7.5 Application

When a motor runs with a load connected, it draws a current equal to a value between the no-load value and the rated current of the motor. The minimum load current can be determined by studying the characteristics of the connected load. When the current drawn by the motor is less than the minimum load current drawn, it can be inferred that the motor is either disconnected from the load or the coupling mechanism is faulty. If the motor is allowed to run in this condition, it may aggravate the fault in the coupling mechanism or harm the personnel handling the machine. Therefore, the motor has to be disconnected from the power supply as soon as the above condition is detected.

37M detects the condition by monitoring the current values and helps disconnect the motor from the power supply instantaneously or after a delay according to the requirement.

When the motor is at standstill, the current will be zero and it is not recommended to activate the trip during this time. The minimum current drawn by the motor when it is connected to the power supply is the no load current, that is, the higher pickup value current. If the current drawn is below the lower pickup value current, the motor is disconnected from the power supply. 37M detects this condition and interprets that the motor is de-energized and disables the function to prevent unnecessary trip events.

4.1.7.6 Signals

Table 293: 37M Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block all binary outputs by resetting timers

Table 294: 37M Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.1.7.7 Settings

Table 295: 37M Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value low	0.01...0.50	xIn	0.01	0.10	Current setting/Pickup value low
Pickup value high	0.01...1.00	xIn	0.01	0.50	Current setting/Pickup value high
Trip delay time	400...600000	ms	10	2000	Trip delay time

Table 296: 37M Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 297: 37M Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.1.7.8 Monitored data

Table 298: 37M Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
37M	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.7.9 Technical data

Table 299: 37M Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × I_n
Pickup time	Typically 300 ms
Reset time	Typically 40 ms
Reset ratio	Typically 1.04
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms

4.1.7.10 Technical revision history

Table 300: 37M Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

4.1.8 Loss of phase 37

4.1.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of phase	PHPTUC	3I<	37

4.1.8.2 Function block

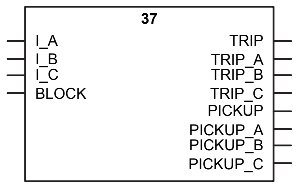


Figure 139: Function block

4.1.8.3 Functionality

The loss of phase function 37 is used to detect an undercurrent that is considered as a fault condition.

37 picks up when the current is less than the set limit. Operation time characteristics are according to definite time (DT).

The function contains a blocking functionality. It is possible to block function outputs and reset the definite timer if desired.

4.1.8.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 37 can be described with a module diagram. All the modules in the diagram are explained in the next sections.

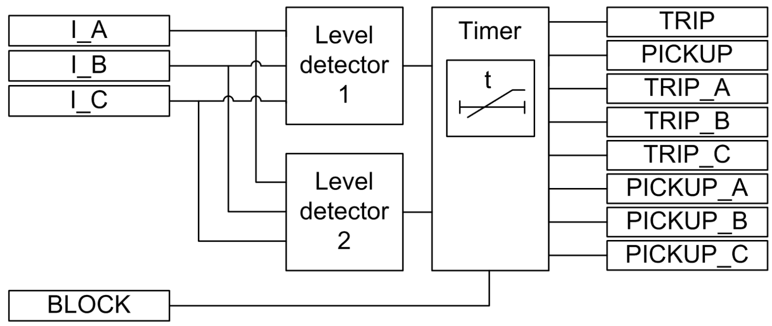


Figure 140: Functional module diagram

Level detector 1

This module compares the phase currents (RMS value) to the *Pickup value* setting. The *Operation mode* setting can be used to select the "Three Phase" or "Single Phase" mode.

If in the "Three Phase" mode all the phase current values are less than the value of the *Pickup value* setting, the condition is detected and an enabling signal is sent to the timer. This signal is disabled after one or several phase currents have exceeded the set *Pickup value* value of the element.

If in the "Single Phase" mode any of the phase current values are less than the value of the *Pickup value* setting, the condition is detected and an enabling signal is sent to the timer. This signal is disabled after all the phase currents have exceeded the set *Pickup value* value of the element.

The protection relay does not accept the *Pickup value* to be smaller than *Current block value*.

Level detector 2

This is a low-current detection module that monitors the de-energized condition of the protected object. The module compares the phase currents (RMS value) to the *Current block value* setting. If all the phase current values are less than the *Current block value* setting, a signal is sent to block the operation of the timer.

Timer

Once activated, the timer activates the `PICKUP` output and the phase-specific `PICKUP_X` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output and the phase-specific `TRIP_X` output are activated. If the fault disappears before the module trips, the reset timer is activated.

If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the PICKUP output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available through the monitored data view.

The BLOCK signal blocks the operation of the function and resets the timer.

4.1.8.5 Application

In some cases, smaller distribution power transformers are used where the high-side protection involves only power fuses. When one of the high-side fuses blows in a single-phase condition, knowledge of it on the secondary side is lacking. The resulting negative-sequence current leads to a premature failure due to excessive heating and breakdown of the transformer insulation. Knowledge of this condition when it occurs allows for a quick fuse replacement and saves the asset.

The *Current block value* setting can be set to zero to not block 37 with a low three-phase current. However, this results in an unnecessary event sending when the transformer or protected object is disconnected.

Phase-specific pickup and trip can give a better picture about the evolving faults when one phase has picked up first and another follows.

37 is meant to be a general protection function, so that it could be used in other cases too.

In case of undercurrent-based motor protection, see the Loss of load protection.

4.1.8.6 Signals

Table 301: 37 Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase Bcurrent
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block all binary outputs by resetting timers

Table 302: 37 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
TRIP_A	BOOLEAN	Trip phase A
TRIP_B	BOOLEAN	Trip phase B
TRIP_C	BOOLEAN	Trip phase C
PICKUP	BOOLEAN	Pickup
PICKUP_A	BOOLEAN	Pickup phase A
PICKUP_B	BOOLEAN	Pickup phase B
PICKUP_C	BOOLEAN	Pickup phase C

4.1.8.7 Settings

Table 303: 37 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Current block value	0.00...0.50	xIn	0.01	0.10	Low current setting to block internally
Pickup value	0.01...1.00	xIn	0.01	0.50	Current setting to pickup
Trip delay time	50...200000	ms	10	2000	Trip delay time

Table 304: 37 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=Three Phase 2=Single Phase			1=Three Phase	Number of phases needed to pickup

Table 305: 37 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.1.8.8 Monitored data

Table 306: 37 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
37	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.1.8.9 Technical data

Table 307: 37 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the current measured: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × I_n
Pickup time	Typically <55 ms
Reset time	<40 ms
Reset ratio	Typically 1.04
Retardation time	<35 ms
Trip time accuracy in definite time mode	mode ±1.0% of the set value or ±20 ms

4.1.9 Thermal overload protection for motors 49M

4.1.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Thermal overload protection for motors	MPTTR	3Ith>M	49M

4.1.9.2 Function block

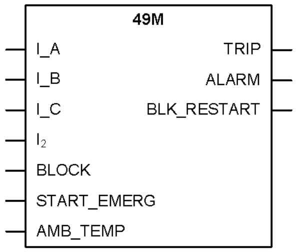


Figure 141: Function block

4.1.9.3 Functionality

The thermal overload protection for motors function 49M protects the electric motors from overheating. 49M models the thermal behavior of motor on the basis of the measured load current and disconnects the motor when the thermal content reaches 100 percent.

Thermal overload conditions are the most often encountered abnormal conditions in industrial motor applications. The thermal overload conditions are typically the result of an abnormal rise in the motor running current, which produces an increase in the thermal dissipation of the motor and temperature or reduces cooling. 49M prevents an electric motor from drawing excessive current and overheating, which causes the premature insulation failures of the windings and, in worst cases, burning out of the motors.

4.1.9.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 49M can be described using a module diagram. All the modules in the diagram are explained in the next sections.

The function uses ambient temperature which can be measured locally or remotely. Local measurement is done by the protection relay. Remote measurement uses analog GOOSE to connect `AMB_TEMP` input.

If the quality of remotely measured temperature is invalid or communication channel fails the function uses ambient temperature set in *Env temperature Set*.

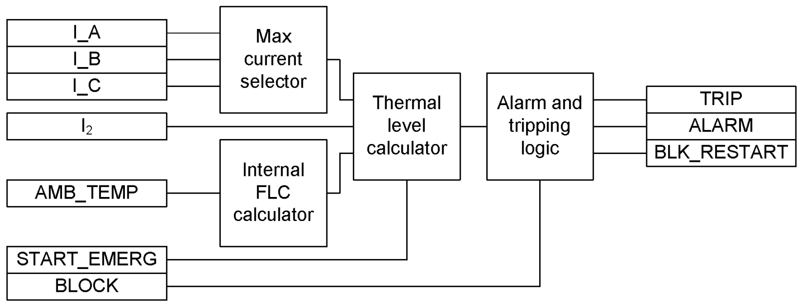


Figure 142: Functional module diagram

Max current selector

Max current selector selects the highest measured TRMS phase current and reports it to Thermal level calculator.

Internal FLC calculator

Full load current (FLC) of the motor is defined by the manufacturer at an ambient temperature of 40°C. Special considerations are required with an application where the ambient temperature of a motor exceeds or remains below 40°C. A motor operating at a higher temperature, even if at or below rated load, can subject the motor windings to excessive temperature similar to that resulting from overload operation at normal ambient temperature. The motor rating has to be appropriately reduced for operation in such high ambient temperatures. Similarly, when the ambient temperature is considerably lower than the nominal 40°C, the motor can be slightly overloaded. For calculating thermal level it is better that the FLC values are scaled for different temperatures. The scaled currents are known as internal FLC. An internal FLC is calculated based on the ambient temperature shown in the table. The *Env temperature mode* setting defines whether the thermal level calculations are based on FLC or internal FLC.

When the value of the *Env temperature mode* setting is set to the "FLC Only" mode, no internal FLC is calculated. Instead, the FLC given in the data sheet of the manufacturer is used. When the value of the *Env temperature mode* setting is set to "Set Amb Temp" mode, the internal FLC is calculated based on the ambient temperature taken as an input through the *Env temperature Set* setting. When the *Env temperature mode* setting is on "Use input" mode, the internal FLC is calculated from temperature data available through resistance temperature detectors (RTDs) using the `AMB_TEMP` input.

Table 308: *Modification of internal FLC*

Ambient Temperature T_{amb}	Internal FLC
<20°C	FLC x 1.09
20 to <40°C	FLC x (1.18 - T_{amb} x 0.09/20)
40°C	FLC
>40 to 65°C	FLC x (1 –[(T_{amb} -40)/100])
>65°C	FLC x 0.75

The ambient temperature is used for calculating thermal level and it is available in the monitored data view from the `TEMP_AMB` output. The activation of the `BLOCK` input does not affect the `TEMP_AMB` output.

The *Env temperature Set* setting is used:

- If the ambient temperature measurement value is not connected to the AMB_TEMP input in ACT.
- When the ambient temperature measurement connected to 49M is set to *Not in use* in the RTD function.
- In case of any errors or malfunctioning in the RTD output.

Thermal level calculator

The module calculates the thermal load considering the TRMS and negative-sequence currents. The heating up of the motor is determined by the square value of the load current.

However, in case of unbalanced phase currents, the negative-sequence current also causes additional heating. By deploying a protection based on both current components, abnormal heating of the motor is avoided.

The thermal load is calculated based on different situations or operations and it also depends on the phase current level. The equations used for the heating calculations are:

$$\theta_B = \left[\left(\frac{I}{k \times I_r}\right)^2 + K_2 \times \left(\frac{I_2}{k \times I_r}\right)^2\right] \times \left(1 - e^{-t/\tau}\right) \times p\%$$

(Equation 16)

$$\theta_A = \left[\left(\frac{I}{k \times I_r}\right)^2 + K_2 \times \left(\frac{I_2}{k \times I_r}\right)^2\right] \times \left(1 - e^{-t/\tau}\right) \times 100\%$$

(Equation 17)

I	TRMS value of the measured max of phase currents
I_r	set *Current reference*, FLC or internal FLC
I_2	measured negative sequence current
k	set value of *Overload factor*
K_2	set value of *Negative Seq factor*
p	set value of *Weighting factor*
τ	time constant

The equation θ_B is used when the values of all the phase currents are below the overload limit, that is, k x I_r. The equation θ_A is used when the value of any one of the phase currents exceeds the overload limit.

During overload condition, the thermal level calculator calculates the value of θ_B in background, and when the overload ends the thermal level is brought linearly from θ_A to θ_B with a speed of 1.66 percent per second. For the motor at standstill, that is, when the current is below the value of 0.12 x I_r, the cooling is expressed as:

$$\theta = \theta_{02} \times e^{\frac{-t}{\tau}}$$

(Equation 18)

θ_{02} initial thermal level when cooling begins

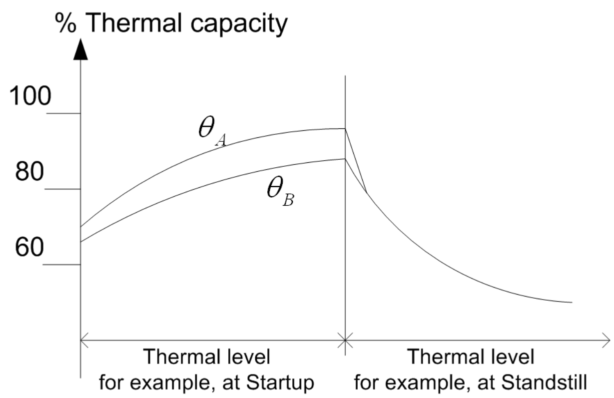


Figure 143: Thermal behavior

The required overload factor and negative sequence current heating effect factor are set by the values of the *Overload factor* and *Negative Seq factor* settings.

In order to accurately calculate the motor thermal condition, different time constants are used in the above equations. These time constants are employed based on different motor running conditions, for example starting, normal or stop, and are set through the *Time constant start*, *Time constant normal* and *Time constant stop* settings. Only one time constant is valid at a time.

Table 309: Time constant and the respective phase current values

Time constant (tau) in use	Phase current
Time constant start	Any current whose value is over 2.5 x I_r
Time constant normal	Any current whose value is over 0.12 x I_r and all currents are below 2.5 x I_r
Time constant stop	All the currents whose values are below 0.12 x I_r

The *Weighting factor p* setting determines the ratio of the thermal increase of the two curves θ_A and θ_B.

The thermal level at the power-up of the protection relay is defined by the *Initial thermal Val* setting.

The temperature calculation is initiated from the value defined in the *Initial thermal Val* setting. This is done if the protection relay is powered up or the function is disabled and then enabled or reset through the Clear menu.

The calculated temperature of the protected object relative to the operate level, the TEMP_RL output, is available through the monitored data view. The activation of the BLOCK input does not affect the calculated temperature.

The thermal level at the beginning of the start-up condition of a motor and at the end of the start-up condition is available in the monitored data view at the THERMLEV_ST and THERMLEV_END outputs respectively. The activation of the BLOCK input does not have any effect on these outputs.

Alarm and tripping logic

The module generates alarm, restart inhibit and tripping signals.

When the thermal level exceeds the set value of the *Alarm thermal value* setting, the ALARM output is activated. Sometimes a condition arises when it becomes necessary to inhibit the restarting of a motor, for example in case of some extreme starting condition like long starting time. If the thermal content exceeds the set value of the *Restart thermal val* setting, the BLK_RESTART output is activated. The time for the next possible motor start-up is available through the monitored data view from the T_ENARESTART output. The T_ENARESTART output estimates the time for the BLK_RESTART deactivation considering as if the motor is stopped.

When the emergency start signal START_EMERG is set high, the thermal level is set to a value below the thermal restart inhibit level. This allows at least one motor start-up, even though the thermal level has exceeded the restart inhibit level.

When the thermal content reaches 100 percent, the TRIP output is activated. The TRIP output is deactivated when the value of the measured current falls below 12 percent of *Current reference* or the thermal content drops below 100 percent.

The activation of the BLOCK input blocks the ALARM, BLK_RESTART and TRIP outputs.

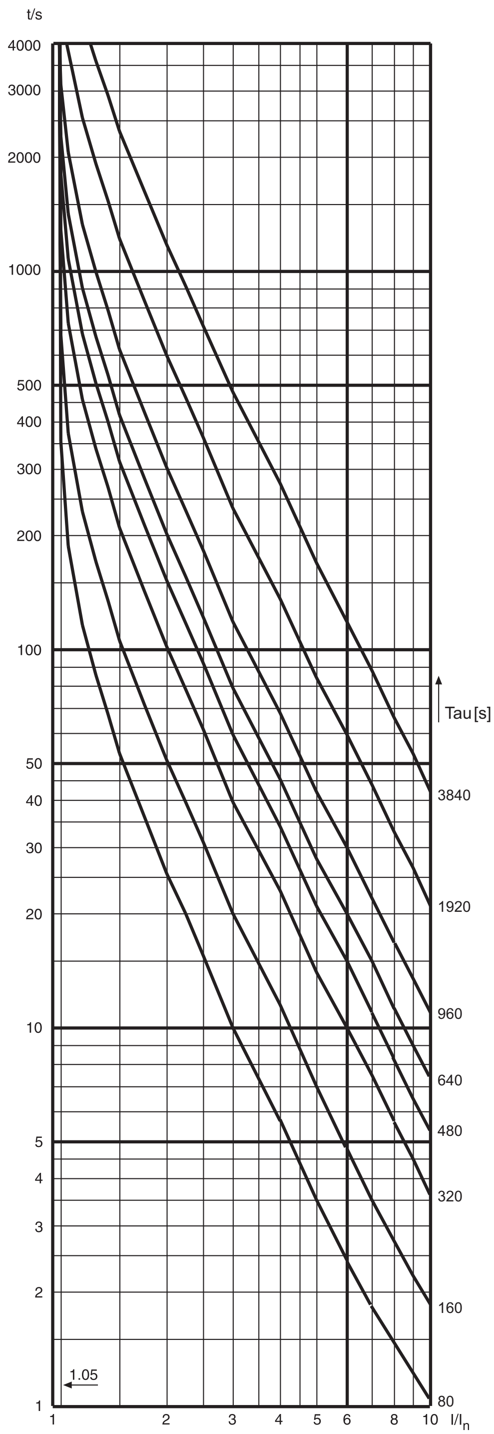


Figure 144: Trip curves when no prior load and p=20...100 %. Overload factor = 1.05.

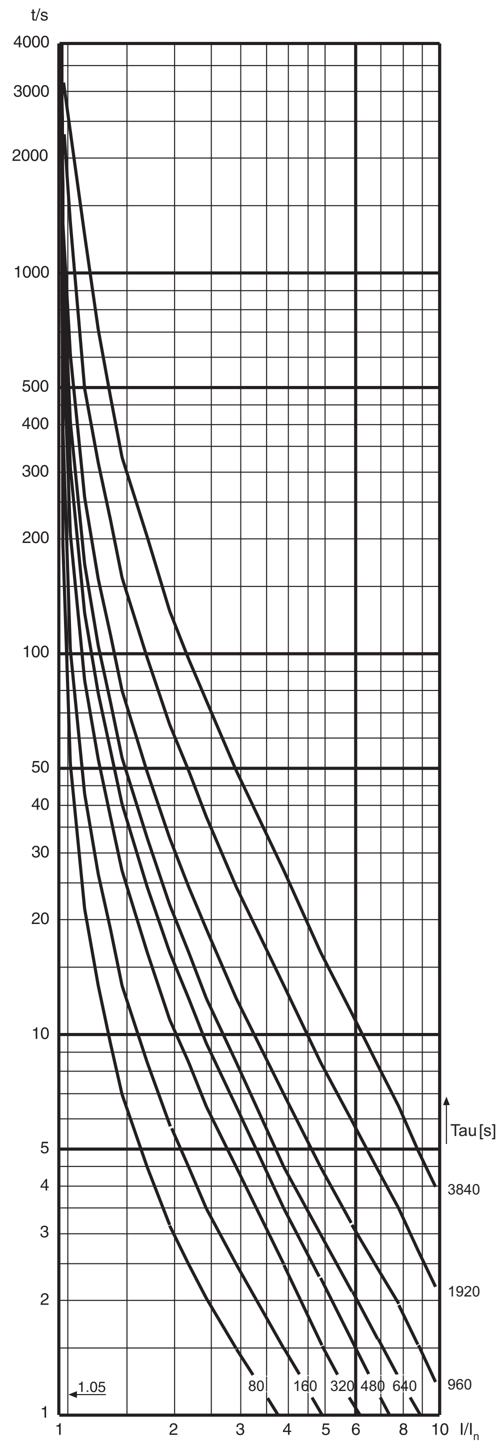


Figure 145: Trip curves at prior load 1 x FLC and p=100 %, Overload factor = 1.05.

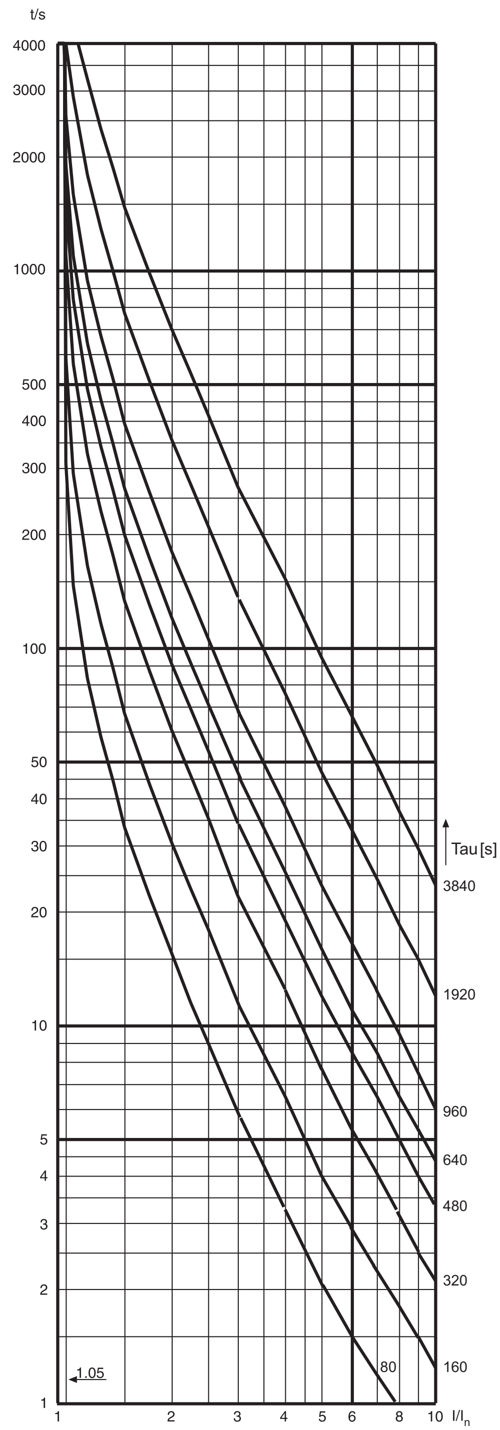


Figure 146: Trip curves at prior load 1 x FLC and p=50 %. Overload factor = 1.05.

4.1.9.5 Application

49M is intended to limit the motor thermal level to predetermined values during the abnormal motor operating conditions. This prevents a premature motor insulation failure.

The abnormal conditions result in overheating and include overload, stalling, failure to start, high ambient temperature, restricted motor ventilation, reduced speed operation, frequent starting or jogging, high or low line voltage or frequency, mechanical failure of the driven load, improper installation and unbalanced line voltage or single phasing. The protection of insulation failure by the implementation of current sensing cannot detect some of these conditions, such as restricted ventilation. Similarly, the protection by sensing temperature alone can be inadequate in cases like frequent starting or jogging. The thermal overload protection addresses these deficiencies to a larger extent by deploying a motor thermal model based on load current.

The thermal load is calculated using the true RMS phase value and negative sequence value of the current. The heating up of the motor is determined by the square value of the load current. However, while calculating the thermal level, the rated current should be re-rated or de-rated depending on the value of the ambient temperature. Apart from current, the rate at which motor heats up or cools is governed by the time constant of the motor.

Setting the weighting factor

There are two thermal curves: one which characterizes the short-time loads and long-time overloads and which is also used for tripping and another which is used for monitoring the thermal condition of the motor. The value of the *Weighting factor p* setting determines the ratio of the thermal increase of the two curves.

When the *Weighting factor p* setting is 100 percent, a pure single time constant thermal unit is produced which is used for application with the cables. As presented in Figure 147, the hot curve with the value of *Weighting factor p* being 100 percent only allows an operate time which is about 10 percent of that with no prior load. For example, when the set time constant is 640 seconds, the operate time with the prior load 1 x FLC (full Load Current) and overload factor 1.05 is only 2 seconds, even if the motor could withstand at least 5 to 6 seconds. To allow the use of the full capacity of the motor, a lower value of *Weighting factor p* should be used.

Normally, an approximate value of half of the thermal capacity is used when the motor is running at full load. Thus by setting *Weighting factor p* to 50 percent, the protection relay notifies a 45 to 50 percent thermal capacity use at full load.

For direct-on-line started motors with hot spot tendencies, the value of *Weighting factor p* is typically set to 50 percent, which will properly distinguish between short-time thermal stress and long-time thermal history. After a short period of thermal stress, for example a motor start-up, the thermal level starts to decrease quite sharply, simulating the leveling out of the hot spots. Consequently, the probability of successive allowed start-ups increases.

When protecting the objects without hot spot tendencies, for example motors started with soft starters, and cables, the value of *Weighting factor p* is set to 100 percent. With the value of *Weighting factor p* set to 100 percent, the thermal level decreases slowly after a heavy load condition. This makes the protection suitable for applications where no hot spots are expected. Only in special cases where the thermal overload protection is required to follow the characteristics of the object to be protected more closely and the thermal capacity of the object is very well known, a value between 50 and 100 percent is required.

For motor applications where, for example, two hot starts are allowed instead of three cold starts, the value of the setting *Weighting factor p* being 40 percent has proven to be useful. Setting the value of *Weighting factor p* significantly below 50 percent should be handled carefully as there is a possibility to overload the protected object as a thermal unit might allow too many hot starts or the thermal history of the motor has not been taken into account sufficiently.

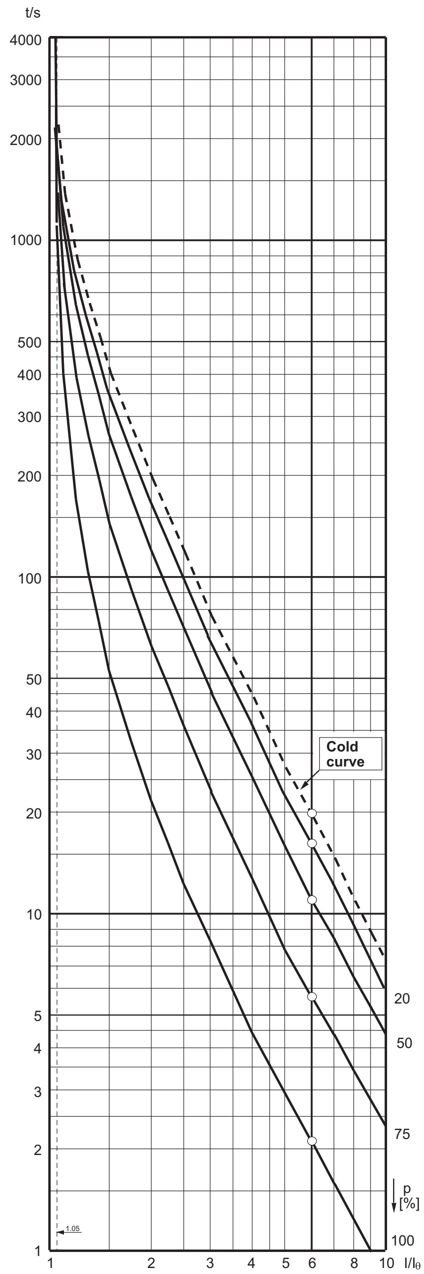


Figure 147: The influence of Weighting factor p at prior load 1xFLC, timeconstant = 640 s, and Overload factor = 1.05

Setting the overload factor

The value of *Overload factor* defines the highest permissible continuous load. The recommended value is 1.05.

Setting the negative sequence factor

During the unbalance condition, the symmetry of the stator currents is disturbed and a counter-rotating negative sequence component current is set up. An increased stator current causes additional heating in the stator and the negative sequence component current excessive heating in the rotor. Also mechanical problems like rotor vibration can occur.

The most common cause of unbalance for three-phase motors is the loss of phase resulting in an open fuse, connector or conductor. Often mechanical problems can be more severe than the heating effects and therefore a separate unbalance protection is used.

Unbalances in other connected loads in the same busbar can also affect the motor. A voltage unbalance typically produces 5 to 7 times higher current unbalance. Because the thermal overload protection is based on the highest TRMS value of the phase current, the additional heating in stator winding is automatically taken into account. For more accurate thermal modeling, the *Negative Seq factor* setting is used for taking account of the rotor heating effect.

$$Negative\,Seq\ factor = \frac{R_{R2}}{R_{R1}}$$

(Equation 19)

R_{R2} Rotor negative sequence resistance

R_{R1} Rotor positive sequence resistance

A conservative estimate for the setting can be calculated:

$$Negative\,Seq\ factor = \frac{175}{I_{LR}^2}$$

(Equation 20)

I_{LR} Locked rotor current (multiple of set *Rated current*). The same as the start-up current at the beginning of the motor start-up.

For example, if the rated current of a motor is 230 A, start-up current is 5.7 x I_r,

$$Negative\,Seq\ factor = \frac{175}{5.7^2} = 5.4$$

(Equation 21)

Setting the thermal restart level

The restart disable level can be calculated as follows:

$$\theta_i = 100\% - \left(\frac{\text{startup time of the motor}}{\text{operate time when no prior load}} \times 100\% + \text{margin} \right)$$

(Equation 22)

For example, the motor start-up time is 11 seconds, start-up current 6 x rated and *Time constant start* is set for 800 seconds. Using the trip curve with no prior load, the operation time at 6 x rated current is 25 seconds, one motor start-up uses 11/25 ≈ 45 percent of the thermal capacity of the motor. Therefore, the restart disable level must be set to below 100 percent - 45 percent = 55 percent, for example to 50 percent (100 percent - (45 percent + margin), where margin is 5 percent).

Setting the thermal alarm level

Tripping due to high overload is avoided by reducing the load of the motor on a prior alarm.

The value of *Alarm thermal value* is set to a level which allows the use of the full thermal capacity of the motor without causing a trip due to a long overload time. Generally, the prior alarm level is set to a value of 80 to 90 percent of the trip level.

4.1.9.6 Signals

Table 310: 49M Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_2	SIGNAL	0	Negative sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
START_EMERG	BOOLEAN	0=False	Signal for indicating the need for emergency start
AMB_TEMP	FLOAT32	0	The ambient temperature used in the calculation

Table 311: 49M Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
ALARM	BOOLEAN	Thermal Alarm
BLK_RESTART	BOOLEAN	Thermal overload indicator, to inhibit restart

4.1.9.7 Settings

Table 312: 49M Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Overload factor	1.00...1.20		0.01	1.05	Overload factor (k)
Alarm thermal value	50.0...100.0	%	0.1	95.0	Thermal level above which function gives an alarm
Restart thermal Val	20.0...80.0	%	0.1	40.0	Thermal level above which function inhibits motor restarting
Negative Seq factor	0.0...10.0		0.1	0.0	Heating effect factor for negative sequence current
Weighting factor p	20.0...100.0	%	0.1	50.0	Weighting factor (p)
Time constant normal	80...4000	s	1	320	Motor time constant during the normal operation of motor
Time constant start	80...4000	s	1	320	Motor time constant during the start of motor
Time constant stop	80...60000	s	1	500	Motor time constant during the standstill condition of motor
Env temperature mode	1=FLC Only 2=Use input 3=Set Amb Temp			1=FLC Only	Mode of measuring ambient temperature
Env temperature Set	-20.0...70.0	°C	0.1	40.0	Ambient temperature used when no external temperature measurement available

Table 313: 49M Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 314: 49M Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Current reference	0.30...2.00	xIn	0.01	1.00	The load current leading to Temperature raise temperature
Initial thermal Val	0.0...100.0	%	0.1	74.0	Initial thermal level of the motor

4.1.9.8 Monitored data

Table 315: 49M Monitored data

Name	Type	Values (Range)	Unit	Description
TEMP_RL	FLOAT32	0.00...9.99		The calculated temperature of the protected object relative to the trip level
TEMP_AMB	FLOAT32	-99...999	°C	The ambient temperature used in the calculation
THERMLEV_ST	FLOAT32	0.00...9.99		Thermal level at beginning of motor startup
THERMLEV_END	FLOAT32	0.00...9.99		Thermal level at the end of motor startup situation
T_ENARESTART	INT32	0...99999	s	Estimated time to reset of block restart
49M	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
Therm-Lev	FLOAT32	0.00...9.99		Thermal level of protected object (1.00 is the trip level)

4.1.9.9 Technical data

Table 316: 49M Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	Current measurement: ±1.5% of the set value or ±0.002 × I_n (at currents in the range of 0.01...4.00 × I_n)
Trip time accuracy[1)]	±2.0% of the theoretical value or ±0.50 s

1) Overload current > 1.2 × Operate level temperature

4.1.9.10 Technical revision history

Table 317: 49M Technical revision history

Technical revision	Change
B	Added a new input `AMB_TEMP`. Added a new selection for the *Env temperature mode* setting "Use input".
C	Internal improvement.
D	Time constant stop range maximum value changed from 8000 s to 60000 s.
E	Internal improvement.

4.2 Ground-fault protection

4.2.1 Non-directional ground-fault protection 51N, 51G, 50N, 50G, 50N-3, 50G-3

4.2.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Non-directional ground-fault protection, low stage	EFLPTOC	Io>	51N, 51G
Non-directional ground-fault protection, high stage	EFHPTOC	Io>>	50N, 50G
Non-directional ground-fault protection, instantaneous stage	EFIPTOC	Io>>>	50N-3, 50G-3

4.2.1.2 Function block

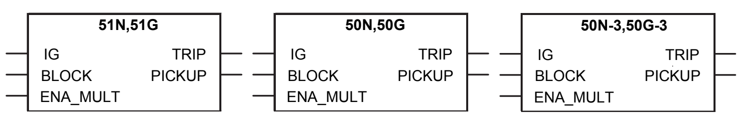


Figure 148: Function block

4.2.1.3 Functionality

The non-directional ground-fault protection function 51N, 51G, 50N, 50G, 50N-3, 50G-3 is used as non-directional ground-fault protection for feeders.

The function picks up and trips when the residual current exceeds the set limit. The trip time characteristic for low stage 51N, 51G and high stage 50N, 50G can be selected to be either definite time (DT) or inverse definite minimum time (IDMT). The instantaneous stage 50N-3, 50G-3 always trips with the DT characteristic.

In the DT mode, the function trips after a predefined trip time and resets when the fault current disappears. The IDMT mode provides current-dependent timer characteristics.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.2.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

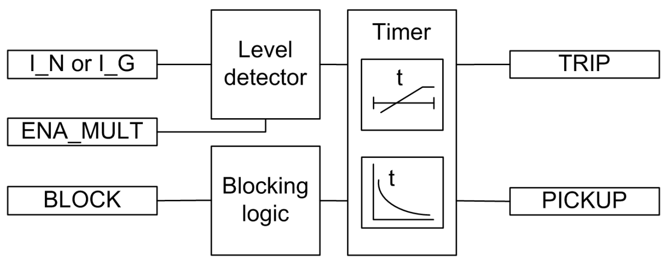


Figure 149: Functional module diagram

Level detector

The operating quantity can be selected with the setting *IG/I0 signal Sel*. The selectable options are "Measured IG" and "Calculated I0". The operating quantity is compared to the set *Pickup value*. If the measured value exceeds the set *Pickup value*, the level detector sends an enable-signal to the timer module. If the `ENA_MULT` input is active, the *Pickup value* setting is multiplied by the *Pickup value Mult* setting.

The protection relay does not accept the *Pickup value* or *Pickup value Mult* setting if the product of these settings exceeds the *Pickup value* setting range.

The pickup value multiplication is normally done when the inrush detection function (INR) is connected to the `ENA_MULT` input.

Timer

Once activated, the timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated.

When the user-programmable IDMT curve is selected, the operation time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set *Reset delay time* value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The `PICKUP` output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT trip and reset times.

The setting parameter *Minimum trip time* defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking**

mode which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.2.1.5 Measurement modes

The function operates on three alternative measurement modes: "RMS", "DFT" and "Peak-to-Peak". The measurement mode is selected with the *Measurement mode* setting.

Table 318: Measurement modes supported by 51N/50N or 51G/50G stages

Measurement mode	51N, 51G	50N, 50G	50N-3, 50G-3
RMS	x	x	
DFT	x	x	
Peak-to-Peak	x	x	x

For a detailed description of the measurement modes, see the Measurement modes section in this manual.

4.2.1.6 Timer characteristics

51N, 51G, 50N, 50G supports both DT and IDMT characteristics. The user can select the timer characteristics with the *Operating curve type* and *Type of reset curve* settings. When the DT characteristic is selected, it is only affected by the *Trip delay time* and *Reset delay time* settings.

The protection relay provides 16 IDMT characteristics curves, of which seven comply with the IEEE C37.112 and six with the IEC 60255-3 standard. Two curves follow the special characteristics of ABB praxis and are referred to as RI and RD. In addition to this, a user programmable curve can be used if none of the standard curves are applicable. The user can choose the DT characteristic by selecting the *Operating curve type* values "ANSI Def. Time" or "IEC Def. Time". The functionality is identical in both cases.

The following characteristics, which comply with the list in the IEC 61850-7-4 specification, indicate the characteristics supported by different stages:

Table 319: Timer characteristics supported by different stages

Operating curve type	51N, 51G	50N, 50G
(1) ANSI Extremely Inverse	x	x
(2) ANSI Very Inverse	x	
(3) ANSI Normal Inverse	x	x
(4) ANSI Moderately Inverse	x	
(5) ANSI Definite Time	x	x
(6) Long Time Extremely Inverse	x	
(7) Long Time Very Inverse	x	
(8) Long Time Inverse	x	
(9) IEC Normal Inverse	x	x
(10) IEC Very Inverse	x	x
(11) IEC Inverse	x	
(12) IEC Extremely Inverse	x	x
(13) IEC Short Time Inverse	x	
(14) IEC Long Time Inverse	x	
(15) IEC Definite Time	x	x
(17) User programmable curve	x	x
(18) RI type	x	
(19) RD type	x	

50N-3, 50G-3 supports only definite time characteristics.

For a detailed description of timers, see the General function block features section in this manual.

Table 320: Reset time characteristics supported by different stages

Reset curve type	51N, 51G	50N, 50G	Note
(1) Immediate	x	x	Available for all reset time curves
(2) Def time reset	x	x	Available for all reset time curves
(3) Inverse reset	x	x	Available only for ANSI and user programmable curves

The *Type of reset curve* setting does not apply to 50N-3, 50G-3 or when the DT operation is selected. The reset is purely defined by the *Reset delay time* setting.

4.2.1.7 Application

51N, 51G, 50N, 50G, 50N-3, 50G-3 is designed for protection and clearance of ground faults in distribution and sub-transmission networks where the neutral point is isolated or grounded via a resonance coil or through low resistance. It also applies to solidly grounded networks and ground-fault protection of different equipment connected to the power systems, such as shunt capacitor bank or shunt reactors and for backup ground-fault protection of power transformers.

Many applications require several steps using different current pickup levels and time delays. 51N, 51G, 50N, 50G, 50N-3, 50G-3 consists of three different protection stages:

- Low 51N, 51G
- High 50N, 50G
- Instantaneous 50N-3, 50G-3

51N, 51G contains several types of time-delay characteristics. 50N, 50G and 50N-3, 50G-3 are used for fast clearance of serious ground faults.

4.2.1.8 Signals

Table 321: 51N,51G Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Ground current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 322: 50N,50G Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Ground current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 323: 50N-3,50G-3 Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Ground current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 324: 51N,51G Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 325: 50N,50G Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 326: 50N-3,50G-3 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.2.1.9 Settings

Table 327: 51N,51G Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.010...5.000	xIn	0.005	0.010	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type

Table 328: 51N,51G Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 329: 51N,51G Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 330: 51N,51G Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0

Table 331: 50N,50G Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.10...40.00	xIn	0.01	0.10	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Operating curve type	1=ANSI Ext Inv 3=ANSI Norm Inv 5=ANSI DT 9=IEC Norm Inv 10=IEC Very Inv 12=IEC Ext Inv 15=IEC DT 17=Programmable			15=IEC DT	Selection of time delay curve type

Table 332: 50N,50G Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 333: 50N,50G Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 334: 50N,50G Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0

Table 335: 50N-3,50G-3 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	1.00...40.00	xIn	0.01	1.00	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Trip delay time	20...200000	ms	10	20	Trip delay time

Table 336: 50N-3,50G-3 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 337: 50N-3,50G-3 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0

4.2.1.10 Monitored data

Table 338: 51N,51G Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
51N,51G	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 339: 50N,50G Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
50N,50G	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 340: 50N-3,50G-3 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
50N-3,50G-3	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.1.11 Technical data

4.2.1.12 Technical revision history

Table 341: 50N-3, 50G-3 Technical revision history

Technical revision	Change
B	The minimum and default values changed to 40 ms for the *Trip delay time* setting
C	Minimum and default values changed to 20 ms for the *Trip delay time* setting Minimum value changed to 1.00 x I_n for the *Pickup value* setting
D	Added a setting parameter for the "Measured IG" or "Calculated I0" selection
E	Internal improvement
F	Internal improvement

Table 342: 50N, 50G Technical revision history

Technical revision	Change
B	Minimum and default values changed to 40 ms for the *Trip delay time* setting
C	Added a setting parameter for the "Measured IG" or "Calculated I0" selection
D	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting
E	Internal improvement
F	Internal improvement

Table 343: 51N, 51G Technical revision history

Technical revision	Change
B	The minimum and default values changed to 40 ms for the *Trip delay time* setting
C	*Pickup value* step changed to 0.005
D	Added a setting parameter for the "Measured IG" or "Calculated I0" selection
E	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting
F	Internal improvement
G	Internal improvement

4.2.2 Directional ground-fault protection 67/51N, 67/50N

4.2.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional ground-fault protection, low stage	DEFLPDEF	I0> ->	67/51N
Directional ground-fault protection, high stage	DEFHPDEF	I0>> ->	67/50N

4.2.2.2 Function block

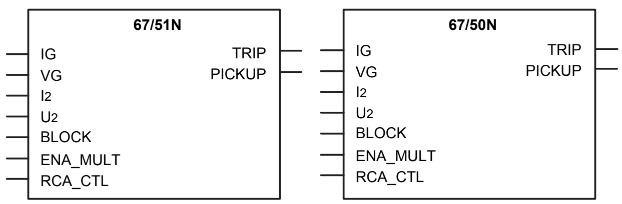


Figure 150: Function block

4.2.2.3 Functionality

The directional ground-fault function 67/51N, 67/50N is used as directional ground-fault protection for feeders.

The function picks up and trips when the operating quantity (current) and polarizing quantity (voltage) exceed the set limits and the angle between them is inside the set operating sector. The trip time characteristic for low stage (DEFLPDEF) and high stage (DEFHPDEF) can be selected to be either definite time (DT) or inverse definite minimum time (IDMT).

In the DT mode, the function trips after a predefined trip time and resets when the fault current disappears. The IDMT mode provides current-dependent timer characteristics.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.2.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 67/51N, 67/50N can be described using a module diagram. All the modules in the diagram are explained in the next sections.

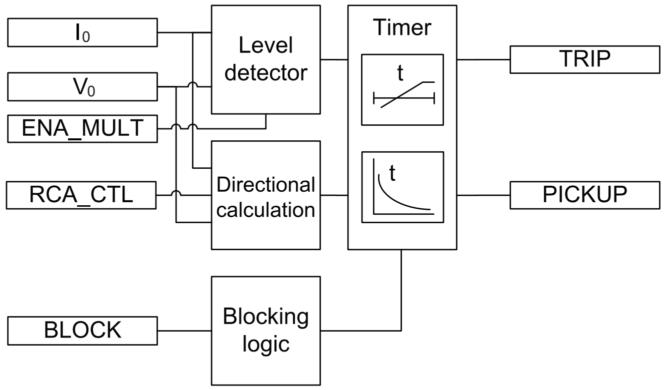


Figure 151: Functional module diagram

Level detector

The magnitude of the operating quantity is compared to the set *Pickup value* and the magnitude of the polarizing quantity is compared to the set *Voltage pickup value*. If both the limits are exceeded, the level detector sends an enabling signal to the timer module. When the *Enable voltage limit* setting is set to "False", *Voltage pickup value* has no effect and the level detection is purely based on the operating quantity. If the ENA_MULT input is active, the *Pickup value* setting is multiplied by the *Pickup value Mult* setting.

The operating quantity (residual current) can be selected with the setting *IG/I0 signal Sel*. The options are "Measured IG" and "Calculated I0". If "Measured IG" is selected, the current ratio for IG-channel is given in **Configuration/Analog inputs/Current (IG,CT)**. If "Calculated I0" is selected, the current ratio is obtained from the phase-current channels given in **Configuration/Analog inputs/Current (3I,CT)**.

The operating quantity (residual voltage) can be selected with the setting *Vg or V0* The options are "Measured VG" and "Calculated V0". If "Measured VG" is selected, the voltage ratio for VG-channel is given in **Configuration/Analog inputs/Voltage (VG,VT)**. If "Calculated V0" is selected, the voltage ratio is obtained from the phase-voltage channels given in **Configuration/Analog inputs/Voltage (3V,VT)**.

Example 1: IG is measured with cable core CT (100/1 A) and VG is measured from open-delta connected VTs (20/sqrt(3) kV : 100/sqrt(3) V : 100/3 V). In this case, "Measured IG" and "Measured VG" are selected. The nominal values for residual current and residual voltage are obtained from CT and VT ratios entered in Residual current IG: **Configuration/Analog inputs/Current (IG,CT)**: 100 A : 1 A. The Residual voltage VG: **Configuration/Analog inputs/Voltage (VG,VT)**: 11.547 kV : 100 V. The *Pickup value* of 1.0 × In corresponds to 1.0 * 100 A = 100 A in the primary. The *Voltage pickup value* of 1.0 × Vn corresponds to 1.0 * 11.547 kV = 11.547 kV in the primary.

Example 2: Both I0 and V0 are calculated from the phase quantities. Phase CT-ratio is 100 : 1 A and phase VT-ratio is 20/sqrt(3) kV : 100/sqrt(3) V. In this case, "Calculated I0" and "Calculated V0" are selected. The nominal values for residual current and residual voltage are obtained from CT and VT ratios entered in Residual current I0: **Configuration/Analog inputs/Current (3I,CT)**: 100 A : 1 A. The residual voltage V0: **Configuration/Analog inputs/Voltage (3V,VT)**: 20.000 kV : 100 V. The *Pickup value* of 1.0 × In corresponds to 1.0 * 100 A = 100 A in the primary. The *Voltage pickup value* of 1.0 × Vn corresponds to 1.0 * 20.000 kV = 20.000 kV in the primary.

If "Calculated V0" is selected, the residual voltage nominal value is always phase-to-phase voltage. Thus, the valid maximum setting for residual Voltage pickup value is 0.577 x Vn. The calculated V0 requires that all the three phase-to-ground voltages are connected to the protection relay. V0 cannot be calculated from the phase-to-phase voltages.

If the *Enable voltage limit* setting is set to "True", the magnitude of the polarizing quantity is checked even if the *Directional mode* was set to "Non-directional" or *Allow Non Dir* to "True". The protection relay does not accept the *Pickup value* or *Pickup value Mult* setting if the product of these settings exceeds the *Pickup value* setting range.

Typically, the `ENA_MULT` input is connected to the inrush detection function INR. In case of inrush, INR activates the `ENA_MULT` input, which multiplies *Pickup value* by the *Pickup value Mult* setting.

Directional calculation

The directional calculation module monitors the angle between the polarizing quantity and operating quantity. Depending on the *Pol quantity* setting, the polarizing quantity can be the residual voltage (measured or calculated) or the negative sequence voltage. When the angle is in the operation sector, the module sends the enabling signal to the timer module.

The minimum signal level which allows the directional operation can be set with the *Min trip current* and *Min trip voltage* settings.

If *Pol quantity* is set to "Zero. seq. volt", the residual current and residual voltage are used for directional calculation.

If *Pol quantity* is set to "Neg. seq. volt", the negative sequence current and negative sequence voltage are used for directional calculation.

In the phasor diagrams representing the operation of 67/51N, 67/50N, the polarity of the polarizing quantity (VG or V2) is reversed, that is, the polarizing quantity in the phasor diagrams is either -VG or -V2. Reversing is done by switching the polarity of the residual current measuring channel (see the connection diagram in the application manual). Similarly the polarity of the calculated IG and I_2 is also switched.

For defining the operation sector, there are five modes available through the *Operation mode* setting.

Table 344: Operation modes

Operation mode	Description
Phase angle	The operating sectors for forward and reverse are defined with the settings *Min forward angle*, *Max forward angle*, *Min reverse angle* and *Max reverse angle*.
IoSin	The operating sectors are defined as "forward" when |IG| x sin (ANGLE) has a positive value and "reverse" when the value is negative. ANGLE is the angle difference between -VG and IG.
IoCos	As "IoSin" mode. Only cosine is used for calculating the operation current.
Phase angle 80	The sector maximum values are frozen to 80 degrees respectively. Only *Min forward angle* and *Min reverse angle* are settable.
Phase angle 88	The sector maximum values are frozen to 88 degrees. Otherwise as "Phase angle 80" mode.

Polarizing quantity selection "Neg. seq. volt." is available only in the "Phase angle" operation mode.

The directional operation can be selected with the *Directional mode* setting. The alternatives are "Non-directional", "Forward" and "Reverse" operation. The operation criterion is selected with the *Operation mode* setting. By setting *Allow Non Dir* to "True", non-directional operation is allowed when the directional information is invalid, that is, when the magnitude of the polarizing quantity is less than the value of the *Min trip voltage* setting.

Typically, the network rotating direction is counter-clockwise and defined as "ABC". If the network rotating direction is reversed, meaning clockwise, that is, "ACB", the equation for calculating the negative sequence voltage component need to be changed. The network rotating direction is defined with a system parameter *Phase rotation*. The calculation of the component is affected but the angle difference calculation remains the same. When the residual voltage is used as the polarizing method, the network rotating direction change has no effect on the direction calculation.

The network rotating direction is set in the protection relay using the parameter in the HMI menu: **Configuration/System/Phase rotation**. The default parameter value is "ABC".

If the *Enable voltage limit* setting is set to "True", the magnitude of the polarizing quantity is checked even if *Directional mode* is set to "Non-directional" or *Allow Non Dir* to "True".

The *Characteristic angle* setting is used in the "Phase angle" mode to adjust the operation according to the method of neutral point grounding so that in an isolated network the *Characteristic angle* (φ_{RCA}) = -90° and in a compensated network φ_{RCA} = 0°. In addition, the characteristic angle can be changed via the control signal `RCA_CTL`. `RCA_CTL` affects the *Characteristic angle* setting.

The *Correction angle* setting can be used to improve selectivity due the inaccuracies in the measurement transformers. The setting decreases the operation sector. The correction can only be used with the "IoCos" or "IoSin" modes.

The polarity of the polarizing quantity can be reversed by setting the *Pol reversal* to "True", which turns the polarizing quantity by 180 degrees.

For definitions of different directional ground-fault characteristics, see the Directional ground-fault characteristics section in this manual.

For definitions of different directional ground-fault characteristics, refer to general function block features information.

The directional calculation module calculates several values which are presented in the monitored data.

Table 345: Monitored data values

Monitored data values	Description
FAULT_DIR	The detected direction of fault during fault situations, that is, when `PICKUP` output is active.
DIRECTION	The momentary operating direction indication output.
ANGLE	
ANGLE_RCA	The angle difference between the operating angle and *Characteristic angle*, that is, ANGLE_RCA = ANGLE – *Characteristic angle*.
I_OPER	The current that is used for fault detection. If the *Operation mode* setting is "Phase angle", "Phase angle 80" or "Phase angle 88", I_OPER is the measured or calculated residual current. If the *Operation mode* setting is "IoSin", I_OPER is calculated as follows I_OPER = IG x sin(ANGLE). If the *Operation mode* setting is "IoCos", I_OPER is calculated as follows I_OPER = IG x cos(ANGLE).

Monitored data values are accessible on the LHMI or through tools via communications.

Timer

Once activated, the timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated.

When the user-programmable IDMT curve is selected, the operation time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set *Reset delay time* value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The `PICKUP` output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT trip and reset times.

The setting parameter *Minimum trip time* defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*

.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.2.2.5 Directional ground-fault principles

In many cases it is difficult to achieve selective ground-fault protection based on the magnitude of residual current only. To obtain a selective ground-fault protection scheme, it is necessary to take the phase angle of IG into account. This is done by comparing the phase angle of the operating and polarizing quantity.

Relay characteristic angle

The *Characteristic angle* setting, also known as Relay Characteristic Angle (RCA), Relay Base Angle or Maximum Torque Angle (MTA), is used in the "Phase angle" mode to turn the directional characteristic if the expected fault current angle does not coincide with the polarizing quantity to produce the maximum torque. That is, RCA is the angle between the maximum torque line and polarizing quantity. If the polarizing quantity is in phase with the maximum torque line, RCA is 0 degrees. The angle is positive if the operating current lags the polarizing quantity and negative if it leads the polarizing quantity.

Example 1

The "Phase angle" mode is selected, compensated network (φRCA = 0 deg)

=> *Characteristic angle* = 0 deg

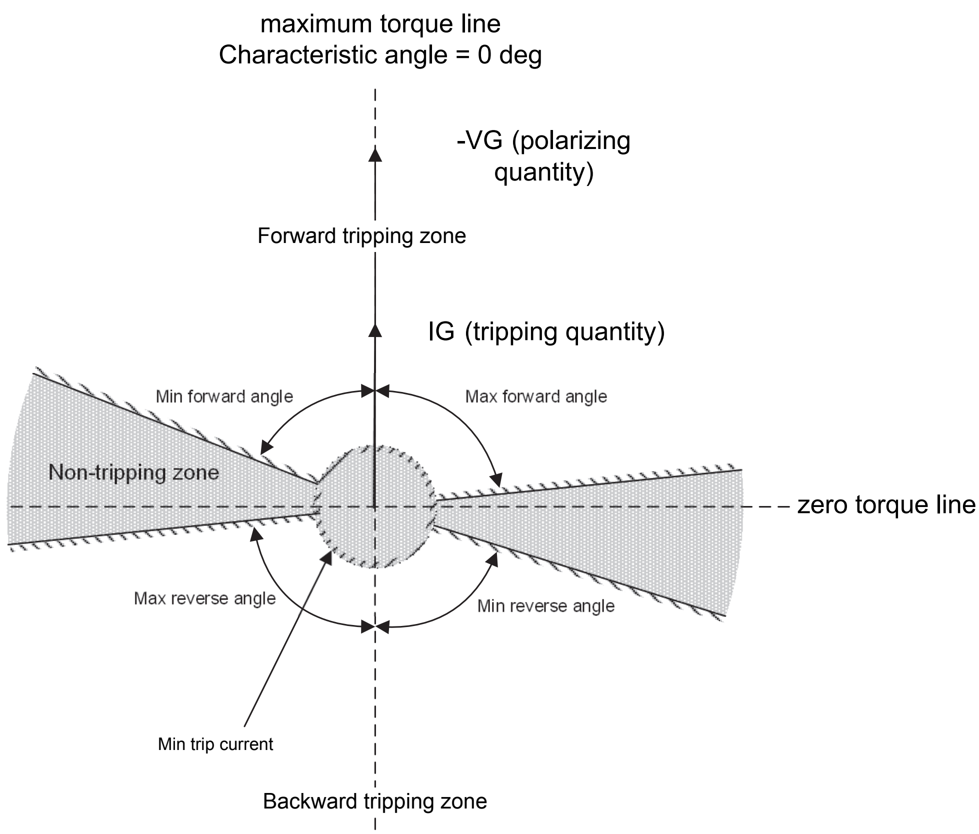


Figure 152: Definition of the relay characteristic angle, RCA=0 degrees in a compensated network

Example 2

The "Phase angle" mode is selected, solidly grounded network (φRCA = +60 deg)

=> *Characteristic angle* = +60 deg

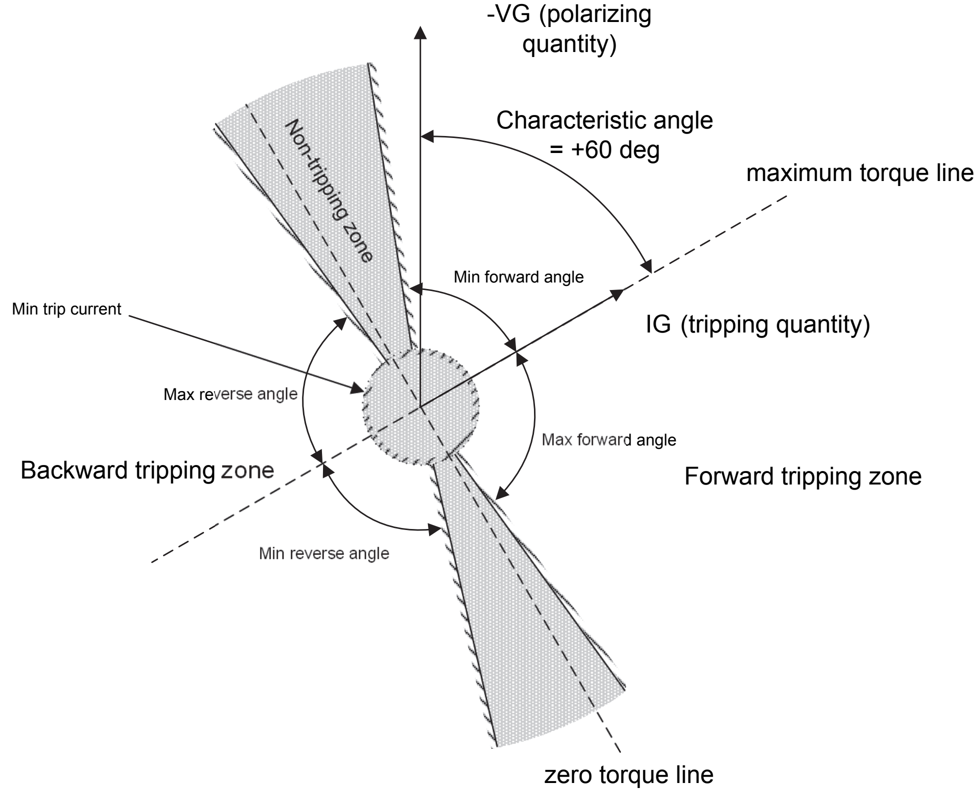


Figure 153: Definition of the relay characteristic angle, RCA=+60 degrees in a solidly grounded network

Example 3

The "Phase angle" mode is selected, isolated network (φRCA = -90 deg)

=> *Characteristic angle* = -90 deg

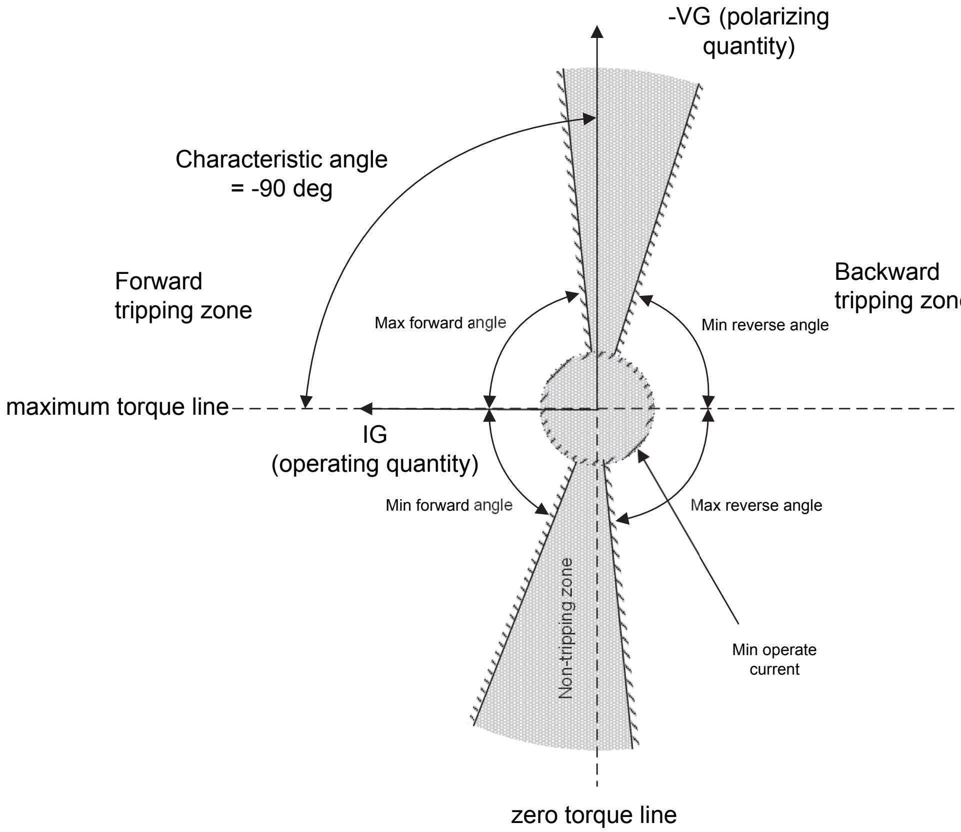


Figure 154: Definition of the relay characteristic angle, RCA=–90 degrees in an isolated network

Directional ground-fault protection in an isolated neutral network

In isolated networks, there is no intentional connection between the system neutral point and ground. The only connection is through the phase-to-ground capacitances (C_0) of phases and leakage resistances (R_0). This means that the residual current is mainly capacitive and has a phase shift of -90 degrees compared to the polarizing voltage. Consequently, the relay characteristic angle (RCA) should be set to -90 degrees and the operation criteria to "IoSin" or "Phase angle". The width of the operating sector in the phase angle criteria can be selected with the settings *Min forward angle*, *Max forward angle*, *Min reverse angle* or *Max reverse angle*. Figure 155 illustrates a simplified equivalent circuit for an ungrounded network with a ground fault in phase C.

For definitions of different directional ground-fault characteristics, see Directional ground-fault principles.

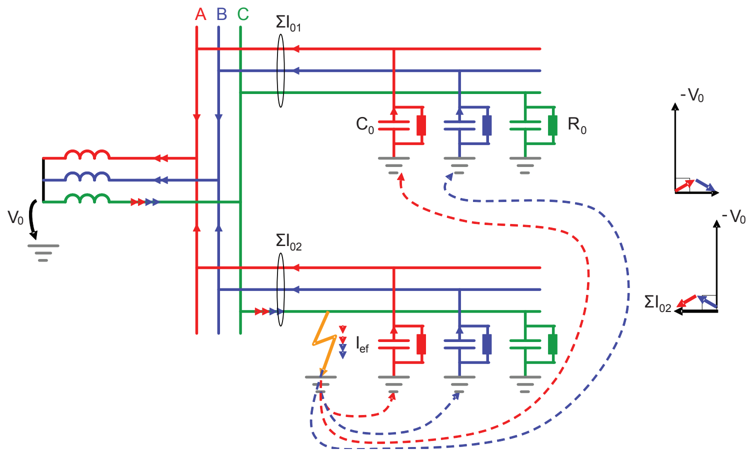


Figure 155: Ground-fault situation in an isolated network

Directional ground-fault protection in a compensated network

In compensated networks, the capacitive fault current and the inductive resonance coil current compensate each other. The protection cannot be based on the reactive current measurement, since the current of the compensation coil would disturb the operation of the protection relays. In this case, the selectivity is based on the measurement of the active current component. The magnitude of this component is often small and must be increased by means of a parallel resistor in the compensation equipment. When measuring the resistive part of the residual current, the relay characteristic angle (RCA) should be set to 0 degrees and the operation criteria to "IoCos" or "Phase angle". Figure 156 illustrates a simplified equivalent circuit for a compensated network with a ground fault in phase C.

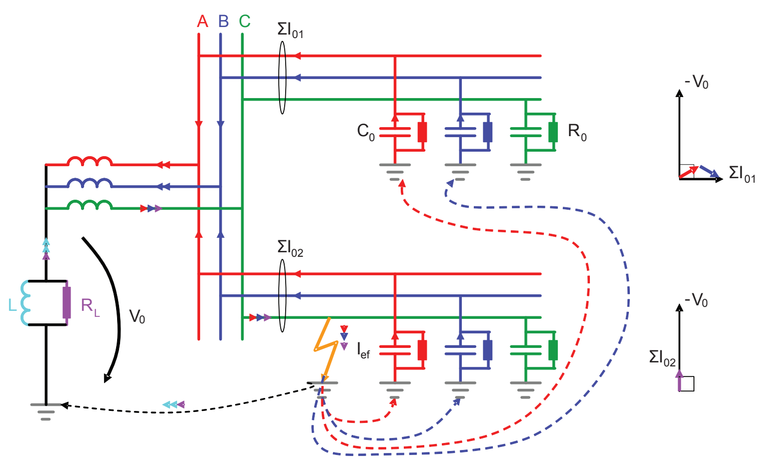


Figure 156: Ground-fault situation in a compensated network

The Petersen coil or the grounding resistor may be temporarily out of operation. To keep the protection scheme selective, it is necessary to update the *Characteristic angle* setting accordingly. This can be done with an auxiliary input in the protection relay which receives a signal from an auxiliary switch of the disconnector of the Petersen coil in compensated networks. As a result the characteristic angle is set automatically to suit the grounding method used. The RCA_CTL input can be used to change the operation criteria as described in Table 346 and Table 347.

Table 346: Relay characteristic angle control in Iosin(φ) and Iocos(φ) operation criteria

Operation mode setting:	RCA_CTL = FALSE	RCA_CTL = TRUE
Iosin	Actual operation mode: Iosin	Actual operation mode: Iocos
Iocos	Actual operation mode: Iocos	Actual operation mode: Iosin

Table 347: Characteristic angle control in phase angle operation mode

Characteristic angle setting	RCA_CTL = FALSE	RCA_CTL = TRUE
-90°	φ_{RCA} = -90°	φ_{RCA} = 0°
0°	φ_{RCA} = 0°	φ_{RCA} = -90°

Use of the extended phase angle characteristic

The traditional method of adapting the directional ground-fault protection function to the prevailing neutral grounding conditions is done with the *Characteristic angle* setting. In an ungrounded network, *Characteristic angle* is set to -90 degrees and in a compensated network *Characteristic angle* is set to 0 degrees. In case the grounding method of the network is temporarily changed from compensated to ungrounded due to the disconnection of the arc suppression coil, the *Characteristic angle* setting should be modified correspondingly. This can be done using the setting groups or the RCA_CTL input. Alternatively, the operating sector of the directional ground-fault protection function can be extended to cover the operating sectors of both neutral grounding principles. Such characteristic is valid for both ungrounded and compensated network and does not require any modification in case the neutral grounding changes temporarily from the ungrounded to compensated network or vice versa.

The extended phase angle characteristic is created by entering a value of over 90 degrees for the *Min forward angle* setting; a typical value is 170 degrees (*Min reverse angle* in case *Directional mode* is set to "Reverse"). The *Max forward angle* setting should be set to cover the possible measurement inaccuracies of current and voltage transformers; a typical value is 80 degrees (*Max reverse angle* in case *Directional mode* is set to "Reverse").

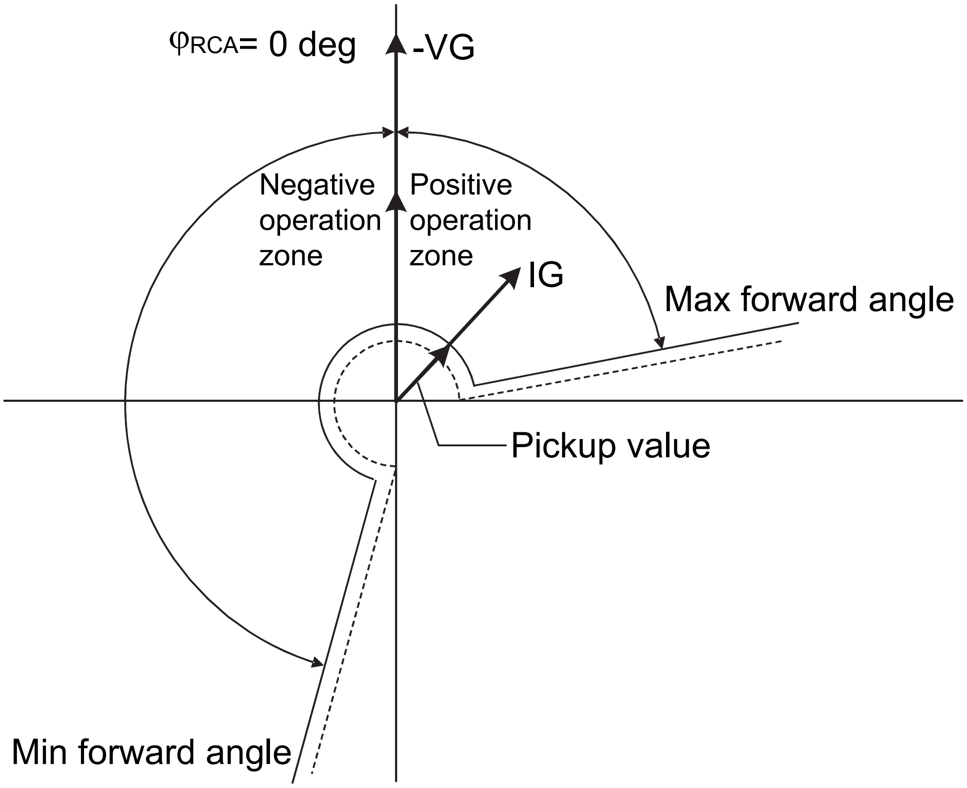


Figure 157: Extended operation area in directional ground-fault protection

4.2.2.6 Measurement modes

The function operates on three alternative measurement modes: "RMS", "DFT" and "Peak-to-Peak". The measurement mode is selected with the *Measurement mode* setting.

Table 348: Measurement modes supported by 67/51N, 67/50N stages

Measurement mode	67/51N	67/50N
RMS	x	x
DFT	x	x
Peak-to-Peak	x	x

For a detailed description of the measurement modes, see the Measurement modes section in this manual.

4.2.2.7 Timer characteristics

67/51N, 67/50N supports both DT and IDMT characteristics. The user can select the timer characteristics with the *Operating curve type* setting.

The protection relay provides 16 IDMT characteristics curves, of which seven comply with the IEEE C37.112 and six with the IEC 60255-3 standard. Two curves follow the special characteristics of ABB praxis and are referred to as RI and RD. In addition to this, a user programmable curve can be used if none of the standard curves are applicable. The user can choose the DT characteristic by selecting the *Operating curve type* values "ANSI Def. Time" or "IEC Def. Time". The functionality is identical in both cases.

The following characteristics, which comply with the list in the IEC 61850-7-4 specification, indicate the characteristics supported by different stages.

Table 349: Timer characteristics supported by different stages

Operating curve type	67/51N	67/50N
(1) ANSI Extremely Inverse	x	x
(2) ANSI Very Inverse	x	
(3) ANSI Normal Inverse	x	x
(4) ANSI Moderately Inverse	x	
(5) ANSI Definite Time	x	x
(6) Long Time Extremely Inverse	x	
(7) Long Time Very Inverse	x	
(8) Long Time Inverse	x	
(9) IEC Normal Inverse	x	
(10) IEC Very Inverse	x	
(11) IEC Inverse	x	
(12) IEC Extremely Inverse	x	
(13) IEC Short Time Inverse	x	
(14) IEC Long Time Inverse	x	
(15) IEC Definite Time	x	x
(17) User programmable curve	x	x
(18) RI type	x	
(19) RD type	x	

For a detailed description of the timers, see the General function block features section in this manual.

Table 350: Reset time characteristics supported by different stages

Reset curve type	67/51N	67/50N	Note
(1) Immediate	x	x	Available for all operate time curves
(2) Def time reset	x	x	Available for all operate time curves
(3) Inverse reset	x	x	Available only for ANSI and user programmable curves

4.2.2.8 Directional ground-fault characteristics

Phase angle characteristic

The operation criterion phase angle is selected with the *Operation mode* setting using the value "Phase angle".

When the phase angle criterion is used, the function indicates with the `DIRECTION` output whether the operating quantity is within the forward or reverse operation sector or within the non-directional sector.

The forward and reverse sectors are defined separately. The forward operation area is limited with the *Min forward angle* and *Max forward angle* settings. The reverse operation area is limited with the *Min reverse angle* and *Max reverse angle* settings.

The sector limits are always given as positive degree values.

In the forward operation area, the *Max forward angle* setting gives the clockwise sector and the *Min forward angle* setting correspondingly the counterclockwise sector, measured from the *Characteristic angle* setting.

In the reverse operation area, the *Max reverse angle* setting gives the clockwise sector and the *Min reverse angle* setting correspondingly the counterclockwise sector, measured from the complement of the *Characteristic angle* setting (180 degrees phase shift) .

The relay characteristic angle (RCA) is set to positive if the operating current lags the polarizing quantity. It is set to negative if it leads the polarizing quantity.

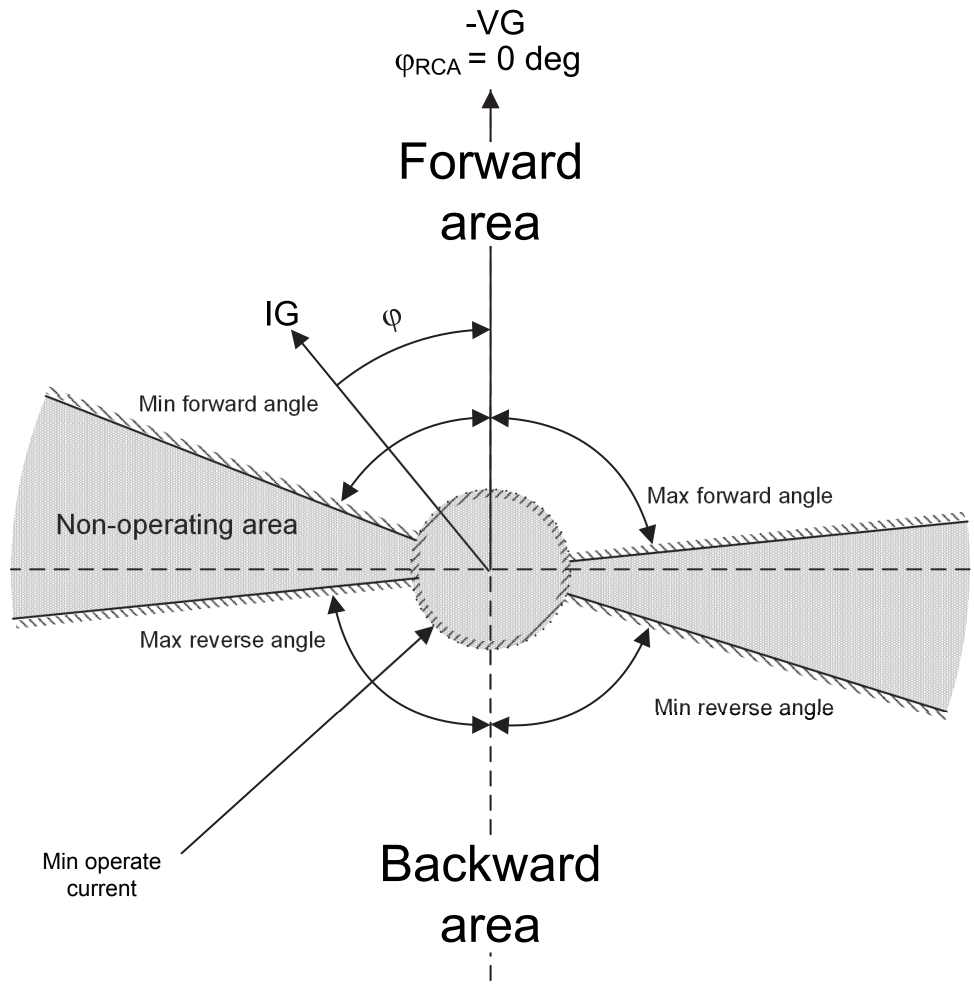


Figure 158: Configurable operating sectors in phase angle characteristic

Table 351: Momentary operating direction

Fault direction	The value for DIRECTION
Angle between the polarizing and operating quantity is not in any of the defined sectors.	0 = unknown
Angle between the polarizing and operating quantity is in the forward sector.	1= forward
Angle between the polarizing and operating quantity is in the reverse sector.	2 = backward
Angle between the polarizing and operating quantity is in both the forward and the reverse sectors, that is, the sectors are overlapping.	3 = both

If the *Allow Non Dir* setting is "False", the directional operation (forward, reverse) is not allowed when the measured polarizing or operating quantities are invalid, that is, their magnitude is below the set minimum values. The minimum values can be defined with the settings *Min trip current* and *Min trip voltage*. In case of low magnitudes, the FAULT_DIR and DIRECTION outputs are set to 0 = unknown, except when the *Allow non dir* setting is "True". In that case, the function is allowed to operate in the directional mode as non-directional, since the directional information is invalid.

Iosin(φ) and Iocos(φ) criteria

A more modern approach to directional protection is the active or reactive current measurement. The operating characteristic of the directional operation depends on the grounding principle of the network. The I_0sin(φ) characteristics is used in an isolated network, measuring the reactive component of the fault current caused by the ground capacitance. The I_0cos(φ) characteristics is used in a compensated network, measuring the active component of the fault current.

The operation criteria Iosin(φ) and Iocos(φ) are selected with the *Operation mode* setting using the values "IoSin" or "IoCos" respectively.

The angle correction setting can be used to improve selectivity. The setting decreases the operation sector. The correction can only be used with the Iosin(φ) or Iocos(φ) criterion. The RCA_CTL input is used to change the IG characteristic:

Table 352: Relay characteristic angle control in the IoSin and IoCos operation criteria

Operation mode:	RCA_CTL = "False"	RCA_CTL = "True"
IoSin	Actual operation criterion: Iosin(φ)	Actual operation criterion: Iocos(φ)
IoCos	Actual operation criterion: Iocos(φ)	Actual operation criterion: Iosin(φ)

When the Iosin(φ) or Iocos(φ) criterion is used, the component indicates a forward- or reverse-type fault through the FAULT_DIR and DIRECTION outputs, in which 1 equals a forward fault and 2 equals a reverse fault. Directional operation is not allowed (the *Allow non dir* setting is "False") when the measured polarizing or operating quantities are not valid, that is, when their magnitude is below the set minimum values. The minimum values can be defined with the *Min trip current* and *Min trip voltage* settings. In case of low magnitude, the FAULT_DIR and DIRECTION outputs are set to 0 = unknown, except when the *Allow non dir* setting is "True". In that case, the function is allowed to operate in the directional mode as non-directional, since the directional information is invalid.

The calculated Iosin(φ) or Iocos(φ) current used in direction determination can be read through the `I_OPER` monitored data. The value can be passed directly to a decisive element, which provides the final pickup and trip signals.

The `I_OPER` monitored data gives an absolute value of the calculated current.

The following examples show the characteristics of the different operation criteria:

Example 1.

Iosin(φ) criterion selected, forward-type fault

`=> FAULT_DIR = 1`

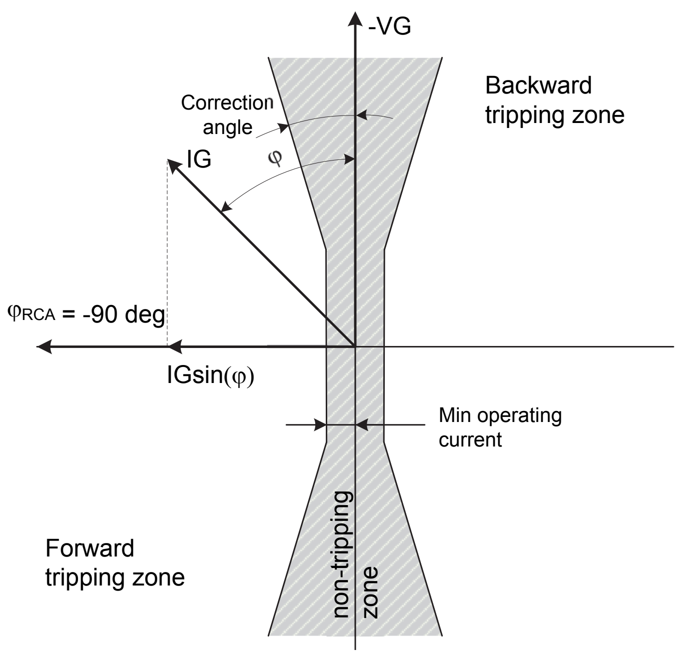


Figure 159: Operating characteristic Iosin(φ) in forward fault

The operating sector is limited by angle correction, that is, the operating sector is 180 degrees - 2*(angle correction).

Example 2.

Iosin(φ) criterion selected, reverse-type fault

`=> FAULT_DIR = 2`

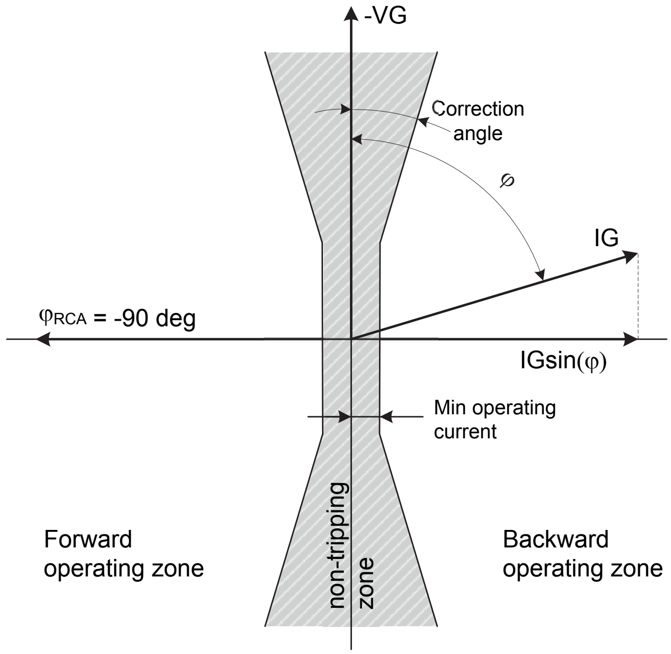


Figure 160: Operating characteristic Iosin(φ) in reverse fault

Example 3.

Iocos(φ) criterion selected, forward-type fault

```
=> FAULT_DIR = 1
```

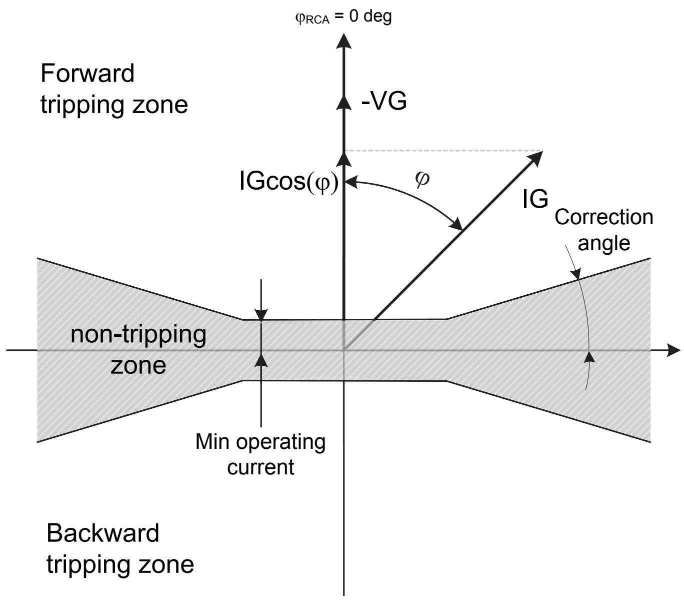


Figure 161: Operating characteristic Iocos(φ) in forward fault

Example 4.

Iocos(φ) criterion selected, reverse-type fault

`=> FAULT_DIR = 2`

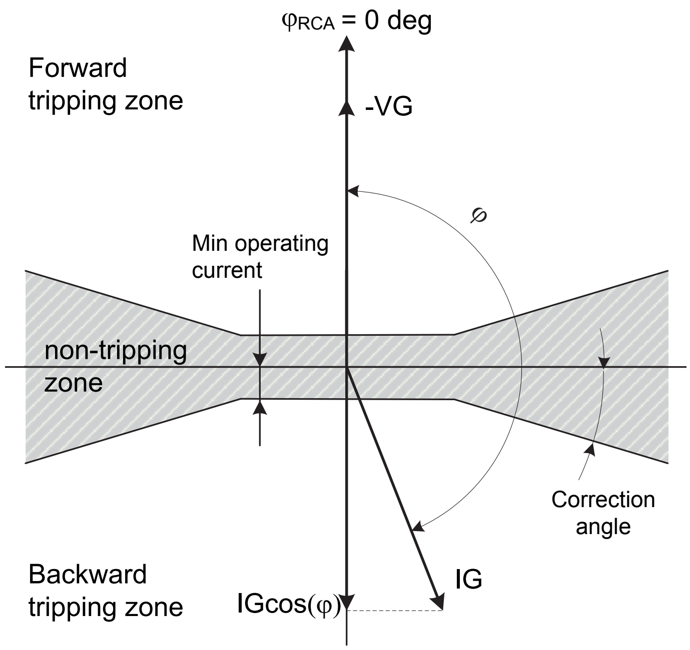


Figure 162: Operating characteristic Iocos(φ) in reverse fault

Phase angle 80

The operation criterion phase angle 80 is selected with the *Operation mode* setting by using the value "Phase angle 80".

Phase angle 80 implements the same functionality as the phase angle but with the following differences:

- The *Max forward angle* and *Max reverse angle* settings cannot be set but they have a fixed value of 80 degrees
- The sector limits of the fixed sectors are rounded.

The sector rounding is used for cancelling the CT measurement errors at low current amplitudes. When the current amplitude falls below three percent of the nominal current, the sector is reduced to 70 degrees at the fixed sector side. This makes the protection more selective, which means that the phase angle measurement errors do not cause faulty operation.

There is no sector rounding on the other side of the sector.

If the current amplitude falls below one percent of the nominal current, the direction enters the non-directional area.

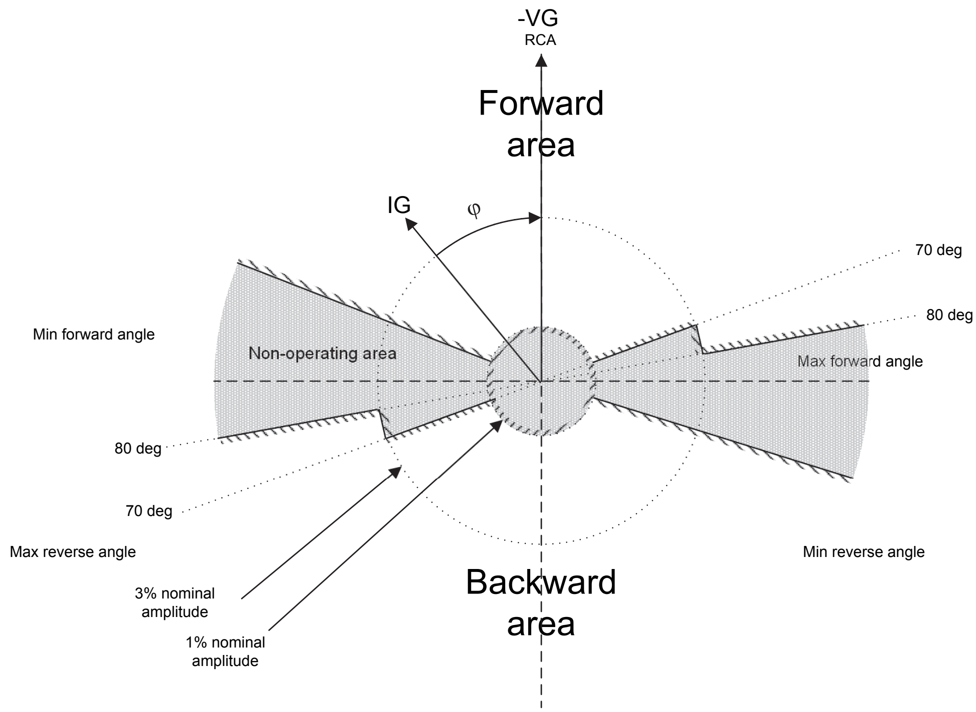


Figure 163: Operating characteristic for phase angle classic 80

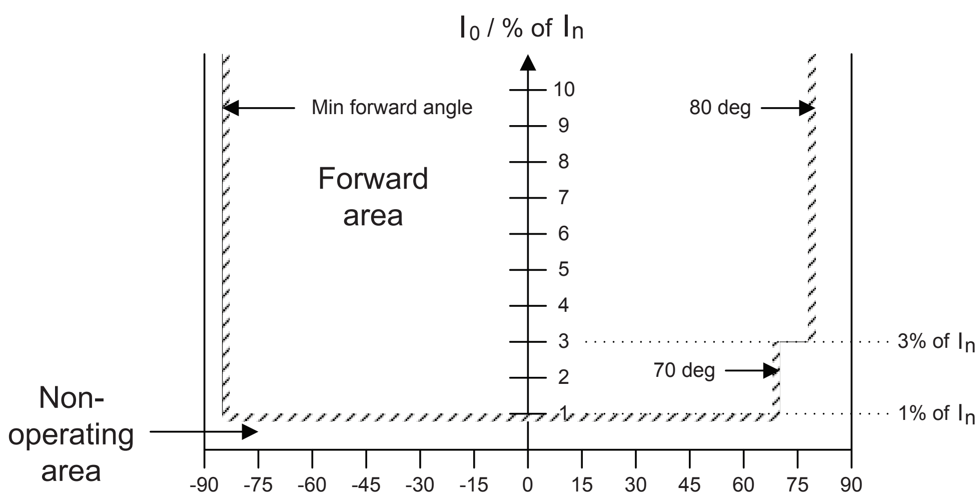


Figure 164: Phase angle classic 80 amplitude

Phase angle 88

The operation criterion phase angle 88 is selected with the *Operation mode* setting using the value "Phase angle 88".

Phase angle 88 implements the same functionality as the phase angle but with the following differences:

- The *Max forward angle* and *Max reverse angle* settings cannot be set but they have a fixed value of 88 degrees
- The sector limits of the fixed sectors are rounded.

Sector rounding in the phase angle 88 consists of three parts:

- If the current amplitude is between 1...20 percent of the nominal current, the sector limit increases linearly from 73 degrees to 85 degrees
- If the current amplitude is between 20...100 percent of the nominal current, the sector limit increases linearly from 85 degrees to 88 degrees
- If the current amplitude is more than 100 percent of the nominal current, the sector limit is 88 degrees.

There is no sector rounding on the other side of the sector.

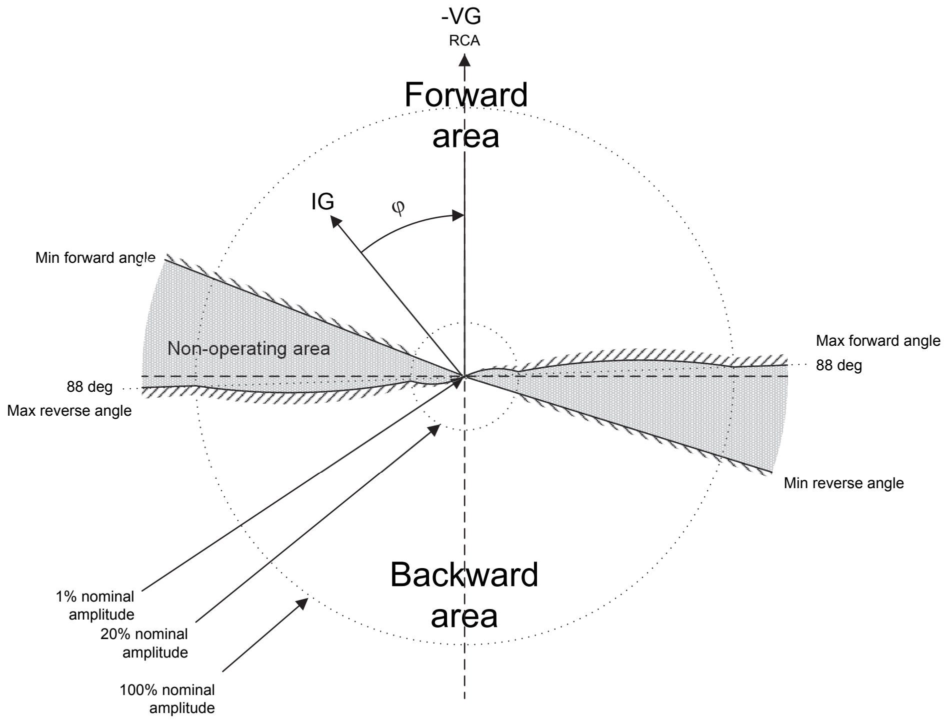


Figure 165: Operating characteristic for phase angle classic 88

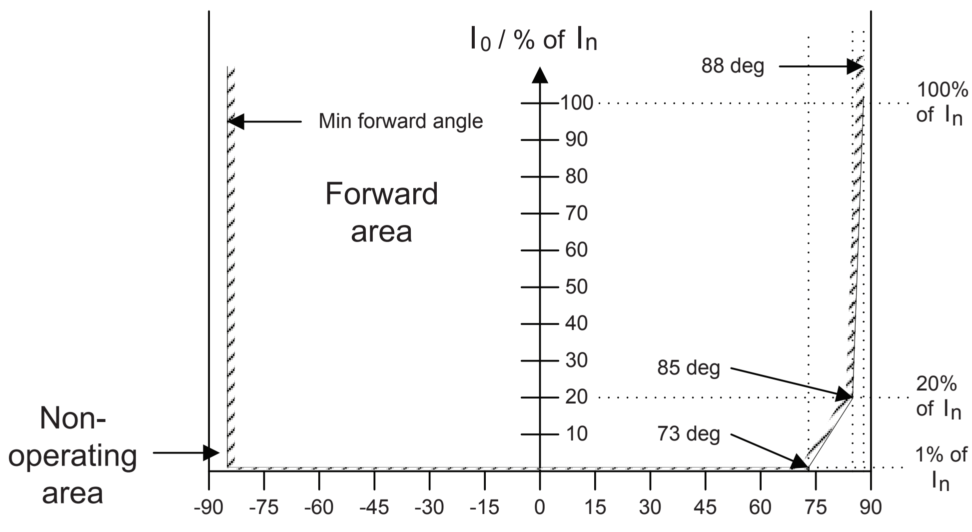


Figure 166: Phase angle classic 88 amplitude

4.2.2.9 Application

The directional ground-fault protection 67/51N, 67/50N is designed for protection and clearance of ground faults and for ground-fault protection of different equipment connected to the power systems, such as shunt capacitor banks or shunt reactors, and for backup ground-fault protection of power transformers.

Many applications require several steps using different current pickup levels and time delays. 67/51N, 67/50N consist of two different stages.

- Low 67/51N
- High 67/50N

67/51N contains several types of time delay characteristics. 67/50N is used for fast clearance of serious ground faults.

The protection can be based on the phase angle criterion with extended operating sector. It can also be based on measuring either the reactive part Iosin(φ) or the active part Iocos(φ) of the residual current. In isolated networks or in networks with high impedance grounding, the phase-to-ground fault current is significantly smaller than the short-circuit currents. In addition, the magnitude of the fault current is almost independent of the fault location in the network.

The function uses the residual current components Iocos(φ) or Iosin(φ) according to the grounding method, where φ is the angle between the residual current and the reference residual voltage (-VG). In compensated networks, the phase angle criterion with extended operating sector can also be used. When the relay characteristic angle RCA is 0 degrees, the negative quadrant of the operation sector can be extended with the *Min forward angle* setting. The operation sector can be set between 0 and -180 degrees, so that the total operation sector is from +90 to -180 degrees. In other words, the sector can be up to 270 degrees wide. This allows the protection settings to stay the same when the resonance coil is disconnected from between the neutral point and ground.

System neutral grounding is meant to protect personnel and equipment and to reduce interference for example in telecommunication systems. The neutral grounding sets challenges for protection systems, especially for ground-fault protection.

In isolated networks, there is no intentional connection between the system neutral point and ground. The only connection is through the line-to-ground capacitances (C_0) of phases and leakage resistances (R_0). This means that the residual current is mainly capacitive and has -90 degrees phase shift compared to the residual voltage (-VG). The characteristic angle is -90 degrees.

In resonance-grounded networks, the capacitive fault current and the inductive resonance coil current compensate each other. The protection cannot be based on the reactive current measurement, since the current of the compensation coil would disturb the operation of the relays. In this case, the selectivity is based on the measurement of the active current component. This means that the residual current is mainly resistive and has zero phase shift compared to the residual voltage (-VG) and the characteristic angle is 0 degrees. Often the magnitude of this component is small, and must be increased by means of a parallel resistor in the compensation equipment.

In networks where the neutral point is grounded through low resistance, the characteristic angle is also 0 degrees (for phase angle). Alternatively, Iocos(φ) operation can be used.

In solidly grounded networks, the *Characteristic angle* is typically set to +60 degrees for the phase angle. Alternatively, Iosin(φ) operation can be used with a reversal polarizing quantity. The polarizing quantity can be rotated 180 degrees by setting the *Pol reversal* parameter to "True" or by switching the polarity of the residual voltage measurement wires. Although the Iosin(φ) operation can be used in solidly grounded networks, the phase angle is recommended.

Connection of measuring transformers in directional ground fault applications

The residual current IG can be measured with a core balance current transformer or the residual connection of the phase current signals. If the neutral of the network is either isolated or grounded with high impedance, a core balance current transformer is recommended to be used in ground-fault protection. To ensure sufficient accuracy of residual current measurements and consequently the selectivity of the scheme, the core balance current transformers should have a transformation ratio of at least 70:1. Lower transformation ratios such as 50:1 or 50:5 are not recommended.

Attention should be paid to make sure the measuring transformers are connected correctly so that 67/51N, 67/50N is able to detect the fault current direction without failure. As directional ground fault uses residual current and residual voltage (-VG), the poles of the measuring transformers must match each other and also the fault current direction. Also the grounding of the cable sheath must be taken into notice when using core balance current transformers. The following figure describes how measuring transformers can be connected to the protection relay.

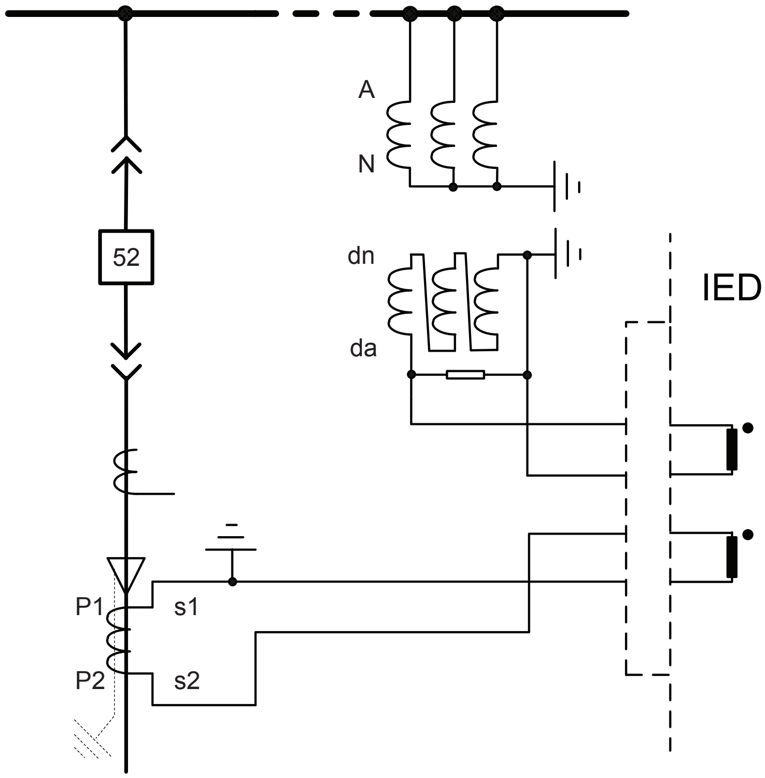


Figure 167: Connection of measuring transformers

4.2.2.10 Signals

Table 353: 67/51N Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
I_2	SIGNAL	0	Negative phase sequence current
U_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier
RCA_CTL	BOOLEAN	0=False	Relay characteristic angle control

Table 354: 67/50N Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
I_2	SIGNAL	0	Negative phase sequence current
U_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier
RCA_CTL	BOOLEAN	0=False	Relay characteristic angle control

Table 355: 67/51N Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 356: 67/50N Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.2.2.11 Settings

Table 357: 67/51N Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.010...5.000	xIn	0.005	0.010	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type
Trip delay time	50...200000	ms	10	50	Trip delay time
Characteristic angle	-179...180	deg	1	-90	Characteristic angle
Max forward angle	0...180	deg	1	80	Maximum phase angle in forward direction
Max reverse angle	0...180	deg	1	80	Maximum phase angle in reverse direction
Min forward angle	0...180	deg	1	80	Minimum phase angle in forward direction
Min reverse angle	0...180	deg	1	80	Minimum phase angle in reverse direction
Voltage pickup value	0.010...1.000	xUn	0.001	0.010	Voltage pickup value

Table 358: 67/51N Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type
Operation mode	1=Phase angle 2=IoSin 3=IoCos 4=Phase angle 80 5=Phase angle 88			1=Phase angle	Operation criteria
Enable voltage limit	0=False 1=True			1=True	Enable voltage limit

Table 359: 67/51N Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 360: 67/51N Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
Minimum trip time	50...60000	ms	1	50	Minimum trip time for IDMT curves
Allow Non Dir	0=False 1=True			0=False	Allows prot activation as non-dir when dir info is invalid
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Min trip current	0.005...1.000	xIn	0.001	0.005	Minimum trip current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum trip voltage
Correction angle	0.0...10.0	deg	0.1	0.0	Angle correction
Pol reversal	0=False 1=True			0=False	Rotate polarizing quantity
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used Uo signal
Pol quantity	3=Zero seq. volt. 4=Neg. seq. volt.			3=Zero seq. volt.	Reference quantity used to determine fault direction

Table 361: 67/50N Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.10...40.00	xIn	0.01	0.10	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Operating curve type	1=ANSI Ext Inv 3=ANSI Norm Inv 5=ANSI DT 15=IEC DT 17=Programmable			15=IEC DT	Selection of time delay curve type
Trip delay time	40...200000	ms	10	40	Trip delay time
Characteristic angle	-179...180	deg	1	-90	Characteristic angle
Max forward angle	0...180	deg	1	80	Maximum phase angle in forward direction
Max reverse angle	0...180	deg	1	80	Maximum phase angle in reverse direction
Min forward angle	0...180	deg	1	80	Minimum phase angle in forward direction
Min reverse angle	0...180	deg	1	80	Minimum phase angle in reverse direction
Voltage pickup value	0.010...1.000	xUn	0.001	0.010	Voltage pickup value

Table 362: 67/50N Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type
Operation mode	1=Phase angle 2=IoSin 3=IoCos 4=Phase angle 80 5=Phase angle 88			1=Phase angle	Operation criteria
Enable voltage limit	0=False 1=True			1=True	Enable voltage limit

Table 363: 67/50N Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 364: 67/50N Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
Minimum trip time	40...60000	ms	1	40	Minimum trip time for IDMT curves
Allow Non Dir	0=False 1=True			0=False	Allows prot activation as non-dir when dir info is invalid
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Min trip current	0.005...1.000	xIn	0.001	0.005	Minimum trip current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum trip voltage
Correction angle	0.0...10.0	deg	0.1	0.0	Angle correction
Pol reversal	0=False 1=True			0=False	Rotate polarizing quantity
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used Uo signal
Pol quantity	3=Zero seq. volt. 4=Neg. seq. volt.			3=Zero seq. volt.	Reference quantity used to determine fault direction

4.2.2.12 Monitored data

Table 365: 67/51N Monitored data

Name	Type	Values (Range)	Unit	Description
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information

Table continues on next page

Name	Type	Values (Range)	Unit	Description
ANGLE_RCA	FLOAT32	-180.00...180.00	deg	Angle between polarizing and operating quantity
ANGLE	FLOAT32	-180.00...180.00	deg	Angle between operating angle and characteristic angle
I_OPER	FLOAT32	0.00...40.00	xIn	Calculated operating current
67/51N	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 366: 67/50N Monitored data

Name	Type	Values (Range)	Unit	Description
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information
ANGLE_RCA	FLOAT32	-180.00...180.00	deg	Angle between polarizing and operating quantity
ANGLE	FLOAT32	-180.00...180.00	deg	Angle between operating angle and characteristic angle
I_OPER	FLOAT32	0.00...40.00	xIn	Calculated operating current
67/50N	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.2.13 Technical data

Table 367: 67/51N, 67/50N Technical data

Characteristic		Value		
Operation accuracy	67/51N	Depending on the frequency of the measured current: f_n ±2 Hz		
		Current: ±1.5% of the set value or ±0.002 × I_n Voltage ±1.5% of the set value or ±0.002 × V_n Phase angle: ±2°		
	67/50N	Current: ±1.5% of the set value or ±0.002 × I_n (at currents in the range of 0.1…10 × I_n) ±5.0% of the set value (at currents in the range of 10…40 × I_n) Voltage: ±1.5% of the set value or ±0.002 × V_n Phase angle: ±2°		
Pickup time 1)2)		Minimum	Typical	Maximum
	67/50N I_{Fault} = 2 × set *Pickup value*	42 ms	46 ms	49 ms
	67/51N I_{Fault} = 2 × set *Pickup value*	58 ms	62 ms	66 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<30 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode		±5.0% of the theoretical value or ±20 ms 3)		
Suppression of harmonics		RMS: No suppression DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,… Peak-to-Peak: No suppression		

1) *Measurement mode* = default (depends on stage), current before fault = 0.0 × I_n, f_n = 50 Hz, ground-fault current with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 2.5 × I_n, *Pickup value* multiples in range of 1.5...20

4.2.2.14 Technical revision history

Table 368: 67/50N Technical revision history

Technical revision	Change
B	Maximum value changed to 180 deg for the *Max forward angle* setting
C	Added a setting parameter for the "Measured IG" or "Calculated I0" selection and setting parameter for the "Measured VG", "Calculated V0" or "Neg. seq. volt." selection for polarization. *Trip delay time* and *Minimum trip time* changed from 60 ms to 40 ms. The sector default setting values are changed from 88 degrees to 80 degrees.
D	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
E	Unit added to calculated operating current output (I_OPER).
F	Added setting *Pol quantity*.

Table 369: 67/51N Technical revision history

Technical revision	Change
B	Maximum value changed to 180 deg for the *Max forward angle* setting. *Pickup value* step changed to 0.005
C	Added a setting parameter for the "Measured IG" or "Calculated I0" selection and setting parameter for the "Measured VG", "Calculated V0" or "Neg. seq. volt." selection for polarization. The sector default setting values are changed from 88 degrees to 80 degrees.
D	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
E	Unit added to calculated operating current output (I_OPER).
F	Added setting *Pol quantity*. Minimum value for *Trip delay time* and *Minimum trip time* changed from “60 ms” to “50 ms”. Default value for *Trip delay time* and *Minimum trip time* changed from “60 ms” to “50 ms”.

4.2.3 Transient/intermittent ground-fault protection 67NIEF

4.2.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Transient/intermittent ground-fault protection	INTRPTEF	Io> -> IEF	67NIEF

4.2.3.2 Function block

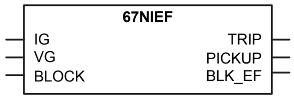


Figure 168: Function block

4.2.3.3 Functionality

The transient/intermittent ground-fault protection function 67NIEF is a function designed for the protection and clearance of permanent and intermittent ground faults in distribution and sub-transmission networks. Fault detection is done from the residual current and residual voltage signals by monitoring the transients.

The operating time characteristics are according to definite time (DT).

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.2.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 67NIEF can be described with a module diagram. All the modules in the diagram are explained in the next sections.

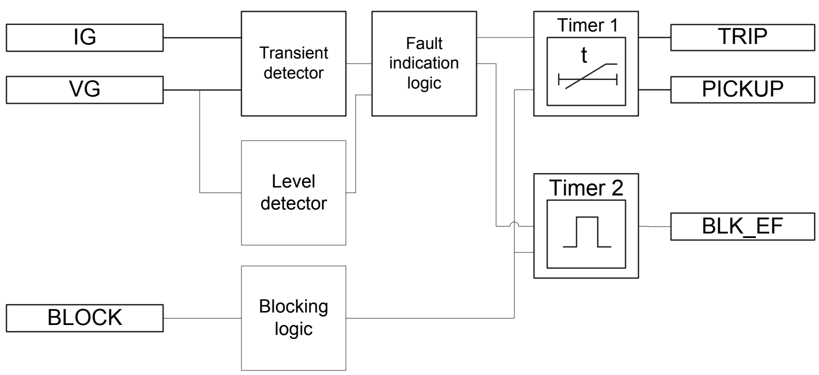


Figure 169: Functional module diagram

Level detector

The residual voltage can be selected from the *Vg or V0* setting. The options are "Measured VG" and "Calculated V0". If "Measured VG" is selected, the voltage ratio for VG-channel is given in the global setting **Configuration/Analog inputs/Voltage (VG,VT)**. If "Calculated V0" is selected, the voltage ratio is obtained from phase-voltage channels given in the global setting **Configuration/Analog inputs/Voltage (3V,VT)**.

Example 1: VG is measured from open-delta connected VTs (20/sqrt(3) kV : 100/sqrt(3) V : 100/3 V). In this case, "Measured VG" is selected. The nominal values for residual voltage is obtained from VT ratios entered in Residual voltage VG: **Configuration/ Analog inputs/Voltage (VG,VT)**: 11.547 kV :100 V. The residual voltage start value of 1.0 × Vn corresponds to 1.0 × 11.547 kV = 11.547 kV in the primary.

Example 2: V0 is calculated from phase quantities. The phase VT-ratio is 20/sqrt(3) kV : 100/sqrt(3) V. In this case, "Calculated V0" is selected. The nominal values for residual current and residual voltage are obtained from VT ratios entered in Residual voltage V0: **Configuration/Analog inputs/Voltage (3V,VT)**: 20.000 kV : 100 V. The residual voltage start value of 1.0 × Vn corresponds to 1.0 × 20.000 kV = 20.000 kV in the primary.

If "Calculated V0" is selected, the residual voltage nominal value is always phase-to-phase voltage. Thus, the valid maximum setting for residual voltage pickup value is 0.577 × Vn. Calculated V0 requires that all three phase-to-ground voltages are connected to the protection relay. V0 cannot be calculated from the phase-to-phase voltages.

Transient detector

The Transient detector module is used for detecting transients in the residual current and residual voltage signals.

The transient detection is supervised with a settable current threshold. With a special filtering technique, the setting *Min trip current* is based on the fundamental frequency current. This setting should be set based on the value of the parallel resistor of the coil, with security margin. For example, if the resistive current of the parallel resistor is 10 A, then a value of 0.7×10 A = 7 A could be used. The same setting is also applicable in case the coil is disconnected and the network becomes ungrounded. Generally, a smaller value should be used and it must never exceed the value of the parallel resistor in order to allow operation of the faulted feeder.

Fault indication logic

Depending on the set *Operation mode*, 67NIEF has two independent modes for detecting ground faults. The "Transient EF" mode is intended to detect all kinds of ground faults. The "Intermittent EF" mode is dedicated for detecting intermittent ground faults in cable networks.

To satisfy the sensitivity requirements, basic ground-fault protection (based on fundamental frequency phasors) should always be used in parallel with the 67NIEF function.

The Fault indication logic module determines the direction of the fault. The fault direction determination is secured by multi-frequency neutral admittance measurement and special filtering techniques. This enables fault direction determination which is not sensitive to disturbances in measured IG and VG signals, for example, switching transients.

When *Directional mode* setting "Forward" is used, the protection operates when the fault is in the protected feeder. When *Directional mode* setting "Reverse" is used, the protection operates when the fault is outside the protected feeder (in the background network). If the direction has no importance, the value "Non-directional" can be selected. The detected fault direction (FAULT_DIR) is available in the monitored data view.

In the "Transient EF" mode, when the start transient of the fault is detected and the VG level exceeds the set *Voltage start value*, Timer 1 is activated. Timer 1 is kept activated until the VG level exceeds the set value or in case of a drop-off, the drop-off duration is shorter than the set *Reset delay time*.

In the "Intermittent EF" mode, when the start transient of the fault is detected and the VG level exceeds the set *Voltage pickup value*, the Timer 1 is activated. When a required number of intermittent ground-fault transients set with the *Peak counter limit* setting are detected without the function being reset (depends on the drop-off time set with the *Reset delay time* setting), the `PICKUP` output is activated. The Timer 1 is kept activated as long as transients are occurring during the drop-off time defined by setting *Reset delay time*.

Timer 1

The time characteristic is according to DT.

In the "Transient EF" mode, the `TRIP` output is activated after *Trip delay time* if the residual voltage exceeds the set *Voltage pickup value*. The *Reset delay time* starts to elapse when residual voltage falls below *Voltage pickup value*. If there is no `TRIP` activation, for example, the fault disappears momentarily, `PICKUP` stays activated until the the *Reset delay time* elapses. After `TRIP` activation, `PICKUP` and `TRIP` signals are reset as soon as VG falls below *Voltage pickup value*.

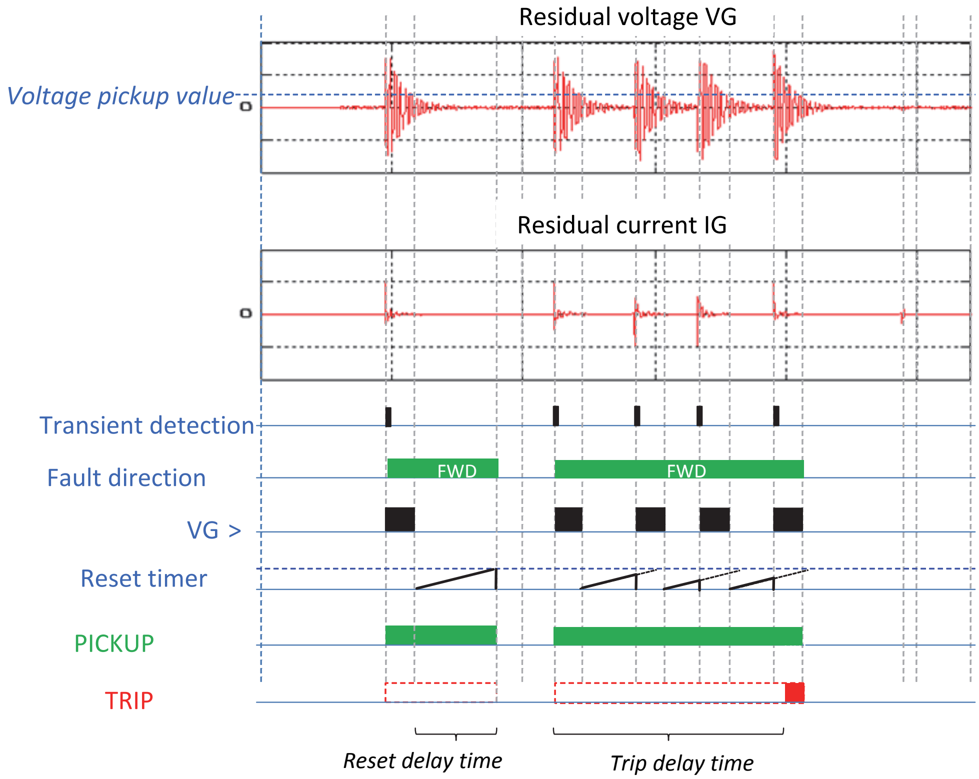


Figure 170: Example of 67NIEF operation in "Transient EF" mode in the faulty feeder

In the "Intermittent EF" mode the `TRIP` output is activated when the following conditions are fulfilled:

- the number of transients that have been detected exceeds the *Peak counter limit* setting
- the timer has reached the time set with the *Trip delay time*
- and one additional transient is detected during the drop-off cycle

The *Reset delay time* starts to elapse from each detected transient (peak). In case there is no `TRIP` activation, for example, the fault disappears momentarily `PICKUP` stays activated until the *Reset delay time* elapses, that is, reset takes place if time between transients is more than *Reset delay time*. After `TRIP` activation, a fixed pulse length of 100 ms for `TRIP` is given, whereas `PICKUP` is reset after *Reset delay time* elapses

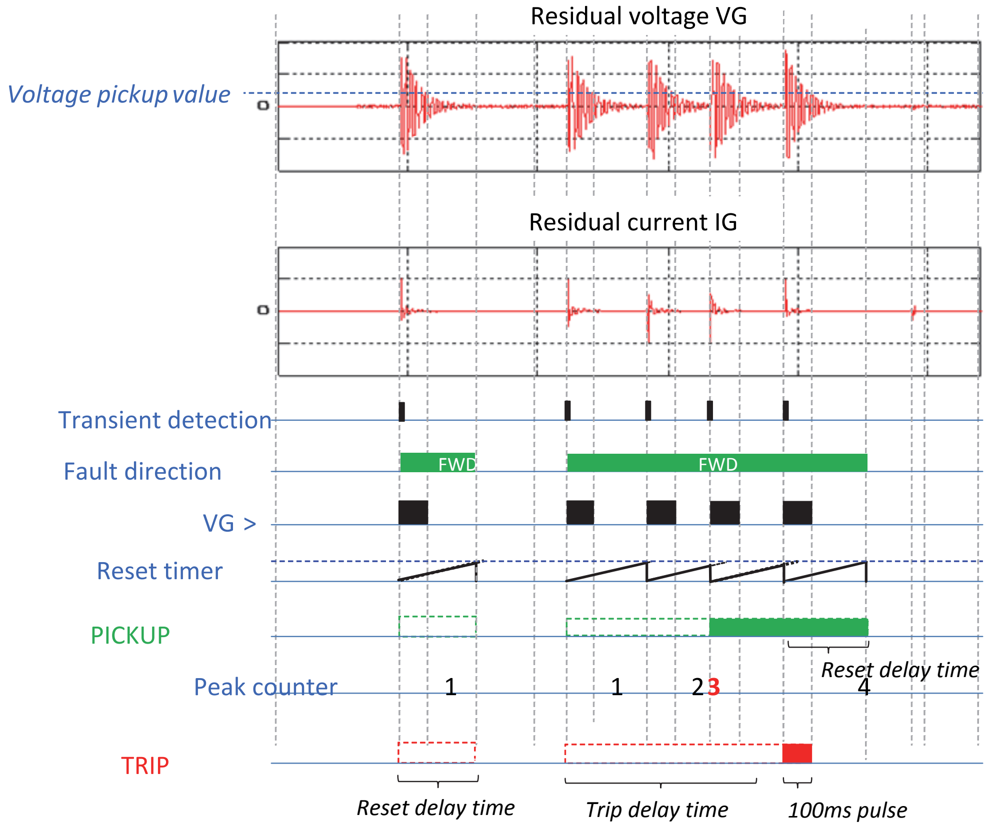


Figure 171: Example of 67NIEF operation in "Intermittent EF" mode in the faulty feeder, Peak counter limit=3

The timer calculates the pickup duration value PICKUP_DUR which indicates the percentage ratio of the start situation and the set operating time. The value is available in the monitored data view.

Timer 2

If the function is used in the directional mode and an opposite direction transient is detected, the `BLK_EF` output is activated for the fixed delay time of 25 ms. If the `PICKUP` output is activated when the `BLK_EF` output is active, the `BLK_EF` output is deactivated.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.2.3.5 Application

67NIEF is a ground-fault function dedicated to operate in intermittent and permanent ground faults occurring in distribution and sub-transmission networks. Fault detection is done from the residual current and residual voltage signals by monitoring the transients with predefined criteria. As the function has a dedicated purpose for the fault types, fast detection and clearance of the faults can be achieved.

Intermittent ground fault

Intermittent ground fault is a special type of fault that is encountered especially in compensated networks with underground cables. A typical reason for this type of fault is the deterioration of cable insulation either due to mechanical stress or due to insulation material aging process where water or moisture gradually penetrates the cable insulation. This eventually reduces the voltage withstand of the insulation, leading to a series of cable insulation breakdowns. The fault is initiated as the phase-to-ground voltage exceeds the reduced insulation level of the fault point and mostly extinguishes itself as the fault current drops to zero for the first time, as shown in Figure 172. As a result, very short transients, that is, rapid changes in the form of spikes in residual current (IG) and in residual voltage (VG), can be repeatedly measured. Typically, the fault resistance in case of an intermittent ground fault is only a few ohms.

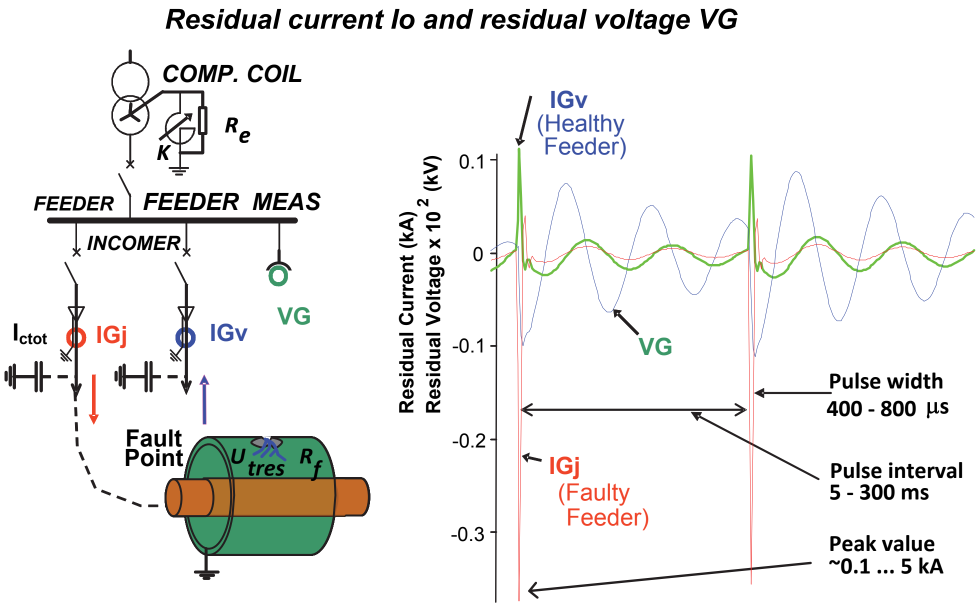


Figure 172: Typical intermittent ground-fault characteristics

Ground-fault transients

In general, ground faults generate transients in currents and voltages. There are several factors that affect the magnitude and frequency of these transients, such as the fault moment on the voltage wave, fault location, fault resistance and the parameters of the feeders and the supplying transformers. In the fault initiation, the voltage of the faulty phase decreases and the corresponding capacitance is discharged to ground (→ discharge transients). At the same time, the voltages of the healthy phases increase and the related capacitances are charged (→ charge transient).

If the fault is permanent (non-transient) in nature, only the initial fault transient in current and voltage can be measured, whereas the intermittent fault creates repetitive transients.

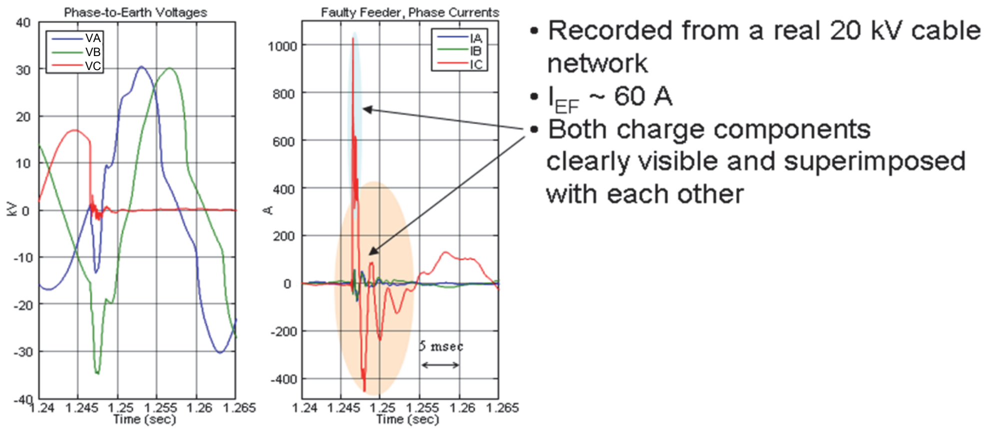


Figure 173: Example of ground-fault transients, including discharge and charge transient components, when a permanent fault occurs in a 20 kV network in phase C

4.2.3.6 Signals

Table 370: 67NIEF Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 371: 67NIEF Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
BLK_EF	BOOLEAN	Block signal for EF to indicate opposite direction peaks

4.2.3.7 Settings

Table 372: 67NIEF Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode, Non-directional / Forward / Reverse
Trip delay time	40...1200000	ms	10	500	Trip delay time
Voltage pickup value	0.05...0.50	xUn	0.01	0.20	Voltage pickup value for transient EF

Table 373: 67NIEF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=Intermittent EF 2=Transient EF			1=Intermittent EF	Operation criteria
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used Uo signal

Table 374: 67NIEF Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	40...60000	ms	1	500	Reset delay time
Peak counter limit	2...20		1	2	Min requirement for peak counter before pickup in IEF mode
Min trip current	0.01...1.00	xIn	0.01	0.01	Minimum operating current for transient detector

4.2.3.8 Monitored data

Table 375: 67NIEF Monitored data

Name	Type	Values (Range)	Unit	Description
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
67NIEF	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.3.9 Technical data

Table 376: 67NIEF Technical data

Characteristic	Value
Operation accuracy (VG criteria with transient protection)	Depending on the frequency of the measured current: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × VG
Trip time accuracy	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5

4.2.3.10 Technical revision history

Table 377: 67NIEF Technical revision history

Technical revision	Change
B	Minimum and default values changed to 40 ms for the *Trip delay time* setting
C	The *Minimum trip current* setting is added. Correction in IEC 61850 mapping: DO BlkEF renamed to InhEF. Minimum value changed from 0.01 to 0.10 (default changed from 0.01 to 0.20) for the *Voltage pickup value* setting. Minimum value changed from 0 ms to 40 ms for the *Reset delay time* setting.
D	Voltage pickup value description changed from "Voltage pickup value for transient EF" to "Voltage pickup value" since the pickup value is effective in both operation modes. Added support for calculated V0. Vg or V0 source (measured/calculated) can be selected with "Vg or V0". *Voltage pickup value* setting minimum changed from 0.10 to 0.05.
E	*Min trip current* setting scaling corrected to RMS level from peak level.

4.2.4 Admittance-based ground-fault protection 21YN

4.2.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Admittance-based ground-fault protection	EFPADM	Yo> ->	21YN

4.2.4.2 Function block

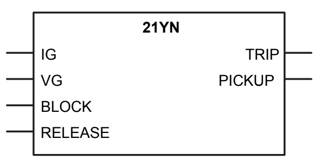


Figure 174: Function block

4.2.4.3 Functionality

The admittance-based ground-fault protection function 21YN provides a selective ground-fault protection function for high-resistance grounded, ungrounded and compensated networks. It can be applied for the protection of overhead lines as well as with underground cables. It can be used as an alternative solution to traditional residual current-based ground-fault protection functions, such as the IoCos mode in 67/51N, 67/50N. Main advantages of 21YN include a versatile applicability, good sensitivity and easy setting principles.

21YN is based on evaluating the neutral admittance of the network, that is, the quotient:

$$\underline{Y}o = \underline{IG} / -\underline{VG}$$

(Equation 23)

The measured admittance is compared to the admittance characteristic boundaries in the admittance plane. The supported characteristics include overadmittance, oversusceptance, overconductance or any combination of the three. The directionality of the oversusceptance and overconductance criteria can be defined as forward, reverse or non-directional, and the boundary lines can be tilted if required by the application. This allows the optimization of the shape of the admittance characteristics for any given application.

The function supports two calculation algorithms for admittance. The admittance calculation can be set to include or exclude the prefault zero-sequence values of IG and VG. Furthermore, the calculated admittance is recorded at the time of the trip and it can be monitored for post-fault analysis purposes.

To ensure the security of the protection, the admittance calculation is supervised by a residual overvoltage condition which releases the admittance protection during a fault condition. Alternatively, the release signal can be provided by an external binary signal.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.2.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 21YN can be described using a module diagram. All the modules in the diagram are explained in the next sections.

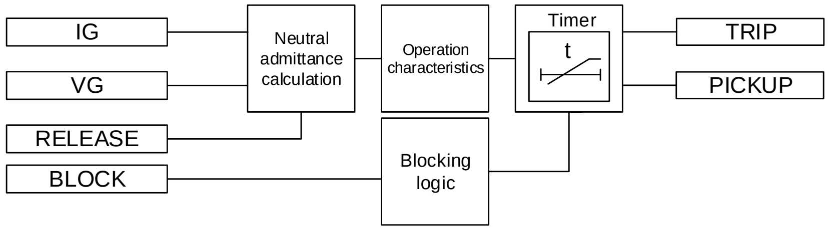


Figure 175: Functional module diagram

Neutral admittance calculation

The residual current can be selected from the *IG or I0* setting. The setting options are "Measured IG" and "Calculated I0". If "Measured IG" is selected, the current ratio for IG-channel is given in **Configuration/Analog inputs/Current (IG,CT)**. If "Calculated I0" is selected, the current ratio is obtained from phase-current channels given in **Configuration/Analog inputs/Current (3I,CT)**.

Respectively, the residual voltage can be selected from the *Vg or V0* setting. The setting options are "Measured VG" and "Calculated V0". If "Measured VG" is selected, the voltage ratio for VG-channel is given in **Configuration/Analog inputs/Voltage (VG,VT)**. If "Calculated V0" is selected, the voltage ratio is obtained from phase-voltage channels given in **Configuration/Analog inputs/Voltage (3V,VT)**.

Example 1: VG is measured from open-delta connected VTs (20/sqrt(3) kV : 100/sqrt(3) V:100/3 V). In this case, "Measured VG" is selected. The nominal values for residual voltage is obtained from the VT ratios entered in Residual voltage VG: **Configuration/ Analog inputs/Voltage (VG,VT)**: 11.547 kV : 100 V. The residual voltage pickup value of 1.0 × Vn corresponds to 1.0 × 11.547 kV = 11.547 kV in the primary.

Example 2: V0 is calculated from phase quantities. The phase VT-ratio is 20/sqrt(3) kV : 100/sqrt(3) V. In this case, "Calculated V0" is selected. The nominal value for residual voltage is obtained from the VT ratios entered in Residual voltage V0 : **Configuration/ Analog inputs/Voltage (3V,VT)** : 20.000kV : 100V. The residual voltage pickup value of 1.0 × Vn corresponds to 1.0 × 20.000 kV = 20.000 kV in the primary.

In case, if "Calculated V0" is selected, the residual voltage nominal value is always phase-to-phase voltage. Thus, the valid maximum setting for residual voltage pickup value is 0.577 × Vn. The calculated V0 requires that all three phase-to-ground voltages are connected to the protection relay. V0 cannot be calculated from the phase-to-phase voltages.

When the residual voltage exceeds the set threshold *Voltage pickup value*, a ground fault is detected and the neutral admittance calculation is released.

To ensure a sufficient accuracy for the IG and VG measurements, it is required that the residual voltage exceeds the value set by *Min trip voltage*. If the admittance calculation mode is "Delta", the minimum change in the residual voltage due to a fault must be 0.01 × Vn to enable the operation. Similarly, the residual current must exceed the value set by *Min trip current*.

The polarity of the polarizing quantity VG can be changed, that is, rotated by 180 degrees, by setting the *Pol reversal* parameter to "True" or by switching the polarity of the residual voltage measurement wires.

As an alternative for the internal residual overvoltage-based pickup condition, the neutral admittance protection can also be externally released by utilizing the `RELEASE` input.

When *Admittance Clc mode* is set to "Delta", the external logic used must be able to give RELEASE in less than 0.1 s from fault initiation. Otherwise the collected pre-fault values are overwritten with fault time values. If it is slower, *Admittance Clc mode* must be set to “Normal”.

Neutral admittance is calculated as the quotient between the residual current and residual voltage (polarity reversed) fundamental frequency phasors. The *Admittance Clc mode* setting defines the calculation mode.

Admittance Clc mode = "Normal"

$$\underline{Yo} = \frac{\underline{IG}_{fault}}{-\underline{VG}_{fault}}$$

(Equation 24)

Admittance Clc mode = "Delta"

$$\underline{Yo} = \frac{\underline{IG}_{fault} - \underline{IG}_{prefault}}{-(\underline{VG}_{fault} - \underline{VG}_{prefault})} = \frac{\Delta \underline{IG}}{-\Delta \underline{VG}}$$

(Equation 25)

$\underline{Yo}$	Calculated neutral admittance [Siemens]
$\underline{IG}_{fault}$	Residual current during the fault [Amperes]
$\underline{VG}_{fault}$	Residual voltage during the fault [Volts]
$\underline{IG}_{prefault}$	Prefault residual current [Amperes]
$\underline{VG}_{prefault}$	Prefault residual voltage [Volts]
$\Delta\underline{IG}$	Change in the residual current due to fault [Amperes]
$\Delta\underline{VG}$	Change in the residual voltage due to fault [Volts]

Traditionally, admittance calculation is done with the calculation mode "Normal", that is, with the current and voltage values directly measured during the fault. As an alternative, by selecting the calculation mode "Delta", the prefault zero-sequence asymmetry of the network can be removed from the admittance calculation. Theoretically, this makes the admittance calculation totally immune to fault resistance, that is, the estimated admittance value is not affected by fault resistance. Utilization of the change in VG and IG due to a fault in the admittance calculation also mitigates the effects of the VT and CT measurement errors, thus improving the measuring accuracy, the sensitivity and the selectivity of the protection.

Calculation mode "Delta" is recommended in case a high sensitivity of the protection is required, if the network has a high degree of asymmetry during the healthy state or if the residual current measurement is based on sum connection, that is, the Holmgren connection.

Neutral admittance calculation produces certain values during forward and reverse faults.

Fault in reverse direction, that is, outside the protected feeder.

$$\underline{Y}o = -\underline{Y}_{Fdtot}$$

(Equation 26)

$$\approx -j \cdot \frac{I_{gFd}}{V_{ph}}$$

(Equation 27)

$\underline{Y}_{Fdtot}$	Sum of the phase-to-ground admittances ($\underline{Y}_{FdA}$, $\underline{Y}_{FdB}$, $\underline{Y}_{FdC}$) of the protected feeder
I_{gFd}	Magnitude of the ground-fault current of the protected feeder when the fault resistance is zero ohm
V_{ph}	Magnitude of the nominal phase-to-ground voltage of the system

Equation 26 shows that in case of outside faults, the measured admittance equals the admittance of the protected feeder with a negative sign. The measured admittance is dominantly reactive; the small resistive part of the measured admittance is due to the leakage losses of the feeder. Theoretically, the measured admittance is located in the third quadrant in the admittance plane close to the im($\underline{Y}$o) axis, see Figure 176.

The result of Equation 26 is valid regardless of the neutral grounding method. In compensated networks the compensation degree does not affect the result. This enables a straightforward setting principle for the neutral admittance protection: admittance characteristic is set to cover the value $\underline{Y}o = -\underline{Y}_{Fdtot}$ with a suitable margin.

Due to inaccuracies in voltage and current measurement, the small real part of the calculated neutral admittance may appear as positive, which brings the measured admittance in the fourth quadrant in the admittance plane. This should be considered when setting the admittance characteristic.

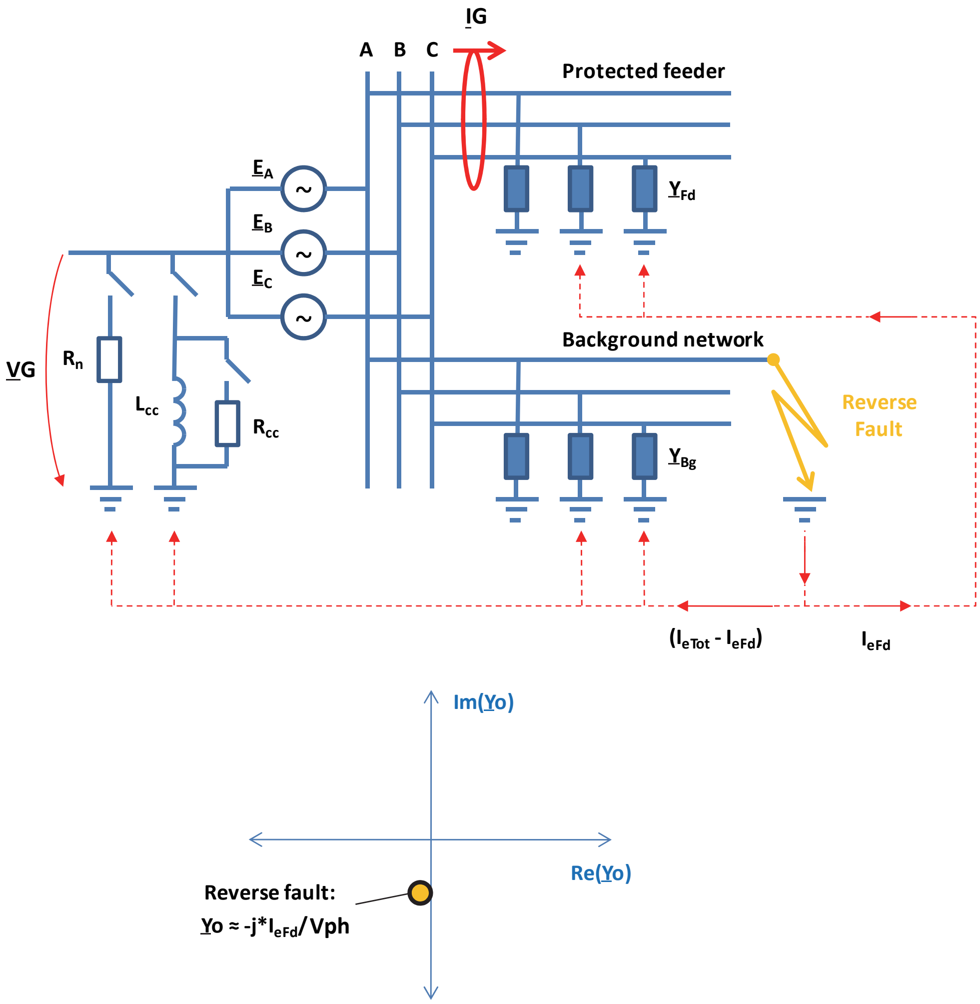


Figure 176: Admittance calculation during a reverse fault

R_{CC}	Resistance of the parallel resistor
L_{CC}	Inductance of the compensation coil
R_n	Resistance of the neutral grounding resistor
$\underline{Y}_{Fd}$	Phase-to-ground admittance of the protected feeder
$\underline{Y}_{Bg}$	Phase-to-ground admittance of the background network

For example, in a 15 kV compensated network with the magnitude of the ground-fault current in the protected feeder being 10 A (Rf = 0 Ω), the theoretical value for the measured admittance during a ground fault in the reverse direction, that is, outside the protected feeder, can be calculated.

$$\underline{Y}o \approx -j \cdot \frac{I_{gFd}}{V_{ph}} = -j \cdot \frac{10A}{15/\sqrt{3}kV} = -j \cdot 1.15 \ milliSiemens$$

(Equation 28)

The result is valid regardless of the neutral grounding method.

In this case, the resistive part of the measured admittance is due to leakage losses of the protected feeder. As they are typically very small, the resistive part is close to zero. Due to inaccuracies in the voltage and current measurement, the small real part of the apparent neutral admittance may appear positive. This should be considered in the setting of the admittance characteristic.

Fault in the forward direction, that is, inside the protected feeder.

Ungrounded network:

$$\underline{Y}o = \underline{Y}_{Bgtot}$$

(Equation 29)

$$\approx j \cdot \left(\frac{I_{gTot} - I_{gFd}}{V_{ph}} \right)$$

(Equation 30)

Compensated network:

$$\underline{Y}o = \underline{Y}_{Bgtot} + \underline{Y}_{CC}$$

(Equation 31)

$$\approx \frac{I_{Rcc} + j \cdot \left(I_{gTot} \cdot (1-K) - I_{gFd} \right)}{V_{ph}}$$

(Equation 32)

High-resistance grounded network:

$$\underline{Y}o = \underline{Y}_{Bgtot} + \underline{Y}_{Rn}$$

(Equation 33)

$$\approx \frac{I_{Rn} + j \cdot \left(I_{gTot} - I_{gFd} \right)}{V_{ph}}$$

(Equation 34)

$\underline{Y}_{Bgtot}$	Sum of the phase-to-ground admittances ($\underline{Y}_{BgA}$, $\underline{Y}_{BgB}$, $\underline{Y}_{BgC}$) of the background network
$\underline{Y}_{CC}$	Admittance of the grounding arrangement (compensation coil and parallel resistor)
I_{Rcc}	Rated current of the parallel resistor
I_{gFd}	Magnitude of the ground-fault current of the protected feeder when the fault resistance is zero ohm
I_{gTot}	Magnitude of the uncompensated ground-fault current of the network when Rf is zero ohm
K	Compensation degree, K = 1 full resonance, K<1 undercompensated, K>1 overcompensated
I_{Rn}	Rated current of the neutral grounding resistor

Equation 29 shows that in case of a fault inside the protected feeder in ungrounded networks, the measured admittance equals the admittance of the background network. The admittance is dominantly reactive; the small resistive part of the measured admittance is due to the leakage losses of the background network. Theoretically, the measured admittance is located in the first quadrant in the admittance plane, close to the im(Yo) axis, see Figure 177.

Equation 31 shows that in case of a fault inside the protected feeder in compensated networks, the measured admittance equals the admittance of the background network and the coil including the parallel resistor. Basically, the compensation degree determines the imaginary part of the measured admittance and the resistive part is due to the parallel resistor of the coil and the leakage losses of the background network and the losses of the coil. Theoretically, the measured admittance is located in the first or fourth quadrant in the admittance plane, depending on the compensation degree, see Figure 177.

Before the parallel resistor is connected, the resistive part of the measured admittance is due to the leakage losses of the background network and the losses of the coil. As they are typically small, the resistive part may not be sufficiently large to secure the discrimination of the fault and its direction based on the measured conductance. This and the rating and the operation logic of the parallel resistor should be considered when setting the admittance characteristic in compensated networks.

Equation 33 shows that in case of a fault inside the protected feeder in high-resistance grounded systems, the measured admittance equals the admittance of the background network and the neutral grounding resistor. Basically, the imaginary part of the measured admittance is due to the phase-to-ground capacitances of the background network, and the resistive part is due to the neutral grounding resistor and the leakage losses of the background network. Theoretically, the measured admittance is located in the first quadrant in the admittance plane, see Figure 177.

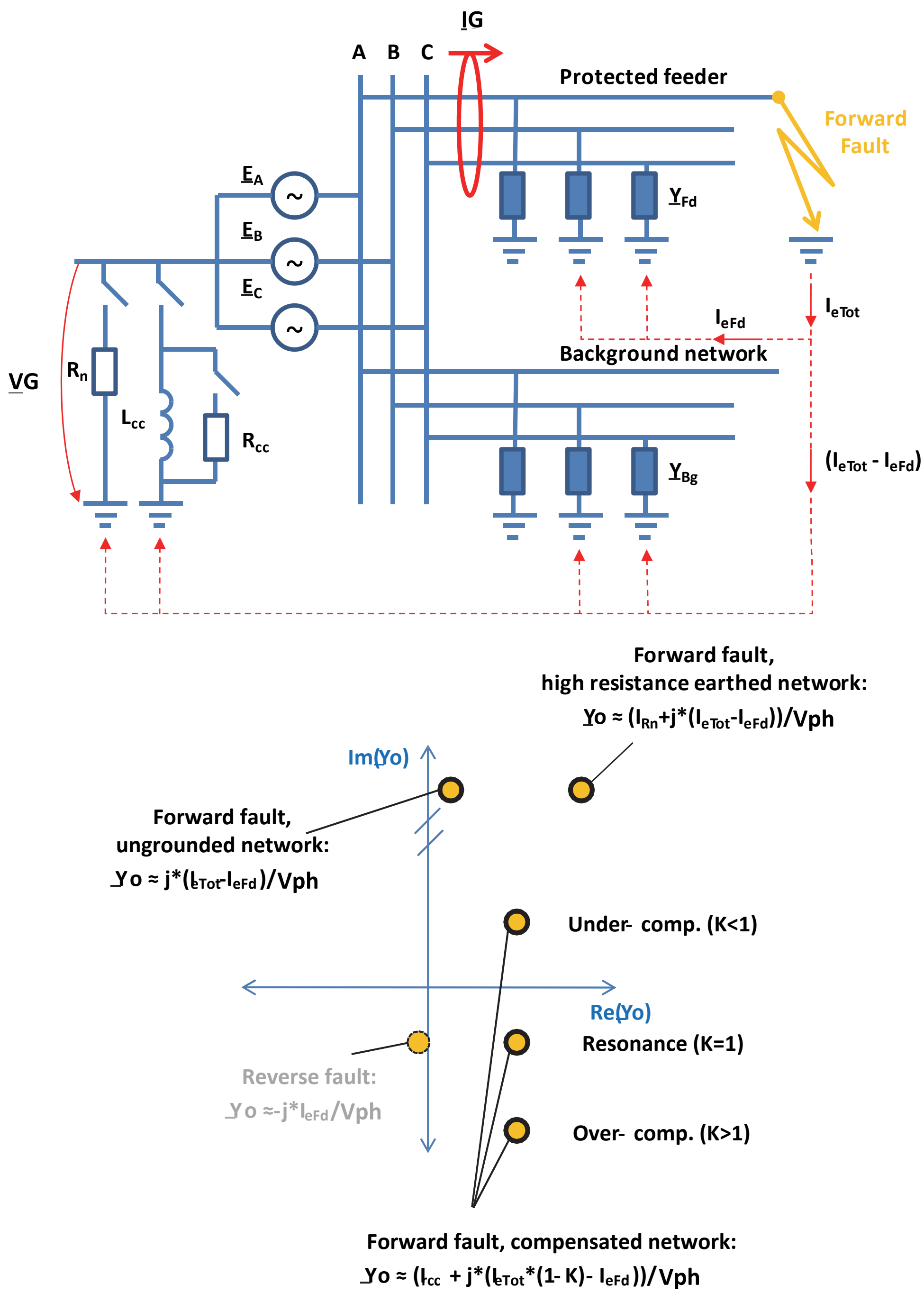


Figure 177: Admittance calculation during a forward fault

When the network is fully compensated in compensated networks, theoretically during a forward fault, the imaginary part of the measured admittance equals the susceptance of the protected feeder with a negative sign. The discrimination between a forward and reverse fault must therefore be based on the real part of the measured admittance, that is, conductance. Thus, the best selectivity is achieved when the compensated network is operated either in the undercompensated or overcompensated mode.

For example, in a 15 kV compensated network, the magnitude of the ground-fault current of the protected feeder is 10 A (Rf = 0 Ω) and the magnitude of the network is 100 A (Rf = 0 Ω). During a ground fault, a 15 A resistor is connected in parallel to the coil after a 1.0 second delay. Compensation degree is overcompensated, K = 1.1.

During a ground fault in the forward direction, that is, inside the protected feeder, the theoretical value for the measured admittance after the connection of the parallel resistor can be calculated.

$$\underline{Yo} \approx \frac{I_{Rcc} + j \cdot \left(I_{gTot} \cdot (1-K) - I_{gFd} \right)}{V_{ph}}$$
$$= \frac{15A + j \cdot \left(100A \cdot (1-1.1) - 10A \right)}{15kV / \sqrt{3}} \approx (1.73 - j \cdot 2.31) \ milliSiemens$$

(Equation 35)

Before the parallel resistor is connected, the resistive part of the measured admittance is due to the leakage losses of the background network and the losses of the coil. As they are typically small, the resistive part may not be sufficiently large to secure the discrimination of the fault and its direction based on the measured conductance. This and the rating and the operation logic of the parallel resistor should be considered when setting the admittance characteristic.

When a high sensitivity of the protection is required, the residual current should be measured with a cable/ring core CT, that is, the Ferranti CT. Also the use of the sensitive `IG` input should be considered. The residual voltage measurement should be done with an open delta connection of the three single pole-insulated voltage transformers.

The sign of the admittance characteristic settings should be considered based on the location of characteristic boundary in the admittance plane. All forward-settings are given with positive sign and reverse-settings with negative sign.

Operation characteristic

After the admittance calculation is released, the calculated neutral admittance is compared to the admittance characteristic boundaries in the admittance plane. If the calculated neutral admittance $\underline{Y}$o moves outside the characteristic, the enabling signal is sent to the timer.

21YN supports a wide range of different characteristics to achieve the maximum flexibility and sensitivity in different applications. The basic characteristic shape is selected with the *Operation mode* and *Directional mode* settings. *Operation mode* defines which operation criterion or criteria are enabled and *Directional mode* defines if the forward, reverse or non-directional boundary lines for that particular operation mode are activated.

Table 378: Operation criteria

Operation mode	Description
Yo	Admittance criterion
Bo	Susceptance criterion
Go	Conductance criterion
Yo, Go	Admittance criterion combined with the conductance criterion
Yo, Bo	Admittance criterion combined with the susceptance criterion
Go, Bo	Conductance criterion combined with the susceptance criterion
Yo, Go, Bo	Admittance criterion combined with the conductance and susceptance criterion

The options for the *Directional mode* setting are "Non-directional", "Forward" and "Reverse".

Figure 178, Figure 179 and Figure 180 illustrate the admittance characteristics supported by 21YN and the settings relevant to that particular characteristic. The most typical characteristics are highlighted and explained in details in the chapter Neutral admittance characteristics. Operation is achieved when the calculated neutral admittance $\underline{Y}$o moves outside the characteristic (the operation area is marked with gray).

The settings defining the admittance characteristics are given in primary milliSiemens (mS). The conversion equation for the admittance from secondary to primary is:

$$Y_{pri} = Y_{sec} \cdot \frac{ni_{CT}}{nu_{VT}}$$

(Equation 36)

ni_{CT}	CT ratio for the residual current IG
nu_{VT}	VT ratio for the residual voltage VG

Example: Admittance setting in the secondary is 5.00 milliSiemens. The CT ratio is 100/1 A and the VT ratio is 11547/100 V. The admittance setting in the primary can be calculated.

$$Y_{pri} = 5.00\ milliSiemens \cdot \frac{100/1A}{11547/100V} = 4.33\ milliSiemens$$

(Equation 37)

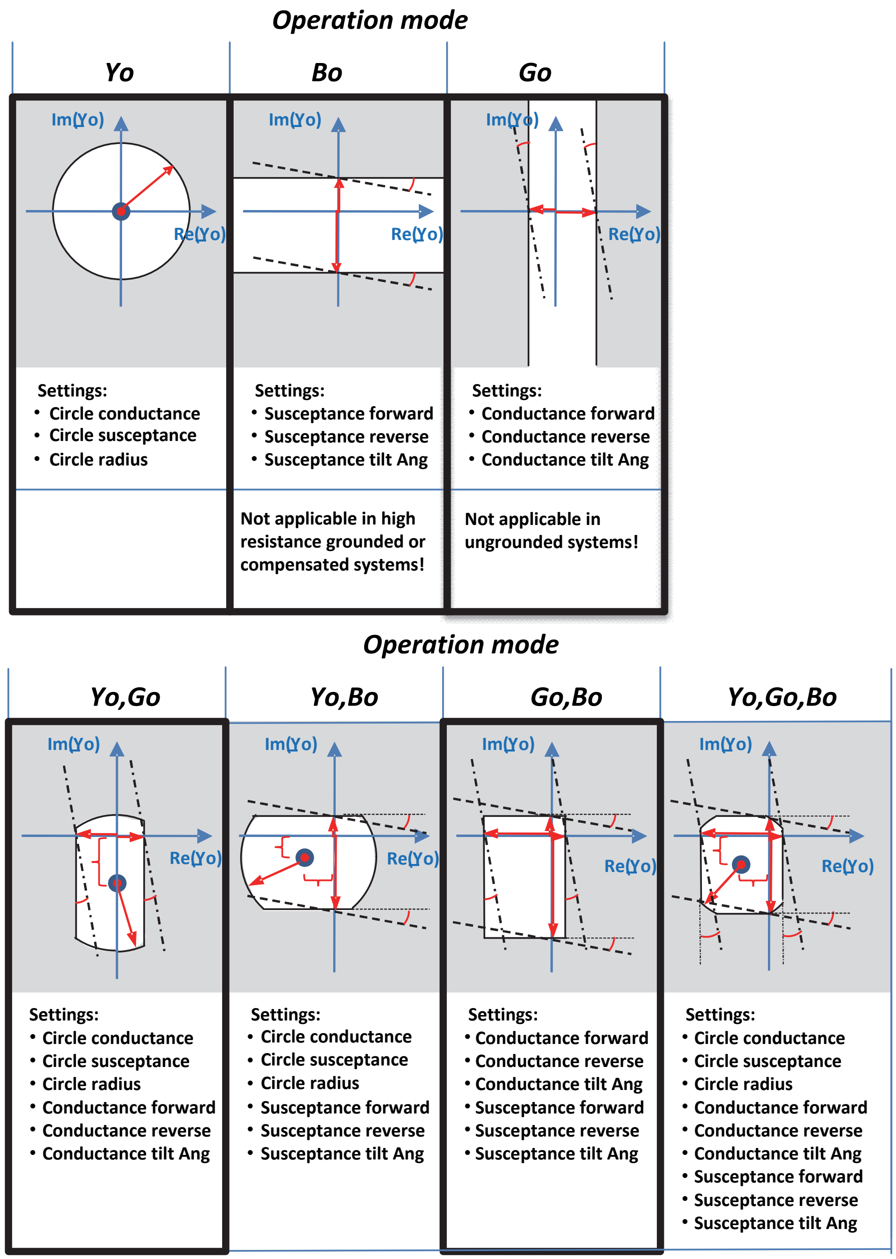


Figure 178: Admittance characteristic with different operation modes when Directional mode = "Non-directional"

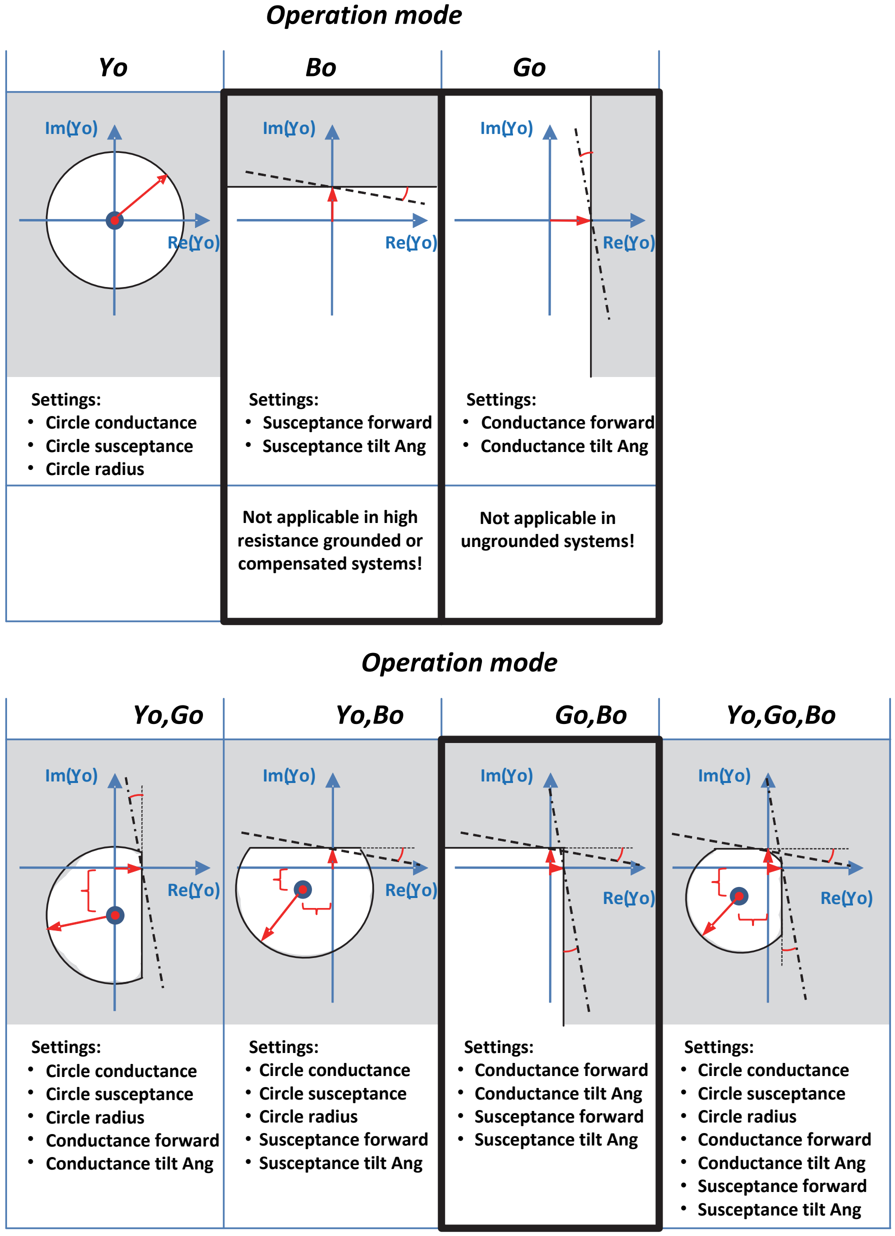


Figure 179: Admittance characteristic with different operation modes when Directional mode = "Forward"

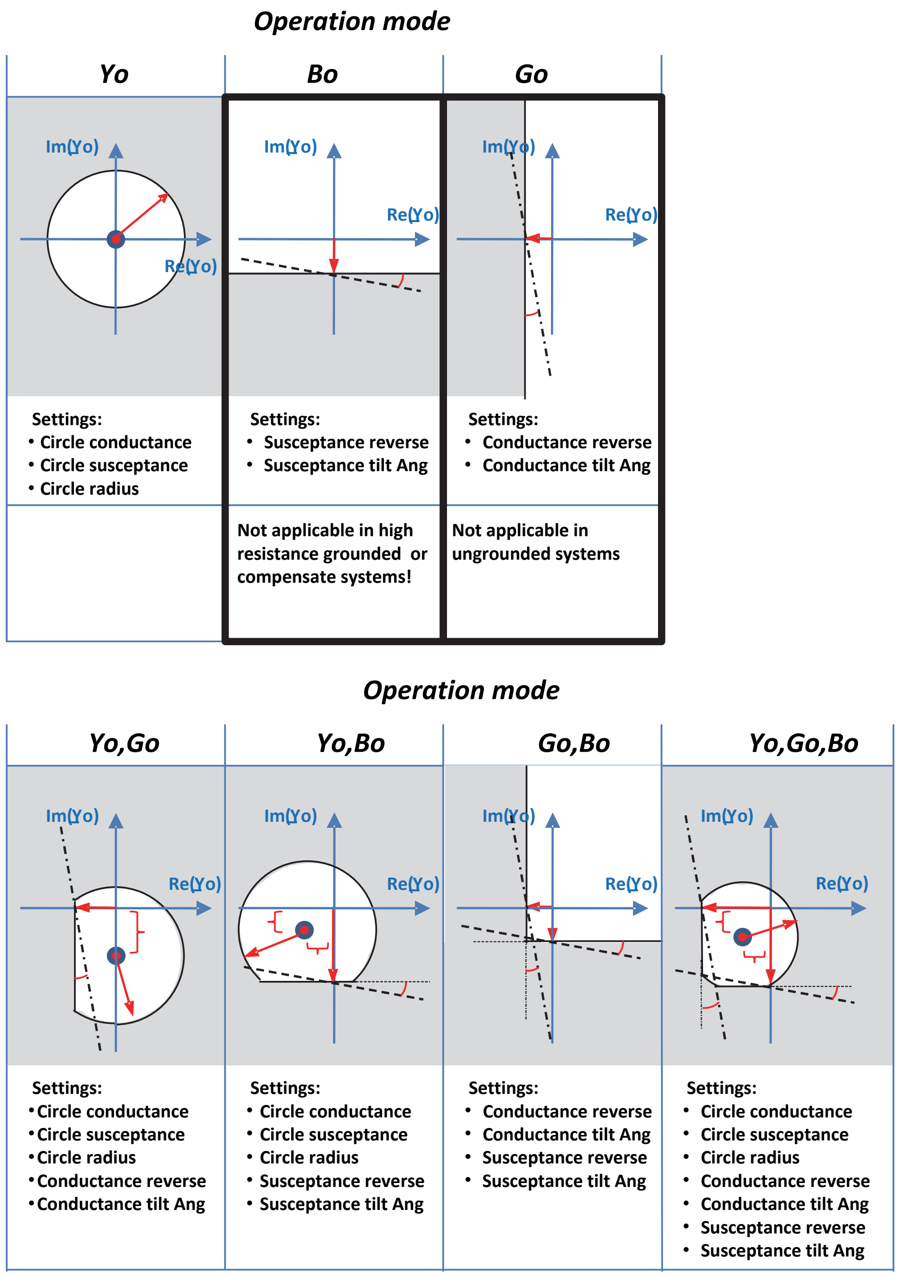


Figure 180: Admittance characteristic with different operation modes when Directional mode = "Reverse"

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set with the *TRIP delay* *time* setting, the TRIP output is activated. If the fault disappears before the module operates, the reset timer is activated. If the reset timer reaches the value set with the *Reset delay time* setting, the operation timer resets and the PICKUP output is deactivated. The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.2.4.5 Neutral admittance characteristics

The applied characteristic should always be set to cover the total admittance of the protected feeder with a suitable margin. However, more detailed setting value selection principles depend on the characteristic in question.

The settings defining the admittance characteristics are given in primary milliSiemens.

The forward and reverse boundary settings should be set so that the forward setting is always larger than the reverse setting and that there is space between them.

Overadmittance characteristic

The overadmittance criterion is enabled with the setting *Operation mode* set to "Yo". The characteristic is a circle with the radius defined with the *Circle radius* setting. For the sake of application flexibility, the midpoint of the circle can be moved away from the origin with the *Circle conductance* and *Circle susceptance* settings. Default values for *Circle conductance* and *Circle susceptance* are 0.0 mS, that is, the characteristic is an origin-centered circle.

Operation is achieved when the measured admittance moves outside the circle.

The overadmittance criterion is typically applied in ungrounded networks, but it can also be used in compensated networks, especially if the circle is set off from the origin.

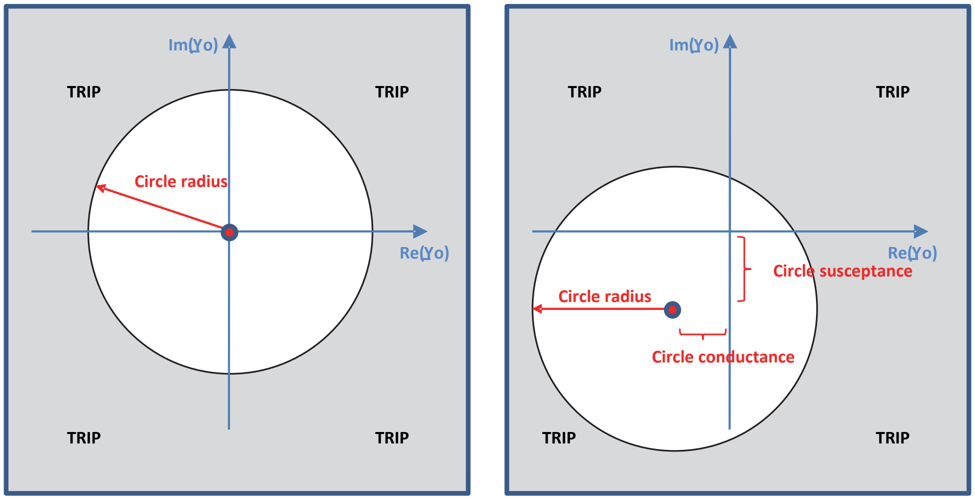


Figure 181: Overadmittance characteristic. Left figure: classical origin-centered admittance circle. Right figure: admittance circle is set off from the origin.

Non-directional overconductance characteristic

The non-directional overconductance criterion is enabled with the *Operation mode* setting set to "Go" and *Directional mode* to "Non-directional". The characteristic is defined with two overconductance boundary lines with the *Conductance forward* and *Conductance reverse* settings. For the sake of application flexibility, the boundary lines can be tilted by the angle defined with the *Conductance tilt Ang* setting. By default, the tilt angle is zero degrees, that is, the boundary line is a vertical line in the admittance plane. A positive tilt value rotates the boundary line counterclockwise from the vertical axis.

In case of non-directional conductance criterion, the *Conductance reverse* setting must be set to a smaller value than *Conductance forward*.

Operation is achieved when the measured admittance moves over either of the boundary lines.

The non-directional overconductance criterion is applicable in high-resistance grounded and compensated networks. It must not be applied in ungrounded networks.

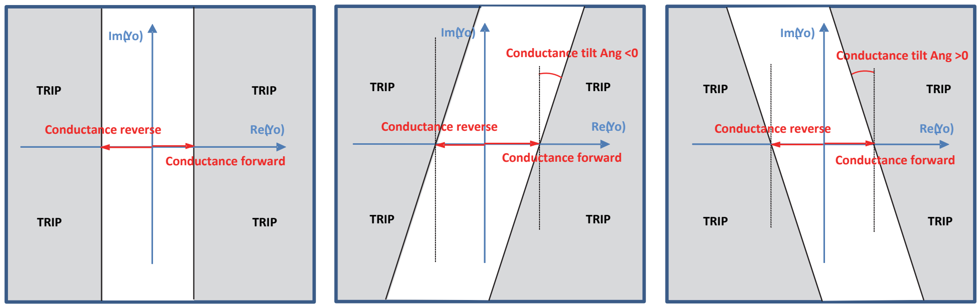


Figure 182: Non-directional overconductance characteristic. Left figure: classical non-directional overconductance criterion. Middle figure: characteristic is tilted with negative tilt angle. Right figure: characteristic is tilted with positive tilt angle.

Forward directional overconductance characteristic

The forward directional overconductance criterion is enabled with the *Operation mode* setting set to "Go" and *Directional mode* set to "Forward". The characteristic is defined by one overconductance boundary line with the *Conductance forward* setting. For the sake of application flexibility, the boundary line can be tilted with the angle defined with the *Conductance tilt Ang* setting. By default, the tilt angle is zero degrees, that is, the boundary line is a vertical line in the admittance plane. A positive tilt value rotates the boundary line counterclockwise from the vertical axis.

Operation is achieved when the measured admittance moves over the boundary line.

The forward directional overconductance criterion is applicable in high-resistance grounded and compensated networks. It must not be applied in ungrounded networks.

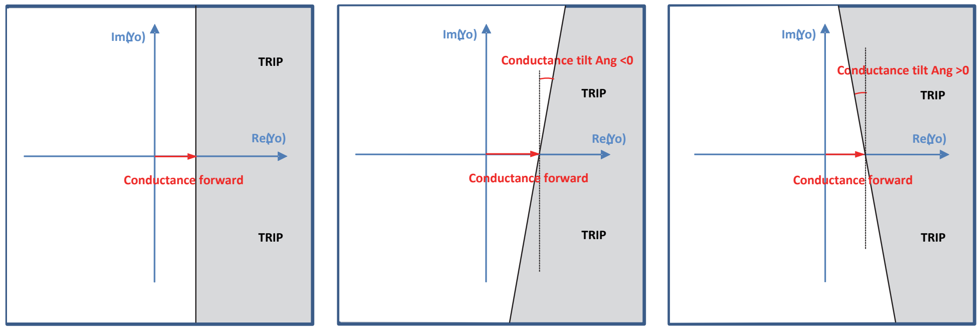


Figure 183: Forward directional overconductance characteristic. Left figure: classical forward directional overconductance criterion. Middle figure: characteristic is tilted with negative tilt angle. Right figure: characteristic is tilted with positive tilt angle.

Forward directional oversusceptance characteristic

The forward directional oversusceptance criterion is enabled with the *Operation mode* setting set to "Bo" and *Directional mode* to "Forward". The characteristic is defined by one oversusceptance boundary line with the *Susceptance forward* setting. For the sake of application flexibility, the boundary line can be tilted by the angle defined with the *Susceptance tilt Ang* setting. By default, the tilt angle is zero degrees, that is, the boundary line is a horizontal line in the admittance plane. A positive tilt value rotates the boundary line counterclockwise from the horizontal axis.

Operation is achieved when the measured admittance moves over the boundary line.

The forward directional oversusceptance criterion is applicable in ungrounded networks. It must not be applied to compensated networks.

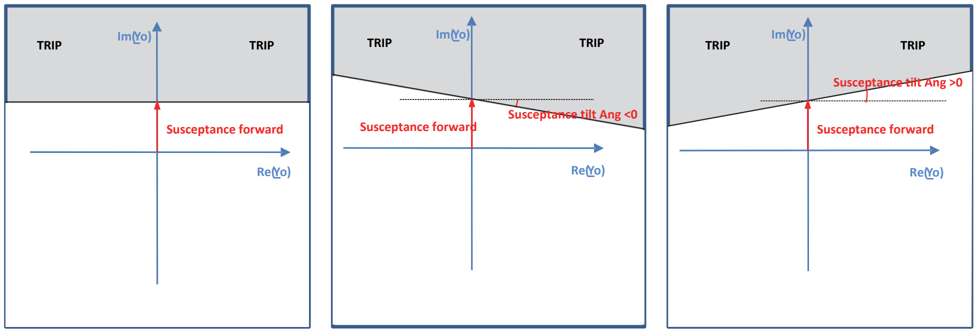


Figure 184: *Forward directional oversusceptance characteristic. Left figure: classical forward directional oversusceptance criterion. Middle figure: characteristic is tilted with negative tilt angle. Right figure: characteristic is tilted with positive tilt angle.*

Combined overadmittance and overconductance characteristic

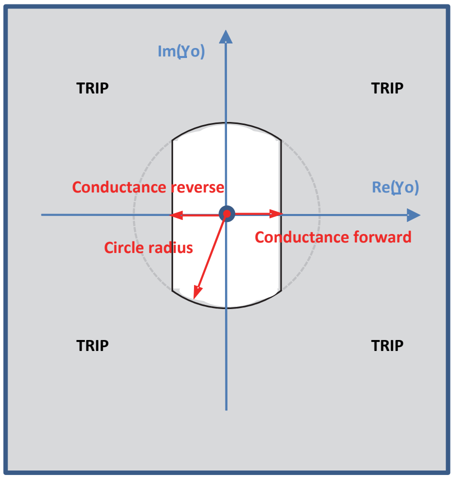
The combined overadmittance and overconductance criterion is enabled with the *Operation mode* setting set to "Yo, Go" and *Directional mode* to "Non-directional". The characteristic is a combination of a circle with the radius defined with the *Circle radius* setting and two overconductance boundary lines with the settings *Conductance forward* and *Conductance reverse*. For the sake of application flexibility, the midpoint of the circle can be moved from the origin with the *Circle conductance* and *Circle susceptance* settings. Also the boundary lines can be tilted by the angle defined with the *Conductance tilt Ang* setting. By default, the *Circle conductance* and *Circle susceptance* are 0.0 mS and *Conductance tilt Ang* equals zero degrees, that is, the characteristic is a combination of an origin-centered circle with two vertical overconductance boundary lines. A positive tilt value for the *Conductance tilt Ang* setting rotates boundary lines counterclockwise from the vertical axis.

In case of the non-directional conductance criterion, the *Conductance reverse* setting must be set to a smaller value than *Conductance forward*.

Operation is achieved when the measured admittance moves outside the characteristic.

The combined overadmittance and overconductance criterion is applicable in ungrounded, high-resistance grounded and compensated networks or in systems where the system grounding may temporarily change during normal operation from compensated network to ungrounded system.

Compared to the overadmittance criterion, the combined characteristic improves sensitivity in high-resistance grounded and compensated networks. Compared to the non-directional overconductance criterion, the combined characteristic enables the protection to be applied also in ungrounded systems.



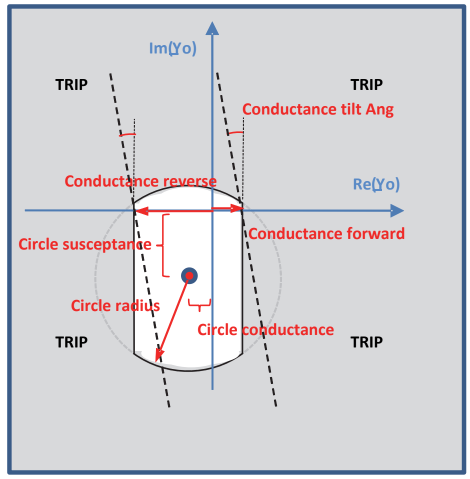


Figure 185: *Combined overadmittance and overconductance characteristic. Left figure: classical origin-centered admittance circle combined with two overconductance boundary lines. Right figure: admittance circle is set off from the origin.*

Combined overconductance and oversusceptance characteristic

The combined overconductance and oversusceptance criterion is enabled with the *Operation mode* setting set to "Go, Bo".

By setting *Directional mode* to "Forward", the characteristic is a combination of two boundary lines with the settings *Conductance forward* and *Susceptance forward*. See Figure 186.

By setting *Directional mode* to "Non-directional", the characteristic is a combination of four boundary lines with the settings *Conductance forward*, *Conductance reverse*, *Susceptance forward* and *Susceptance reverse*. See Figure 187.

For the sake of application flexibility, the boundary lines can be tilted by the angle defined with the *Conductance tilt Ang* and *Susceptance tilt Ang* settings. By default, the tilt angles are zero degrees, that is, the boundary lines are straight lines in the admittance plane. A positive *Conductance tilt Ang* value rotates the overconductance boundary line counterclockwise from the vertical axis. A positive *Susceptance tilt Ang* value rotates the oversusceptance boundary line counterclockwise from the horizontal axis.

In case of the non-directional conductance and susceptance criteria, the *Conductance reverse* setting must be set to a smaller value than *Conductance forward* and the *Susceptance reverse* setting must be set to a smaller value than *Susceptance forward*.

Operation is achieved when the measured admittance moves outside the characteristic.

The combined overconductance and oversusceptance criterion is applicable in high-resistance grounded, ungrounded and compensated networks or in the systems where the system grounding may temporarily change during normal operation from compensated to ungrounded system.

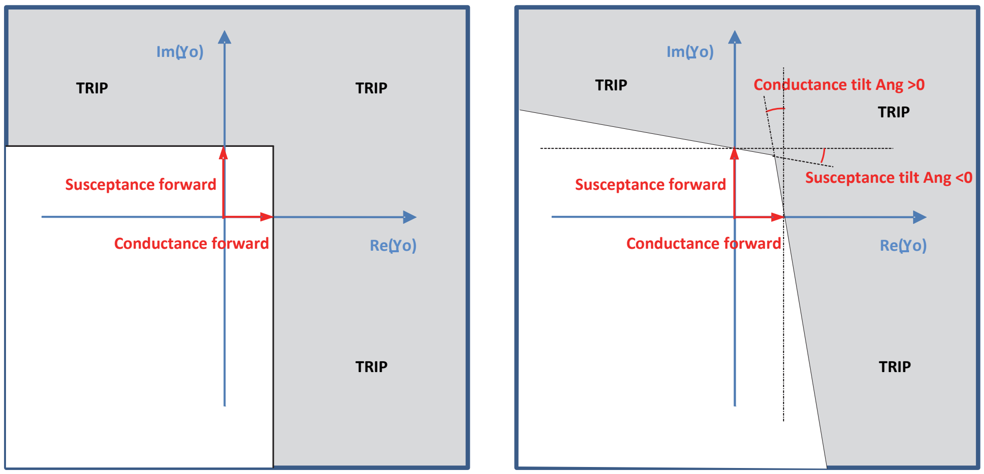


Figure 186: Combined forward directional overconductance and forward directional oversusceptance characteristic. Left figure: the Conductance tilt Ang and Susceptance tilt Ang settings equal zero degrees. Right figure: the setting Conductance tilt Ang > 0 degrees and the setting Susceptance tilt Ang < 0 degrees.

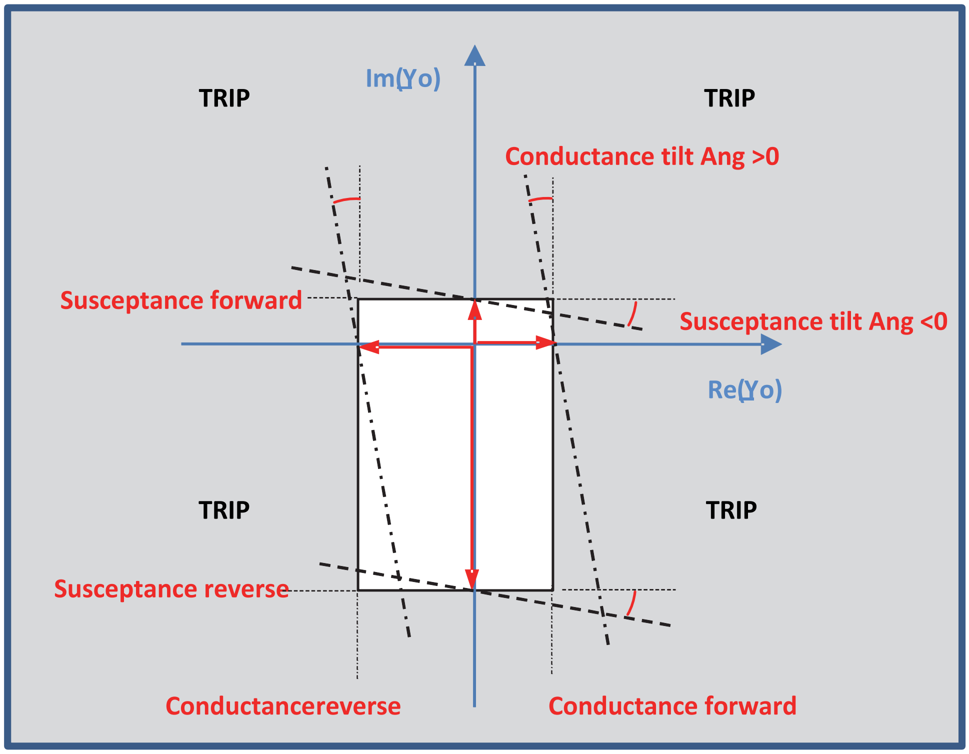


Figure 187: Combined non-directional overconductance and non-directional oversusceptance characteristic

The non-directional overconductance and non-directional oversusceptance characteristic provides a good sensitivity and selectivity when the characteristic is set to cover the total admittance of the protected feeder with a proper margin.

The sign of the admittance characteristic settings should be considered based on the location of characteristic boundary in the admittance plane. All forward-settings are given with positive sign and reverse-settings with negative sign.

4.2.4.6 Application

Admittance-based ground-fault protection provides a selective ground-fault protection for high-resistance grounded, ungrounded and compensated networks. It can be applied for the protection of overhead lines as well as with underground cables. It can be used as an alternative solution to traditional residual current-based ground-fault protection functions, for example the IoCos mode in 67/51N, 67/50N. Main advantages of 21YN include versatile applicability, good sensitivity and easy setting principles.

Residual overvoltage condition is used as a pickup condition for the admittance-based ground-fault protection. When the residual voltage exceeds the set threshold *Voltage pickup value*, a ground fault is detected and the neutral admittance calculation is released. In order to guarantee a high security of protection, that is, avoid false pickups, the *Voltage pickup value* setting must be set above the highest possible value of VG during normal operation with a proper margin. It should consider all possible operation conditions and configuration changes in the network. In ungrounded systems, the healthy-state VG is typically less than 1%×Vph (Vph = nominal phase-to-ground voltage). In compensated networks, the healthy-state VG may reach values even up to 30%×Vph if the network includes large parts of overheadlines without a phase transposition. Generally, the highest VG is achieved when the compensation coil is tuned to the full resonance and when the parallel resistor of the coil is not connected.

The residual overvoltage-based trip condition for the admittance protection enables a multistage protection principle. For example, one instance of 21YN could be used for alarming to detect faults with a high fault resistance using a relatively low value for the *Voltage pickup value* setting. Another instance of 21YN could then be set to trip with a lower sensitivity by selecting a higher value of the *Voltage pickup value* setting than in the alarming instance (stage).

To apply the admittance-based ground-fault protection, at least the following network data are required:

- System grounding method
- Maximum value for VG during the healthy state
- Maximum ground-fault current of the protected feeder when the fault resistance Rf is zero ohm
- Maximum uncompensated ground-fault current of the system (Rf = 0 Ω)
- Rated current of the parallel resistor of the coil (active current forcing scheme) in the case of a compensated neutral network
- Rated current of the neutral grounding resistor in the case of a high-resistance grounded system
- Knowledge of the magnitude of VG as a function of the fault resistance to verify the sensitivity of the protection in terms of fault resistance

Figure 188 shows the influence of fault resistance on the residual voltage magnitude in ungrounded and compensated networks. Such information should be available to verify the correct *Voltage pickup value* setting, which helps fulfill the requirements for the sensitivity of the protection in terms of fault resistance.

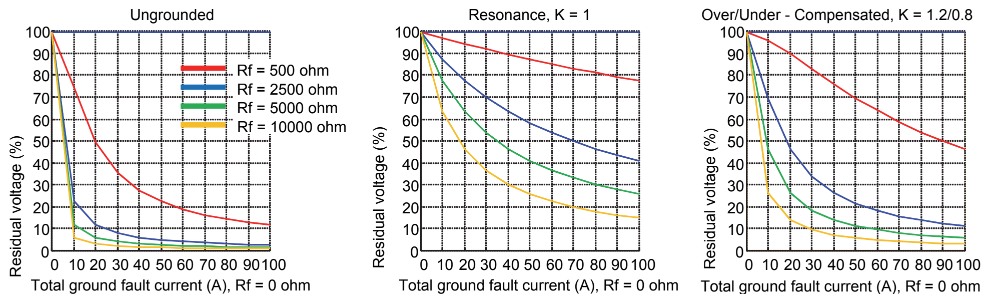


Figure 188: Influence of fault resistance on the residual voltage magnitude in 10 kV ungrounded and compensated networks. The leakage resistance is assumed to be 30 times larger than the absolute value of the capacitive reactance of the network. Parallel resistor of the compensation coil is assumed to be disconnected.

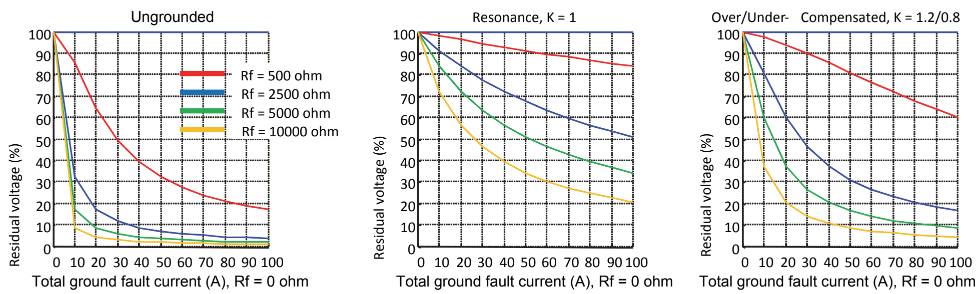


Figure 189: Influence of fault resistance on the residual voltage magnitude in 15 kV ungrounded and compensated networks. The leakage resistance is assumed to be 30 times larger than the absolute value of the capacitive reactance of the network. Parallel resistor of the compensation coil is assumed to be disconnected.

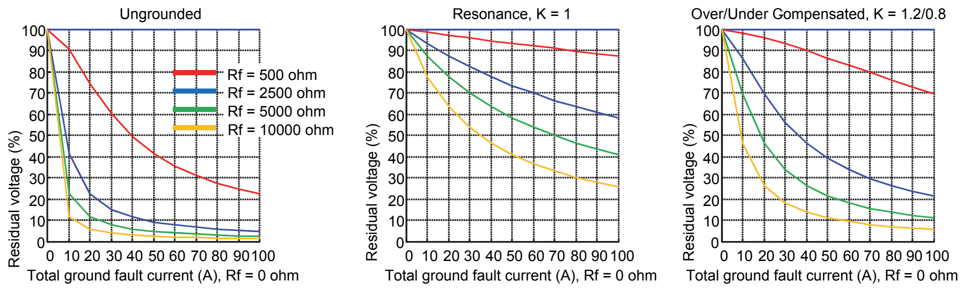


Figure 190: *Influence of fault resistance on the residual voltage magnitude in 20 kV ungrounded and compensated networks. The leakage resistance is assumed to be 30 times larger than the absolute value of the capacitive reactance of the network. Parallel resistor of the compensation coil is assumed to be disconnected.*

Example

In a 15 kV, 50 Hz compensated network, the maximum value for VG during the healthy state is 10%×Vph. Maximum ground-fault current of the system is 100 A. The maximum ground-fault current of the protected feeder is 10 A (Rf = 0 Ω). The applied active current forcing scheme uses a 15 A resistor (at 15 kV), which is connected in parallel to the coil during the fault after a 1.0 second delay.

Solution: As a pickup condition for the admittance-based ground-fault protection, the internal residual overvoltage condition of 21YN is used. The *Voltage pickup value* setting must be set above the maximum healthy-state VG of 10%×Vph with a suitable margin.

Voltage pickup value = 0.15 × Vn

According to Figure 189, this selection ensures at least a sensitivity corresponding to a 2000 ohm fault resistance when the compensation degree varies between 80% and 120%. The greatest sensitivity is achieved when the compensation degree is close to full resonance.

A ground-fault current of 10 A can be converted into admittance.

$$\underline{Y}_{Fdtot} = \frac{10A}{15kV/\sqrt{3}} \approx j \cdot 1.15 \text{ mS}$$

(Equation 38)

A parallel resistor current of 15 A can be converted into admittance.

$$G_{cc} = \frac{15A}{15kV/\sqrt{3}} \approx 1.73 \text{ mS}$$

(Equation 39)

According to Equation 26, during an outside fault 21YN measures the following admittance:

$$\underline{Y}o = -\underline{Y}_{Fdtot} \approx -j \cdot 1.15 \text{ mS}$$

(Equation 40)

According to Equation 29, during an inside fault 21YN measures the admittance after the connection of the parallel resistor:

$$\underline{Y}o = \underline{Y}_{Bgtot} + \underline{Y}_{CC} \approx (1.73 + j \cdot B) \text{ mS}$$

(Equation 41)

Where the imaginary part of the admittance, B, depends on the tuning of the coil (compensation degree).

The admittance characteristic is selected to be the combined overconductance and oversusceptance characteristic ("Box"-characteristics) with four boundary lines:

Operation mode = "Go, Bo"

Directional mode = "Non-directional"

The admittance characteristic is set to cover the total admittance of the protected feeder with a proper margin, see Figure 191. Different setting groups can be used to allow adaptation of protection settings to different feeder and network configurations.

Conductance forward

This setting should be set based on the parallel resistor value of the coil. It must be set to a lower value than the conductance of the parallel resistor, in order to enable dependable operation. The selected value should move the boundary line from origin to include some margin for the admittance operation point due to CT/VT-errors, when fault is located outside the feeder.

Conductance forward: 15 A/(15 kV/sqrt(3)) * 0.2 = +0.35 mS corresponding to 3.0 A (at 15 kV). The selected value provides margin considering also the effect of CT/VT-errors in case of outside faults.

In case of smaller rated value of the parallel resistor, for example, 5 A (at 15 kV), the recommended security margin should be larger, for example 0.7, so that sufficient margin for CT/VT-errors can be achieved.

Susceptance forward

By default, this setting should be based on the minimum trip current of 1 A.

Susceptance forward: 1 A/(15 kV/sqrt(3)) = +0.1 mS

Susceptance reverse

This setting should be set based on the value of the maximum ground-fault current produced by the feeder (considering possible feeder topology changes) with a security margin. This ensures that the admittance operating point stays inside the "Box"-characteristics during outside fault. The recommended security margin should not be lower than 1.5.

Susceptance reverse: - (10 A * 1.5)/ (15 kV/sqrt(3)) = -1.73 mS

Conductance reverse

This setting is used to complete the non-directional characteristics by closing the "Box"-characteristic. In order to keep the shape of the characteristic reasonable and to allow sufficient margin for the admittance operating point during outside fault, it is recommended to use the same value as for setting Susceptance reverse.

Conductance reverse = -1.73 mS

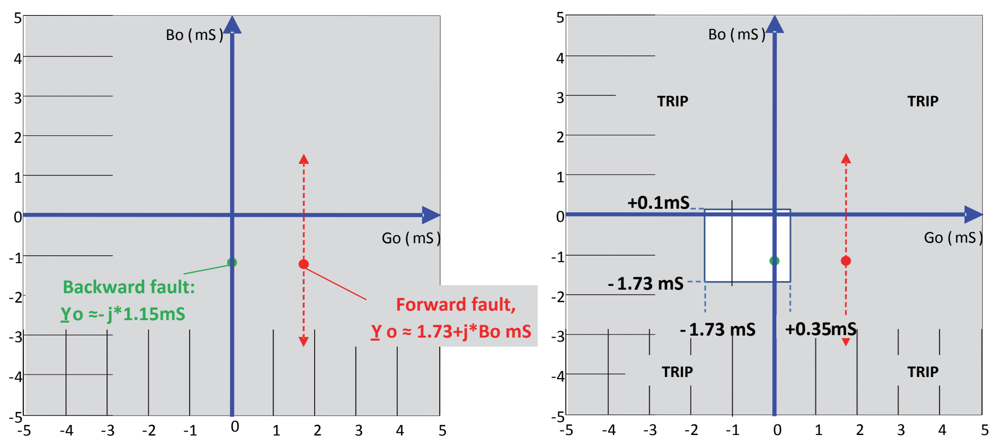


Figure 191: Admittances of the example

4.2.4.7 Signals

Table 379: 21YN Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
RELEASE	BOOLEAN	0=False	External trigger to release neutral admittance protection

Table 380: 21YN Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.2.4.8 Settings

Table 381: 21YN Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage pickup value	0.01...2.00	xUn	0.01	0.15	Voltage pickup value
Directional mode	1=Non-directional 2=Forward 3=Reverse			2=Forward	Directional mode
Operation mode	1=Yo 2=Go 3=Bo 4=Yo, Go 5=Yo, Bo 6=Go, Bo 7=Yo, Go, Bo			1=Yo	Operation criteria
Trip delay time	60...200000	ms	10	60	Trip delay time
Circle radius	0.05...500.00	mS	0.01	1.00	Admittance circle radius
Circle conductance	-500.00...500.00	mS	0.01	0.00	Admittance circle midpoint, conductance
Circle susceptance	-500.00...500.00	mS	0.01	0.00	Admittance circle midpoint, susceptance
Conductance forward	-500.00...500.00	mS	0.01	1.00	Conductance threshold in forward direction
Conductance reverse	-500.00...500.00	mS	0.01	-1.00	Conductance threshold in reverse direction
Susceptance forward	-500.00...500.00	mS	0.01	1.00	Susceptance threshold in forward direction
Susceptance reverse	-500.00...500.00	mS	0.01	-1.00	Susceptance threshold in reverse direction

Table 382: 21YN Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Conductance tilt Ang	-30...30	deg	1	0	Tilt angle of conductance boundary line
Susceptance tilt Ang	-30...30	deg	1	0	Tilt angle of susceptance boundary line

Table 383: 21YN Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 384: 21YN Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Admittance Clc mode	1=Normal 2=Delta			1=Normal	Admittance calculation mode
Reset delay time	0...60000	ms	1	20	Reset delay time
Pol reversal	0=False 1=True			0=False	Rotate polarizing quantity
Min trip current	0.01...1.00	xIn	0.01	0.01	Minimum operating current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum operating voltage
IG or I0	1=Measured IG 2=Calculated I0			1=Measured IG	Selection for used Io signal
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used Uo signal

4.2.4.9 Monitored data

Table 385: 21YN Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
Y0_REAL	FLOAT32	-1000.00...1000.00	mS	Real part of calculated neutral admittance
Y0_IMAG	FLOAT32	-1000.00...1000.00	mS	Imaginary part of calculated neutral admittance
21YN	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.4.10 Technical data

Table 386: 21YN Technical data

Characteristic	Value		
Operation accuracy[1)]	At the frequency f = f_n		
	±1.0% or ±0.01 mS (In range of 0.5...100 mS)		
Pickup time[2)]	Minimum	Typical	Maximum
	56 ms	60 ms	64 ms
Table continues on next page			

Characteristic	Value
Reset time	40 ms
Trip time accuracy	±1.0% of the set value of ±20 ms
Suppression of harmonics	-50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) VG = 1.0 × Vn
2) Includes the delay of the signal output contact, results based on statistical distribution of 1000 measurements

4.2.4.11 Technical revision history

Table 387: 21YN Technical revision history

Technical revision	Change
B	Internal improvement.
C	*Voltage pickup value* setting range and default value change.
D	Internal improvement.
E	Internal improvement.

4.2.5 Harmonics-based ground-fault protection 51NHA

4.2.5.1 Identification

Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Harmonics-based ground-fault protection	HAEFPTOC	Io>HA	51NHA

4.2.5.2 Function block

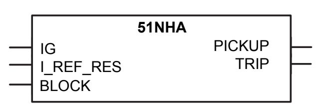


Figure 192: Function block

4.2.5.3 Functionality

The harmonics-based ground-fault protection function 51NHA is used instead of a traditional ground-fault protection in networks where a fundamental frequency component of the bround-fault current is low due to compensation.

By default, 51NHA is used as a standalone mode. Substation-wide application can be achieved using horizontal communication where the detection of a faulty feeder is done by comparing the harmonics ground-fault current measurements.

The function picks up when the harmonics content of the ground-fault current exceeds the set limit. The operation time characteristic is either definite time (DT) or inverse definite minimum time (IDMT). If the horizontal communication is used for the exchange of current values between the protection relays, the function operates according to the DT characteristic.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.2.5.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 51NHA can be described using a module diagram. All the modules in the diagram are explained in the next sections.

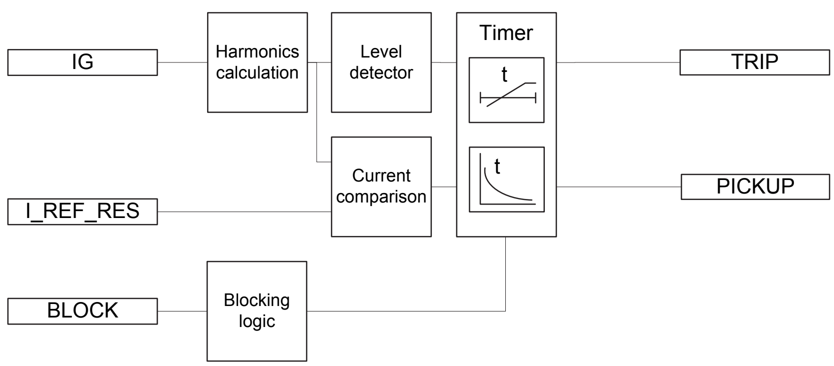


Figure 193: Functional module diagram

Harmonics calculation

This module feeds the measured residual current to the high-pass filter, where the frequency range is limited to start from two times the fundamental frequency of the network (for example, in a 50 Hz network the cutoff frequency is 100 Hz), that is, summing the harmonic components of the network from the second harmonic. The output of the filter, later referred to as the harmonics current, is fed to the Level detector and Current comparison modules.

The harmonics current I_HARM_RES is available in the monitored data view. The value is also sent over horizontal communication to the other protection relays on the parallel feeders configured in the protection scheme.

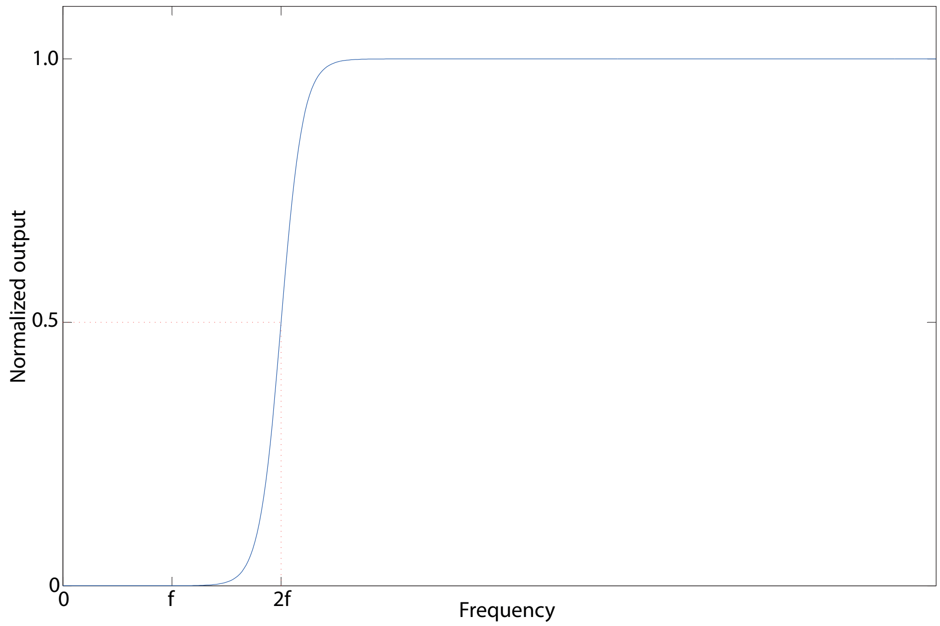


Figure 194: High-pass filter

Level detector

The harmonics current is compared to the *Pickup value* setting. If the value exceeds the value of the *Pickup value* setting, Level detector sends an enabling signal to the Timer module.

Current comparison

The maximum of the harmonics currents reported by other parallel feeders in the substation, that is, in the same busbar, is fed to the function through the `I_REF_RES` input. If the locally measured harmonics current is higher than `I_REF_RES`, the enabling signal is sent to Timer.

If the locally measured harmonics current is lower than `I_REF_RES`, the fault is not in that feeder. The detected situation blocks Timer internally, and simultaneously also the `BLKD_I_REF` output is activated.

The module also supervises the communication channel validity which is reported to the Timer.

Timer

The `PICKUP` output is activated when Level detector sends the enabling signal. Functionality and the time characteristics depend on the selected value of the *Enable reference use* setting.

Table 388: Values of the Enable reference use setting

Enable reference use		Functionality
Standalone		In the standalone mode, depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of the *Trip delay time* setting in the DT mode or the value defined by the inverse time curve, the `TRIP` output is activated.
Reference use	Communication valid	When using the horizontal communication, the function is forced to use the DT characteristics. When the operation timer has reached the value of the *Minimum trip time* setting and simultaneously the enabling signal from the Current comparison module is active, the `TRIP` signal is activated.
	Communication invalid	Function operates as in the standalone mode.

The *Enable reference use* setting forces the function to use the DT characteristics where the operating time is set with the *Minimum trip time* setting.

If the communication for some reason fails, the function switches to use the *Operation curve type* setting, and if DT is selected, *Trip delay time* is used. If the IDMT curve is selected, the time characteristics are according to the selected curve and the *Minimum trip time* setting is used for restricting too fast an operation time.

In case of a communication failure, the pickup duration may change substantially depending on the user settings.

When the programmable IDMT curve is selected, the operation time characteristics are defined with the *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E* parameters.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the Timer reset state is activated. The functionality of Timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the value of the *Reset delay time* setting is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. If the drop-off situation continues, the reset timer is reset and the PICKUP output is deactivated.

The "Inverse reset" selection is only supported with ANSI or the programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT operation and reset times.

The setting parameter *Minimum trip time* defines the minimum desired operation time for IDMT. The setting is applicable only when the IDMT curves are used

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve but always at least the value of the *Minimum trip time* setting. More information can be found in the IDMT curves for overcurrent protection.

Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation, and the set operating time, which can be either according to DT or IDMT. The value is available in the monitored data view.

More information can be found in the General function block features.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.2.5.5 Application

During a ground fault, 51NHA calculates the maximum current for the current feeder. The value is sent over an analog GOOSE to other protection relays of the busbar in the substation. At the configuration level, all the values received over the analog GOOSE are compared through the MAX function to find the maximum value. The maximum value is sent back to 51NHA as the `I_REF_RES` input. The operation of 51NHA is allowed in case `I_REF_RES` is lower than the locally measured harmonics current. If `I_REF_RES` exceeds the locally measured harmonics current, the operation of 51NHA is blocked.

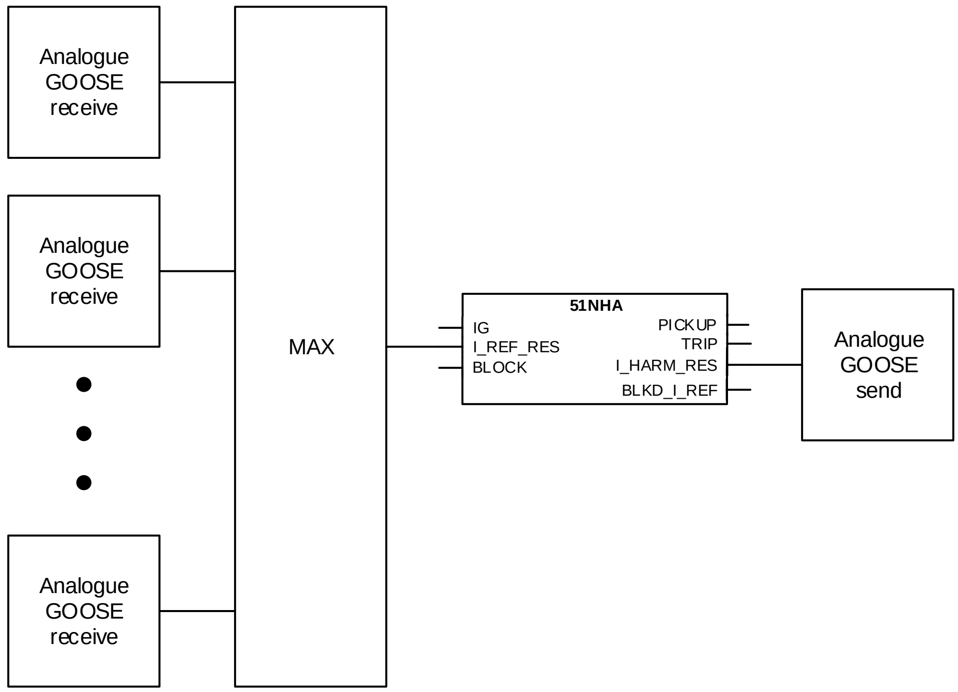


Figure 195: Protection scheme based on the analog GOOSE communication with three analog GOOSE receivers

4.2.5.6 Signals

Table 389: 51NHA Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
I_REF_RES	FLOAT32	0.0	Reference current

Table 390: 51NHA Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.2.5.7 Settings

Table 391: 51NHA Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...5.00	xIn	0.01	0.10	Pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	100...200000	ms	10	600	Trip delay time
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type

Table 392: 51NHA Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	100...200000	ms	10	500	Minimum trip time for IDMT curves
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type
Enable reference use	0=False 1=True			0=False	Enable using current reference from other IEDs instead of stand-alone

Table 393: 51NHA Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 394: 51NHA Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time

4.2.5.8 Monitored data

Table 395: 51NHA Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
I_HARM_RES	FLOAT32	0.0...30000.0	A	Calculated harmonics current
BLKD_I_REF	BOOLEAN	0=False 1=True		Current comparison status indicator
51NHA	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.5.9 Technical data

Table 396: 51NHA Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±5% of the set value or ±0.004 × I_n
Pickup time [1)2)]	Typically 77 ms
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Table continues on next page	

Characteristic	Value
Trip time accuracy in IDMT mode [3)]	±5.0% of the set value or ±20 ms
Suppression of harmonics	-50 dB at f = f_n
	-3 dB at f = 13 × f_n

1) Fundamental frequency current = 1.0 × I_n, harmonics current before fault = 0.0 × I_n, harmonics fault current 2.0 × *Pickup value*, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 2.5 × I_n, *Pickup value* multiples in range of 2...20

4.2.5.10 Technical revision history

Table 397: 51NHA Technical revision history

Technical revision	Change
B	Internal improvement.
C	Internal improvement.

4.2.6 Wattmetric-based ground-fault protection 32N

4.2.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Wattmetric-based ground-fault protection	WPWDE	Po> ->	32N

4.2.6.2 Function block

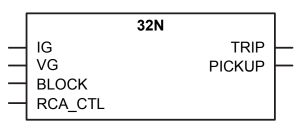


Figure 196: Function block

4.2.6.3 Functionality

The wattmetric-based ground-fault protection function 32N can be used to detect ground faults in ungrounded networks, compensated networks (Petersen coil-grounded networks) or networks with a high-impedance grounding. It can be used as an alternative solution to the traditional residual current-based ground-fault protection functions, for example, the IoCos mode in the directional ground-fault protection function 67/51N, 67/50N.

32N measures the ground-fault power 3UoIoCosφ and gives a trip signal when the residual current IG, residual voltage VG and the ground-fault power exceed the set limits and the angle (φ) between the residual current and the residual voltage is inside the set operating sector, that is, forward or backward sector. The operating time characteristic can be selected to be either definite time (DT) or a special wattmetric-type inverse definite minimum type (wattmetric type IDMT).

The wattmetric-based ground-fault protection is very sensitive to current transformer errors and it is recommended that a core balance CT is used for measuring the residual current.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.2.6.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

For 32N, certain notations and definitions are used.
Residual voltage VG or V0 = (VA+VB+VC)/3 = V_0, where V_0 = zero-sequence voltage
Residual current IG or I0 = -(IA+IB+IC) = 3×- I_0, where I_0 = zero-sequence current
The minus sign (-) is needed to match the polarity of calculated and measured residual currents.

The operation of 32N can be described with a module diagram. All the modules in the diagram are explained in the next sections.

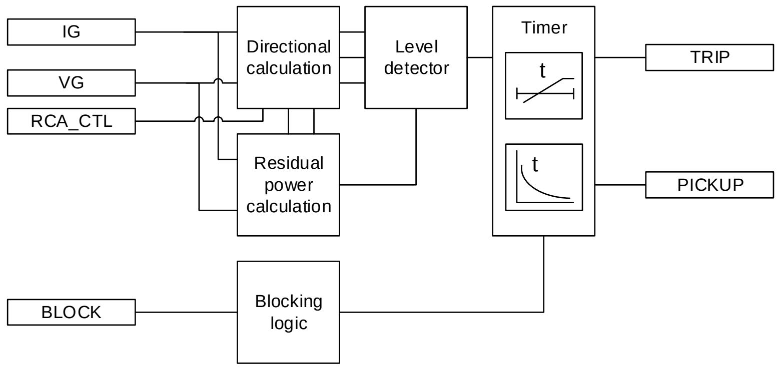


Figure 197: Function module diagram

Directional calculation

The Directional calculation module monitors the angle between the operating quantity (residual current IG or I0) and polarizing quantity (residual voltage VG or V0). The operating quantity can be selected with the setting *Io signal Sel*. The selectable options are “Measured IG” and “Calculated I0”. The polarizing quantity can be selected with the setting *Pol signal Sel*. The selectable options are “Measured VG” and “Calculated V0”. When the angle between operating quantity and polarizing quantity after considering the *Characteristic angle* setting is in the operation sector, the module sends an enabling signal to Level detector. The directional operation is selected with the *Directional mode* setting. Either the “Forward” or “Reverse” operation mode can be selected. The direction of fault is calculated based on the phase angle difference between the operating quantity IG or I0 and polarizing quantity VG or V0, and the value (ANGLE) is available in the monitored data view.

In the phasor diagrams representing the operation of 32N, the polarity of the polarizing quantity (residual voltage VG or V0) is reversed. Reversing is done by switching the polarity of the residual current measuring channel (See the connection diagram in the application manual).

If the angle difference lies between -90° to 0° or 0° to +90°, a forward-direction fault is considered. If the phase angle difference lies within -90° to -180° or +90° to +180°, a reverse-direction fault is detected. Thus, the normal width of a sector is 180°.

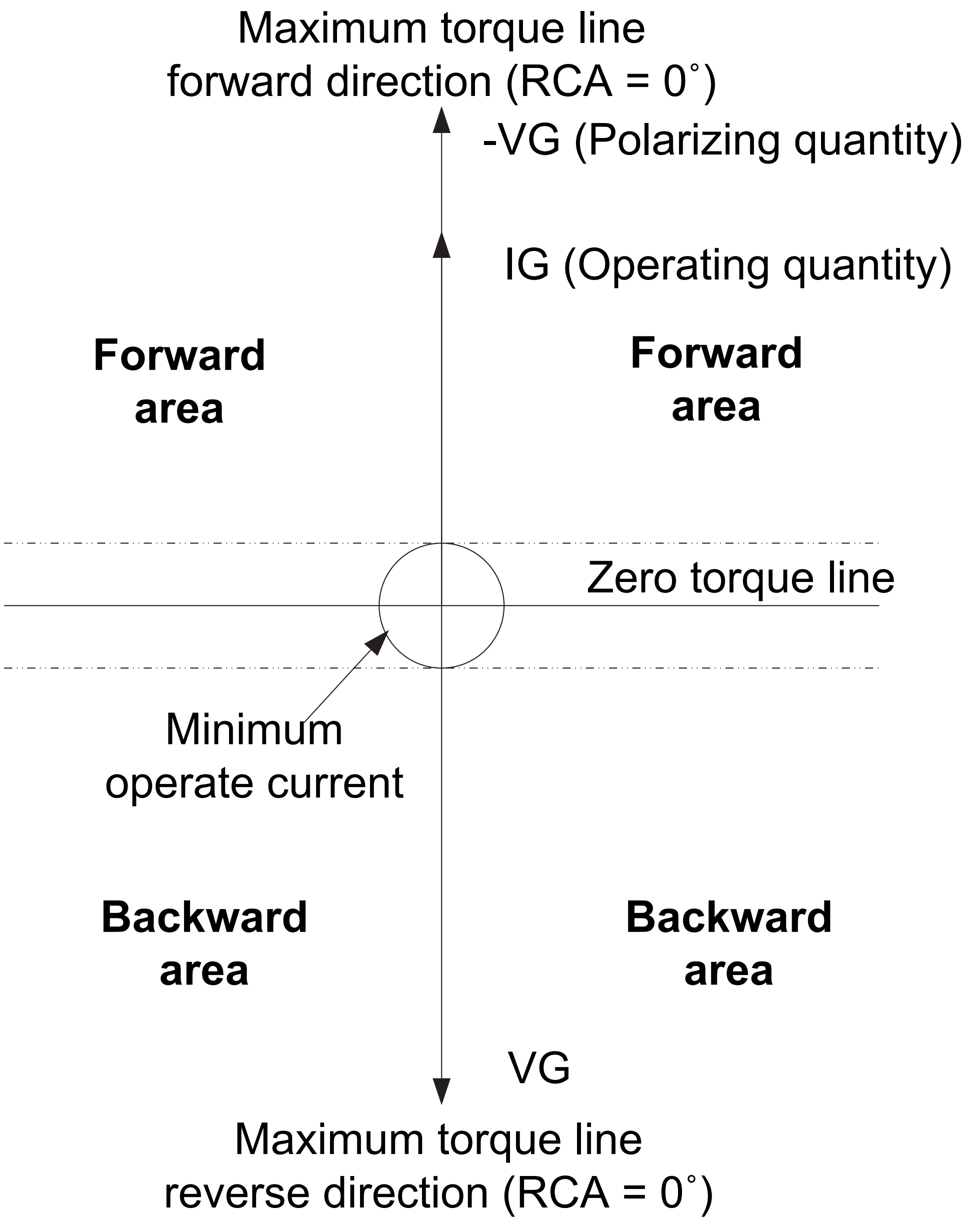


Figure 198: Definition of the relay characteristic angle

The phase angle difference is calculated based on the *Characteristic angle* setting (also known as Relay Characteristic Angle (RCA) or Relay Base Angle or Maximum Torque Angle (MTA)). The *Characteristic angle* setting is done based on the method of grounding employed in the network. For example, in case of an ungrounded network, the *Characteristic angle* setting is set to -90°, and in case of a compensated network, the *Characteristic angle* setting is set to 0°. In general, *Characteristic angle* is selected so that it is close to the expected fault angle value, which results in maximum sensitivity.

Characteristic angle can be set anywhere between -179° to +180°. Thus, the effective phase angle (ϕ) for calculating the residual power considering characteristic angle is according to the equation.

$$\phi = \left(\angle(-VG) - \angle IG - Characteristic\ angle\right)$$

(Equation 42)

In addition, the characteristic angle can be changed via the control signal `RCA_CTL`. The `RCA_CTL` input is used in the compensated networks where the compensation coil sometimes is temporarily disconnected. When the coil is disconnected, the compensated network becomes isolated and the *Characteristic angle* setting must be changed. This can be done automatically with the `RCA_CTL` input, which results in the addition of -90° in the *Characteristic angle* setting.

The value (ANGLE_RCA) is available in the monitored data view.

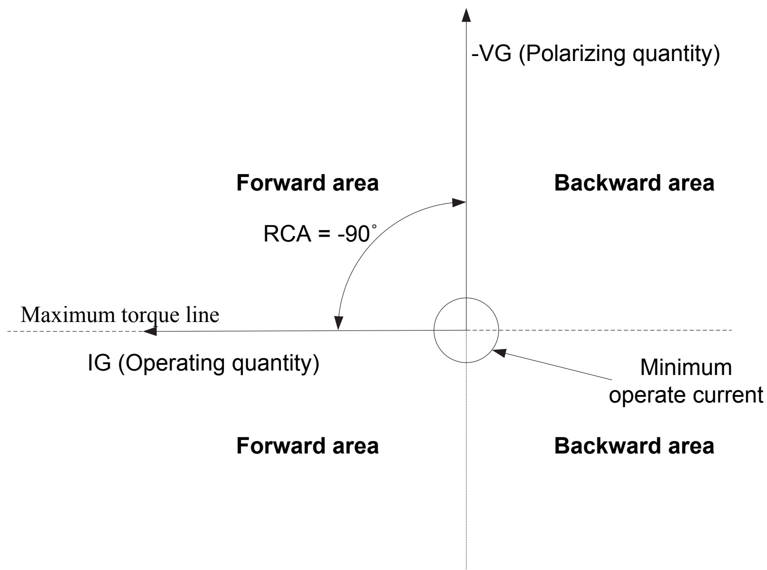


Figure 199: Definition of relay characteristic angle, RCA = -90° in an isolated network

Characteristic angle should be set to a positive value if the operating signal lags the polarizing signal and to a negative value if the operating signal leads the polarizing signal.

Type of network	Recommended characteristic angle
Compensated network	0°
Ungrounded network	-90°

In ungrounded networks, when the characteristic angle is -90°, the measured residual power is reactive (varmetric power).

The fault direction is also indicated FAULT_DIR (available in the monitored data view), which indicates 0 if a fault is not detected, 1 for faults in the forward direction and 2 for faults in the backward direction.

The direction of the fault is detected only when the correct angle calculation can be made. If the magnitude of the operating quantity or polarizing quantity is not high enough, the direction calculation is not reliable. Hence, the magnitude of the operating quantity is compared to the *Min trip current* setting and the magnitude of the polarizing quantity is compared to *Min trip voltage*, and if both the operating quantity and polarizing quantity are higher than their respective limit, a valid angle is calculated and the residual power calculation module is enabled.

The *Correction angle* setting can be used to improve the selectivity when there are inaccuracies due to the measurement transformer. The setting decreases the operation sector. The *Correction angle* setting should be done carefully as the phase angle error of the measurement transformer varies with the connected burden as well as with the magnitude of the actual primary current that is being measured. An example of how *Correction angle* alters the operating region is as shown:

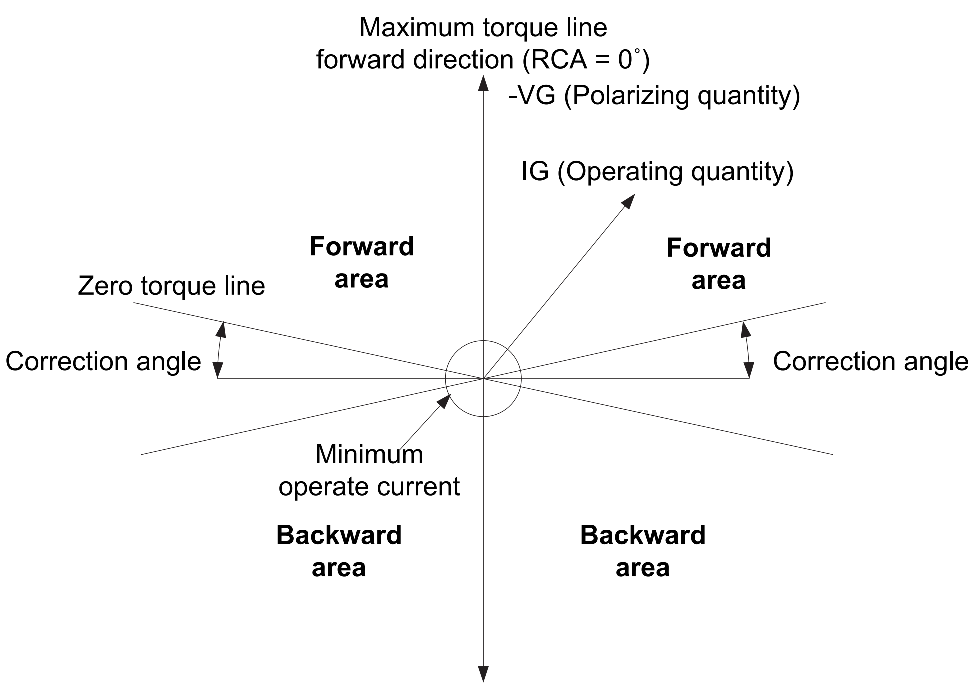


Figure 200: Definition of correction angle

The polarity of the polarizing quantity can be changed (rotated by 180°) by setting *Pol reversal* to "True" or by switching the polarity of the residual voltage measurement wires.

Residual power calculation

The Residual power calculation module calculates the magnitude of residual power 3VGIGCosφ. Angle φ is the angle between the operating quantity and polarizing quantity, compensated with a characteristic angle. The angle value is received from the Directional calculation module. The Directional calculation module enables the residual power calculation only if the minimum signal levels for both operating quantity and polarizing quantity are exceeded. However, if the angle calculation is not valid, the calculated residual power is zero. Residual power (RES_POWER) is calculated continuously and it is available in the monitored data view. The power is given in relation to nominal power calculated as Pn = Vn × In, where Vn and In are obtained from the entered voltage transformer and current transformer ratios entered, and depend on the *Io signal Sel* and *Vg or V0* settings.

Level detector

Level detector compares the magnitudes of the measured operating quantity (residual current IG), polarizing quantity (residual voltage VG) and calculated residual power to the set *Current pickup value* (×In), *Voltage pickup value* (×Vn) and *Power pickup value* (×Pn) respectively. When all three quantities exceed the limits, Level detector enables the Timer module.

When calculating the setting values for Level detector, it must be considered that the nominal values for current, voltage and power depend on whether the residual quantities are measured from a dedicated measurement channel or calculated from phase quantities, as defined in the *Io signal Sel* and *Vg or V0* settings.

For residual current IG or I0, if "Measured IG" is selected, the nominal values for primary and secondary are obtained from the current transformer ratio entered for residual current channel **Configuration/Analog inputs/Current (IG, CT)**. If "Calculated I0" is selected, the nominal values for primary and secondary are obtained from the current transformer ratio entered for phase current channels **Configuration/Analog inputs/Current (3I, CT)**.

For residual voltage VG or V0, if "Measured VG" is selected, the nominal values for primary and secondary are obtained from the voltage transformer ratio entered for residual voltage channel **Configuration/Analog inputs/Voltage (VG, VT)**. If "Calculated V0" is selected, the nominal values for primary and secondary are obtained from the voltage transformer ratio entered for phase voltage channels **Configuration/Analog inputs/Voltage (3V, VT)**.

Calculated V0 requires that all three phase-to-ground voltages are connected to the protection relay. V0 cannot be calculated from the phase-to-phase voltages.

As nominal power is the result of the multiplication of the nominal current and the nominal voltage Pn = Vn × In, the calculation of the setting value for *Power pickup value* (×Pn) depends on whether IG and VG or V0 are measured or calculated from the phase quantities.

Table 398: Measured and calculated IG or I0 and VG or V0

	Measured IG	Calculated I0
Measured VG	Pn = (VG, VT) × (IG, CT)	Pn = (VG, VT) × (3I, CT)
Calculated V0	Pn = (3V, VT) × (IG, CT)	Pn = (3V, VT) × (3I, CT)

Example 1. IG is measured with cable core CT (100/1A) and VG is measured from open delta-connected VTs (20/sqrt(3) kV:100/sqrt(3) V:100/3 V). In this case, "Measured IG" and "Measured VG" are selected. The nominal values for residual current and residual voltage are obtained from CT and VT ratios.

Residual current IG: **Configuration/Analog inputs/Current (IG, CT)**: 100 A:1 A

Residual voltage VG: **Configuration/Analog inputs/Current (VG, VT)**: 11.547 kV:100 V

Residual Current pickup value of 1.0 × In corresponds then 1.0 × 100 A = 100 A in primary

Residual Voltage pickup value of 1.0 × Vn corresponds then 1.0 × 11.547 kV = 11.547 kV in primary

Residual Power pickup value of 1.0 × Pn corresponds then 1.0 × 11.547 kV × 100 A = 1154.7kW in primary

Example 2. Both I0 and V0 are calculated from phase quantities. Phase CT-ratio is 100:1 A and Phase VT-ratio 20/sqrt(3) kV:100/sqrt(3) V. In this case "Calculated I0" and "Calculated V0" are selected. The nominal values for residual current and residual voltage are obtained from CT and VT ratios entered in:

Residual current I0: **Configuration/Analog inputs/Current (3I, CT)**: 100 A:1 A

Residual voltage V0: **Configuration/Analog inputs/Current (3V, VT)**: 20.000 kV:100 V

Residual Current pickup value of 1.0 × In corresponds then 1.0 × 100 A = 100 A in primary

Residual Voltage pickup value of 1.0 × Vn corresponds then 1.0 × 20.000 kV = 20.000 kV in primary

Residual Power pickup value of 1.0 × Pn corresponds then 1.0 × 20.000 kV × 100 A = 2000kW in primary

If "Calculated V0" is selected for the *Vg or V0* setting, the nominal value for residual voltage Vn is always phase-to-phase voltage. Thus, the valid maximum setting for residual *Voltage pickup value* is 0.577 × Vn, which corresponds to full phase-to-ground voltage in primary.

Timer

Once activated, Timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or wattmetric IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated. If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The reset time is identical for both DT or wattmeter IDMT. The reset time depends on the *Reset delay time* setting.

Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set operation time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.2.6.5 Timer characteristics

In the wattmetric IDMT mode, the `TRIP` output is activated based on the timer characteristics:

$$t[s] = \frac{k * P_{ref}}{P_{cal}}$$

(Equation 43)

t[s]	operation time in seconds
k	set value of *Time multiplier*
P_{ref}	set value of *Reference power*
P_{cal}	calculated residual power

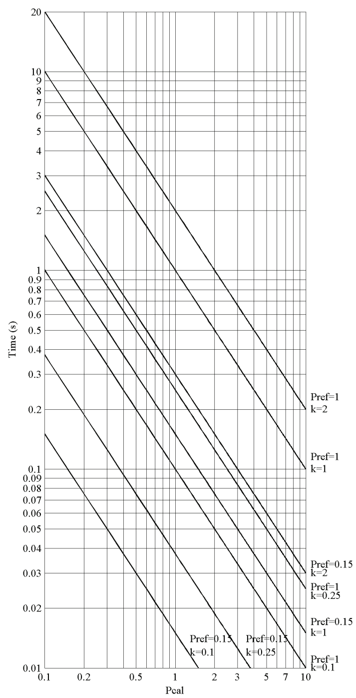


Figure 201: Operation time curves for wattmetric IDMT for S_{ref} set at 0.15 xPn

4.2.6.6 Measurement modes

The function operates on three alternative measurement modes: "RMS", "DFT" and "Peak-to-Peak". The measurement mode is selected with the *Measurement mode* setting.

4.2.6.7 Application

The wattmetric method is one of the commonly used directional methods for detecting the ground faults especially in compensated networks. The protection uses the residual power component 3VGIGCosφ (φ is the angle between the polarizing quantity and operating quantity compensated with a relay characteristic angle).

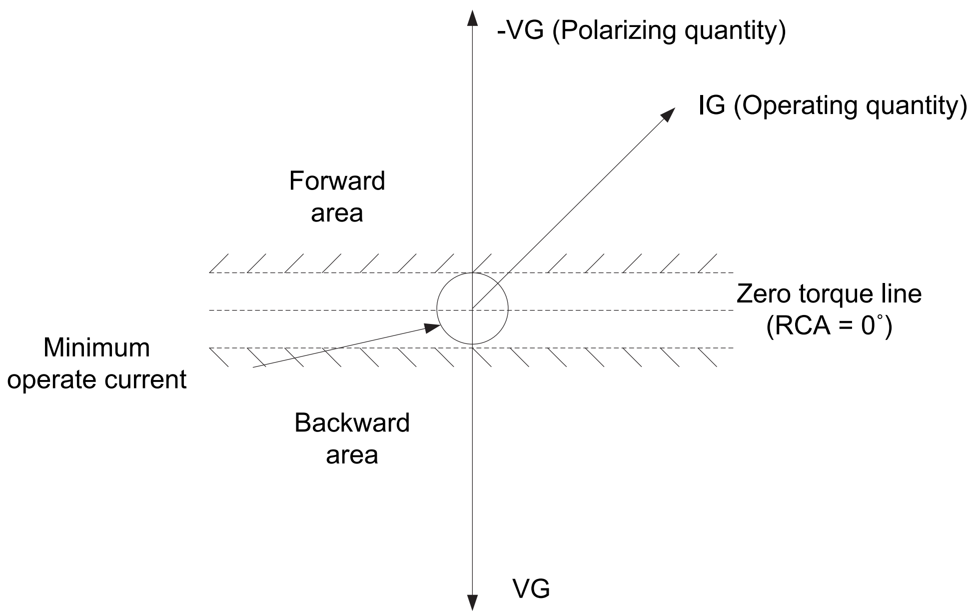


Figure 202: Characteristics of wattmetric protection

In a fully compensated radial network with two outgoing feeders, the ground-fault currents depend mostly on the system ground capacitances (C_0) of the lines and the compensation coil (L). If the coil is tuned exactly to the system capacitance, the fault current has only a resistive component. This is due to the resistances of the coil and distribution lines together with the system leakage resistances (R_0). Often a resistor (R_L) in parallel with the coil is used for increasing the fault current.

When a single phase-to-ground fault occurs, the capacitance of the faulty phase is bypassed and the system becomes unsymmetrical. The fault current is composed of the currents flowing through the ground capacitances of two healthy phases. The protection relay in the healthy feeder tracks only the capacitive current flowing through its ground capacitances. The capacitive current of the complete network (sum of all feeders) is compensated with the coil.

A typical network with the wattmetric protection is an undercompensated network where the coil current $I_L = I_{Ctot} - I_{Cfd}$ (I_{Ctot} is the total ground-fault current of the network and I_{Cfd} is the ground-fault current of the healthy feeder).

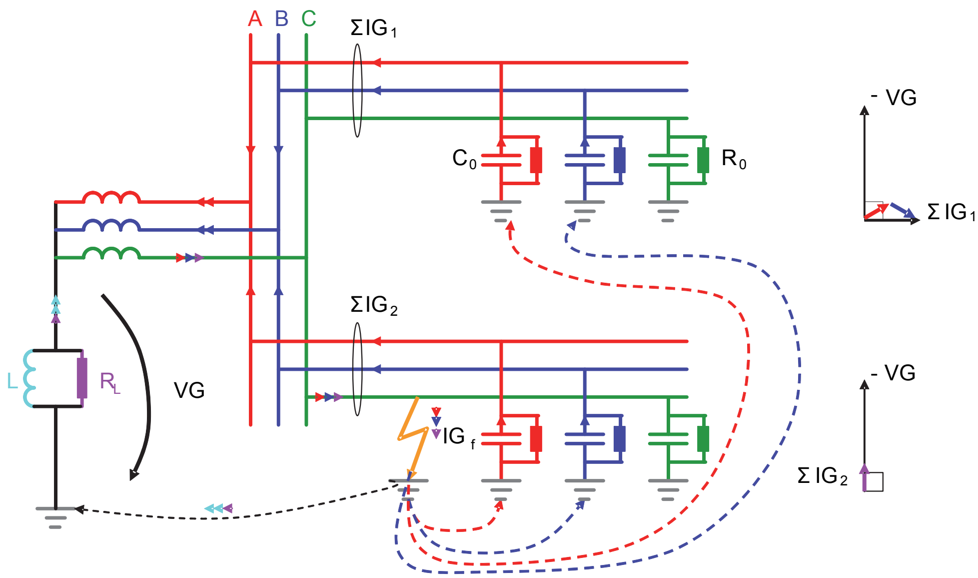


Figure 203: Typical radial compensated network employed with wattmetric protection

The wattmetric function is activated when the residual active power component exceeds the set limit. However, to ensure a selective trip, it is also required that the residual current and residual voltage also exceed the set limit.

It is highly recommended that core balance current transformers are used for measuring IG when using the wattmetric method. When a low transformation ratio is used, the current transformer can suffer accuracy problems and even a distorted secondary current waveform with some core balance current transformers. Therefore, to ensure a sufficient accuracy of the residual current measurement and consequently a better selectivity of the scheme, the core balance current transformer should preferably have a transformation ratio of at least 70:1. Lower transformation ratios such as 50:1 or 50:5 are not recommended, unless the phase displacement errors and current transformer amplitude are checked first.

It is not recommended to use the directional wattmetric protection in case of a ring or meshed system as the wattmetric requires a radial power flow to operate.

The relay characteristic angle needs to be set based on the system grounding. In an ungrounded network, that is, when the network is only coupled to ground via the capacitances between the phase conductors and ground, the characteristic angle is chosen as -90º.

In compensated networks, the capacitive fault current and inductive resonance coil current compensate each other, meaning that the fault current is mainly resistive and has zero phase shift compared to the residual voltage. In such networks, the characteristic angle is chosen as 0º. Often the magnitude of an active component is small and must be increased by means of a parallel resistor in a compensation coil. In networks where the neutral point is grounded through a low resistance, the characteristic angle is always 0º.

As the amplitude of the residual current is independent of the fault location, the selectivity of the ground-fault protection is achieved with time coordination.

The use of wattmetric protection gives a possibility to use the dedicated inverse definite minimum time characteristics. This is applicable in large high-impedance grounded networks with a large capacitive ground-fault current.

In a network employing a low-impedance grounded system, a medium-size neutral point resistor is used. Such a resistor gives a resistive ground-fault current component of about 200...400 A for an excessive ground fault. In such a system, the directional residual power protection gives better possibilities for selectivity enabled by the inverse time power characteristics.

4.2.6.8 Signals

Table 399: 32N Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
RCA_CTL	BOOLEAN	0=False	Relay characteristic angle control

Table 400: 32N Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.2.6.9 Settings

Table 401: 32N Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Directional mode	2=Forward 3=Reverse			2=Forward	Directional mode
Current pickup value	0.010...5.000	xIn	0.001	0.010	Minimum trip residual current for deciding fault direction
Voltage pickup value	0.010...1.000	xUn	0.001	0.010	Pickup value for residual voltage
Power pickup value	0.003...1.000	xPn	0.001	0.003	Pickup value for residual active power
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Reference power	0.050...1.000	xPn	0.001	0.150	Reference value of residual power for Wattmetric IDMT curves
Characteristic angle	-179...180	deg	1	-90	Characteristic angle
Time multiplier	0.05...2.00		0.01	1.00	Time multiplier for Wattmetric IDMT curves
Operating curve type	5=ANSI DT 15=IEC DT 20=Wattmetric IDMT			15=IEC DT	Selection of time delay curve type
Trip delay time	60...200000	ms	10	60	Trip delay time for definite time

Table 402: 32N Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 403: 32N Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT 3=Peak-to-Peak			2=DFT	Selects used current measurement mode
Correction angle	0.0...10.0	deg	0.1	2.0	Angle correction
Min trip current	0.010...1.000	xIn	0.001	0.010	Minimum trip current
Min trip voltage	0.01...1.00	xUn	0.01	0.01	Minimum trip voltage
Reset delay time	0...60000	ms	1	20	Reset delay time
Pol reversal	0=False 1=True			0=False	Rotate polarizing quantity
Io signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Selection for used Io signal
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used polarization signal

4.2.6.10 Monitored data

Table 404: 32N Monitored data

Name	Type	Values (Range)	Unit	Description
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information
ANGLE	FLOAT32	-180.00...180.00	deg	Angle between operating angle and characteristic angle
ANGLE_RCA	FLOAT32	-180.00...180.00	deg	Angle between polarizing and operating quantity
RES_POWER	FLOAT32	-160.000...160.000	xPn	Calculated residual active power
32N	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.6.11 Technical data

Table 405: 32N Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	Current and voltage: ±1.5% of the set value or ±0.002 × I_n Power: ±3% of the set value or ±0.002 × P_n
Pickup time 1)2)	Typically 63 ms
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Trip time accuracy in IDMT mode	±5.0% of the set value or ±20 ms
Suppression of harmonics	-50 dB at f = n × f_n, where n = 2,3,4,5,…

1) IG varied during the test, VG = 1.0 × V_n = phase-to-ground voltage during ground fault in compensated or ungrounded network, the residual power value before fault = 0.0 pu, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.2.6.12 Technical revision history

Table 406: 32N Technical revision history

Technical revision	Change
B	Equation for residual power calculation has been updated: Po = 3VGIGCosϕ. The previous equation was: Po = VGIGCosϕ. The change has an effect on the *Power pickup value* definition. The previous equation is in use in the 615 Ver.4.0 with SW revision 4.0 and 615 Ver.4.0 FP1 with SW revision 4.1. All newer versions of 615 series have the updated equation.
C	Internal improvement

4.2.7 Third harmonic-based stator ground-fault protection 27/59THN

4.2.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Third harmonic-based stator ground-fault protection	H3EFPSEF	dUo>/Uo3H	27/59THN

4.2.7.2 Function block

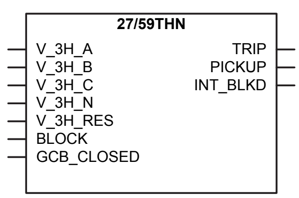


Figure 204: Function block

4.2.7.3 Functionality

The third harmonic-based stator ground-fault protection 27/59THN is used to detect stator ground fault at the neutral point and at least up to 15...20% from the neutral point along the stator winding. 27/59THN compares the third harmonic voltages produced by the generator itself at both neutral and terminal side of the generator for detecting ground fault.

27/59THN provides two alternative protection methods.

- Differential of the third harmonic component measured both at generator neutral and terminal side
- Neutral side third harmonic undervoltage

27/59THN operates with the definite time DT characteristics.

The function contains a blocking functionality. Blocking deactivates all outputs and reset timers.

4.2.7.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 27/59THN can be described using a module diagram. All the modules in the diagram are explained in the next sections.

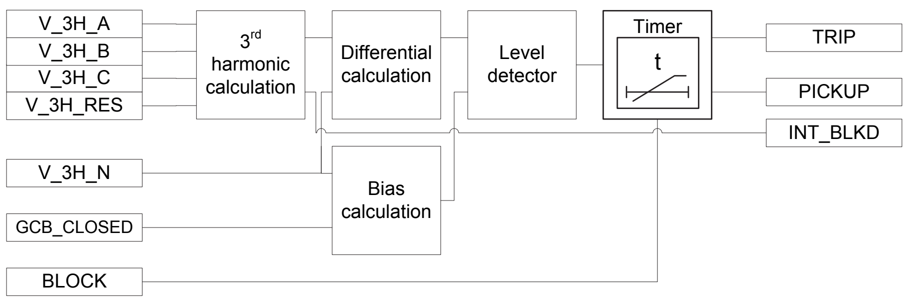


Figure 205: Functional module diagram

3rd harmonic calculation (terminal side)

3rd harmonic calculation calculates the magnitude and phase angle of the third harmonic voltage at the generator terminal $\overline{V}_{3H\_T}$. Calculation of the third harmonic voltage depends on the availability of terminal side voltage and is specified by the *Voltage selection* setting.

- *Voltage selection* setting is set to "No voltage" if phase-to-ground voltages are not available at the terminal side. Even in a situation where only phase-to-phase voltages are available, *Voltage selection* is set to "No Voltage" because phase-to-phase voltages do not contain a third harmonic component. With *Voltage selection* set to "No Voltage", third harmonic-based ground-fault protection is based on third harmonic neutral side undervoltage protection.
- *Voltage selection* setting is set to "Measured VG" if the terminal side voltage is fed from an open delta voltage connection of the voltage transformer. In this case, the terminal side third harmonic voltage $\overline{V}_{3H\_T}$ is same as the measured open delta

voltage $\overline{V}_{3H\_RES}$. This is the recommended option for calculating the terminal side third harmonic voltage.

$$\overline{V}_{3H\_T} = \overline{V}_{3H\_RES}$$

(Equation 44)

- *Voltage selection* setting is set to "Calculated V0" if all three phase-to-ground voltages are available. In this case, the terminal side third harmonic voltage is calculated as a vector average of the third harmonic voltage of all three phases.

$$\overline{V}_{3H\_T} = \frac{1}{3} \cdot \left(\overline{V}_{3H\_A} + \overline{V}_{3H\_B} + \overline{V}_{3H\_C} \right)$$

(Equation 45)

- If only one phase-to-ground voltage is available, the *Voltage selection* setting is set to the respective phase, that is, "Phase A" or "Phase B" or "Phase C" based on the available phase. In this case, the magnitude of the terminal side third harmonic voltage is assumed to be equal to the third harmonic voltage of the phase available.

$$\overline{V}_{3H\_T} = \overline{V}_{3H\_A} \text{ or } \overline{V}_{3H\_B} \text{ or } \overline{V}_{3H\_C}$$

(Equation 46)

The function is internally blocked if the magnitude of calculated $\overline{V}_{3H\_T}$ is lower than the set *Voltage block value*, this also activates the `INT_BLKD` output.

Differential calculation

The amplitude of the third harmonic differential voltage can be calculated using the following equation.

$$VD_{3H} = \left| \overline{V}_{3H\_T} + \overline{V}_{3H\_N} \right|$$

(Equation 47)

VD_{3H}	Magnitude of the third harmonic differential voltage
$\overline{V}_{3H\_T}$	Terminal side third harmonic voltage phasor
$\overline{V}_{3H\_N}$	Neutral side third harmonic voltage phasor

The magnitude of the third harmonic differential voltage `UD_3H` and the phase angle difference between the terminal side and neutral side third harmonic voltage `U_3HANGL_T_N` are available in the Monitored data view.

Bias calculation

The amplitude of the third harmonic bias voltage can be calculated using the following equation.

$$VB_{3H} = Beta \cdot \left|\overline{V}_{3H\_N}\right|$$

(Equation 48)

VB_{3H}	Magnitude of the third harmonic bias voltage
Beta	Setting to achieve the required degree of security under healthy conditions
$\overline{V}_{3H\_N}$	Neutral side third harmonic voltage phasor

The third harmonic bias voltage calculation shown in Equation 48 is valid under all operating conditions if there is no generator circuit breaker between generator and transformer. But if the generator circuit breaker is used, it is needed to reduce the sensitivity of the protection when it is open. The use of the generator circuit breaker is defined by *Generator CB used* setting set to "Yes" and the open position is sensed when the binary input `GCB_CLOSED` available is FALSE.

With the generator breaker in the open position, function desensitizes the protection by multiplying the value of the *Beta* setting with the set constant *CB open factor* setting.

$$VB_{3H} = CB\ open\ factor \cdot Beta \cdot \left|\overline{V}_{3H\_N}\right|$$

(Equation 49)

Neutral side third harmonic voltage is measured via a voltage transformer between the generator neutral point and the ground. The magnitude of the third harmonic biased voltage `UB_3H` is available in the Monitored data view.

Level detector

In the third harmonic differential method, the Level detector compares the third harmonic differential voltage with the third harmonic bias voltage. If the differential voltage exceeds the biased voltage, the module sends an enabling signal to start the timer.

If the terminal voltage is not available, that is, *Voltage selection* is set to "No voltage" the module compares the neutral side third harmonic voltage `V_3H_N` to the set *Voltage N 3.H Lim*.

Timer

Once activated, the Timer activates the `PICKUP` output. The Timer characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated. If the fault disappears before the module operates, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the PICKUP output is deactivated.

The Timer calculates the pickup duration PICKUP_DUR value, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the Monitored data view.

The binary input BLOCK can be used to block the function. The activation of the BLOCK input deactivates all outputs and resets internal timers.

4.2.7.5 Application

Mechanical and thermal stress deteriorates stator winding insulation, which can eventually cause a ground fault between the winding and stator core.

The fault current magnitude in case of stator ground fault depends on the grounding type. Common practice in most countries is to ground the generator neutral side through a resistor. The resistor is selected such as to limit the maximum ground-fault current in the range of 5...10 A. The same can be done by connecting a single phase voltage transformer between the neutral side and ground, and with an equivalent resistor on the secondary side of the transformer.

In a normal operating condition, that is, when there is no ground fault, the residual voltage is close to zero with no zero-sequence current flowing in the generator. When a phase-to-ground fault occurs, the residual voltage increases and the current flows through the neutral. The simplest way to protect the stator winding against a ground fault is by providing residual overvoltage protection (or residual/neutral overcurrent protection). However, at best these simple schemes can protect only 95% of the stator winding, leaving 5% of the neutral end unprotected. This is because the voltage generated in the faulted winding decreases as the fault point becomes closer to the neutral point and it is not enough to drive the protection. Under certain unfavorable conditions, the blind zone may extend up to 20% from the neutral point.

A ground fault close to the neutral point is not dangerous, but an undetected fault may develop into an interturn fault or phase-to-phase fault. Also an undetected ground fault near the neutral point is bypassing the high-impedance grounding, and then another ground fault at the terminal results in a catastrophic situation.

Therefore, it is important to extend the protection to full 100%. The third harmonic voltage-based protection is one such protection which provides effective protection during a ground fault at the neutral point, and at least in the range up to 15...20% from the neutral point along the stator winding.

To achieve a complete stator ground-fault protection, two protection functions should always run in parallel.

- Fundamental frequency-based residual overvoltage protection 59N, 59G
- Third harmonic voltage-based protection 27/59THN

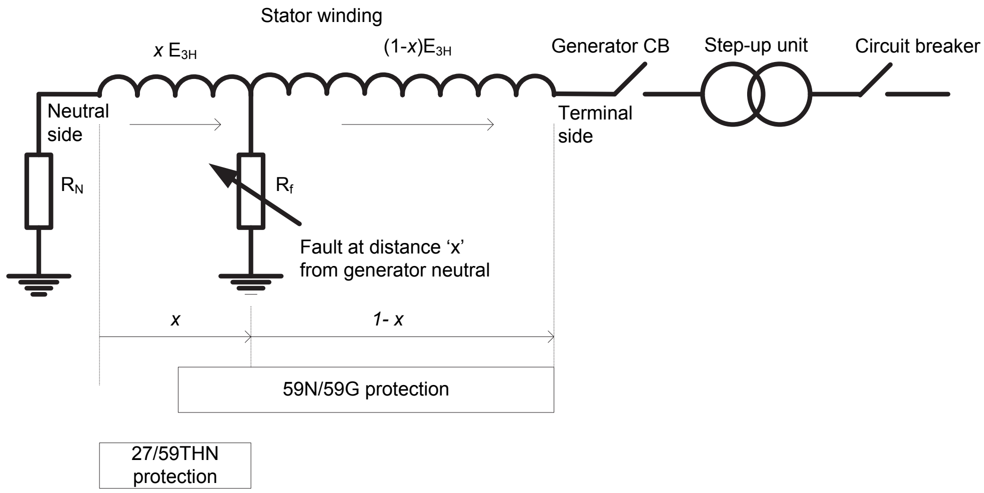


Figure 206: Complete stator ground-fault protection

Third harmonic voltage-based differential protection

The voltage generated by a generator is not a perfect sinusoidal wave but contains triplen harmonics voltages. These triplen harmonics appear in each phase with the same magnitude and angle, due to which they do not sum to zero and thus also appear in the neutral side of the generator as a zero-sequence quantity. Among all the triplen harmonics voltages generated, the third harmonic voltage has the highest magnitude with the magnitude varying between 1% and 10% of the terminal voltage, depending on the generator design philosophy. However, for a particular generator the magnitude of third harmonics on the neutral side and terminal side depends also on the active power generated.

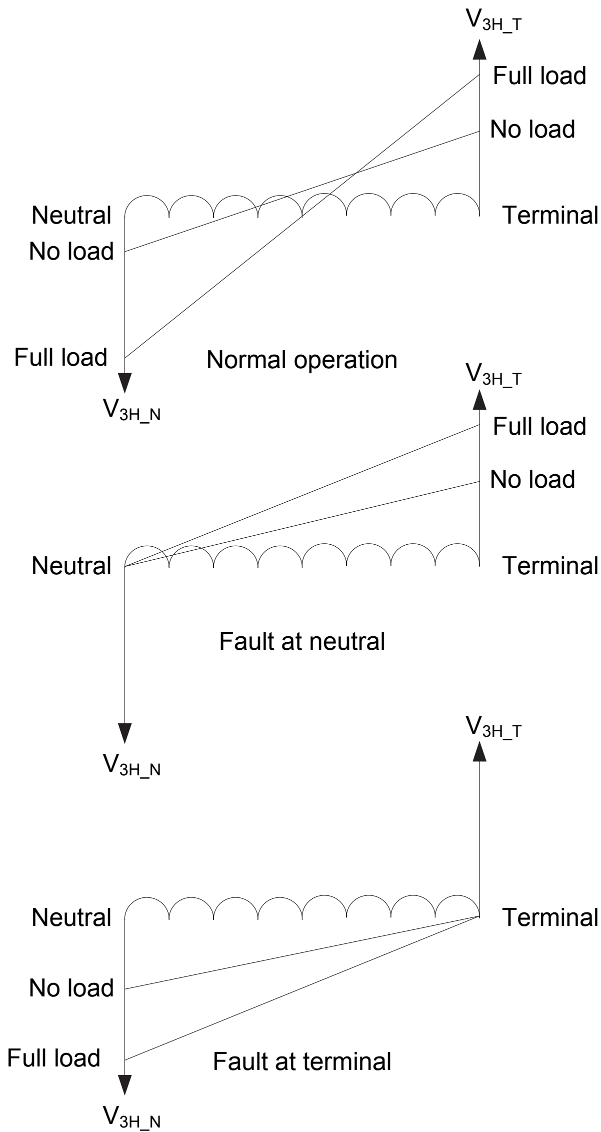


Figure 207: Typical example of the third-harmonic voltage measured at the generator neutral and terminals under different conditions

The operating equation of the protection is described in the following equation.

$$\left|\overline{V}_{3H\_T} + \overline{V}_{3H\_N}\right| - Beta \cdot \left|\overline{V}_{3H\_N}\right| = 0$$

(Equation 50)

The third harmonic voltages $\overline{V}_{3H\_T}$ and $\overline{V}_{3H\_N}$ are the phasor with its real and imaginary parts. $\overline{V}_{3H\_T}$ is approximately in the opposite direction to that of the $\overline{V}_{3H\_N}$, however the actual no-fault angle between those two phasors depends on the type of generator grounding. For example, the angle is about 145 degrees for a high-resistance-grounded unit generator.

The equation defines the "operate" and "restrain" regions of the protection. The third harmonic differential protection operates according to the following equation.

$$\left|\overline{V}_{3H\_T} + \overline{V}_{3H\_N}\right| \geq Beta \cdot \left|\overline{V}_{3H\_N}\right|$$

(Equation 51)

$\overline{V}_{3H\_N}$	Neutral side third harmonic voltage phasor
$\overline{V}_{3H\_T}$	Terminal side third harmonic voltage phasor
Beta	Setting to achieve a required degree of security under healthy conditions
$\left\|\overline{V}_{3H\_T} + \overline{V}_{3H\_N}\right\|$	Magnitude of the third harmonic differential voltage
$Beta \cdot \left\|\overline{V}_{3H\_N}\right\|$	Magnitude of the third harmonic bias (restrain) voltage

Factor *Beta*, which is a setting, can be determined from the condition.

$$\frac{Beta \cdot \left|\overline{V}_{3H\_N}\right|}{\left|\overline{V}_{3H\_T} + \overline{V}_{3H\_N}\right|} = K$$

(Equation 52)

K is the security factor, for example K = 1.5. Equation 52 must be satisfied in the normal, healthy condition of the protected generator, with a high enough value for K, so that no unwanted operation of the protection should be expected, regardless the load on the generator.

To assure a reliable functioning of the protection, it is necessary that the generator produces third harmonic voltage which is at least 1% of the generator rated voltage.

As phase-to-phase voltages do not contain a third harmonic component, in situations where the VTs on the terminal side are connected between phase-to-phase, the differential protection in Equation 52 cannot work. In such case, the *Voltage selection* setting is set to "No Voltage" and 27/59THN operates as a simple neutral side third harmonic undervoltage protection.

When 27/59THN is reduced to function as only a third harmonic neutral point undervoltage protection, it is necessary to block the function during start-up and shutdown of generator and also when there is no sufficient voltage.

Calculating Beta value

The setting *Beta* gives the proportion of the third harmonic voltage in the neutral point of the generator to be used as bias quantity. *Beta* must be set so that there is no risk of trip during the normal, non-faulted operation of the generator. If *Beta* is set high, this limits the portion of the stator winding covered by the protection. In most cases, the default setting “3.00” gives an acceptable sensitivity for a ground fault near the neutral point of the stator winding. However, to assure the best performance, measurements during the normal operation of the generator are to be made during commissioning.

1. The value of the *Beta* setting must be set to “1.00”.
2. Loading of the generator is done at 5 to 10 different load points and the third harmonic differential and bias voltage are measured. Both quantities can be obtained from the Monitored data view of the function.
3. A graph indicating differential and bias voltages as a functions of the load on the generator must be plotted.
4. Based on the graph, such value of the *Beta* setting must be selected that the bias voltage, even in the worst condition, is at least 30% to 50% higher than the differential voltage.

The angle between the third harmonic voltage phasors $\overline{V}_{3H\_T}$ and $\overline{V}_{3H\_N}$ is 150°, and with the *Beta* setting value "1.0", protection guarantees a stability margin of 25%. This requires the value of *Beta* to be increased so as to increase the stability of protection. The recommended value of the *Beta* setting is at least “1.2”.

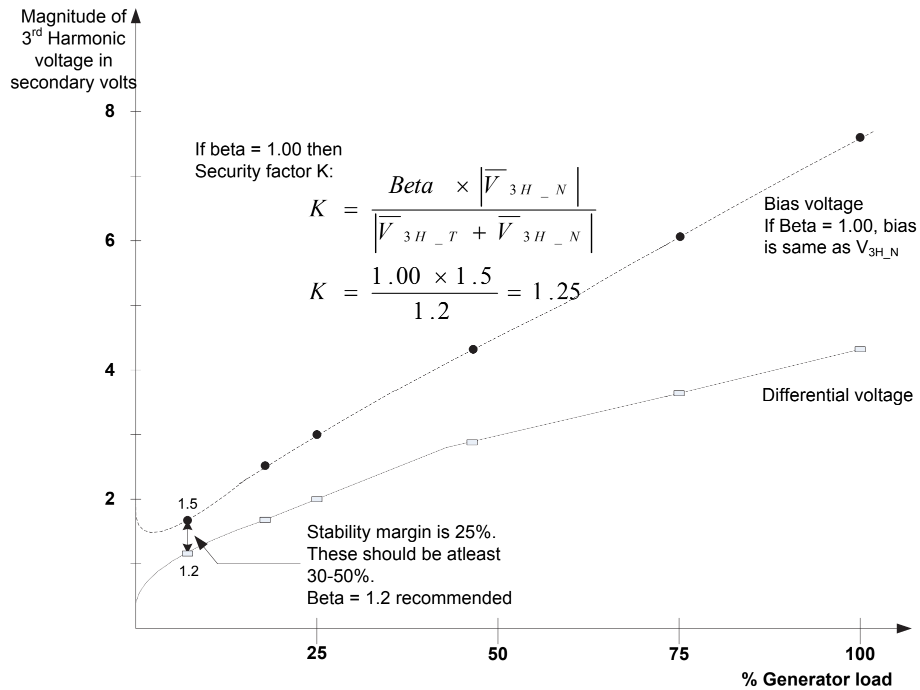


Figure 208: Typical example of variation of the bias voltage and differential voltage with a change in the active generated load (the angle between the third harmonic terminal and neutral voltage is 150°)

Calculating CB Open factor

One of the factors, though not major, governing the magnitude of the generated third harmonic voltage is the generator terminal capacitance. If there is no generator breaker, the capacitive coupling to ground is the same under all operating conditions. However, the generator breaker normally exists between the protected generator and its power transformer.

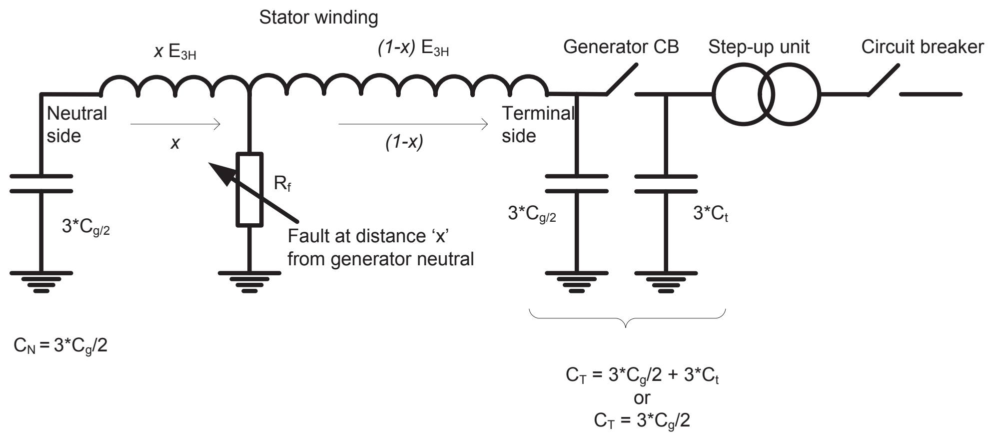


Figure 209: Capacitance seen at generator terminal and neutral side

C_g	Phase capacitance of generator stator winding
C_t	Total external phase capacitance of the system as seen from the generator
C_N	Phase-to-ground lumped capacitance of the generator stator winding, between the ground-fault location and the generator neutral
C_T	Phase-to-ground lumped capacitance of the generator stator winding, between the generator terminal and ground-fault location

When there is a generator breaker, the capacitive coupling to ground differs between the operating conditions when the generator is running with the generator breaker open (before synchronization) and with the circuit breaker closed.

With the generator breaker open, the total capacitance is smaller compared to normal operating conditions. This means that the neutral side third harmonic voltage is reduced compared to the normal operating condition. Therefore, there is a need to reduce the sensitivity of the protection. When generator breaker is open, 27/59THN desensitizes the protection by multiplying the *Beta* setting with a set constant *CB open factor* setting.

$$\left|\overline{V}_{3H\_T} + \overline{V}_{3H\_N}\right| \geq CB\ open\ factor \cdot Beta \cdot \left|\overline{V}_{3H\_N}\right|$$

(Equation 53)

The *CB Open factor* setting is obtained during commissioning.

1. For a particular value of *Beta* the third harmonic neutral voltage is measured with the generator in the no-load condition and the circuit breaker in the closed position.
2. With the same condition, the third harmonic neutral voltage with the circuit breaker in the open position is measured.
3. *CB Open factor* should be set equal to the ratio of the third harmonic neutral voltage measured with the circuit breaker in the closed position to that in the open.

4.2.7.6 Signals

Table 407: 27/59THN Input signals

Name	Type	Default	Description
V_3H_A	SIGNAL	0	Third harmonic of phase A voltage
V_3H_B	SIGNAL	0	Third harmonic of phase B voltage
V_3H_C	SIGNAL	0	Third harmonic of phase C voltage
V_3H_N	SIGNAL	0	Third harmonic of neutral voltage
V_3H_RES	SIGNAL	0	Third harmonic of residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
GCB_CLOSED	BOOLEAN	0=False	Generator CB in closed position

Table 408: 27/59THN Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
INT_BLKD	BOOLEAN	Protection internally blocked

4.2.7.7 Settings

Table 409: 27/59THN Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Beta	0.50...10.00		0.01	3.00	Portion of neutral side 3rd harmonic used as bias
Voltage N 3.H Lim	0.005...0.200	xUn	0.001	0.010	Pickup value for 3rd harmonic residual undervoltage protection
Trip delay time	20...300000	ms	10	20	Trip delay time

Table 410: 27/59THN Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage selection	1=No voltage 2=Measured VG 3=Calculated V0 4=Phase A 5=Phase B 6=Phase C			2=Measured VG	Type of voltage connection available at generator terminal
CB open factor	1.00...10.00		0.01	1.00	Multiplication factor for beta when CB is in open condition

Table 411: 27/59THN Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 412: 27/59THN Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage block value	0.010...0.100	xUn	0.001	0.010	Low level blocking for 3rd harmonic differential protection
Generator CB used	0=No 1=Yes			0=No	Defines if generator circuit breaker exists
Reset delay time	0...60000	ms	1	20	Reset delay time

4.2.7.8 Monitored data

Table 413: 27/59THN Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
UD_3H	FLOAT32	0.00...40.00	xUn	3rd harmonic differential voltage amplitude
UB_3H	FLOAT32	0.00...40.00	xUn	3rd harmonic bias voltage amplitude
U_3H_T	FLOAT32	0.00...40.00	xUn	Terminal side 3rd harmonic voltage amplitude
U_3H_N	FLOAT32	0.00...40.00	xUn	Neutral side 3rd harmonic voltage amplitude
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
U_3H_N	FLOAT32	0.00...40.00	xUn	Neutral side 3rd harmonic voltage amplitude
U_3HANGL_T_N	FLOAT32	-180.00...180.00	deg	Phase angle between 3rd harmonic terminal and neutral voltage
27/59THN	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.7.9 Technical data

Table 414: 27/59THN Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured voltage: f_n ±2 Hz
	±5% of the set value or ±0.004 × V_n
Pickup time1)2)	Typically 35 ms
Reset time	Typically 35 ms
Reset ratio	Typically 0.96 (differential mode) Typically 1.04 (under voltage mode)
Trip time accuracy	±1.0% of the set value of ±20 ms

1) f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.2.8 Multifrequency admittance-based ground-fault protection 67YN

4.2.8.1 Identification

Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Multifrequency admittance-based ground-fault protection	MFADPSDE	Io> ->Y	67YN

4.2.8.2 Function block

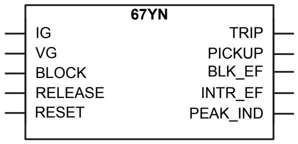


Figure 210: Function block

4.2.8.3 Functionality

The multifrequency admittance-based ground-fault protection function 67YN provides selective directional ground-fault protection for high-impedance grounded networks, that is, for compensated, ungrounded and high resistance grounded systems. It can be applied for the ground-fault protection of overhead lines and underground cables.

The operation of 67YN is based on multifrequency neutral admittance measurement, utilizing cumulative phasor summing technique. This concept provides extremely secure, dependable and selective ground-fault protection also in cases where the residual quantities are highly distorted and contain non-fundamental frequency components.

The sensitivity that can be achieved is comparable with traditional fundamental frequency based methods such as IoCos/IoSin (67/51N, 67/50N), Watt/Varmetric (32N) and neutral admittance (21YN).

67YN is capable of detecting faults with dominantly fundamental frequency content as well as transient, intermittent and restriking ground faults. 67YN can be used as an alternative solution to transient or intermittent function 67NIEF.

67YN supports fault direction indication both in operate and non-operate direction, which may be utilized during fault location process. The inbuilt transient detector can be used to identify restriking or intermittent ground faults, and discriminate them from permanent or continuous ground faults.

The operation characteristic is defined by a tilted operation sector, which is universally valid for ungrounded and compensated networks.

The operating time characteristic is according to the definite time (DT).

The function contains a blocking functionality to block function outputs, timers or the function itself.

4.2.8.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 67YN can be described using a module diagram. All the modules in the diagram are explained in the following sections.

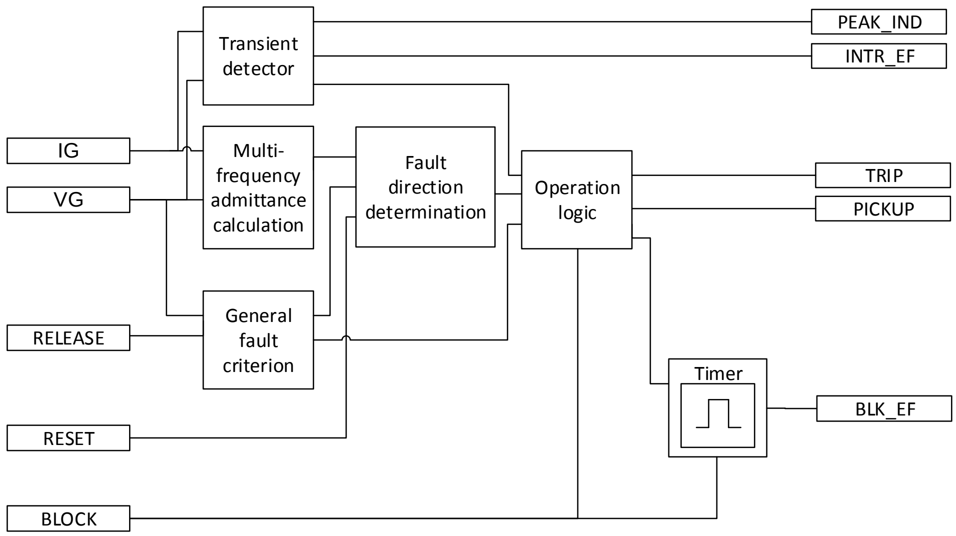


Figure 211: Functional module diagram

General fault criterion

The General fault criterion (GFC) module monitors the presence of ground fault in the network and it is based on the value of the fundamental frequency zero-sequence voltage defined as the vector sum of fundamental frequency phase voltage phasors divided by three.

$$\overline{V_0^1} = \left(\overline{V_A^1} + \overline{V_B^1} + \overline{V_C^1}\right) / 3$$

(Equation 54)

When the magnitude of $\underline{V}_o^1$ exceeds setting *Voltage pickup value*, a ground fault is detected. The GFC module reports the exceeded value to the Fault direction determination module and Operation logic. The reporting is referenced as General Fault Criterion release.

The setting *Voltage pickup value* defines the basic sensitivity of the 67YN function. To avoid unselective pickup or trip, *Voltage pickup value* must always be set to a value which exceeds the maximum healthy-state zero-sequence voltage value, taking into consideration of possible network topology changes, compensation coil and parallel resistor switching status and compensation degree variations.

As an alternative for internal residual zero-sequence overvoltage based pickup-condition, 67YN function can also be externally released by utilizing the `RELEASE` input. In this case, the external release signal overrides the *Voltage pickup value* setting and sets the internal limit to minimum value.

Multi-frequency admittance calculation

Multi-frequency admittance calculation module calculates neutral admittances utilizing fundamental frequency and the 2nd, 3rd, 5th, 7th and 9th harmonic components of residual current and zero-sequence voltage. The following admittances are calculated, if the magnitude of a particular harmonic in residual current and zero-sequence voltage are measurable by the protection relay.

Fundamental frequency admittance (conductance and susceptance)

$$\overline{Y_0^1} = \frac{3 \cdot \overline{I_0^1}}{-\overline{V_0^1}} = G_o^1 + j \cdot B_o^1$$

(Equation 55)

$\overline{Y_0^1}$	The fundamental frequency neutral admittance phasor.
$\overline{I_0^1}$	The fundamental frequency zero-sequence current phasor $(= (\overline{I_A^1} + \overline{I_B^1} + \overline{I_C^1}) / 3)$
$\overline{V_0^1}$	The fundamental frequency zero-sequence voltage phasor $= \overline{V_A^1} + \overline{V_B^1} + \overline{V_C^1} / 3$
G_o^1	The fundamental frequency conductance, $\mathrm{Re}\left(\overline{Y_0^1}\right)$
B_o^1	The fundamental frequency susceptance, $\mathrm{Im}\left(\overline{Y_0^1}\right)$

Harmonic susceptance

$$\mathrm{Im}\left[\overline{Y_0^n}\right] = \mathrm{Im}\left[\frac{3 \cdot \overline{I_0^n}}{-\overline{V_0^n}}\right] = j \cdot B_o^n$$

(Equation 56)

where n = 2, 3, 5, 7 and 9

$\overline{Y_0^n}$ The nth harmonic frequency neutral admittance phasor.

$\overline{I_0^n}$ The nth harmonic frequency zero-sequence current phasor.

$\overline{V_0^n}$ The nth harmonic frequency zero-sequence voltage phasor.

B_o^n The nth harmonic frequency susceptance, $\mathrm{Im}\left(\overline{Y_0^n}\right)$

For fault direction determination, the fundamental frequency admittance and harmonic susceptances are summed together in phasor format. The result is the sum admittance phasor defined as below.

$$\overline{Y}_{osum} = \mathrm{Re}\left[\overline{Y_0^1}\right] + j \cdot \mathrm{Im}\left[\overline{Y_0^1} + \sum_{n=2}^{9} \overline{Y_0^n}\right] = G_o^1 + j \cdot B_{osum}$$

(Equation 57)

The polarity of the polarizing quantity (residual voltage) can be changed (rotated by 180 degrees) by setting the *Pol reversal* parameter to "True" or by switching the polarity of the residual voltage measurement wires.

Fault direction determination

If a ground fault is detected by the GFC module, the fault direction is evaluated based on the calculated sum admittance phasor $\overline{Y}_{osum}$ obtained from the Multi-frequency admittance calculation module. To obtain dependable and secure fault direction determination regardless of the fault type (transient, intermittent, restriking, permanent, high or low ohmic), the fault direction is calculated using a special filtering algorithm, Cumulative Phasor Summing (CPS) technique. This filtering method is advantageous during transient, intermittent and restriking ground faults with dominantly non-sinusoidal or transient content. It is equally valid during continuous (stable) ground faults.

The concept of CPS is illustrated in Figure 212. It is the result of adding values of the measured sum admittance phasors together in phasor format in chronological order during the fault. Using the discrete sum admittance phasors $\overline{Y}_{osum}$ in different time instants ($t_1...t_5$), the corresponding accumulated sum admittance phasor $\overline{Y}_{osum\_CPS}$ is calculated. This phasor is used as directional phasor in determining the direction of the fault.

$$\overline{Y}_{osum\_CPS}(t_1) = \overline{Y}_{osum}(t_1)$$

(Equation 58)

$$\overline{Y}_{osum\_CPS}(t_2) = \overline{Y}_{osum}(t_1) + \overline{Y}_{osum}(t_2)$$

(Equation 59)

$$\overline{Y}_{osum\_CPS}(t_3) = \overline{Y}_{osum}(t_1) + \overline{Y}_{osum}(t_2) + \overline{Y}_{osum}(t_3)$$

(Equation 60)

$$\overline{Y}_{osum\_CPS}(t_4) = \overline{Y}_{osum}(t_1) + \overline{Y}_{osum}(t_2) + \overline{Y}_{osum}(t_3) + \overline{Y}_{osum}(t_4)$$

(Equation 61)

$$\overline{Y}_{osum\_CPS}(t_5) = \overline{Y}_{osum}(t_1) + \overline{Y}_{osum}(t_2) + \overline{Y}_{osum}(t_3) + \overline{Y}_{osum}(t_4) + \overline{Y}_{osum}(t_5)$$

(Equation 62)

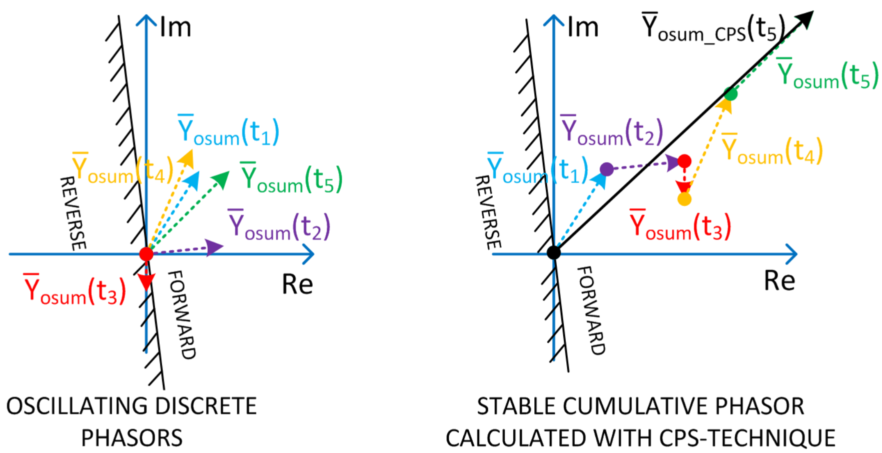


Figure 212: Principle of Cumulative Phasor Summing (CPS)

The CPS technique provides a stable directional phasor quantity despite individual phasors varying in magnitude and phase angle in time due to a non-stable fault type such as restriking or intermittent ground fault. This is also true for harmonic components included in the sum admittance phasor. Harmonics have typically a highly fluctuating character.

Harmonic components provide a more distinctive directional determination in compensated networks than the fundamental frequency component. The higher the frequencies, the compensation coil appears as very high impedance and the harmonics are not affected by compensation coil and degree of compensation. When harmonics are present, they cause the sum admittance phasor to behave as in case of an ungrounded network, where directional phasors point in fully opposite directions in the faulty and healthy feeder.

The direction of the 67YN function is defined with setting *Directional mode* as “Forward” or “Reverse”. The operation characteristic is defined by tilted operation sector as illustrated in Figure 213. The characteristic provides universal applicability, that is, it is valid both in compensated and ungrounded networks, also if the compensation coil is temporarily switched off. The tilt of the operation sector is defined with setting *Tilt angle* to compensate the measurement errors of residual current and voltage transformers. The typical setting value of 5 degrees is recommended, but it should always reflect the actual maximum expected measurement errors.

In case of ungrounded network operation, adequate tilt angle must be allowed to ensure dependable operation of 67YN.

In Figure 214, phasors 1...4 demonstrate the behavior of the directional phasor in different network fault conditions.

- Phasor 1 depicts the direction of accumulated sum admittance phasor in case of ground fault outside the protected feeder (assuming that the admittance of the protected feeder is dominantly capacitive). The result is valid regardless of the fault type (low ohmic, high(er) ohmic, permanent, intermittent or restriking). In case harmonic components are present in the fault quantities, they would turn the phasor align to the negative $\mathrm{Im}(\overline{Yo})$ axis.
- Phasor 2 depicts the direction of accumulated sum admittance phasor in case of ground fault inside the protected feeder when the network is ungrounded. The result is also valid in compensated networks when there are harmonic components present in the fault quantities (typically low ohmic permanent or intermittent or restriking fault). In this case, the result is valid regardless of network’s actual compensation degree. Harmonics would turn the phasor align to the positive $\mathrm{Im}(\overline{Yo})$ axis.
- Phasors 3 and 4 depict the direction of accumulated sum admittance phasor in case of higher-ohmic ground fault in the protected feeder without harmonics in the fault quantities when the network is compensated. As no harmonic components are present, the phase angle of the accumulated phasor is determined by the compensation degree of the network. With high degree of overcompensation, the phasor turns towards the negative $\mathrm{Im}(\overline{Yo})$ axis (as phasor 4).

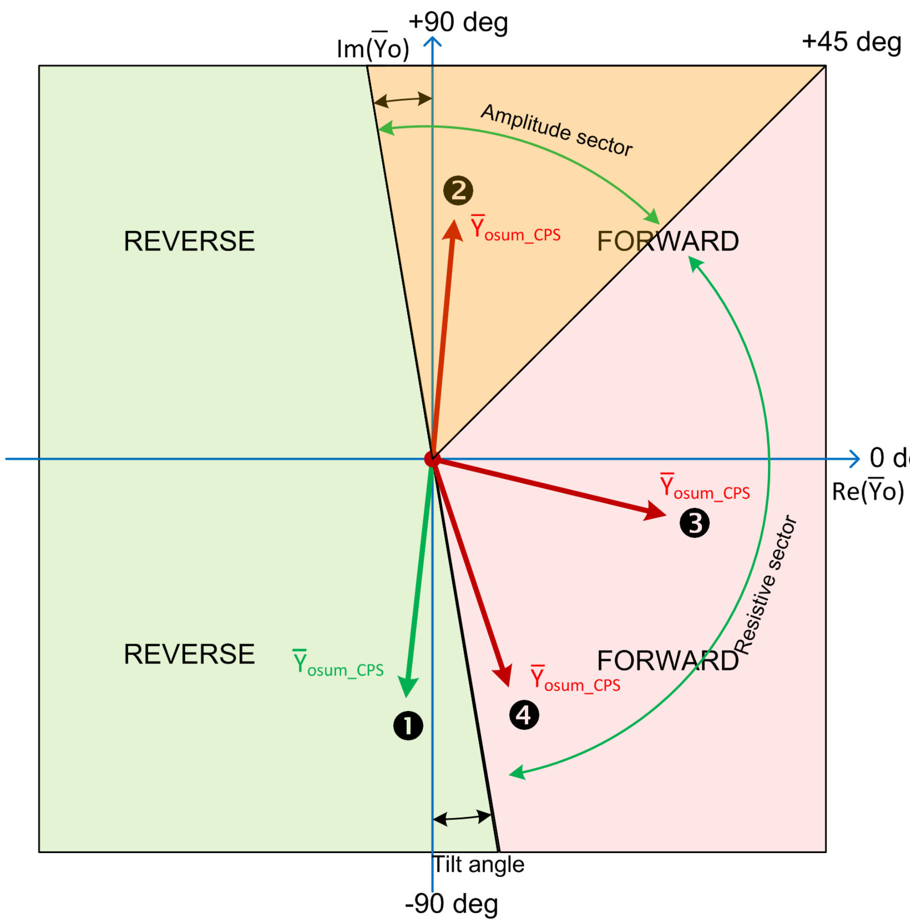


Figure 213: Directional characteristic of 67YN

The residual current is recommended to be measured with accurate core balance current transformer to minimize the measurement errors, especially phase displacement. This is especially important, when high sensitivity of protection is targeted.

The characteristic *Tilt angle* should reflect the measurement errors, that is, the larger the measurement errors, the larger the *Tilt angle* setting should be. Typical setting value of 5 degrees is recommended.

The detected fault direction is available in the Monitored data view as parameter *DIRECTION*.

To adapt the fault direction determination to possible fault direction change during the fault, for example, during manual fault location process, a cyclic accumulation of sum admittance phasors is conducted. The duration of this directional evaluation cycle is 1.2 · *Reset delay time* (minimum of 600 ms). If the fault direction based on the cyclic phasor accumulation is opposite to the function direction output for *Reset delay time* or 500 ms (minimum of 500 ms), the function is reset and fault direction calculation of 67YN is restarted.

In case the ground-fault protection is alarming, the 67YN includes also a `RESET` input, which can be utilized to externally re-trigger the fault direction determination, if re-evaluation of fault direction during a persistent ground fault is required. It is also recommended to connect the pickup signal of non-directional ground-fault protection (51N, 51G, 50N, 50G, 50N-3, 50G-3), set to trip in case of a cross-country fault, to `RESET` input of 67YN to reset phasor accumulation during a cross-country fault. 67YN is then able to adapt to possible fault direction change more rapidly, if single phase ground fault still persists in the system after the other faulty feeder has been tripped (cross-country fault has been transformed back to a single phase ground fault).

The direction of the 67YN function is supervised by a settable current magnitude threshold. The trip current used in the magnitude supervision is measured with a special filtering method, which provides very stable residual current estimate regardless of the fault type. This stabilized current estimate is the result from fundamental frequency admittance calculation utilizing the CPS technique. The stabilized current value is obtained (after conversion) from the corresponding admittance value by multiplying it with the system nominal phase-to-ground voltage value, which is entered as a base value for the residual voltage ($V_{baseres}$). The equations for calculating the stabilized values of the fundamental frequency admittance and the corresponding current are given below.

$$\overline{Y_{o\ stab}^{1}} = \frac{3 \cdot \overline{I_{0\ CPS}^{1}}}{-\overline{V_{0\ CPS}^{1}}} = \mathrm{Re}\left[\overline{Y_{o\ stab}^{1}}\right] + j \cdot \mathrm{Im}\left[\overline{Y_{o\ stab}^{1}}\right] = G_{ostab}^{1} + j \cdot B_{ostab}^{1}$$

(Equation 63)

$\overline{Y_{o\ stab}^{1}}$	The stabilized fundamental frequency admittance estimate, which is result from fundamental frequency admittance calculation utilizing the Cumulative Phasor Summing (CPS) technique.
$\overline{I_{0\ CPS}^{1}}$	The fundamental frequency zero-sequence current phasor calculated utilizing the Cumulative Phasor Summing (CPS) technique.
$\overline{V_{0\ CPS}^{1}}$	The fundamental frequency zero-sequence voltage phasor calculated utilizing the Cumulative Phasor Summing (CPS) technique.
G_{ostab}^{1}	The real-part of stabilized fundamental frequency conductance estimate.
B_{ostab}^{1}	The imaginary part of stabilized fundamental frequency susceptance estimate.

$$\overline{I^1_{o\ stab}} = (G^1_{ostab} + j \cdot B^1_{ostab}) \cdot V_{baseres} = I^1_{oCosstab} + j \cdot I^1_{oSinstab}$$

(Equation 64)

$\overline{I^1_{o\ stab}}$	The stabilized fundamental frequency residual current estimate, which is obtained (after conversion) from the corresponding admittance value by multiplying it with the system nominal phase-to-ground voltage value.
$\overline{I^1_{o\ Cosstab}}$	The real-part of stabilized fundamental frequency residual current estimate.
$\overline{I^1_{o\ Sinstab}}$	The imaginary-part of stabilized fundamental frequency residual current estimate.

The main advantage of the filtering method is that due to the admittance calculation, the resulting current value does not depend on the value of fault resistance, that is, the estimated current magnitude equals the value that would be measured during a solid ground fault ($R_f = 0\ \Omega$). Another advantage of the method is that it is capable of estimating correct current magnitude also during intermittent or restriking faults.

The setting *Min trip current* defines the minimum trip current.

Setting *Operating quantity* defines whether the current magnitude supervision is based on either the “Adaptive” or “Amplitude” methods.

When “Adaptive” is selected, the method adapts the principle of magnitude supervision automatically to the system grounding condition. In case the phase angle of accumulated sum admittance phasor is greater than 45 degrees, the set minimum trip current threshold is compared to the amplitude of $\overline{I^1_{o\ stab}}$ (see Figure 214). In case the phase angle of accumulated sum admittance phasor is below 45 degrees, the set minimum trip current threshold is compared to the resistive component of $\overline{I^1_{o\ stab}}$. This automatic adaptation of the magnitude supervision enables secure and dependable directional determination in compensated networks, and it is also valid when the network is ungrounded (compensation coil is switched off).

In case operation direction is set to reverse, the resistive and amplitude sectors are mirrored in the operation characteristics.

When “Amplitude” is selected, the set minimum trip current threshold is compared to the amplitude of $\overline{I^1_{o\ stab}}$. This selection can be used in ungrounded networks.

In compensated networks, setting *Operating quantity* should be set to “Adaptive”. This enables secure and dependable directional determination on compensated networks and it is also valid when compensation coil is switched off and network becomes ungrounded.

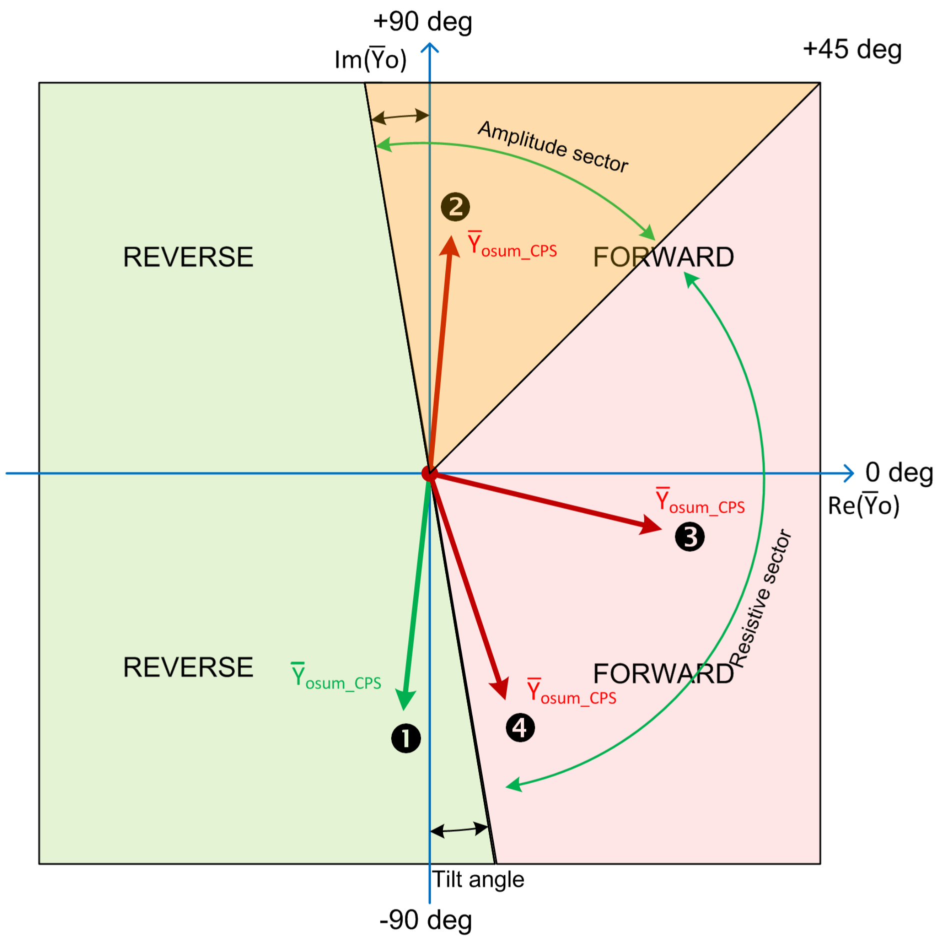


Figure 214: Illustration of amplitude and resistive current sectors if Operating quantity is set "Adaptive" and Directional mode is set "Forward"

The setting rules for current thresholds are given below.

In case the "Adaptive" operating quantity is selected, the setting *Min trip current* should be set to value:

$$[pu] < p \cdot IRtot$$

(Equation 65)

IRtot The total resistive ground-fault current of the network corresponding to the resistive current of the parallel resistor of the coil and the natural losses of the system (typically in order of 1...5 % of the total capacitive ground-fault current of the network).

p security factor = 0.5…0.7

This setting should be set based on the total resistive ground-fault current of the network including the parallel resistor of the coil and the network losses. It must be set to a value which is lower than total resistive ground-fault current in order to enable dependable operation.

For example, if the resistive current of the parallel resistor is 10 A (at primary voltage level), then a value of 0.5 · 10 A = 5 A could be used. The same setting is also applicable in case the coil is disconnected and the network becomes ungrounded (as in this case this setting is compared to the amplitude of $\overline{I}^{1}_{o\ stab}$). The selected setting value must never exceed the ampere value of the parallel resistor in order to allow operation in the faulty feeder. In case of smaller ampere value of the parallel resistor, for example 5 A, the recommended security factor should be larger, for example 0.7, so that sufficient margin for CT and VT errors can be achieved.

In case the “Amplitude” operating quantity is selected, the setting should be selected based on the capacitive ground-fault current values produced by the background network in case of a solid ground fault with a security margin.

The main task of the current magnitude supervision module is to secure the correct directional determination of a ground fault, so that only the faulty feeder is disconnected or alarmed. Therefore, the threshold values should be selected carefully and not set too high as this can inhibit the disconnection of the faulty feeder.

The residual current should be measured with accurate core balance current transformer to minimize the measurement errors, especially phase displacement.

Transient detector

The Transient detector module is used for detecting transients in the residual current and zero-sequence voltage signals. Whenever transient is detected, this is indicated with the `PEAK_IND` output. When the number of detected transients equals or exceeds the *Peak counter limit* setting (without the function being reset, depending on the drop-off time set with the *Reset delay time* setting), `INTR_EF` output is activated. This indicates detection of restriking or intermittent ground fault in the network. Transient detector affects the operation of 67YN (`PICKUP` and `TRIP` outputs) when operation mode is “Intermittent EF”. For other operation modes, (“General EF”, “Alarming EF”), `PEAK_IND` and

INTR_EF outputs can be used for monitoring purposes. The operation of the Transient detector is illustrated in Figure 215.

Several factors affect the magnitude and frequency of fault transients, such as the fault inception angle on the voltage wave, fault location, fault resistance and the parameters of the feeders and the supplying transformers. If the fault is permanent (non-transient) in nature, the initial fault transient in current and voltage can be measured, whereas the intermittent fault creates repetitive transients. The practical sensitivity of transient detection is limited to approximately few hundreds of ohms of fault resistance. Therefore the application of transient detection is limited to low ohmic ground faults.

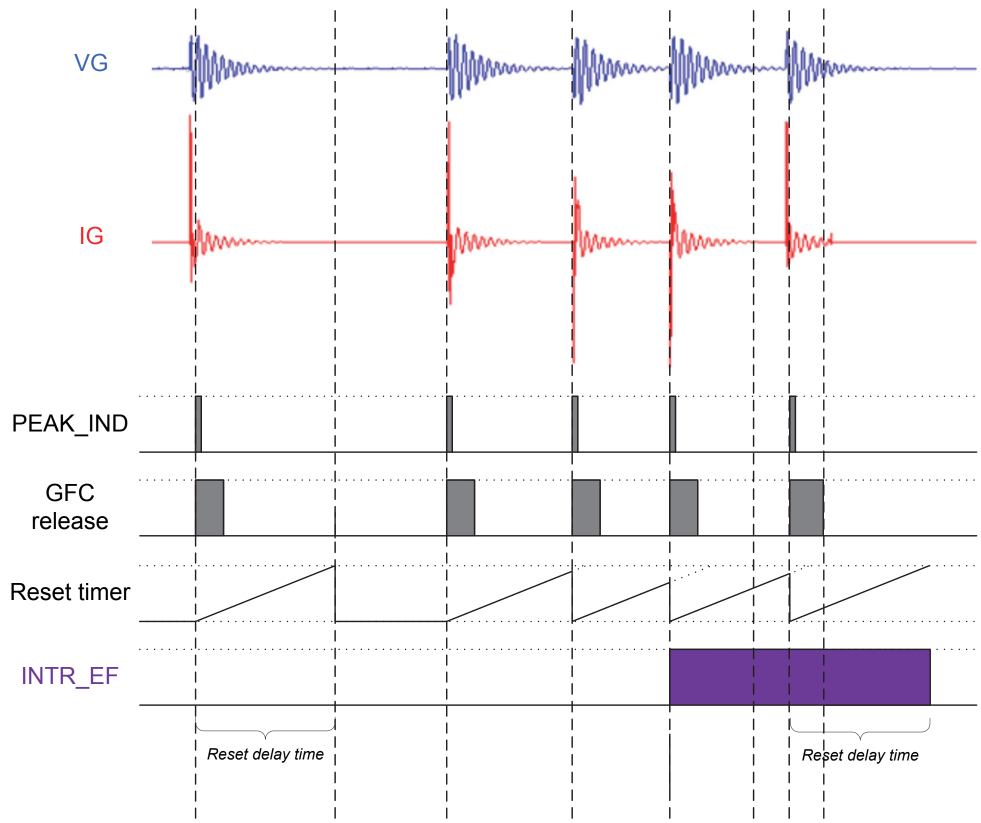


Figure 215: Example of operation of Transient detector: indication of detected transient by PEAK_IND output and detection of restriking or intermittent ground fault by INTR_EF output (setting Peak counter limit = 3)

Operation logic

67YN supports three operation modes selected with setting Operation mode: “General EF”, “Alarming EF” and “Intermittent EF”.

Operation mode “General EF” is applicable in all kinds of ground faults in ungrounded and compensated networks. It is intended to detect all kinds of ground faults regardless of their type (transient, intermittent or restriking, permanent, high or low ohmic). The setting *Voltage pickup value* defines the basic sensitivity of the 67YN function.

In “General EF” mode, the operate timer is started in the following conditions.

- Ground fault is detected by the General Fault Criterion (GFC)
- Fault direction equals *Directional mode* setting
- Estimated stabilized fundamental frequency residual current exceeds the set *Min trip current* level

The PICKUP output is activated once *Pickup delay time* has elapsed. TRIP output is activated once *Trip delay time* has elapsed and the above three conditions are valid. Reset timer is started if any of the above three conditions is not valid. In case fault is transient and self-extinguishes, PICKUP output stays activated until the elapse of reset timer (setting Reset delay time). After TRIP output activation, PICKUP and TRIP outputs are reset immediately, if any of the above three conditions is not valid. The pickup duration value PICKUP_DUR, available in the Monitored data view, indicates the percentage ratio of the pickup situation and the set operating time.

In case detection of temporary ground faults is not desired, the activation of PICKUP output can be delayed with setting *Pickup delay time*. The same setting can be also used to avoid restarting of the function during long lasting post-fault oscillations, if time constant of post-fault oscillations is very long (network losses and damping is low).

To keep the operate timer activated between current spikes during intermittent or restriking ground fault, the *Reset delay time* should be set to a value exceeding the maximum expected time interval between fault spikes (obtained at full resonance condition). Recommended value is at least 300 ms.

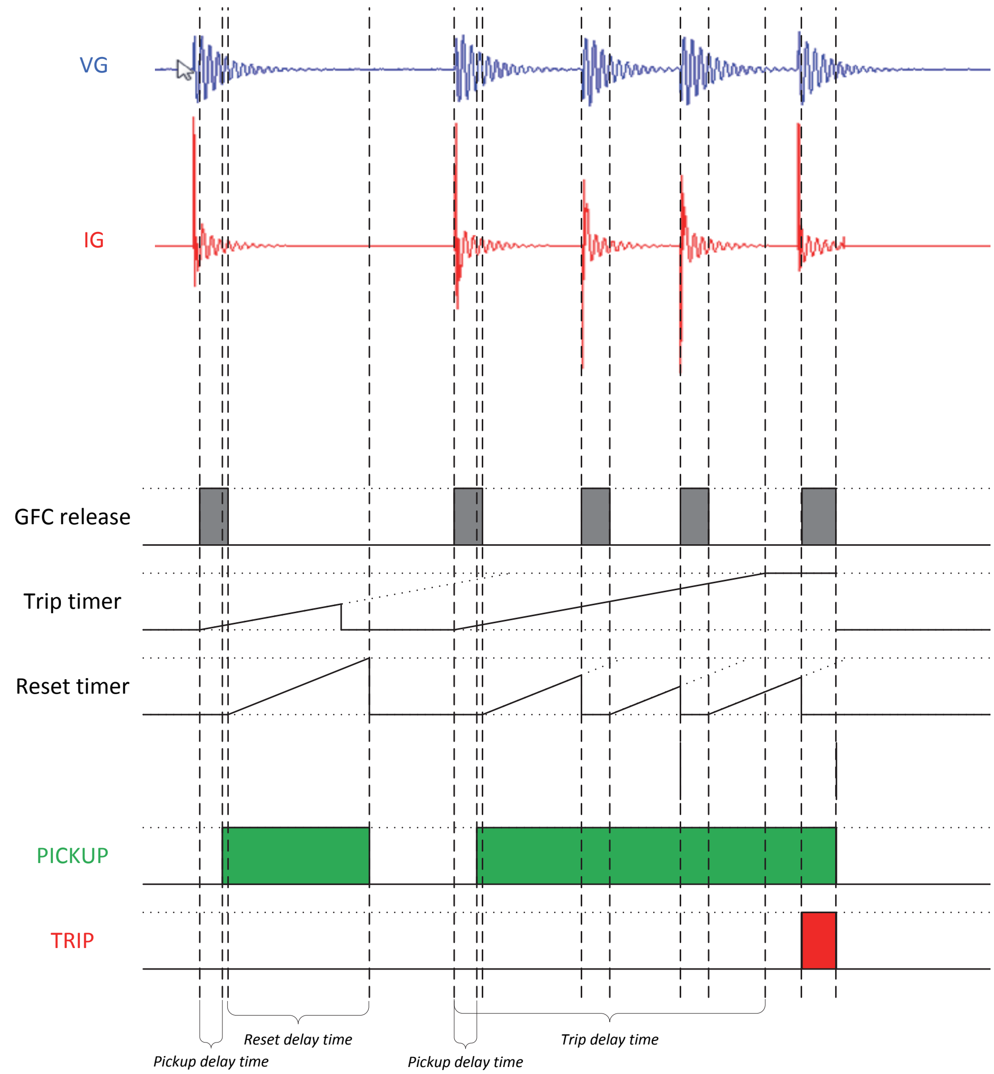


Figure 216: Operation in "General EF" mode

Operation mode "Alarming EF" is applicable in all kinds of ground faults in ungrounded and compensated networks, where fault detection is only alarming. It is intended to detect ground faults regardless of their type (transient, intermittent or restriking, permanent, high or low ohmic). The setting *Voltage pickup value* defines the basic sensitivity of the 67YN function. In "Alarming EF" mode, the operate timer is started during the following conditions.

- Ground fault is detected by the GFC
- Fault direction equals *Directional mode setting*
- Estimated stabilized fundamental frequency residual current exceeds the set *Min trip current* level

The PICKUP output is activated once *Pickup delay time* has elapsed. TRIP output is not valid in the "Alarming EF" mode. Reset timer is started if any of the above three conditions are not valid. In case the fault is transient and self-extinguishes, PICKUP output stays activated until the elapse of reset timer (setting *Reset delay time*).

In case detection of temporary ground faults is not desired, the activation of PICKUP output can be delayed with setting *Pickup delay time*.

To keep the operate timer activated between current spikes during intermittent or restriking ground fault, the *Reset delay time* should be set to a value exceeding the maximum expected time interval between fault spikes (obtained at full resonance condition). The recommended value is at least 300 ms.

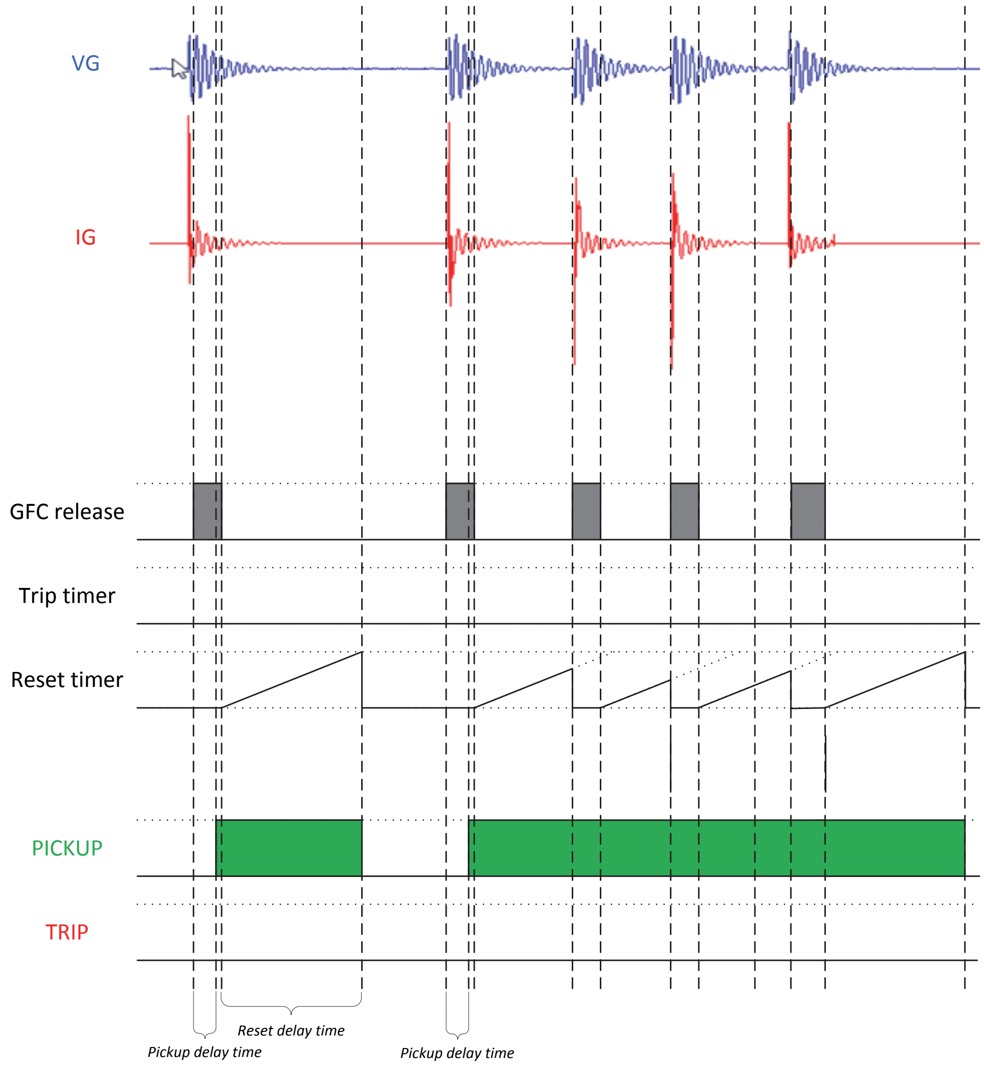


Figure 217: Operation in "Alarming EF" mode

Operation mode "Intermittent EF" is dedicated for detecting restriking or intermittent ground faults. A required number of intermittent ground fault transients set with the *Peak counter limit* setting must be detected for operation. Therefore, transient faults or permanent faults with only initial fault ignition transient are not detected in "Intermittent EF" mode. The application of "Intermittent EF" mode is limited to low ohmic intermittent or restriking ground faults.

In the "Intermittent EF" mode, the operate timer is started when the following conditions are met.

- Transient is detected by the Transient detector (indicated with PEAK_IND output)
- Ground fault is detected by the GFC at time of transient
- Fault direction equals *Directional mode* setting
- Estimated stabilized fundamental frequency residual current exceeds the set *Min trip current* level

When a required number of intermittent ground-fault transients set with the *Peak counter limit* setting are detected without the function being reset (depends on the drop-off time set with the *Reset delay time* setting), the PICKUP output is activated. The INTR_EF output is activated to indicate the fault type is intermittent or restriking ground fault. The operate timer is kept activated as long as transients occur during the drop-off time defined by setting *Reset delay time*.

The TRIP output is activated when *Trip delay time* has elapsed, required number of transients has been detected, ground fault is detected by the GFC, fault direction matches the *Directional mode* setting and estimated stabilized fundamental frequency residual current exceeds set *Minimum trip current* setting.

The *Reset delay time* starts to elapse from each detected transient. Function is reset if time between current peaks is more that *Reset delay time* or if the General Fault Criterion release is reset. After TRIP output activation, PICKUP and TRIP outputs are reset immediately at the falling edge of General Fault Criterion release, that is, when zero-sequence voltage falls below *Voltage pickup value*. This should be considered if “Intermittent EF" mode is applied in case ground faults are only alarmed to avoid repetitive pickup and trip events.

To keep the operate timer activated between current spikes during intermittent or restriking ground fault, *Reset delay time* should be set to a value exceeding the maximum expected time interval between (obtained at full resonance condition). The recommended value is at least 300 ms.

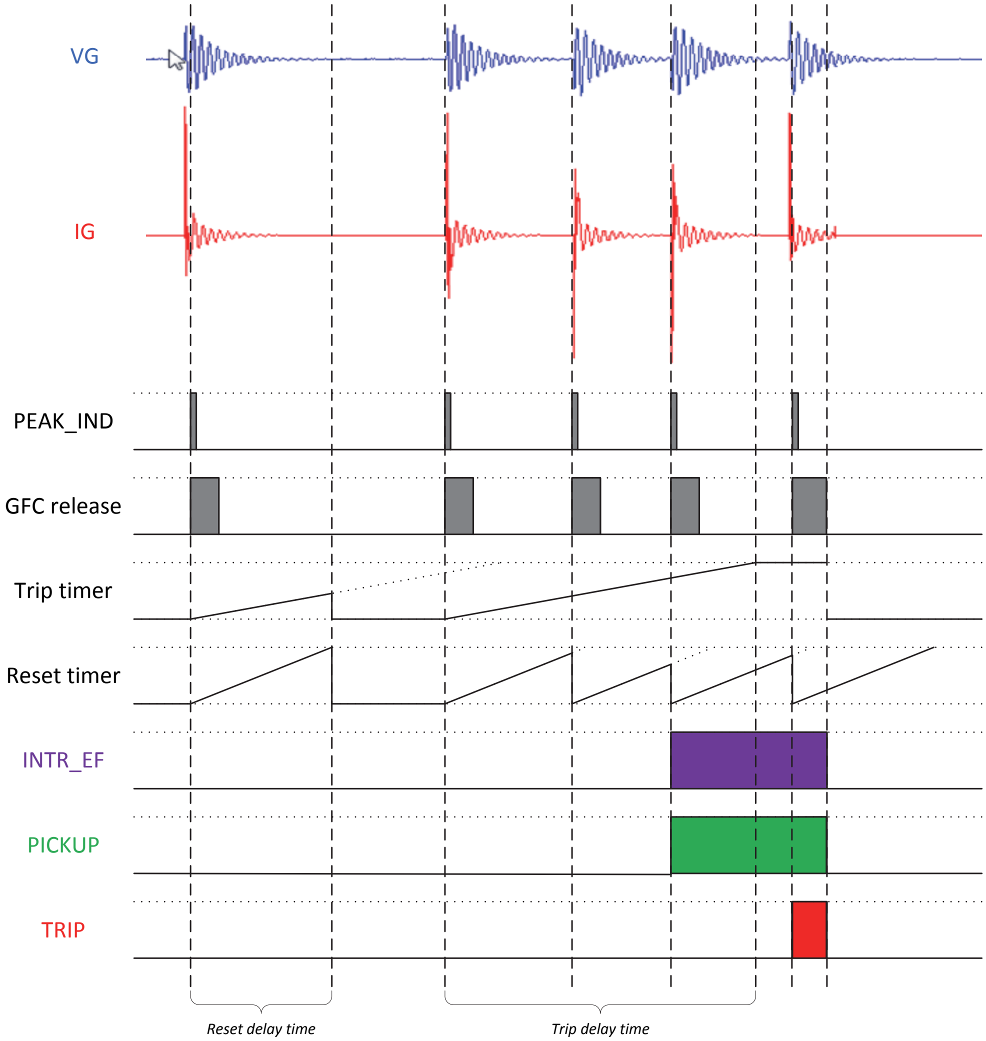


Figure 218: Operation in "Intermittent EF" mode, Peak counter limit = 3

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

Timer

If the detected fault direction is opposite to the set directional mode and GFC release is active, BLK_EF output is activated once *Pickup delay time* has elapsed. Reset timer is activated at the falling edge of General Fault Criterion release, that is, when zero-sequence voltage falls below *Voltage pickup value*. BLK_EF is reset once the reset delay time elapses. Activation of the BLOCK input deactivates the BLK_EF output and resets Timer.

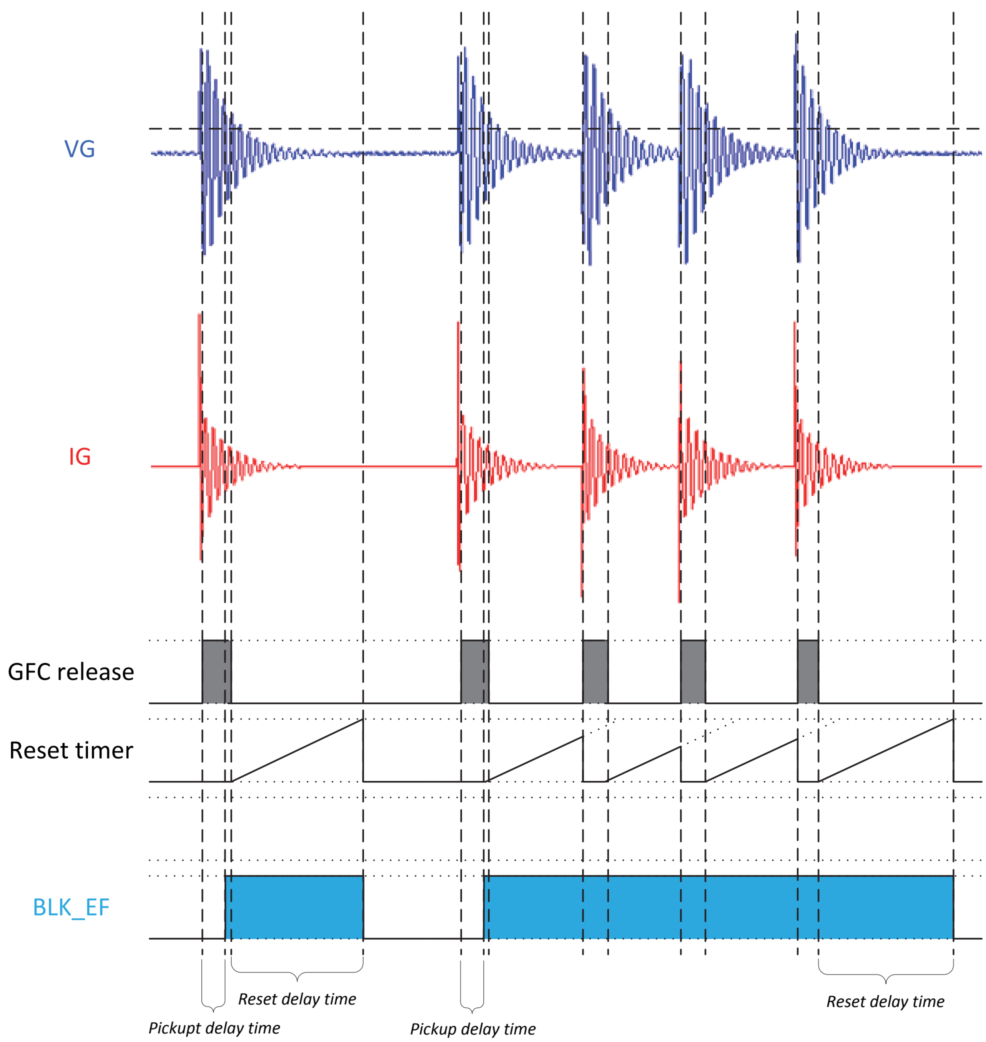


Figure 219: Activation of BLK_EF output (indication that fault is located opposite to the set operate direction)

4.2.8.5 Application

67YN provides selective directional ground-fault protection for high-impedance grounded networks, that is, for compensated, ungrounded and high resistance grounded systems. It can be applied for the ground-fault protection of overhead lines and underground cables.

The operation of 67YN is based on multi-frequency neutral admittance measurement utilizing cumulative phasor summing technique. This concept provides extremely secure, dependable and selective ground-fault protection also in cases where the residual quantities are highly distorted and contain non-fundamental frequency components. 67YN is well-suited for compensated networks where measurement signals may have such characteristics, for example, during intermittent ground faults.

67YN is capable of operating with both low ohmic and higher ohmic ground faults, where the sensitivity limit is defined with residual overvoltage condition. This allows ground faults with several kilohms of fault resistance to be detected in a symmetrical system. The sensitivity that can be achieved is comparable with traditional fundamental frequency based methods such as the IoCos/IoSin (67/51N, 67/50N), Watt/Varmetric (32N) and neutral admittance (21YN).

67YN is capable of detecting faults with dominantly fundamental frequency content as well as transient, intermittent or restriking ground faults. 67YN can be used as an alternative solution to transient or intermittent function 67NIEF.

67YN supports Fault direction indication in operate and non-operate direction which may be utilized during fault location process. The inbuilt transient detector can be used to identify restriking or intermittent ground faults, and discriminate them from permanent or continuous ground faults.

The direction of 67YN can be set as forward or reverse. The operation characteristic is defined by a tilted operation sector, which is universally valid both in ungrounded and compensated networks. The tilt of the operation sector should be selected based on the measurement errors of the applied residual current and voltage measurement transformers.

The operating time characteristic is according to the definite time (DT).

The function contains a blocking functionality to block function outputs, timers or the function itself.

67YN supports both tripping and alarming mode of operation. For alarming ground-fault protection application, the function contains a dedicated operation mode.

67YN provides reliability and sensitivity of protection with a single function. This enables simpler implementation of protection schemes as separate fault type dedicated ground-fault functions and coordination between them are not necessarily required. Other advantages of 67YN includes versatile applicability, good selectivity, good sensitivity and easy setting principles.

One instance (stage) of 67YN function is available.

4.2.8.6 Signals

Table 415: 67YN Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Residual current
VG	SIGNAL	0	Residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
RELEASE	BOOLEAN	0=False	External trigger to release neutral admittance protection
RESET	BOOLEAN	0=False	External trigger to reset direction calculatio

Table 416: 67YN Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
BLK_EF	BOOLEAN	Block signal for EF to indicate opposite direction peaks
INTR_EF	BOOLEAN	Intermittent ground-fault indication
PEAK_IND	BOOLEAN	Current transient detection indication

4.2.8.7 Settings

Table 417: 67YN Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Directional mode	2=Forward 3=Reverse			2=Forward	Directional mode
Voltage pickup value	0.01...1.00	xUn	0.01	0.10	Voltage pickup value
Trip delay time	60...1200000	ms	10	500	Trip delay time

Table 418: 67YN Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Operating quantity	1=Adaptive 2=Amplitude			1=Adaptive	Operating quantity selection
Min trip current	0.005...5.000	xIn	0.001	0.010	Minimum alarm current
Characteristic tilt angle	2.0...20.0	deg	0.1	5.0	Characteristic tilt angle

Table 419: 67YN Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=Intermittent EF 3=General EF 4=Alarming EF			3=General EF	Operation criteria

Table 420: 67YN Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
IG/I0 signal Sel	1=Measured IG 2=Calculated I0			1=Measured IG	Measured IG or calculated I0
Vg or V0	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used Uo signal
Peak counter limit	2...20		1	2	Peak counter limit for restriking EF
Pickup delay time	30...60000	ms	1	30	Pickup delay time
Reset delay time	0...60000	ms	1	500	Reset delay time
Pol reversal	0=False 1=True			0=False	Rotate polarizing quantity

4.2.8.8 Monitored data

Table 421: 67YN Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
FAULT_DIR	Enum	0=unknown 1=forward 2=backward 3=both		Detected fault direction
DIRECTION	Enum	0=unknown 1=forward 2=backward 3=both		Direction information
ANGLE	FLOAT32	-180.00...180.00	deg	Angle between operating angle and characteristic angle
67YN	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.2.8.9 Technical data

Table 422: 67YN Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured voltage: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × V_n
Pickup time[1)]	Typically 35 ms
Reset time	Typically 40 ms
Trip time accuracy	±1.0% of the set value or ±20 ms

1) Includes the delay of the signal output contact, results based on statistical distribution of 1000 measurements

4.3 Differential protection

4.3.1 Line differential protection with in-zone power transformer 87L

4.3.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Line differential protection with in-zone power transformer	LNPLDF	3Id/I>	87L

4.3.1.2 Function block

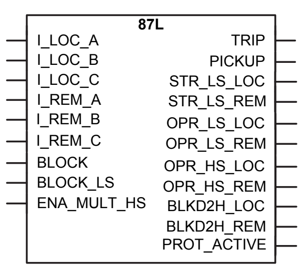


Figure 220: Function block

4.3.1.3 Functionality

The line differential protection with in-zone power transformer function 87L is used as feeder differential protection for the distribution network lines and cables. 87L includes low, stabilized and high, non-stabilized stages. The line differential protection can also be used when there is an in-zone transformer in the protected feeder section.

The stabilized low stage provides a fast clearance of faults while remaining stable with high currents passing through the protected zone increasing errors on current measuring. Second harmonic restraint insures that the low stage does not operate due to energizing of a tapped or in-zone transformer. The high stage provides a very fast clearance of severe faults with a high differential current regardless of their harmonics.

The operating time characteristic for the low stage can be selected to be either definite time (DT) or inverse definite time (IDMT). The direct inter-trip ensures both ends are always operated, even without local criteria.

4.3.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The function can also be set into test mode by setting the *Operation* setting to “test/ blocked”.

The operation of 87L can be described using a module diagram. All the modules in the diagram are explained in the following sections.

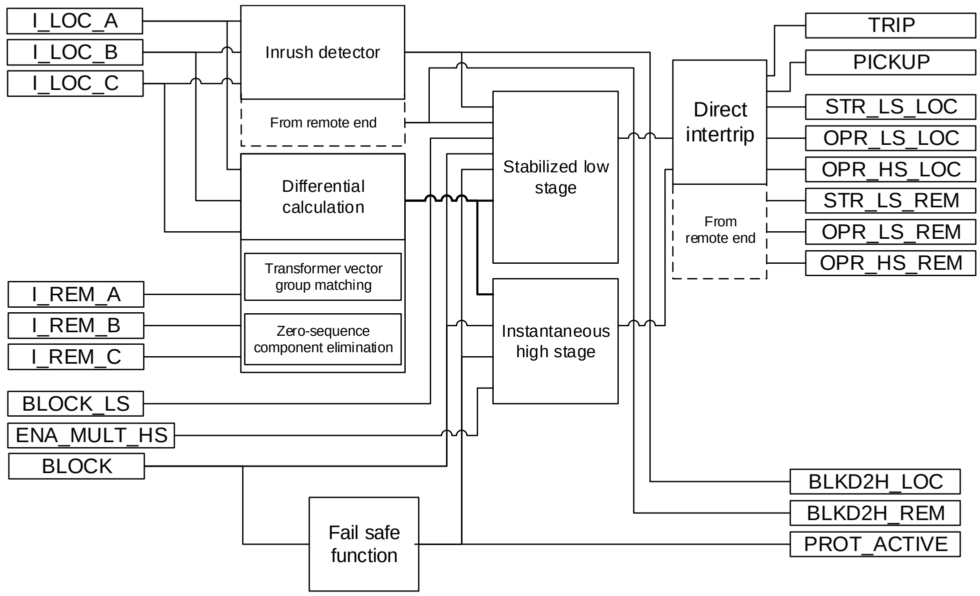


Figure 221: Functional module diagram. I_LOC_x stands for current of the local end and I_REM_x for phase currents of the remote ends.

Stabilized low stage

In the stabilized low stage, the higher the load current is, the higher the differential current required for tripping is. This happens on normal operation or during external faults. When an internal fault occurs, the currents on both sides of the protected object flow towards the fault and cause the stabilizing current to be considerably lower. This makes the operation more sensitive during internal faults. The low stage includes a timer delay functionality.

The characteristic of the low stage taking the apparent differential current into account is influenced by various factors:

- Small tapped loads within the protection zone
- Current transformer errors
- Current transformer saturation
- Small asymmetry of the communication channel go and return paths
- Small steady state line charging current
- In-zone transformer no load current
- Impact of tap changer positions

The timer is activated according to the calculated differential, stabilizing current and the set differential characteristic.

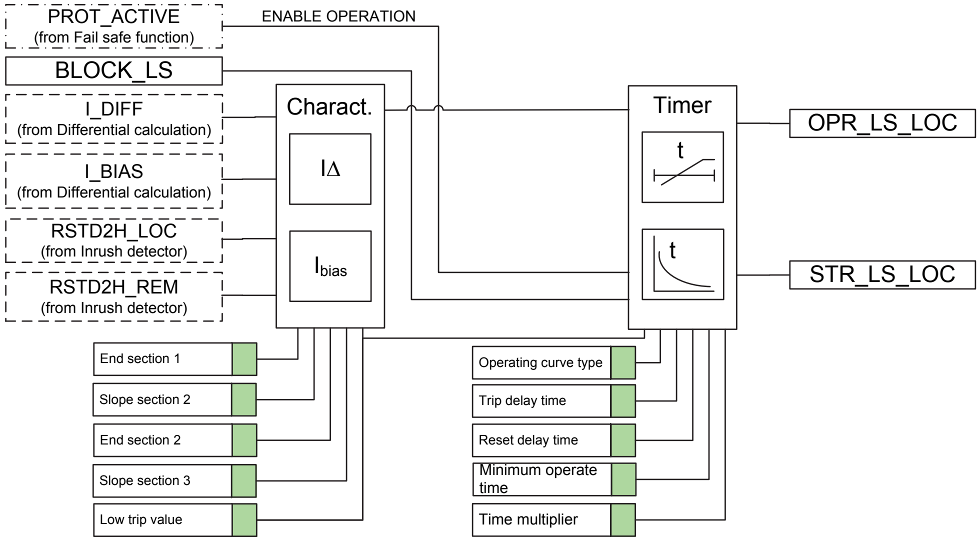


Figure 222: Operation logic of the stabilized low stage

The stabilization affects the operation of the function.

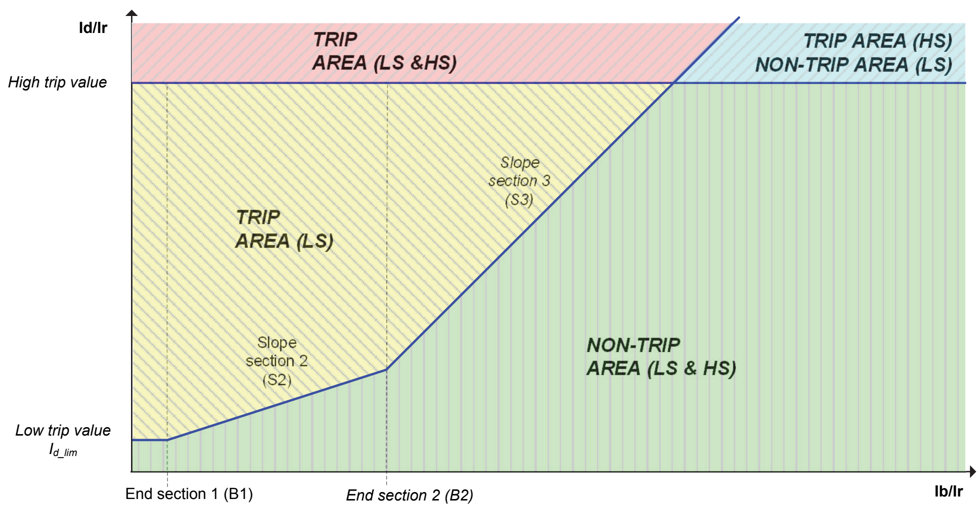


Figure 223: Operating characteristics of the protection. (LS) stands for the low stage and (HS) for the high stage.

The slope of the operating characteristic curve of the differential function varies in the different sections of the range:

- Section 1 where $0.0 < I_b/I_r <$ *End section 1*. The differential current required for tripping is constant. The value of the differential current is the same as the basic setting (*Low trip value*) selected for the function. The basic setting allows the appearance of the no-load current of the line, the load current of the tapped load and minor inaccuracies of the current transformers. It can also be used to influence the overall level of the operating characteristic.

- Section 2 where *End section 1* < I_b/I_r < *End Section 2*. This is called the influence area of the starting ratio. In this section, the variations in the starting ratio affect the slope of the characteristic, meaning the required change for tripping in the differential current in comparison with the change in the load current. CT errors should be considered in the starting ratio.
- Section 3 where *End section 2* < I_b/I_r. By setting the slope in this section, attention can be paid to prevent unnecessary operation of the protection when there is an external fault, and the differential current is mainly produced by saturated current transformers.

The operation of the differential protection is based on the fundamental frequency components. The operation is accurate and stable and the DC component and the harmonics of the current do not cause unwanted operations.

Inrush detector

The transformer inrush currents cause high degrees of second harmonic to the measured phase currents. The inrush detector detects inrush situations in transformers. The second harmonic based local blocking is selected into use with the *Restraint mode* parameter. The blocking for the low stage on the local end is issued when the second harmonic blocking is selected and the inrush is detected.

The inrush detector calculates the ratio of the second harmonic current `I_2H_LOC_A` and the fundamental frequency current `I_1H_LOC_A`. If the line differential protection is used in normal mode (*Winding selection* is “Not in use”), the calculated value is compared with the parameter value of the *Pickup value 2.H* setting. If the calculated value exceeds the set value and the fundamental frequency current `I_1H_LOC_A` is more that seven percent of the nominal current, the output signal `BLK2H_A` is activated. The inrush detector handles the other phases the same way.

If the line differential protection is used in the in-zone transformer mode (*Winding selection* is “Winding 1” or “Winding 2”), the weighed average is calculated for the 2nd harmonic ratios in different phases and the weighed ratio is then compared with the value of the *Pickup value 2.H* setting. If the calculated weighed ratio value exceeds the set value and the fundamental frequency current `I_1H_LOC_A` is more than seven percent of the nominal current, output signal `BLK2H_A` is activated.

The locally detected transformer inrush is also transferred to the remote end as a binary indication signal independently of the local *Restraint mode* setting parameter value. When the internal blocking of the stabilized low stage is activated, the `RSTD2H_LOC` and `RSTD2H_REM` outputs will also be activated at the same time depending on whether the inrush has been detected on local or remote end or on both ends.

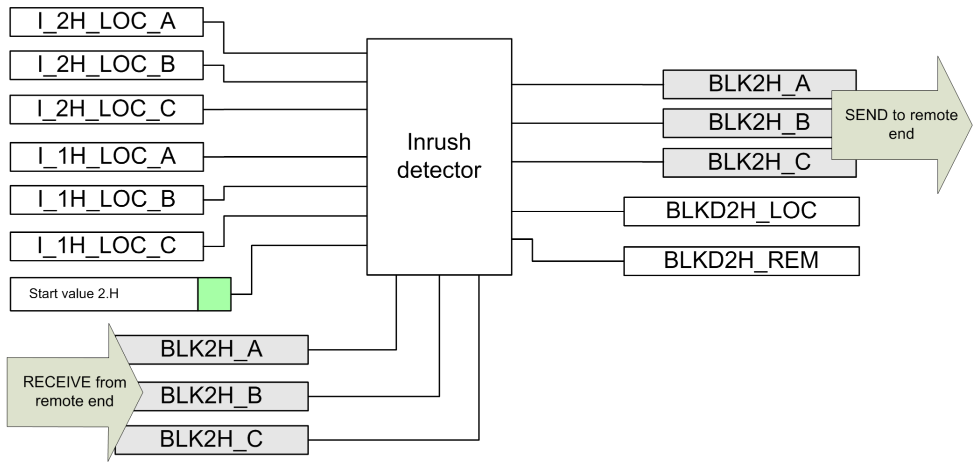


Figure 224: Inrush current detection logic

Differential calculation

The operating principle is to calculate on both ends differential current from currents entering and leaving the protection zone by utilizing the digital communication channels for data exchange. The differential currents are almost zero on normal operation. The differential protection is phase segregated and the differential currents are calculated separately on both ends.

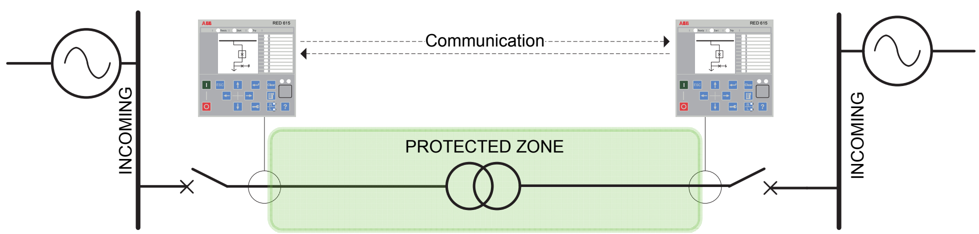


Figure 225: Basic protection principle

The differential current $I\Delta$ (I_d) of the protection relay is obtained on both ends with the formula:

$$I_d = \left| \bar{I}_{LOC} + \bar{I}_{REM} \right|$$

(Equation 66)

The stabilizing current I_{bias} (I_b) of the protection relay is obtained on both ends with the formula:

$$I_b = \frac{\left|\bar{I}_{LOC} - \bar{I}_{REM}\right|}{2}$$

(Equation 67)

Depending on the location of the star points of the current transformers, the polarity of the local end remote currents may be different causing malfunction of the calculation algorithms. The CT transformation ratio may be different and this needs to be compensated to provide a correct differential current calculation result on both ends.

The operation characteristics related settings are given in units as percentage of the current transformer secondary nominal current on each line end protection relay. For the actual primary setting, the corresponding CT ratio on each line end has to be considered. An example of how the *CT ratio correction* parameter values should be selected on both line ends in the example case to compensate the difference in the nominal levels can be presented.

Another example for differential application without in-zone transformer where line rated current is 400 A. The ratio of CTs are 800/1 and 400/1.

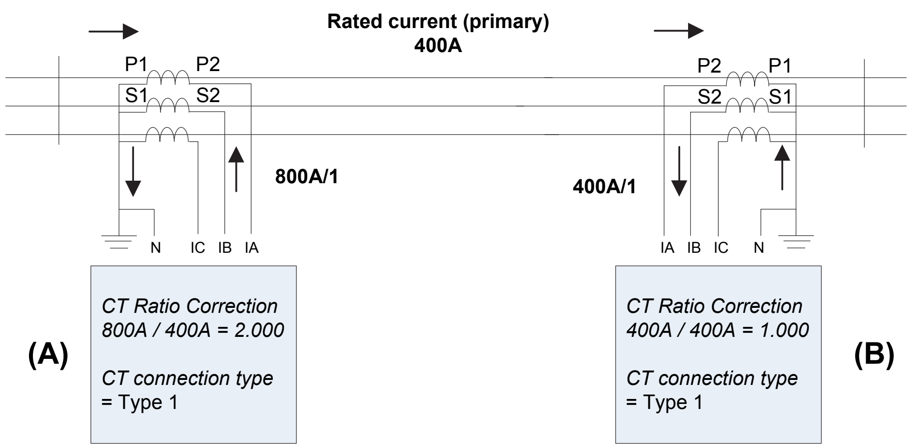


Figure 226: Example of CT ratio correction setting calculation in line differential application

The settings for *CT ratio Corrections* for protection relay A and protection relay (B) are:

CT ratio Correction (A) = 800 A / 400 A = 2.000

CT ratio Correction (B) = 400 A / 400 A = 1.000

The CT secondary current often differs from the rated current at the rated load of the power transformer. The CT transforming ratio can be corrected on both sides of the power transformer with the *CT ratio Correction* setting.

First, the rated load of the power transformer is calculated on both sides when the apparent power and phase-to-phase voltage are known.

$$I_{nT} = \frac{S_n}{\sqrt{3} \cdot V_n}$$

(Equation 68)

I_{nT} rated load of the power transformer

S_n rated power of the power transformer

V_n rated phase-to-phase voltage

Next, the settings for the CT ratio correction can be calculated with the formula:

$$CT\ ratio\, correction = \frac{I_n}{I_{nT}}$$

(Equation 69)

I_n nominal primary current of the CT

After the CT ratio correction, the measured currents and corresponding setting values of 87L are expressed in multiples of the rated power transformer current Ir (×Ir) or percentage value of Ir (%Ir).

An example shows how the CT ratio correction settings are calculated; when the rated power of the transformer is 5 MVA, the ratio of CTs on the 20 kV side is 200/1 and that on the 10.5 kV side is 300/1.

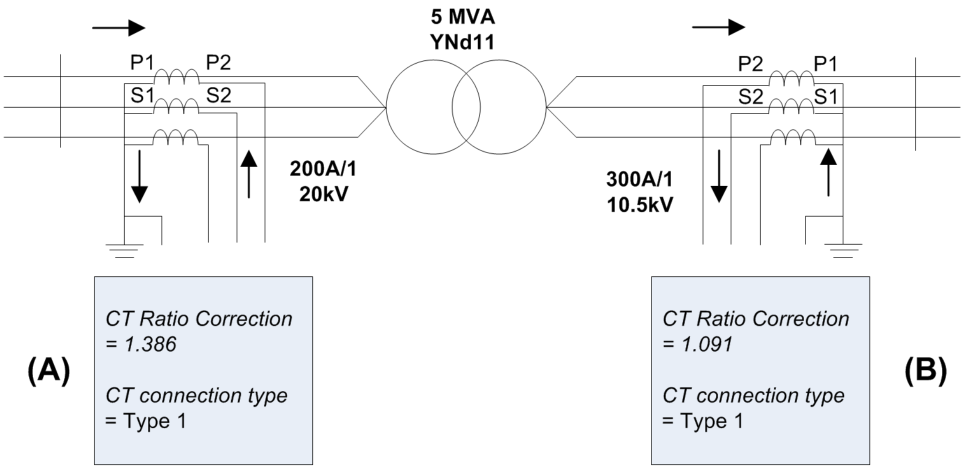


Figure 227: Example of CT ratio correction setting calculation with in-zone transformer

The rated load of the transformer is:

HV side (A): I_{nT_A} = 5 MVA / (1.732 × 20 kV) = 144.3 A

LV side (A): I_{nT_B} = 5 MVA / (1.732 × 10.5 kV) = 274.9 A

So the settings for *CT ratio Corrections* at HV (A) and LV (B) side are:

CT ratio Correction (A) = 200 A / 144.3 A = 1.386

CT ratio Correction (B) = 300 A / 274.9 A = 1.091

CT connections

The connections of the primary current transformers are designated as "Type 1" and "Type 2".

- If the positive directions of the winding 1 and winding 2 protection relay currents are opposite, the *CT connection type* setting parameter is "Type 1". The connection examples of "Type 1" are as shown in the Figure 228 and Figure 229.
- If the positive directions of the winding 1 and winding 2 protection relay currents equate, the *CT connection type* setting parameter is "Type 2". The connection examples of "Type 2" are as shown in the Figure 230 and Figure 231.
- The default value of the *CT connection type* setting is "Type 1".

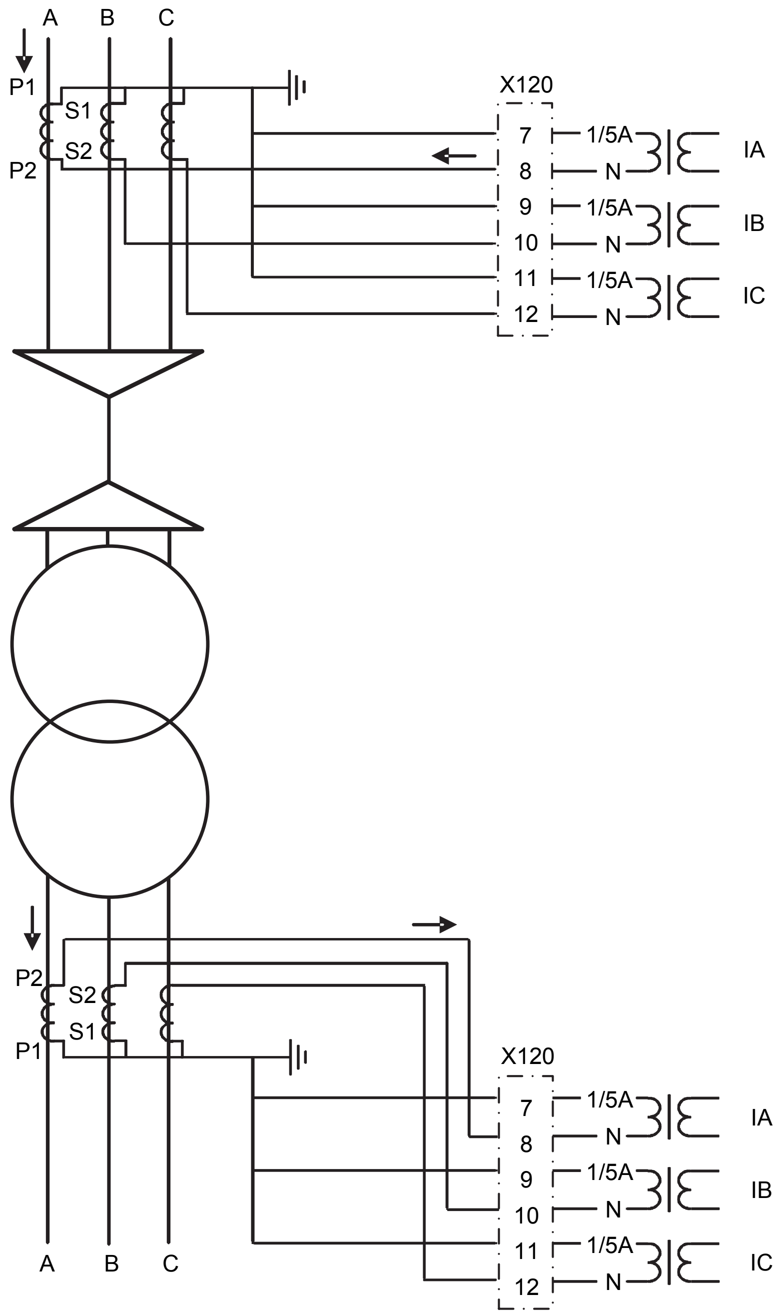


Figure 228: Connection example of current transformers of Type 1

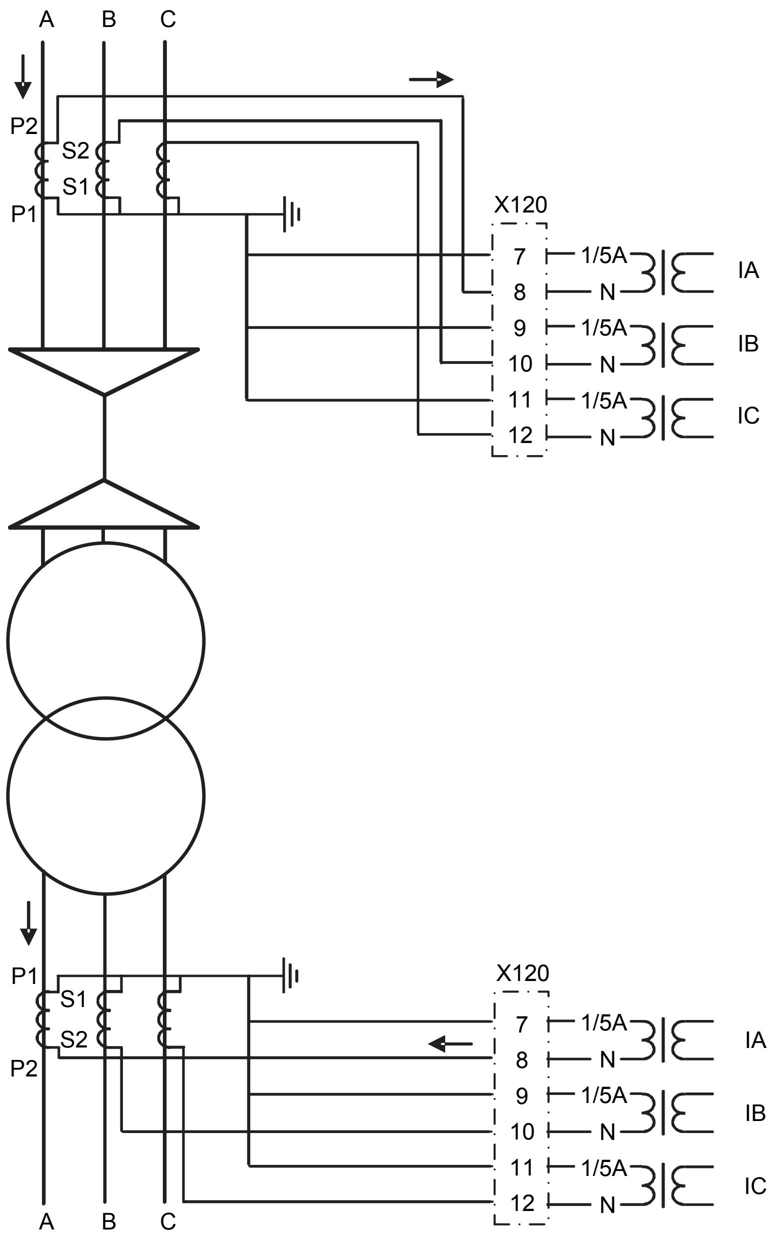


Figure 229: Connection example of current transformers of Type 1

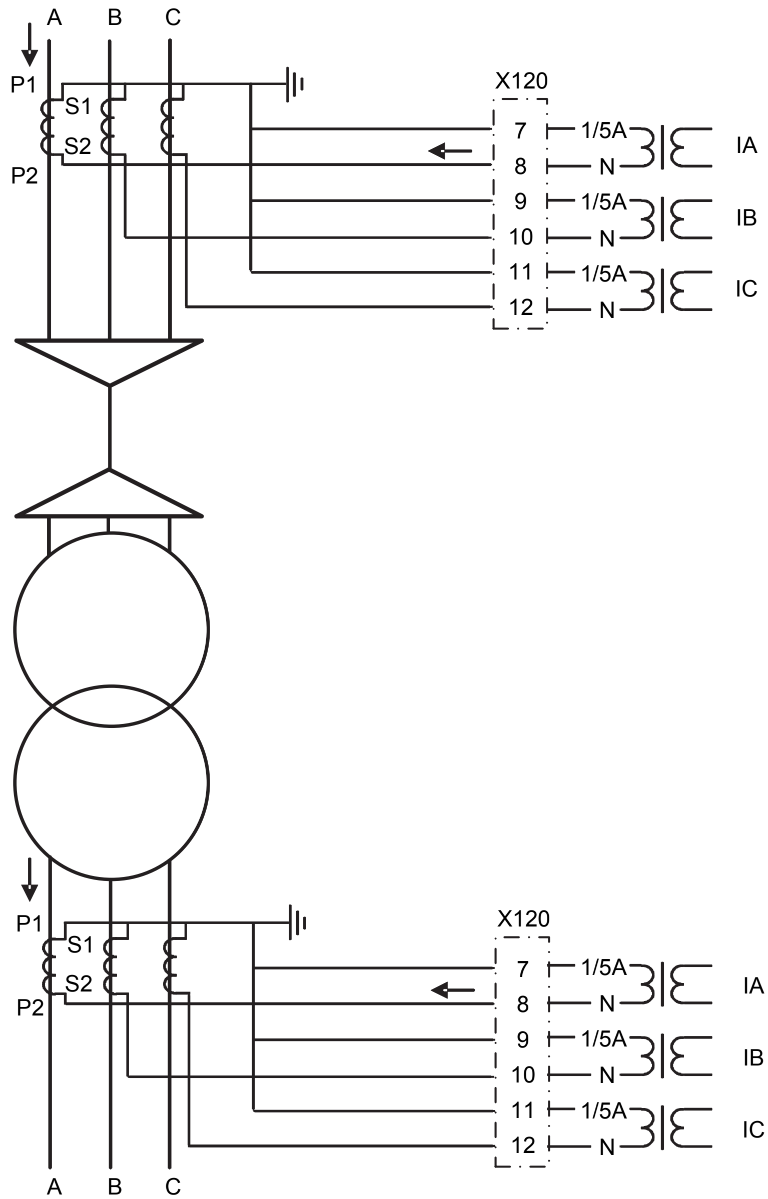


Figure 230: Connection example of current transformers of Type 2

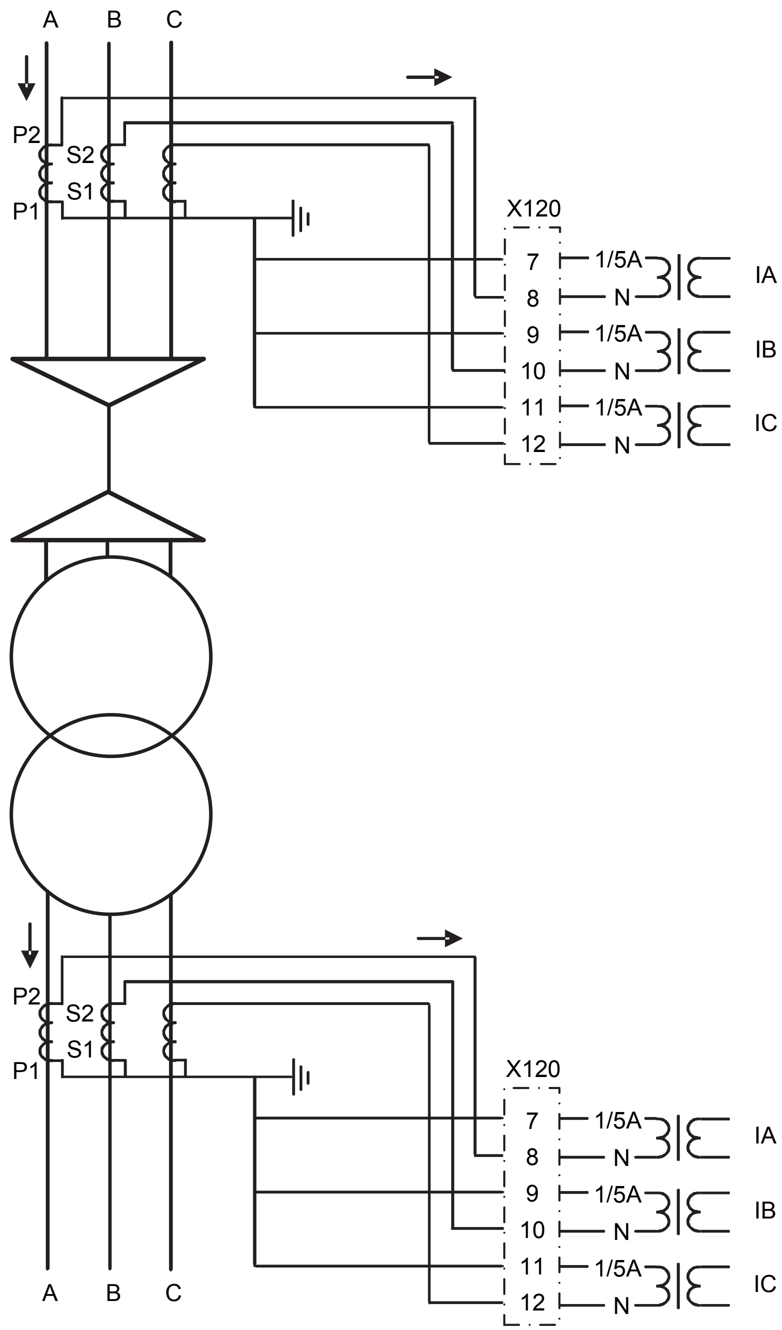


Figure 231: Connection example of current transformers of Type 2

Transformer vector group matching

Before differential and bias currents can be calculated, the phase difference of the currents must be vector group matched based on the transformer connection type. The vector group of the power transformer is numerically matched on the high voltage and low voltage sides by means of the *Winding selection*, *Winding 1 type*, *Winding 2 type* and *Clock number* settings. Thus no interposing CTs are needed if there is only a power transformer inside the protected zone. The matching is based on phase shifting and a numerical delta connection in the protection relay. If the neutral of a star-connected power transformer is grounded, any ground-fault in the network is perceived by the protection relay as a differential current. The elimination of the zero-sequence component can be selected for that winding by setting the Zro A elimination parameter.

Winding selection setting defines the protection relay location respect to the transformer. If the protection relay is situated at the HV side of the transformer, then protection relay location setting is set to “Winding 1” and respectively to “Winding 2” if protection relay is situated at the LV side. If the differential protection relays are used to protect a line without in-zone transformer, then the setting is set to “Not in use”. In this case vector group matching is ignored.

The matching of the phase difference is based on the phase shifting and the numerical delta connection inside the protection relay. The *Winding 1 type* parameter determines the connection on winding 1 (“Y”, “YN”, “D”, “Z”, “ZN”). The vector group matching can be implemented either on both, winding 1 and winding 2, or only on winding 1 or winding 2, at intervals of 30° with the *Clock number* setting. Similarly, the *Winding 2 type* parameter determines the connections of the phase windings on the low voltage side (“y”, “yn”, “d”, “z”, “zn”).

When the vector group matching is Yy0 and the *CT connection type* is according to “Type 2”, the phase angle of the phase currents connected to the protection relay does not change. When the vector group matching is Yy6, the phase currents are on one side turned 180° in the protection relay.

Example 1, vector group matching of an YNd11-connected power transformer on winding 1, *CT connection type* according to type 1. The *Winding 1 type* setting is “YN”, *Winding 2 type* is “d” and *Clock number* is “Clk Num 11”. This is compensated internally by giving winding 1 internal compensation value +30° and winding 2 internal compensation value 0°:

$$\bar{I}_{AmHV} = \frac{\bar{I}_A - \bar{I}_B}{\sqrt{3}}$$

(Equation 70)

$$\bar{I}_{BmHV} = \frac{\bar{I}_B - \bar{I}_C}{\sqrt{3}}$$

(Equation 71)

$$\bar{I}_{CmHV} = \frac{\bar{I}_C - \bar{I}_A}{\sqrt{3}}$$

(Equation 72)

Example 2, if vector group is Yd11 and *CT connection type* is according to type 1, the compensation is a little different. The *Winding 1 type* setting is “Y”, *Winding 2 type* is “d” and *Clock number* is “Clk Num 11”. This is compensated internally by giving winding 1 internal compensation value 0° and winding 2 internal compensation value -30°:

$$\bar{I}_{AmLV} = \frac{\bar{I}_A - \bar{I}_C}{\sqrt{3}}$$

(Equation 73)

$$\bar{I}_{BmLV} = \frac{\bar{I}_B - \bar{I}_A}{\sqrt{3}}$$

(Equation 74)

$$\bar{I}_{CmLV} = \frac{\bar{I}_C - \bar{I}_B}{\sqrt{3}}$$

(Equation 75)

The “Y” side currents stay untouched, while the “d” side currents are compensated to match the currents actually flowing in the windings.

In this example there is no neutral current on either side of the transformer (assuming there are no grounding transformers installed). In the previous example, the matching is done differently to have the winding 1 neutral current compensated at the same time.

Table 423: 87L vector group matching

Vector group of the transformer	Winding 1 type	Winding 2 type	Phase shift	Zero sequence current elimination
Yy0	Y	y	0	Not needed
YNy0	YN	y	0	HV side
YNyn0	YN	yn	0	HV & LV side
Yyn0	Y	yn	0	LV side
Yy2	Y	y	2	Not needed
YNy2	YN	y	2	(Automatic)
YNyn2	YN	yn	2	(Automatic)
Yyn2	Y	yn	2	(Automatic)
Yy4	Y	y	4	Not needed
YNy4	YN	y	4	(Automatic)
YNyn4	YN	yn	4	(Automatic)
Yyn4	Y	yn	4	(Automatic)
Yy6	Y	y	6	Not needed
YNy6	YN	y	6	HV side
YNyn6	YN	yn	6	HV & LV side

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Phase shift	Zero sequence current elimination
Yyn6	Y	yn	6	LV side
Yy8	Y	y	8	Not needed
YNy8	YN	y	8	(Automatic)
YNyn8	YN	yn	8	(Automatic)
Yyn8	Y	yn	8	(Automatic)
Yy10	Y	y	10	Not needed
YNy10	YN	y	10	(Automatic)
YNyn10	YN	yn	10	(Automatic)
Yyn10	Y	yn	10	(Automatic)
Yd1	Y	d	1	Not needed
YNd1	YN	d	1	(Automatic)
Yd5	Y	d	5	Not needed
YNd5	YN	d	5	(Automatic)
Yd7	Y	d	7	Not needed
YNd7	YN	d	7	(Automatic)
Yd11	Y	d	11	Not needed
YNd11	YN	d	11	(Automatic
Dd0	D	d	0	Not needed
Dd2	D	d	2	Not needed
Dd4	D	d	4	Not needed
Dd6	D	d	6	Not needed
Dd8	D	d	8	Not needed
Dd10	D	d	10	Not needed
Dy1	D	y	1	Not needed
Dyn1	D	yn	1	(Automatic)
Dy5	D	y	5	Not needed
Dyn5	D	yn	5	(Automatic)
Dy7	D	y	7	Not needed
Dyn7	D	yn	7	(Automatic)
Dy11	D	y	11	Not needed
Dyn11	D	yn	11	(Automatic)
Yz1	Y	z	1	Not needed
YNz1	YN	z	1	(Automatic)
YNzn1	YN	zn	1	LV side
Yzn1	Y	zn	1	(Automatic)
Yz5	Y	z	5	Not needed
Table continues on next page				

Vector group of the transformer	Winding 1 type	Winding 2 type	Phase shift	Zero sequence current elimination
YNz5	YN	z	5	(Automatic)
YNzn5	YN	zn	5	LV side
Yzn5	Y	zn	5	(Automatic)
Yz7	Y	z	7	Not needed
YNz7	YN	z	7	(Automatic)
YNzn7	YN	zn	7	LV side
Yzn7	Y	zn	7	(Automatic)
Yz11	Y	z	11	Not needed
YNz11	YN	z	11	(Automatic)
YNzn11	YN	zn	11	LV side
Yzn11	Y	zn	11	(Automatic)
Zy1	Z	y	1	Not needed
Zyn1	Z	yn	1	(Automatic)
ZNyn1	ZN	yn	1	HV side
ZNy1	ZN	y	1	(Automatic)
Zy5	Z	y	5	Not needed
Zyn5	Z	yn	5	(Automatic)
ZNyn5	ZN	yn	5	HV side
ZNy5	ZN	y	5	(Automatic)
Zy7	Z	y	7	Not needed
Zyn7	Z	yn	7	(Automatic)
ZNyn7	ZN	yn	7	HV side
ZNy7	ZN	y	7	(Automatic)
Zy11	Z	y	11	Not needed
Zyn11	Z	yn	11	(Automatic)
ZNyn11	ZN	yn	11	HV side
ZNy11	ZN	y	11	(Automatic)
Dz0	D	z	0	Not needed
Dzn0	D	zn	0	LV side
Dz2	D	z	2	Not needed
Dzn2	D	zn	2	(Automatic)
Dz4	D	z	4	Not needed
Dzn4	D	zn	4	(Automatic)
Dz6	D	z	6	Not needed
Dzn6	D	zn	6	LV side
Dz8	D	z	8	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Phase shift	Zero sequence current elimination
Dzn8	D	zn	8	(Automatic)
Dz10	D	z	10	Not needed
Dzn10	D	zn	10	(Automatic)
Zd0	Z	d	0	Not needed
ZNd0	ZN	d	0	HV side
Zd2	Z	d	2	Not needed
ZNd2	ZN	d	2	(Automatic)
Zd4	Z	d	4	Not needed
ZNd4	ZN	d	4	(Automatic)
Zd6	Z	d	6	Not needed
ZNd6	ZN	d	6	HV side
Zd8	Z	d	8	Not needed
ZNd8	ZN	d	8	(Automatic)
Zd10	Z	d	10	Not needed
ZNd10	ZN	d	10	(Automatic)
Zz0	Z	z	0	Not needed
ZNz0	ZN	z	0	HV side
ZNzn0	ZN	zn	0	HV & LV side
Zzn0	Z	zn	0	LV side
Zz2	Z	z	2	Not needed
ZNz2	ZN	z	2	(Automatic)
ZNzn2	ZN	zn	2	(Automatic)
Zzn2	Z	zn	2	(Automatic)
Zz4	Z	z	4	Not needed
ZNz4	ZN	z	4	(Automatic)
ZNzn4	ZN	zn	4	(Automatic)
Zzn4	Z	zn	4	(Automatic)
Zz6	Z	z	6	Not needed
ZNz6	ZN	z	6	HV side
ZNzn6	ZN	zn	6	HV & LV side
Zzn6	Z	zn	6	LV side
Zz8	Z	z	8	Not needed
ZNz8	ZN	z	8	(Automatic)
ZNzn8	ZN	zn	8	(Automatic)
Zzn8	Z	zn	8	(Automatic)
Zz10	Z	z	10	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Phase shift	Zero sequence current elimination
ZNz10	ZN	z	10	(Automatic)
ZNzn10	ZN	zn	10	(Automatic)
Zzn10	Z	zn	10	(Automatic)

Zero-sequence component elimination

If *Clock number* is “Clk Num 2“, “Clk Num 4”, “Clk Num 8” or “Clk Num 10”, the vector group matching is always done on both, winding 1 and winding 2. The combination results in the correct compensation. In this case the zero-sequence component is always removed from both sides automatically. The *Zro A elimination* parameter cannot change this.

If *Clock number* is “Clk Num 1”, “Clk Num 5”, “Clk Num 7” or “Clk Num 11”, the vector group matching is done on one side only. A possible zero-sequence component of the phase currents at ground faults occurring outside the protection area is automatically eliminated in the numerically implemented delta connection before the differential current and the biasing current are calculated. This is why the vector group matching is almost always made on the star connected side of the “Ynd” and “Dyn” connected transformers.

If *Clock number* is “Clk Num 0” or “Clk Num 6”, the zero-sequence component of the phase currents is not eliminated automatically on either side. Therefore, the zero-sequence component on the star connected side that is grounded at its star point has to be eliminated by using the Zro A elimination parameter.

The same parameter has to be used to eliminate the zero-sequence component if there is, for example, a grounding transformer on the delta-connected side of the “Ynd” power transformer in the area to be protected. In this case, the vector group matching is normally made on the side of the star connection. On the side of the delta connection, the elimination of the zero-sequence component has to be eliminated by using the Zro A elimination parameter.

By using the Zro A elimination parameter, the zero-sequence component of the local phase currents is calculated and reduced for each phase current:

$$\bar{I}_{LOC\_A} = \bar{I}_{LOC\_A} - \frac{1}{3} \times \left(\bar{I}_{LOC\_A} + \bar{I}_{LOC\_B} + \bar{I}_{LOC\_C} \right)$$

(Equation 76)

$$\bar{I}_{LOC\_B} = \bar{I}_{LOC\_B} - \frac{1}{3} \times \left(\bar{I}_{LOC\_A} + \bar{I}_{LOC\_B} + \bar{I}_{LOC\_C} \right)$$

(Equation 77)

$$\bar{I}_{LOC\_C} = \bar{I}_{LOC\_C} - \frac{1}{3} \times \left(\bar{I}_{LOC\_A} + \bar{I}_{LOC\_B} + \bar{I}_{LOC\_C} \right)$$

Fail safe function

To prevent malfunction during communication interference, the operation of 87L is blocked when the protection communication supervision detects severe interference in the communication channel. The timer reset stage is activated in case the stabilized stage is started during a communication interruption. The protection communication supervison is connected internally from PCS to 87L (dotted OK line).

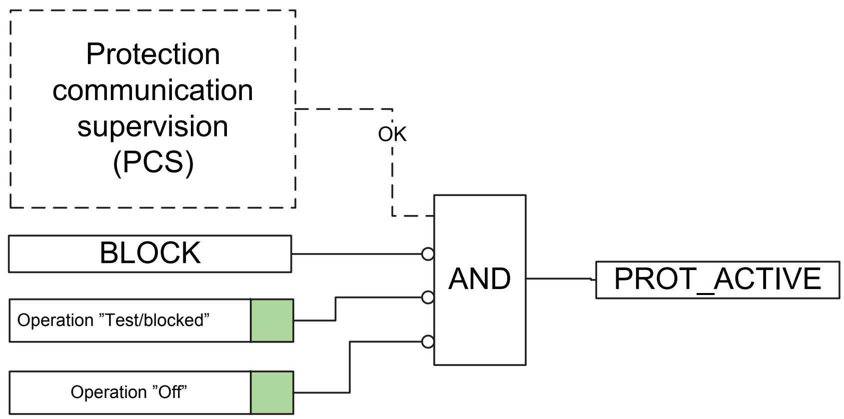


Figure 232: Operation logic of the fail safe function

The function can also be set into "test/blocked" state with the *Operation* setting. This can also be utilized during the commissioning.

The BLOCK input is provided for blocking the function with the logic. When the function is blocked, the monitored data and measured values are still available but the binary outputs are blocked. When the function is blocked, the direct inter-trip is also blocked.

The PROT_ACTIVE output is always active when the protection function is capable of operating. PROT_ACTIVE can be used as a blocking signal for backup protection functions.

Timer

Once activated, the timer activates the STR_LS_LOC output. Depending on the value of the set *Operating curve type*, the timer characteristics are according to DT or IDMT. When the operation timer has reached the value set with the *Trip delay time* in the DT mode, the maximum value defined by the inverse time curve, the OPR_LS_LOC output is activated. When the operation mode is according to IDMT, *Low trip value* is used as reference value

(Trip value) in the IDMT equations presented in the Standard inverse-time characteristics section.

A timer reset state is activated when a drop-off situation happens. The reset is done according to the DT characteristics.

For a detailed description of the timer characteristics, see the “General function block features” section in this manual.

Instantaneous high stage

In addition to the stabilized low stage, 87L has an instantaneous high stage. The stabilizing is not done with the instantaneous high stage. The instantaneous high stage trips immediately when the differential current amplitude is higher than the set value of the *High trip value* setting. If the ENA_MULT_HS input is active, the *High trip value* setting is internally multiplied by the *High Op value Mult* setting.

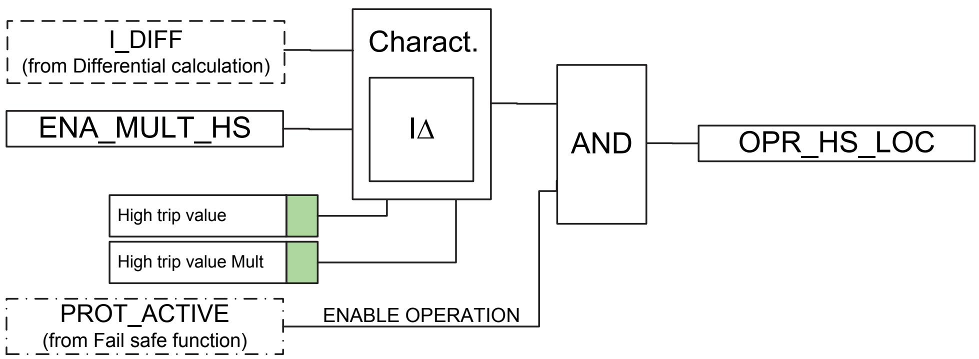


Figure 233: Operation logic of instantaneous high stage

Direct inter-trip

Direct inter-trip is used to ensure the simultaneous opening of the circuit breakers at both ends of the protected line when a fault is detected. Both pickup and trip signals are sent to the remote end via communication. The direct-intertripping of the line differential protection is included into 87L. The TRIP output is combined to operate the signal from both stages, local and remote, so that it can be used for the direct inter-trip signal locally.

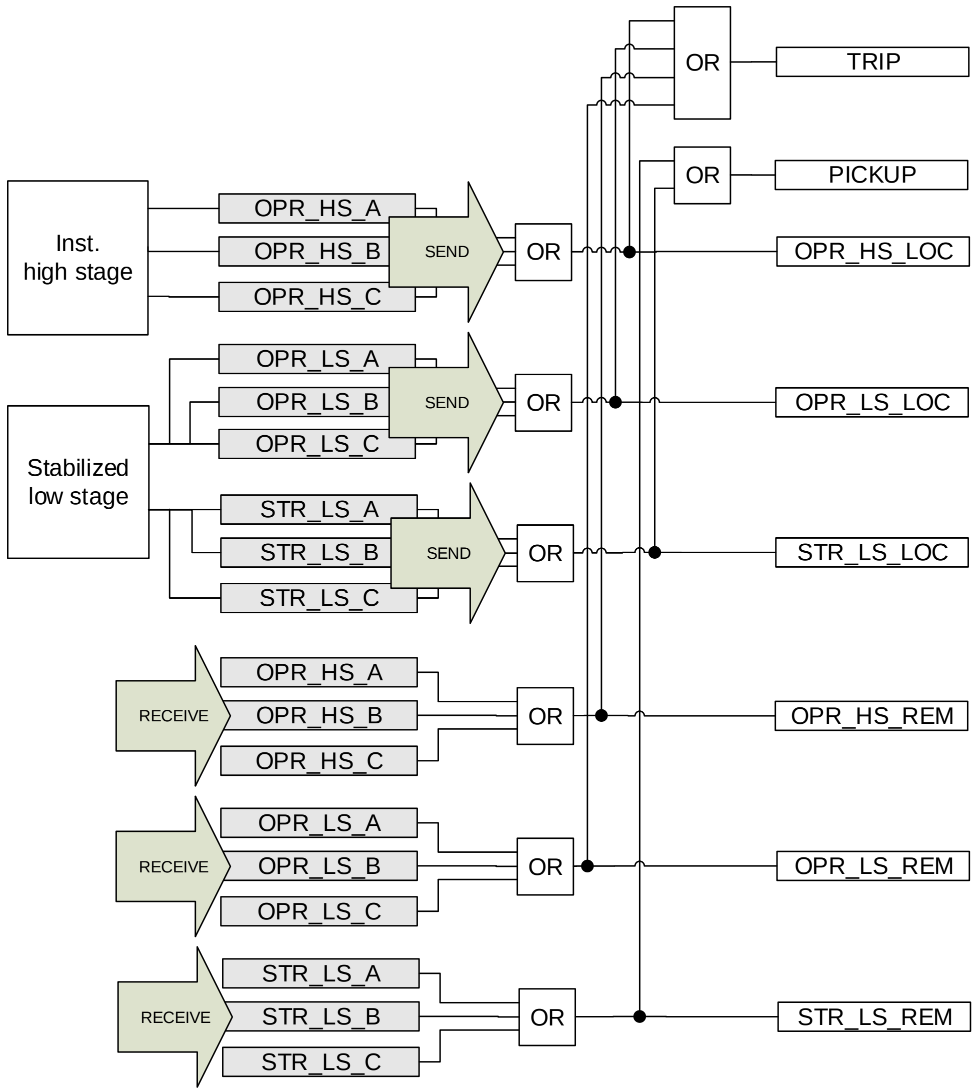


Figure 234: Operation logic of the direct intertrip function

The pickup and trip signals are also provided separately for the low and high stages, and in local and remote.

Blocking functionality

There are two independent inputs that can be used for blocking the function: `BLOCK` and `BLOCK_LS`. The difference between these inputs is that `BLOCK_LS` (when TRUE) blocks only the stabilized low stage leaving the instantaneous high stage operative. `BLOCK` (when TRUE) blocks both stages and also the `PROT_ACTIVE` output is updated according to the `BLOCK` input status, as described in the Fail safe function chapter.

The BLOCK and BLOCK_LS input statuses affect only the behavior of the local protection instance. When a line differential protection stage (stabilized low or instantaneous high) is blocked, also the received remote signals related to the corresponding stage are ignored (received direct inter-trip signals from the remote end). The binary signal transfer functionality should therefore be used for transferring the possible additional blocking information between the local and remote terminals whenever the blocking logic behavior needs to be the same on both line ends.

Test mode

The line differential function in one protection relay can be set to test mode, that is, the *Operation* setting is set to “test/blocked”. This blocks the line differential protection outputs in the protection relay and sets the remote protection relay to a remote test mode, such that the injected currents are echoed back with the shifted phase. It is also possible that both protection relays are simultaneously in the test mode. When the line differential protection function is in the test mode:

- The remote end protection relay echoes locally injected current samples back with the shifted phase. The current samples that are sent to the remote protection relay are scaled with the CT ratio correction setting.
- The operation of both stages (stabilized low or instantaneous high) are blocked, and also the direct inter-trip functionality is blocked (both receive and send) in the protection relay where the test mode is active.
- The remote end line differential protection function that is in the normal mode (On) is not affected by the local end being in the test mode. This means that the remote end function is operative but, at the same time, it ignores the received current samples from the other end protection relay which is in the test mode.
- The PROT_ACTIVE output is false only in the protection relay that is currently in the test mode.

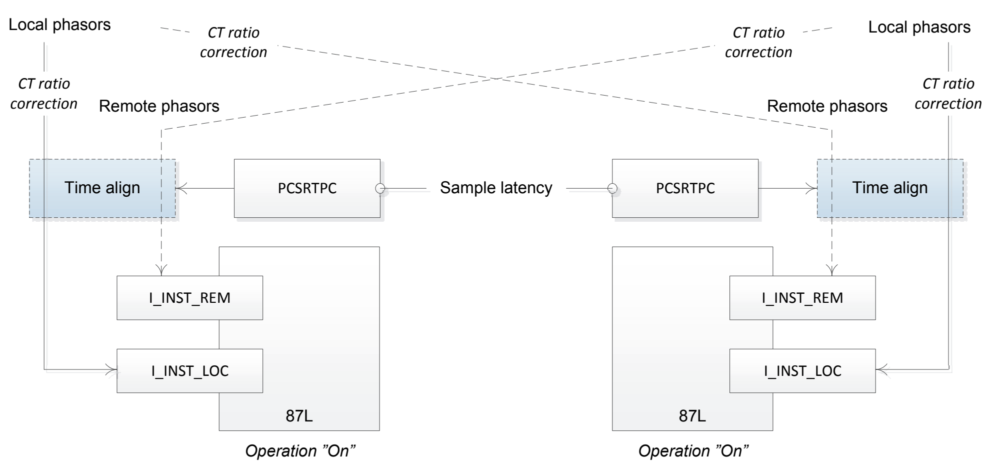


Figure 235: Operation during the normal operation of the line differential protection

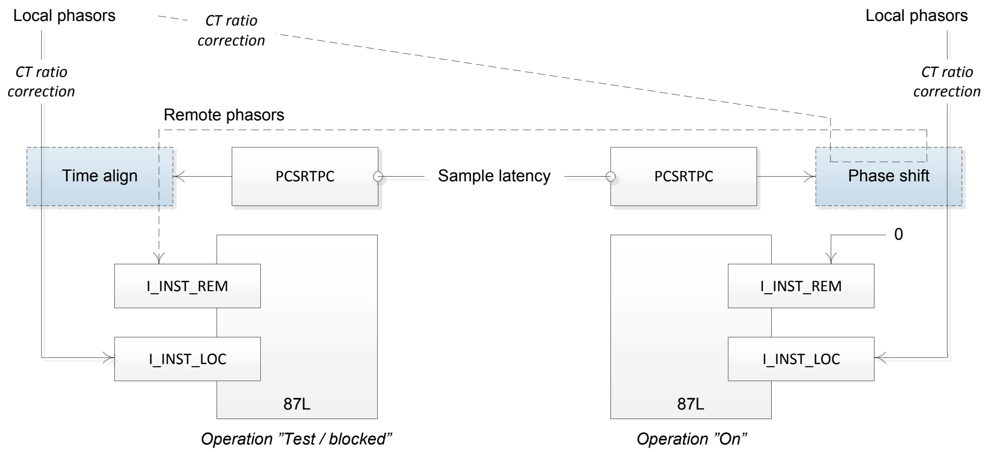


Figure 236: Operation during test operation of the line differential protection

4.3.1.5 Commissioning

The commissioning of the line differential protection scheme would be difficult without any support features in the functionality because of the relatively long distance between the protection relays. This has been taken into consideration in the design of the line differential protection. The communication channel can be used for echoing the locally fed current phasors from the remote end. By using this mode, it is possible to verify that differential calculation is done correctly in each phase. Also, the protection communication operation is taken into account with the differential current calculation when this test mode is used.

Required material for testing the protection relay

- Calculated settings
- Terminal diagram
- Circuit diagrams
- Technical and application manuals of the protection relay
- Single of three-phase secondary current source
- Single of three-phase primary current source
- Timer with start and stop interfaces
- Auxiliary voltage source for the protection relays
- PC with related software, a Web browser for WHMI

The setting and configuration of the protection relay must be completed before testing.

The terminal diagram, available in the technical manual, is a general diagram of the protection relay.

The same diagram is not always applicable to each specific delivery, especially for the configuration of all the binary inputs and outputs. Therefore, before testing, check that the available terminal diagram corresponds to the protection relay.

The circuit diagrams of the application are recommended to be available. These are required for checking the terminal block numbers of the current, trip, alarm and possibly other auxiliary circuits.

The technical and application manuals contain application and functionality summaries, function blocks, logic diagrams, input and output signals, setting parameters and technical data sorted per function.

The minimum requirement for a secondary current injection test device is the ability to work as a one phase current source.

The protection relay should be prepared for the test before testing a particular function. The logic diagram of the tested protection function must be considered while performing the test. All included functions in the protection relay are tested according to the corresponding test instructions in this chapter. The functions can be tested in any order according to user preferences. Therefore, the test instructions are presented in alphabetical order. Only the functions that are in use (*Operation* is set to "On") should be tested.

The response from the test can be viewed in different ways.

- Binary output signals
- Monitored data values in the LHMI (logical signals)
- A PC with a Web browser for WHMI use (logical signals and phasors)

All used setting groups should be tested.

Checking the external optical and electrical connections

The user must check the installation to verify that the protection relay is connected to the other required parts of the protection system. The protection relay and all the connected circuits are to be de-energized during the check-up.

Checking CT circuits

Check that the wiring is in strict accordance with the supplied connection diagram.

The CTs must be connected in accordance with the terminal diagram provided with the protection relay, both with regards to phases and polarity. The following tests are recommended for every primary CT or CT core connected to the protection relay.

- Primary injection test to verify the current ratio of the CT, the correct wiring up to the protection relay and correct phase sequence connection (that is A, B, C.)
- Polarity check to prove that the predicted direction of the secondary current flow is correct for a given direction of the primary current flow. This is an essential test for the proper operation of the directional function, protection or measurement in the protection relay.
- CT secondary loop resistance measurement to confirm that the current transformer secondary loop DC resistance is within specification and that there are no high resistance joints in the CT winding or wiring.
- CT excitation test to ensure that the correct core in the CT is connected to the protection relay. Normally only a few points along the excitation curve are checked to ensure that there are no wiring errors in the system, for example, due to a mistake in connecting the CT's measurement core to the protection relay.
- CT excitation test to ensure that the CT is of the correct accuracy rating and that there are no short circuited turns in the CT windings. Manufacturer's design curves should be available for the CT to compare the actual results.
- Grounding check of the individual CT secondary circuits to verify that each three-phase set of main CTs is properly connected to the station ground and only at one electrical point.
- Insulation resistance check.
- Phase identification of CT shall be made.

Both the primary and the secondary sides must be disconnected from the line and the protection relay when plotting the excitation characteristics.

If the CT secondary circuit is opened or its ground connection is missing or removed without the CT primary being de-energized first, dangerous voltages may be produced. This can be lethal and cause damage to the insulation. The re-energizing of the CT primary should be prohibited as long as the CT secondary is open or ungrounded.

Checking of the power supply

Check that the auxiliary supply voltage remains within the permissible input voltage range under all operating conditions. Check that the polarity is correct before powering the protection relay.

Checking binary I/O circuits

Always check the binary input circuits from the equipment to the protection relay interface to make sure that all signals are connected correctly. If there is no need to test a particular input, the corresponding wiring can be disconnected from the terminal of the protection relay during testing. Check all the connected signals so that both input voltage level and polarity are in accordance with the protection relay specifications. However, attention must be paid to the electrical safety instructions.

Always check the binary output circuits from the protection relay to the equipment interface to make sure that all signals are connected correctly. If a particular output needs to be tested, the corresponding wiring can be disconnected from the terminal of the protection relay during testing. Check all the connected signals so that both load and polarity are in accordance with the protection relay specifications. However, attention must be paid to the electrical safety instructions.

Checking optical connections

Check that the Tx and Rx optical connections are correct.

A relay equipped with optical connections requires a minimum depth of 180 mm (7.2 inches) for plastic fiber cables and 275 mm (10.9 inches) for glass fiber cables. Check the allowed minimum bending radius from the optical cable manufacturer.

Applying required settings for the protection relay

Download all calculated settings and measurement transformer parameters in the protection relay.

Connecting test equipment to the protection relay

Before testing, connect the test equipment according to the protection relay specific connection diagram.

Pay attention to the correct connection of the input and output current terminals. Check that the input and output logical signals in the logic diagram for the function under test are connected to the corresponding binary inputs and outputs of the protection relay. Select the correct auxiliary voltage source according to the power supply module of the protection relay. Select the correct auxiliary voltage source according to the power supply module of the protection relay.

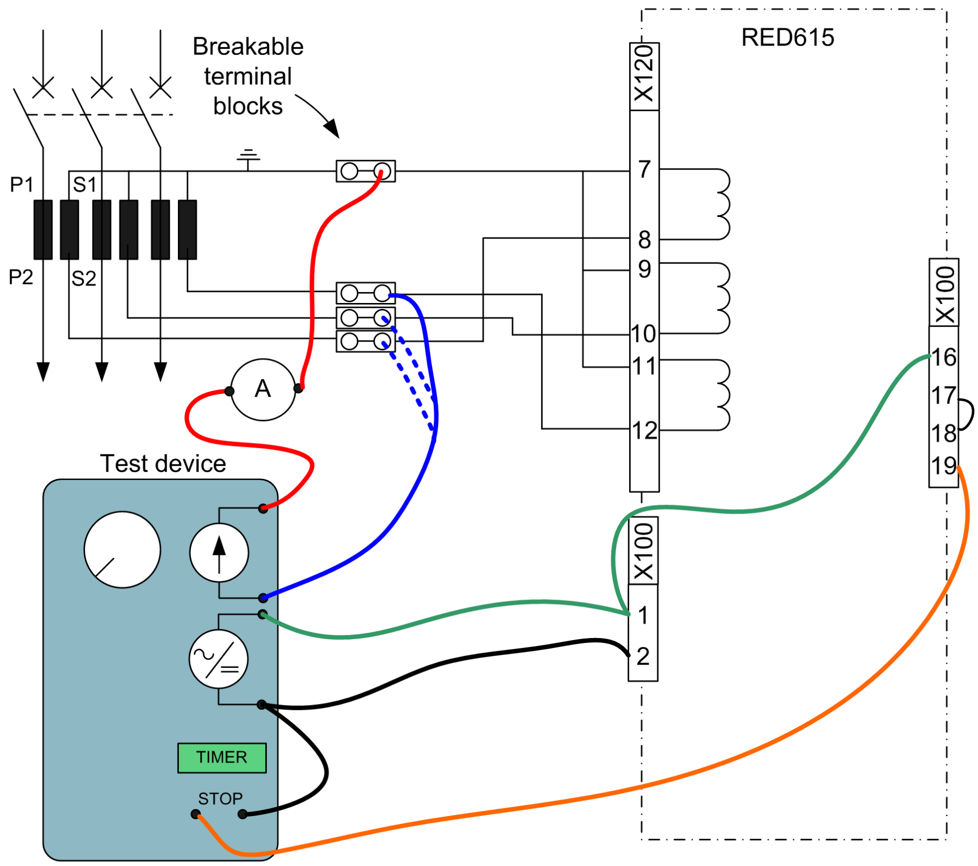


Figure 237: Example of connections to test the line differential protection relay

Secondary current injection

There are two alternative modes to check the operation of a line differential protection relay. These are not exclusive methods for each other and can be used for various test on the protection relay.

Normal mode

In normal mode, that is, the mode when the function is on normal operation, the local end protection relay sends phasors to the remote end protection relay and receives phasors measured by the remote end protection relay. This mode can be used in testing the operating level and time of the low and high stages of the local end protection relay. This is due to a test situation when the remote end does not measure any current and therefore, all the current fed to the local end current circuit is seen as differential current at both ends.

Testing of the line differential protection is done with both protection relays separated geographically from each other. It is important to note that local actions in one protection relay cause operation also in the remotely located protection relay. When testing the line differential function, actions have to be done in both protection relays.

Before the test, the trip signal to the circuit breaker shall be blocked, for example by breaking the trip circuit by opening the terminal block or by using some other suitable method.

When injecting current to one phase in the local end protection relay, the current is seen as a differential current at both ends. If a current $I_{injected}$ is injected, A in phase A, the differential and stabilizing currents for phase A are:

$$ID\_A = I_{injected}$$

(Equation 78)

$$IB\_A = I_{injected} / 2$$

(Equation 79)

The operation is equal for phases B and C.

Verifying the settings

1. Block the unwanted trip signals from the protection relay units involved.
2. Inject a current in phase A and increase the current until the function operates for phase A.
   The injected operate current corresponds to the set *Low operate value*. The monitored values for ID_A should be equal to the injected current.
3. Repeat point 2 by current injection in phases B and C.
4. Measure the operating time by injecting the single-phase current in phase A.
   The injected current should be four times the operating current. The time measurement is stopped by the trip output from the protection relay unit.
5. Disconnect the test equipment and reconnect the current transformers and all other circuits including the trip circuit.

Phasor echoing method

The line differential function in one protection relay can be set to special test mode, that is, the *Operation* setting is set to “test/blocked”. When this mode is in use, the remote end protection relay echoes locally injected current phasors back with the shifted phase and settable amplitude. Therefore, the local end line differential function is also automatically blocked and the remote end line differential function discards the phasors it receives from the protection relay in the test mode.

When the test mode is active, the *CT connection type* is still used by the line differential protection function as in the normal operation mode. The setting can be used for shifting the phase (0 or 180 degrees).

Parameter Setting

Parameter Name	IED Value	New Value	Unit	Min.	Max.	Step
Operation	test/blocked	test/blocked				
Winding selection	Not in use	Not in use				
CT ratio correction	1.000	1.000		0.200	5.000	0.001
CT connection type	Type 2	Type 2				
Restraint mode	None	None				
Reset delay time	0	0	ms	0	60000	1
Low operate value #	10	10	%In	10	200	1
High operate value #	200	200	%In	200	4000	1
High Op value Mult #	1.0	1.0		0.5	1.0	0.1
End section 1 #	0	0	%In	0	200	1
Slope section 2 #	50	50	%	10	50	1
End section 2 #	200	200	%In	200	2000	1
Slope section 3 #	100	100	%	100	200	1
Operating curve type #	IEC Def. Time	IEC Def. Time				
Operate delay time #	45	45	ms	45	200000	1

Figure 238: An example of a test mode situation where three-phase currents are injected to the local end protection relay

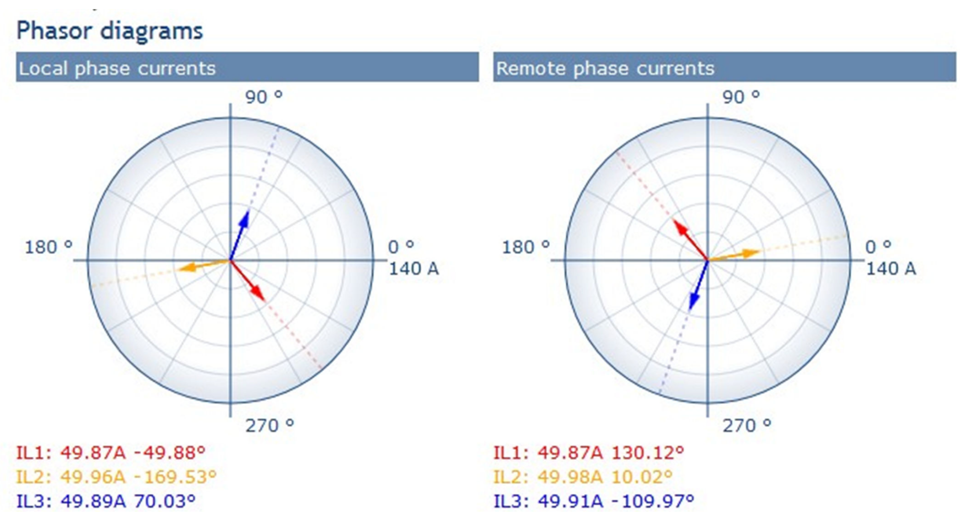


Figure 239: Local and remote end currents presented in a web HMI of the protection relay

4.3.1.6 Application

87L is designed for the differential protection of overhead line and cable feeders in a distribution network. 87L provides absolute selectivity and fast trip times as unit protection also in short lines where distance protection cannot be applied.

87L provides selective protection for radial, looped and meshed network topologies and can be used in isolated neutral networks, resistance grounded networks, compensated (impedance grounded) networks and solidly grounded networks. In a typical network configuration where the line differential protection scheme is applied, the protected zone, that is, the line or cable, is fed from two directions.

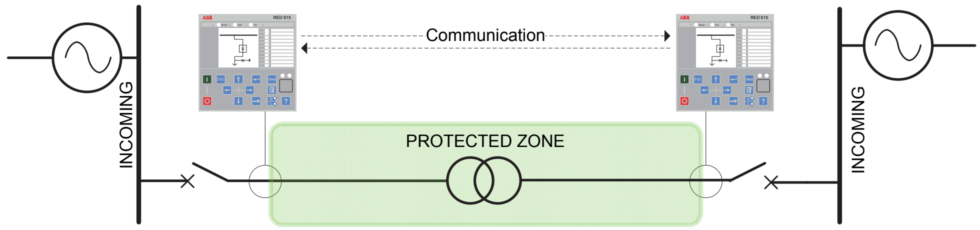


Figure 240: Line protection with phase segregated line differential with in-zone transformer

87L can be utilized for various types of network configurations or topologies. Case A shows the protection of a ring-type distribution network. The network is also used in the closed ring mode. 87L is used as the main protection for different sections of the feeder. In case B, the interconnection of two substations is done with parallel lines and each line is protected with the line differential protection. In case C, the connection line to mid scale power generation (typical size around 10...50 MVA) is protected with the line differential function. The protection includes the transformer from the protection field. In case D, the connection between two substations and a small distribution transformer is located at the tapped load. The use of 87L is not limited to these applications.

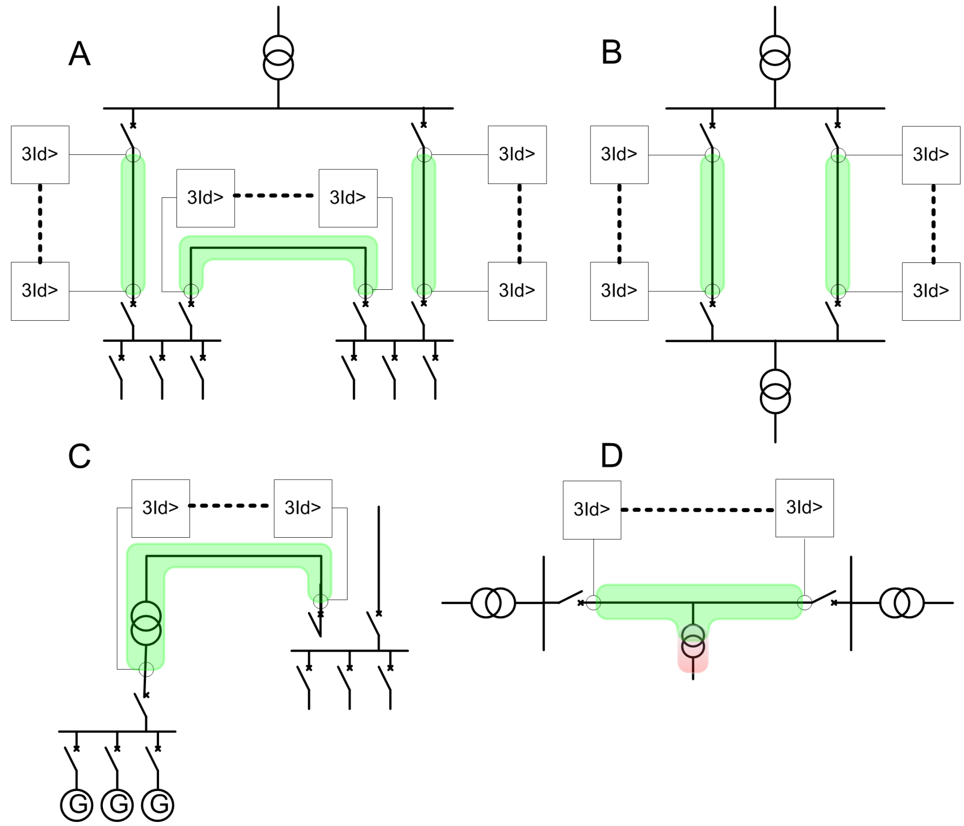


Figure 241: Line differential applications

Communication supervision

A typical line differential protection application includes 87L as the main protection. Backup over current functions is needed if a protection communication failure occurs. When the communication supervision function detects a failure in the communication between the protective units, the safe operation of the line is still guaranteed by blocking the line differential protection and unblocking the over current functions.

When a communication failure is detected, the protection communication supervision function issues block for the 87L line differential protection and unblock for the instantaneous and high stages (instance 2) of the over current protection. These are used to give backup protection for the remote end feeder protection relay. In situations where the selectivity is weaker than usually, the protection should still be available for the system.

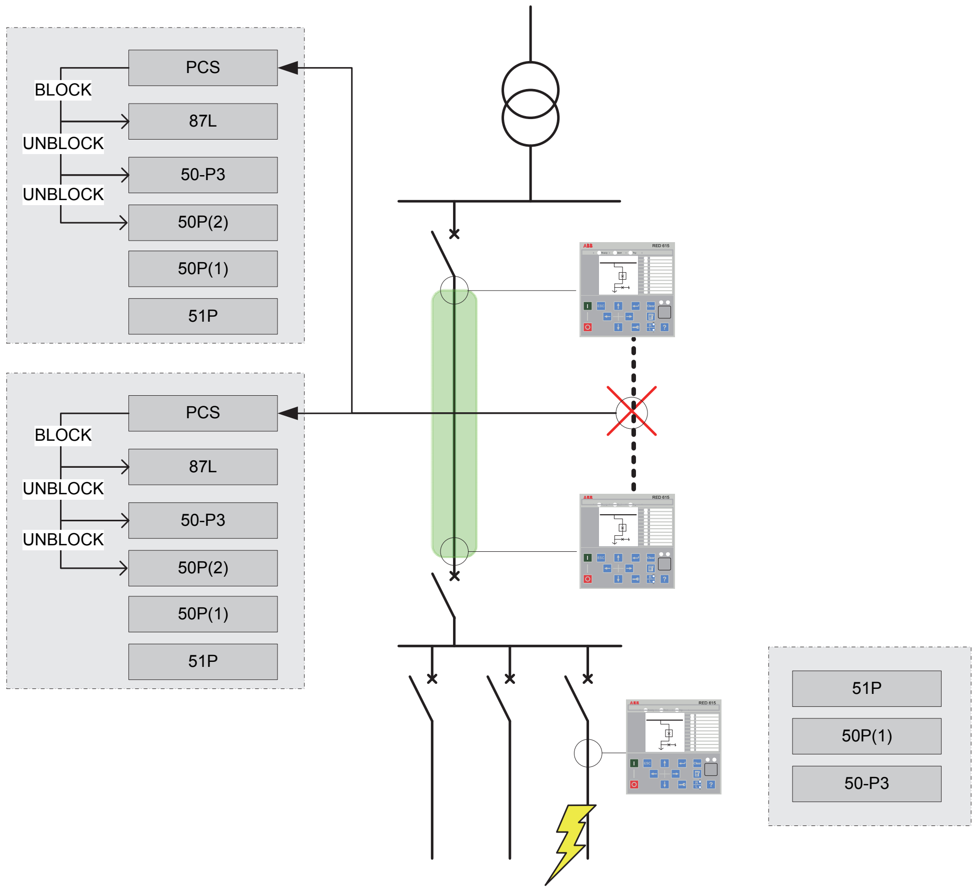


Figure 242: Protection communication supervision detects failures on communication

In-zone transformer

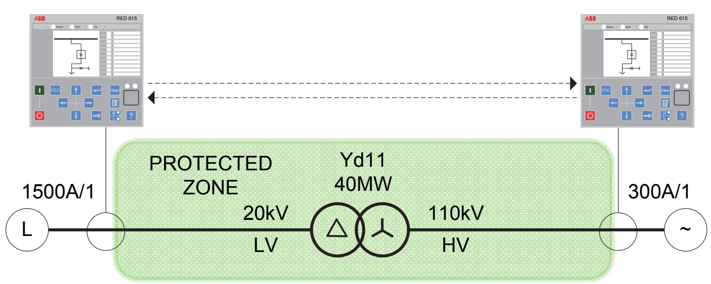


Figure 243: In-zone transformer example about CT ratio correction calculation

The CT ratio correction calculation starts with the rated load current calculation for HV and LV sides. The rated load current is defined as the rated power of the transformer divided by the square root of three times the nominal phase-to-phase voltage at the HV or LV side.

$$I_{nT} = \frac{S_n}{\sqrt{3} \cdot V_n}$$

(Equation 80)

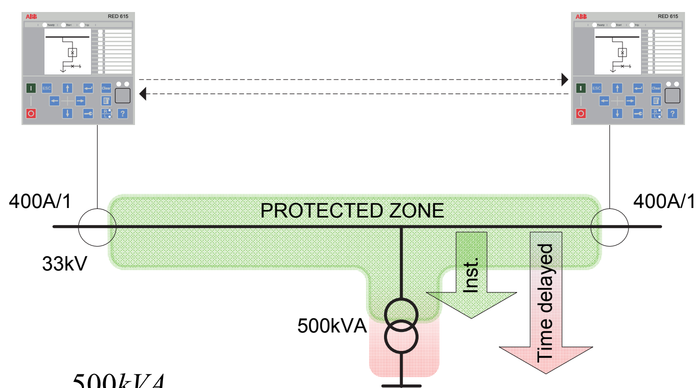
The rated load current of the transformer on the HV side is 209.9 A (40 MW / (√3 × 110 kV)) and the rated load current of the transformer on the LV side is 1154.7 A (40 MW / (√3 × 20 kV)). This means that the CT ratio corrections for the HV and LV sides are:

CT ratio correction (HV) = 1.429 (300 A / 209.9 A)

CT ratio correction (LV) = 1.299 (1500 A / 1154.7 A)

Small power transformers in a tap

With a relatively small power transformer in a line tap, the line differential protection can be applied without the need of current measurement from the tap. In such cases, the line differential function is time delayed for low differential currents below the high set limit and 87L coordinates with the downstream protection relays in the relevant tap. For differential currents above the set limit, the operation is instantaneous. As a consequence, when the load current of the tap is negligible, the low resistive line faults are cleared instantaneously at the same time as maximum sensitivity for the high resistive faults are maintained but with a time delayed operation. The maximum sensitivity for high resistive faults is maintained at the same time, but with a time delayed operation.

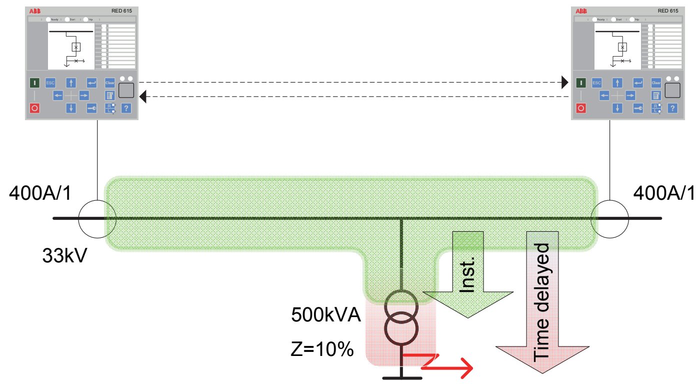


$$I_L = \frac{500kVA}{\sqrt{3} \cdot 33kV} \cong 8.75A$$

$$I_\Delta > \left[\frac{8.75A}{400\ A}\right] * 1A = 0.02A = 2\%$$

Figure 244: Influence of the tapped transformer load current to the stabilized low stage setting

The stabilized stage provides both DT and IDMT characteristics that are used for time selective protection against faults which are not covered by the instantaneous stage. The impedance of the line is typically an order of magnitude lower than the transformer impedance providing significantly higher fault currents when the fault is located on the line.



$$I_F = \frac{1.1 \cdot 500kVA}{\sqrt{3} \cdot 33kV \cdot 0.10} \cong 96.23A$$

$$\mathrm{I}_{\Delta} < \left[\frac{96.23A}{400\ A}\right] * 1\mathrm{A} = 0.24A = 24\%$$

Figure 245: Influence of the short circuit current at LV side of the tapped transformer to the differential current

Detection of the inrush current during transformer start-up

When the line is energized, the transformer magnetization inrush current is seen as differential current by the line differential protection and may cause malfunction of the protection if not taken into account. The inrush situation may only be detected on one end but the differential current is always seen on both ends. The inrush current includes high order harmonic components which can be detected and used as the blocking criteria for the stabilized stage. The inrush detection information is changed between two ends so that fast and safe blocking of the stabilized stage can be issued on both ends.

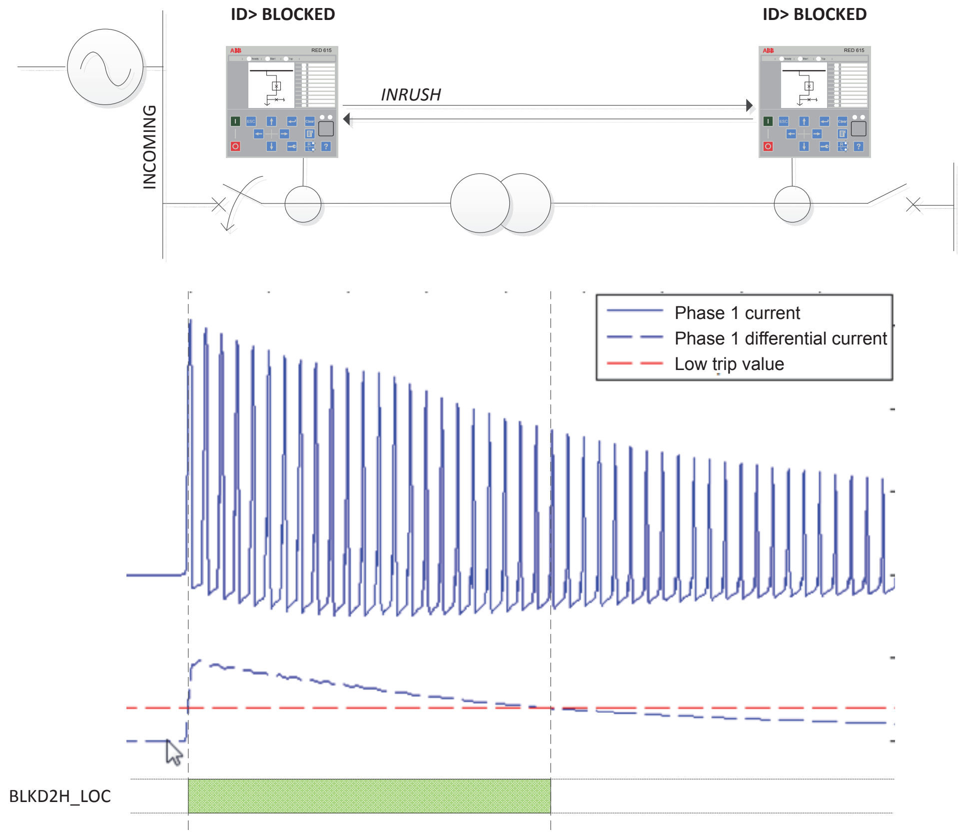


Figure 246: Blocking of line differential functions during detected transformer start-up current

If the protection stage is allowed to start during the inrush situation, the time delay can be selected so that the stabilized stage does not trip in the inrush situation.

4.3.1.7 Signals

Table 424: 87L Input signals

Name	Type	Default	Description
I_LOC_A	SIGNAL	0	Phase A local current
I_LOC_B	SIGNAL	0	Phase B local current
I_LOC_C	SIGNAL	0	Phase C local current
I_REM_A	SIGNAL	0	Phase A remote current
I_REM_B	SIGNAL	0	Phase B remote current
I_REM_C	SIGNAL	0	Phase C remote current

Table continues on next page

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
BLOCK_LS	BOOLEAN	0=False	Signal for blocking the stab. stage
ENA_MULT_HS	BOOLEAN	0=False	Enables the high stage multiplier

Table 425: 87L Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
STR_LS_LOC	BOOLEAN	Pickup stabilized stage local
STR_LS_REM	BOOLEAN	Pickup stabilized stage remote
OPR_LS_LOC	BOOLEAN	Trip stabilized stage local
OPR_LS_REM	BOOLEAN	Trip stabilized stage remote
OPR_HS_LOC	BOOLEAN	Trip instantaneous stage local
OPR_HS_REM	BOOLEAN	Trip instantaneous stage remote
BLKD2H_LOC	BOOLEAN	Restraint due 2nd harmonics detected local
BLKD2H_REM	BOOLEAN	Restraint due 2nd harmonics detected remote
PRO_ACTIVE	BOOLEAN	Status of the protection, true when function is operative

4.3.1.8 Settings

Table 426: 87L Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Low trip value	10...200	%Ir	1	10	Basic setting for the stabilized stage pickup
High trip value	200...4000	%Ir	1	2000	Instantaneous stage trip value
Pickup value 2.H	10...50	%	1	20	The ratio of the 2. harmonic component to fundamental component required for blocking
High Op value Mult	0.5...1.0		0.1	1.0	Multiplier for scaling the high stage trip value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IDMT curves
End section 1	0...200	%Ir	1	100	Turn-point between the first and the second line of the operating characteristics
Slope section 2	10...50	%	1	50	Slope of the second line of the operating characteristics
End section 2	200...2000	%Ir	1	500	Turn-point between the second and the third line of the operating characteristics
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Slope section 3	10...200	%	1	150	Slope of the third line of the operating characteristics
Operating curve type	1=ANSI Ext Inv 3=ANSI Norm Inv 5=ANSI DT 9=IEC Norm Inv 10=IEC Very Inv 12=IEC Ext Inv 15=IEC DT			15=IEC DT	Selection of time delay curve for stabilized stage
Trip delay time	45...200000	ms	1	45	Trip delay time

Table 427: 87L Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=on 4=test/blocked 5=off			1=on	Operation Disable / Enable
Winding selection	1=Not in use 2=Winding 1 3=Winding 2			1=Not in use	IED location respect to transformer, HV (Winding 1) side or LV (Winding 2) side
Winding 1 type	1=Y 2=YN 3=D 4=Z 5=ZN			1=Y	Connection of the HV side windings. Determined by the transformer connection group (e.g. Dyn11 ->"D")
Winding 2 type	1=y 2=yn 3=d 4=z 5=zn			1=y	Connection of the LV side windings. Determined by the transformer connection group (e.g. Dyn11 ->"yn")
Clock number	0=Clk Num 0 1=Clk Num 1 2=Clk Num 2 4=Clk Num 4 5=Clk Num 5 6=Clk Num 6 7=Clk Num 7 8=Clk Num 8 10=Clk Num 10 11=Clk Num 11			0=Clk Num 0	Setting the phase shift between HV and LV with clock number for connection group compensation (e.g. Dyn11 -> 11)
CT ratio correction	0.200...5.000		0.001	1.000	Local phase current transformer ratio correction
CT connection type	1=Type 1 2=Type 2			1=Type 1	CT connection type. Determined by the directions of the connected current transformers.
Zro A elimination	1=Not eliminated 2=Winding 1 3=Winding 2 4=Winding 1 and 2			1=Not eliminated	Elimination of the zero-sequence current
Restraint mode	1=None 2=Harmonic2			1=None	Selects what restraint modes are in use

Table 428: 87L Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	0	Reset delay time
Minimum trip time	45...60000	ms	1	45	Minimum trip time for stabilized stage IDMT curves

4.3.1.9 Monitored Data

Table 429: 87L Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
I_AMPL_LOC_A	FLOAT32	0.00...40.00	xIr	Local phase A amplitude after correction
I_AMPL_LOC_B	FLOAT32	0.00...40.00	xIr	Local phase B amplitude after correction
I_AMPL_LOC_C	FLOAT32	0.00...40.00	xIr	Local phase C amplitude after correction
I_AMPL_REM_A	FLOAT32	0.00...40.00	xIr	Remote phase A amplitude after correction
I_AMPL_REM_B	FLOAT32	0.00...40.00	xIr	Remote phase B amplitude after correction
I_AMPL_REM_C	FLOAT32	0.00...40.00	xIr	Remote phase C amplitude after correction
ID_A	FLOAT32	0.00...80.00	xIr	Differential current phase A
ID_B	FLOAT32	0.00...80.00	xIr	Differential current phase B
ID_C	FLOAT32	0.00...80.00	xIr	Differential current phase C
IB_A	FLOAT32	0.00...80.00	xIr	Stabilization current phase A
IB_B	FLOAT32	0.00...80.00	xIr	Stabilization current phase B
IB_C	FLOAT32	0.00...80.00	xIr	Stabilization current phase C
I_ANGL_DIFF_A	FLOAT32	-180.00...180.00	deg	Current phase angle differential between local and remote, phase A
I_ANGL_DIFF_B	FLOAT32	-180.00...180.00	deg	Current phase angle differential between local and remote, phase B
I_ANGL_DIFF_C	FLOAT32	-180.00...180.00	deg	Current phase angle differential between local and remote, phase C
87L	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
IA-diff	FLOAT32	0.00...80.00		Differential current phase A
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
IB-diff	FLOAT32	0.00...80.00		Differential current phase B
IC-diff	FLOAT32	0.00...80.00		Differential current phase C
IA-bias	FLOAT32	0.00...80.00		Stabilization current phase A
IB-bias	FLOAT32	0.00...80.00		Stabilization current phase B
IC-bias	FLOAT32	0.00...80.00		Stabilization current phase C

4.3.1.10 Technical data

Table 430: 87L Technical data

Characteristics	Value		
Operation accuracy [1]	Depending on the frequency of the measured current: f_n ±2 Hz		
	Low stage	±2.5% of the set value	
	High stage	±2.5% of the set value	
High stage, trip time [2)3)]	Minimum	Typical	Maximum
	22 ms	25 ms	29 ms
Reset time	Typically 40 ms		
Reset ratio	Typically 0.96		
Retardation time (Low stage)	<40 ms		
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode	±5.0% of the set value or ±20 ms [4]		

1) With the symmetrical communication channel (as when using dedicated fiber optic).
2) Without additional delay in the communication channel (as when using dedicated fiber optic).
3) Including the delay of the output contact. When differential current = 2 × *High trip value* and f_n = 50 Hz with galvanic pilot wire link + 5 ms.
4) *Low operate value* multiples in range of 1.5...20.

4.3.1.11 Technical revision history

Table 431: 87L Technical revision history

Technical revision	Change
B	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
C	Support for in-zone transformer added. Differential and bias currents are shown as rated currents in the **Measurements** view.
D	Internal Improvement.

4.3.2 Stabilized and instantaneous differential protection for two-winding transformers 87T

4.3.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Stabilized and instantaneous differential protection for two-winding transformers	TR2PTDF	3dI>T	87T

4.3.2.2 Function block

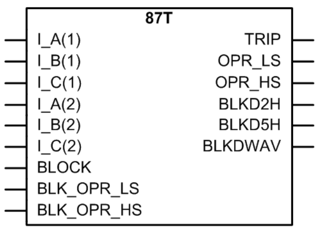


Figure 247: Function block

4.3.2.3 Functionality

The stabilized and instantaneous differential protection function 87T is designed to protect two-winding transformers and generator-transformer blocks. 87T includes low biased and high instantaneous stages.

The biased low stage provides a fast clearance of faults while remaining stable with high currents passing through the protected zone increasing errors on current measuring. The second harmonic restraint, together with the waveform based algorithms, ensures that the low stage does not trip due to the transformer inrush currents. The fifth harmonic restraint ensures that the low stage does not trip on apparent differential current caused by a harmless transformer over-excitation.

The instantaneous high stage provides a very fast clearance of severe faults with a high differential current regardless of their harmonics.

The setting characteristic can be set more sensitive with the aid of tap changer position compensation. The correction of transformation ratio due to the changes in tap position is done automatically based on the tap changer status information.

4.3.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 87T can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

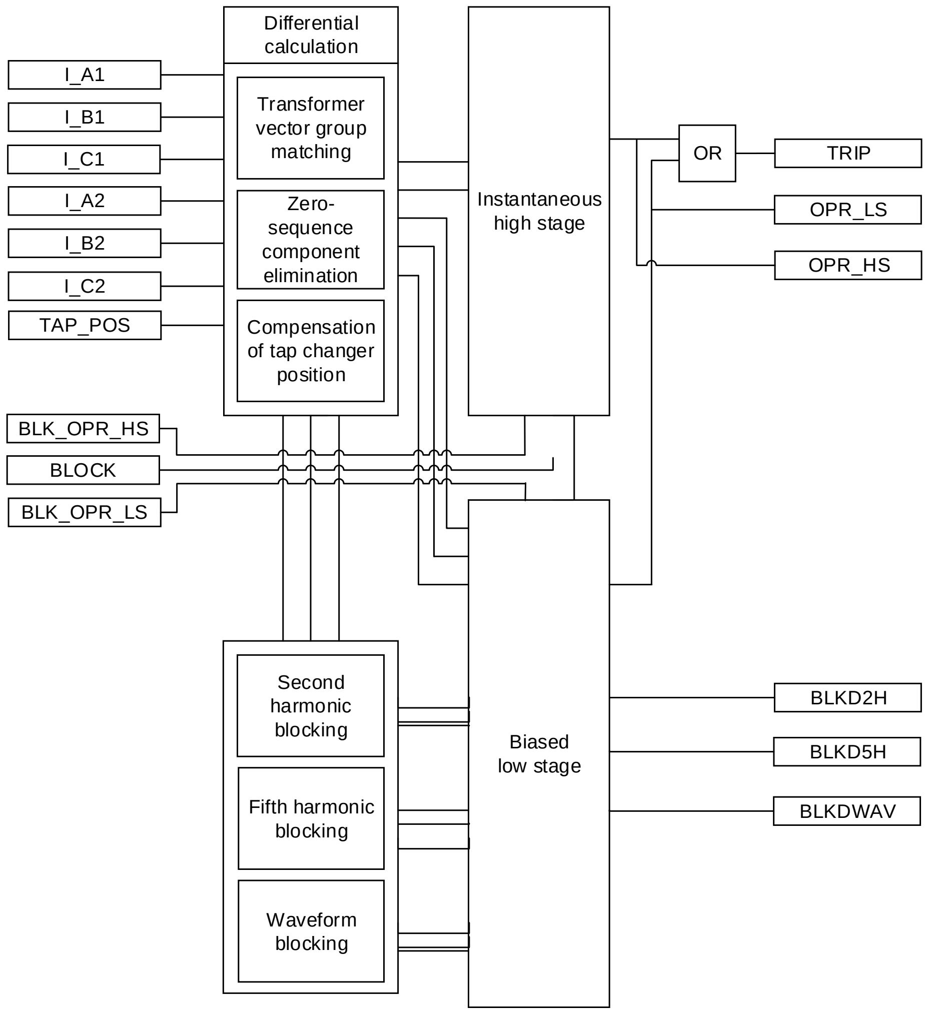


Figure 248: Functional module diagram

Differential calculation

87T operates phase-wise on a difference of incoming and outgoing currents. The positive direction of the currents is towards the protected object.

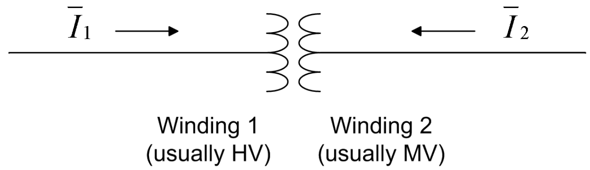


Figure 249: Positive direction of the currents

$$I_d = \left|\overline{I}_{W1} + \overline{I}_{W2}\right|$$

(Equation 81)

In a normal situation, no fault occurs in the area protected by 87T. Then the currents $\overline{I}_{W1}$ and $\overline{I}_{W2}$ are equal and the differential current I_d is zero. In practice, however, the differential current deviates from zero in normal situations. In the power transformer protection, the differential current is caused by CT inaccuracies, variations in tap changer position (if not compensated), transformer no-load current and instantaneous transformer inrush currents. An increase in the load current causes the differential current, caused by the CT inaccuracies and the tap changer position, to grow at the same percentage rate.

In a biased differential protection relay in normal operation or during external faults, the higher the load current is the higher is the differential current required for tripping. When an internal fault occurs, the currents on both sides of the protected object are flowing into it. This causes the biasing current to be considerably smaller, which makes the operation more sensitive during internal faults.

$$I_b = \frac{\left|\overline{I}_{W1} - \overline{I}_{W2}\right|}{2}$$

(Equation 82)

If the biasing current is small compared to the differential current or if the phase angle between the winding 1 and winding 2 phase currents is close to zero (in a normal situation, the phase difference is 180 degrees), a fault has most certainly occurred in the area protected by the differential protection relay. Then the trip value set for the instantaneous stage is automatically halved and the internal blocking signals of the biased stage are inhibited.

Transformer vector group matching

The phase difference of the winding 1 and winding 2 currents that is caused by the vector group of the power transformer is numerically compensated. The matching of the phase difference is based on the phase shifting and the numerical delta connection inside the protection relay. The *Winding 1 type* parameter determines the connection on winding 1 (”Y”, ”YN”, ”D”, ”Z”, ”ZN”). The *Winding 2 type* parameter determines the connections of the phase windings on the low voltage side (“y”, ”yn”, ”d”, ”z”, ”zn”).

The vector group matching can be implemented either on both, winding 1 and winding 2, or only on winding 1 or winding 2, at intervals of 30° with the *Clock number* setting.

When the vector group matching is Yy0 and the *CT connection type* is according to "Type 2", the phase angle of the phase currents connected to the protection relay does not change. When the vector group matching is Yy6, the phase currents are turned 180° in the protection relay.

Example 1

Vector group matching of a Ynd11-connected power transformer on winding 1, *CT connection type* according to type 1. The *Winding 1 type* setting is ”YN”, *Winding 2 type* is “d” and *Clock number* is “Clk Num 11”. This is compensated internally by giving winding 1 internal compensation value +30° and winding 2 internal compensation value 0°:

$$\bar{I}_{AmHV} = \frac{\bar{I}_A - \bar{I}_B}{\sqrt{3}}$$
$$\bar{I}_{BmHV} = \frac{\bar{I}_B - \bar{I}_C}{\sqrt{3}}$$
$$\bar{I}_{CmHV} = \frac{\bar{I}_C - \bar{I}_A}{\sqrt{3}}$$

(Equation 83)

Example 2

But if vector group is Yd11 and *CT connection type* is according to type 1, the compensation is a little different. The *Winding 1 type* setting is ”Y”, *Winding 2 type* is “d” and *Clock number* is “Clk Num 11”. This is compensated internally by giving winding 1 internal compensation value 0° and winding 2 internal compensation value -30°;

$$\bar{I}_{AmLV} = \frac{\bar{I}_A - \bar{I}_C}{\sqrt{3}}$$
$$\bar{I}_{BmLV} = \frac{\bar{I}_B - \bar{I}_A}{\sqrt{3}}$$
$$\bar{I}_{CmLV} = \frac{\bar{I}_C - \bar{I}_B}{\sqrt{3}}$$

(Equation 84)

The "Y" side currents stay untouched, while the "d" side currents are compensated to match the currents actually flowing in the windings.

In this example there is no neutral current on either side of the transformer (assuming there are no grounding transformers installed). In the previous example, however, the matching is done differently to have the winding 1 neutral current compensated at the same time.

Zero-sequence component elimination

If *Clock number* is "Clk Num 2", "Clk Num 4", "Clk Num 8" or "Clk Num 10", the vector group matching is always done on both, winding 1 and winding 2. The combination results in the correct compensation. In this case the zero-sequence component is always removed from both sides automatically. The *Zro A elimination* parameter cannot change this.

If *Clock number* is "Clk Num 1", "Clk Num 5", "Clk Num 7" or "Clk Num 11", the vector group matching is done on one side only. A possible zero-sequence component of the phase currents at ground faults occurring outside the protection area is eliminated in the numerically implemented delta connection before the differential current and the biasing current are calculated. This is why the vector group matching is almost always made on the star connected side of the "Ynd" and "Dyn" connected transformers.

If *Clock number* is "Clk Num 0" or "Clk Num 6", the zero-sequence component of the phase currents is not eliminated automatically on either side. Therefore, the zero-sequence component on the star connected side that is grounded at its star point has to be eliminated by using the *Zro A elimination* parameter.

The same parameter has to be used to eliminate the zero-sequence component if there is, for example, an grounding transformer on the delta-connected side of the "Ynd" power transformer in the area to be protected. In this case, the vector group matching is normally made on the side of the star connection. On the side of the delta connection, the elimination of the zero-sequence component has to be separately selected.

By using the *Zro A elimination* parameter, the zero-sequence component of the phase currents is calculated and reduced for each phase current:

$$\bar{I}_{Am} = \bar{I}_A - \frac{1}{3} x \left(\bar{I}_A + \bar{I}_B + \bar{I}_C \right)$$
$$\bar{I}_{Bm} = \bar{I}_B - \frac{1}{3} x \left(\bar{I}_A + \bar{I}_B + \bar{I}_C \right)$$
$$\bar{I}_{Cm} = \bar{I}_C - \frac{1}{3} x \left(\bar{I}_A + \bar{I}_B + \bar{I}_C \right)$$

(Equation 85)

In many cases with the grounded neutral of a "wye" winding, it is possible to make the compensation so that a zero-sequence component of the phase currents is automatically eliminated. For example, in a case of a "Ynd" transformer, the compensation is made on the winding 1 side to automatically eliminate the zero-sequence component of the phase currents on that side (and the "d" side does not have them). In those cases, explicit elimination is not needed.

Compensation of tap changer position

The position of the tap changer used for voltage control can be compensated and the position information is provided for the protection function through the tap position indication function 84T.

Typically, the tap changer is located within the high voltage winding, that is, winding 1, of the power transformer. The *Tapped winding* parameter specifies whether the tap changer is connected to the high voltage side winding or the low voltage side winding. This parameter is also used to enable and disable the automatic adaptation to the tap changer position. The possible values are "Not in use", "Winding 1" or "Winding 2".

The *Tap nominal* parameter tells the number of the tap, which results in the nominal voltage (and current). When the current tap position deviates from this value, the input current values on the side where the tap changer resides are scaled to match the currents on the other side.

A correct scaling is determined by the number of steps and the direction of the deviation from the nominal tap and the percentage change in voltage resulting from a deviation of one tap step. The percentage value is set using the *Step of tap* parameter.

The operating range of the tap changer is defined by the *Min winding tap* and *Max winding tap* parameters. The *Min winding tap* parameter tells the tap position number resulting in the minimum effective number of winding turns on the side of the transformer where the tap changer is connected. Correspondingly, the *Max winding tap* parameter tells the tap position number resulting in the maximum effective number of winding turns.

The *Min winding tap* and *Max winding tap* parameters help the tap position compensation algorithm know in which direction the compensation is being made. This ensures also that if the current tap position information is corrupted for some reason, the automatic tap changer position adaptation does not try to adapt to any unrealistic position values.

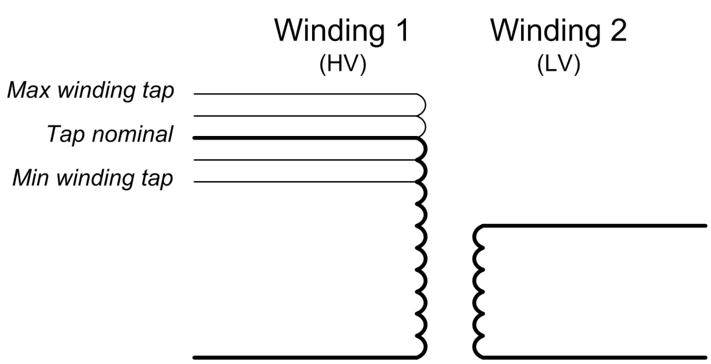


Figure 250: Simplified presentation of the high voltage and medium voltage windings with demonstration of the Max winding tap, Min winding tap and Tap nominal parameters

The position value is available through the Monitored data view on LHMI or through other communication tools in the tap position indication function. When the quality of the `TAP_POS` value is not good, the position information in `TAP_POS` is not used but the last value with the good quality information is used instead. In addition, the minimum sensitivity of the biased stage, set by the *Low trip value* setting, is automatically desensitized with the total range of the tap position correction. The new acting low trip value is

$$Desensitized\ Low\ trip\ value = Low\,trip\,value + ABS(Max\,Winding\ tap - Min\,winding\ tap) \times Step\ of\ tap$$

(Equation 86)

Second harmonic blocking

The transformer magnetizing inrush currents occur when energizing the transformer after a period of de-energization. The inrush current can be many times the rated current and the halving time can be up to several seconds. To the differential protection, the inrush current represents a differential current, which would cause the differential protection to trip almost always when the transformer is connected to the network. Typically, the inrush current contains a large amount of second harmonics.

Blocking the operation of the 87T biased low stage at a magnetizing inrush current is based on the ratio of the amplitudes of the second harmonic digitally filtered from the differential current and the fundamental frequency (Id2f /Id1f).

The blocking also prevents unwanted operation at the recovery and sympathetic magnetizing inrushes. At the recovery inrush, the magnetizing current of the transformer to be protected increases momentarily when the voltage returns to normal after the clearance of a fault outside the protected area. The sympathetic inrush is caused by the energization of another transformer running in parallel with the protected transformer already connected to the network.

The ratio of the second harmonic to a fundamental component can vary considerably between the phases. Especially when the delta compensation is done for a Ynd1 connected transformer and the two phases of the inrush currents are otherwise equal but opposite in phase angle, the subtraction of the phases in a delta compensation results in a very small second harmonic component.

Some measures have to be taken in order to avoid the false tripping of a phase having too low a ratio of the second harmonic to the fundamental component. One way could be to always block all the phases when the second harmonic blocking conditions are fulfilled in at least one phase. The other way is to calculate the weighted ratios of the second harmonic to the fundamental component for each phase using the original ratios of the phases. The latter option is used here. The second harmonic ratios I_2H_RAT_x are given in Monitored data.

The ratio to be used for second harmonic blocking is, therefore, calculated as a weighted average on the basis of the ratios calculated from the differential currents of the three phases. The ratio of the concerned phase is of most weight compared to the ratios of the other two phases. In this protection relay, if the weighting factors are four, one and one, four is the factor of the phase concerned. The operation of the biased stage on the concerned phase is blocked if the weighted ratio of that phase is above the set blocking limit *Pickup value 2.H* and if blocking is enabled through the *Restraint mode* parameter.

Using separate blocking for the individual phases and weighted averages calculated for the separate phases provides a blocking scheme that is stable at the connection inrush currents.

If the peak value of the differential current is very high, that is I_r>12×In, the limit for the second harmonic blocking is desensitized (in the phase in question) by increasing it proportionally to the peak value of the differential current.

The connection of the power transformer against a fault inside the protected area does not delay the operation of the tripping, because in such a situation the blocking based on the second harmonic of the differential current is prevented by a separate algorithm based on a different waveform and a different rate of change of the normal inrush current and the inrush current containing the fault current. The algorithm does not eliminate the blocking at inrush currents, unless there is a fault in the protected area.

The feature can also be enabled and disabled with the *Harmonic deblock 2.H* parameter.

Fifth harmonic blocking

The inhibition of 87T operation in the situations of overexcitation is based on the ratio of the fifth harmonic and the fundamental component of the differential current (Id5f/Id1f). The ratio is calculated separately for each phase without weighting . If the ratio exceeds the setting value of *Pickup value 5.H* and if blocking is enabled through the *Restraint mode* parameter, the operation of the biased stage of 87T in the concerned phase is blocked.The fifth harmonic ratios I_5H_RAT_x are given in Monitored data.

At dangerous levels of overvoltage, which can cause damage to the transformer, the blocking can be automatically eliminated. If the ratio of the fifth harmonic and the fundamental component of the differential current exceeds the *Stop value 5.H* parameter, the blocking removal is enabled. The enabling and disabling of deblocking feature is also done through the *Harmonic deblock 5.H* parameter.

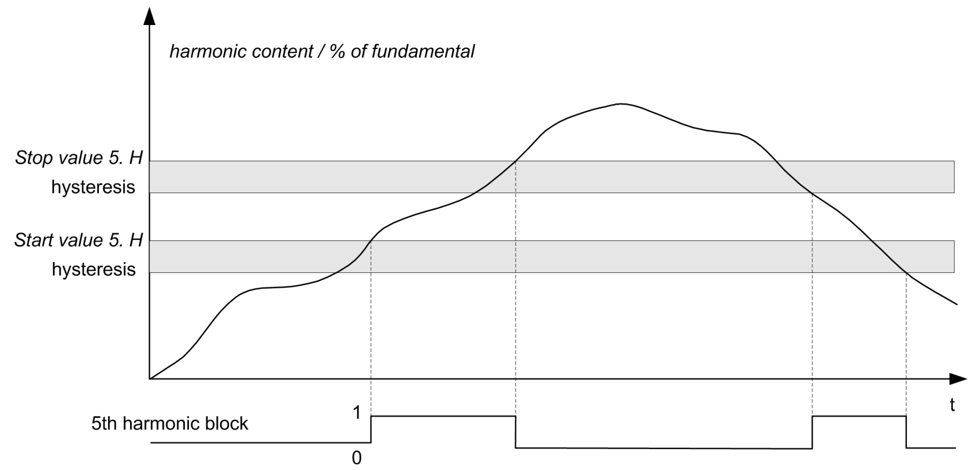


Figure 251: The limits and operation of the fifth harmonic blocking when both blocking and deblocking features are enabled using the Harmonic deblock 5.H control parameter.

The fifth harmonic blocking has a hysteresis to avoid rapid fluctuation between "TRUE" and "FALSE". The blocking also has a counter, which counts the required consecutive fulfillments of the condition. When the condition is not fulfilled, the counter is decreased (if >0).

Also the fifth harmonic deblocking has a hysteresis and a counter which counts the required consecutive fulfillments of the condition. When the condition is not fulfilled, the counter is decreased (if >0).

Waveform blocking

The biased low stage can always be blocked with waveform blocking. The stage can not be disabled with the *Restraint mode* parameter. This algorithm has two parts. The first part is intended for external faults while the second is intended for inrush situations. The algorithm has criteria for a low current period during inrush where also the differential current (not derivative) is checked.

Biased low stage

The current differential protection needs to be biased because the possible appearance of a differential current can be due to something else than an actual fault in the transformer (or generator).

In the case of transformer protection, a false differential current can be caused by:

- CT errors
- Varying tap changer positions (if not automatically compensated)
- Transformer no-load current

- Transformer inrush currents
- Transformer overexcitation in overvoltage
- Underfrequency situations
- CT saturation at high currents passing through the transformer

The differential current caused by CT errors or tap changer positions increases at the same percent ratio as the load current.

In the protection of generators, the false differential current can be caused by various factors.

- CT errors
- CT saturation at high currents passing through the generator

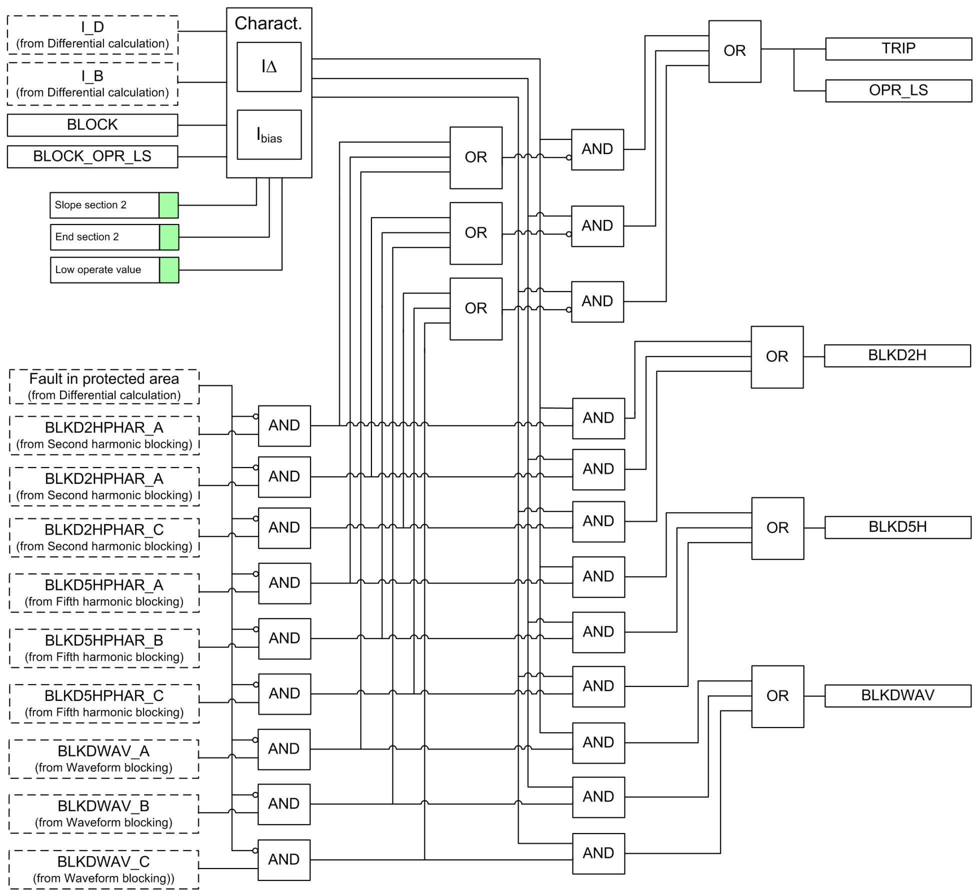


Figure 252: Operation logic of the biased low stage

The high currents passing through a protected object can be caused by the short circuits outside the protected area, the large currents fed by the transformer in motor start-up or the transformer inrush situations. Therefore, the operation of the differential protection is biased in respect to the load current. In biased differential protection, the higher the differential current required for the protection to trip, the higher the load current.

The operating characteristic of the biased low stage is determined by *Low trip value*, *Slope section 2* and the setting of the second turning point of the operating characteristic curve, *End section 2* (the first turning point is fixed). The settings are the same for all the phases. When the differential current exceeds the operating value determined by the operating characteristic, the differential function awakes. If the differential current stays above the operating value continuously for a suitable period, which is 1.1 times the fundamental cycle, the `OPR_LS` output is activated. The `TRIP` output is always activated when the `OPR_LS` output is activated.

The stage can be blocked internally by the second or fifth harmonic restraint, or by special algorithms detecting inrush and current transformer saturation at external faults. When the operation of the biased low stage is blocked by the second harmonic blocking functionality, the `BLKD2H` output is activated.

When operation of the biased low stage is blocked by the fifth harmonic blocking functionality, the `BLKD5H` output is activated. Correspondingly, when the operation of the biased low stage is blocked by the waveform blocking functionality, the `BLKDWAV` output is activated according to the phase information.

When required, the trip outputs of the biased low stage can be blocked by the `BLK_OPR_LS` or `BLOCK` external control signals.

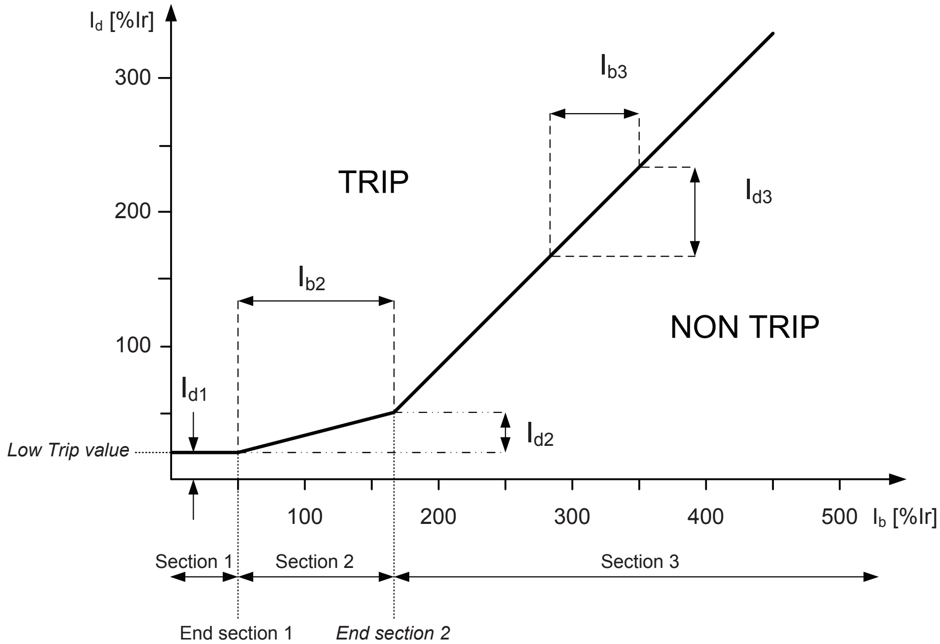


Figure 253: Operation characteristic for biased operation of 87T

The *Low trip value* of the biased stage of the differential function is determined according to the operation characteristic:

Low trip value = Id1

Slope section 2 and *Slope section 3* are determined correspondingly:

$$Slope\ \ section\,2 = \frac{I_{d2}}{I_{b2}} \cdot 100\%$$

(Equation 87)

$$Slope\ \ section\,3 = \frac{I_{d3}}{I_{b3}} \cdot 100\%$$

(Equation 88)

The second turning point *End section 2* can be set in the range of 100 percent to 500 percent.

The slope of the differential function's operating characteristic curve varies in the different sections of the range.

- In section 1, where 0 percent Ir < Ib < End section 1, End section 1 being fixed to 50 percent Ir, the differential current required for tripping is constant. The value of the differential current is the same as the *Low trip value* selected for the function. *Low trip* *value* basically allows the no-load current of the power transformer and small inaccuracies of the current transformers, but it can also be used to influence the overall level of the operating characteristic. At the rated current, the no-load losses of the power transformer are about 0.2 percent. If the supply voltage of the power transformer suddenly increases due to operational disturbances, the magnetizing current of the transformer increases as well. In general the magnetic flux density of the transformer is rather high at rated voltage and a rise in voltage by a few percent causes the magnetizing current to increase by tens of percent. This should be considered in *Low trip value*

- In section 2, where End section 1 < Ib/In < *End section 2*, is called the influence area of *Slope section 2*. In this section, variations in the starting ratio affect the slope of the characteristic, that is, how big a change in the differential current is required for tripping in comparison with the change in the load current. The starting ratio should consider CT errors and variations in the transformer tap changer position (if not compensated). Too high a starting ratio should be avoided, because the sensitivity of the protection for detecting inter-turn faults depends basically on the starting ratio.
- In section 3, where Ib/In > *End section 2*, the slope of the characteristic can be set by *Slope section 3* that defines the increase in the differential current to the corresponding increase in the biasing current.

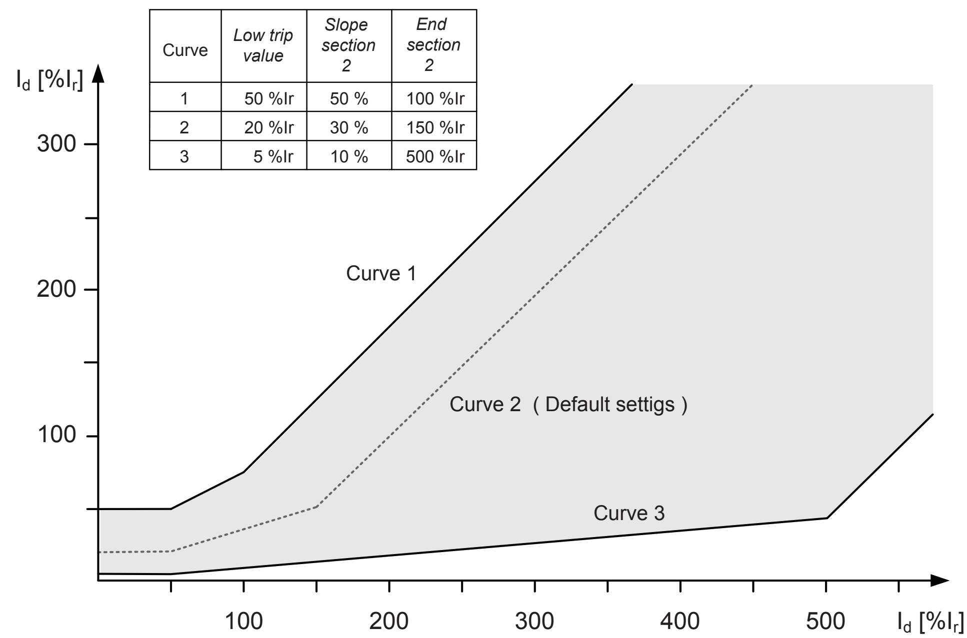


Figure 254: Setting range for biased low stage

If the biasing current is small compared to the differential current of the phase angle between the winding 1 and winding 2 phase currents is close to zero (in a normal situation, the phase difference is 180 degrees), a fault has most likely occurred in the area protected by 87T. Then the internal blocking signals of the biased stage are inhibited.

Instantaneous high stage

The instantaneous high stage operation can be enabled and disabled with the *Enable high set* setting. The corresponding parameter values are "TRUE" and "FALSE."

The operation of the instantaneous high stage is not biased. The instantaneous stage trips and the output `OPR_HS` is activated when the amplitude of the fundamental frequency component of the differential current exceeds the set *High trip value* or when the instantaneous value of the differential current exceeds 2.5 times the value of *High trip value*. The factor 2.5 (=1.8 × √2) is due to the maximum asymmetric short circuit current.

If the biasing current is small compared to the differential current or the phase angle between the winding 1 and winding 2 phase currents is close to zero (in a normal situation, the phase difference is 180 degrees), a fault has occurred in the area protected by 87T. Then the trip value set for the instantaneous stage is automatically halved and the internal blocking signals of the biased stage are inhibited.

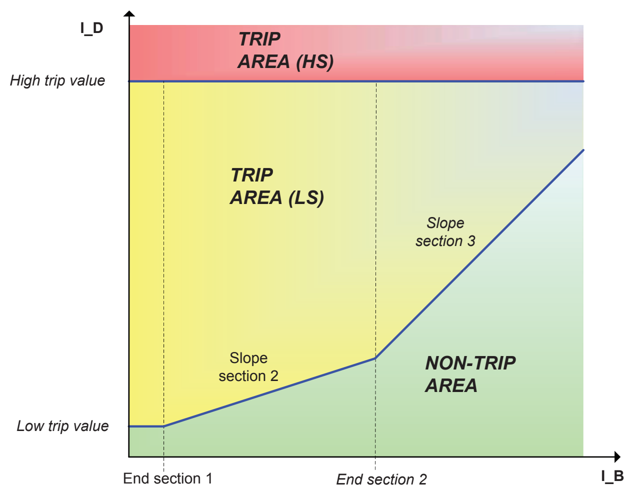


Figure 255: Operating characteristics of the protection. (LS) stands for the biased low stage and (HS) for the instantaneous high stage

The `TRIP` output is activated always when the `OPR_HS` output activates.

The internal blocking signals of the differential function do not prevent the trip signal of the instantaneous differential current stage. When required, the trip outputs of the instantaneous high stage can be blocked by the `BLK_OPR_HS` and `BLOCK` external control signals.

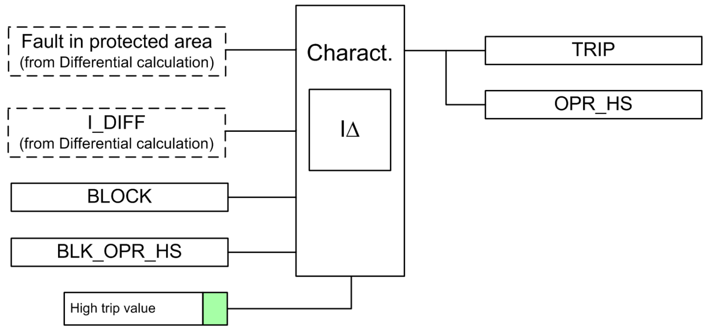


Figure 256: Operation logic of instantaneous high stage

Reset of the blocking signals (de-block)

All three blocking signals, that is, waveform and second and fifth harmonic, have a counter, which holds the blocking on for a certain time after the blocking conditions have ceased to be fulfilled. The deblocking takes place when those counters have elapsed. This is a normal case of deblocking.

The blocking signals can be reset immediately if a very high differential current is measured or if the phase difference of the compared currents (the angle between the compared currents) is close to zero after the automatic vector group matching has been made (in a normal situation, the phase difference is 180 degrees). This does not, however, reset the counters holding the blockings, so the blocking signals may return when these conditions are not valid anymore.

External blocking functionality

87T has three inputs for blocking.

- When the `BLOCK` input is active ("TRUE"), the operation of the function is blocked but measurement output signals are still updated.
- When the `BLK_OPR_LS` input is active ("TRUE"), 87T operates normally except that the `OPR_LS` output is not active or activated in any circumstance. Additionally, the `TRIP` output can be activated only by the instantaneous high stage (if not blocked as well).
- When the `BLK_OPR_HS` input is active ("TRUE"), 87T operates normally except that the `OPR_HS` output is not active or activated in any circumstance. Additionally, the `TRIP` output can be activated only by the biased low stage (if not blocked as well).

4.3.2.5 Application

87T is a unit protection function serving as the main protection for transformers in case of winding failure. The protective zone of a differential protection includes the transformer, the bus-work or the cables between the current transformer and the power transformer. When bushing current transformers are used for the differential protection relay, the protective zone does not include the bus work or cables between the circuit breaker and the power transformer.

In some substations, there is a current differential protection for the busbar. The busbar protection includes bus work or cables between the circuit breaker and the power transformer. Internal electrical faults are very serious and cause immediate damage. Short circuits and ground faults in windings and terminals are normally detected by the differential protection. If enough turns are short-circuited, the interturn faults, which are flashovers between the conductors within the same physical winding, are also detected. The interturn faults are the most difficult transformer-winding faults to detect with electrical protections. A small interturn fault including a few turns results in an undetectable amount of current until the fault develops into an ground fault. Therefore, it is important that the differential protection has a high level of sensitivity and that it is possible to use a sensitive setting without causing unwanted operations for external faults.

It is important that the faulty transformer is disconnected as fast as possible. As 87T is a unit protection function, it can be designed for fast tripping, thus providing a selective disconnection of the faulty transformer. 87T should never trip to faults outside the protective zone.

87T compares the current flowing into the transformer to the current leaving the transformer. A correct analysis of fault conditions by 87T must consider the changes to voltages, currents and phase angles. The traditional transformer differential protection functions required auxiliary transformers for the correction of the phase shift and turns ratio. The numerical microprocessor based differential algorithm implemented in 87T compensates for both the turns ratio and the phase shift internally in the software.

The differential current should theoretically be zero during normal load or external faults if the turns ratio and the phase shift are correctly compensated. However, there are several different phenomena other than internal faults that cause unwanted and false differential currents. The main reasons for unwanted differential currents are:

- Mismatch due to varying tap changer positions
- Different characteristics, loads and operating conditions of the current transformers
- Zero sequence currents that only flow on one side of the power transformer
- Normal magnetizing currents
- Magnetizing inrush currents
- Overexcitation magnetizing currents.

87T is designed mainly for the protection of two-winding transformers. 87T can also be utilized for the protection of generator-transformer blocks as well as short cables and overhead lines. If the distance between the measuring points is relatively long in line protection, interposing CTs can be required to reduce the burden of the CTs.

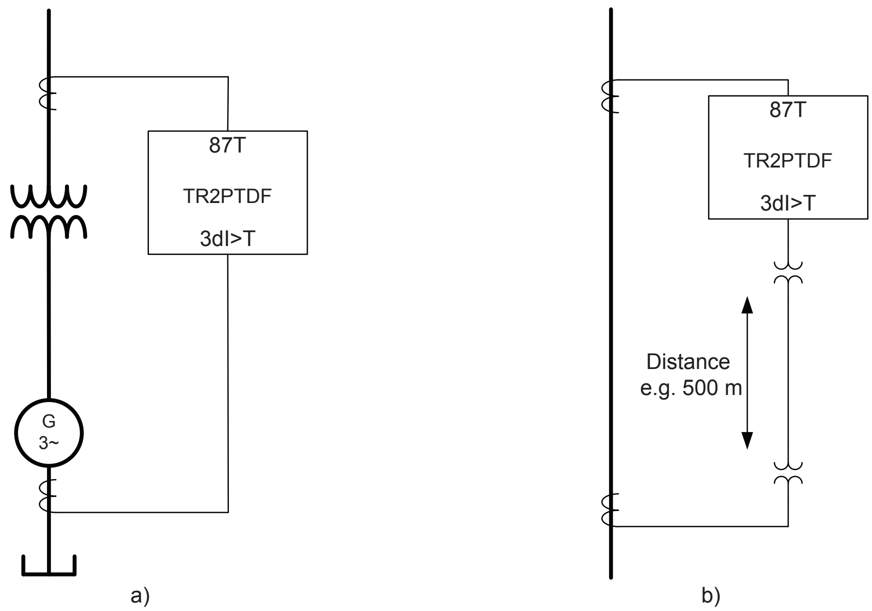


Figure 257: Differential protection of a generator-transformer block and short cable/ line

87T can also be used in three-winding transformer applications or two-winding transformer applications with two output feeders.

On the double-feeder side of the power transformer, the current of the two CTs per phase must be summed by connecting the two CTs of each phase in parallel. Generally this requires the interposing CTs to handle the vector group and/or ratio mismatch between the two windings/feeders.

The accuracy limit factor for the interposing CT must fulfill the same requirements as the main CTs. Please note that the interposing CT imposes an additional burden to the main CTs.

The most important rule in these applications is that at least 75 percent of the short-circuit power has to be fed on the side of the power transformer with only one connection to the protection relay.

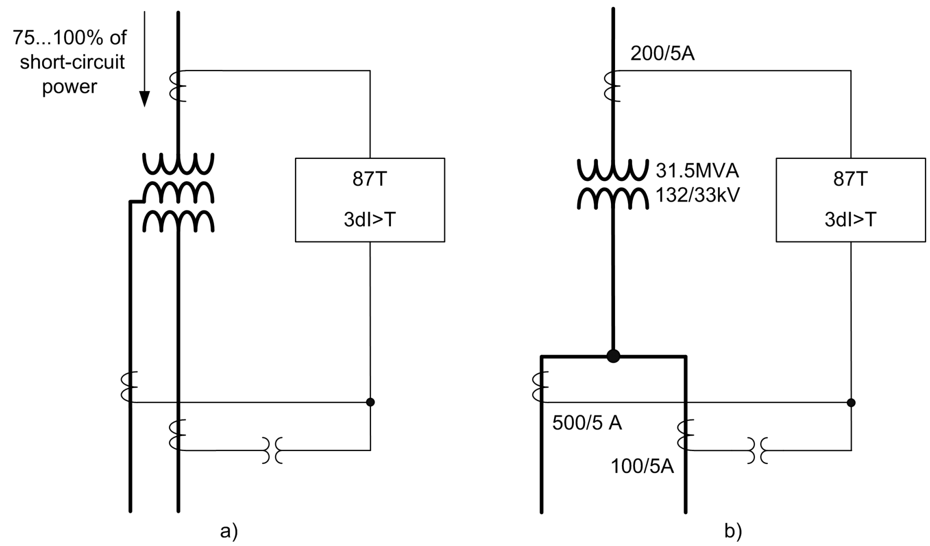


Figure 258: Differential protection of a three-winding transformer and a transformer with two output feeders

87T can also be used for the protection of the power transformer feeding the frequency converter. An interposing CT is required for matching the three-winding transformer currents to a two-winding protection relay.

The fundamental frequency component is numerically filtered with a Fourier filter, DFT. The filter suppresses frequencies other than the set fundamental frequency, and therefore the protection relay is not adapted for measuring the output of the frequency converter, that is, 87T is not suited for protecting of a power transformer or motor fed by a frequency converter

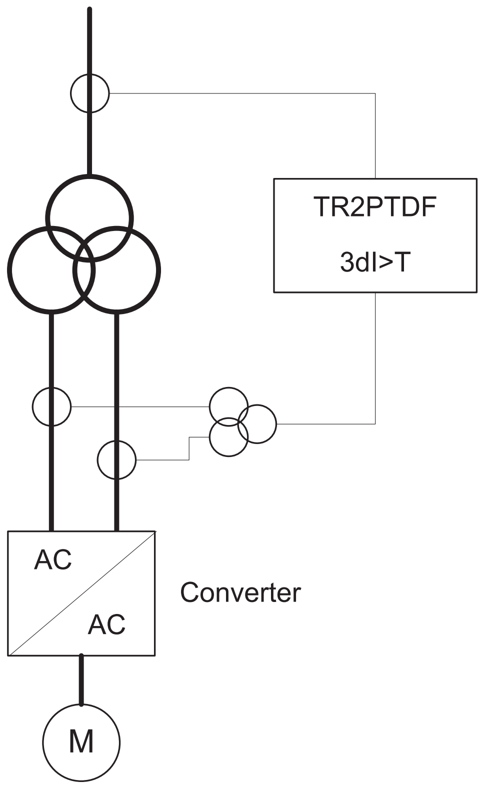


Figure 259: Protection of the power transformer feeding the frequency converter

Transforming ratio correction of CTs

The CT secondary currents often differ from the rated current at the rated load of the power transformer. The CT transforming ratios can be corrected on both sides of the power transformer with the *CT ratio Cor Wnd 1* and *CT ration Cor Wnd 2* settings.

First, the rated load of the power transformer must be calculated on both sides when the apparent power and phase-to-phase voltage are known.

$$I_{nT} = \frac{S_n}{\sqrt{3} \times V_n}$$

(Equation 89)

I_{nT} rated load of the power transformer

S_n rated power of the power transformer

V_n rated phase-to-phase voltage

Next, the settings for the CT ratio correction can be calculated.

$$CT\ ratio\ correction\ = \frac{I_{1n}}{I_{nT}}$$

(Equation 90)

I_{1n} nominal primary current of the CT

After the CT ratio correction, the measured currents and corresponding setting values of 87T are expressed in multiples of the rated power transformer current I_r (xI_r) or percentage value of I_r ($\%I_r$).

The rated input current (1A or 5A) of the relay does not have to be same for the HV and the LV side. For example, the rated secondary current of 5 A can be used on the HV side, while 1A is used on the LV side or vice versa.

Example

The rated power of the transformer is 25 MVA, the ratio of the CTs on the 110 kV side is 300/1 and that on the 21 kV side is 1000/1

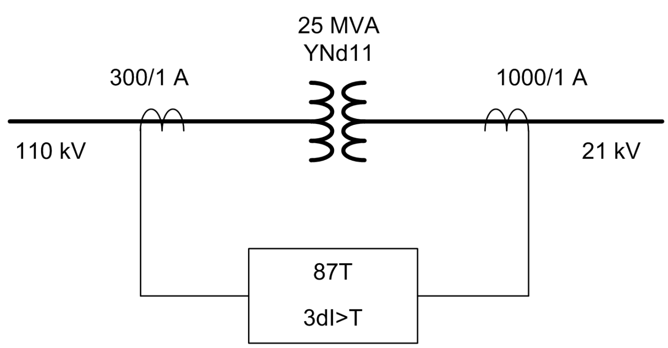


Figure 260: Example of two-winding power transformer differential protection

The rated load of the transformer is calculated:

HV side: I_{nT_Wnd1} = 25 MVA / (1.732 x 110 kV) = 131.2 A

LV side: I_{nT_Wnd2} = 25 MVA / (1.732 x 21 kV) = 687.3 A

Settings:

CT ratio Cor Wnd 1= 300 A / 131.2 A = “2.29”

CT ratio Cor Wnd 2= 1000 A / 687.3 A = “1.45”

Vector group matching and elimination of the zero-sequence component

The vector group of the power transformer is numerically matched on the high voltage and low voltage sides by means of the *Winding 1 type*, *Winding 2 type* and *Clock number* settings. Thus no interposing CTs are needed if there is only a power transformer inside the protected zone. The matching is based on phase shifting and a numerical delta connection in the protection relay. If the neutral of a star-connected power transformer is grounded, any ground fault in the network is perceived by the protection relay as a differential current. The elimination of the zero-sequence component can be selected for that winding by setting the *Zro A elimination* parameter.

Table 432: 87T settings corresponding to the power transformer vector groups and zero-sequence elimination

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
Yy0	Y	y	Clk Num 0	Not needed
YNy0	YN	y	Clk Num 0	HV side
YNyn0	YN	yn	Clk Num 0	HV & LV side
Yyn0	Y	yn	Clk Num 0	LV side
Yy2	Y	y	Clk Num 2	Not needed
YNy2	YN	y	Clk Num 2	Not needed
YNyn2	YN	yn	Clk Num 2	Not needed
Yyn2	Y	yn	Clk Num 2	Not needed
Yy4	Y	y	Clk Num 4	Not needed
YNy4	YN	y	Clk Num 4	Not needed
YNyn4	YN	yn	Clk Num 4	Not needed
Yyn4	Y	yn	Clk Num 4	Not needed
Yy6	Y	y	Clk Num 6	Not needed
YNy6	YN	y	Clk Num 6	HV side
YNyn6	YN	yn	Clk Num 6	HV & LV side
Yyn6	Y	yn	Clk Num 6	LV side
Yy8	Y	y	Clk Num 8	Not needed
YNy8	YN	y	Clk Num 8	Not needed
YNyn8	YN	yn	Clk Num 8	Not needed
Yyn8	Y	yn	Clk Num 8	Not needed
Yy10	Y	y	Clk Num 10	Not needed
YNy10	YN	y	Clk Num 10	Not needed
YNyn10	YN	yn	Clk Num 10	Not needed
Yyn10	Y	yn	Clk Num 10	Not needed
Yd1	Y	d	Clk Num 1	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
YNd1	YN	d	Clk Num 1	Not needed
Yd5	Y	d	Clk Num 5	Not needed
YNd5	YN	d	Clk Num 5	Not needed
Yd7	Y	d	Clk Num 7	Not needed
YNd7	YN	d	Clk Num 7	Not needed
Yd11	Y	d	Clk Num 11	Not needed
YNd11	YN	d	Clk Num 11	Not needed
Dd0	D	d	Clk Num 0	Not needed
Dd2	D	d	Clk Num 2	Not needed
Dd4	D	d	Clk Num 4	Not needed
Dd6	D	d	Clk Num 6	Not needed
Dd8	D	d	Clk Num 8	Not needed
Dd10	D	d	Clk Num 10	Not needed
Dy1	D	y	Clk Num 1	Not needed
Dyn1	D	yn	Clk Num 1	Not needed
Dy5	D	y	Clk Num 5	Not needed
Dyn5	D	yn	Clk Num 5	Not needed
Dy7	D	y	Clk Num 7	Not needed
Dyn7	D	yn	Clk Num 7	Not needed
Dy11	D	y	Clk Num 11	Not needed
Dyn11	D	yn	Clk Num 11	Not needed
Yz1	Y	z	Clk Num 1	Not needed
YNz1	YN	z	Clk Num 1	Not needed
YNzn1	YN	zn	Clk Num 1	LV side
Yzn1	Y	zn	Clk Num 1	Not needed
Yz5	Y	z	Clk Num 5	Not needed
YNz5	YN	z	Clk Num 5	Not needed
YNzn5	YN	zn	Clk Num 5	LV side
Yzn5	Y	zn	Clk Num 5	Not needed
Yz7	Y	z	Clk Num 7	Not needed
YNz7	YN	z	Clk Num 7	Not needed
YNzn7	YN	zn	Clk Num 7	LV side
Yzn7	Y	zn	Clk Num 7	Not needed
Yz11	Y	z	Clk Num 11	Not needed
YNz11	YN	z	Clk Num 11	Not needed
YNzn11	YN	zn	Clk Num 11	LV side

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
Yzn11	Y	zn	Clk Num 11	Not needed
Zy1	Z	y	Clk Num 1	Not needed
Zyn1	Z	yn	Clk Num 1	Not needed
ZNyn1	ZN	yn	Clk Num 1	HV side
ZNy1	ZN	y	Clk Num 1	Not needed
Zy5	Z	y	Clk Num 5	Not needed
Zyn5	Z	yn	Clk Num 5	Not needed
ZNyn5	ZN	yn	Clk Num 5	HV side
ZNy5	ZN	y	Clk Num 5	Not needed
Zy7	Z	y	Clk Num 7	Not needed
Zyn7	Z	yn	Clk Num 7	Not needed
ZNyn7	ZN	yn	Clk Num 7	HV side
ZNy7	ZN	y	Clk Num 7	Not needed
Zy11	Z	y	Clk Num 11	Not needed
Zyn11	Z	yn	Clk Num 11	Not needed
ZNyn11	ZN	yn	Clk Num 11	HV side
ZNy11	ZN	y	Clk Num 11	Not needed
Dz0	D	z	Clk Num 0	Not needed
Dzn0	D	zn	Clk Num 0	LV side
Dz2	D	z	Clk Num 2	Not needed
Dzn2	D	zn	Clk Num 2	Not needed
Dz4	D	z	Clk Num 4	Not needed
Dzn4	D	zn	Clk Num 4	Not needed
Dz6	D	z	Clk Num 6	Not needed
Dzn6	D	zn	Clk Num 6	LV side
Dz8	D	z	Clk Num 8	Not needed
Dzn8	D	zn	Clk Num 8	Not needed
Dz10	D	z	Clk Num 10	Not needed
Dzn10	D	zn	Clk Num 10	Not needed
Zd0	Z	d	Clk Num 0	Not needed
ZNd0	ZN	d	Clk Num 0	HV side
Zd2	Z	d	Clk Num 2	Not needed
ZNd2	ZN	d	Clk Num 2	Not needed
Zd4	Z	d	Clk Num 4	Not needed
ZNd4	ZN	d	Clk Num 4	Not needed
Zd6	Z	d	Clk Num 6	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
ZNd6	ZN	d	Clk Num 6	HV side
Zd8	Z	d	Clk Num 8	Not needed
ZNd8	ZN	d	Clk Num 8	Not needed
Zd10	Z	d	Clk Num 10	Not needed
ZNd10	ZN	d	Clk Num 10	Not needed
Zz0	Z	z	Clk Num 0	Not needed
ZNz0	ZN	z	Clk Num 0	HV side
ZNzn0	ZN	zn	Clk Num 0	HV & LV side
Zzn0	Z	zn	Clk Num 0	LV side
Zz2	Z	z	Clk Num 2	Not needed
ZNz2	ZN	z	Clk Num 2	Not needed
ZNzn2	ZN	zn	Clk Num 2	Not needed
Zzn2	Z	zn	Clk Num 2	Not needed
Zz4	Z	z	Clk Num 4	Not needed
ZNz4	ZN	z	Clk Num 4	Not needed
ZNzn4	ZN	zn	Clk Num 4	Not needed
Zzn4	Z	zn	Clk Num 4	Not needed
Zz6	Z	z	Clk Num 6	Not needed
ZNz6	ZN	z	Clk Num 6	HV side
ZNzn6	ZN	zn	Clk Num 6	HV & LV side
Zzn6	Z	zn	Clk Num 6	LV side
Zz8	Z	z	Clk Num 8	Not needed
ZNz8	ZN	z	Clk Num 8	Not needed
ZNzn8	ZN	zn	Clk Num 8	Not needed
Zzn8	Z	zn	Clk Num 8	Not needed
Zz10	Z	z	Clk Num 10	Not needed
ZNz10	ZN	z	Clk Num 10	Not needed
ZNzn10	ZN	zn	Clk Num 10	Not needed
Zzn10	Z	zn	Clk Num 10	Not needed
Yy0	Y	y	Clk Num 0	Not needed
YNy0	YN	y	Clk Num 0	HV side
YNyn0	YN	yn	Clk Num 0	HV & LV side
Yyn0	Y	yn	Clk Num 0	LV side
Yy2	Y	y	Clk Num 2	Not needed
YNy2	YN	y	Clk Num 2	Not needed
YNyn2	YN	yn	Clk Num 2	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
Yyn2	Y	yn	Clk Num 2	Not needed
Yy4	Y	y	Clk Num 4	Not needed
YNy4	YN	y	Clk Num 4	Not needed
YNyn4	YN	yn	Clk Num 4	Not needed
Yyn4	Y	yn	Clk Num 4	Not needed
Yy6	Y	y	Clk Num 6	Not needed
YNy6	YN	y	Clk Num 6	HV side
YNyn6	YN	yn	Clk Num 6	HV & LV side
Yyn6	Y	yn	Clk Num 6	LV side
Yy8	Y	y	Clk Num 8	Not needed
YNy8	YN	y	Clk Num 8	Not needed
YNyn8	YN	yn	Clk Num 8	Not needed
Yyn8	Y	yn	Clk Num 8	Not needed
Yy10	Y	y	Clk Num 10	Not needed
YNy10	YN	y	Clk Num 10	Not needed
YNyn10	YN	yn	Clk Num 10	Not needed
Yyn10	Y	yn	Clk Num 10	Not needed
Yd1	Y	d	Clk Num 1	Not needed
YNd1	YN	d	Clk Num 1	Not needed
Yd5	Y	d	Clk Num 5	Not needed
YNd5	YN	d	Clk Num 5	Not needed
Yd7	Y	d	Clk Num 7	Not needed
YNd7	YN	d	Clk Num 7	Not needed
Yd11	Y	d	Clk Num 11	Not needed
YNd11	YN	d	Clk Num 11	Not needed
Dd0	D	d	Clk Num 0	Not needed
Dd2	D	d	Clk Num 2	Not needed
Dd4	D	d	Clk Num 4	Not needed
Dd6	D	d	Clk Num 6	Not needed
Dd8	D	d	Clk Num 8	Not needed
Dd10	D	d	Clk Num 10	Not needed
Dy1	D	y	Clk Num 1	Not needed
Dyn1	D	yn	Clk Num 1	Not needed
Dy5	D	y	Clk Num 5	Not needed
Dyn5	D	yn	Clk Num 5	Not needed
Dy7	D	y	Clk Num 7	Not needed

Table continues on next page

Vector group of the transformer	Winding 1 type	Winding 2 type	Clock number	Zro A Elimination
Dyn7	D	yn	Clk Num 7	Not needed
Dy11	D	y	Clk Num 11	Not needed
Dyn11	D	yn	Clk Num 11	Not needed
Yz1	Y	z	Clk Num 1	Not needed
YNz1	YN	z	Clk Num 1	Not needed
YNzn1	YN	zn	Clk Num 1	LV side
Yzn1	Y	zn	Clk Num 1	Not needed
Yz5	Y	z	Clk Num 5	Not needed
YNz5	YN	z	Clk Num 5	Not needed
YNzn5	YN	zn	Clk Num 5	LV side
Yzn5	Y	zn	Clk Num 5	Not needed
Yz7	Y	z	Clk Num 7	Not needed
YNz7	YN	z	Clk Num 7	Not needed
YNzn7	YN	zn	Clk Num 7	LV side
Yzn7	Y	zn	Clk Num 7	Not needed
Yz11	Y	z	Clk Num 11	Not needed
YNz11	YN	z	Clk Num 11	Not needed
YNzn11	YN	zn	Clk Num 11	LV side
Yzn11	Y	zn	Clk Num 11	Not needed
Zy1	Z	y	Clk Num 1	Not needed
Zyn1	Z	yn	Clk Num 1	Not needed
ZNyn1	ZN	yn	Clk Num 1	HV side
ZNy1	ZN	y	Clk Num 1	Not needed
Zy5	Z	y	Clk Num 5	Not needed
Zyn5	Z	yn	Clk Num 5	Not needed
ZNyn5	ZN	yn	Clk Num 5	HV side
ZNy5	ZN	y	Clk Num 5	Not needed
Zy7	Z	y	Clk Num 7	Not needed
Zyn7	Z	yn	Clk Num 7	Not needed
ZNyn7	ZN	yn	Clk Num 7	HV side
ZNy7	ZN	y	Clk Num 7	Not needed
Yy0	Y	y	Clk Num 0	Not needed

Commissioning

The correct settings, which are *CT connection type*, *Winding 1 type*, *Winding 2 type* and *Clock number*, for the connection group compensation can be verified by monitoring the angle values `I_ANGL_A1_B1`, `I_ANGL_B1_C1`, `I_ANGL_C1_A1`, `I_ANGL_A2_B2`, `I_ANGL_B2_C2`, `I_ANGL_C2_A2`, `I_ANGL_A1_A2`, `I_ANGL_B1_B2` and `I_ANGL_C1_C2` while injecting the current into the transformer. These angle values are calculated from the compensated currents. See signal description from Monitored data table.

When a station service transformer is available, it can be used to provide current to the high voltage side windings while the low voltage side windings are short-circuited. This way the current can flow in both the high voltage and low voltage windings. The commissioning signals can be provided by other means as well. The minimum current to allow for phase current and angle monitoring is 0.015 I_r.

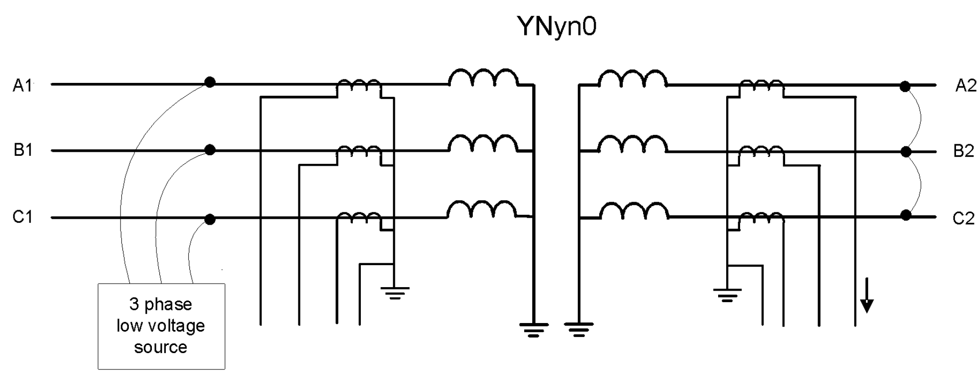


Figure 261: Low voltage test arrangement. The three-phase low voltage source can be the station service transformer.

The *Tapped winding* control setting parameter has to be set to “Not in use” to make sure that the monitored current values are not scaled by the automatic adaptation to the tap changer position. When only the angle values are required, the setting of *Tapped winding* is not needed since angle values are not affected by the tap changer position adaptation.

When injecting the currents in the high voltage winding, the angle values `I_ANGL_A1_B1`, `I_ANGL_B1_C1`, `I_ANGL_C1_A1`, `I_ANGL_A2_B2`, `I_ANGL_B2_C2` and `I_ANGL_C2_A2` have to show +120 deg. Otherwise the phase order can be wrong or the polarity of a current transformer differs from the polarities of the other current transformers on the same side.

If the angle values `I_ANGL_A1_B1`, `I_ANGL_B1_C1` and `I_ANGL_C1_A1` show -120 deg, the phase order is wrong on the high voltage side. If the angle values `I_ANGL_A2_B2`, `I_ANGL_B2_C2` and `I_ANGL_C2_A2` show -120 deg, the phase order is wrong on the low voltage side. If the angle values `I_ANGL_A1_B1`, I_ANGL_B1_C1 and I_ANGL_C1_A1 do not show the same value of +120, the polarity of one current transformer can be wrong. For instance, if the polarity of the current transformer measuring IL2 is wrong, I_ANGL_A1_B1 shows -60 deg, I_ANGL_B1_C1 shows -60 deg and I_ANGL_C1_A1 shows +120 deg.

When the phase order and the angle values are correct, the angle values I_ANGL_A1_A2, I_ANGL_B1_B2 and I_ANGL_C1_C2 usually show ±180 deg. There can be several reasons if the angle values are not ±180 deg. If the values are 0 deg, the value given for *CT connection type* is probably wrong. If the angle values are something else, the value for *Clock number* can be wrong. Another reason is that the combination of *Winding 1 type* and *Winding 2 type* does not match *Clock number*. This means that the resulting connection group is not supported.

Example

If *Winding 1 type* is set to "Y", *Winding 2 type* is set to "y" and *Clock number* is set to "Clk num 1", the resulting connection group "Yy1" is not a supported combination. Similarly if *Winding 1 type* is set to "Y", *Winding 2 type* is set to "d" and *Clock number* is set to "Clk num 0", the resulting connection group "Yd0" is not a supported combination. All the non-supported combinations of *Winding 1 type*, *Winding 2 type* and *Clock number* settings result in the default connection group compensation that is "Yy0".

4.3.2.6 CT connections and transformation ratio correction

The connections of the primary current transformers are designated as "Type 1" and "Type 2".

- If the positive directions of the winding 1 and winding 2 protection relay currents are opposite, the *CT connection type* setting parameter is "Type 1". The connection examples of "Type 1" are as shown in Figure 262 and Figure 263.
- If the positive directions of the winding 1 and winding 2 protection relay currents equate, the *CT connection type* setting parameter is "Type 2". The connection examples of "Type 2" are as shown in Figure 264 and Figure 265.
- The default value of the *CT connection type* setting is "Type 1".

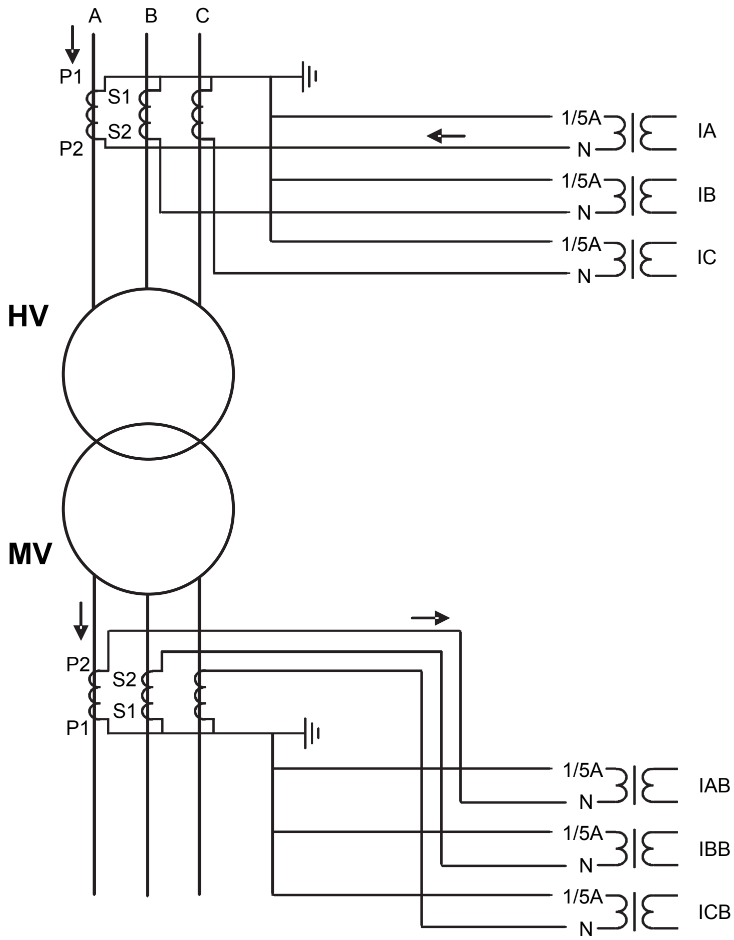


Figure 262: Connection example of current transformers of Type 1

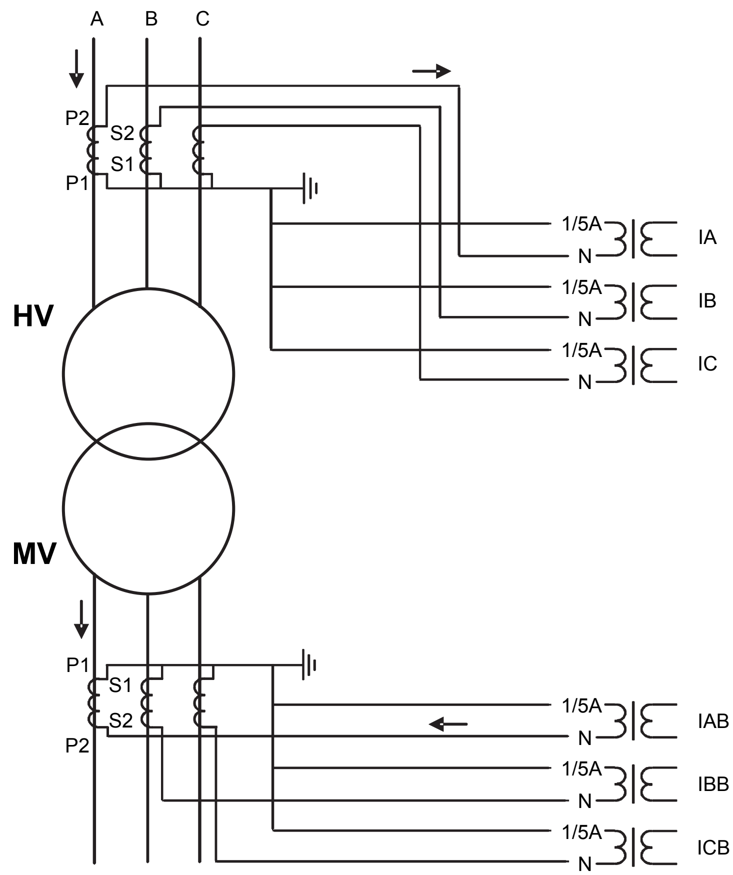


Figure 263: Alternative connection example of current transformers of Type 1

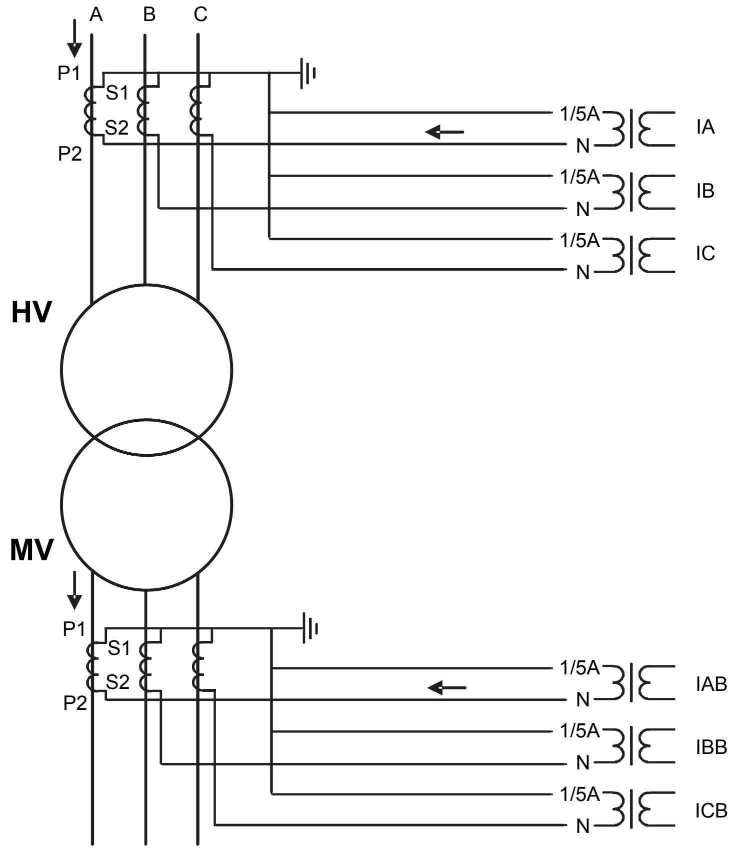


Figure 264: Connection of current transformers of Type 2 and example of the currents during an external fault

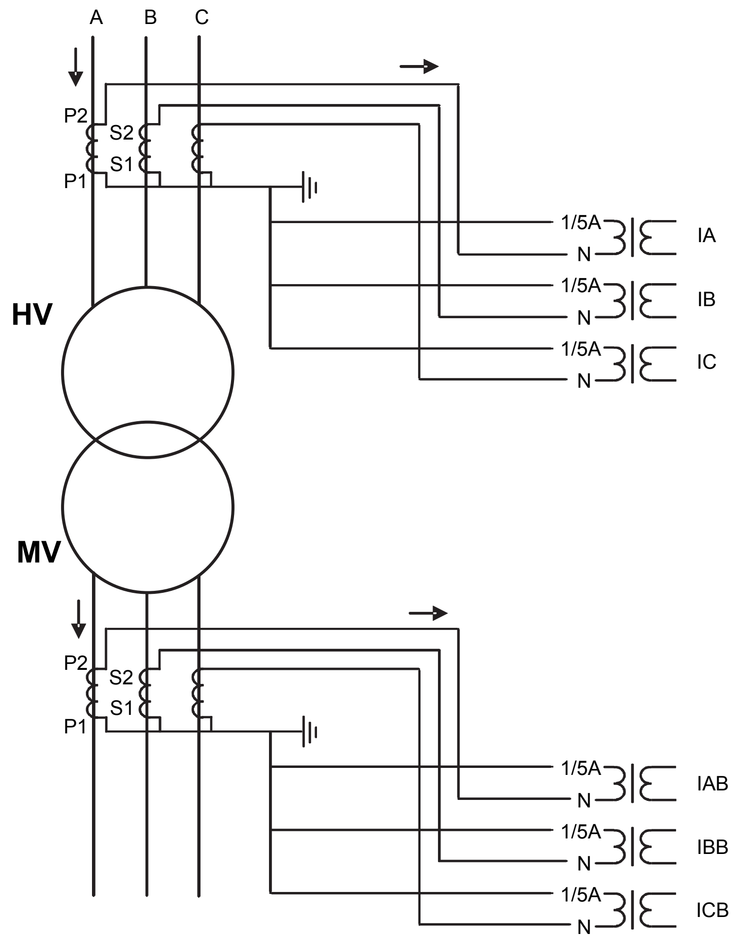


Figure 265: Alternative connection example of current transformers of Type 2

The CT secondary currents often differ from the rated current at the rated load of the power transformer. The CT transforming ratios can be corrected on both sides of the power transformer with the *CT ratio Cor Wnd 1* and *CT ratio Cor Wnd 2* settings.

4.3.2.7 Signals

Table 433: 87T Input signals

Name	Type	Default	Description
I_A(1)	SIGNAL	0	Phase A primary current
I_B(1)	SIGNAL	0	Phase B primary current
I_C(1)	SIGNAL	0	Phase C primary current
I_A(2)	SIGNAL	0	Phase A secondary current
I_B(2)	SIGNAL	0	Phase B secondary current
Table continues on next page			

Name	Type	Default	Description
I_C(2)	SIGNAL	0	Phase C secondary current
BLOCK	BOOLEAN	0=False	Block
BLK_OPR_LS	BOOLEAN	0=False	Blocks trip outputs from biased stage
BLK_OPR_HS	BOOLEAN	0=False	Blocks trip outputs from instantaneous stage

Table 434: 87T Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip combined
OPR_LS	BOOLEAN	Trip from low set
OPR_HS	BOOLEAN	Trip from high set
BLKD2H	BOOLEAN	2nd harmonic restraint block status
BLKD5H	BOOLEAN	5th harmonic restraint block status
BLKDWAV	BOOLEAN	Waveform blocking status

4.3.2.8 Settings

Table 435: 87T Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
High trip value	500...3000	%Ir	10	1000	Instantaneous stage setting
Low trip value	5...50	%Ir	1	20	Basic setting for biased operation
Slope section 2	10...50	%	1	30	Slope of the second line of the operating characteristics
End section 2	100...500	%Ir	1	150	Turn-point between the second and the third line of the operating characteristics
Restraint Mode	5=Waveform 6=2.h + waveform 8=5.h + waveform 9=2.h + 5.h + wav			9=2.h + 5.h + wav	Restraint Mode
Pickup value 2.H	7...20	%	1	15	The ratio of the 2. harmonic to fundamental component required for blocking
Pickup value 5.H	10...50	%	1	35	The ratio of the 5. harmonic to fundamental component required for blocking

Table 436: 87T Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Enable high set	0=False 1=True			1=True	Enable high set stage
Slope section 3	10...100	%	1	100	Slope of the third line of the operating characteristics
Harmonic deblock 2.H	0=False 1=True			1=True	Selects if the 2. harmonic deblocking is allowed in case of switch on to a fault (Allow / Do not allow)
Stop value 5.H	10...50	%	1	35	The ratio of the 5. harmonic to fundamental component required to remove 5. harmonic blocking
Harmonic deblock 5.H	0=False 1=True			0=False	Selects if the 5. harmonic deblocking is allowed in case of severe overvoltage situation (Allow / Do not allow)

Table 437: 87T Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
CT connection type	1=Type 1 2=Type 2			1=Type 1	CT connection type. Determined by the directions of the connected current transformers
Winding 1 type	1=Y 2=YN 3=D 4=Z 5=ZN			1=Y	Connection of the HV side windings. Determined by the transformer connection group (e.g. Dyn11 ->"D")
Winding 2 type	1=y 2=yn 3=d 4=z 5=zn			1=y	Connection of the LV side windings. Determined by the transformer connection group (e.g. Dyn11 ->"yn")
Clock number	0=Clk Num 0 1=Clk Num 1 2=Clk Num 2 4=Clk Num 4 5=Clk Num 5 6=Clk Num 6 7=Clk Num 7 8=Clk Num 8 10=Clk Num 10 11=Clk Num 11			0=Clk Num 0	Setting the phase shift between HV and LV with clock number for connection group compensation (e.g. Dyn11 -> 11)
Zro A elimination	1=Not eliminated 2=Winding 1 3=Winding 2 4=Winding 1 and 2			1=Not eliminated	Elimination of the zero-sequence current: 1 -> not eliminated, 2-> on HV only, 3 -> on LV only, 4 -> both on HV and LV
CT ratio Cor Wnd 1	0.40...4.00		0.01	1.00	CT ratio correction, winding 1
CT ratio Cor Wnd 2	0.40...4.00		0.01	1.00	CT ratio correction, winding 2

Table 438: 87T Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Min winding tap	-36...36		1	36	The tap position number resulting the minimum number of effective winding turns on the side of the transformer where the tap changer is.
Max winding tap	-36...36		1	0	The tap position number resulting the maximum number of effective winding turns on the side of the transformer where the tap changer is.
Tap nominal	-36...36		1	18	The nominal position of the tap changer resulting the default transformation ratio of the transformer (as if there was no tap changer)
Tapped winding	1=Not in use 2=Winding 1 3=Winding 2			1=Not in use	The winding where the tap changer is connected to. Also used to
Step of tap	0.60...9.00	%	0.01	1.50	The percentage change in voltage corresponding one step of the tap changer

4.3.2.9 Monitored data

Table 439: 87T Monitored data

Name	Type	Values (Range)	Unit	Description
OPR_A	BOOLEAN	0=False 1=True		Trip phase A
OPR_B	BOOLEAN	0=False 1=True		Trip phase B
OPR_C	BOOLEAN	0=False 1=True		Trip phase C
BLKD2H_A	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase A status
BLKD2H_B	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase B status
BLKD2H_C	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase C status
BLKD5H_A	BOOLEAN	0=False 1=True		5th harmonic restraint block phase A status
BLKD5H_B	BOOLEAN	0=False 1=True		5th harmonic restraint block phase B status
BLKD5H_C	BOOLEAN	0=False 1=True		5th harmonic restraint block phase C status
BLKDWAV_A	BOOLEAN	0=False 1=True		Waveform blocking phase A status
BLKDWAV_B	BOOLEAN	0=False 1=True		Waveform blocking phase B status

Table continues on next page

Name	Type	Values (Range)	Unit	Description
BLKDWAV_C	BOOLEAN	0=False 1=True		Waveform blocking phase C status
2nd harmonic block	BOOLEAN	0=False 1=True		2nd harmonic restraint block
2nd harmonic block phase A	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase A
2nd harmonic block phase B	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase B
2nd harmonic block phase C	BOOLEAN	0=False 1=True		2nd harmonic restraint block phase C
5th harmonic block	BOOLEAN	0=False 1=True		5th harmonic restraint block
5th harmonic block phase A	BOOLEAN	0=False 1=True		5th harmonic restraint block phase A
5th harmonic block phase B	BOOLEAN	0=False 1=True		5th harmonic restraint block phase B
5th harmonic block phase C	BOOLEAN	0=False 1=True		5th harmonic restraint block phase C
I_AMPL_A1	FLOAT32	0.00...40.00	xIr	Connection group compensated primary current phase A
I_AMPL_B1	FLOAT32	0.00...40.00	xIr	Connection group compensated primary current phase B
I_AMPL_C1	FLOAT32	0.00...40.00	xIr	Connection group compensated primary current phase C
I_AMPL_A2	FLOAT32	0.00...40.00	xIr	Connection group compensated secondary current phase A
I_AMPL_B2	FLOAT32	0.00...40.00	xIr	Connection group compensated secondary current phase B
I_AMPL_C2	FLOAT32	0.00...40.00	xIr	Connection group compensated secondary current phase C
Differential Current phase A	FLOAT32	0.00...80.00	xIr	Differential Current phase A
Differential Current phase B	FLOAT32	0.00...80.00	xIr	Differential Current phase B
Differential Current phase C	FLOAT32	0.00...80.00	xIr	Differential Current phase C
Restraint Current phase A	FLOAT32	0.00...80.00	xIr	Restraint Current phase A
Restraint Current phase B	FLOAT32	0.00...80.00	xIr	Restraint Current phase B

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Restraint Current phase C	FLOAT32	0.00...80.00	xIr	Restraint Current phase C
I_2H_RAT_A	FLOAT32	0.00...1.00		Differential current second harmonic ratio, phase A
I_2H_RAT_B	FLOAT32	0.00...1.00		Differential current second harmonic ratio, phase B
I_2H_RAT_C	FLOAT32	0.00...1.00		Differential current second harmonic ratio, phase C
Angle difference between HV PhAPhB	FLOAT32	-180.00...180.00	deg	Angle difference between HV PhAPhB
Angle difference between HV PhBPhC	FLOAT32	-180.00...180.00	deg	Angle difference between HV PhBPhC
Angle difference between HV PhCPhA	FLOAT32	-180.00...180.00	deg	Angle difference between HV PhCPhA
Angle diff betw LV PhAPhB	FLOAT32	-180.00...180.00	deg	Angle difference between LV PhAPhB
Angle diff betw LV PhBPhC	FLOAT32	-180.00...180.00	deg	Angle difference between LV PhBPhC
Angle diff betw LV PhCPhA	FLOAT32	-180.00...180.00	deg	Angle difference between LV PhCPhA
Angle diff betw HVLV PhA	FLOAT32	-180.00...180.00	deg	Angle difference between HVLV PhA
Angle diff betw HVLV PhB	FLOAT32	-180.00...180.00	deg	Angle difference between HVLV PhB
Angle diff betw HVLV PhC	FLOAT32	-180.00...180.00	deg	Angle difference between HVLV PhC
I_5H_RAT_A	FLOAT32	0.00...1.00		Differential current fifth harmonic ratio, phase A
I_5H_RAT_B	FLOAT32	0.00...1.00		Differential current fifth harmonic ratio, phase B
I_5H_RAT_C	FLOAT32	0.00...1.00		Differential current fifth harmonic ratio, phase C
87T	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
IA-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IA
IB-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IB
IC-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IC

Table continues on next page

Name	Type	Values (Range)	Unit	Description
IA-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IA
IB-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IB
IC-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IC

4.3.2.10 Technical data

Table 440: 87T Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n ±2 Hz		
		±3.0% of the set value or ±0.002 × I_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	Low stage High stage	36 ms 21 ms	41 ms 22 ms	46 ms 24 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5, …		

1) Current before fault = 0.0, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the output contact. When differential current = 2 × set operate value and f_n = 50 Hz.

4.3.2.11 Technical revision history

Table 441: 87T Technical revision history

Technical revision	Change
B	5th harmonic and waveform blockings taken to event data set
C	Added setting *Slope section 3*. Added input `TAP_POS`

4.3.3 Numerically stabilized low-impedance restricted ground-fault protection 87LOZREF

4.3.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Numerically stabilized low-impedance restricted ground-fault protection	LREFPNDF	dIoLo>	87LOZREF

4.3.3.2 Function block

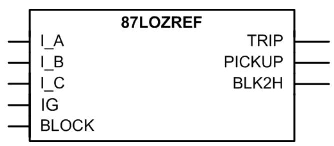


Figure 266: Function block

4.3.3.3 Functionality

The numerically stabilized low-impedance restricted ground-fault protection function 87LOZREF for a two winding transformer is based on the numerically stabilized differential current principle. No external stabilizing resistor or non-linear resistor are required.

The fundamental components of the currents are used for calculating the residual current of the phase currents, the neutral current, differential currents and stabilizing currents. The operating characteristics are according to the definite time.

The function contains a blocking functionality. The neutral current second harmonic is used for blocking during the transformer inrush situation. It is also possible to block function outputs, timers or the function itself, if desired.

4.3.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 87LOZREF can be described using a module diagram. All the modules in the diagram are explained in the next sections.

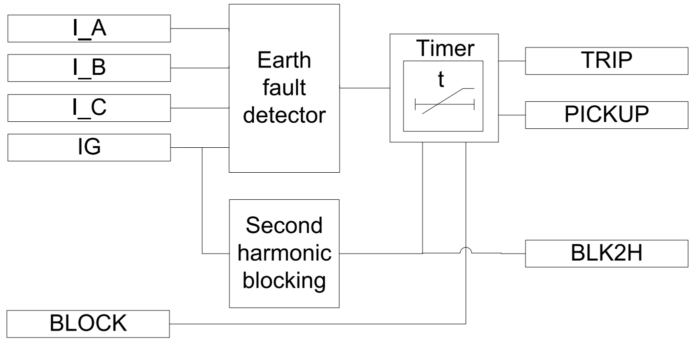


Figure 267: Functional module diagram

Earth fault detector

The operation is based on comparing the amplitude and the phase difference between the sum of the fundamental frequency component of the phase currents (ΣI, residual current) and the fundamental frequency component of the neutral current (IG) flowing in the conductor between the transformer or generator's neutral point and ground. The differential current is calculated as the absolute value of the difference between the residual current (the sum of the fundamental frequency components of the phase currents I_A, I_B and I_C) and the neutral current. The directional differential current ID_COSPHI is the product of the differential current and cosφ. The value is available in the monitored data view.

$$ID\_COSPHI = \left(\left| \overline{\Sigma I} - \overline{IG} \right| \right) \times \cos \varphi$$

(Equation 91)

$\overline{\Sigma I}$	Residual current
φ	Phase difference between the residual and neutral currents
$\overline{IG}$	Neutral current

A ground fault occurring in the protected area, that is, between the phase CTs and the neutral connection CT, causes a differential current. The directions, that is, the phase difference of the residual current and the neutral current, are considered in the operation criteria to maintain selectivity. A correct value for *CT connection type* is determined by the connection polarities of the current transformer.

The current transformer ratio mismatch between the phase current transformer and neutral current transformer (residual current in the analog input settings) is taken into account by the function with the properly set analog input setting values.

During a ground fault in the protected area, the currents ΣI and IG are directed towards the protected area. The factor cosφ is 1 when the phase difference of the residual current and the neutral current is 180 degrees, that is, when the currents are in opposite direction at the ground faults within the protected area. Similarly, ID_COSPHI is specified to be 0 when the phase difference between the residual current and the neutral current is less than 90 degrees in situations where there is no ground fault in the protected area. Thus tripping is possible only when the phase difference between the residual current and the neutral current is above 90 degrees.

The stabilizing current IB used by the stabilizing current principle is calculated as an average of the phase currents in the windings to be protected. The value is available in the monitored data view.

$$IB = \frac{\left|\overline{I\_A}\right| + \left|\overline{I\_B}\right| + \left|\overline{I\_C}\right|}{3}$$

(Equation 92)

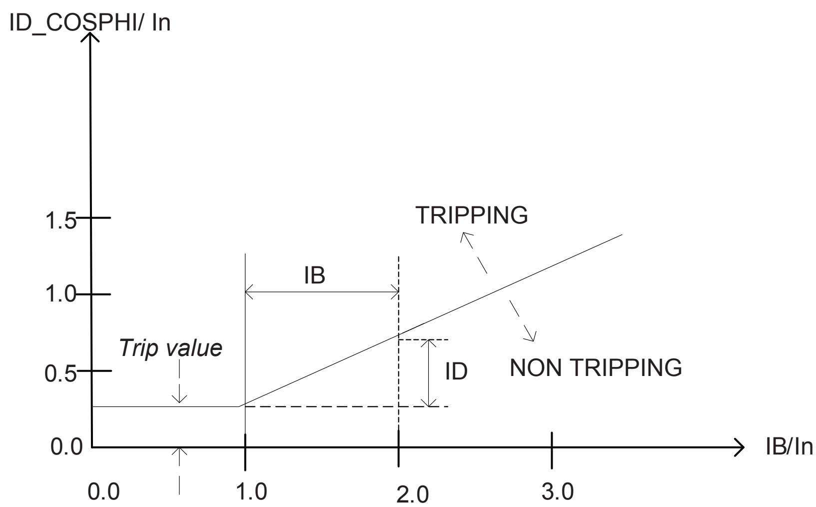


Figure 268: Operating characteristics of the stabilized ground-fault protection function

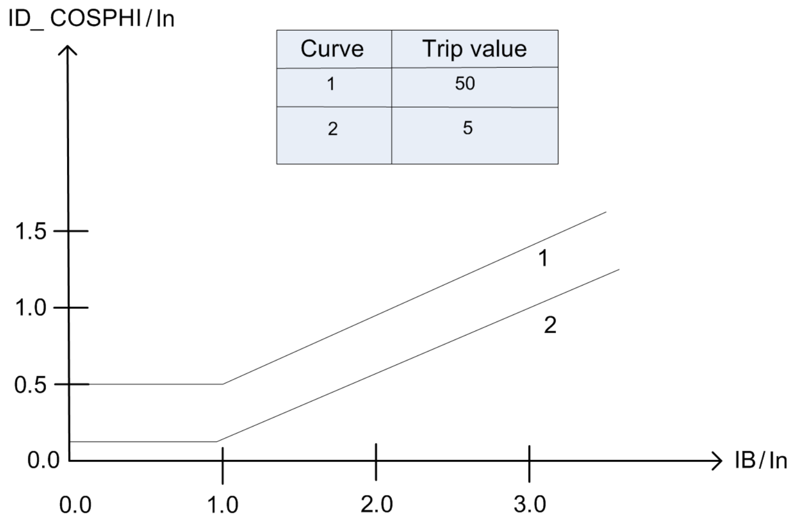


Figure 269: Setting range of the operating characteristics for the stabilized differential current principle of the ground-fault protection function

The *Trip value* setting is used for defining the characteristics of the function. The differential current value required for tripping is constant at the stabilizing current values 0.0 < IB/In < 1.0, where In is the nominal current, and the In in this context refers to the nominal of the phase current inputs. When the stabilizing current is higher than 1.0, the slope of the operation characteristic (ID/IB) is constant at 50 percent. Different operating characteristics are possible based on the *Trip value* setting.

For the protection of the trip, the measured neutral current has to be above 4 percent. When the condition has been fulfilled, the measured neutral current must stay above 2 percent, otherwise reset time is started.

To calculate the directional differential current ID_COSPHI, the fundamental frequency amplitude of both the residual and neutral currents has to be above 4 percent of In. If neither or only one condition is fulfilled at a time, the cosφ term is forced to 1. After the conditions are fulfilled, both currents must stay above 2 percent of In to allow the continuous calculation of the cosφ term.

Second harmonic blocking

This module compares the ratio of the current second harmonic (IG_2H) and IG to the set value *Pickup value 2.H*. If the ratio (IG_2H / IG) value exceeds the set value, the `BLK2H` output is activated.

The blocking also prevents unwanted operation at the recovery and sympathetic magnetizing inrushes. At the recovery inrush, the magnetizing current of the transformer to be protected increases momentarily when the voltage returns to normal after the clearance of a fault outside the protected area. The sympathetic inrush is caused by the energization of a transformer running in parallel with the protected transformer connected to the network.

The second harmonic blocking is disabled when *Restraint mode* is set to "None" and enabled when set to "Harmonic2".

Timer

Once activated, the Timer activates the PICKUP output. The time characteristic is according to DT. When the operation timer has reached the value set by *Minimum trip time*, the TRIP output is activated. If the fault disappears before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the reset timer resets and the PICKUP output is deactivated.

The Timer calculates the pickup duration value PICKUP_DUR which indicates the percentage ratio of the pickup situation and the set trip time. The value is available through the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operate timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated. The activation of the output of the second harmonic blocking signal BLK2H deactivates the TRIP output.

4.3.3.5 Application

A ground-fault protection using an overcurrent element does not adequately protect the transformer winding in general and the star-connected winding in particular.

The restricted ground-fault protection is mainly used as a unit protection for the transformer windings. 80LOZREF is a sensitive protection applied to protect the star-connected winding of a transformer. This protection system remains stable for all the faults outside the protected zone.

87LOZREF provides higher sensitivity for the detection of ground faults than the overall transformer differential protection. This is a high-speed unit protection scheme applied to the star-connected winding of the transformer. 87LOZREF is normally applied when the transformer is grounded solidly or through low-impedance resistor (NER). 87LOZREF can be also applied on the delta side of the transformer if a grounding transformer (zig-zag transformer) is used there. In 87LOZREF, the difference of the fundamental component of all three phase currents and the neutral current is provided to the differential element to detect the ground fault in the transformer winding based on the numerical stabilized differential current principle.

Connection of current transformers

The connections of the primary current transformers are designated as "Type 1" and "Type 2".

- If the positive directions of the winding 1 and winding 2 protection relay currents are opposite, the *CT connection type* setting parameter is "Type 1". The connection examples of "Type 1" are as shown in figures and .
- If the positive directions of the winding 1 and winding 2 protection relay currents equate, the *CT connection type* setting parameter is "Type 2". The connection examples of "Type 2" are as shown in figures and .
- The default value of the *CT connection type* setting is "Type 1".

- If the positive directions of the winding 1 and winding 2 protection relay currents are opposite, the *CT connection type* setting parameter is "Type 1". The connection examples of "Type 1" are as shown in figures 270 and 271.
- If the positive directions of the winding 1 and winding 2 protection relay currents equate, the *CT connection type* setting parameter is "Type 2". The connection examples of "Type 2" are as shown in figures 272 and 273.
- The default value of the *CT connection type* setting is "Type 1".

In case the groundings of the current transformers on the phase side and the neutral side are both either inside or outside the area to be protected, the setting parameter *CT connection type* is "Type 1".

If the grounding of the current transformers on the phase side is inside the area to be protected and the neutral side is outside the area to be protected or if the grounding on the phase side is outside the area and on the neutral side inside the area, the setting parameter *CT connection type* is "Type 2".

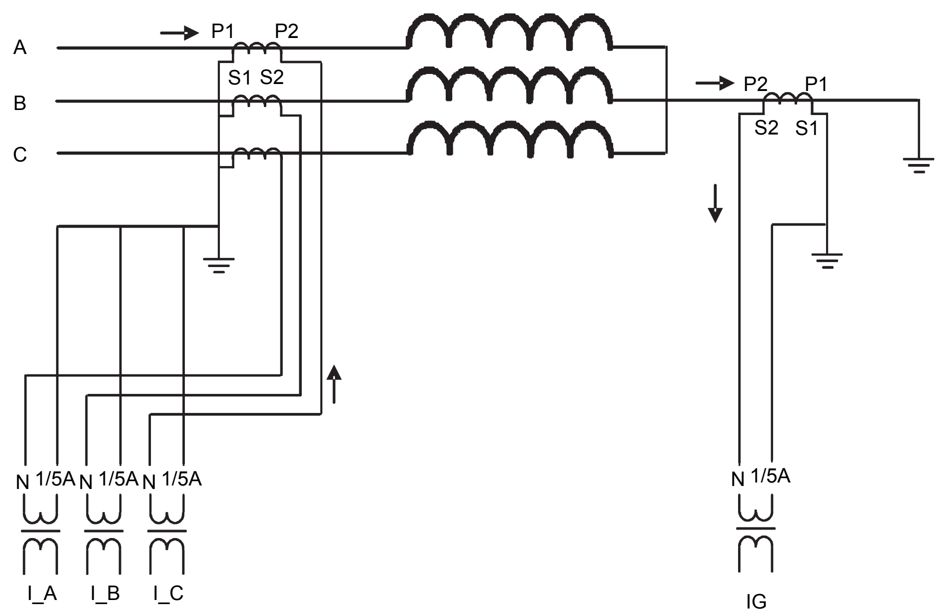


Figure 270: Connection of the current transformers of Type 1. The connected phase currents and the neutral current have opposite directions at an external ground-fault situation. Both groundings are inside the area to be protected.

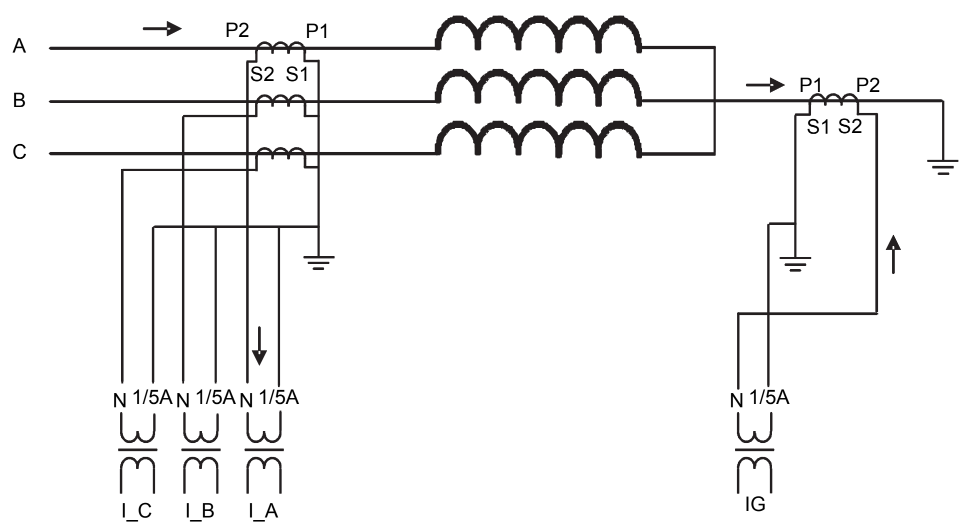


Figure 271: Connection of the current transformers of Type 1. The connected phase currents and the neutral current have opposite directions at an external ground-fault situation. Both groundings are outside the area to be protected.

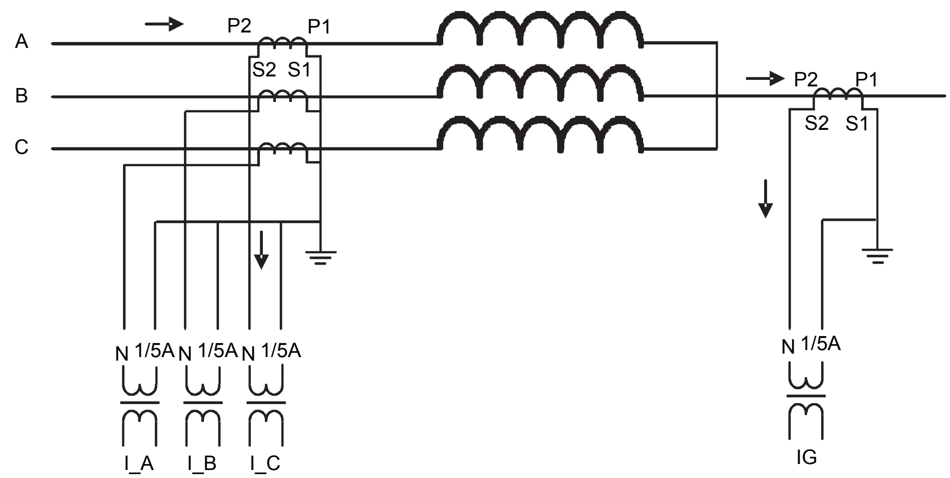


Figure 272: Connection of the current transformers of Type 2. The phase currents and the neutral current have equal directions at an external ground-fault situation. Phase grounding is inside and neutral grounding is outside the area to be protected.

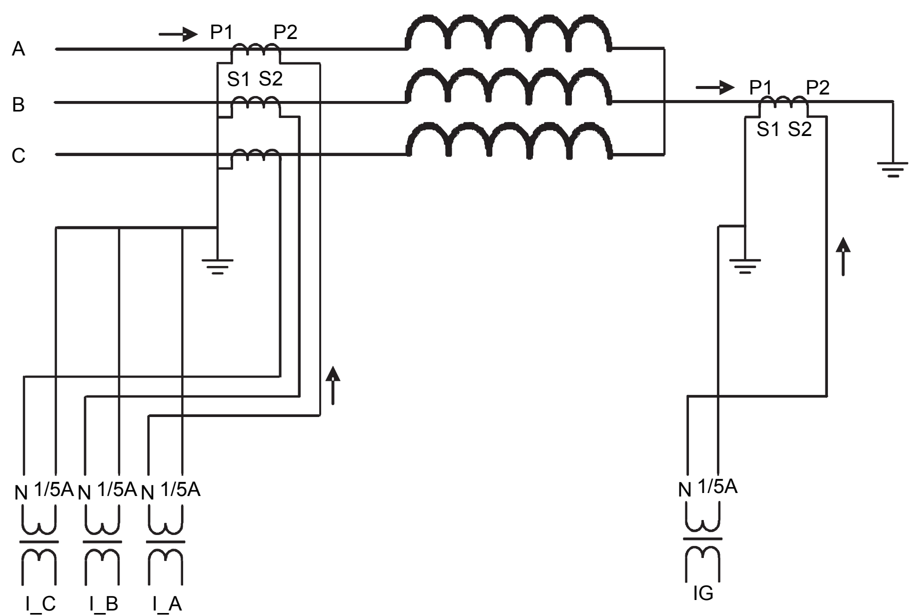


Figure 273: Connection of the current transformers of Type 2. The phase currents and the neutral current have equal directions at an external ground-fault situation. Phase grounding is outside and neutral grounding is inside the area to be protected.

Internal and external faults

87LOZREF does not respond to any faults outside the protected zone. An external fault is detected by checking the phase angle difference of the neutral current and the sum of the phase currents. When the difference is less than 90 degrees, the operation is internally restrained or blocked. Hence the protection is not sensitive to an external fault.

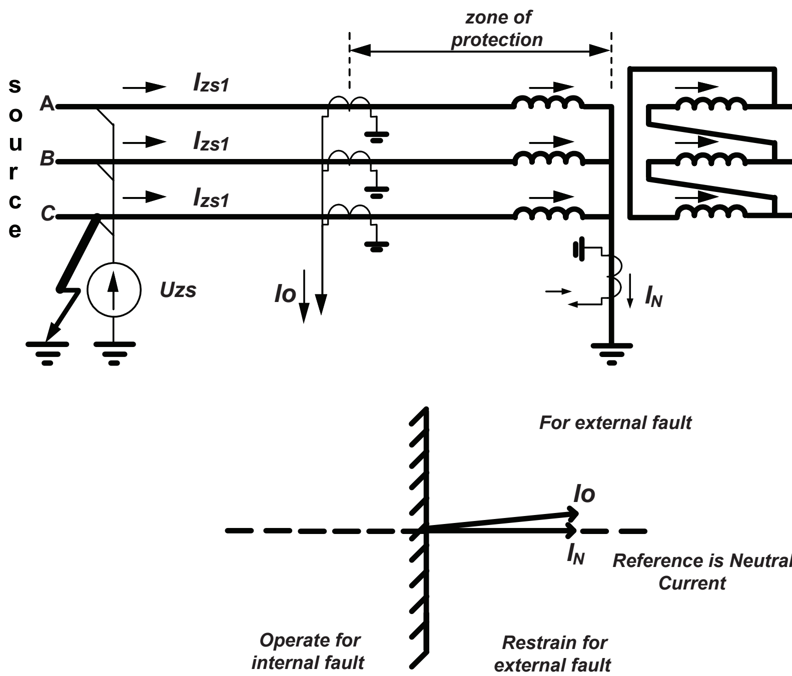


Figure 274: Current flow in all the CTs for an external fault

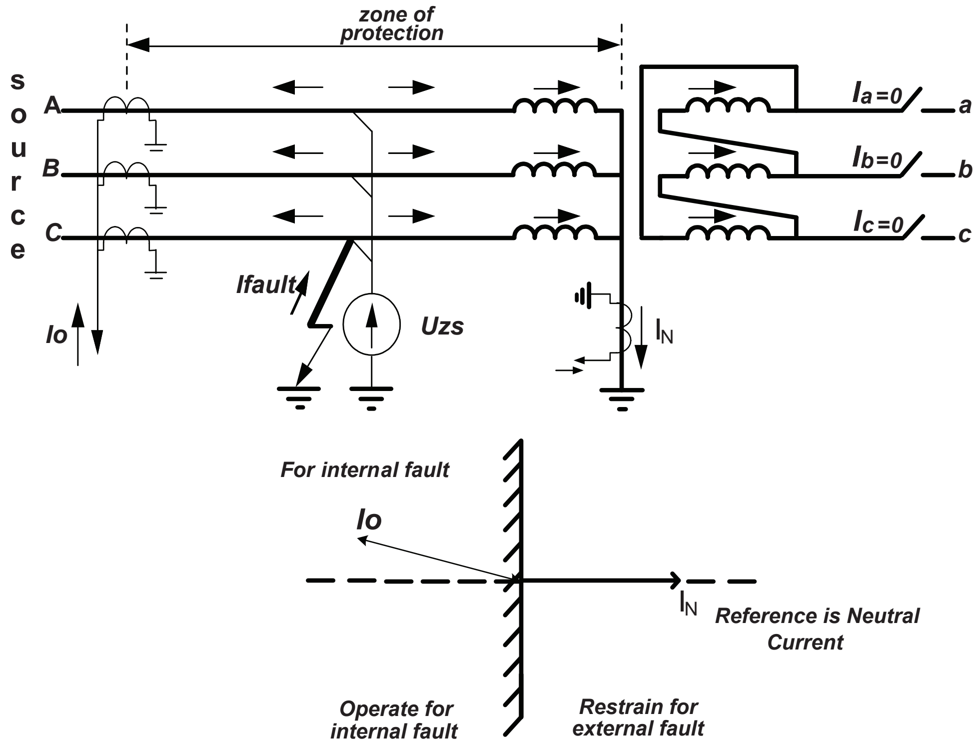


Figure 275: Current flow in all the CTs for an internal fault

87LOZREF does not respond to phase-to-phase faults either, as in this case the fault current flows between the two line CTs and so the neutral CT does not experience this fault current.

Blocking based on the second harmonic of the neutral current

The transformer magnetizing inrush currents occur when the transformer is energized after a period of de-energization. The inrush current can be many times the rated current, and the halving time can be up to several seconds. For the differential protection relay, the inrush current represents the differential current, which causes the protection relay to trip almost always when the transformer is connected to the network. Typically, the inrush current contains a large amount of second harmonics.

The blocking also prevents unwanted operation at the recovery and sympathetic magnetizing inrushes. At the recovery inrush, the magnetizing current of the transformer to be protected increases momentarily when the voltage returns to normal after the clearance of a fault outside the protected area. The sympathetic inrush is caused by the energization of a transformer running in parallel with the protected transformer already connected to the network.

Blocking the pickup of the restricted ground-fault protection at the magnetizing inrush is based on the ratio of the second harmonic and the fundamental frequency amplitudes of the neutral current IG_2H / IG. Typically, the second harmonic content of the neutral current at the magnetizing inrush is higher than that of the phase currents.

4.3.3.6 Signals

Table 442: 87LOZREF Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
IG	SIGNAL	0	Zero-sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 443: 87LOZREF Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
BLK2H	BOOLEAN	2nd harmonic block

4.3.3.7 Settings

Table 444: 87LOZREF Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip value	5.0...50.0	%In	1.0	5.0	Trip value

Table 445: 87LOZREF Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	40...300000	ms	1	40	Minimum trip time
Restraint mode	1=None 2=Harmonic2			1=None	Restraint mode
Pickup value 2.H	10...50	%	1	50	The ratio of the 2. harmonic to fundamental component required for blocking

Table 446: 87LOZREF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
CT connection type	1=Type 1 2=Type 2			2=Type 2	CT connection type

Table 447: 87LOZREF Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.3.3.8 Monitored data

Table 448: 87LOZREF Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
RES2H	BOOLEAN	0=False 1=True		2nd harmonic restraint
IDIFF	FLOAT32	0.00...80.00	xIn	Differential current
IBIAS	FLOAT32	0.00...80.00	xIn	Stabilization current
87LOZREF	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.3.3.9 Technical data

Table 449: 87LOZREF Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n ±2 Hz		
		±2.5% of the set value or ±0.002 x I_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 2.0 × set *Trip value*	37 ms	41 ms	45 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Table continues on next page				

Characteristic	Value
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5, …

1) Current before fault = 0.0, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.3.3.10 Technical revision history

Table 450: 87LOZREF Technical revision history

Technical revision	Change
B	Unit for setting *Pickup value 2.H* changed from %In to %.
C	Internal Improvement.

4.3.4 High-impedance differential protection 87A, 87B, 87C

4.3.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
High-impedance differential protection for phase A	HIAPDIF	dHi_A>	87A
High-impedance differential protection for phase B	HIBPDIF	dHi_B>	87B
High-impedance differential protection for phase C	HICPDIF	dHi_C>	87C

4.3.4.2 Function block

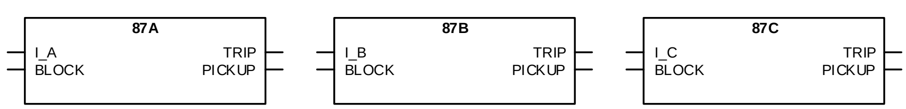


Figure 276: Function block

4.3.4.3 Functionality

The high-impedance differential protection function 87A, 87B, 87C is a general differential protection. It provides a phase-segregated short circuit protection for the busbar. However, the function can also be used for providing generator, motor, transformer and reactor protection.

The function starts and operates when the differential current exceeds the set limit. The operate time characteristics are according to definite time (DT).

The function contains a blocking functionality. It is possible to block the function outputs, timer or the whole function.

4.3.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 87A, 87B, 87C can be described with a module diagram. All the modules in the diagram are explained in the next sections.

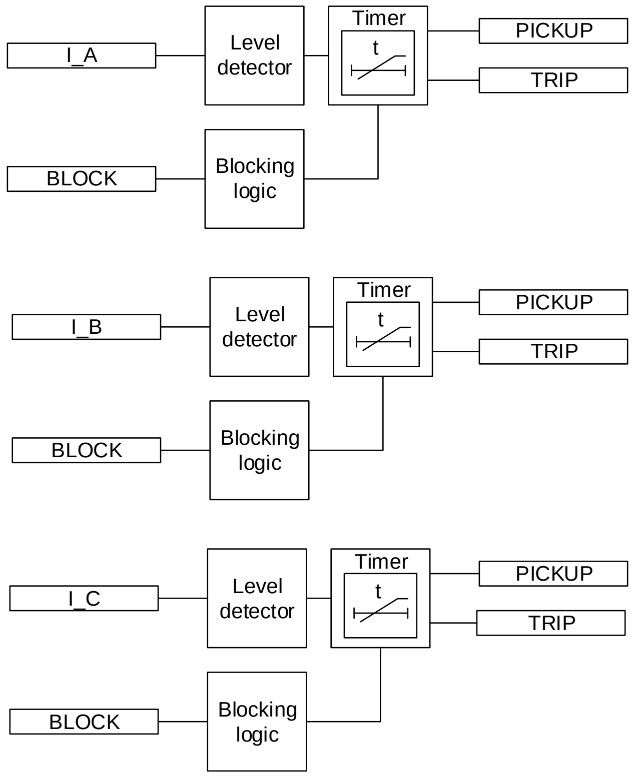


Figure 277: Functional module diagram

The module diagram illustrates all the phases of the function. Functionality for phases A, B and C is identical.

All three phases have independent settings.

Level detector

The module compares differential currents `I_A` calculated by the peak-to-peak measurement mode to the set *Operate value*. The Timer module is activated if the differential current exceeds the value of the *Operate value* setting.

Timer

Once activated, Timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer reaches the value set by *Trip delay time*, the `TRIP` output is activated. If the fault disappears before the module operates, the reset timer is activated.

If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the PICKUP output is deactivated.

Timer calculates the start duration PICKUP_DUR value, which indicates the percentage ratio of the start situation and the set operating time. The value is available in the Monitored data view.

The activation of the BLOCK input resets Timer and deactivates the PICKUP and TRIP outputs.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.3.4.5 Application

87A, 87B, 87C provides a secure and dependable protection scheme against all types of faults. The high-impedance principle is used for differential protection due to its capability to manage the through-faults also with the heavy current transformer (CT) saturation.

For current transformer recommendations, see the Requirements for measurement transformers section in this manual.

High-impedance principle

The phase currents are measured from both the incoming and the outgoing feeder sides of the busbar. The secondary of the current transformer in each phase is connected in parallel with a protection relay measuring branch. Hence, the relay measures only the difference of the currents. In an ideal situation, there is a differential current to operate the relay only if there is a fault between the CTs, that is, inside the protected zone.

If there is a fault outside the zone, a high current, known as the through-fault current, can go through the protected object. This can cause partial saturation in the CTs. The relay operation is avoided with a stabilizing resistor (R_S) in the protection relay measuring branch. R_s increases the impedance of the protection relay; hence the name high-impedance differential scheme.

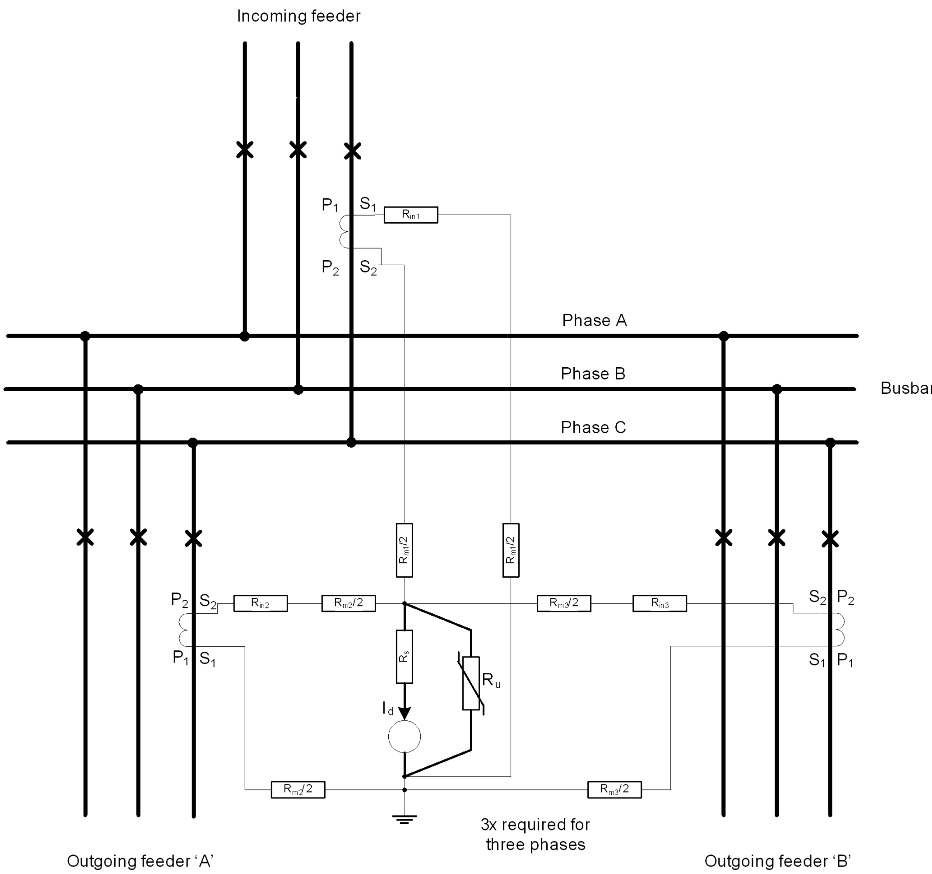


Figure 278: Phase-segregated bus differential protection based on high-impedance principle

CT secondary winding resistances (R_{in}) and connection wire resistances ($R_m/2$) are also shown in Figure 279.

Figure 279 demonstrates a simplified circuit consisting only of one incoming and outgoing feeder. To keep it simple, the voltage-dependent resistor (R_u) is not included. The wiring resistances are presented as total wiring resistances R_{m1} and R_{m2}.

R_{m1} is the maximum wiring resistance concerning all incoming feeder sets, whereas R_{m2} is the maximum wiring resistance concerning all outgoing feeder sets.

The lower part of Figure 279 shows the voltage balance when there is no fault in the system and no CT saturation.

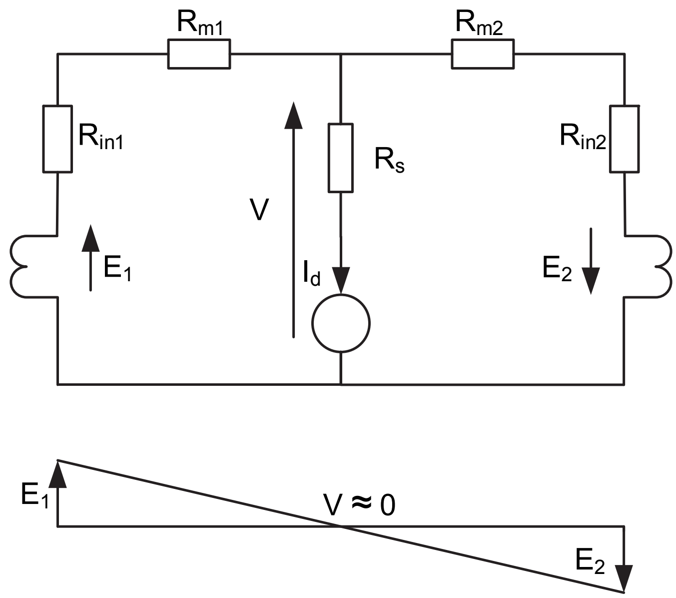


Figure 279: Equivalent circuit when there is no fault or CT saturation

When there is no fault, the CT secondary currents and their emf voltages, E_1 and E_2, are opposite and the protection relay measuring branch has no voltage or current. If an in-zone fault occurs, the secondary currents have the same direction. The relay measures the sum of the currents as a differential and trips the circuit breaker. If the fault current goes through only one CT, its secondary emf magnetizes the opposite CT, that is, $E_1 \approx E_2$.

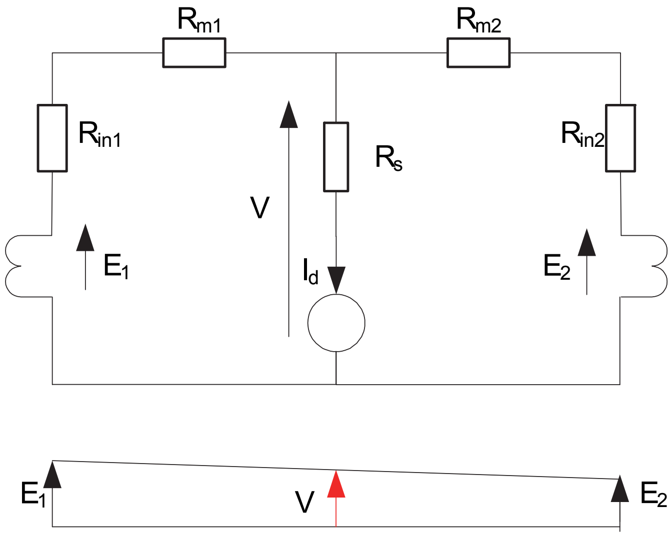


Figure 280: Equivalent circuit in case of in-zone fault

Figure 281 shows CT saturation at a through-fault, that is, out-of-zone, situation. The magnetization impedance of a saturated CT is almost zero. The saturated CT winding can be presented as a short circuit. When one CT is saturated, the current of the non-saturated CT follows two paths, one through the protection relay measuring branch (R_s + relay) and the other through the saturated CT ($R_m + R_{in2}$).

The protection relay must not operate during the saturation. This is achieved by increasing the relay impedance by using the stabilizing resistor (R_s) which forces the majority of the differential current to flow through the saturated CT. As a result, the relay operation is avoided, that is, the relay operation is stabilized against the CT saturation at through-fault current. The stabilizing voltage V_s is the basis of all calculations.

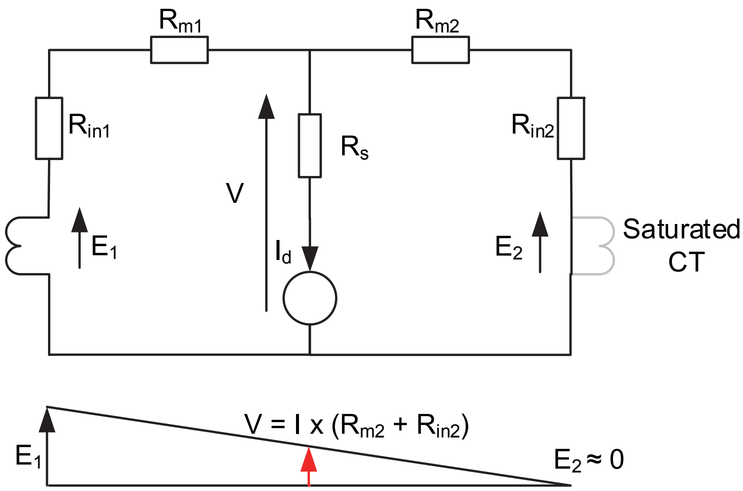


Figure 281: Equivalent circuit in case of the CT saturation at through-fault

The CT saturation happens most likely in the case of an in-zone fault. This is not a problem, because although the operation remains stable (non-operative) during the saturated parts of the CT secondary current waveform, the non-saturated part of the current waveform causes the protection to operate.

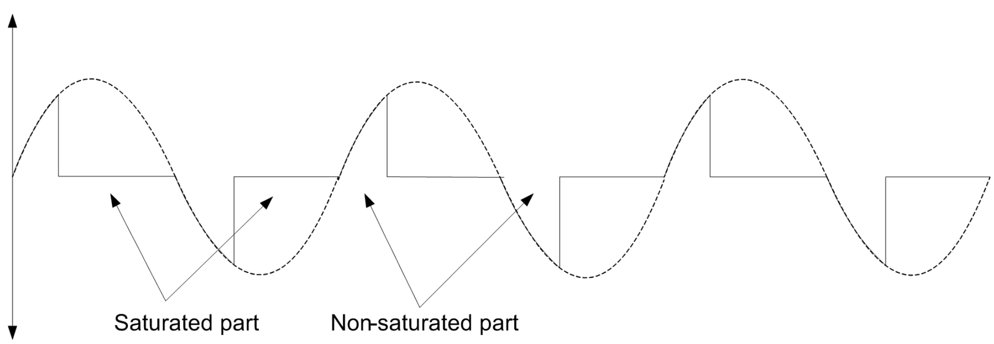


Figure 282: Secondary waveform of a saturated CT

The secondary circuit voltage can easily exceed the isolation voltage of the CTs, connection wires and the protection relay because of the stabilizing resistance and CT saturation. A voltage dependent resistor (VDR, R_u) is used to limit the voltage as shown in Figure 278.

Busbar protection scheme

The basic concept for any bus differential protection relay is a direct use of Kirchoff's first law that the sum of all currents connected to one differential protection zone is zero. If the sum is not zero, an internal fault has occurred. In other words, as seen by the busbar differential protection, the sum of all currents that flow into the protection zone, that is, currents with positive value, must be equal to currents that flow out of the protection zone, that is, currents with negative value, at any instant of time.

Figure 283 shows an example of a phase segregated single busbar protection employing high-impedance differential protection. The example system consists of a single incoming busbar feeder and two outgoing busbar feeders. The CTs from both the outgoing busbar feeders and the incoming busbar feeders are connected in parallel with the polarity. During normal load conditions, the total instantaneous incoming current is equal to the total instantaneous outgoing current and the difference current is negligible. A fault in the busbar results in an imbalance between the incoming and the outgoing current. The difference current flows through the protection relay, which generates a trip signal.

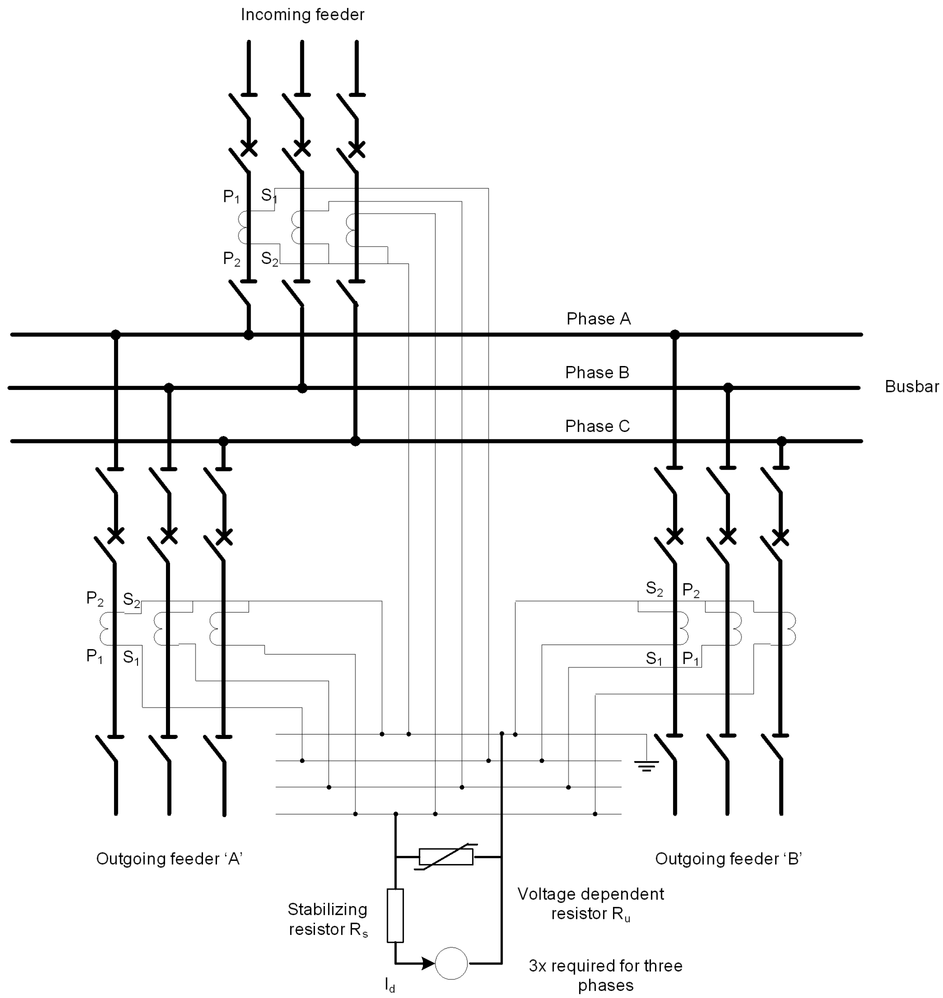


Figure 283: Phase-segregated single busbar protection employing high-impedance differential protection

Figure 284 shows an example for a system consisting of two busbar section coupled with a bus coupler. Each busbar section consists of two feeders and both sections are provided with a separate differential protection to form different zones. The formed zones overlap at the bus coupler.

When the bus coupler is in the open position, each section of the busbar handles the current flow independently, that is, the instantaneous incoming current is equal to the total instantaneous outgoing current and the difference current is negligible. The difference current is no longer zero with a fault in the busbar and the protection operates.

With the bus coupler in the closed position, the current also flows from one busbar section to another busbar section. Thus, the current flowing through the bus coupler needs to be considered in calculating differential current. During normal condition, the summation of the current on each bus section is zero. However, if there is a fault in any busbar section, the difference current is no longer zero and the protection operates.

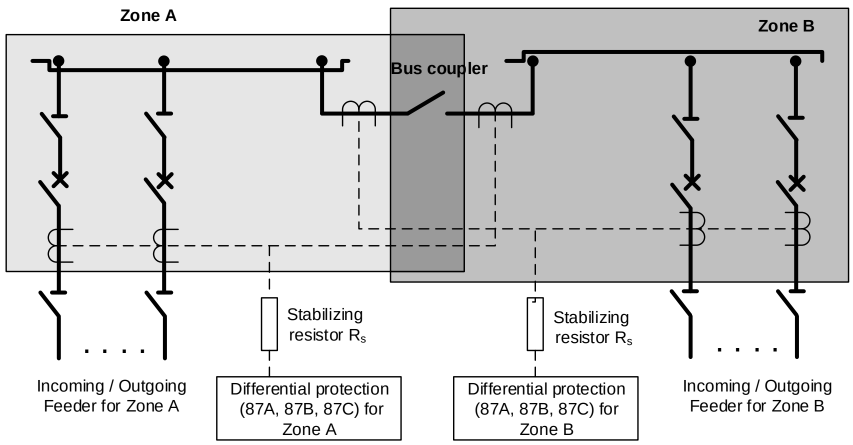


Figure 284: Differential protection on busbar with bus coupler (Single-phase representation)

Flux-balancing principle

87A, 87B, 87C can be used to realize flux-balance based phase-segregated three-phase differential protection. Stabilizing resistors are not needed in this application as core balance current transformers are used instead. They must be wired so that the measured current will be the differential current between the motor terminal and the neutral sides.

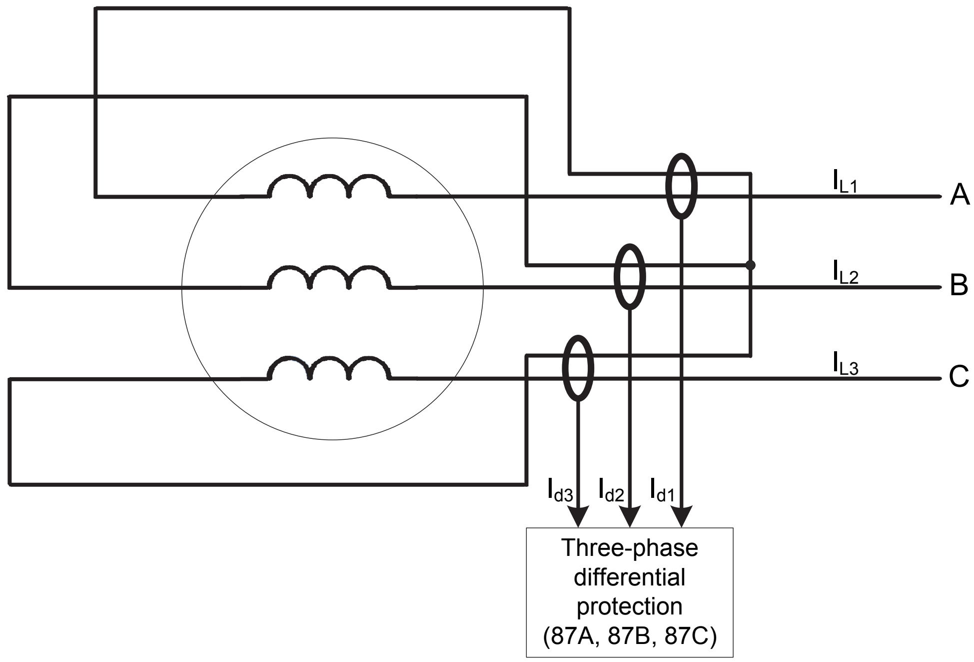


Figure 285: Three-phase differential protection for motors based on flux-balancing principle

In this scheme, the currents flowing through the core balance transformer cancel each other out when there is no fault within the protected zone. When fault occurs within the protected zone, the currents flowing through the core balance transformer add up so that the differential protection trips when the differential current exceeds its threshold.

87A, 87B, 87C uses the peak-to-peak measurement mode.

4.3.4.6 Example calculations for busbar high-impedance differential protection

The protected object in the example for busbar differential protection is a single-bus system with two zones of protection.

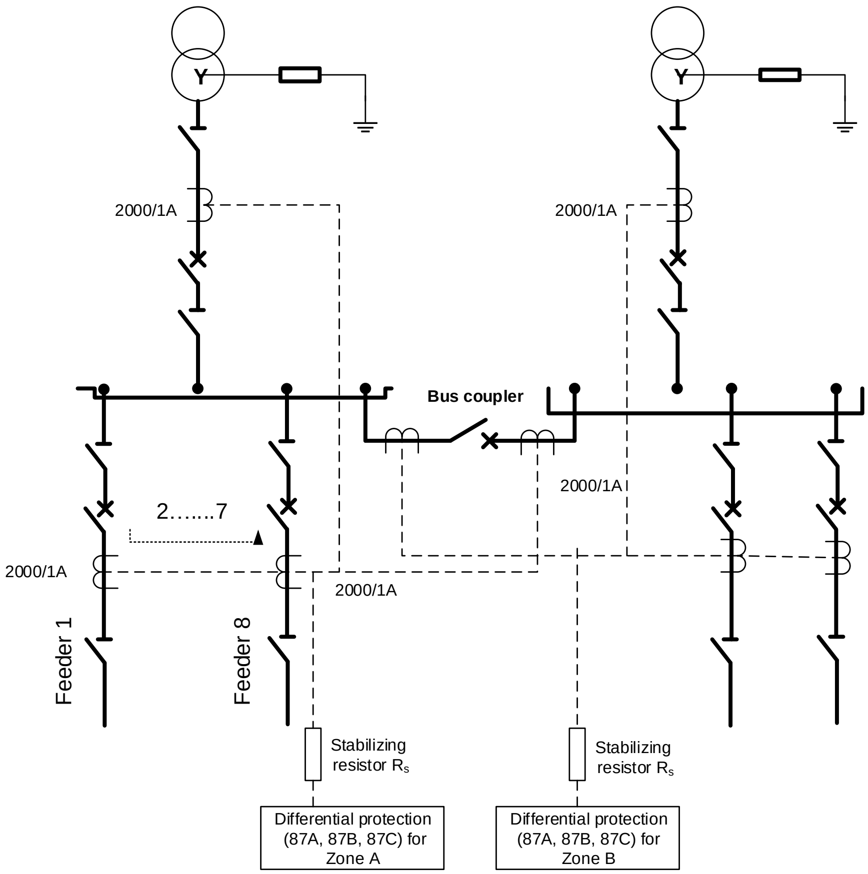


Figure 286: Example for busbar differential protection

Bus data:

V_n	20 kV
I_n	2000 A
I_{kmax}	25 kA

10 feeders per protected zone including bus coupler and incomer.

CT data is assumed to be:

CT	2000/1 A
R_{in}	15.75 Ω
V_{kn}	436 V
I_e	<7 mA (at U_{kn})
R_m	1Ω

The stabilizing voltage is calculated using the formula:

$$V_s = \frac{25000A}{2000}\left(15.75\Omega + 1.\Omega\right) \approx 209.37\ V$$

(Equation 93)

In this case, the requirement for the current transformer knee point voltage is fulfilled because $V_{kn} > 2V_s$.

The magnetizing curve of the CT is assumed to be linear. The magnetizing current at the stabilizing voltage can be estimated as:

$$I_m = \frac{V_s}{V_{kn}} \cdot I_e$$

(Equation 94)

$$I_m = \frac{209.37V}{436V} \cdot 7mA \approx 3.4mA$$

(Equation 95)

To obtain adequate protection stability, the setting current I_{rs} must be at the minimum of the sum of magnetizing currents of all connected CTs.

$$I_{rs} = 10 \cdot 3.4mA \approx 34\,mA$$

(Equation 96)

The sensitivity of the stabilizing resistor is calculated based on Equation 97.

$$R_S = \frac{209.37\ V}{0.034A} \approx 6160\,\Omega$$

(Equation 97)

The calculated value is the maximum value for the stabilizing resistor. If the value is not available, the next available value below should be selected and the protection relay setting current is tuned according to the selected resistor. For example, in this case, the resistance value 5900 Ω is used.

$$I_{rs} = \frac{209.37V}{5900\,\Omega} \approx 35\,mA$$

(Equation 98)

The sensitivity of the protection is obtained as per Equation 99, assuming $I_u = 0$.

$$I_{prim} = 2000 \cdot (0.035\,A + 10 \cdot 0.0034\,A + 0\,A) \approx 140A$$

(Equation 99)

The power of the stabilizing resistor is calculated:

$$P \geq \frac{(436V)^2}{5900\Omega} \approx 32W$$

(Equation 100)

Based onEquation 101 and Equation 102, the need for voltage-dependent resistor is checked.

$$V_{max} = \frac{25000A}{2000}(5900\Omega + 15.75\Omega + 1.00\Omega) \approx 74.0kV$$

(Equation 101)

$$\breve{u} = 2 \cdot \sqrt{2 \cdot 436V \cdot (74000V - 436V)} \approx 16.0kV$$

(Equation 102)

The voltage-dependent resistor (one for each phase) is needed in this case as the voltage during the fault is higher than 2 kV.

The leakage current through the VDR at the stabilizing voltage can be available from the VDR manual, assuming that to be approximately 2 mA at stabilizing voltage

$$Iu \approx 0.002A$$

(Equation 103)

The sensitivity of the protection can be recalculated taking into account the leakage current through the VDR as per Equation 104.

$$I_{prim} = 2000 \cdot (0.035A + 10 \cdot 0.0034A + 0.002A) \approx 142A$$

(Equation 104)

4.3.4.7 Signals

Table 451: 87A Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 452: 87B Input signals

Name	Type	Default	Description
I_B	SIGNAL	0	Phase B current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 453: 87C Input signals

Name	Type	Default	Description
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 454: 87A Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 455: 87B Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

Table 456: 87C Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.3.4.8 Settings

Table 457: 87A Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip value	1.0...200.0	%In	1.0	5.0	Pickup value, percentage of the nominal current
Minimum trip time	20...300000	ms	10	20	Minimum trip time

Table 458: 87A Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 459: 87A Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time

Table 460: 87B Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip value	1.0...200.0	%In	1.0	5.0	Pickup value, percentage of the nominal current
Minimum trip time	20...300000	ms	10	20	Minimum trip time

Table 461: 87B Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 462: 87B Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time

Table 463: 87C Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip value	1.0...200.0	%In	1.0	5.0	Pickup value, percentage of the nominal current
Minimum trip time	20...300000	ms	10	20	Minimum trip time

Table 464: 87C Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 465: 87C Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time

4.3.4.9 Monitored data

Table 466: 87A Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
87A	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 467: 87B Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
87B	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 468: 87C Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
87C	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.3.4.10 Technical data

Table 469: 87A, 87B, 87C Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the current measured: f_n ±2 Hz		
		±1.5% of the set value or ±0.002 × I_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 2.0 × set *Pickup value*	12 ms	16 ms	24 ms
	I_{Fault} = 10 × set *Pickup value*	10 ms	12 ms	14 ms
Reset time		<40 ms		
Table continues on next page				

Characteristic	Value
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms

1) Measurement mode = default (depends on stage), current before fault = 0.0 × I_n, f_n = 50 Hz, fault current with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.3.4.11 Technical revision history

Table 470: 87A, 87B, 87C Technical revision history

Technical revision	Change
B	Function name changed from HIPDIF to HIAPDIF, HIBPDIF, HICPDIF

4.3.5 Motor differential protection 87G

4.3.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Motor differential protection	MPDIF	3dI>M	87G, 87M

4.3.5.2 Function block

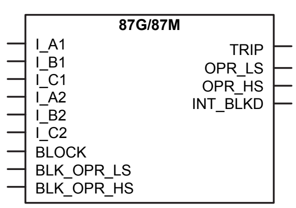


Figure 287: Function block

4.3.5.3 Functionality

The motor winding failure protection function 87G, 87M is a unit protection function. The possibility of internal failures of the motor is relatively low. However, the consequences in terms of cost and production loss are often serious, which makes the differential protection an important protection function.

The stability of the differential protection is enhanced by a DC restraint feature. This feature decreases the sensitivity of the differential protection optionally for a temporary time period to avoid an unnecessary disconnection of the motor during the external faults that have a fault current with high DC currents. 87G, 87M also includes a CT saturation-based blocking which prevents unnecessary tripping in case of the detection of the magnetizing inrush currents which can be present at the switching operations, overvoltages or external faults.

4.3.5.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 87G, 87M can be described using a module diagram. All the modules in the diagram are explained in the next sections.

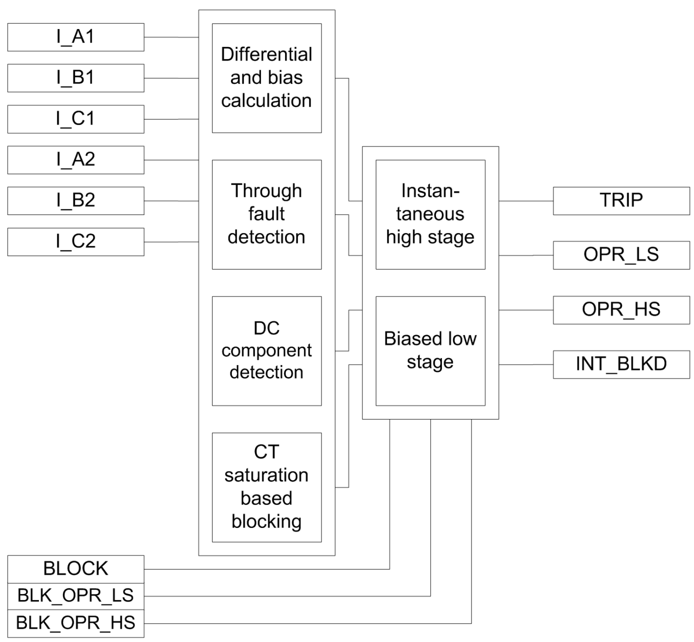


Figure 288: Functional module diagram

Differential and bias calculation

Differential calculation module calculates the differential current. The differential current is the difference in current between the phase and neutral sides of the machine. The phase currents $\bar{I}_1$ and $\bar{I}_2$ denote the fundamental frequency components on the phase and neutral sides of the current. The amplitude of the differential current I_d is obtained using the equation (assuming that the positive direction of the current is towards the machine):

$$I_d = \left|\bar{I}_1 + \bar{I}_2\right|$$

(Equation 105)

During normal conditions, there is no fault in the area protected by the function block, so the currents $\bar{I}_1$ and $\bar{I}_2$ are equal and the differential current $I_d = 0$. However, in practice some differential current exists due to inaccuracies in the current transformer on the phase and neutral sides, but it is very small during normal conditions.

The module calculates the differential current for all three phases.

The low-stage differential protection is stabilized with a bias current. The bias current is also known as the stabilizing current. Stabilization means that the differential current required for tripping increases according to the bias current and the operation characteristics. When an internal fault occurs, the currents on both sides of the protected object are flowing into it. This causes the biasing current to be considerably smaller, which makes the operation more sensitive during internal faults.

The traditional way for calculating the stabilized current is:

$$I_b = \left|\frac{\bar{I}_1 - \bar{I}_2}{2}\right|$$

(Equation 106)

The module calculates the bias current for all three phases.

Through-fault detection

Through-fault (TF) detection module is for detecting whether the fault is external, that is, going through, or internal. This information is essential for ensuring the correct operation of the protection in case of the CT saturation.

- In a through-fault situation, CTs can saturate because of a high fault current magnitude. Such AC saturation does not happen immediately when the fault begins. Thus, the TF module sees the fault as external because the bias current is high but the differential current remains low. If the AC saturation then occurs, a CT saturation-based blocking is allowed to work to prevent tripping.
- Normally, the phase angle between the machine neutral and line side CTs is 180 degrees. If an internal fault occurs during a through fault, an angle less than 50 degrees clearly indicates an internal fault and the TF module overrules, that is, deblocks the presence of any blocking due to CT saturation.

CT saturation-based blocking

Higher currents during the motor startup or abnormally high magnetizing currents at an overvoltage (transformer-fed motor) or an external fault may saturate the current transformers. The uneven saturation of the star and line side CTs (for example, due to burden differences) may lead to a differential current which can cause a differential protection to trip. This module blocks the operation of 87G, 87M biased low stage internally in case of the CT saturation. Once the blocking is activated, it is held for a certain time after the blocking conditions have ceased to be fulfilled.

DC component detection

On detection of a DC component, the function temporarily desensitizes the differential protection. The functioning of this module depends on the *DC restrain Enable* setting. The DC components are continuously extracted from the three instantaneous differential currents. The highest DC component of all three is taken as a kind of DC restraint in a sense that the highest effective, temporary sensitivity of the protection is temporarily decreased as a function of this highest DC offset. The calculated DC restraint current is not allowed to decay (from its highest ever measured value) faster than with a time constant of one second. The value of the temporarily effective sensitivity limit is limited upwards to the rated current of the machine or 3.3 times that of *Low trip value*, whichever is smaller. The temporary extra limit decays exponentially from its maximum value with a time constant of one second.

This feature should be used in case of networks where very long time constants are expected. The temporary sensitivity limit is higher to the set operating characteristics. In other words, the temporary limit has superposed the unchanged operating characteristics and temporarily determines the highest sensitivity of the protection. The temporary sensitivity is less than the sensitivity in section 1 of the operating characteristic and is supposed to prevent an unwanted trip during the external faults with lower currents.

Biased low stage

The current differential protection needs to be biased because of the possible appearance of a differential current which can be due to something else than an actual fault in the motor. In case of differential protection, a false differential current can be caused by:

- CT errors
- CT saturation at high currents passing through the motor

The differential current caused by CT errors increases at the same percent ratio as the load current.

The high currents passing through the protected object can be caused by the through fault. Therefore, the operation of the differential protection is biased with respect to the load current. In the biased differential protection, the higher the differential current required for the protection of operation, the higher the load current.

Based on the conditions checked from the through-fault module, the DC (component) detection module and the CT saturation-based blocking modules, the biased low-stage module decides whether the differential current is due to the internal faults or some false reason. In case of detection of the TF, DC or CT saturation, the internal differential blocking signal is generated, which in turn blocks the trip signal. In case of internal faults, the operation of the differential protection is affected by the bias current.

The *Low trip value* setting for the stabilized stage of the function block is determined with the equation:

$$Low\,trip\,value = \frac{I_{d1}}{I_n} \cdot 100\%$$

(Equation 107)

The *Slope section 2* setting is determined correspondingly:

$$Slope\,section\,2 = \frac{I_{d2}}{I_{b2}} \cdot 100\%$$

(Equation 108)

$$Slope\,section\,3 = \frac{I_{d3}}{I_{b3}} \cdot 100\%$$

(Equation 109)

The end of the first section *End section 1* can be set at a desired point within the range of 0 to 100 percent (or % I_n). Accordingly, the end of the second section *End section 2* can be set within the range of 100 percent to 300 percent (or % I_n).

The slope of the operating characteristic for the function block varies in different parts of the range.

In section 1, where $0.0 < I_b/I_n <$ *End section 1*, the differential current required for tripping is constant. The value of the differential current is the same as the *Low trip value* setting selected for the function block. The *Low trip value* setting allows for small inaccuracies of the current transformers but it can also be used to influence the overall level of the operating characteristic.

Section 2, where *End section 1* $< I_b/I_n <$ *End section 2*, is called the influence area of the setting *Slope section 2*. In this section, variations in *End section 2* affect the slope of the characteristic, that is, how big the change in the differential current required for tripping is in comparison to the change in the load current. The *End section 2* setting allows for CT errors.

In section 3, where $I_b/I_n >$ *End section 2*, the slope of the characteristic can be set by *Slope section 3* that defines the increase in the differential current to the corresponding increase in the biasing current.

The required differential current for tripping at a certain stabilizing current level can be calculated using the formulae:

For a stabilizing current lower than *End section 1*

$$I_{doperate}[\%I_n] = \text{Set } \mathit{Low\ trip\ values}$$

(Equation 110)

For a stabilizing current higher than *End section 1* but lower than *End section 2*

$$I_{doperate}[\%I_n] = \mathit{Low\ trip\ value} + (I_b[\%I_n] - \mathit{End\ section\ 1}) \cdot \mathit{Slope\ section}\ 2$$

(Equation 111)

For higher stabilizing current values exceeding *End section 2*

$$I_{doperate}[\%I_n] = \mathit{Low\ trip\ value} + (\mathit{End\ section}\ 2 - \mathit{End\ section}\ 1) \cdot \mathit{Slope\ section}\ 2 + (I_b[\%I_n] - \mathit{End\ section}\ 2)$$

(Equation 112)

When the differential current exceeds the operating value determined by the operating characteristics, the OPR_LS output is activated. The TRIP output is always activated when the OPR_LS output activates.

The trip signal due to the biased stage can be blocked by the activation of the BLK_OPR_LS or BLOCK input. Also, when the operation of the biased low stage is blocked by the waveform blocking functionality, the INT_BLKD output is activated according to the phase information.

The phase angle difference between the two currents I_A1 and I_A2 is theoretically 180 electrical degrees for the external fault and 0 electrical degrees for the internal fault conditions. If the phase angle difference is less than 50 electrical degrees or if the biasing current drops below 30 percent of the differential current, a fault has most likely occurred in the area protected by 87G, 87M. Then the internal blocking signals (CT saturation and DC blocking) of the biased stage are inhibited.

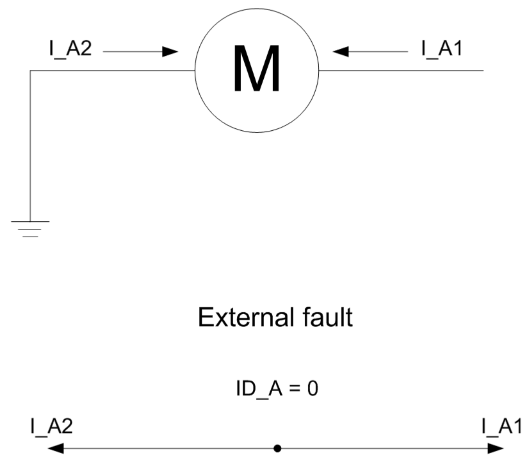


Figure 289: Positive direction of current

Instantaneous high stage

The differential protection includes an unbiased instantaneous high stage. The instantaneous stage trips and the OPR_HS output is activated when the amplitude of the fundamental frequency component of the differential current exceeds the set *High trip value* or when the instantaneous peak values of the differential current exceed 2.5 · *High trip value*. The factor 2.5 (= 1.8 · √2) is due to the maximum asymmetric short circuit current.

The TRIP output is always activated when the OPR_HS output activates.

The internal blocking signals of the function block do not prevent the operation of the instantaneous stage. When required, the trip signal due to instantaneous operation can be blocked by the binary inputs BLK_OPR_HS or BLOCK.

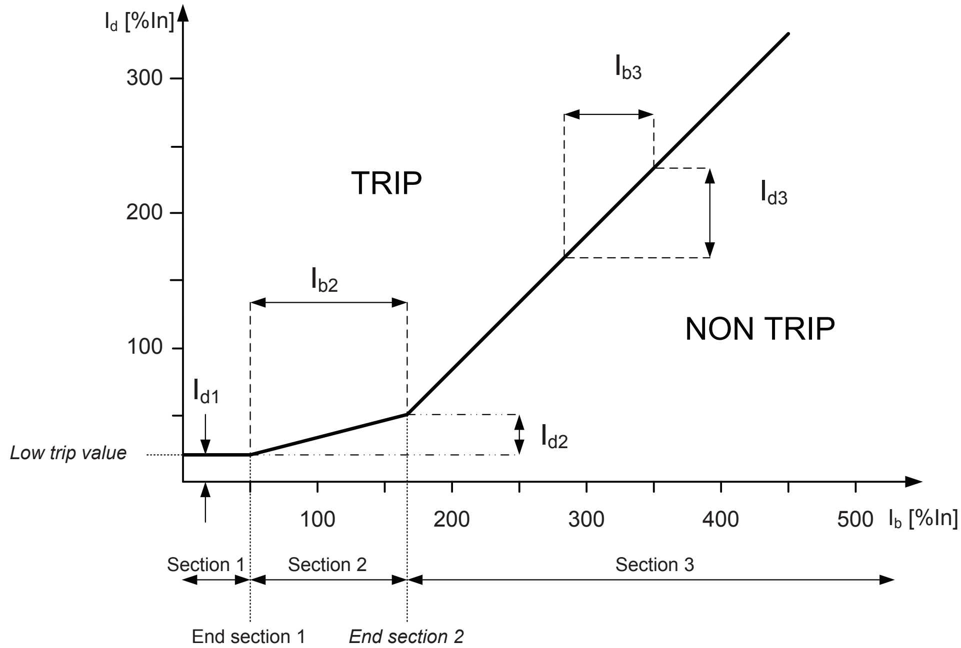


Figure 290: Operating characteristic for the stabilized stage of the generator differential protection function

4.3.5.5 Application

The differential protection works on the principle of calculating the differential current at the two ends of the winding, that is, the current entering the winding is compared to the current exiting the winding. In case of any internal fault, the currents entering and exiting the winding are different, which results in a differential current, which is then used as a base for generating the trip signal. Due to this principle, the differential protection does not trip during external faults. However, it should be noted that interturn faults in the same phase are usually not detected unless they developed into some other kind of fault.

The short circuit between the phases of the stator windings normally causes large fault currents. The short circuit creates a risk of damages to the insulation, windings and stator core. The large short circuit currents cause large current forces which can damage other components in the machine. The short circuit can also initiate explosion and fire. When a short circuit occurs in a machine, there is a damage that has to be repaired. The severity and the repair time depend on the degree of damage, which is highly dependent on the fault time. The fast fault clearance of this fault type is of greatest importance to limit the damages and the economic loss.

To limit the damages in connection to the stator winding short circuits, the fault clearance time must be as short as possible (instantaneous). The fault current contributions from both the external power system (via the machine or the block circuit breaker) and from the machine itself must be disconnected as fast as possible.

The DC restraint feature should be used in case of an application with a long DC time constant in the fault currents is present. This fault current may be of a lesser magnitude (less than rated current) but is unpleasant and tends to saturate the CT and trip the differential protection for external faults. This feature is effective at moderate through-currents and ineffective at higher through-currents.

Although the short circuit fault current is normally very large, that is, significantly larger than the rated current of the machine, it is possible that a short circuit can occur between phases close to the neutral point of the machine, causing a relatively small fault current. The fault current fed from the synchronous machine can also be limited due to a low excitation of the synchronous generator. This is normally the case at the run-up of the synchronous machine, before synchronization to the network. Therefore, it is desired that the detection of the machine phase-to-phase short circuits shall be relatively sensitive, thus detecting the small fault currents.

It is also important that the machine short circuit protection does not trip for external faults when a large fault current is fed from the machine. To combine fast fault clearance, sensitivity and selectivity, the machine current differential protection is normally the best alternative for the phase-to-phase short circuits.

The risk of an unwanted differential protection operation caused by the current transformer saturation is a universal differential protection problem. If a big synchronous machine is tripped in connection to an external short circuit, it gives an increased risk of a power system collapse. Besides, there is a production loss for every unwanted trip of the machine. Therefore, preventing the unwanted disconnection of machines has a great economical value.

Recommendations for current transformers

The more important the object to be protected is, the more attention is paid to the current transformers. It is not normally possible to dimension the current transformers so that they repeat the currents with high DC components without saturating when the residual flux of the current transformer is high. The differential protection function block operates reliably even though the current transformers are partially saturated.

The accuracy class recommended for current transformers to be used with the differential function block is 5P, in which the limit of the current error at the rated primary current is 1 percent and the limit of the phase displacement is 60 minutes. The limit of the composite error at the rated accuracy limit primary current is 5 percent.

The approximate value of the actual accuracy limit factor F_a corresponding to the actual CT burden can be calculated on the basis of the rated accuracy limit factor F_n (ALF) at the rated burden, the rated burden S_n, the internal burden S_{in} and the actual burden S_a of the current transformer.

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a}$$

(Equation 113)

Example 1

The rated burden S_n of the current transformer 5P20 is 10 VA, the secondary rated current 5A, the internal resistance R_{in} = 0.07 Ω and the rated accuracy limit factor F_n corresponding to the rated burden is 20 (5P20). The internal burden of the current transformer is S_{in} = (5A)² × 0.07 Ω = 1.75 VA. The input impedance of the protection relay at a rated current of 5A is < 20 mΩ. If the measurement conductors have a resistance of 0.113 Ω, the actual burden of the current transformer is S_a = (5A)² × (0.113 + 0.020) Ω = 3.33 VA. Thus, the accuracy limit factor F_a corresponding to the actual burden is about 46.

The CT burden can grow considerably at the rated current 5A. The actual burden of the current transformer decreases at the rated current of 1 A while the repeatability simultaneously improves.

At faults occurring in the protected area, the fault currents can be very high compared to the rated currents of the current transformers. Due to the instantaneous stage of the differential function block, it is sufficient that the current transformers are capable of repeating the current required for an instantaneous tripping during the first cycle.

Thus the current transformers usually are able to reproduce the asymmetric fault current without saturating within the next 10 ms after the occurrence of the fault to secure that the trip times of the protection relay comply with the retardation time.

The accuracy limit factors corresponding to the actual burden of the phase current transformer to be used in differential protection must fulfill the requirement:

$$F_a > K_r \times Ik_{\max} \times (T_{dc} \times \omega \times (1 - e^{\frac{-T_m}{T_{dc}}}) + 1)$$

(Equation 114)

Ik_{max}	The maximum through-going fault current (in I_R) at which the protection is not allowed to trip
T_{dc}	The primary DC time constant related to Ik_{max}
ω	The angular frequency, that is, 2 x π x f_n
T_m	The time to saturate, that is, the duration of the saturation-free transformation
K_r	The remanence factor 1/(1-r), where r is the maximum remanence flux in pu from the saturation flux

The parameter r is the maximum remanence flux density in the CT core in pu from the saturation flux density. The value of the parameter r depends on the magnetic material used and also on the construction of the CT. For instance, if the value r = 0.4, the remanence flux density can be 40 percent of the saturation flux density. The manufacturer of the CT has to be contacted when an accurate value for the parameter r is needed. The value r = 0.4 is recommended to be used when an accurate value is not available.

The required minimum time-to-saturate T_m in 87G, 87M is half-fundamental cycle period (10 ms when f_n = 50 Hz).

Two typical cases are considered for the determination of the sufficient actual accuracy limit factor F_a:

1. A fault occurring at the substation bus.

   The protection must be stable at a fault arising during a normal operating situation. The reenergizing of the transformer against a bus fault leads to very high fault currents and thermal stress. Therefore, reenergizing is not preferred in this case. The remanence can be neglected.
   The maximum through-going fault current Ik_{max} is typically 6 I_R for a motor. At a short circuit fault close to the supply transformer, the DC time constant T_{dc} of the fault current is almost the same as that of the transformer, the typical value being 100 ms.

   Ik_{max} = 6 I_R

   T_{dc} = 100 ms

   ω = 100π Hz

   T_m = 10 ms

   K_r = 1

   Equation 114 with these values gives the result:

$$F_a > K_r \times Ik_{\max} \times (T_{dc} \times \omega \times (1 - e^{\frac{-T_m}{T_{dc}}}) + 1) \approx 24$$

2. Reenergizing against a fault occurring further down in the network.

   The protection must be stable also during reenergization against a fault on the line. In this case, the existence of remanence is very probable. It is assumed to be 40 percent here.
   On the other hand, the fault current is now smaller and since the ratio of the resistance and reactance is greater in this location, having a full DC offset is not possible.

Furthermore, the DC time constant (T_{dc}) of the fault current is now smaller, assumed to be 50 ms here.
Assuming the maximum fault current is 30 percent lower than in the bus fault and a DC offset 90 percent of the maximum.

Ik_{max}	$= 0.7 \times 6 = 4.2$ (I_R)
T_{dc}	= 50 ms
ω	= 100π Hz
T_m	= 10 ms
K_r	= 1/(1-0.4) = 1.6667

Equation 114 with these values gives the result:

$$F_a > K_r \times Ik_{\max} \times 0.9 \times (T_{dc} \times \omega \times (1 - e^{\frac{-T_m}{T_{dc}}}) + 1) \approx 24$$

If the actual burden of the current transformer S_a in the accuracy limit factor equation cannot be reduced low enough to provide a sufficient value for F_a, there are two alternatives to deal with the situation.

1. A current transformer with a higher rated burden S_n can be chosen (which also means a higher rated accurate limit F_n).
2. A current transformer with a higher nominal primary current I_{1n} (but the same rated burden) can be chosen.

Alternative 2 is more cost-effective and therefore often better, although the sensitivity of the scheme is slightly reduced.

Example 2

Here the actions according to alternative 2 are taken to improve the actual accuracy limit factor.

$$F_a = \left(\frac{I_R CT}{I_R Motor} \right) \times F_n$$

(Equation 115)

$I_R CT$	rated primary current of the CT, for example, 1500A
$I_R Motor$	rated current of the motor under protection, for example, 1000A
F_n	rated accuracy limit factor of the CT, for example, 30
F_a	actual accuracy limit factor due to oversizing the CT, substituting the values in the equation, F_a = 45

In differential protection it is important that the accuracy limit factors F_a of the phase current transformers at both sides correspond with each other, that is, the burdens of the current transformers on both sides are to be as close to each other as possible. If high inrush or start currents with high DC components pass through the protected object when it is connected to the network, special attention is required for the performance and the burdens of the current transformers and the settings of the function block.

Connection of current transformers

- If the positive directions of the winding 1 and winding 2 protection relay currents are opposite, the *CT connection type* is of "Type 1". The connection examples of "Type 1" are as shown in figures 291 and 292.
- If the positive directions of the winding 1 and winding 2 protection relay currents equate, the *CT connection type* setting parameter is "Type 2". The connection examples of "Type 2" are as shown in figures 293 and 294.
- The default value of the *CT connection type* setting is "Type 1".

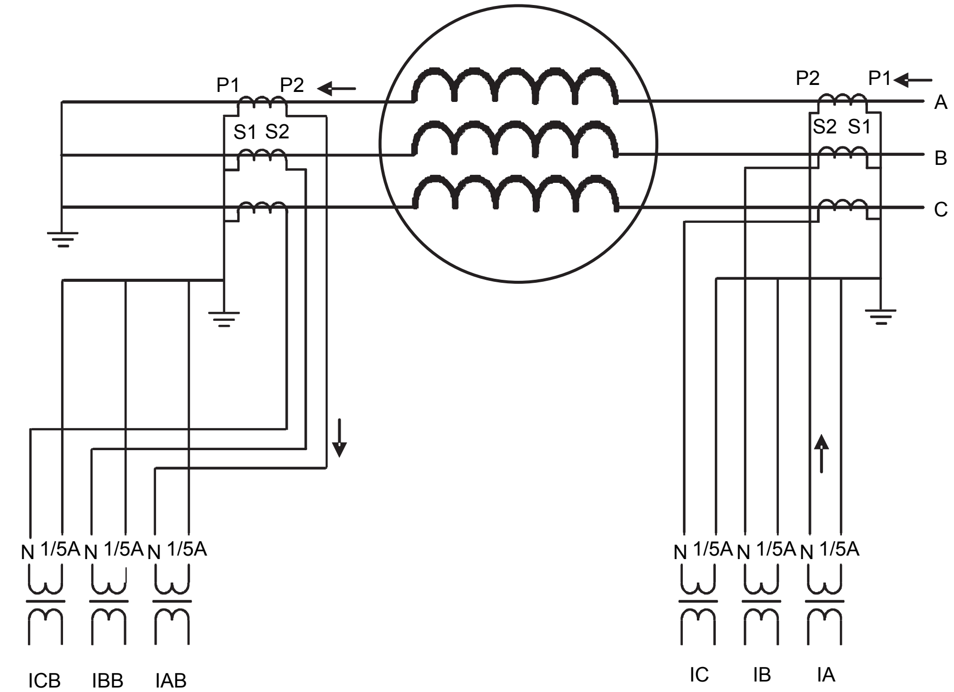


Figure 291: Connection of current transformer of Type 1, example 1

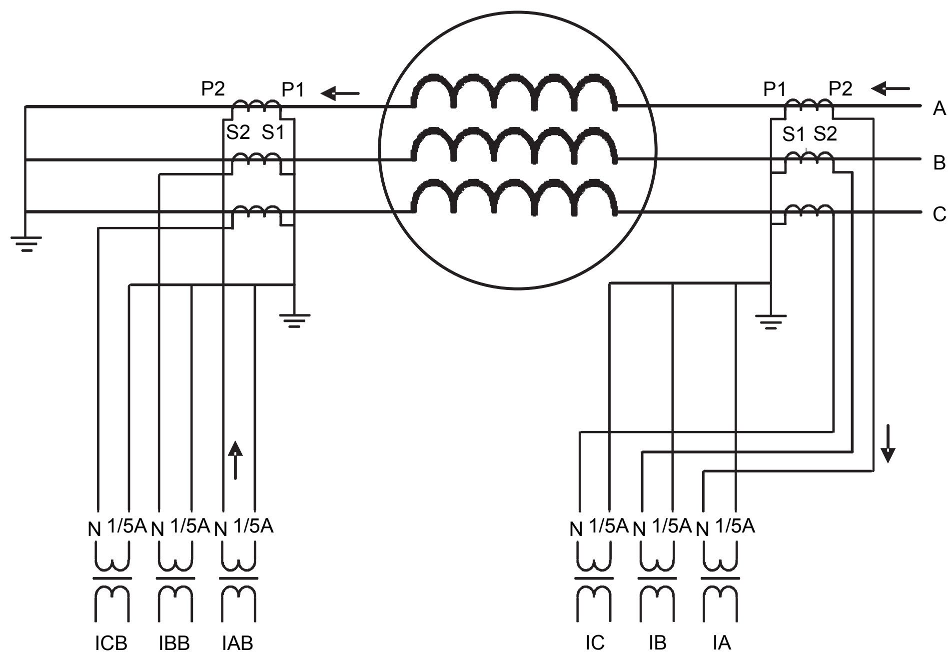


Figure 292: Connection of current transformer of Type 1, example 2

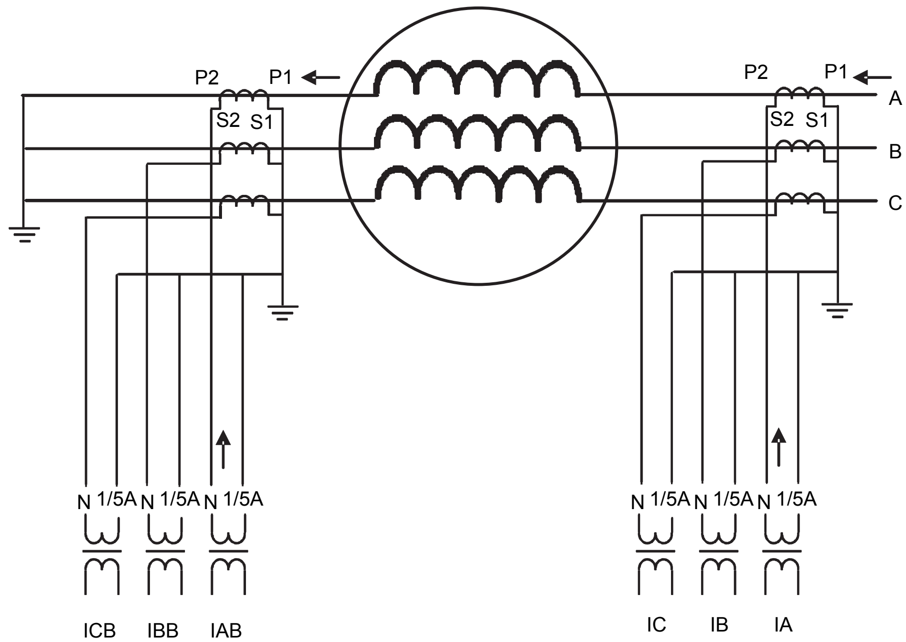


Figure 293: Connection of current transformer of Type 2, example 1

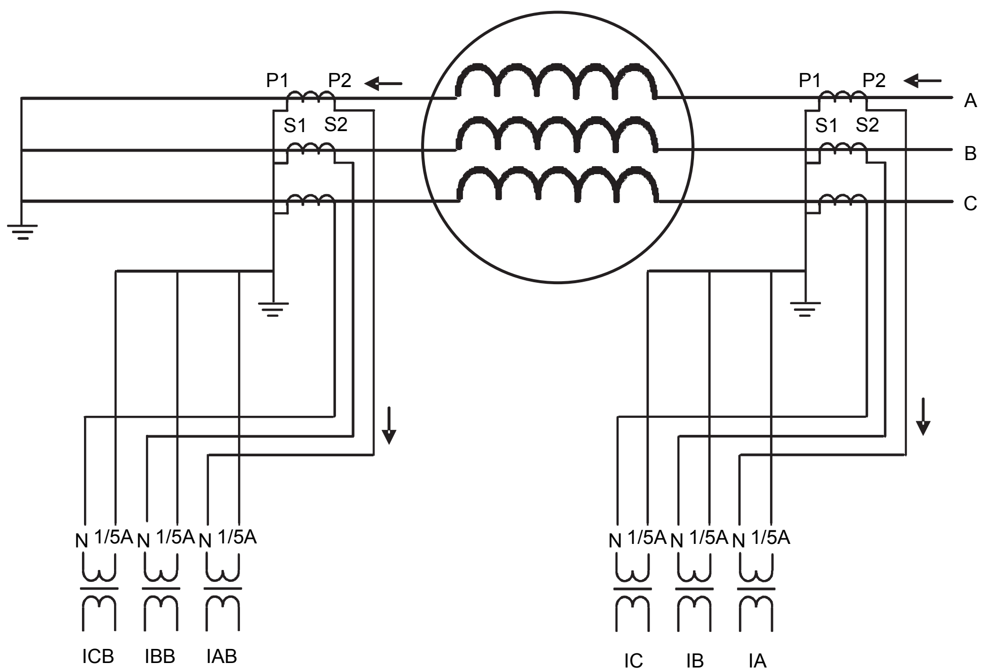


Figure 294: Connection of current transformer of Type 2, example 2

Saturation of current transformers

There are basically two types of saturation phenomena that have to be detected: the AC saturation and the DC saturation. The AC saturation is caused by a high fault current where the CT magnetic flux exceeds its maximum value. As a result, the secondary current is distorted as shown in Figure 295. A DC component in the current also causes the flux to increase until the CT saturates. This is known as DC saturation.

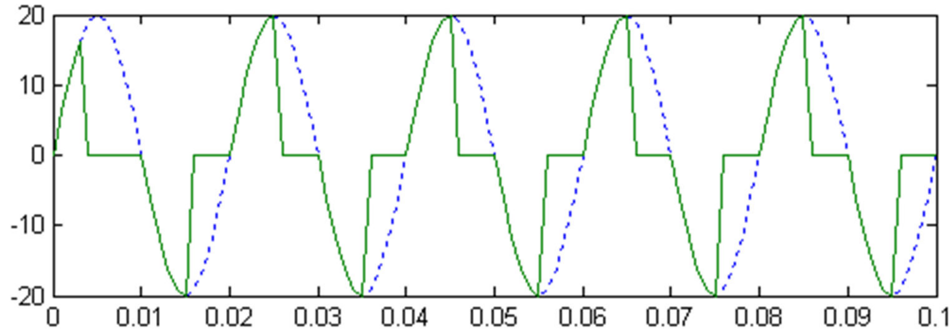


Figure 295: AC saturation

When having a short circuit in a power line, the short circuit current contains a DC component. The magnitude of the DC component depends on the phase angle when the short circuit occurs. Figure 296 shows the secondary current of the CT in the fault situation. Because of the DC component, the flux reaches its maximum value at 0.07 seconds, causing saturation. As the DC component decays, the CT recovers gradually from the saturation.

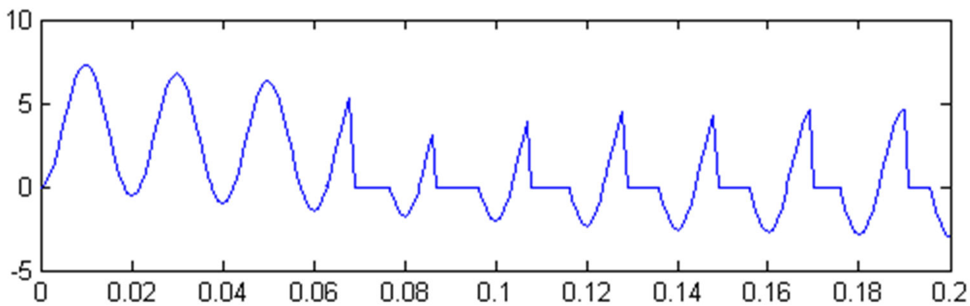


Figure 296: DC saturation

4.3.5.6 Signals

Table 471: 87G, 87M Input signals

Name	Type	Default	Description
I_A1	Signal	0	Phase A primary current
I_B1	Signal	0	Phase B primary current
I_C1	Signal	0	Phase C primary current
I_A2	Signal	0	Phase A secondary current
I_B2	Signal	0	Phase B secondary current
I_C2	Signal	0	Phase C secondary current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
BLK_OPR_LS	BOOLEAN	0=False	Blocks trip outputs from biased stage
BLK_OPR_HS	BOOLEAN	0=False	Blocks trip outputs from instantaneous stage

Table 472: 87G, 87M Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
OPR_LS	BOOLEAN	Trip from low set
OPR_HS	BOOLEAN	Trip from high set
INT_BLKD	BOOLEAN	Internal block status

4.3.5.7 Settings

Table 473: 87G, 87M Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Low trip value	5...30	%Ir	1	5	Basic setting for the stabilized stage pickup
High trip value	100...1000	%Ir	10	500	Instantaneous stage trip value
Slope section 2	10...50	%	1	30	Slope of the second line of the operating characteristics
End section 1	0...100	%Ir	1	50	Turn-point between the first and the second line of the operating characteristics
End section 2	100...300	%Ir	1	150	Turn-point between the second and the third line of the operating characteristics

Table 474: 87G, 87M Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Slope section 3	10...100	%	1	100	Slope of the third line of the operating characteristics
DC restrain enable	0=False 1=True			0=False	Setting for enabling DC restrain feature

Table 475: 87G, 87M Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
CT connection type	1=Type 1 2=Type 2			1=Type 1	CT connection type. Determined by the directions of the connected current transformers
CT ratio Cor Line	0.40...4.00		0.01	1.00	CT ratio correction, line side
CT ratio Cor Neut	0.40...4.00		0.01	1.00	CT ratio correction, neutral side

4.3.5.8 Monitored data

Table 476: 87G, 87M Monitored data

Name	Type	Values (Range)	Unit	Description
OPR_A	BOOLEAN	0=False 1=True		Trip phase A
OPR_B	BOOLEAN	0=False 1=True		Trip phase B
OPR_C	BOOLEAN	0=False 1=True		Trip phase C
INT_BLKD_A	BOOLEAN	0=False 1=True		Internal block status phase A
INT_BLKD_B	BOOLEAN	0=False 1=True		Internal block status phase B
INT_BLKD_C	BOOLEAN	0=False 1=True		Internal block status phase C
ID_A	FLOAT32	0.00...80.00	xIr	Differential current phase A
ID_B	FLOAT32	0.00...80.00	xIr	Differential current phase B
ID_C	FLOAT32	0.00...80.00	xIr	Differential current phase C
IB_A	FLOAT32	0.00...80.00	xIr	Biasing current phase A
IB_B	FLOAT32	0.00...80.00	xIr	Biasing current phase B
IB_C	FLOAT32	0.00...80.00	xIr	Biasing current phase C
I_ANGL_A1_B1	FLOAT32	-180.00...180.00	deg	Current phase angle phase A to B, line side
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
I_ANGL_B1_C1	FLOAT32	-180.00...180.00	deg	Current phase angle phase B to C, line side
I_ANGL_C1_A1	FLOAT32	-180.00...180.00	deg	Current phase angle phase C to A, line side
I_ANGL_A2_B2	FLOAT32	-180.00...180.00	deg	Current phase angle Phase AB, neutral side
I_ANGL_B2_C2	FLOAT32	-180.00...180.00	deg	Current phase angle Phase BC, neutral side
I_ANGL_C2_A2	FLOAT32	-180.00...180.00	deg	Current phase angle Phase CA, neutral side
I_ANGL_A1_A2	FLOAT32	-180.00...180.00	deg	Current phase angle diff between line and neutral side, Phase A
I_ANGL_B1_B2	FLOAT32	-180.00...180.00	deg	Current phase angle diff between line and neutral side, Phase B
I_ANGL_C1_C2	FLOAT32	-180.00...180.00	deg	Current phase angle diff between line and neutral side, Phase C
87G	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
IA-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IA
IB-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IB
IC-diff	FLOAT32	0.00...80.00		Measured differential current amplitude phase IC
IA-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IA
IB-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IB
IC-bias	FLOAT32	0.00...80.00		Measured bias current amplitude phase IC

4.3.5.9 Technical data

Table 477: 87G, 87M Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the current measured: f_n ±2 Hz		
		±3% of the set value or ±0.002 x I_n		
Trip time [1)2)]		Minimum	Typical	Maximum
	Low stage	36 ms	40 ms	42 ms
	High stage	18 ms	22 ms	27 ms
Reset time		<40 ms		
Reset ratio		Typically 0.95		
Retardation time		<20 ms		

1) F_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the power output contact

4.4 Unbalance protection

4.4.1 Negative-sequence overcurrent protection 46

4.4.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative-sequence overcurrent protection	NSPTOC	I2>	46

4.4.1.2 Function block

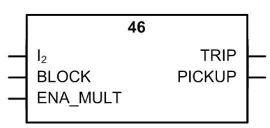


Figure 297: Function block

4.4.1.3 Functionality

The negative-sequence overcurrent protection function 46 is used for increasing sensitivity to detect single-phase and phase-to-phase faults or unbalanced loads due to, for example, broken conductors or unsymmetrical feeder voltages.

46 can also be used for detecting broken conductors.

The function is based on the measurement of the negative sequence current. In a fault situation, the function picks up when the negative sequence current exceeds the set limit. The trip time characteristics can be selected to be either definite time (DT) or inverse definite minimum time (IDMT). In the DT mode, the function trips after a predefined trip time and resets when the fault current disappears. The IDMT mode provides current-dependent timer characteristics.

The function contains a blocking functionality. It is possible to block function outputs, timers or the function itself, if desired.

4.4.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 46 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

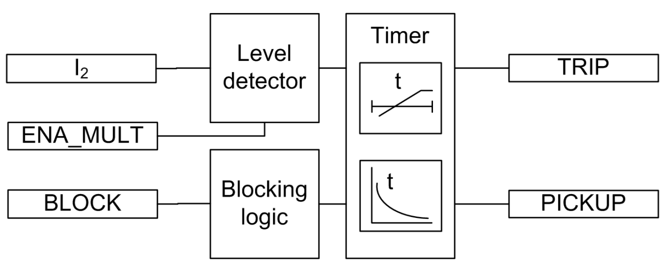


Figure 298: Functional module diagram

Level detector

The measured negative sequence current is compared to the set *Pickup value*. If the measured value exceeds the set *Pickup value*, the level detector activates the timer module. If the `ENA_MULT` input is active, the set *Pickup value* is multiplied by the set *Pickup value Mult*.

The protection relay does not accept the *Pickup value* or *Pickup value Mult* setting if the product of the settings exceeds the *Pickup value* setting range.

Timer

Once activated, the timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value of *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated.

When the user-programmable IDMT curve is selected, the operation time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation happens, that is, a fault suddenly disappears before the trip delay is exceeded, the timer reset state is activated. The functionality of the timer in the reset state depends on the combination of the *Operating curve type*, *Type of reset curve* and *Reset delay time* settings. When the DT characteristic is selected, the reset timer runs until the set *Reset delay time* value is exceeded. When the IDMT curves are selected, the *Type of reset curve* setting can be set to "Immediate", "Def time reset" or "Inverse reset". The reset curve type "Immediate" causes an immediate reset. With the reset curve type "Def time reset", the reset time depends on the *Reset delay time* setting. With the reset curve type "Inverse reset", the reset time depends on the current during the drop-off situation. The `PICKUP` output is deactivated when the reset timer has elapsed.

The "Inverse reset" selection is only supported with ANSI or user programmable types of the IDMT operating curves. If another operating curve type is selected, an immediate reset occurs during the drop-off situation.

The setting *Time multiplier* is used for scaling the IDMT trip and reset times.

The setting parameter *Minimum trip time* defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with great care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.4.1.5 Application

Since the negative sequence current quantities are not present during normal, balanced load conditions, the negative sequence overcurrent protection elements can be set for faster and more sensitive operation than the normal phase-overcurrent protection for fault conditions occurring between two phases. The negative sequence overcurrent protection also provides a back-up protection functionality for the feeder ground-fault protection in solid and low resistance grounded networks.

The negative sequence overcurrent protection provides the back-up ground-fault protection on the high voltage side of a delta-wye connected power transformer for ground faults taking place on the wye-connected low voltage side. If a ground fault occurs on the wye-connected side of the power transformer, negative sequence current quantities appear on the delta-connected side of the power transformer.

Probably the most common application for the negative sequence overcurrent protection is rotating machines, where negative sequence current quantities indicate unbalanced loading conditions (unsymmetrical voltages). Unbalanced loading normally causes extensive heating of the machine and can result in severe damage even over a relatively short time period.

Multiple time curves and time multiplier settings are also available for coordinating with other devices in the system.

4.4.1.6 Signals

Table 478: 46 Input signals

Name	Type	Default	Description
I_2	SIGNAL	0	Negative phase sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_MULT	BOOLEAN	0=False	Enable signal for current multiplier

Table 479: 46 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.4.1.7 Settings

Table 480: 46 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.01...5.00	xIn	0.01	0.30	Pickup value
Pickup value mult	0.8...10.0		0.1	1.0	Multiplier for scaling the pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...200000	ms	10	40	Trip delay time
Operating curve type	1=ANSI Ext Inv 2=ANSI Very Inv 3=ANSI Norm Inv 4=ANSI Mod Inv 5=ANSI DT 6=LT Ext Inv 7=LT Very Inv 8=LT Inv 9=IEC Norm Inv 10=IEC Very Inv 11=IEC Inv 12=IEC Ext Inv 13=IEC ST Inv 14=IEC LT Inv 15=IEC DT 17=Programmable 18=RI Type 19=RD Type			15=IEC DT	Selection of time delay curve type

Table 481: 46 Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset			1=Immediate	Selection of reset curve type

Table 482: 46 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Curve parameter A	0.0086...120.0000		1	28.2000	Parameter A for customer programmable curve
Curve parameter B	0.0000...0.7120		1	0.1217	Parameter B for customer programmable curve
Curve parameter C	0.02...2.00		1	2.00	Parameter C for customer programmable curve
Curve parameter D	0.46...30.00		1	29.10	Parameter D for customer programmable curve
Curve parameter E	0.0...1.0		1	1.0	Parameter E for customer programmable curve

Table 483: 46 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	20...60000	ms	1	20	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time

4.4.1.8 Monitored data

Table 484: 46 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
46	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.4.1.9 Technical data

Table 485: 46 Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n		
		±1.5% of the set value or ±0.002 × I_n		
Pickup time [1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 2 × set *Pickup value* I_{Fault} = 10 × set *Pickup value*	23 ms 15 ms	26 ms 18 ms	28 ms 20 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<35 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode		±5.0% of the theoretical value or ±20 ms [3)]		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…		

1) Negative sequence current before fault = 0.0, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 2.5 × I_n, *Pickup value* multiples in range of 1.5...20

4.4.1.10 Technical revision history

Table 486: 46 Technical revision history

Technical revision	Change
B	Minimum and default values changed to 40 ms for the *Trip delay time* setting
C	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting
D	Internal improvement
E	Internal Improvements

4.4.2 Phase discontinuity protection 46PD

4.4.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase discontinuity protection	PDNSPTOC	I2/I1>	46PD

4.4.2.2 Function block

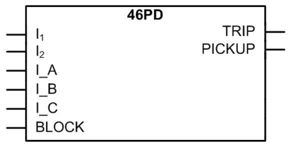


Figure 299: Function block

4.4.2.3 Functionality

The phase discontinuity protection function 46PD is used for detecting unbalance situations caused by broken conductors.

The function picks up and trips when the unbalance current I_2/I_1 exceeds the set limit. To prevent faulty operation at least one phase current needs to be above the minimum level. 46PD trips with DT characteristic.

The function contains a blocking functionality. It is possible to block the function output, timer or the function itself, if desired.

4.4.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 46PD can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

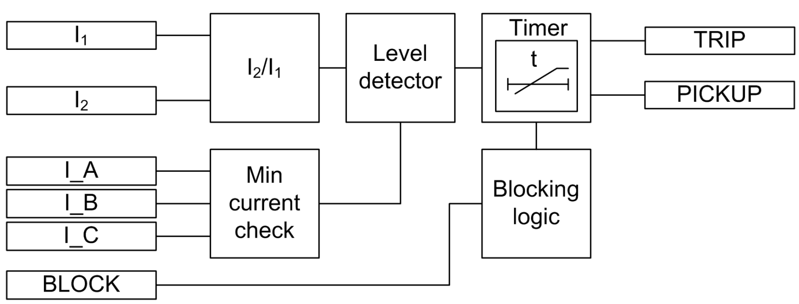


Figure 300: Functional module diagram

I_2/I_1

The I_2/I_1 module calculates the ratio of the negative and positive sequence current. It reports the calculated value to the level detector.

Level detector

The level detector compares the calculated ratio of the negative and positive-sequence currents to the set *Pickup value*. If the calculated value exceeds the set *Pickup value* and the min current check module has exceeded the value of *Min phase current*, the level detector reports the exceeding of the value to the timer.

Min current check

The min current check module checks whether the measured phase currents are above the set *Min phase current*. At least one of the phase currents needs to be above the set limit to enable the level detector module.

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated. If the fault disappears before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.4.2.5 Application

In three-phase distribution and subtransmission network applications the phase discontinuity in one phase can cause an increase of zero-sequence voltage and short overvoltage peaks and also oscillation in the corresponding phase.

46PD is a three-phase protection with DT characteristic, designed for detecting broken conductors in distribution and subtransmission networks. The function is applicable for both overhead lines and underground cables.

The operation of 46PD is based on the ratio of positive-sequence and negative-sequence currents. This gives better sensitivity and stability compared to plain negative-sequence current protection since the calculated ratio of positive-sequence and negative-sequence currents is relatively constant during load variations.

The unbalance of the network is detected by monitoring the negative-sequence and positive-sequence current ratio, where the negative-sequence current value is I_2 and I_1 is the positive-sequence current value. The unbalance is calculated with the equation.

$$Iratio = \frac{I_2}{I_1}$$

(Equation 116)

Broken conductor fault situation can occur in phase A in a feeder.

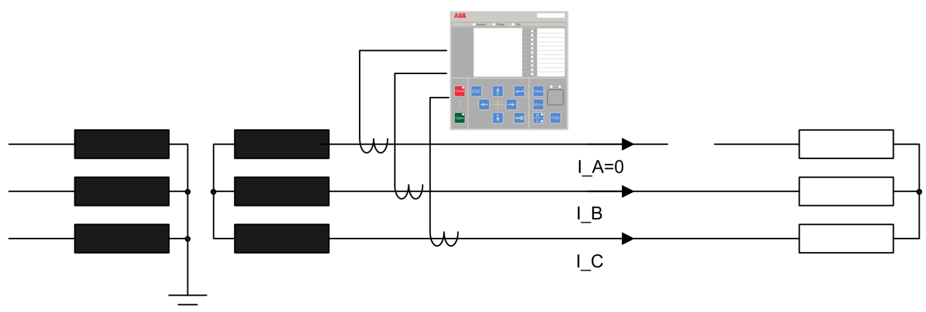


Figure 301: Broken conductor fault in phase A in a distribution or subtransmission feeder

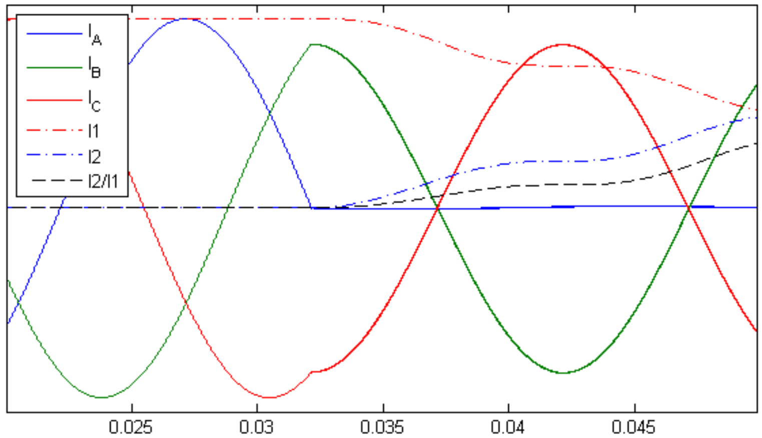


Figure 302: Three-phase current quantities during the broken conductor fault in phase A with the ratio of negative-sequence and positive-sequence currents

4.4.2.6 Signals

Table 487: 46PD Input signals

Name	Type	Default	Description
I_1	SIGNAL	0	Positive sequence current
I_2	SIGNAL	0	Negative sequence current
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 488: 46PD Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.4.2.7 Settings

Table 489: 46PD Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	10...100	%	1	10	Pickup value
Trip delay time	100...30000	ms	1	100	Trip delay time

Table 490: 46PD Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 491: 46PD Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
Min phase current	0.05...0.30	xIn	0.01	0.10	Minimum phase current

4.4.2.8 Monitored data

Table 492: 46PD Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
RATIO_I2_I1	FLOAT32	0.00...999.99	%	Measured current ratio I2 / I1
46PD	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.4.2.9 Technical data

Table 493: 46PD Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±2% of the set value
Pickup time	<70 ms
Reset time	Typically 40 ms
Table continues on next page	

Characteristic	Value
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

4.4.2.10 Technical revision history

Table 494: 46PD Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement
D	Internal improvement

4.4.3 Phase reversal protection 46R

4.4.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Phase reversal protection	PREVPTOC	I2>>	46R

4.4.3.2 Function block

Figure 303: Function block

4.4.3.3 Functionality

The phase reversal protection function 46R is used to detect the reversed connection of the phases to a three-phase motor by monitoring the negative phase sequence current I_2 of the motor.

46R picks up and trips when I_2 exceeds the set limit. 46R operates on definite time (DT) characteristics. 46R is based on the calculated I_2, and the function detects too high I_2

values during the motor start-up. The excessive I_2 values are caused by incorrectly connected phases, which in turn makes the motor rotate in the opposite direction.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.4.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 46R can be described with a module diagram. All the modules in the diagram are explained in the next sections.

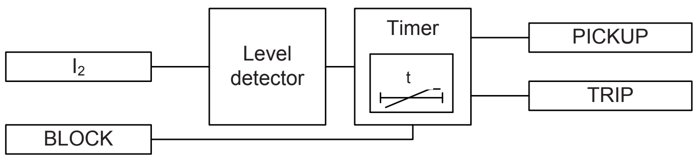


Figure 304: Functional module diagram

Level detector

The level detector compares the negative-sequence current to the set *Pickup value*. If the I_2 value exceeds the set *Pickup value*, the level detector sends an enabling signal to the timer module.

Timer

Once activated, the timer activates the `PICKUP` output. When the operation timer has reached the set *Trip delay time* value, the `TRIP` output is activated. If the fault disappears before the module trips, the reset timer is activated. If the reset timer reaches the value of 200 ms, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

4.4.3.5 Application

The rotation of a motor in the reverse direction is not a desirable operating condition. When the motor drives fans and pumps, for example, and the rotation direction is reversed due to a wrong phase sequence, the driven process can be disturbed and the flow of the cooling air of the motor can become reversed too. With a motor designed only for a particular rotation direction, the reversed rotation direction can lead to an inefficient cooling of the motor due to the fan design.

In a motor, the value of the negative-sequence component of the phase currents is very negligible when compared to the positive-sequence component of the current during a healthy operating condition of the motor. But when the motor is started with the phase connections in the reverse order, the magnitude of I_2 is very high. So whenever the value of I_2 exceeds the pickup value, the function detects the reverse rotation direction and provides an operating signal that disconnects the motor from the supply.

4.4.3.6 Signals

Table 495: 46R Input signals

Name	Type	Default	Description
I_2	SIGNAL	0	Negative sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 496: 46R Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.4.3.7 Settings

Table 497: 46R Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...1.00	xIn	0.01	0.75	Pickup value
Trip delay time	100...60000	ms	10	100	Trip delay time

Table 498: 46R Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

4.4.3.8 Monitored data

Table 499: 46R Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
46R	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.4.3.9 Technical data

Table 500: 46R Technical data

<table>
<tr><th colspan="2">Characteristic</th><th colspan="3">Value</th></tr>
<tr><td colspan="2" rowspan="2">Operation accuracy</td><td colspan="3">Depending on the frequency of the measured current: f_n ±2 Hz</td></tr>
<tr><td colspan="3">±1.5% of the set value or ±0.002 × I_n</td></tr>
<tr><td rowspan="2">Pickup time[1)2)]</td><td rowspan="2">I_{Fault} = 2.0 × set Pickup value</td><td>Minimum</td><td>Typical</td><td>Maximum</td></tr>
<tr><td>23 ms</td><td>25 ms</td><td>28 ms</td></tr>
<tr><td colspan="2">Reset time</td><td colspan="3">Typically 40 ms</td></tr>
<tr><td colspan="2">Reset ratio</td><td colspan="3">Typically 0.96</td></tr>
<tr><td colspan="2">Retardation time</td><td colspan="3"><35 ms</td></tr>
<tr><td colspan="2">Trip time accuracy in definite time mode</td><td colspan="3">±1.0% of the set value or ±20 ms</td></tr>
<tr><td colspan="2">Suppression of harmonics</td><td colspan="3">DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…</td></tr>
</table>

1) Negative-sequence current before = 0.0, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.4.3.10 Technical revision history

Table 501: PREVPTOC Technical revision history46R Technical revision history

Technical revision	Change
B	Internal improvement

4.4.4 Negative-sequence overcurrent protection for machines 46M

4.4.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative-sequence overcurrent protection for machines	MNSPTOC	I2>M	46M

4.4.4.2 Function block

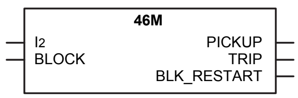


Figure 305: Function block

4.4.4.3 Functionality

The negative-sequence overcurrent protection for machines function 46M protects electric motors from phase unbalance. A small voltage unbalance can produce a large negative-sequence current flow in the motor. For example, a 5 percent voltage unbalance produces a stator negative-sequence current of 30 percent of the full load current, which can severely heat the motor. 46M detects the large negative-sequence current and disconnects the motor.

The function contains a blocking functionality. It is possible to block the function outputs, timers or the function itself, if desired.

4.4.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 46M can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

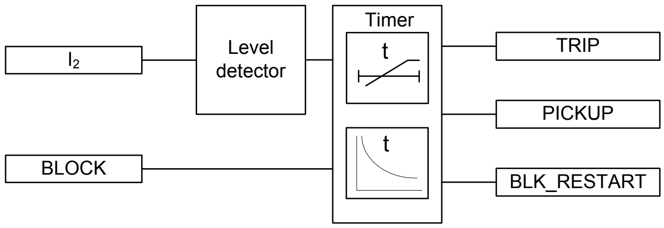


Figure 306: Functional module diagram

Level detector

The calculated negative-sequence current is compared to the *Pickup value* setting. If the measured value exceeds the *Pickup value* setting, the function activates the timer module.

Timer

Once activated, the timer activates the `PICKUP` output. Depending on the value of the set *Operating curve type*, the time characteristics are according to DT or IDMT. When the operation timer has reached the value set by *Trip delay time* in the DT mode or the maximum value defined by the inverse time curve, the `TRIP` output is activated.

In a drop-off situation, that is, when the value of the negative-sequence current drops below the *Pickup value* setting, the reset timer is activated and the `PICKUP` output resets after the time delay of *Reset delay time* for the DT characteristics. For IDMT, the reset time depends on the curve type selected.

For the IDMT curves, it is possible to define minimum and maximum trip times with the *Minimum trip time* and *Maximum trip time* settings. The *Machine time Mult* setting parameter corresponds to the machine constant, equal to the I_2^2t constant of the machine, as stated by the machine manufacturer. In case there is a mismatch between the used CT and the protected motor's nominal current values, it is possible to fit the IDMT curves for the protected motor using the *Rated current* setting.

The activation of the `TRIP` output activates the `BLK_RESTART` output. The deactivation of the `TRIP` output activates the cooling timer. The timer is set to the value entered in the *Cooling time* setting. The `BLK_RESTART` output is kept active until the cooling timer is exceeded. If the negative-sequence current increases above the set value during this period, the `TRIP` output is activated immediately.

The `T_ENARESTART` output indicates the duration for which the `BLK_RESTART` output remains active, that is, it indicates the remaining time of the cooling timer. The value is available in the monitored data view.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

4.4.4.5 Timer characteristics

46M supports both DT and IDMT characteristics. The DT timer characteristics can be selected with "ANSI Def. Time" or "IEC Def. Time" in the *Operating curve type* setting. The functionality is identical in both cases. When the DT characteristics are selected, the functionality is only affected by the *Trip delay time* and *Reset delay time* settings.

The protection relay provides two user-programmable IDMT characteristics curves, "Inv. curve A" and "Inv. curve B".

Current-based inverse definite minimum time curve (IDMT)

In inverse-time modes, the trip time depends on the momentary value of the current: the higher the current, the shorter the trip time. The trip time calculation or integration starts immediately when the current exceeds the set *Pickup value* and the `PICKUP` output is activated.

The `TRIP` output of the component is activated when the cumulative sum of the integrator calculating the overcurrent situation exceeds the value set by the inverse time mode. The set value depends on the selected curve type and the setting values used.

The *Minimum trip time* and *Maximum trip time* settings define the minimum trip time and maximum trip time possible for the IDMT mode. For setting these parameters, a careful study of the particular IDMT curves is recommended.

Inv. curve A

The inverse time equation for curve type A is:

$$t[s] = \frac{k}{\left(\frac{I_2}{I_r}\right)^2}$$

(Equation 117)

t[s]	Trip time in seconds
k	Set *Machine time Mult*
I_2	Negative-sequence current
I_r	Set *Rated current*

If the negative sequence current drops below the *Pickup value* setting, the reset time is defined as:

$$t[s] = a \times \left(\frac{b}{100} \right)$$

(Equation 118)

t[s]	Reset time in seconds
a	set *Cooling time*
b	percentage of pickup time elapse (PICKUP_DUR)

When the reset period is initiated, the time for which PICKUP has been active is saved. If the fault reoccurs, that is, the negative-sequence current rises above the set value during the reset period, the trip calculations are continued using the saved values. If the reset period elapses without a fault being detected, the operation timer is reset and the saved values of pickup time and integration are cleared.

Inv. curve B

The inverse time equation for curve type B is:

$$t[s] = \frac{k}{\left(\frac{I_2}{I_r} \right)^2 - \left(\frac{I_S}{I_r} \right)^2}$$

(Equation 119)

t[s]	Trip time in seconds
k	*Machine time Mult*
I_2	Negative-sequence current
I_S	Set *Pickup value*
I_r	Set *Rated current*

If the fault disappears, the negative-sequence current drops below the *Pickup value* setting and the PICKUP output is deactivated. The function does not reset instantaneously. Resetting depends on the equation or the *Cooling time* setting.

The timer is reset in two ways:

- When the negative sequence current drops below pickup value, the subtraction in the denominator becomes negative and the cumulative sum starts to decrease. The decrease in the sum indicates the cooling of the machine and the cooling speed

depends on the value of the negative-sequence current. If the sum reaches zero without a fault being detected, the accumulation stops and the timer is reset.
- If the reset time set through the *Cooling time* setting elapses without a fault being detected, the timer is reset.

The reset period thus continues for a time equal to the *Cooling time* setting or until the operate time decreases to zero, whichever is less.

4.4.4.6 Application

In a three-phase motor, the conditions that can lead to unbalance are single phasing, voltage unbalance from the supply and single-phase fault. The negative sequence current damages the motor during the unbalanced voltage condition, and therefore the negative sequence current is monitored to check the unbalance condition.

When the voltages supplied to an operating motor become unbalanced, the positive-sequence current remains substantially unchanged, but the negative-sequence current flows due to the unbalance. For example, if the unbalance is caused by an open circuit in any phase, a negative-sequence current flows and it is equal and opposite to the previous load current in a healthy phase. The combination of positive and negative-sequence currents produces phase currents approximately 1.7 times the previous load in each healthy phase and zero current in the open phase.

The negative-sequence currents flow through the stator windings inducing negative-sequence voltage in the rotor windings. This can result in a high rotor current that damages the rotor winding. The frequency of the induced current is approximately twice the supply frequency. Due to skin effect, the induced current with a frequency double the supply frequency encounters high rotor resistance which leads to excessive heating even with phase currents with value less than the rated current of the motor.

The negative-sequence impedance of induction or a synchronous motor is approximately equal to the locked rotor impedance, which is approximately one-sixth of the normal motor impedance, considering that the motor has a locked-rotor current of six times the rated current. Therefore, even a three percent voltage unbalance can lead to 18 percent stator negative sequence current in windings. The severity of this is indicated by a 30-40 percent increase in the motor temperature due to the extra current.

4.4.4.7 Signals

Table 502: 46M Input signals

Name	Type	Default	Description
I_2	SIGNAL	0	Negative sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 503: 46M Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
BLK_RESTART	BOOLEAN	Overheated machine reconnection blocking

4.4.4.8 Settings

Table 504: 46M Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.01...0.50	xIn	0.01	0.20	Pickup value
Operating curve type	5=ANSI DT 15=IEC DT 17=Inv. Curve A 18=Inv. Curve B			15=IEC DT	Selection of time delay curve type
Machine time Mult	5.0...100.0		0.1	5.0	Machine related time constant
Trip delay time	100...120000	ms	10	1000	Trip delay time

Table 505: 46M Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Maximum trip time	500000...7200000	ms	1000	1000000	Max trip time regardless of the inverse characteristic
Minimum trip time	100...120000	ms	1	100	Minimum trip time for IDMT curves
Cooling time	5...7200	s	1	50	Time required to cool the machine

Table 506: 46M Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Rated current	0.30...2.00	xIn	0.01	1.00	Rated current (Ir) of the machine (used only in the IDMT)
Reset delay time	0...60000	ms	1	20	Reset delay time

4.4.4.9 Monitored data

Table 507: 46M Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
T_ENARESTART	INT32	0...10000	s	Estimated time to reset of block restart
46M	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.4.4.10 Technical data

Table 508: 46M Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n		
		±1.5% of the set value or ±0.002 × I_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 2.0 × set *Pickup value*	23	25 ms	28 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<35 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Trip time accuracy in inverse time mode		±5.0% of the theoretical value or ±20 ms[3)]		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…		

1) Negative-sequence current before = 0.0, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) *Pickup value* multiples in range of 1.10...5.00

4.4.4.11 Technical revision history

Table 509: 46M Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

4.5 Voltage protection

4.5.1 Three-phase overvoltage protection 59

4.5.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase overvoltage protection	PHPTOV	3U>	59

4.5.1.2 Function block

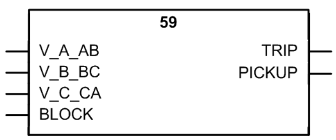


Figure 307: Function block

4.5.1.3 Functionality

The three-phase overvoltage protection function 59 is applied on power system elements, such as generators, transformers, motors and power lines, to protect the system from excessive voltages that could damage the insulation and cause insulation breakdown. The three-phase overvoltage function includes a settable value for the detection of overvoltage either in a single phase, two phases or three phases.

59 includes both definite time (DT) and inverse definite minimum time (IDMT) characteristics for the delay of the trip.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.5.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 59 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

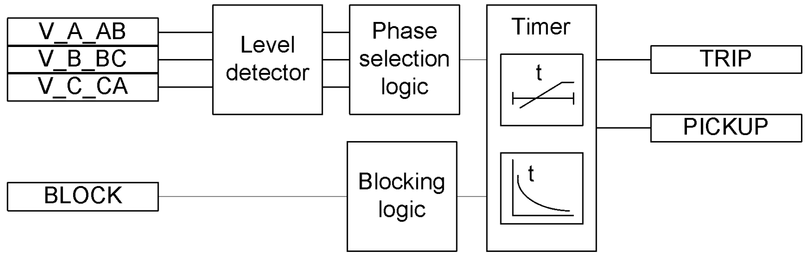


Figure 308: Functional module diagram

Level detector

The fundamental frequency component of the measured three-phase voltages are compared phase-wise to the set value of the *Pickup value* setting. If the measured value is higher than the set value of the *Pickup value* setting, the level detector enables the phase selection logic module. The *Relative hysteresis* setting can be used for preventing unnecessary oscillations if the input signal slightly differs from the *Pickup value* setting. After leaving the hysteresis area, the pickup condition has to be fulfilled again and it is not sufficient for the signal to only return to the hysteresis area.

The *Voltage selection* setting is used for selecting phase-to-ground or phase-to-phase voltages for protection.

For the voltage IDMT operation mode, the used IDMT curve equations contain discontinuity characteristics. The *Curve Sat relative* setting is used for preventing undesired operation.

For a more detailed description of the IDMT curves and the use of the *Curve Sat Relative* setting, see the IDMT curve saturation of the over voltage protection section in this manual.

Phase selection logic

If the fault criteria are fulfilled in the level detector, the phase selection logic detects the phase or phases in which the fault level is detected. If the number of faulty phases match with the set *Num of pickup phases*, the phase selection logic activates the Timer.

Timer

Once activated, the Timer activates the `PICKUP` output. Depending on the value of the set *Operating curve type*, the time characteristics are selected according to DT or IDMT.

For a detailed description of the voltage IDMT curves, see the IDMT curves for overvoltage protection section in this manual.

When the operation timer has reached the value set by *Trip delay time* in the DT mode or the maximum value defined by the IDMT, the TRIP output is activated.

When the user-programmable IDMT curve is selected, the trip time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation occurs, that is, a fault suddenly disappears before the trip delay is exceeded, the reset state is activated. The behavior in the drop-off situation depends on the selected trip time characteristics. If the DT characteristics are selected, the reset timer runs until the set *Reset delay time* value is exceeded. If the drop-off situation exceeds the set *Reset delay time*, the Timer is reset and the PICKUP output is deactivated.

When the IDMT operate time curve is selected, the functionality of the Timer in the drop-off state depends on the combination of the *Type of reset curve* and *Reset delay time* settings.

Table 510: Reset time functionality when IDMT operation time curve selected

Reset functionality		Setting Type of reset curve	Setting Type of time reset	Setting Reset delay time
Instantaneous reset	Operation timer is “Reset instantaneously” when drop-off occurs	“Immediate”	Setting has no effect	Setting has no effect
Frozen timer	Operation timer is frozen during drop-off	“Def time reset”	“Freeze Op timer”	Operate timer is reset after the set *Reset delay time* has elapsed
Linear decrease	Operation timer value linearly decreases during the drop-off situation	“Def time reset”	“Decrease Op timer”	Operate timer is reset after the set *Reset delay time* has elapsed

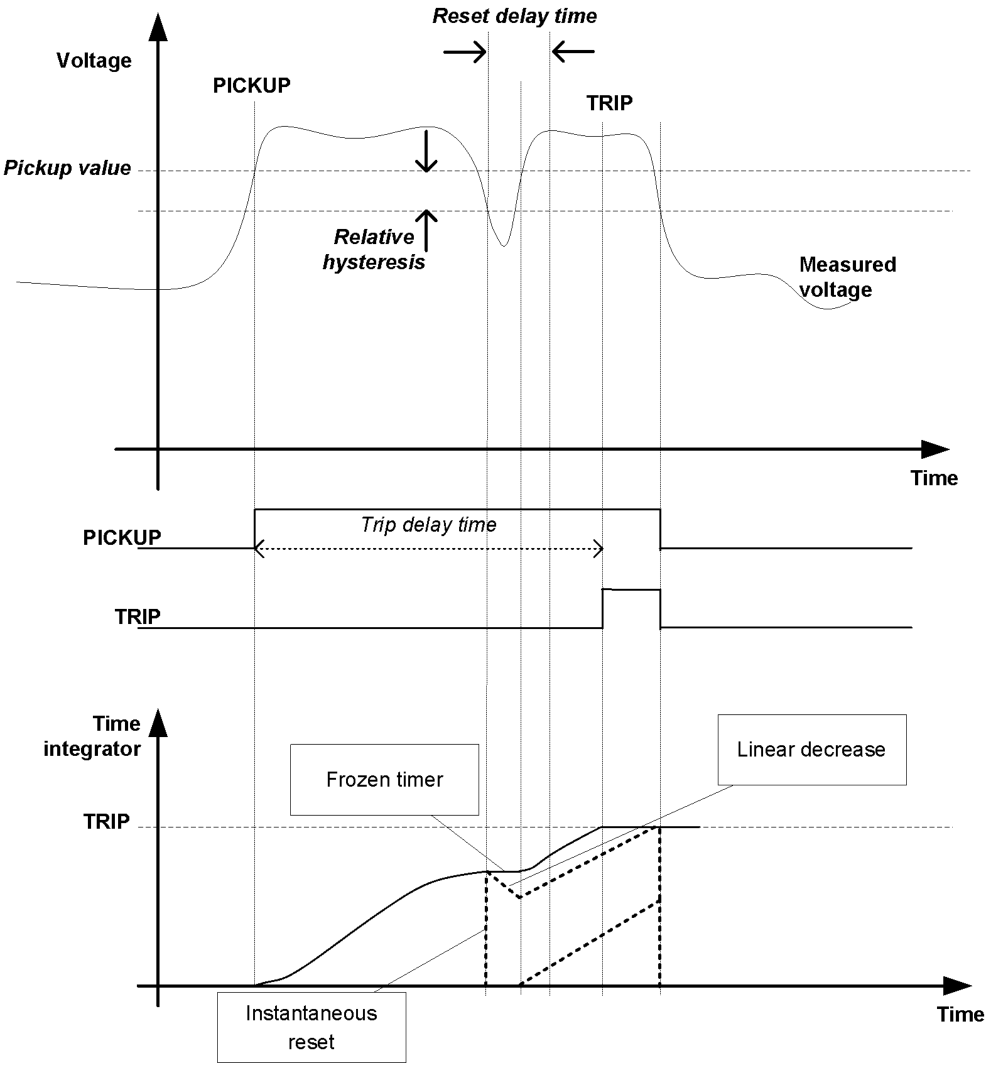


Figure 309: Behavior of different IDMT reset modes. Operate signal is based on settings Type of reset curve = "Def time reset" and Type of time reset= "Freeze Op timer". The effect of other reset modes is also presented

The *Time multiplier* setting is used for scaling the IDMT trip times.

The *Minimum trip time* setting parameter defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overvoltage protection section in this manual.

The Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` input signal activation is preselected with the global *Blocking mode* setting.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` is blocked and the Timers are reset. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

The “Freeze timers” mode of blocking has no effect during the inverse reset mode.

4.5.1.5 Timer characteristics

The operating curve types supported by 59 are:

Table 511: Timer characteristics supported by IDMT operate curve types

Operating curve type
(5) ANSI Def. Time
(15) IEC Def. Time
(17) Inv. Curve A
(18) Inv. Curve B
(19) Inv. Curve C
(20) Programmable

4.5.1.6 Application

Overvoltage in a network occurs either due to the transient surges on the network or due to prolonged power frequency overvoltages. Surge arresters are used to protect the network against the transient overvoltages, but the relay's protection function is used to protect against power frequency overvoltages.

The power frequency overvoltage may occur in the network due to contingencies such as:

- The defective operation of the automatic voltage regulator when the generator is in isolated operation.
- Operation under manual control with the voltage regulator out of service. A sudden variation of load, in particular the reactive power component, gives rise to a substantial change in voltage because of the inherent large voltage regulation of a typical alternator.
- Sudden loss of load due to the tripping of outgoing feeders, leaving the generator isolated or feeding a very small load. This causes a sudden rise in the terminal voltage due to the trapped field flux and overspeed.

If a load sensitive to overvoltage remains connected, it leads to equipment damage.

It is essential to provide power frequency overvoltage protection, in the form of time delayed element, either IDMT or DT to prevent equipment damage.

4.5.1.7 Signals

Table 512: 59 Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 513: 59 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.1.8 Settings

Table 514: 59 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...1.60	xUn	0.01	1.10	Pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	40...300000	ms	10	40	Trip delay time
Operating curve type	5=ANSI DT 15=IEC DT 17=Inv. Curve A 18=Inv. Curve B 19=Inv. Curve C 20=Programmable			15=IEC DT	Selection of time delay curve type

Table 515: 59 Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset			1=Immediate	Selection of reset curve type
Type of time reset	1=Freeze Op timer 2=Decrease Op timer			1=Freeze Op timer	Selection of time reset

Table 516: 59 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.005...200.000		1	1.000	Parameter A for customer programmable curve
Curve parameter B	0.50...100.00		1	1.00	Parameter B for customer programmable curve
Curve parameter C	0.0...1.0		1	0.0	Parameter C for customer programmable curve
Curve parameter D	0.000...60.000		1	0.000	Parameter D for customer programmable curve
Curve parameter E	0.000...3.000		1	1.000	Parameter E for customer programmable curve
Voltage selection	1=phase-to-earth 2=phase-to-phase			2=phase-to-phase	Parameter to select phase or phase-to-phase voltages

Table 517: 59 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	40...60000	ms	1	40	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Curve Sat Relative	0.0...10.0		0.1	0.0	Tuning parameter to avoid curve discontinuities
Relative hysteresis	1.0...5.0	%	0.1	4.0	Relative hysteresis for operation

4.5.1.9 Monitored data

Table 518: 59 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
59	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.1.10 Technical data

Table 519: 59 Technical data

<table>
<tr><th colspan="2">Characteristic</th><th colspan="3">Value</th></tr>
<tr><td colspan="2" rowspan="2">Operation accuracy</td><td colspan="3">Depending on the frequency of the measured voltage: f_n ±2 Hz</td></tr>
<tr><td colspan="3">±1.5% of the set value or ±0.002 × V_n</td></tr>
<tr><td rowspan="2">Pickup time1)2)</td><td rowspan="2">U_{Fault} = 1.1 × set Pickup value</td><td>Minimum</td><td>Typical</td><td>Maximum</td></tr>
<tr><td>23 ms</td><td>27 ms</td><td>31 ms</td></tr>
<tr><td colspan="2">Reset time</td><td colspan="3">Typically 40 ms</td></tr>
<tr><td colspan="2">Reset ratio</td><td colspan="3">Depends on the set Relative hysteresis</td></tr>
<tr><td colspan="2">Retardation time</td><td colspan="3"><35 ms</td></tr>
<tr><td colspan="2">Trip time accuracy in definite time mode</td><td colspan="3">±1.0% of the set value or ±20 ms</td></tr>
<tr><td colspan="2">Trip time accuracy in inverse time mode</td><td colspan="3">±5.0% of the theoretical value or ±20 ms3)</td></tr>
<tr><td colspan="2">Suppression of harmonics</td><td colspan="3">DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…</td></tr>
</table>

1) *Pickup value* = 1.0 × V_n, Voltage before fault = 0.9 × V_n, f_n = 50 Hz, overvoltage in one phase-to-phase with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Maximum *Pickup value* = 1.20 × V_n, *Pickup value* multiples in range of 1.10...2.00

4.5.1.11 Technical revision history

Table 520: 59 Technical revision history

Technical revision	Change
B	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
C	Curve Sat relative max range widened from 3.0 to 10.0 % and default value changed from 2.0 to 0.0 %.
D	Added setting *Type of time reset*.

4.5.2 Three-phase undervoltage protection 27

4.5.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase undervoltage protection	PHPTUV	3U<	27

4.5.2.2 Function block

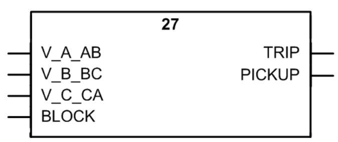


Figure 310: Function block

4.5.2.3 Functionality

The three-phase undervoltage protection function 27 is used to disconnect from the network devices, for example electric motors, which are damaged when subjected to service under low voltage conditions. 27 includes a settable value for the detection of undervoltage either in a single phase, two phases or three phases.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.5.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 27 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

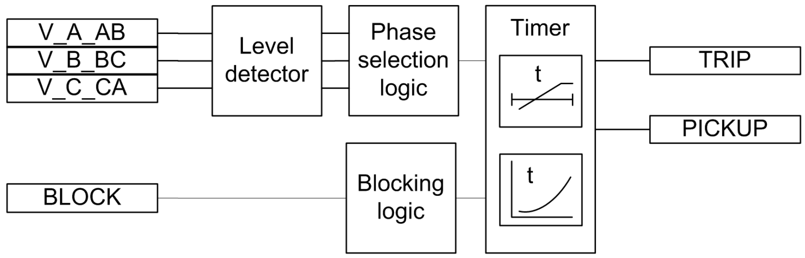


Figure 311: Functional module diagram

Level detector

The fundamental frequency component of the measured three phase voltages are compared phase-wise to the set *Pickup value*. If the measured value is lower than the set value of the *Pickup value* setting, the level detector enables the phase selection logic module. The *Relative hysteresis* setting can be used for preventing unnecessary oscillations if the input signal slightly varies above or below the *Pickup value* setting. After leaving the hysteresis area, the pickup condition has to be fulfilled again and it is not sufficient for the signal to only return back to the hysteresis area.

The *Voltage selection* setting is used for selecting the phase-to-ground or phase-to-phase voltages for protection.

For the voltage IDMT mode of operation, the used IDMT curve equations contain discontinuity characteristics. The *Curve Sat relative* setting is used for preventing unwanted operation.

For more detailed description on IDMT curves and usage of *Curve Sat Relative* setting, see the IDMT curves for under voltage protection section in this manual.

The level detector contains a low-level blocking functionality for cases where one of the measured voltages is below the desired level. This feature is useful when unnecessary pickups and trips are wanted to avoid during, for example, an autoreclose sequence. The low-level blocking is activated by default (*Enable block value* is set to "True") and the blocking level can be set with the *Voltage block value* setting.

Phase selection logic

If the fault criteria are fulfilled in the level detector, the phase selection logic detects the phase or phases in which the fault level is detected. If the number of faulty phases match with the set *Num of pickup phases*, the phase selection logic activates the Timer.

Timer

Once activated, the Timer activates the `PICKUP` output. Depending on the value of the set *Operating curve type*, the time characteristics are selected according to DT or IDMT.

For a detailed description of the voltage IDMT curves, see the IDMT curves for under voltage protection section in this manual.

When the operation timer has reached the value set by *Trip delay time* in the DT mode or the maximum value defined by the IDMT, the `TRIP` output is activated.

When the user-programmable IDMT curve is selected, the trip time characteristics are defined by the parameters *Curve parameter A*, *Curve parameter B*, *Curve parameter C*, *Curve parameter D* and *Curve parameter E*.

If a drop-off situation occurs, that is, a fault suddenly disappears before the trip delay is exceeded, the reset state is activated. The behavior in the drop-off situation depends on the selected trip time characteristics. If the DT characteristics are selected, the reset timer runs until the set *Reset delay time* value is exceeded. If the drop-off situation exceeds the set *Reset delay time*, the Timer is reset and the `PICKUP` output is deactivated.

When the IDMT trip time curve is selected, the functionality of the Timer in the drop-off state depends on the combination of the *Type of reset curve* and *Reset delay time* settings.

Table 521: Reset time functionality when IDMT operation time curve selected

Reset functionality		Setting Type of reset curve	Setting Type of time reset	Setting Reset delay time
Instantaneous reset	Operation timer is “Reset instantaneously” when drop-off occurs	“Immediate”	Setting has no effect	Setting has no effect
Frozen timer	Operation timer is frozen during drop-off	“Def time reset”	“Freeze Op timer”	Operate timer is reset after the set *Reset delay time* has elapsed
Linear decrease	Operation timer value linearly decreases during the drop-off situation	“Def time reset”	“Decrease Op timer”	Operate timer is reset after the set *Reset delay time* has elapsed

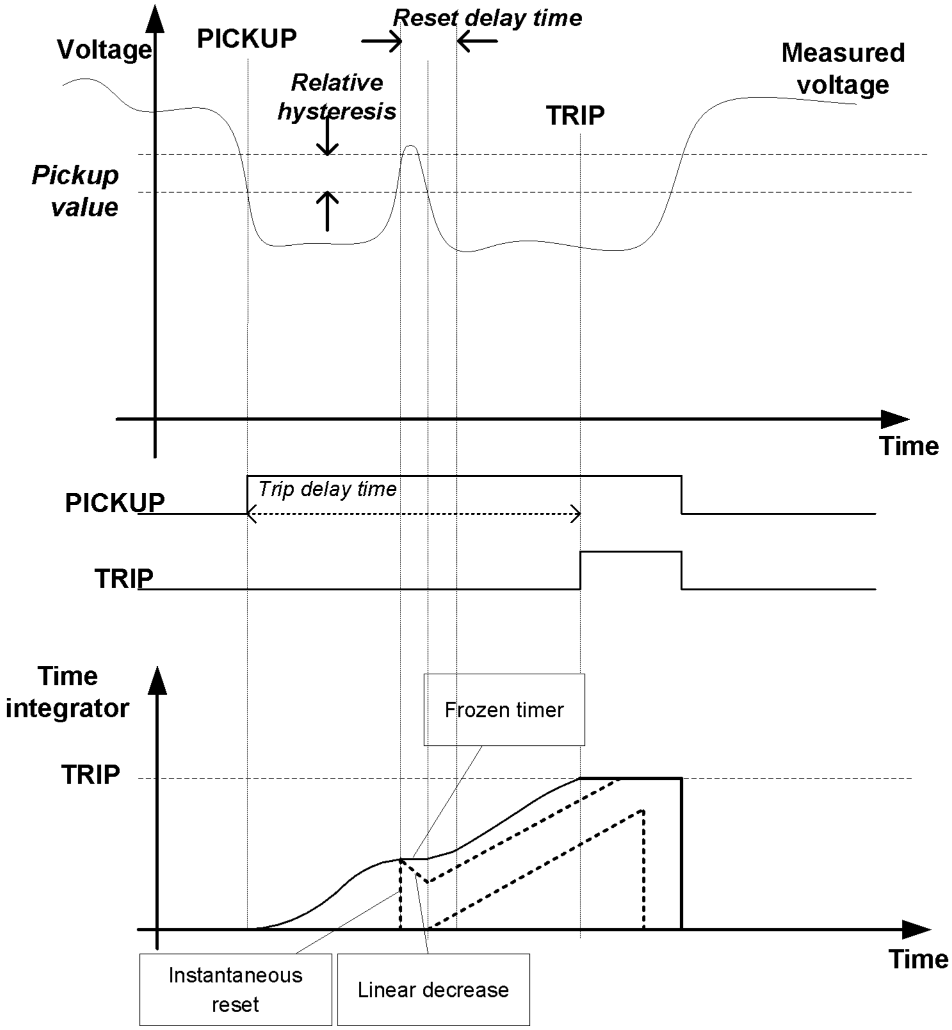


Figure 312: Behavior of different IDMT reset modes. Operate signal is based on settings Type of reset curve = "Def time reset" and Type of time reset= "Freeze Op timer". The effect of other reset modes is also presented

The *Time multiplier* setting is used for scaling the IDMT trip times.

The *Minimum trip time* setting parameter defines the minimum desired trip time for IDMT. The setting is applicable only when the IDMT curves are used.

The *Minimum trip time* setting should be used with care because the operation time is according to the IDMT curve, but always at least the value of the *Minimum trip time* setting. For more information, see the IDMT curves for overcurrent protection section in this manual.

The Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK input signal activation is preselected with the global *Blocking mode* setting.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the Timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

The "Freeze timers" mode of blocking has no effect during the "Inverse reset" mode.

4.5.2.5 Timer characteristics

The operating curve types supported by 27 are:

Table 522: Supported IDMT operate curve types

Operating curve type
(5) ANSI Def. Time
(15) IEC Def. Time
(21) Inv. Curve A
(22) Inv. Curve B
(23) Programmable

4.5.2.6 Application

27 is applied to power system elements, such as generators, transformers, motors and power lines, to detect low voltage conditions. Low voltage conditions are caused by abnormal operation or a fault in the power system. 27 can be used in combination with overcurrent protections. Other applications are the detection of a no-voltage condition, for example before the energization of a high voltage line, or an automatic breaker trip in case

of a blackout. 27 is also used to initiate voltage correction measures, such as insertion of shunt capacitor banks, to compensate for a reactive load and thereby to increase the voltage.

27 can be used to disconnect from the network devices, such as electric motors, which are damaged when subjected to service under low voltage conditions. 27 deals with low voltage conditions at power system frequency. Low voltage conditions can be caused by:

- Malfunctioning of a voltage regulator or incorrect settings under manual control (symmetrical voltage decrease)
- Overload (symmetrical voltage decrease)
- Short circuits, often as phase-to-ground faults (unsymmetrical voltage increase).

27 prevents sensitive equipment from running under conditions that could cause overheating and thus shorten their life time expectancy. In many cases, 27 is a useful function in circuits for local or remote automation processes in the power system.

4.5.2.7 Signals

Table 523: 27 Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 524: 27 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.2.8 Settings

Table 525: 27 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.05...1.20	xUn	0.01	0.90	Pickup value
Time multiplier	0.05...15.00		0.01	1.00	Time multiplier in IEC/ANSI IDMT curves
Trip delay time	60...300000	ms	10	60	Trip delay time
Operating curve type	5=ANSI DT 15=IEC DT 21=Inv. Curve A 22=Inv. Curve B 23=Programmable			15=IEC DT	Selection of time delay curve type

Table 526: 27 Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Type of reset curve	1=Immediate 2=Def time reset			1=Immediate	Selection of reset curve type
Type of time reset	1=Freeze Op timer 2=Decrease Op timer			1=Freeze Op timer	Selection of time reset

Table 527: 27 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required for trip activation
Curve parameter A	0.005...200.000		1	1.000	Parameter A for customer programmable curve
Curve parameter B	0.50...100.00		1	1.00	Parameter B for customer programmable curve
Curve parameter C	0.0...1.0		1	0.0	Parameter C for customer programmable curve
Curve parameter D	0.000...60.000		1	0.000	Parameter D for customer programmable curve
Curve parameter E	0.000...3.000		1	1.000	Parameter E for customer programmable curve
Voltage selection	1=phase-to-earth 2=phase-to-phase			2=phase-to-phase	Parameter to select phase or phase-to-phase voltages

Table 528: 27 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Minimum trip time	60...60000	ms	1	60	Minimum trip time for IDMT curves
Reset delay time	0...60000	ms	1	20	Reset delay time
Curve Sat Relative	0.0...10.0		0.1	0.0	Tuning parameter to avoid curve discontinuities
Voltage block value	0.05...1.00	xUn	0.01	0.20	Low level blocking for undervoltage mode
Enable block value	0=False 1=True			1=True	Enable internal blocking
Relative hysteresis	1.0...5.0	%	0.1	4.0	Relative hysteresis for operation

4.5.2.9 Monitored data

Table 529: 27 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
27	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.2.10 Technical data

Table 530: 27 Technical data

<table>
<tr><th colspan="2">Characteristic</th><th colspan="3">Value</th></tr>
<tr><td colspan="2" rowspan="2">Operation accuracy</td><td colspan="3">Depending on the frequency of the voltage measured: f_n ±2 Hz</td></tr>
<tr><td colspan="3">±1.5% of the set value or ±0.002 × V_n</td></tr>
<tr><td rowspan="2">Pickup time[1)2)]</td><td rowspan="2">U_{Fault} = 0.9 × set Pickup value</td><td>Minimum</td><td>Typical</td><td>Maximum</td></tr>
<tr><td>62 ms</td><td>66 ms</td><td>70 ms</td></tr>
<tr><td colspan="2">Reset time</td><td colspan="3">Typically 40 ms</td></tr>
<tr><td colspan="2">Reset ratio</td><td colspan="3">Depends on the set Relative hysteresis</td></tr>
<tr><td colspan="2">Retardation time</td><td colspan="3"><35 ms</td></tr>
<tr><td colspan="5">Table continues on next page</td></tr>
</table>

Characteristic	Value
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Trip time accuracy in inverse time mode	±5.0% of the theoretical value or ±20 ms[3)]
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) *Pickup value* = 1.0 × V_n, Voltage before fault = 1.1 × V_n, f_n = 50 Hz, undervoltage in one phase-to-phase with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact
3) Minimum *Pickup value* = 0.50, *PIckup value* multiples in range of 0.90...0.20

4.5.2.11 Technical revision history

Table 531: 27 Technical revision history

Technical revision	Change
B	Step value changed from 0.05 to 0.01 for the *Time multiplier* setting.
C	Curve Sat relative max range widened from 3.0 to 10.0 % and default value changed from 2.0 to 0.0 %.
D	Added setting *Type of time reset*.

4.5.3 Residual overvoltage protection 59N, 59G

4.5.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Residual overvoltage protection	ROVPTOV	Uo>	59N, 59G

4.5.3.2 Function block

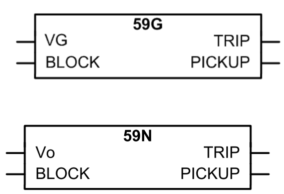


Figure 313: Function block

4.5.3.3 Functionality

The residual overvoltage protection function 59N, 59G is used in distribution networks where the residual overvoltage can reach non-acceptable levels in, for example, high impedance grounding.

The function picks up when the residual voltage exceeds the set limit. 59N, 59G operates with the definite time (DT) characteristic.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.5.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 59N, 59G can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

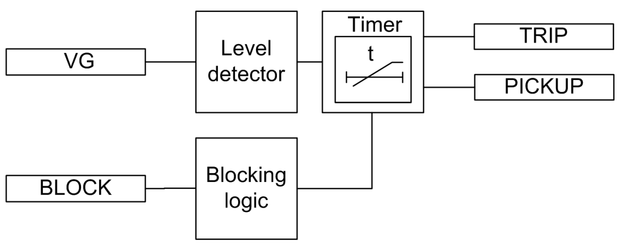


Figure 314: Functional module diagram

Level detector

The residual voltage is compared to the set *Pickup value*. If the value exceeds the set *Pickup value*, the level detector sends an enable signal to the timer. The residual voltage can be selected with the *VG/V0 Select* setting. The options are "Measured VG" and "Calculated V0". If "Measured VG" is selected, the voltage ratio for VG-channel is given in the global setting **Configuration/Analog inputs/Voltage (VG,VT)**. If "Calculated V0" is selected, the voltage ratio is obtained from phase-voltage channels given in the global setting **Configuration/Analog inputs/Voltage (3V,VT)**.

Example 1: VG is measured from the open-delta connected VTs (20/sqrt(3) kV : 100/sqrt(3) V : 100/3 V). In this case, "Measured VG" is selected. The nominal values for residual voltage is obtained from the VT ratios entered in Residual voltage VG: **Configuration/Analog inputs/Voltage (VG,VT)**: 11.547 kV:100 V. The residual voltage pickup value of 1.0 × Vn corresponds to 1.0 × 11.547 kV = 11.547 kV in the primary.

Example 2: V0 is calculated from the phase quantities. The phase VT-ratio is 20/sqrt(3) kV : 100/sqrt(3) V. In this case, "Calculated V0" is selected. The nominal value for residual voltage is obtained from the VT ratios entered in Residual voltage V0: **Configuration/Analog inputs/Voltage (3V,VT)**: 20.000kV : 100V. The residual voltage pickup value of 1.0 × Vn corresponds to 1.0 × 20.000 kV = 20.000 kV in the primary.

If "Calculated V0" is selected, the nominal value of residual voltage is always phase-to-phase voltage. Thus, the valid maximum setting for residual voltage *Pickup value* is 0.577 × Vn. The calculated V0 requires that all three phase-to-ground voltages are connected to the protection relay. V0 cannot be calculated from the phase-to-phase voltages.

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated. If the fault disappears before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the start situation and the set operation time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.5.3.5 Application

59N, 59G is designed to be used for ground-fault protection in isolated neutral, resistance grounded or reactance grounded systems. In compensated networks, the pickup of the function can be used to control the switching device of the neutral resistor. The function can also be used for the back-up protection of feeders for busbar protection when a more dedicated busbar protection would not be justified.

In compensated and isolated neutral systems, the system neutral voltage, that is, the ground voltage, increases in case of any fault connected to ground. Depending on the type of the fault and the fault resistance, the ground voltage reaches different values. The highest ground voltage, equal to the phase-to-ground voltage, is achieved for a single-phase ground fault. The ground voltage increases approximately the same amount in the whole system and does not provide any guidance in finding the faulty component. Therefore, this function is often used as a back-up protection or as a release signal for the feeder ground-fault protection.

The protection can also be used for the ground-fault protection of generators and motors and for the unbalance protection of capacitor banks.

The ground voltage can be calculated internally based on the measurement of the three-phase voltage. This voltage can also be measured by a single-phase voltage transformer, located between a transformer star point and ground, or by using an open-delta connection of three single-phase voltage transformers.

4.5.3.6 Signals

Table 532: 59N,59G Input signals

Name	Type	Default	Description
VG/V0	SIGNAL	0	Residual voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 533: 59N,59G Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.3.7 Settings

Table 534: 59N,59G Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.010...1.000	xUn	0.001	0.030	Pickup value
Trip delay time	40...300000	ms	1	40	Trip delay time

Table 535: 59N,59G Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
VG/V0 Select	1=Measured VG 2=Calculated V0			1=Measured VG	Selection for used VG/V0 signal

Table 536: 59N,59G Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.5.3.8 Monitored data

Table 537: 59N,59G Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
59N,59G	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.3.9 Technical data

Table 538: 59N, 59G Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured voltage: f_n ±2 Hz		
		±1.5% of the set value or ±0.002 × V_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	V_{Fault} = 2 × set *Pickup value*	48 ms	51 ms	54 ms
Table continues on next page				

Characteristic	Value
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) Residual voltage before fault = 0.0 × V_n, f_n = 50 Hz, residual voltage with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.4 Negative-sequence overvoltage protection 47

4.5.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative-sequence overvoltage protection	NSPTOV	U2>	47

4.5.4.2 Function block

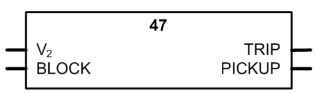


Figure 315: Function block

4.5.4.3 Functionality

The negative-sequence overvoltage protection function 47 is used to detect negative-sequence overvoltage conditions. 47 is used for the protection of machines.

he function picks up when the negative-sequence voltage exceeds the set limit. 47 operates with the definite time (DT) characteristics.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.5.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 47 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

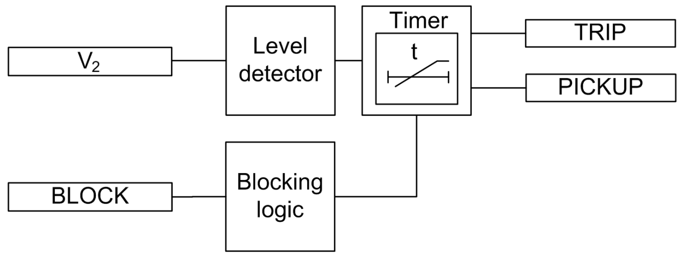


Figure 316: Functional module diagram

Level detector

The calculated negative-sequence voltage is compared to the set *Pickup value* setting. If the value exceeds the set *Pickup value*, the level detector enables the timer.

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated if the overvoltage condition persists. If the negative-sequence voltage normalizes before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.5.4.5 Application

A continuous or temporary voltage unbalance can appear in the network for various reasons. The voltage unbalance mainly occurs due to broken conductors or asymmetrical loads and is characterized by the appearance of a negative-sequence component of the voltage. In rotating machines, the voltage unbalance results in a current unbalance, which heats the rotors of the machines. The rotating machines, therefore, do not tolerate a continuous negative-sequence voltage higher than typically 1-2 percent x V_n.

The negative-sequence component current I_2, drawn by an asynchronous or a synchronous machine, is linearly proportional to the negative-sequence component voltage V_2. When V_2 is P% of V_n, I_2 is typically about 5 x P% x I_n.

The negative-sequence overcurrent 46 blocks are used to accomplish a selective protection against the voltage and current unbalance for each machine separately. Alternatively, the protection can be implemented with the 47 function, monitoring the voltage unbalance of the busbar.

If the machines have an unbalance protection of their own, the 47 operation can be applied as a backup protection or it can be used as an alarm. The latter can be applied when it is not required to trip loads tolerating voltage unbalance better than the rotating machines.

If there is a considerable degree of voltage unbalance in the network, the rotating machines should not be connected to the network at all. This logic can be implemented by inhibiting the closure of the circuit breaker if the 47 operation has picked up. This scheme also prevents connecting the machine to the network if the phase sequence of the network is not correct.

An appropriate value for the setting parameter *Voltage pickup value* is approximately 3 percent of V_n. A suitable value for the setting parameter *Trip delay time* depends on the application. If the 47 operation is used as a backup protection, the trip time should be set in accordance with the trip time of 46 used as the main protection. If the 47 operation is used as the main protection, the trip time should be approximately one second.

4.5.4.6 Signals

Table 539: 47 Input signals

Name	Type	Default	Description
V_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 540: 47 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.4.7 Settings

Table 541: 47 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.010...1.000	xUn	0.001	0.030	Pickup value
Trip delay time	40...120000	ms	1	40	Trip delay time

Table 542: 47 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 543: 47 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.5.4.8 Monitored data

Table 544: 47 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
47	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.4.9 Technical data

Table 545: 47 Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the voltage measured: f_n		
		±1.5% of the set value or ±0.002 × V_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	V_{Fault} = 1.1 × set *Pickup value* V_{Fault} = 2.0 × set *Pickup value*	33 ms 24 ms	35 ms 26 ms	37 ms 28 ms
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		
Retardation time		<35 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…		

1) Negative-sequence voltage before fault = 0.0 × V_n, f_n = 50 Hz, negative-sequence overvoltage with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.4.10 Technical revision history

Table 546: NSPTOV Technical revision history

Technical revision	Change
B	Internal change
C	Internal improvement.
D	Internal improvement.

4.5.5 Positive-sequence undervoltage protection 47U, 27PS

4.5.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Positive-sequence undervoltage protection	PSPTUV	U1<	47U, 27PS

4.5.5.2 Function block

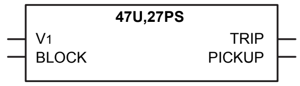


Figure 317: Function block

4.5.5.3 Functionality

The positive-sequence undervoltage protection function 47U, 27PS is used to detect positive-sequence undervoltage conditions. 47U, 27PS is used for the protection of small power generation plants. The function helps in isolating an embedded plant from a fault line when the fault current fed by the plant is too low to cause an overcurrent function to pickup but high enough to maintain the arc. Fast isolation of all the fault current sources is necessary for a successful autoreclosure from the network-end circuit breaker.

The function picks up when the positive-sequence voltage drops below the set limit. 47U, 27PS operates with the definite time (DT) characteristics.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.5.5.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 47U, 27PS can be described using a module diagram. All the modules in the diagram are explained in the next sections.

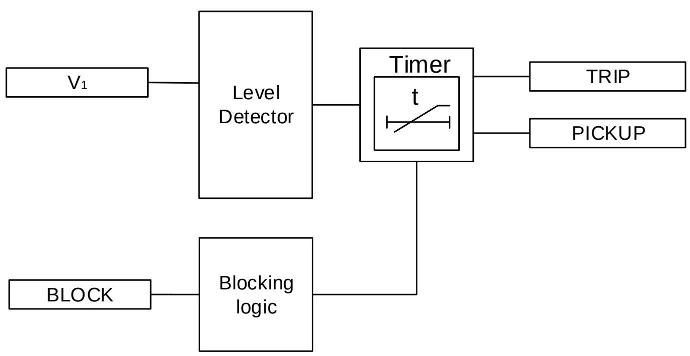


Figure 318: Functional module diagram. V_1 is used for representing positive phase sequence voltage.

Level detector

The calculated positive-sequence voltage is compared to the set *Pickup value* setting. If the value drops below the set *Pickup value*, the level detector enables the timer. The *Relative hysteresis* setting can be used for preventing unnecessary oscillations if the input signal slightly varies from the *Pickup value* setting. After leaving the hysteresis area, the pickup condition has to be fulfilled again and it is not sufficient for the signal to only return to the hysteresis area.

Timer

Once activated, the timer activates the `PICKUP` output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated if the undervoltage condition persists. If the positive-sequence voltage normalizes before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.5.5.5 Application

47U, 27PS can be applied for protecting a power station used for embedded generation when network faults like short circuits or phase-to-ground faults in a transmission or a distribution line cause a potentially dangerous situations for the power station. A network fault can be dangerous for the power station for various reasons. The operation of the protection can cause an islanding condition, also called a loss-of-mains condition, in which a part of the network, that is, an island fed by the power station, is isolated from the rest of the network. There is then a risk of an autoreclosure taking place when the voltages of different parts of the network do not synchronize, which is a straining incident for the power station. Another risk is that the generator can lose synchronism during the network fault. A sufficiently fast trip of the utility circuit breaker of the power station can avoid these risks.

The lower the three-phase symmetrical voltage of the network is, the higher is the probability that the generator loses the synchronism. The positive-sequence voltage is also available during asymmetrical faults. It is a more appropriate criterion for detecting the risk of loss of synchronism than, for example, the lowest phase-to-phase voltage.

Analyzing the loss of synchronism of a generator is rather complicated and requires a model of the generator with its prime mover and controllers. The generator can be able to trip synchronously even if the voltage drops by a few tens of percent for some hundreds of milliseconds. The setting of 47U, 27PS is thus determined by the need to protect the power station from the risks of the islanding conditions since that requires a higher setting value.

The loss of synchronism of a generator means that the generator is unable to operate as a generator with the network frequency but enters into an unstable condition in which it operates by turns as a generator and a motor. Such a condition stresses the generator thermally and mechanically. This kind of loss of synchronism should not be mixed with the one between an island and the utility network. In the islanding situation, the condition of the generator itself is normal but the phase angle and the frequency of the phase-to-phase voltage can be different from the corresponding voltage in the rest of the network. The island can have a frequency of its own relatively fast when fed by a small power station with a low inertia.

47U, 27PS complements other loss-of-grid protection principles based on the frequency and voltage operation.

Motor stalling and failure to start can lead to a continuous undervoltage. The positive-sequence undervoltage is used as a backup protection against the motor stall condition.

4.5.5.6 Signals

Table 547: 47U,27PS Input signals

Name	Type	Default	Description
V_1	SIGNAL	0	Positive phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 548: 47U,27PS Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.5.7 Settings

Table 549: 47U,27PS Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.010...1.200	xUn	0.001	0.500	Pickup value
Trip delay time	40...120000	ms	10	40	Trip delay time

Table 550: 47U,27PS Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage block value	0.01...1.00	xUn	0.01	0.20	Internal blocking level
Enable block value	0=False 1=True			1=True	Enable Internal Blocking

Table 551: 47U,27PS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 552: 47U,27PS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time
Relative hysteresis	1.0...5.0	%	0.1	4.0	Relative hysteresis for operation

4.5.5.8 Monitored data

Table 553: 47U,27PS Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
47U,27PS	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.5.9 Technical data

Table 554: 27PS Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured voltage: f_n ±2 Hz		
		±1.5% of the set value or ±0.002 × V_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	V_{Fault} = 0.99 × set *Pickup value* V_{Fault} = 0.9 × set *Pickup value*	52 ms 44 ms	55 ms 47 ms	58 ms 50 ms
Reset time		Typically 40 ms		
Reset ratio		Depends on the set *Relative hysteresis*		
Retardation time		<35 ms		
Trip time accuracy in definite time mode		±1.0% of the set value or ±20 ms		
Suppression of harmonics		DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…		

1) *Pickup value* = 1.0 × V_n, positive-sequence voltage before fault = 1.1 × V_n, f_n = 50 Hz, positive sequence undervoltage with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.5.10 Technical revision history

Table 555: 47U, 27PS Technical revision history

Technical revision	Change
B	-
C	Internal improvement
D	Internal improvement

4.5.6 Overexcitation protection 24

4.5.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Overexcitation protection	OEPVPH	U/f>	24

4.5.6.2 Function block

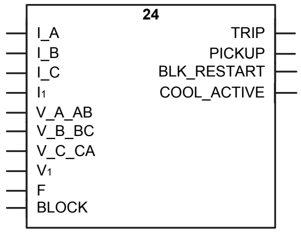


Figure 319: Function block

4.5.6.3 Functionality

The overexcitation protection function 24 is used to protect generators and power transformers against an excessive flux density and saturation of the magnetic core.

The function calculates the V/f ratio (volts/hertz) proportional to the excitation level of the generator or transformer and compares this value to the setting limit. The function picks up when the excitation level exceeds the set limit and trips when the set tripping time has elapsed. The tripping time characteristic can be selected to be either definite time (DT) or overexcitation inverse definite minimum time (overexcitation type IDMT).

This function contains a blocking functionality. It is possible to block the function outputs, reset timer or the function itself, if desired.

4.5.6.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 24 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

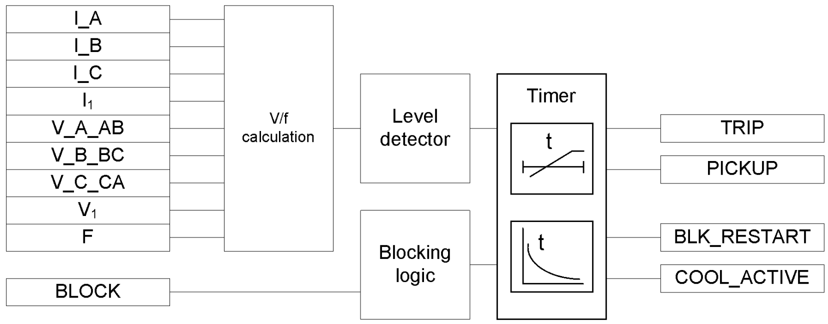


Figure 320: Functional module diagram

V/f calculation

This module calculates the V/f ratio, that is, the excitation level from the internal induced voltage (E) and frequency. The actual measured voltage (V_m) deviates from the internal induced voltage (emf) E, a value the equipment has to withstand. This voltage compensation is based on the load current (I_L) and the leakage reactance (X_{leak}) of the equipment. The leakage reactance of the transformer or generator is set through the *Leakage React* setting in percentage of the Z base.

The internal induced voltage (E) is calculated from the measured voltage. The settings *Voltage selection* and *Phase supervision* determine which voltages and currents are to be used. If the *Voltage selection* setting is set to "phase-to-ground" or "phase-to-phase", the *Phase supervision* setting is used for determining which phases or phase-to-phase voltages ("A or AB", "B or BC" and "C or CA") and currents are to be used for the calculation of the induced voltage.

Table 556: Voltages and currents used for induced voltage (emf) E calculation

Voltage selection setting	Phase supervision setting	Calculation of internal induced voltage (emf) E[1)]
phase-to-ground	A or AB	$\overline{E} = \sqrt{3} \times \left(\overline{V_A} + \overline{I_A} \times (j \times X_{leak}) \right)$
phase-to-ground	B or BC	$\overline{E} = \sqrt{3} \times \left(\overline{V_B} + \overline{I_B} \times (j \times X_{leak}) \right)$
phase-to-ground	C or CA	$\overline{E} = \sqrt{3} \times \left(\overline{V_C} + \overline{I_C} \times (j \times X_{leak}) \right)$
phase-to-phase	A or AB	$\overline{E} = \overline{V_{AB}} + \left((\overline{I_A} - \overline{I_B}) \times (j \times X_{leak}) \right)$
Table continues on next page		

Voltage selection setting	Phase supervision setting	Calculation of internal induced voltage (emf) E[1)]
phase-to-phase	B or BC	$\overline{E} = \overline{V_{BC}} + \left((\overline{I_B} - \overline{I_C}) \times (j \times X_{leak}) \right)$
phase-to-phase	C or CA	$\overline{E} = \overline{V_{CA}} + \left((\overline{I_C} - \overline{I_A}) \times (j \times X_{leak}) \right)$
Pos sequence	N/A	$\overline{E} = \sqrt{3} \times \left(\overline{V_1} + \overline{I_1} \times (j \times X_{leak}) \right)$

1) Voltages, currents and the leakage reactance X_{leak} in the calculations are given in volts, amps and ohms.

If all three phase or phase-to-phase voltages and phase currents are fed to the protection relay, the positive-sequence alternative is recommended.

If the leakage reactance of the protected equipment is unknown or if the measured voltage (V_m) is to be used in the excitation level calculation, then by setting the leakage reactance value to zero the calculated induced voltage (E) is equal to the measured voltage.

The calculated V/f ratio is scaled to a value based on the nominal V_n/f_n ratio. However, the highest allowed continuous voltage (in % V_n) can be defined by setting the parameter *Voltage Max Cont* to change the basis of the voltage. The measured voltage is compared to the new base value to obtain the excitation level.

The excitation level (M) can be calculated:

$$M = \frac{\frac{E}{f_m}}{\frac{V_n}{f_n} \cdot \frac{Volt\ Max\ continuous}{100}}$$

(Equation 120)

M	excitation level (V/f ratio or volts/hertz) in pu
E	internal induced voltage (emf)
f_m	measured frequency
V_n	nominal phase-to-phase voltage
f_n	nominal frequency

If the input frequency (f_m) is less than 20 percent of the nominal frequency (f_n), the calculation of the excitation level is disabled and forced to zero value. This means that the function is blocked from picking up and tripping during a low-frequency condition.

The calculated excitation level (V/f ratio or volts/hertz) VOLTPERHZ is available in the Monitored data view.

Level detector

Level detector compares the calculated excitation level to the *Pickup value* setting. If the excitation level exceeds the set limit, the module sends an enabling signal to start Timer.

Timer

Once activated, Timer activates the `PICKUP` output. Depending on the value of the *Operating curve type* setting, the time characteristics are according to DT or IDMT. When the operation timer has reached the value set by *Trip delay time* in the DT mode or the value defined by the inverse time curve, the `TRIP` output is activated.

In a drop-off situation, that is, when the excitation level drops below *Pickup value* before the function trips, the reset timer is activated and the `PICKUP` output resets after the time delay of *Reset delay time* for the DT characteristics. For the IDMT curves, the reset operation is as described in the Timer characteristics chapter.

For the IDMT curves, it is possible to define the maximum and minimum trip times via the *Minimum trip time* and *Maximum trip time* settings. The *Maximum trip time* setting is used to prevent infinite pickup situations at low degrees of overexcitation. The *Time multiplier* setting is used for scaling the IDMT trip times.

The activation of the `TRIP` output activates the `BLK_RESTART` output.

For the DT characteristics, the deactivation of the `TRIP` output activates the cooling timer. The timer is set to the value entered in the *Cooling time* setting. The `BLK_RESTART` and `COOL_ACTIVE` outputs are kept active until the cooling timer is reset. If the excitation increases above the set value during this period, the `PICKUP` output is activated immediately. For IDMT, the deactivation of `BLK_RESTART` and `COOL_ACTIVE` depends on the curve type selected.

The `T_ENARESTART` output indicates in seconds the duration for which the `BLK_RESTART` output still remains active. The value is available in the Monitored data view.

Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set trip time. The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.5.6.5 Timer characteristics

24 supports both DT and IDMT characteristics. The DT timer characteristics can be selected as "ANSI Def. Time" or "IEC Def. Time" in the *Operating curve type* setting. The functionality is identical in both cases. When the DT characteristics are selected, the functionality is only affected by the *Trip delay time* and *Reset delay time* settings.

24 also supports four overexcitation IDMT characteristic curves: "OvExt IDMT Crv1", "OvExt IDMT Crv2", "OvExt IDMT Crv3" and "OvExt IDMT Crv4".

Overexcitation inverse definite minimum time curve (IDMT)

In the inverse time modes, the trip time depends on the momentary value of the excitation: the higher the excitation level, the shorter the trip time. The trip time calculation or integration starts immediately when the excitation level exceeds the set *Pickup value* and the PICKUP output is activated.

The TRIP output is activated when the cumulative sum of the integrator calculating the overexcitation situation exceeds the value set by the inverse time mode. The set value depends on the selected curve type and the setting values used.

The *Minimum trip time* and *Maximum trip time* settings define the minimum trip time and maximum trip time possible for the IDMT mode. For setting these parameters, a careful study of the particular IDMT curves is recommended.

The tripping time of the function block can vary much between different operating curve types even if other setting parameters for the curves were not changed.

Once activated, the timer activates the PICKUP output for the IDMT curves. If the excitation level drops below the *Pickup value* setting before the function trips, the reset timer is activated. If the fault reoccurs during the reset time, the tripping calculation is made based on the effects of the period when PICKUP was previously active. This is intended to allow a tripping condition to occur in less time to account for the heating effects from the previous active pickup period.

When TRIP becomes active, the reset time is based on the following equation.

$$reset\ time = \left(\frac{PICKUP\_DUR}{100} \right) \cdot Cooling\ time$$

(Equation 121)

For the IDMT curves, when the fault disappears, the integral value calculated during PICKUP is continuously decremented by a constant that causes its value to become zero when the reset time elapses during the reset period. If a fault reoccurs, the integration continues from the current integral value and the pickup time is adjusted, as shown in Figure 321. The pickup time becomes the value at the time when the fault dropped off minus the amount of reset time that occurred. If the reset period elapses without a fault being detected, the saved values of the pickup time and integration are cleared.

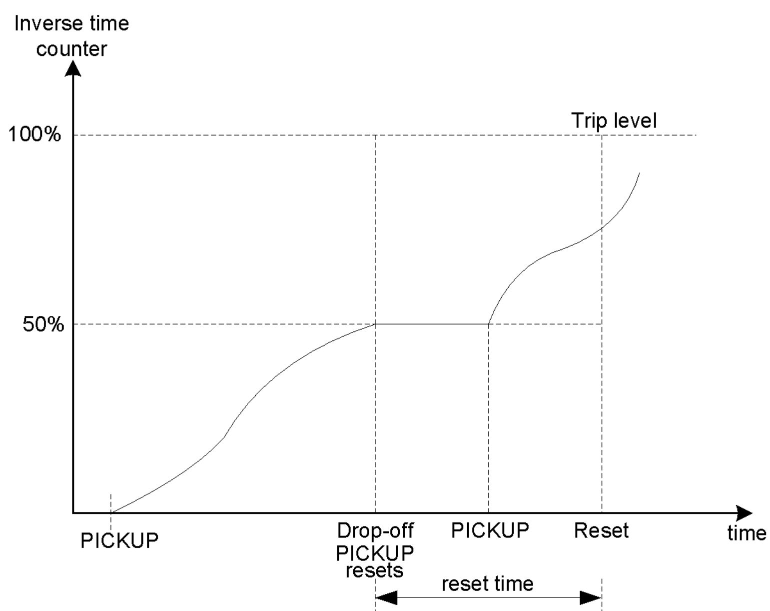


Figure 321: An example of a delayed reset in the inverse time characteristics. When the pickup becomes active during the reset period, the trip time counter continues from the level corresponding to the drop-off (reset time = 0.50 · Cooling time)

Overexcitation IDMT curves 1, 2 and 3

The base equation for the IDMT curves "OvExt IDMT Crv1", "OvExt IDMT Crv2" and "OvExt IDMT Crv3" is:

$$t(s) = 60 \cdot e^{\left(\frac{ak+b-100M}{c}\right)}$$

(Equation 122)

t(s)	Trip time in seconds
M	Excitation level (V/f ratio or volts/hertz) in pu
k	*Time multiplier* setting

The constant "60" in Equation 122 converts time from minutes to seconds.

Table 557: Parameters a, b and c for different IDMT curves

Operating curve type setting	a	b	c
OvExt IDMT Crv1	2.5	115.00	4.886
OvExt IDMT Crv2	2.5	113.50	3.040
OvExt IDMT Crv3	2.5	108.75	2.443

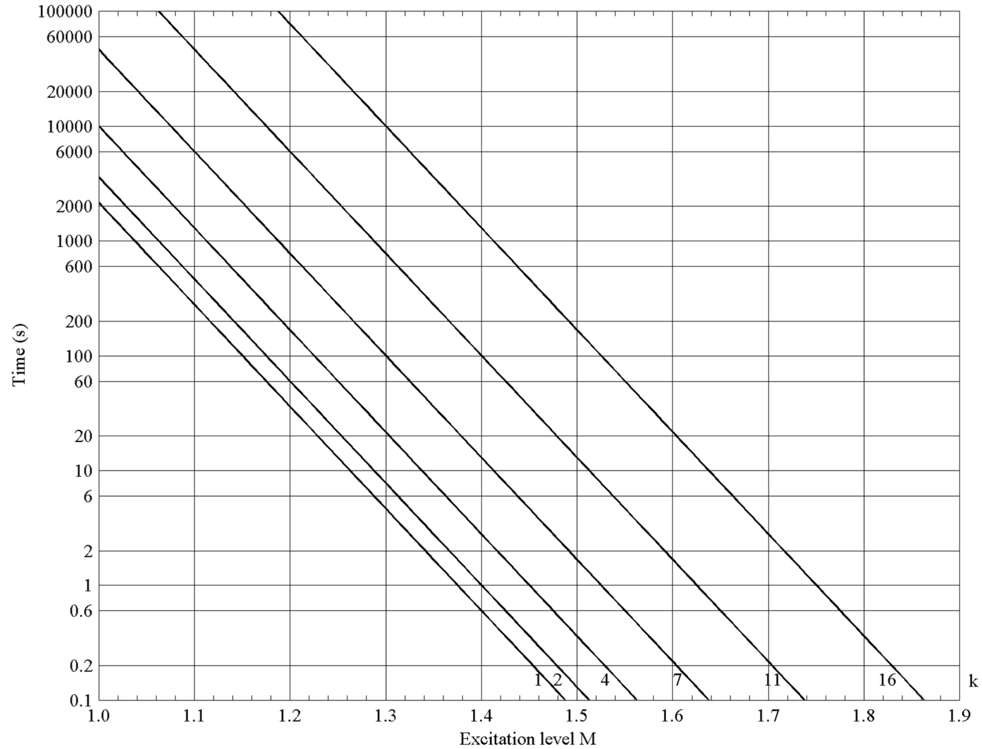


Figure 322: Trip time curves for the overexcitation IDMT curve ("OvExt IDMT Crv1") for parameters a = 2.5, b = 115.0 and c = 4.886

Overexcitation IDMT curve 4

The base equation for the IDMT curve “OvExt IDMT Crv4” is:

$$t(s) = d + \frac{0.18k}{(M-1)^2}$$

(Equation 123)

t(s)	Trip time in seconds
d	*Constant delay* setting in milliseconds
M	Excitation value (V/f ratio or volts/hertz) in pu
k	*Time multiplier* setting

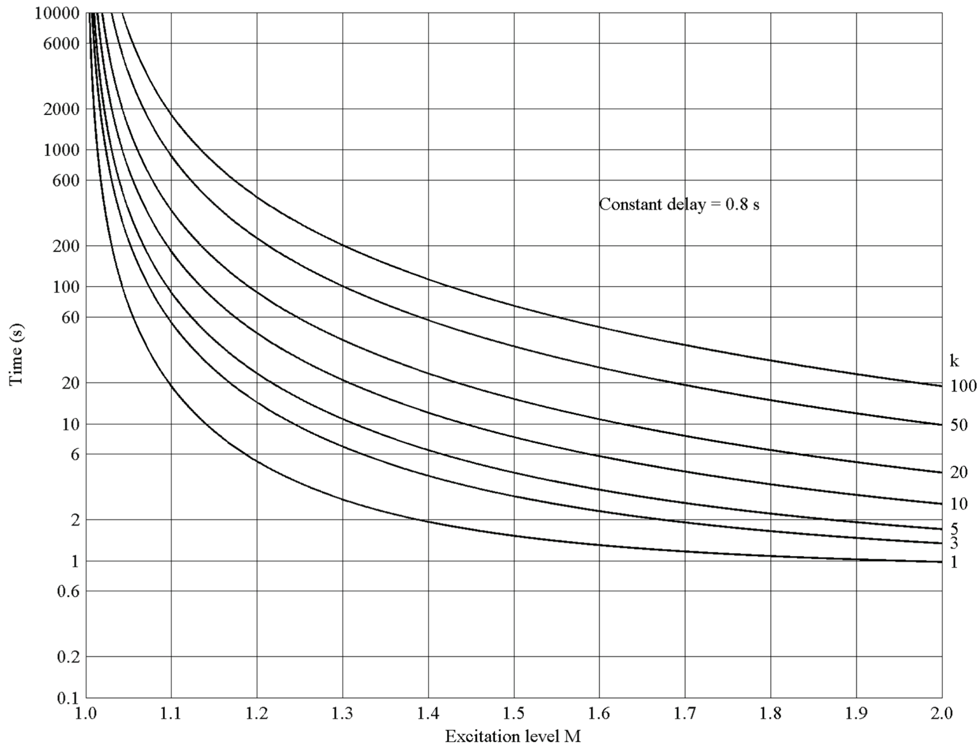


Figure 323: Trip time curves for the overexcitation IDMT curve 4 ("OvExt IDMT Crv4") for different values of the Time multiplier setting when the Constant delay is 800 milliseconds

The activation of the `TRIP` output activates the `BLK_RESTART` output.

If the excitation level increases above the set value when `BLK_RESTART` is active, the `TRIP` output is activated immediately.

If the excitation level increases above the set value when `BLK_RESTART` is not active but `COOL_ACTIVE` is active, the `TRIP` output is not activated instantly. In this case, the remaining part of the cooling timer affects the calculation of the operation timer as shown in Figure 324. This compensates for the heating effect and makes the overall trip time shorter.

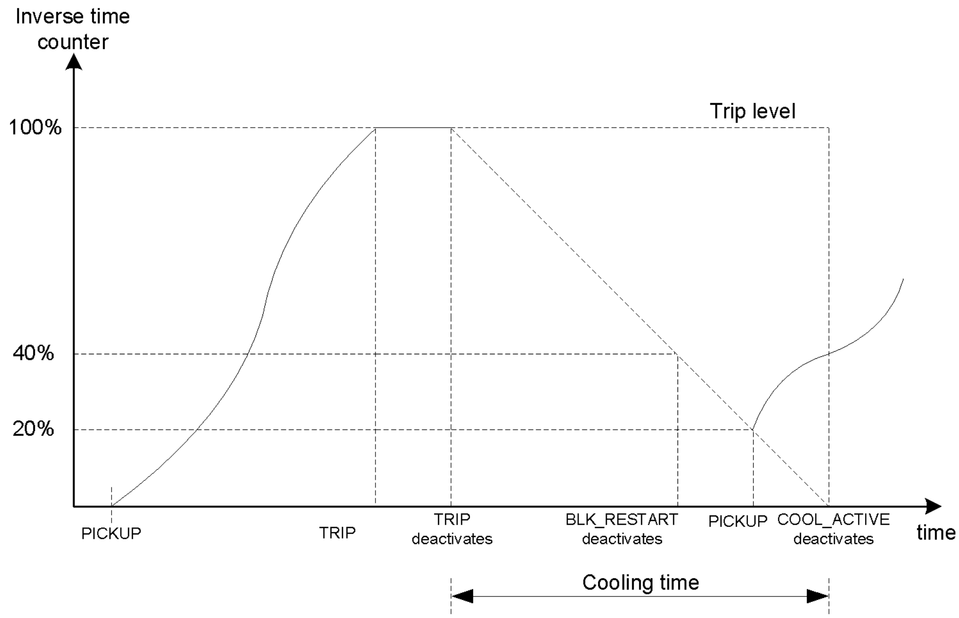


Figure 324: Example of an inverse time counter operation if `TRIP` *occurs when* `BLK_RESTART` *is inactive while* `COOL_ACTIVE` *is active.*

4.5.6.6 Application

If the laminated core of a power transformer or generator is subjected to a magnetic flux density beyond its designed limits, the leakage flux increases. This results in a heavy hysteresis and eddy current losses in the non-laminated parts. These losses can cause excessive heating and severe damage to the insulation and adjacent parts in a relatively short time.

Overvoltage, underfrequency or a combination of the two, results in an excessive flux density level. Since the flux density is directly proportional to the voltage and inversely proportional to the frequency, the overexcitation protection calculates the relative V/Hz ratio instead of measuring the flux density directly. The nominal level (nominal voltage at nominal frequency) is usually considered as the 100 percent level, which can be exceeded slightly based on the design.

The greatest risk for overexcitation exists in a thermal power station when the generator-transformer unit is disconnected from the rest of the network or in the network islands where high voltages or low frequencies can occur.

Overexcitation can occur during the start-up and shutdown of the generator if the field current is not properly adjusted. The loss-of-load or load shedding can also result in overexcitation if the voltage control and frequency governor do not function properly. The low frequency in a system isolated from the main network can result in overexcitation if the voltage-regulating system maintains a normal voltage.

Overexcitation protection for the transformer is generally provided by the generator overexcitation protection, which uses the VTs connected to the generator terminals. The curves that define the generator and transformer V/Hz limits must be coordinated properly to protect both equipment.

If the generator can be operated with a leading power factor, the high-side voltage of the transformer can have a higher pu V/Hz than the generator V/Hz. This needs to be considered in a proper overexcitation protection of the transformer. Also, measurement for the voltage must not be taken from any winding where OLTC is located.

It is assumed that overexcitation is a symmetrical phenomenon caused by events such as loss-of-load. A high phase-to-ground voltage does not mean overexcitation. For example, in an ungrounded power system, a single-phase-to-ground fault means high voltages of the healthy two phases to ground but no overexcitation on any winding. The phase-to-phase voltages remain essentially unchanged. An important voltage to be considered for the overexcitation is the voltage between the two ends of each winding.

Example calculations for overexcitation protection

Example 1

Nominal values of the machine

Nominal phase-to-phase voltage (V_n)	11000 V
Nominal phase current (I_n)	7455 A
Nominal frequency (f_n)	50 Hz
Leakage reactance (X_{leak})	20% or 0.2 pu

Measured voltage and load currents of the machine

Phase A-to-phase B voltage (V_{AB})	11500∠0° V
Phase A current (I_A)	5600∠-63.57° A
Phase B current (I_B)	5600∠176.42° A
Measured frequency (f_m)	49.98 Hz
The setting *Voltage Max Cont*	100%
The setting *Voltage selection*	phase-to-phase
The setting *Phase supervision*	A or AB

The pu leakage reactance X_{leakPU} is converted to ohms.

$$X_{leak\Omega} = X_{leakPU} \cdot \left({V_n}\big/{\left(I_n \cdot \sqrt{3}\right)} \right) = 0.2 \cdot \left({11000}\big/{\left(7455 \cdot \sqrt{3}\right)} \right) = 0.170378\ ohms$$

(Equation 124)

The internal induced voltage E of the machine is calculated.

$$\overline{E} = \overline{V_{AB}} + (\overline{I_A} - \overline{I_B}) \cdot (jX_{leak})$$

(Equation 125)

E = 11500∠0°+ (5600∠-63.57°- 5600∠176.42°) · (0.170378∠90°) = 12490 V

The excitation level M of the machine is calculated.

$$Excitation\, level\ M = \frac{{12490}\big/{49.98}}{{11000}\big/{50} \cdot 1.00} = 1.1359$$

(Equation 126)

Example 2

The situation and the data are according to Example 1. In this case, the manufacturer of the machine allows the continuous operation at 105 percent of the nominal voltage at the rated load and this value to be used as the base for overexcitation.

Usually, the V/f characteristics are specified so that the ratio is 1.00 at the nominal voltage and nominal frequency. Therefore, the value 100 percent for the setting *Voltage Max Cont* is recommended.

If the *Voltage Max Cont* setting is 105 percent, the excitation level M of the machine is calculated with the equation.

$$Excitation\, level\ M = \frac{{12490}\big/{49.98}}{{11000}\big/{50} \cdot 1.05} = 1.0818$$

(Equation 127)

Example 3

In this case, the function operation is according to IDMT. The *Operating curve type* setting is selected as "OvExt IDMT Crv2". The corresponding example settings for the IDMT curve operation are given as: *Pickup value* = 110%, *Voltage Max Cont* = 100%, *Time multiplier* = 4, *Maximum trip time* = 1000 s, *Minimum trip time* = 1 s and *Cooling time* = 200 s.

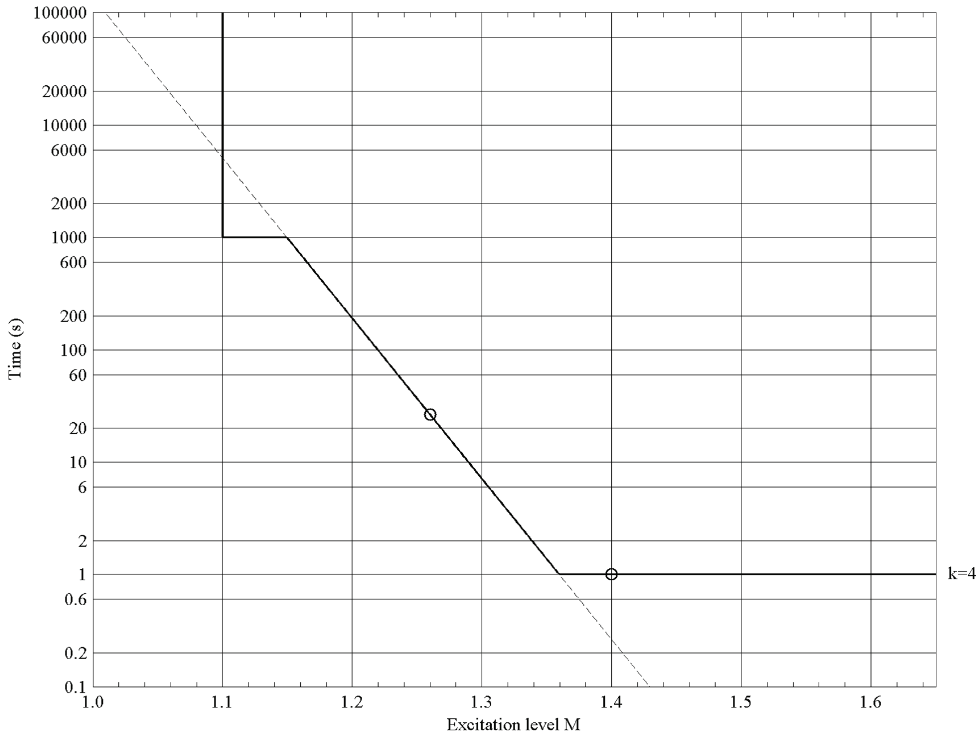


Figure 325: Tripping curve of "OvExt IDMT Crv2" based on the settings specified in example 3. The two dots marked on the curve are referred to in the text.

If the excitation level stays at 1.26, the tripping occurs after 26.364 s as per the marked dot in Figure 325. For the excitation level of 1.4, the second dot in Figure 325, the curve "OvExt IDMT Crv2" gives 0.2636 s as per Equation, but the *Minimum trip time* setting limits the trip time to 1.0 s.

The *Maximum trip time* setting limits the trip time to 1000 s if the excitation level stays between 1.1 and 1.16.

In general, however, the excitation level seldom remains constant. Therefore, the exact trip times in any inverse time mode are difficult to predict.

Example 4

In this case, the function operation is according to IDMT. The *Operating curve type* setting is selected as "OvExt IDMT Crv4". The corresponding example settings for the

IDMT curve operation are given as: *Pickup value* = 110%, *Voltage Max Cont* = 100%, *Time multiplier* = 5, *Maximum trip time* = 3600 s, *Constant delay* = 0.8 s and *Cooling time* = 100 s.

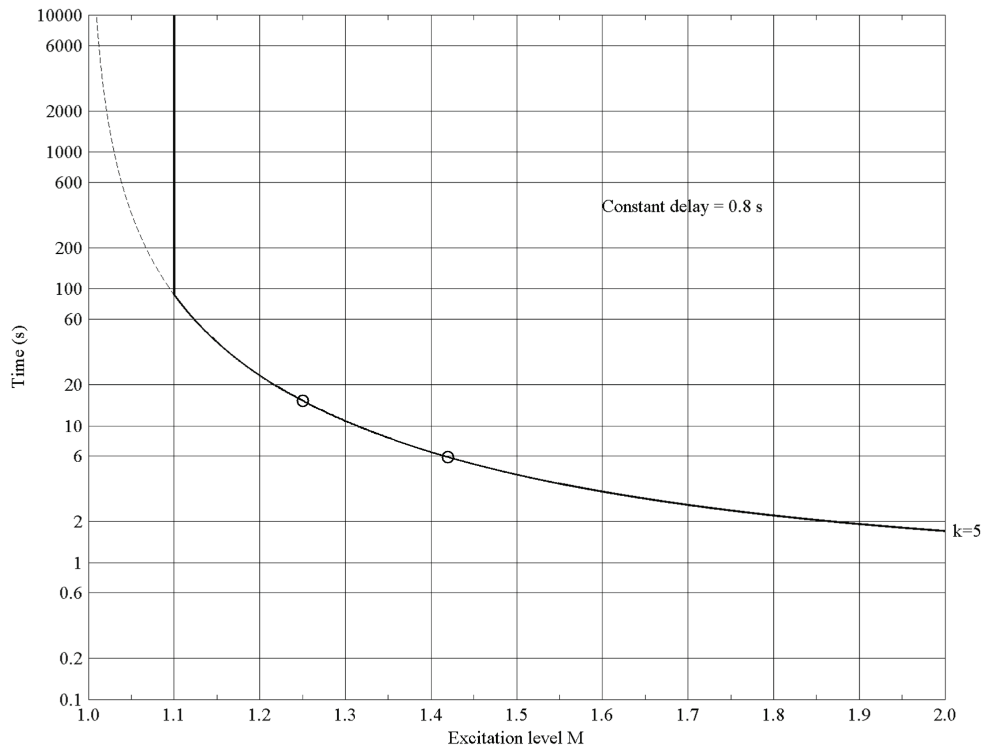


Figure 326: Tripping curve of "OvExt IDMT Crv4" based on the specified settings. The two dots marked on the curve are referred to in the text.

If the excitation level stays at 1.25, the tripping occurs after 15.20 s. At the excitation level of 1.42, the time to tripping would be 5.90 s as per the two dots in Figure 326. In this case, the setting *Maximum trip time* 3600 s does not limit the maximum trip time because the trip time at *Pickup value* = 110% (1.1 pu) is approximately 75 s.

4.5.6.7 Signals

Table 558: 24 Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_1	SIGNAL	0	Positive-phase sequence current
Table continues on next page			

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B_BC	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C_CA	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
V_1	SIGNAL	0	Positive-phase sequence voltage
F	SIGNAL	0	Measured frequency
BLOCK	BOOLEAN	0=False	Block signal

Table 559: 24 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup
BLK_RESTART	BOOLEAN	Signal for blocking reconnection of an overheated machine
COOL_ACTIVE	BOOLEAN	Signal to indicate machine is in cooling process

4.5.6.8 Settings

Table 560: 24 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	100...200	%	1	100	Over excitation pickup value
Operating curve type	5=ANSI DT 15=IEC DT 17=OvExt IDMT Crv1 18=OvExt IDMT Crv2 19=OvExt IDMT Crv3 20=OvExt IDMT Crv4			15=IEC DT	Selection of time delay curve type
Time multiplier	0.1...100.0		0.1	3.0	Time multiplier for Overexcitation IDMT curves
Trip delay time	200...200000	ms	10	500	Trip delay time in definite- time mode

Table 561: 24 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Mode Disable/Enable
Cooling time	5...10000	s	1	600	Time required to cool the machine
Constant delay	100...120000	ms	10	800	Parameter constant delay
Maximum trip time	500000...10000000	ms	10	1000000	Maximum trip time for IDMT curves
Voltage selection	1=phase-to-earth 2=phase-to-phase 3=pos sequence			3=pos sequence	Selection of phase / phase-to-phase / pos sequence voltages
Phase selection	1=A or AB 2=B or BC 3=C or CA			1=A or AB	Parameter for phase selection
Leakage React	0.0...50.0	%	0.1	0.0	Leakage reactance of the machine
Voltage Max Cont	80...160	%	1	110	Maximum allowed continuous operating voltage ratio

Table 562: 24 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	100	Resetting time of the trip time counter in DT mode
Minimum trip time	200...60000	ms	10	200	Minimum trip time for IDMT curves

4.5.6.9 Monitored data

Table 563: 24 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time (in %)
T_ENARESTART	INT32	0...10000	s	Estimated time to reset of block restart
VOLTPERHZ	FLOAT32	0.00...10.00	pu	Excitation level, i.e U/f ratio or Volts/Hertz
24	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.6.10 Technical data

Table 564: 24 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±3.0% of the set value
Pickup time 1)2)	Frequency change: Typically 200 ms
	Voltage change: Typically 40 ms
Reset time	Typically 40 ms
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite-time mode	±1.0% of the set value or ±20 ms
Trip time accuracy in inverse-time mode	±5.0% of the theoretical value or ±50 ms

1) f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.7 Low-voltage ride-through protection 27RT

4.5.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Low-voltage ride-through protection	LVRTPTUV	U<RT	27RT

4.5.7.2 Function block

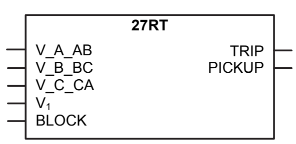


Figure 327: Function block

4.5.7.3 Functionality

The low-voltage ride-through protection function 27RT is principally a three-phase undervoltage protection. It differs from the traditional three-phase undervoltage protection 27 by allowing the grid operators to define its own Low-Voltage Ride-Through (LVRT) curve for generators, as defined by local or national grid codes. The LVRT curve can be defined accurately according to the requirements by setting the appropriate time-voltage coordinates.

The function contains a blocking functionality. 27RT can be blocked with the BLOCK input. Blocking resets timers and outputs.

4.5.7.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 27RT is described using a module diagram. All modules in the diagram are explained in the next sections.

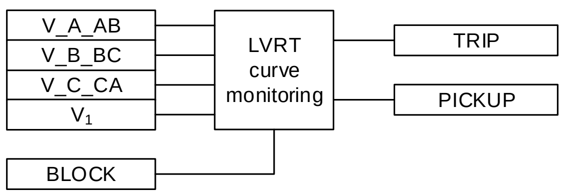


Figure 328: Functional module diagram

LVRT curve monitoring

LVRT curve monitoring starts with detection of undervoltage. Undervoltage detection depends on *Voltage selection* setting. All selectable options are based on fundamental frequency components.

Function uses phase-to-ground voltages when *Voltage selection* is set to “Highest Ph-to-E” or “Lowest Ph-to-E” and phase-to-phase voltages when *Voltage selection* is set to “Highest Ph-to-Ph” or “Lowest Ph-to-Ph”.

When the *Voltage selection* setting is set to “Highest Ph-to-E”, “Lowest Ph-to-E”, “Highest Ph-to-Ph” or “Lowest Ph-to-Ph”, the measured three-phase voltages are compared phase-wise to the set *Voltage pickup value*. If the measured value is lower than the set *Voltage pickup value* setting in number of phases equal to that set *Num of pickup phases*, the PICKUP output is activated.

The setting options available for *Num of pickup phases* are “Exactly 1 of 3”, "Exactly 2 of 3", and “Exactly 3 of 3”, which are different from conventional setting options available in other functions. For example, *Num of pickup phases* is set to "Exactly 2 of 3", any two voltages should drop below *Voltage pickup value* within one cycle network for the

PICKUP output to activate. Even if more than two voltages drop below *Voltage pickup value*, PICKUP output is not activated.

When the *Voltage selection* setting is “Positive Seq”, the positive-sequence component is compared with the set *Voltage pickup value*. If it is lower than the set *Voltage pickup value*, the PICKUP output is activated.

Once PICKUP is activated, the function monitors the behavior of the voltage defined by *Voltage selection setting* with the defined LVRT curve. When defined voltage enters the operating area, the TRIP output is activated instantaneously. The pulse length of TRIP is fixed to 100 ms. PICKUP also deactivates along with TRIP.

If a drop-off situation occurs, that is, voltage restores above *Voltage pickup value*, before TRIP is activated, the function does not reset until maximum recovery time under consideration has elapsed, that is, PICKUP output remains active.

LVRT curve is defined using time-voltage settings coordinates. The settings available are *Recovery time 1…Recovery time 10* and *Voltage level 1…Voltage level 10*. The number of coordinates required to define a LVRT curve is set by *Active coordinate* settings.

When *Recovery time 1* is set to non-zero value, it results into horizontal characteristics from point of fault till *Recovery time 1*.

Two examples of LVRT curve are defined in Figure 329 and Figure 330 with corresponding settings in Table 565.

It is necessary to set the coordinate points correctly in order to avoid maloperation. For example, setting for *Recovery time 2* should be greater than *Recovery time 1*. *Recovery time 1…Recovery time 10* are the respective time setting from the point of fault.

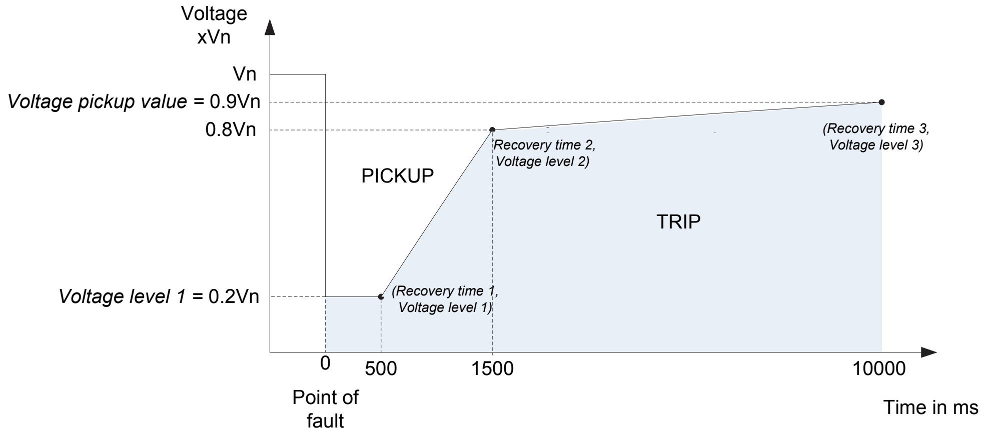


Figure 329: Low voltage ride through example curve A

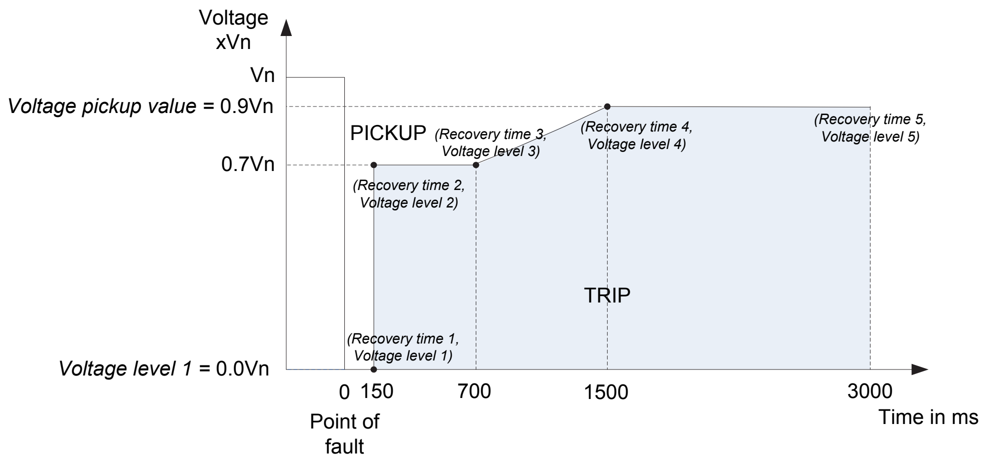


Figure 330: Low voltage ride through example curve B

Table 565: Settings for example A and B

Settings	Curve A	Curve B
Voltage start value	0.9 · Un	0.9 · Un
Active coordinates	3	5
Voltage level 1	0.2 · Un	0 · Un
Recovery time 1	500 ms	150 ms
Voltage level 2	0.8 · Un	0.7 · Un
Recovery time 2	1000 ms	150 ms
Voltage level 3	0.9 · Un	0.7 · Un
Recovery time 3	10000 ms	700 ms

Table continues on next page

Settings	Curve A	Curve B
Voltage level 4	-	0.9 · Un
Recovery time 4	-	1500 ms
Voltage level 5	-	0.9 · Un
Recovery time 5	-	3000 ms

It is necessary that the last active *Voltage level X* setting is set greater than or equal to *Voltage pickup value*. Settings are not accepted if the last active *Voltage level X* setting is not set greater than or equal to *Voltage pickup value*.

Figure 331 describes an example of operation of 27RT protection function set to operate with *Num of pickup phases* set to “Exactly 2 of 3” and *Voltage selection* as “Lowest Ph-to-Ph” voltage.

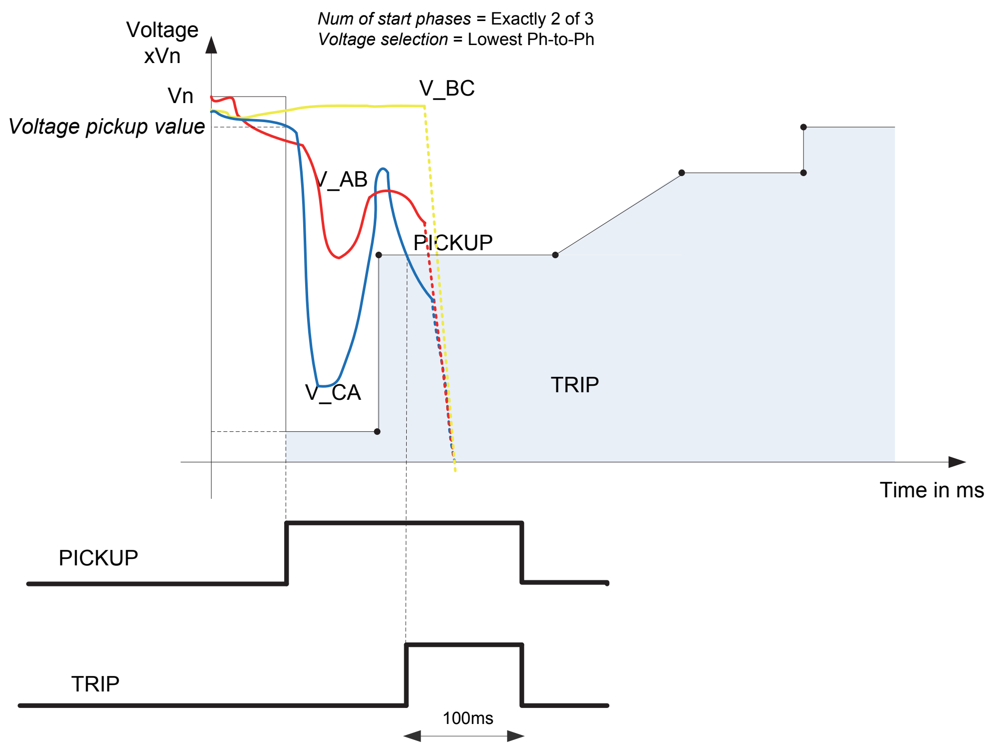


Figure 331: Typical example of operation of 27RT function

Activation of the BLOCK input resets the timers and deactivates the function outputs.

4.5.7.5 Application

Distributed generation, mainly wind and solar farms, are rapidly increasing due to liberalized markets (deregulation) and the global trend to use more renewable sources of energy. These farms are directly connected to grids, and due to their large size may influence the behavior of the grid. These farms are now required to comply with stringent grid connection requirement, which was previously mandatory only for high capacity power plants. These requirements include helping grid in maintaining system stability, reactive power support, transient recovery and voltage-frequency regulation. These requirements make it necessary for the wind and solar farms to remain in operation in the event of network disturbances.

Many grid codes now demand that the distributed generation connected to HV grids must withstand voltage dips to a certain percentage of nominal voltage (down to 0% in some cases) and for a specific duration. Such requirements are known as Low-Voltage Ride-Through (LVRT) or Fault-Ride-Through (FRT) and are described by a voltage versus time characteristics.

Typical LVRT behavior of a distributed generation can be divided into three areas according to the variation in voltage over time.

- At the time of system faults, the magnitude of the voltage may dip to *Voltage level 1* for time defined by *Recovery time 1*. The generating unit has to remain connected to the network during such condition. This boundary defines area A.
- Area B defines the linear growth recovery voltage level from *Voltage level 1* to *Voltage level 2* in a time period from *Recovery time 1* to *Recovery time 2*.
- Area C is the zone where voltage stabilizes. *Voltage level 3* is defined to same value as *Voltage level 2*. The system should remain above this voltage in a time period from *Recovery time 2* to *Recovery time 3*.

The system restores to a normal state and function resets when the voltage is equal or greater than *Voltage level 4* after *Recovery time 4* time period.

When the voltage at the point of common coupling is above the LVRT curve, the generation unit must remain connected, and must be disconnected only if the voltage takes values below the curve.

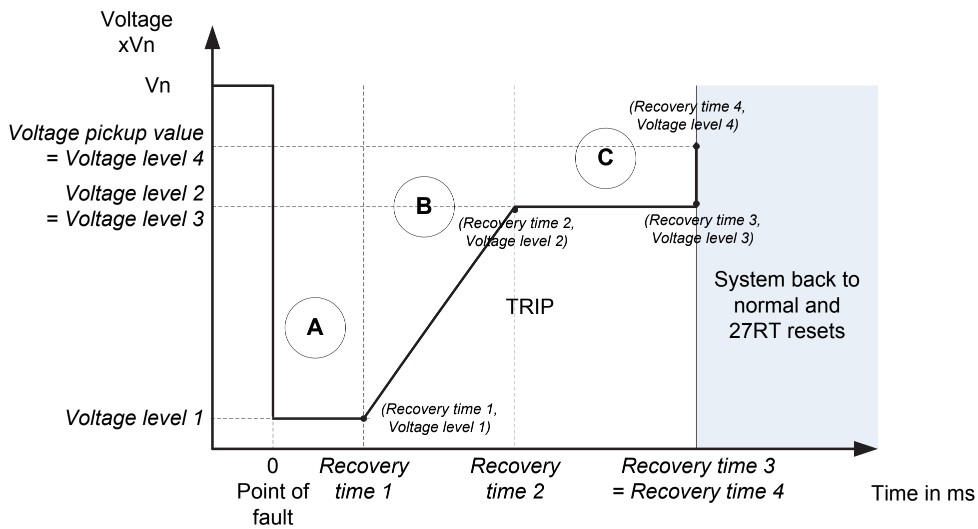


Figure 332: A typical required ride-through voltage capability of generating unit

The LVRT requirement depends on the power system characteristics and the protection employed, varying significantly from each other. The requirement also differs from country to country. 27RT function incorporates four types of LVRT curves which satisfy most of the power system needs. Grid operators can fine-tune the LVRT curve by setting the parameters as per their requirement, making the use simpler in comparison with different conventional undervoltage protection with different operate time setting and logics.

4.5.7.6 Signals

Table 566: 27RT Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_A_BC	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_A_CA	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
V_1	SIGNAL	0	Positive phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 567: 27RT Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.5.7.7 Settings

Table 568: 27RT Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage pickup value	0.05...1.20	xUn	0.01	0.90	Voltage value below which function pickups

Table 569: 27RT Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of pickup phases	4=Exactly 1 of 3 5=Exactly 2 of 3 6=Exactly 3 of 3			4=Exactly 1 of 3	Number of faulty phases
Voltage selection	1=Highest Ph-to-E 2=Lowest Ph-to-E 3=Highest Ph-to-Ph 4=Lowest Ph-to-Ph 5=Positive Seq			4=Lowest Ph-to-Ph	Parameter to select voltage for curve monitoring
Active coordinates	1...10		1	3	Coordinates used for defining LVRT curve
Voltage level 1	0.00...1.20	xUn	0.01	0.20	1st voltage coordinate for defining LVRT curve
Voltage level 2	0.00...1.20	xUn	0.01	0.80	2nd voltage coordinate for defining LVRT curve
Voltage level 3	0.00...1.20	xUn	0.01	0.90	3rd voltage coordinate for defining LVRT curve
Voltage level 4	0.00...1.20	xUn	0.01	0.90	4th voltage coordinate for defining LVRT curve
Voltage level 5	0.00...1.20	xUn	0.01	0.90	5th voltage coordinate for defining LVRT curve
Voltage level 6	0.00...1.20	xUn	0.01	0.90	6th voltage coordinate for defining LVRT curve
Voltage level 7	0.00...1.20	xUn	0.01	0.90	7th voltage coordinate for defining LVRT curve
Voltage level 8	0.00...1.20	xUn	0.01	0.90	8th voltage coordinate for defining LVRT curve
Voltage level 9	0.00...1.20	xUn	0.01	0.90	9th voltage coordinate for defining LVRT curve
Voltage level 10	0.00...1.20	xUn	0.01	0.90	10th voltage coordinate for defining LVRT curve
Recovery time 1	0...300000	ms	1	500	1st time coordinate for defining LVRT curve
Recovery time 2	0...300000	ms	1	1000	2nd time coordinate for defining LVRT curve
Recovery time 3	0...300000	ms	1	10000	3rd time coordinate for defining LVRT curve
Recovery time 4	0...300000	ms	1	10000	4th time coordinate for defining LVRT curve
Recovery time 5	0...300000	ms	1	10000	5th time coordinate for defining LVRT curve
Recovery time 6	0...300000	ms	1	10000	6th time coordinate for defining LVRT curve
Recovery time 7	0...300000	ms	1	10000	7th time coordinate for defining LVRT curve
Recovery time 8	0...300000	ms	1	10000	8th time coordinate for defining LVRT curve
Recovery time 9	0...300000	ms	1	10000	9th time coordinate for defining LVRT curve
Recovery time 10	0...300000	ms	1	10000	10th time coordinate for defining LVRT curve

4.5.7.8 Monitored data

Table 570: 27RT Monitored data

Name	Type	Values (Range)	Unit	Description
27RT	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.7.9 Technical data

Table 571: 27RT Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured voltage: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × V_n
Pickup time[1)2)]	Typically 40 ms
Reset time	Based on maximum value of *Recovery time* setting
Trip time accuracy	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) Tested for *Num of pickup phases* = 1 out of 3, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.8 Voltage vector shift protection 78V

4.5.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage vector shift protection	VVSPPAM	VS	78V

4.5.8.2 Function block

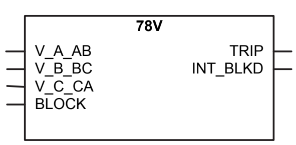


Figure 333: Function block

4.5.8.3 Functionality

The voltage vector shift protection function 78V, also known as vector surge or delta phi function, measures continuously the duration of a voltage cycle. At the instance of islanding, the duration of measured voltage cycle becomes shorter or longer than the previous one, that is, the measured voltage cycle shifts with time. This shifting of voltage is measured in terms of phase angle. 78V issues an instantaneous trip when the shift in voltage vector exceeds the set value.

The function can be blocked with `BLOCK` input. Blocking resets timers and outputs.

4.5.8.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 78V can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

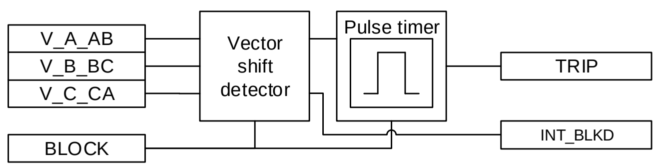


Figure 334: Functional module diagram

Vector shift detector

This module measures the duration of each cycle of the voltage signal phase. The duration of the present cycle is compared to the previous cycle, considered as reference. When the mains is lost, a sudden change is seen in the cycle length, if loading of the generator changes suddenly and power mismatch or unbalance (generation vs. load) in the islanded part of the network is large enough. The cycle shifts with time, that is, the frequency may not change but a vector shift is seen in phase as shown in Figure 335.

This step is measured in degrees for each voltage signal defined by the *Phase supervision* setting. The *Phase supervision* setting determines which voltage is used for detecting vector shift. The available *Phase supervision* options are “All” and “Pos sequence”. If the calculated value of $\Delta\delta$ exceeds the set *Pickup value* setting for all the defined phases, the module sends an enabling signal to start the Pulse timer.

The *Voltage selection* setting is used to select whether the available voltage signal is phase-to-ground or phase-to-phase voltage.

The recommended and the default value for *Phase supervision* is "Pos sequence".

If the magnitude of the voltage level of any of the monitored voltage signal, defined by the *Phase supervision* setting, drops below *Under Volt Blk value* or exceeds *Over Volt Blk value*, the calculation of vector shift is disabled and the INT_BLKD output is activated.

The function is blocked and LOWAMPL_BLKD is activated, if the measured frequency deviates ±5% from the nominal value.

The magnitude of calculated vector shift for three phase-to-ground or phase-to-phase voltages, VSHIFT_A_AB, VSHIFT_B_BC and VSHIFT_C_CA or positive sequence voltage V1SHIFT, which resulted in the activation of last TRIP output, are available in the Monitored data view.

The activation of BLOCK input deactivates the INT_BLKD output.

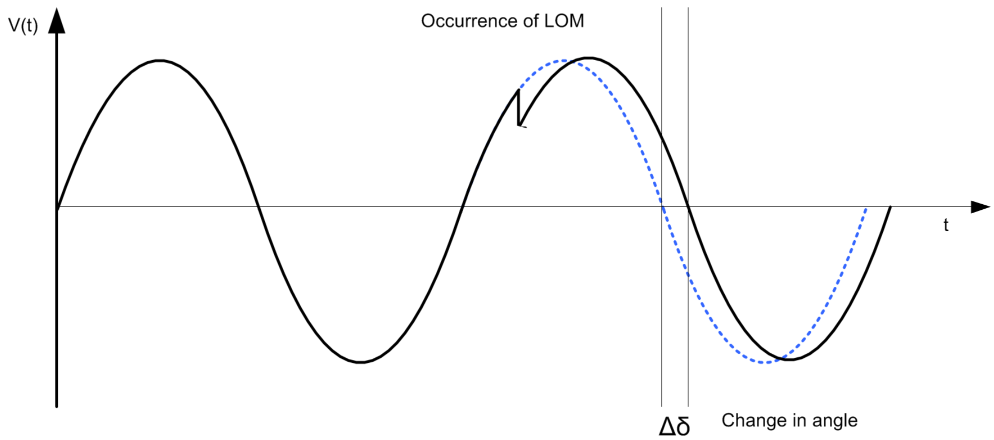


Figure 335: Vector shift during Loss of Mains

Pulse timer

Once the Pulse timer is activated, it activates the TRIP output. The pulse length of TRIP is fixed to 100 ms.

The activation of the BLOCK input deactivates the TRIP binary output and resets the timer.

4.5.8.5 Application

Use of distributed generation (DG) units is increasing due to liberalized markets (deregulation) and the global trend to use more renewable sources of energy. They generate power in the range of 10 kW...10 MW and most of them are interconnected to the distribution network. They can supply power into the network as well as to the local loads. It is not common to connect generators directly to the distribution networks and thus the distributed generation can cause some challenges for the protection of distribution networks. From the protection point of view, one of the most challenging issue is islanding.

Islanding is defined as a condition in which a distributed generation unit continues to supply power to a certain part of the distribution network when power from the larger utility main grid is no longer available after the opening of a circuit-breaker. Islanding is also referred as Loss of Mains (LOM) or Loss of Grid (LOG). When LOM occurs, neither the voltage or the frequency is controlled by the utility supply. These distributed generators are not equipped with voltage and frequency control; therefore, the voltage magnitude of an islanded network may not be kept within the desired limits which causes undefined voltage magnitudes during islanding situations and frequency instability. Uncontrolled frequency represents a high risk for drives and other machines. Islanding can occur as a consequence of a fault in the network, due to circuit breaker maloperation or due to circuit breaker opening during maintenance. If the distributed generator continues its operation after the utility supply is disconnected, faults do not clear under certain conditions as the arc is charged by the distributed generators. Moreover, the distributed generators are incompatible with the current reclosing practices. During the reclosing sequence dead time, the generators in the network tend to drift out of synchronism with the grid and reconnecting them without synchronizing may damage the generators introducing high currents and voltages in the neighboring network.

To avoid these technical challenges, protection is needed to disconnect the distributed generation once it is electrically isolated from the main grid supply. Various techniques are used for detecting Loss of Mains. However, the present function focuses on voltage vector shift.

The vector shift detection guarantees fast and reliable detection of mains failure in almost all operational conditions when a distributed generation unit is running in parallel with the mains supply, but in certain cases this may fail.

If the active and reactive power generated by the distributed generation units is nearly balanced (for example, if the power mismatch or unbalance is less than 5...10%) with the active and reactive power consumed by loads, a large enough voltage phase shift may not occur which can be detected by the vector shift algorithm. This means that the vector shift algorithm has a small non-detection-zone (NDZ) which is also dependent on the type of generators, loads, network and pickup or trip value of the vector shift algorithm. Other network events like capacitor switching, switching of very large loads in weak network or connection of parallel transformer at HV/MV substation, in which the voltage magnitude is not changed considerably (unlike in faults) can potentially cause maloperation of vector shift algorithm, if very sensitive settings are used.

The vector shift detection also protects synchronous generators from damaging due to islanding or loss-of-mains. To detect loss-of-mains with vector shift function, the generator should aim to export or import at least 5...10% of the generated power to the grid, in order to guarantee detectable change in loading after islanding or loss-of-mains.

Multicriteria Loss of Mains

Apart from vector shift, there are other passive techniques which are used for detecting Loss of Mains. Some of these passive techniques are over/under voltage, over/under frequency, rate of change of frequency, voltage unbalance, rate of change of power and so on. These passive methods use voltage and frequency to identify Loss of Mains. The performance of these methods depends on the power mismatch between local generation and load. The advantage of all these methods is that, they are simple and cost effective, but each method has a non detectable zone. To overcome this problem, it is recommended to combine different criteria for detecting Loss of Mains.

Two or more protection functions run in parallel to detect Loss of Mains. When all criteria are fulfilled to indicate Loss of Mains, an alarm or a trip can be generated. Vector shift and rate of change of frequency are two parallel criteria typically used for detection of Loss of Mains.

Chosen protection criteria can be included in the Application Configuration tool to create multicriteria loss of mains alarm or trip.

4.5.8.6 Signals

Table 572: 78V Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B_BC	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C_CA	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 573: 78V Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
INT_BLKD	BOOLEAN	Protection function internally blocked

4.5.8.7 Settings

Table 574: 78V Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	2.0...30.0	deg	0.1	6.0	Pickup value for vector shift

Table 575: 78V Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Over Volt Blk value	0.40...1.50	xUn	0.01	1.20	Voltage above which function will be internally blocked
Under Volt Blk value	0.15...1.00	xUn	0.01	0.80	Voltage below which function will be internally blocked

Table 576: 78V Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 577: 78V Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Phase supervision	7=Ph A + B + C 8=Pos sequence			8=Pos sequence	Monitored voltage phase

4.5.8.8 Monitored data

Table 578: 78V Monitored data

Name	Type	Values (Range)	Unit	Description
VEC_SHT_A_AB	FLOAT32	-180.00...180.00	deg	Vector shift for phase to ground voltage A or phase to phase voltage AB
VEC_SHT_B_BC	FLOAT32	-180.00...180.00	deg	Vector shift for phase to ground voltage B or phase to phase voltage BC
VEC_SHT_C_CA	FLOAT32	-180.00...180.00	deg	Vector shift for phase to ground voltage C or phase to phase voltage CA
VEC_SHT_U1	FLOAT32	-180.00...180.00	deg	Vector shift for positive sequence voltage
78V	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.8.9 Technical data

Table 579: 78V Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured voltage: f_n ±1 Hz
	±1°
Trip time[1)2)]	Typically 53 ms

1) f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.5.9 Three-phase remnant undervoltage protection 27R

4.5.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase remnant undervoltage protection	MSVPR	3U<	27R

4.5.9.2 Function block

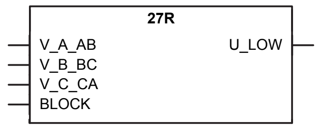


Figure 336: Function block

4.5.9.3 Functionality

Systems with critical motor applications may provide backup power sources to those motors that can be switched in when an undervoltage on the original power source is detected. The 27R function is used, after primary power has been removed, to monitor for an undervoltage condition over a decaying frequency before allowing re-application of backup power.

When the power to a motor is suddenly lost, the motor terminal voltage does not immediately fall to zero but remains as the rotating motor now acts as a generator producing its own voltage. This remanent voltage decays as the motor slows to a stop at a rate depending on the motor and load. Re-applying a power source while the remanent voltage is still present can result in damage to the motor shaft and windings.

The three-phase undervoltage protection 27R operates over the range of 10...70 Hz so it can monitor the voltage while the motor is slowing and prevent application of the backup power until the motor voltage has decayed to a safe level. 27R includes a settable value for the detection of undervoltage either in a single phase, two phases, or all three phases.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.5.9.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 27R can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

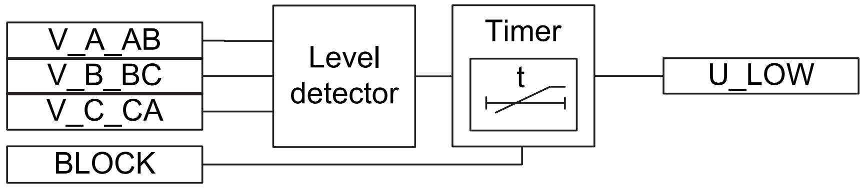


Figure 337: Functional module diagram

Level detector

The fundamental frequency component of the measured three-phase voltages over the range of 10...70 Hz is compared phase-wise to the set *Pickup value* . If the measured value is lower than the set value of the *Pickup value* setting, the Level detector enables the phase selection logic module. The *Relative hysteresis* setting can be used for preventing unnecessary oscillations if the input signal slightly varies above or below the *Pickup value* setting. After leaving the hysteresis area, the pickup condition has to be fulfilled again and it is not sufficient for the signal to only return back to the hysteresis area.

The *Voltage selection* setting is used for selecting the phase-to-ground or phase-to-phase voltages for protection.

Phase selection logic

If the fault criteria are fulfilled in the Level detector, the phase selection logic detects the phase or phases in which the fault level is detected. If the number of faulty phases match with the set *Num of pickup phases*, the phase selection logic activates the Timer.

Timer

Once activated, the Timer activates the `PICKUP` output. The time characteristic is definite time only.

When the operation timer has reached the value set by *Trip delay time*, the `TRIP` output is activated.

In a drop-off situation, that is, when a fault suddenly disappears before the trip delay is exceeded, the reset state is activated. The reset timer runs until the set *Reset delay time* value is exceeded. If the drop-off situation exceeds the set *Reset delay time*, the Timer is reset and the `PICKUP` output is deactivated.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the `BLOCK` input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay program. The influence of the `BLOCK` input signal activation is preselected with the global *Blocking mode* setting.

The Blocking mode setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.5.9.5 Application

Systems with critical motor applications provide backup power sources to those motors that can be switched in when an undervoltage on the original power source is detected. The three-phase undervoltage protection 27R is used to monitor for an undervoltage condition over a decaying frequency after original power is lost, before allowing re-application of backup power. An independent undervoltage function, operating at nominal frequency, can be used to detect the original loss of primary power and initiate the transfer to backup power. 27R provides a permissive signal indicating when restoration of backup power can be completed safely.

When the power to a motor is suddenly lost, the motor terminal voltage does not immediately fall to zero but remains as the rotating motor now acts as a generator producing its own voltage. This remnant voltage decays as the motor slows to a stop at a rate depending on the motor and load. Applying the backup power source while the remnant voltage is still present can result in damage to the motor shaft and windings.

27R operates over the range of 10...70 Hz so it can monitor the voltage while the motor is slowing and prevent transfer of the backup power until the motor voltage has decayed to a safe level. The undervoltage setting is typically set 20...30 percent of rated voltage. There is also a time delay setting to ensure that the remnant voltage remains below the undervoltage setting for the set time. 27R includes a settable value for the detection of undervoltage in either a single phase, two phases, or in all three phases. This setting value should always be set for three phases in the remnant undervoltage application but can be changed if 27R is used as a standard undervoltage function.

The function contains a self-blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.5.9.6 Signals

Table 580: 27R Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 581: 27R Output signals

Name	Type	Description
U_LOW	BOOLEAN	Low remanent voltage

4.5.9.7 Settings

Table 582: 27R Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Pickup value	0.05...1.20	xUn	0.01	0.25	Pickup value
Trip delay time	100...300000	ms	100	100	Trip delay time
Voltage selection	1=phase-to-earth 2=phase-to-phase			2=phase-to-phase	Parameter to select phase or phase-to-phase voltages
Num of phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			3=3 out of 3	Number of phases required for voltage supervision
Phase supervision	1=A or AB 2=B or BC 4=C or CA 7=A&B&C or AB&BC&CA			7=A&B&C or AB&BC&CA	Monitored voltage phase

Table 583: 27R Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

4.5.9.8 Monitored data

Table 584: 27R Monitored data

Name	Type	Values (Range)	Unit	Description
U_AMPL_A	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase A
U_AMPL_B	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase B
U_AMPL_C	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase C
U_AMPL_AB	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase to phase AB
U_AMPL_BC	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase to phase BC
U_AMPL_CA	FLOAT32	0.00...5.00	xUn	Remanent voltage of phase to phase CA
27R	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.5.9.9 Technical data

Table 585: 27R Technical data

Characteristic	Value		
Operation accuracy	±4% of setting or ±0.01 × V_n (70 Hz > = f > 20 Hz)		
	±10% of setting (20 Hz > = f ≥ 10 Hz)		
Pickup time[1)]	Minimum	Typical	Maximum
	30 ms	75 ms	140 ms
Reset time	<180 ms		
Reset ratio	Depends on the relative hysteresis setting		
Retardation time	<45 ms		
Trip time accuracy[2)]	±1.0% of the set value or ±20 ms		
Suppression of harmonics	Operates only in RMS mode		

1) Includes the delay of the signal output contact
2) Trip time delays do not account for variation due to pickup delay

4.6 Frequency protection

4.6.1 Frequency protection 81

4.6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Frequency protection	FRPFRQ	f>/f<,df/dt	81

4.6.1.2 Function block

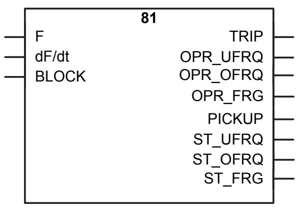


Figure 338: Function block

4.6.1.3 Functionality

The frequency protection function 81 is used to protect network components against abnormal frequency conditions.

The function provides basic overfrequency, underfrequency and frequency rate-of-change protection. Additionally, it is possible to use combined criteria to achieve even more sophisticated protection schemes for the system.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.6.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 81 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

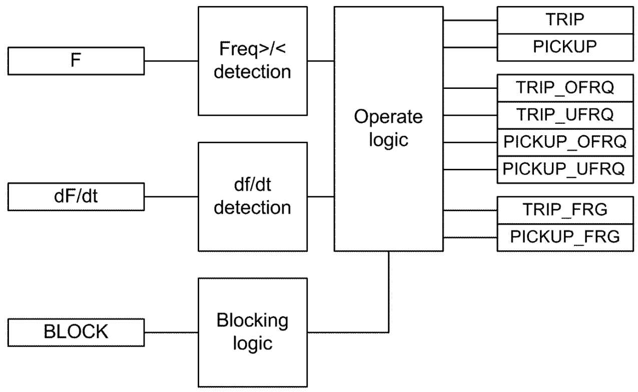


Figure 339: Functional module diagram

Over/under frequency detection

The frequency detection module includes an overfrequency or underfrequency detection based on the *Operation mode* setting.

In the “Freq>” mode, the measured frequency is compared to the set *Pickup value Freq>*. If the measured value exceeds the set value of the *Pickup value Freq>* setting, the module reports the exceeding of the value to the trip logic module.

In the “Freq<” mode, the measured frequency is compared to the set *Pickup value Freq<*. If the measured value is lower than the set value of the *Pickup value Freq<* setting, the module reports the value to the trip logic module.

df/dt detection

The frequency gradient detection module includes a detection for a positive or negative rate-of-change (gradient) of frequency based on the set *Pickup value df/dt* value. The negative rate-of-change protection is selected when the set value is negative. The positive rate-of-change protection is selected when the set value is positive. When the frequency gradient protection is selected and the gradient exceeds the set *Pickup value df/dt* value, the module reports the exceeding of the value to the trip logic module.

The protection relay does not accept the set value "0.00" for the *Pickup value df/dt* setting.

Operate logic

This module is used for combining different protection criteria based on the frequency and the frequency gradient measurement to achieve a more sophisticated behavior of the function. The criteria are selected with the *Operation mode* setting.

Table 586: Operation modes for operation logic

Operation mode	Description
Freq<	The function trips independently as the underfrequency ("Freq<") protection function. When the measured frequency is below the set value of the *Pickup value Freq<* setting, the module activates the PICKUP and PICKUP_UFRQ outputs. The time characteristic is according to DT. When the operation timer has reached the value set by the *Trip Tm Freq* setting, the TRIP and TRIP_UFRQ outputs are activated. If the frequency restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm Freq* setting, the operation timer resets and the PICKUP and PICKUP_UFRQ outputs are deactivated.
Freq>	The function trips independently as the overfrequency ("Freq>") protection function. When the measured frequency exceeds the set value of the *Pickup value Freq>* setting, the module activates the PICKUP and PICKUP_OFRQ outputs. The time characteristic is according to DT. When the operation timer has reached the value set by the *Trip Tm Freq* setting, the TRIP and TRIP_OFRQ outputs are activated. If the frequency restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm Freq* setting, the operation timer resets and the PICKUP and PICKUP_OFRQ outputs are deactivated.
df/dt	The function trips independently as the frequency gradient ("df/dt"), rate-of-change, protection function. When the frequency gradient exceeds the set value of the *Pickup value df/dt* setting, the module activates the PICKUP and PICKUP_FRG outputs. The time characteristic is according to DT. When the operation timer has reached the value set by the *Trip Tm df/dt* setting, the TRIP and TRIP_FRG outputs are activated. If the frequency gradient restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm df/dt* setting, the operation timer resets and the PICKUP and PICKUP_FRG outputs are deactivated.
Freq< + df/dt	A consecutive operation is enabled between the protection methods. When the measured frequency is below the set value of the *Pickup value Freq<* setting, the frequency gradient protection is enabled. After the frequency has dropped below the set value, the frequency gradient is compared to the set value of the *Pickup value df/dt* setting. When the frequency gradient exceeds the set value, the module activates the PICKUP and PICKUP_FRG outputs. The time characteristic is according to DT. When the operation timer has reached the value set by the *Trip Tm df/dt* setting, the TRIP and TRIP_FRG outputs are activated. If the frequency gradient restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm df/dt* setting, the operation timer resets and the PICKUP and PICKUP_FRG outputs are deactivated. The TRIP_UFRQ output is not active when this operation mode is used.
Table continues on next page	

Operation mode	Description
Freq> + df/dt	A consecutive operation is enabled between the protection methods. When the measured frequency exceeds the set value of the *Pickup value Freq>* setting, the frequency gradient protection is enabled. After the frequency exceeds the set value, the frequency gradient is compared to the set value of the *Pickup value df/dt* setting. When the frequency gradient exceeds the set value, the module activates the PICKUP and PICKUP_FRG outputs. The time characteristic is according to DT. When the operation timer has reached the value set by the *Trip Tm df/dt* setting, the TRIP and TRIP_FRG outputs are activated. If the frequency gradient restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm df/dt* setting, the operation timer resets and the PICKUP and PICKUP_FRG outputs are deactivated. The TRIP_OFRQ output is not active when this operation mode is used.
Freq< OR df/dt	A parallel operation between the protection methods is enabled. The PICKUP output is activated when either of the measured values of the protection module exceeds its set value. Detailed information about the active module is available at the PICKUP_UFRQ and PICKUP_FRG outputs. The shortest trip delay time from the set *Trip Tm Freq* or *Trip Tm df/dt* is dominant regarding the TRIP output. The time characteristic is according to DT. The characteristic that activates the TRIP output can be seen from the TRIP_UFRQ or TRIP_FRG output. If the frequency gradient restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm df/dt* setting, the operation timer resets and the PICKUP_FRG output is deactivated. If the frequency restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm Freq* setting, the operation timer resets and the PICKUP_UFRQ output is deactivated.
Freq> OR df/dt	A parallel operation between the protection methods is enabled. The PICKUP output is activated when either of the measured values of the protection module exceeds its set value. Detailed information about the active module is available at the PICKUP_OFRQ and PICKUP_FRG outputs. The shortest trip delay time from the set *Trip Tm Freq* or *Trip Tm df/dt* is dominant regarding the TRIP output. The time characteristic is according to DT. The characteristic that activates the TRIP output can be seen from the TRIP_OFRQ or TRIP_FRG output. If the frequency gradient restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm df/dt* setting, the operation timer resets and the PICKUP_FRG output is deactivated. If the frequency restores before the module trips, the reset timer is activated. If the timer reaches the value set by the *Reset delay Tm Freq* setting, the operation timer resets and the PICKUP_UFRQ output is deactivated.

The module calculates the pickup duration value PICKUP_DUR which indicates the percentage ratio of the pickup situation and set trip time DT. The pickup duration is available according to the selected value of the *Operation mode* setting.

Table 587: Pickup duration value

Operation mode in use	Available pickup duration value
Freq<	ST_DUR_UFRQ
Freq>	ST_DUR_OFRQ
df/dt	ST_DUR_FRG

The combined pickup duration PICKUP_DUR indicates the maximum percentage ratio of the active protection modes. The values are available via the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.6.1.5 Application

The frequency protection function uses the positive phase-sequence voltage to measure the frequency reliably and accurately.

The system frequency stability is one of the main principles in the distribution and transmission network maintenance. To protect all frequency-sensitive electrical apparatus in the network, the departure from the allowed band for a safe operation should be inhibited.

The overfrequency protection is applicable in all situations where high levels of the fundamental frequency of a power system voltage must be reliably detected. The high fundamental frequency in a power system indicates an unbalance between production and consumption. In this case, the available generation is too large compared to the power demanded by the load connected to the power grid. This can occur due to a sudden loss of a significant amount of load or due to failures in the turbine governor system. If the situation continues and escalates, the power system loses its stability.

The underfrequency is applicable in all situations where a reliable detection of a low fundamental power system voltage frequency is needed. The low fundamental frequency in a power system indicates that the generated power is too low to meet the demands of the load connected to the power grid.

The underfrequency can occur as a result of the overload of generators operating in an isolated system. It can also occur as a result of a serious fault in the power system due to the deficit of generation when compared to the load. This can happen due to a fault in the grid system on the transmission lines that link two parts of the system. As a result, the system splits into two with one part having the excess load and the other part the corresponding deficit.

The frequency gradient is applicable in all the situations where the change of the fundamental power system voltage frequency should be detected reliably. The frequency gradient can be used for both increasing and decreasing the frequencies. This function provides an output signal suitable for load shedding, generator shedding, generator boosting, set point change in sub-transmission DC systems and gas turbine startup. The frequency gradient is often used in combination with a low frequency signal, especially in smaller power systems where the loss of a large generator requires quick remedial actions to secure the power system integrity. In such situations, the load shedding actions are required at a rather high frequency level. However, in combination with a large negative frequency gradient, the underfrequency protection can be used at a high setting.

4.6.1.6 Signals

Table 588: 81 Input signals

Name	Type	Default	Description
F	SIGNAL	0	Measured frequency
dF/dt	SIGNAL	0	Rate of change of frequency
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 589: 81 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
OPR_OFRQ	BOOLEAN	Trip signal for overfrequency
OPR_UFRQ	BOOLEAN	Trip signal for underfrequency
OPR_FRG	BOOLEAN	Trip signal for frequency gradient
PICKUP	BOOLEAN	Pickup
ST_OFRQ	BOOLEAN	Pickup signal for overfrequency
ST_UFRQ	BOOLEAN	Pickup signal for underfrequency
ST_FRG	BOOLEAN	Pickup signal for frequency gradient

4.6.1.7 Settings

Table 590: 81 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip mode	1=Freq< 2=Freq> 3=df/dt 4=Freq< + df/dt 5=Freq> + df/dt 6=Freq< OR df/dt 7=Freq> OR df/dt			1=Freq<	Frequency protection trip mode selection
Pickup value Freq>	0.9000...1.2000	xFn	0.0001	1.0500	Frequency pickup value overfrequency
Pickup value Freq<	0.8000...1.1000	xFn	0.0001	0.9500	Frequency pickup value underfrequency
Pickup value df/dt	-0.2000...0.2000	xFn /s	0.0025	0.0100	Frequency pickup value rate of change
Trip Tm Freq	80...200000	ms	10	200	Trip delay time for frequency
Trip Tm df/dt	120...200000	ms	10	400	Trip delay time for frequency rate of change

Table 591: 81 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 592: 81 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay Tm Freq	0...60000	ms	1	0	Reset delay time for frequency
Reset delay Tm df/dt	0...60000	ms	1	0	Reset delay time for rate of change

4.6.1.8 Monitored data

Table 593: 81 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Pickup duration
ST_DUR_OFRQ	FLOAT32	0.00...100.00	%	Pickup duration
ST_DUR_UFRQ	FLOAT32	0.00...100.00	%	Pickup duration
ST_DUR_FRG	FLOAT32	0.00...100.00	%	Pickup duration
81	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.6.1.9 Technical data

Table 594: 81 Technical data

Characteristic		Value
Operation accuracy	f>/f<	±5 mHz
	df/dt	±50 mHz/s (in range |df/dt| <5 Hz/s) ±2.0% of the set value (in range 5 Hz/s < |df/dt| < 15 Hz/s)
Pickup time	f>/f<	<80 ms
	df/dt	<120 ms
Reset time		<150 ms
Trip time accuracy		±1.0% of the set value or ±30 ms

4.6.1.10 Technical revision history

Table 595: 81 Technical revision history

Technical revision	Change
B	Step value changed from 0.001 to 0.0001 for the *Pickup value Freq>* and *Pickup value Freq<* settings.
C	df/dt setting step changed from 0.005 ×Fn /s to 0.0025 ×Fn /s.
D	Internal improvement.

4.7 Impedance protection

4.7.1 Out-of-step protection 78

4.7.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Out of step protection	OOSRPSB	φ>	78

4.7.1.2 Function block

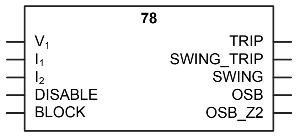


Figure 340: Function block

4.7.1.3 Functionality

The out of step protection function 78 detects out of step conditions by monitoring impedance.

The protection uses two impedance measurement elements known as inner and outer blinders on mho characteristics with a timer. The function calculates the impedance. If the measured impedance stays between inner and outer blinder for a predetermined time and moves farther inside the inner blinder, then an out of step condition is indicated. Trip is generated if out of step is indicated and impedance moves out of mho characteristics. The mho characteristic can be divided into two zones so separate trips can be generated based on the zone. Tripping can also be selected to occur when the impedance is on the way into the zone or for when the impedance is on the way out of the zone.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.7.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 78 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

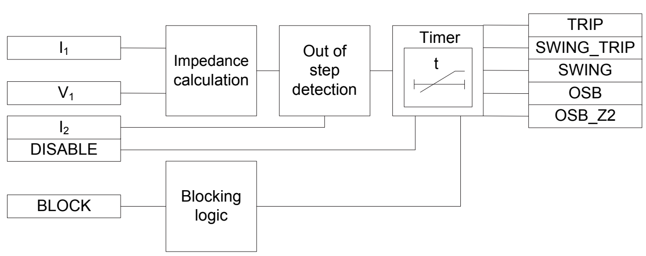


Figure 341: Functional module diagram

Impedance calculation

This module calculates the positive-sequence impedance (Z1) using positive-sequence voltage and current. For the module to calculate impedance it is required that the positive-sequence current is above *Min Ps Seq current* setting and the negative-sequence current is below the *Max Ng Seq current* setting.

The calculated positive-sequence impedance amplitude Z1_AMPL and angle Z1_ANGLE are available in ohms and degrees, respectively, in the Monitored data view.

The calculated impedance is converted to ohms as the operating characteristics are defined with the ohm settings.

Out of step detection

The operating characteristic is a circular offset mho on the impedance plane with two pair of blinders. The mho characteristic is defined with the *Forward reach*, *Reverse reach*, and *Impedance angle* settings. *Forward reach* defines the impedance from the origin to the edge of circle on the top side. *Reverse reach* defines the impedance from the origin to the edge of the circle on the bottom side. The diameter of the mho characteristics is the sum of *Forward reach* and *Reverse reach* settings. Two sets of blinders are defined by *Inner blinder R* and *Outer blinder R* intercepting at R-axis. The blinders are at the same angle as the *Impedance angle*. The second blinder of each outer and inner pair is automatically made symmetrical with the origin of the R-X plane.

For a correct operation, it is required that the setting for *Inner blinder R* is less than the setting for *Outer blinder R*.

The circular mho characteristic can be further divided into two zones by setting *Zone 2 enable* to “Yes”. The boundary between zones is set using the setting *Zone 1 reach*. The lower portion of the circle, Zone 1, is separated from the upper portion, Zone 2, by a line, perpendicular to the blinders, located at a set percentage of the *Forward reach* setting from the origin.

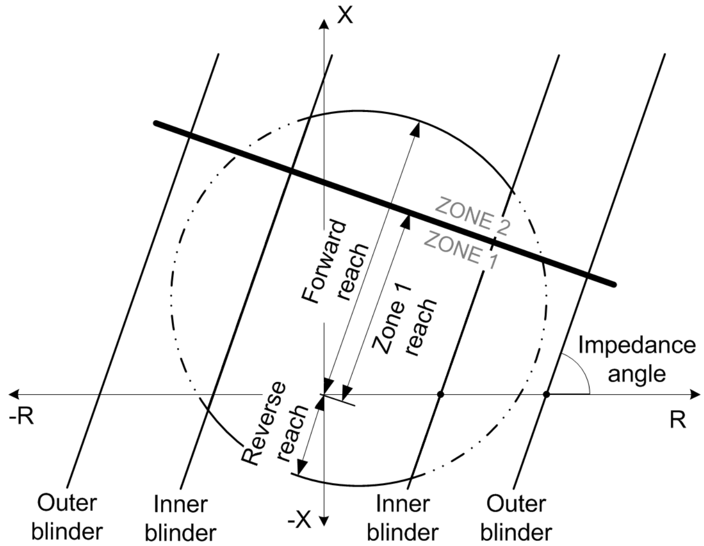


Figure 342: Operating region for out of step with double blinder

An impedance is only considered to be within the mho circle if it is also between the inner blinders.

A third zone, Zone 3, can be enabled by setting *Zone 3 enable* to “Yes”. Zone 3 is defined to include the area outside of the circular mho characteristic but inside the area that is bound with the magnitude of the minimum positive-sequence current defined by setting *Min Ps Seq current* and the rated positive-sequence voltage. Figure shows the three zones. Settings that determine the shape of the zones should be coordinated with the settings for any distance protection functions. The zones and their respective slip counters are applicable only for Way out operations when the *Oos operation mode* setting option is “Way out” or “Adaptive”.

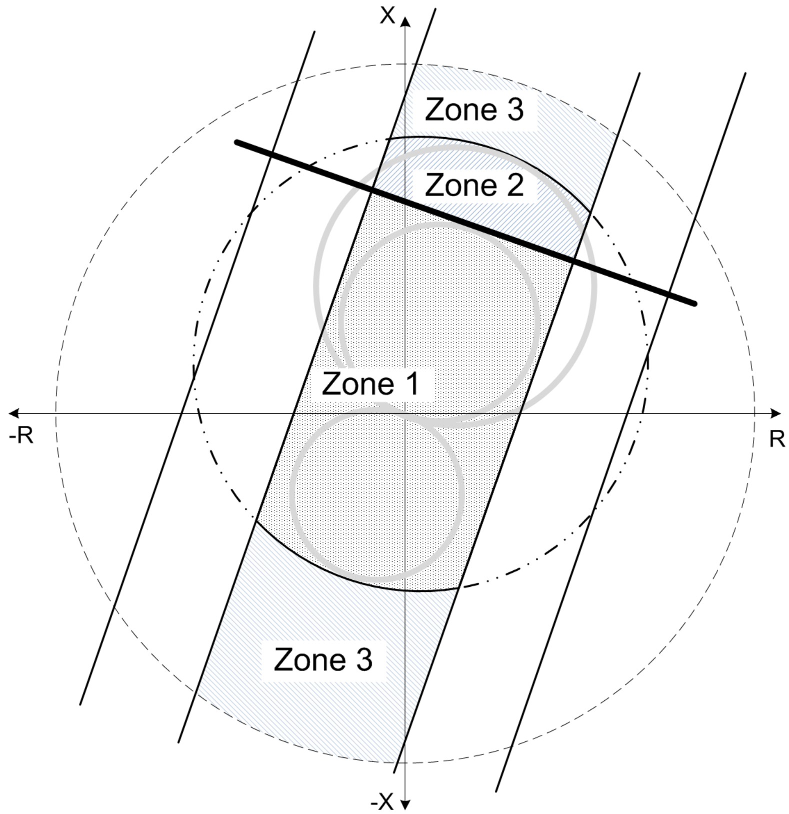


Figure 343: Defined zones

The impedance is continuously monitored for detecting an out of step condition. When the impedance enters inside from the outer blinder, the out of step detection timer is triggered. If impedance remains between outer and inner blinder for the duration of the *Swing time* setting, output `SWING` is activated. If the impedance enters the mho circle in zone 1, out of step blocking (OSB) for zone 1 is detected and output `OSB` is activated, or if the impedance enters the mho circle in zone 2, OSB for zone 2 is detected and output `OSB_Z2` is activated if setting *Zone 2 enable* is set to “Yes”. Both `OSB` and `OSB_Z2` can be activated if the impedance passes through zone 1 and zone 2 while inside the mho circle. The `OSB` or `OSB_Z2` output deactivates when impedance exits and remains outside the mho circle and the inner blinder for a duration of five cycles.

Activation of the `TRIP` output depends on the *Oos trip mode* selected. The options available are “Way in”, “Way out”, and “Adaptive”. If the “Way in” option is selected, the function triggers the delay timer after detecting an OSB condition. When the set *Trip delay time* has elapsed, the `TRIP` output is activated. When using the “Way in” option, the zone-related settings and zone slip counters are not applicable.

If the “Way out” option is selected, after detecting an OSB condition, the function further checks if impedance exits the outer blinder. On exiting the outer blinder, Way out timer defined by *Trip delay time* setting is triggered and the respective zone slip counter is incremented after the set *Trip delay time* has elapsed. If the slip counter value is equal to the set number of slips in the respective enabled zone, the `TRIP` output is activated. If the swing impedance passes through both zone 1 and zone 2, only the zone 1 slip counter is incremented. The zone 2 slip counter is incremented if the impedance passes through the Mho circle but only through the zone 2 portion. The zone 3 slip counter is incremented if the impedance misses the Mho circle entirely and the setting *Zone 3 enable* is also set to “Yes”. Increment of slip counter triggers also the Reset timer. All of the zone slip counters reset after the set *Reset time* has elapsed and the impedance does not cross into the outer blinder again, or on activation of the `TRIP` output.

When the “Way out” or "Adaptive" option is selected, the breaker open time, if known, can be incorporated to optimize breaker trip time when a way out trip command is issued. The ideal time for the breaker to interrupt current is when the swing angle approaches zero. If the swing angle is δ_0 when the impedance exits the outer blinder, the dynamic Trip delay, T_{od}, can be set as shown in Equation 128.

$$T_{od} = \frac{1 - 2 \cdot f_{slip} \cdot (T_{co} + BrkropenTm)}{2 \cdot f_{slip}}$$

(Equation 128)

T_{od}	Dynamic Trip delay
T_{co}	The time for the impedance to travel from the center impedance line (where the swing angle is π radians) to the outer blinder on the opposite side from which it entered.
BrkopenTm	Set *Breaker open time*
f_{slip}	Slip frequency

The *Breaker open time* setting should include the time from when the relay issues a trip command to the time when the breaker receives the command. The function uses the *Breaker open time* setting to determine the trip delay time if it is not set to “0”. If the *Breaker open time* is set to “0”, the function does not dynamically calculate a trip delay but uses the fixed *Trip delay time* before activating the `TRIP` output.

The slip frequency is calculated using Equation 129.

$$f_{slip} = \frac{\delta_i - \delta_0}{2 \cdot \pi \cdot T_{oi}}$$

(Equation 129)

f_{slip}	Slip frequency
T_{oi}	The time for the impedance to pass from the outer to the inner blinder.
δ_0	Swing angle at the outer blinder
δ_I	Swing angle at the inner blinder

The swing angles, δ_0 and δ_I, are estimated from the measured impedance when crossing the blinders. It is the difference in these quantities that is important for determining the slip frequency.

If the "Adaptive" option is selected, after detecting an OSB condition, the function further examines the slip frequency f_{slip}, *V dip time* setting, and swing angle at the outer blinder (δ_0) to determine if the trip is asserted on the way in or on the way out. TRIP is activated on the way in, entering the mho circle from an inner blinder, if the relationship in Equation 130 is true.

$$f_{slip} \leq \frac{(\pi - \delta_0)}{\pi \cdot VoltagedipTm}$$

(Equation 130)

f_{slip}	Slip frequency
δ_0	Swing angle at the outer blinder
VoltagedipTm	Set *V dip time*

Otherwise, TRIP is activated on the way out, when the impedance exits an outer blinder and the swing repeats for the set *Max number slips* count in the respective enabled zone that the swing has passed through.

If the *Swing time* has elapsed but the impedance exits the inner blinder and continues through the opposite blinders without passing through the mho circle, the SWING output is activated. The SWING output remains activated for a time determined by the *Reset time* setting unless another swing occurs before the reset time expires causing the output to remain active for another *Reset time* interval. If this swing is repeated for the set *Max Num slips Zn3* count and the *Zone 3 enable* setting is "Yes", the SWING_TR output is activated. The SWING_TR output remains activated for a time determined by the *Trip dropout time* setting.

If the “Adaptive” option is selected and an OSB condition is not detected, but the impedance enters the mho circle after remaining between the inner and outer blinders for greater than 1.5 cycles, the function assumes a severe swing and assert the `TRIP` output.

The drop out delay for `TRIP` output can be set by *Trip dropout time* setting.

If the polarity of the voltage signal is opposite to the normal polarity, the correction can be done by setting *Voltage reversal* to “Yes”, which rotates the impedance vector by 180 degrees.

The `DISABLE` input can be used to coordinate the correct operation during the start-up situation. The function is blocked by activating the DISABLE signal. Once the DISABLE signal is deactivated, the function remains blocked (outputs disabled) for additional time duration as set through the setting *Disable time*.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the “Freeze timers” mode, the operation timer is frozen to the prevailing value, but the `TRIP` output is not deactivated when blocking is activated. In the “Block all” mode, the whole function is blocked and the timers are reset. In the “Block TRIP output” mode, the function operates normally but the `TRIP` output is not activated.

4.7.1.5 Application

Out of step protection functions detect stable power swings and out of step conditions based on the fact that the voltage/current variation during a power swing is slow compared to the step change during a fault. Both faults and power swings may cause the measured impedance to enter into the operating characteristic of a distance relay element. The apparent impedance moves from the pre-fault value to a fault value in a very short time, a few milliseconds, during a fault condition. However, the rate of change of the impedance is much slower during a power swing or out of step condition than during a fault depending on the slip frequency of the out of step. The impedance measurement should not be used by itself to distinguish between a fault condition and an out of step condition from a phase fault. The fundamental method for discriminating between faults and power swings is to track the rate of change of the measured impedance.

The function measures the rate of change of the impedance using two impedance measurement elements known as blinders together with a timing device. If the measured impedance stays between the blinders for a predetermined time, the function declares a power swing condition and asserts an output that can be used to block the distance protection. However, if the impedance passes the inner blinder and exits on the other side of the mho characteristics (that is, the resistive component of impedance has opposite sign as at the time of point of entry) an out of step tripping is issued by the function.Figure 344 gives an example of out of step detection.

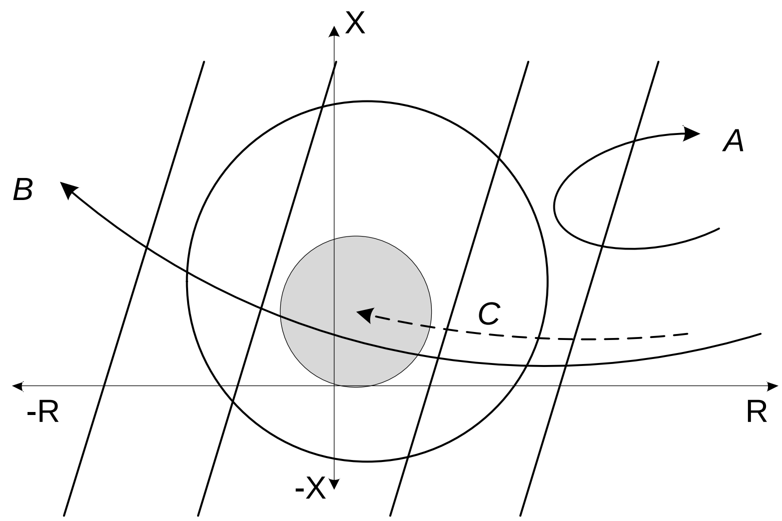


Figure 344: Example of out of step detection

The shaded region indicates a fault zone in a distance protection function. For curve A, the impedance moves into the out of step zone and leaves slowly, indicating the occurrence of a swing that quickly stabilizes. For curve B, the impedance moves slowly into the out of step zone and exits the zone indicating that the network is becoming unstable. For curve C, impedance rapidly moves into, and remains in, the fault zone indicating an actual fault and not an out of step condition.

4.7.1.6 Signals

Table 596: 78 Input signals

Name	Type	Default	Description
V_1	SIGNAL	0.0	Positive phase sequence voltage
I_1	SIGNAL	0.0	Positive phase sequence current
I_2	SIGNAL	0.0	Negative phase sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
DISABLE	BOOLEAN	0=False	Disable input

Table 597: 78 Output signals

Name	Type	Description
TRIP	BOOLEAN	Out of step trip on zone 1 or zone 2
SWING_TRIP	BOOLEAN	Out of step trip on zone 3
SWING	BOOLEAN	Swing condition detected
OSB	BOOLEAN	Out of step block for zone 1
OSB_Z2	BOOLEAN	Out of step block for zone 2

4.7.1.7 Settings

Table 598: 78 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Oos operate mode	1=Way in 2=Way out 3=Adaptive			2=Way out	Operate mode for tripping when out of step condition is detected
Forward reach	0.00...6000.00	ohm	0.01	1000.00	Forward reach of mho circle
Reverse reach	0.00...6000.00	ohm	0.01	100.00	Reverse reach of mho circle
Inner blinder R	1.00...6000.00	ohm	0.01	150.00	Resistance value if inner blinder at R axis
Outer blinder R	1.01...10000.00	ohm	0.01	400.00	Resistance value of outer blinder at R axis
Impedance angle	10.0...90.0	deg	0.1	90.0	Angle of mho circle and blinders with respect to R axis
Swing time	20...300000	ms	10	500	Time between blinders for swing to be detected

Table 599: 78 Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Zone 1 reach	1...100	%	1	70	Percent of Mho forward reach indicating the end of zone 1 and the beginning of zone 2
Max number slips	1...10		1	1	Number of pole slips before operating zone 1
Max Num slips Zn2	1...20		1	1	Number of pole slips before operating zone 2
Max Num slips Zn3	1...20		1	1	Number of pole slips before operating zone 3
Trip delay time	20...60000	ms	10	300	Delay after OOS trip detected
Trip dropout time	20...60000	ms	10	100	Time trip output remains active
V dip time	500...5000	ms	10	2000	Maximum allowable time for voltage to dip
Zone 2 enable	1=Yes 0=No			0=No	Enable zone 2 feature
Zone 3 enable	1=Yes 0=No			0=No	Enable zone 3 feature

Table 600: 78 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 601: 78 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Min Ps Seq current	0.01...10.00	xIn	0.01	0.10	Minimum positive sequence current for operation
Max Ng Seq current	0.01...10.00	xIn	0.01	0.20	Maximum negative sequence current for operation
Breaker open time	0...300	ms	1	30	Opening time of the breaker
Disable time	20...60000	ms	10	5000	Additional time function is disabled after removal of DISABLE input
Reset time	20...60000	ms	10	5000	Time to reset OOS condition and counters
Time to reset OOS condition and counters	0=No 1=Yes			0=No	Rotate voltage signals by 180 degrees

4.7.1.8 Monitored data

Table 602: 78 Monitored data

Name	Type	Values (Range)	Unit	Description
Z1_AMPL	FLOAT32	0.00...99999.00	ohm	Positive sequence impedance amplitude
Z1_ANGLE	FLOAT32	-180...180	deg	Positive sequence impedance phase angle
78	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.7.1.9 Technical data

Table 603: 78 Technical data

Characteristic	Value
Impedance reach	Depending on the frequency of the measured current and voltage: f_n ±2 Hz
	±3.0% of the reach value or ±0.2% of $V_n/(\sqrt{3} \times I_n)$
Reset time	±1.0% of the set value or ±40 ms
Trip time accuracy	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5...

4.7.2 Three-phase underexcitation protection 40

4.7.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase underexcitation protection	UEXPDIS	X<	40

4.7.2.2 Function block

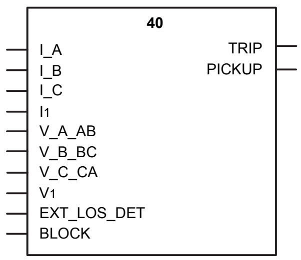


Figure 345: Function block

4.7.2.3 Functionality

The three-phase underexcitation protection function 40 is used to protect the synchronous machine against the underexcitation or loss of excitation condition.

The protection is based on the offset-mho circular characteristics on the impedance plane. The function calculates the apparent impedance from the machine terminal voltages and currents. If the impedance vector enters the offset-mho circle, the function gives the trip signal after a set definite time. The operating time characteristics are according to definite time (DT).

This function contains a blocking functionality. It is possible to block the function outputs, timer or the function itself, if desired.

4.7.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 40 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

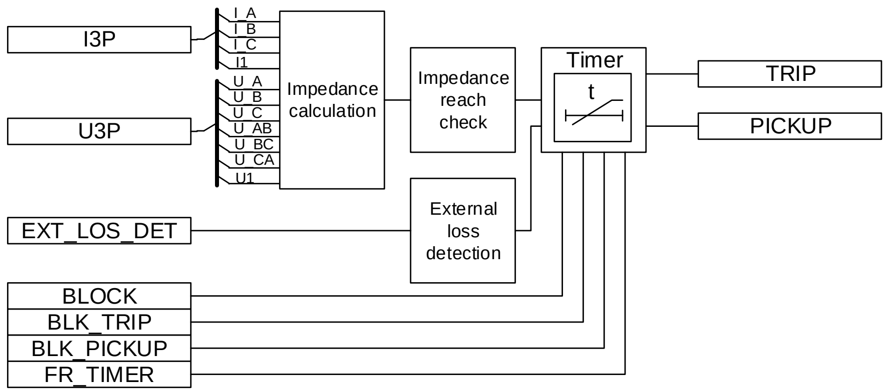


Figure 346: Functional module diagram

Impedance calculation

This module calculates the apparent impedance based on the selected voltages and currents. The *Measurement mode* and *Phase Sel for Z Clc* settings determine which voltages and currents are to be used. If the *Measurement mode* is set to "1Phase-earth" or "1Phase-phase", the *Phase Sel for Z Clc* setting is needed for determining which phase or phase-phase voltages ("A or AB", "B or BC" and "C or CA") and currents should be used for calculating the impedance.

Table 604: Voltages and currents used in impedance calculation

Measurement mode	Phase Sel for Z Clc	Voltages and currents
1Phase-earth	A or AB	V_A, I_A
1Phase-earth	B or BC	V_B, I_B
1Phase-earth	C or CA	V_C, I_C
1Phase-phase	A or AB	V_AB, I_A, I_B
1Phase-phase	B or BC	V_BC, I_B, I_C
1Phase-phase	C or CA	V_CA, I_C, I_A
3Phase-earth	N/A	V_A, V_B, V_C, I_A, I_B, I_C
3Phase-phase	N/A	V_AB, V_BC, V_CA, I_A, I_B, I_C
Pos seqn	N/A	{ V_A,V_B,V_C } or { V_AB,V_BC,V_CA } and I_A, I_B, I_C

If all three phase voltages and phase currents are fed to the protection relay, the positive-sequence alternative is recommended.

If the polarity of the voltage signals is opposite to the normal polarity, the correction can be done by setting *Voltage reversal* to "Yes", which rotates the impedance vector by 180 degrees.

If the magnitude of the voltage is less than $0.05 \cdot V_N$, the calculated impedance is not reliable and the impedance calculation is disabled. V_N is the rated phase-to-phase voltage.

The calculated impedance magnitudes and angles are available in the Monitored data view. The impedance angles are provided between -180...180 degrees.

The calculated apparent impedance is converted to pu impedance as the operating characteristics are defined with the pu settings.

Impedance reach check

The operating characteristic is a circular offset mho on the impedance plane. The operating characteristics are defined with the *Offset*, *Diameter* and *Displacement* settings. If the calculated impedance value enters the circle in the impedance plane, the module sends an enabling signal to start the Timer.

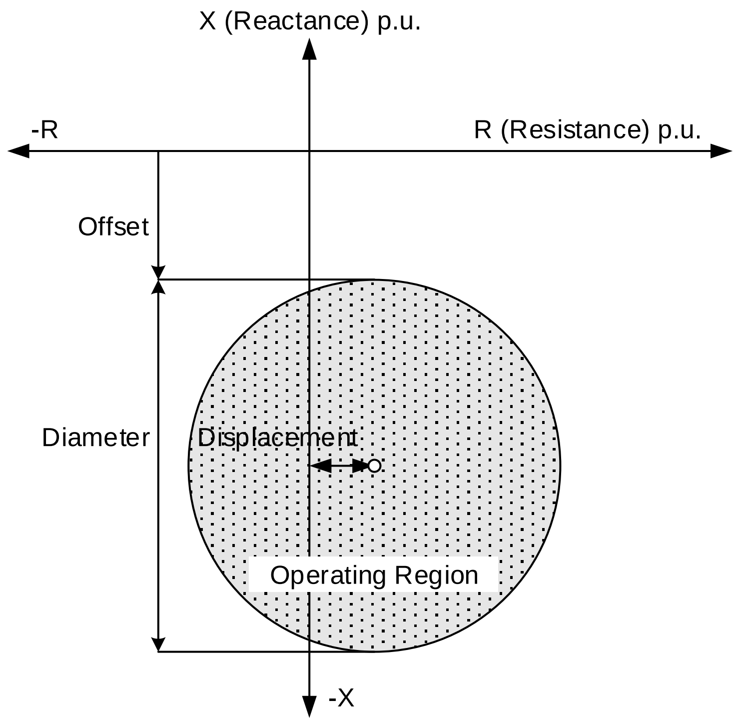


Figure 347: Operating region of the impedance mho circle

A fault in Automatic Voltage Regulator (AVR) or in the excitation system may cause a total loss of excitation. A short circuit on the slip rings reduces the excitation voltage to zero. This causes a gradual reduction of the excitation current and eventually a loss of excitation. An open circuit in the field circuit also causes a loss of excitation. These are typical examples which cause underexcitation in synchronous machines. This module detects the underexcitation condition for the above cases when the calculated impedance enters the operating characteristics.

External loss detection

The module checks the status information of the excitation system. It is activated when the *External Los Det Ena* setting is set to "Enable". The total loss of excitation current or a failure in the excitation system is indicated by connecting the external binary signal to the `EXT_LOS_DET` input. The Timer is enabled immediately when the `EXT_LOS_DET` input is activated.

Timer

Once activated, the Timer activates the PICKUP output. The time characteristic is according to DT. When the duration of the underexcitation exceeds the set definite *Trip delay time*, the TRIP output is activated. If the impedance locus moves out of the offset-mho operating characteristics before the module operates, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operating timer resets and the PICKUP output is deactivated.

The Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the start situation and the set operating time (DT). The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operate timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.7.2.5 Application

There are limits for the underexcitation of a synchronous machine. A reduction of the excitation current weakens the coupling between the rotor and the external power system. The machine may lose the synchronism and start to operate like an induction machine, which increases the consumption of the reactive power. Even if the machine does not lose synchronism, it is not recommended to operate in this state. The underexcitation causes excessive heating in the end region of the stator winding. This can damage the insulation of the stator winding and even the iron core.

The underexcitation also causes the generator to operate in the asynchronous mode. This increases the rotor speed, which causes heating in the rotor iron and damps the windings. A high intake of the reactive power from the network during underexcitation causes problems in the network, for example voltage dip, stability and power swings. Power swings stress the prime mover, causing for example turbine blade cavitation and mechanical stress in the gearbox.

The capability curve of a synchronous generator describes the underexcitation capability of the machine. An excessive capacitive load on the synchronous machine causes it to drop out-of-step. The reason is the steady-state stability limit as defined by the load angle being 90°, which can only be reached when the unit is underexcited.

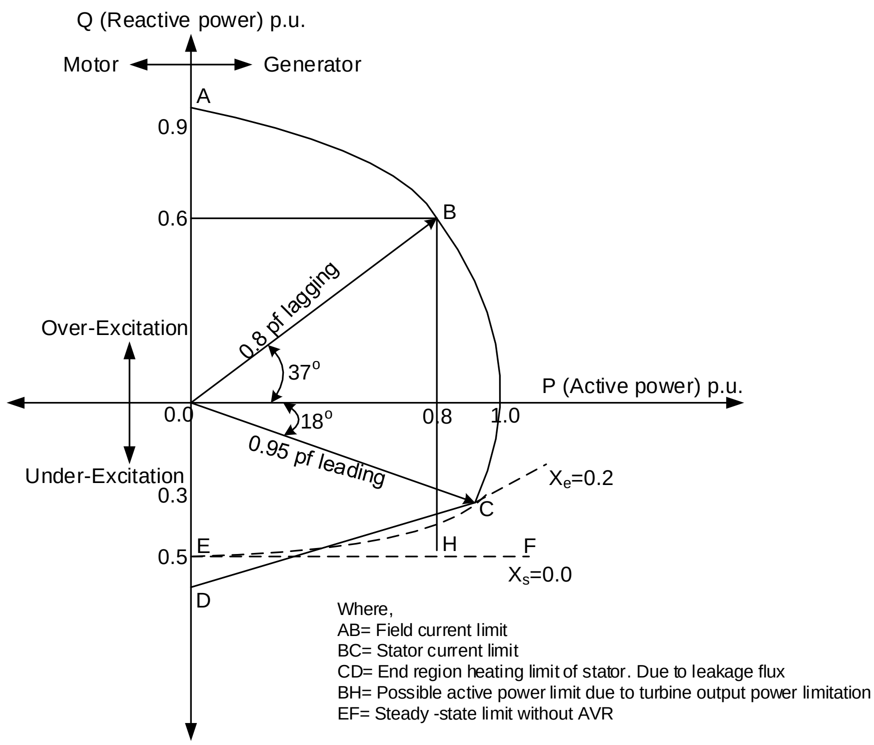


Figure 348: Capability curve of a synchronous generator

40 protects the synchronous machines against an unstable operation due to loss of excitation. A partial or total loss of excitation causes a reactive power intake from the network to the machine, and the reactance of the system viewed from the machine terminals turns negative. This kind of drop-of-reactance condition can be detected by measuring the impedance of the system.

The operating characteristic is an offset-mho circle in the impedance plane, and the circle is parameterized with the *Offset*, *Diameter* and *Displacement* setting values.

Table 605: Parameters of the circle

Setting values	Description
Offset	Distance of the top of the circle from the R-axis. This is usually set equal to - x_d'/2, where x_d' is the transient reactance of the machine. The sign of the setting value determines the top of the circle regarding the R-axis. If the sign is negative, the circle lies below the R-axis.
Diameter	Normally set equal to the machine's synchronous reactance x_d, which determines the size of the impedance circle.
Displacement	Displacement of the center of the circle from the reactance axis or the R-coordinate of the center. The setting can be used to adjust the sensitivity of the underexcitation protection. If the sign of the setting is positive, the circle is shifted to the right, that is, closer to the normal operating point. Respectively, if the sign is negative, the circle is shifted to the left and thus moves away from the normal operating point.

The setting parameters of the off-set mho circle are to be given in pu values. The base impedance (Z_N) in ohms is:

$$Z_N = \left| \frac{V_N^2}{S_N} \right|$$

(Equation 131)

V_N rated (phase-to-phase) voltage in kV

S_N rated power of the protected machine in MVA

The corresponding calculation to convert ohms to pu values is:

$$X_{pu} = \frac{X_{ohm}}{Z_N}$$

(Equation 132)

X_{pu} pu value

X_{ohm} reactance in ohms

Z_N base impedance

Example of impedance locus in underexcitation

In an example of a typical impedance locus, once the impedance locus enters the relay operation characteristics, the relay operates after a settable definite time.

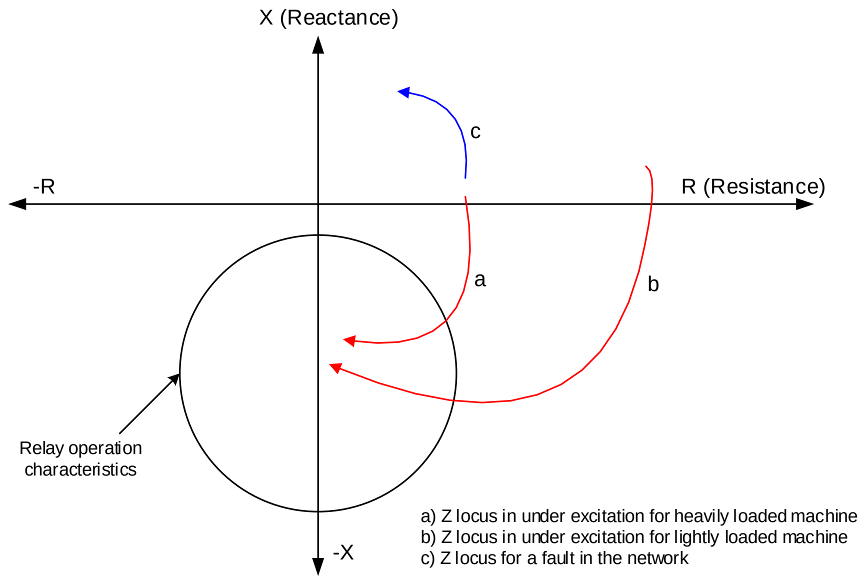


Figure 349: Typical impedance locus in underexcitation: a) heavy load b) light load c) fault in the network

4.7.2.6 Signals

Table 606: 40 Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_1	SIGNAL	0	Positive sequence current
V_A_AB	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B_BC	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C_CA	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
V_1	SIGNAL	0	Positive phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
EXT_LOS_DET	BOOLEAN	0=False	External signal for excitation loss detection

Table 607: 40 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.7.2.7 Settings

Table 608: 40 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Diameter	1...6000	%Zn	1	200	Diameter of the Mho diagram
Offset	-1000...1000	%Zn	1	-10	Offset of top of the impedance circle from the R-axis
Displacement	-1000...1000	%Zn	1	0	Displacement of impedance circle centre from the X-axis
Trip delay time	60...200000	ms	10	5000	Trip delay time

Table 609: 40 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
External Los Det Ena	0=Disable 1=Enable			1=Enable	Enable external excitation loss detection
Voltage reversal	0=No 1=Yes			0=No	Rotate voltage signals by 180 degrees
Impedance Meas mode	1=1Phase-to-earth 2=1Phase-to-phase 3=3Phase-to-earth 4=3Phase-to-phase 5=Pos sequence			5=Pos sequence	Select voltage and currents for impedance calculation
Phase Sel for Z Clc	1=A or AB 2=B or BC 3=C or CA			1=A or AB	Voltage phase selection

Table 610: 40 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	3000	Reset delay time

4.7.2.8 Monitored data

Table 611: 40 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time (in %)
Z_AMPL_A	FLOAT32	0.00...200.00	xZn	Impedance amplitude phase A
Z_ANGLE_A	FLOAT32	-180.00...180.00	deg	Impedance angle phase A
Z_AMPL_B	FLOAT32	0.00...200.00	xZn	Impedance amplitude phase B
Z_ANGLE_B	FLOAT32	-180.00...180.00	deg	Impedance angle phase B
Z_AMPL_C	FLOAT32	0.00...200.00	xZn	Impedance amplitude phase C
Z_ANGLE_C	FLOAT32	-180.00...180.00	deg	Impedance angle phase C
Z_AMPL_AB	FLOAT32	0.00...200.00	xZn	Phase-to-phase A-B impedance amplitude
Z_ANGLE_AB	FLOAT32	-180.00...180.00	deg	Phase-to-phase A-B impedance phase angle
Z_AMPL_BC	FLOAT32	0.00...200.00	xZn	Phase-to-phase B-C impedance amplitude
Z_ANGLE_BC	FLOAT32	-180.00...180.00	deg	Phase-to-phase B-C impedance phase angle
Z_AMPL_CA	FLOAT32	0.00...200.00	xZn	Phase-to-phase C-A impedance amplitude
Z_ANGLE_CA	FLOAT32	-180.00...180.00	deg	Phase-to-phase C-A impedance phase angle
Z1_AMPL	FLOAT32	0.00...200.00	xZn	Positive sequence impedance amplitude
Z1_ANGLE	FLOAT32	-180.00...180.00	deg	Positive sequence impedance phase angle
40	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.7.2.9 Technical data

Table 612: 40 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current and voltage: $f = f_n \pm 2$ Hz
	±3.0% of the set value or ±0.2% Zb
Pickup time[1)2)]	Typically 45 ms
Reset time	Typically 30 ms
Reset ratio	Typically 1.04
Retardation time	Total retardation time when the impedance returns from the operating circle <40 ms
Trip time accuracy	±1.0% of the set value or ±20 ms
Suppression of harmonics	-50 dB at $f = n \times f_n$, where n = 2, 3, 4, 5,…

1) f_n= 50Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.7.3 Three-phase underimpedance protection 21G

4.7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase underimpedance protection	UZPDIS	Z<G	21G

4.7.3.2 Function block

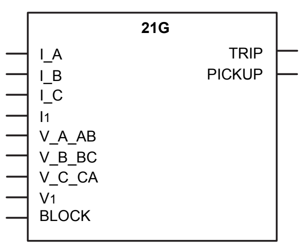


Figure 350: Function block

4.7.3.3 Functionality

The three-phase underimpedance protection 21G is generally applied as a backup protection for generators and transformers against short circuit faults.

The protection is based on the origin-centric circular characteristics on the impedance plane. The function calculates the impedance value from the voltage and current phasors. If the impedance vector enters the origin-centric circle, the function produces the tripping signal after a set delay. The operating time characteristics are according to definite time (DT).

This function contains a blocking functionality. It is possible to block the function outputs, reset timer or the function itself, if desired.

4.7.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 21G can be described with a module diagram. All the modules in the diagram are explained in the next sections.

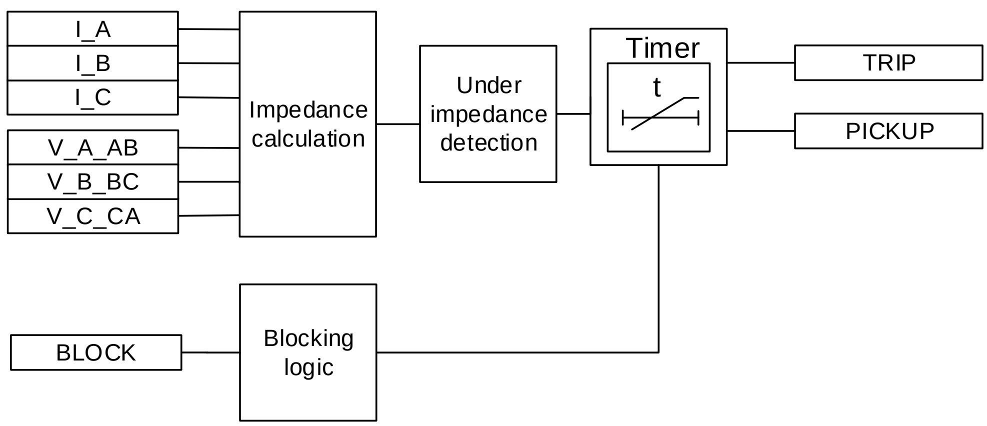


Figure 351: Functional module diagram

Impedance calculation

This module calculates the impedance based on the selected voltages and currents. The *Impedance Meas mode* and *Phase Sel for Z Clc* settings determine which voltages and currents are to be used. If *Impedance Meas mode* is set to "1Phase-phase", the *Phase Sel for Z Clc* setting is needed for determining which phase-phase voltages ("AB", "BC" and "CA") and currents should be used for calculating the impedance.

Table 613: Voltages and currents used in impedance calculation

Impedance Meas mode	Phase Sel for Z Clc	Voltages and currents used in impedance calculation[1)]
1Phase-phase	AB	$\overline{ZAB} = \frac{V\_AB}{I\_A - I\_B}$
1Phase-phase	BC	$\overline{ZBC} = \frac{V\_BC}{I\_B - I\_C}$
1Phase-phase	CA	$\overline{ZCA} = \frac{V\_CA}{I\_C - I\_A}$
3Phase-phase	N/A	$\overline{ZAB} = \frac{V\_AB}{I\_A - I\_B}$ $\overline{ZBC} = \frac{V\_BC}{I\_B - I\_C}$ $\overline{ZCA} = \frac{V\_CA}{I\_C - I\_A}$

1) Voltages and currents in the calculations are given in volts and amps.

If all three phase or phase-phase voltages and phase currents are fed to the protection relay, the "3Phase-phase" mode is recommended.

The current measurement of the function is based on two alternative measurement modes, "DFT" and "Peak-To-Peak". The measurement mode is selected using the *Measurement mode* setting.

If the current magnitude is below $0.02 \cdot I_N$, where I_N is the nominal phase current, the impedance value is not evaluated and the maximum impedance value (99.999 pu) is shown in the Monitored data view.

The calculated impedances are converted to a pu impedance as the operating characteristics are defined using the *Polar reach* setting in %Zb.

The calculated phase-phase impedance amplitudes ZAB_AMPL, ZBC_AMPL and ZCA_AMPL are available as pu values in the Monitored data view.

Underimpedance detection

The operating characteristic is an origin-centric circle on the impedance plane. The origin-centric circular characteristic is defined using the *Polar reach* setting. If the calculated impedance value enters the circle in the impedance plane, the module sends an enabling signal to start the Timer.

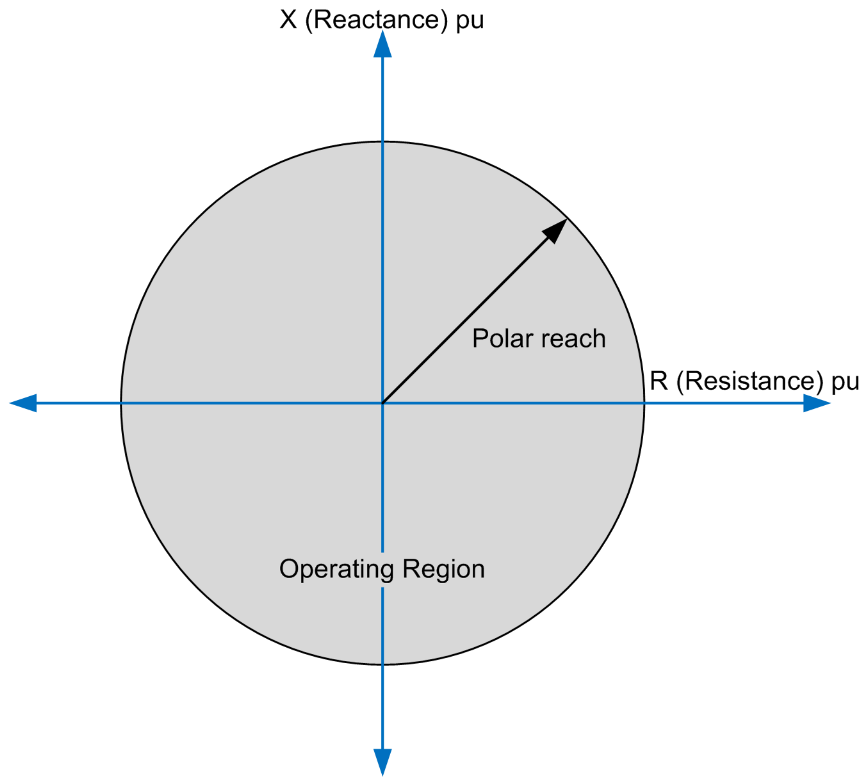


Figure 352: Origin-centric circular operating characteristics

More than one impedance value is available when *Impedance Meas mode* is set to "3Phase-phase", and the function considers the lowest impedance value for picking up and tripping.

Timer

Once activated, the Timer activates `PICKUP` output. The time characteristic is according to DT. When the duration of the underimpedance condition exceeds the set definite *Trip delay time*, the `TRIP` output is activated. If the impedance locus moves out of circular operating characteristics before the module operates, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operating timer resets and the PICKUP output is deactivated.

The Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the start situation and the set operating time (DT). The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operate timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.7.3.5 Application

The three-phase underimpedance protection is used as a backup protection against short circuit faults at the generator terminals or on the high-voltage side of a step-up transformer. This function can be used either instead of the definite time voltage-dependent overcurrent protection or to obtain a limited protection zone and the optimum operating time instead of the non-directional overcurrent protection.

Comparison between overcurrent and underimpedance protection

Phase current for three-phase short circuit is shown in Figure 353. In this case, with an ordinary over current relay having the current setting as $1.2 \cdot I_n$, the time setting should be less than 0.2 seconds, since with a higher value the short-circuit current decays below the set value and the relay drops off. The current setting can also be reduced to $1.1 \cdot I_n$, although this provides no substantial rise in the time setting. In some situations, either of the above current settings is appropriate, but if longer tripping times are required to maintain the time selectivity, the underimpedance protection is needed.

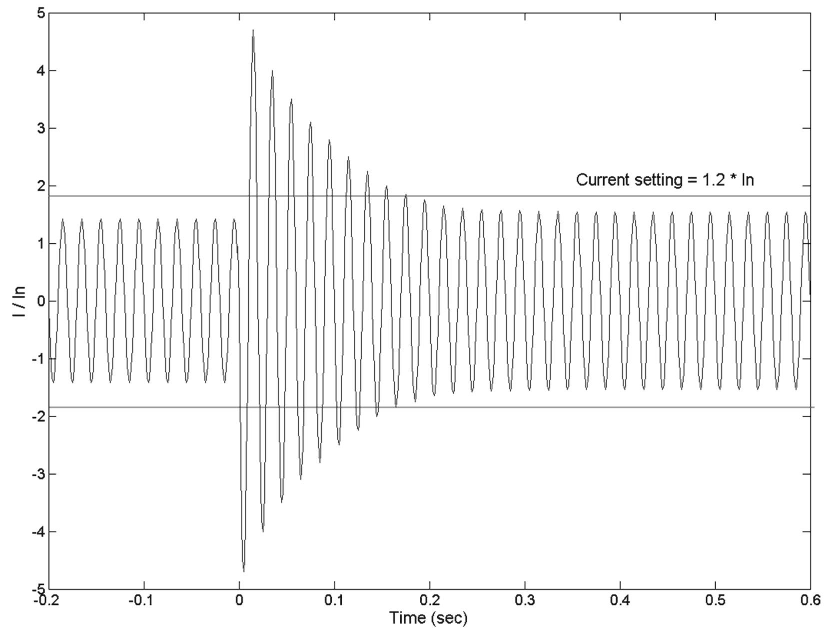


Figure 353: Short circuit current waveform, fault occurs at time 0 seconds (Current setting limit is multiplied by the square root of 2)

The phase voltage in a three-phase short circuit when a fault occurs at time = 0 s is shown in Figure 354. The voltage drop caused by a three-phase fault provides more time for determining the fault by means of an underimpedance protection.

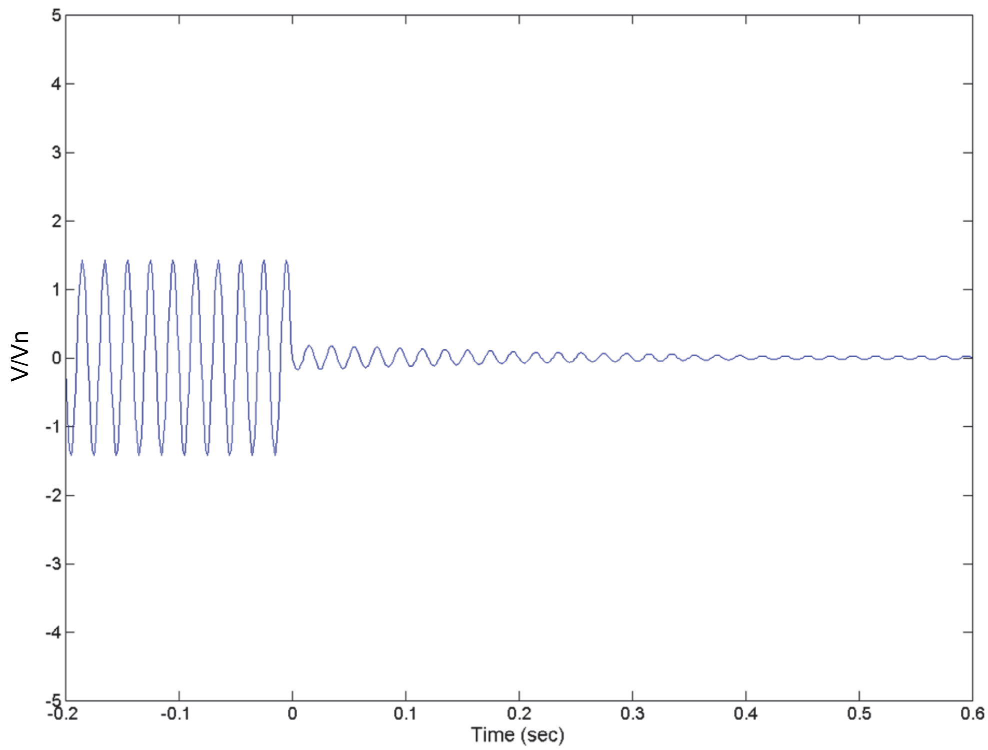


Figure 354: Short-circuit voltage waveform, fault occurs at time 0 seconds

In a typical impedance trajectory during a short circuit, the fault impedance remains inside the impedance circle for a longer time, in which case the underimpedance protection provides longer tripping delay times to maintain the time selectivity.

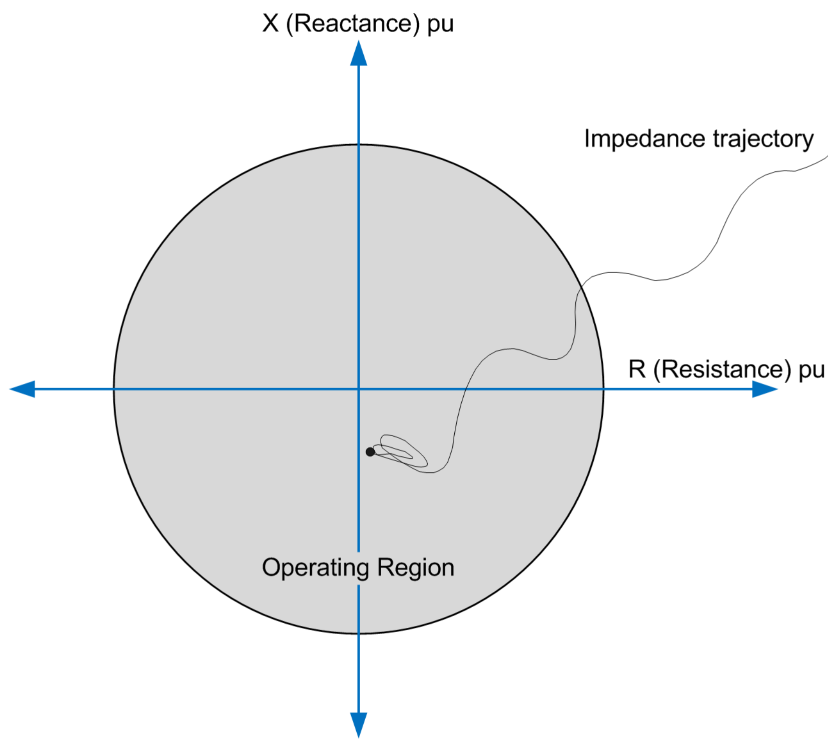


Figure 355: Typical impedance trajectory during a short circuit

Underimpedance protection for transformers

The underimpedance function is used as a short circuit protection instead of the overcurrent protection. It is also used as a backup to the differential protection of transformers.

The voltage and current phasors are measured with the VTs and CTs connected on the HV side of the transformer.

The phase and current shifts due to transformer D/Y connections and other factors complicate the settings for the faults in the secondary winding (as seen from the protection relay), and detailed calculations are necessary for a good coverage.

The *Polar reach* setting is set to a value equal to 150 percent of the transformer short circuit impedance. The setting also provides a backup protection for the busbar and feeder faults on the HV side.

Underimpedance protection for generators

The underimpedance protection is set to protect the zone between the generator windings and the generator side windings of the step-up transformer. The function mainly protects the generator bus, the low-voltage part of the step-up transformer and a part of the stator winding against any short circuits.

The voltages should be measured from the generator terminals and the phase currents from the neutral point of the generator.

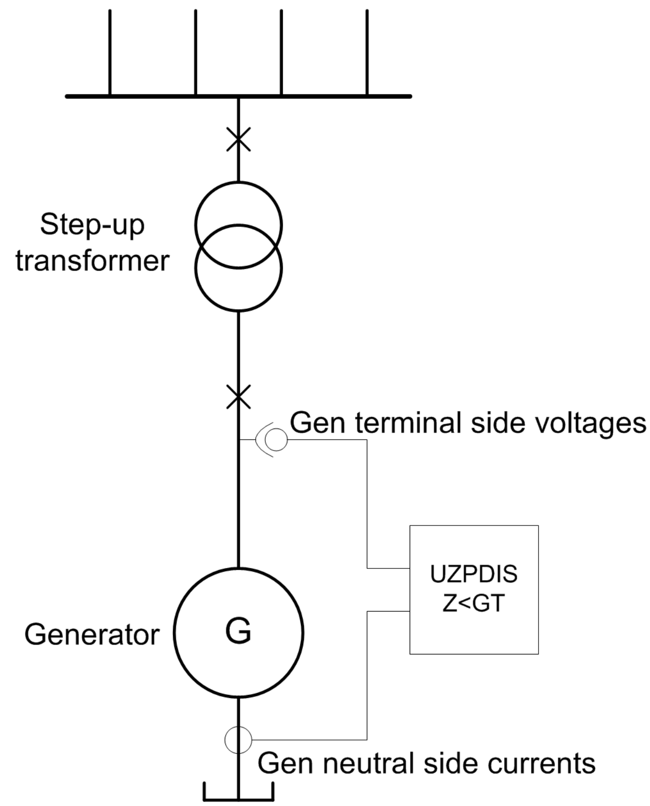


Figure 356: Current and voltage signals for underimpedance protection

To prevent malfunctioning of the underimpedance protection in case of nearby faults, the *Polar reach* setting is set to a value equal to 70 percent of the step-up transformer short circuit impedance.

In directly connected machines where the impedance towards the network is limited only by the lines or bus bars, it must be secured that the function does not cause any selectivity problems. In such cases, it is recommended to use the voltage-dependent overcurrent protection instead of the underimpedance protection.

Function blocking guidelines

The operation of the underimpedance protection must be restrained if the voltage in one or more phases suddenly drops close to zero without any significant change in the current observed at the same time. This situation is considered as a fuse failure or a miniature circuit breaker operation in the voltage transformer secondary circuit. The voltage drop could cause an unwanted operation of the function block since the calculated impedance could fall below the set operating limit even if there is no actual fault in the primary system.

The blocking operation is provided by an external function block, the fuse failure supervision 60, whose output is connected to the BLOCK input of 21G.

4.7.3.6 Signals

Table 614: 21G Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_1	SIGNAL	0	Positive sequence current
V_A_AB	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B_BC	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C_CA	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
V_1	SIGNAL	0	Positive phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 615: 21G Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.7.3.7 Settings

Table 616: 21G Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Percentage reach	1...6000	%Zn	1	7	Radius of the origin centric circle
Trip delay time	40...200000	ms	10	200	Trip delay time

Table 617: 21G Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Measurement mode	2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode
Impedance Meas mode	2=1Phase-to-phase 4=3Phase-to-phase			4=3Phase-to-phase	Select voltage and current signals for impedance calculation
Phase Sel for Z Clc	1=AB 2=BC 3=CA			1=AB	Voltage phase selection

Table 618: 21G Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time

4.7.3.8 Monitored data

Table 619: 21G Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time (in %)
Z_AMPL_AB	FLOAT32	0.00...200.00	xZn	Phase-to-phase A-B impedance amplitude
Z_AMPL_BC	FLOAT32	0.00...200.00	xZn	Phase-to-phase B-C impedance amplitude
Z_AMPL_CA	FLOAT32	0.00...200.00	xZn	Phase-to-phase C-A impedance amplitude
21G	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.7.3.9 Technical data

Table 620: 21G Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current and voltage: f_n ±2 Hz
	±3.0% of the set value or ±0.2 %Zb
Pickup time[1)2)]	Typically 50 ms
Reset time	Typically 40 ms
Reset ratio	Typically 1.04
Retardation time	<40 ms
Trip time accuracy	±1.0% of the set value or ±20 ms

1) f_n = 50 Hz, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.8 Power protection

4.8.1 Underpower protection 32U

4.8.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Underpower protection	DUPPDPR	P<	32U

4.8.1.2 Function block

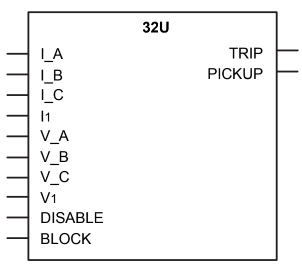


Figure 357: Function block

4.8.1.3 Functionality

The underpower protection function 32U is used for protecting generators and prime movers against the effects of very low power outputs or reverse power condition.

The function operates when the measured active power falls below the set value. The operating characteristics are according to definite time DT.

This function contains a blocking functionality. It is possible to block the function outputs, timer or the function itself, if desired.

4.8.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 32U can be described using a module diagram. All the modules in the diagram are explained in the next sections.

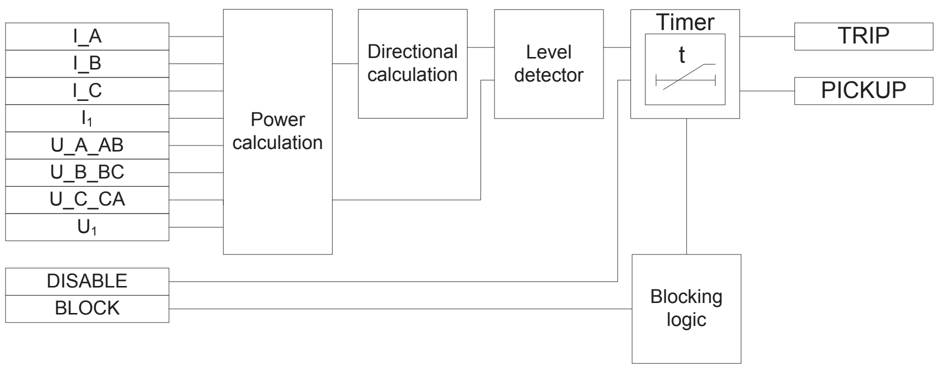


Figure 358: Functional module diagram

Power calculation

This module calculates the apparent power based on the selected voltage and current measurements as described in Table 621. The *Measurement mode* setting determines which voltage and current measurements are to be used.

It is also possible to use positive-sequence components for calculating apparent power, which makes the determination of power insensitive to the possible asymmetry in currents or voltages and corresponds to the real load of the prime mover of the generator.

Table 621: Power calculation

Measurement mode setting	Power calculation
PhsA, PhsB, PhsC	$\bar{S} = \bar{V}_a \cdot \bar{I}_a^* + \bar{V}_b + \bar{I}_b^* + \bar{V}_c \cdot \bar{I}_c^*$ $P = Re(\bar{S})$
Arone	$\bar{S} = \bar{V}_{ab} \cdot \bar{I}_a^* - \bar{V}_{bc} \cdot \bar{I}_c^*$ $P = Re(\bar{S})$
Pos Seq	$\bar{S} = 3 \cdot \bar{V}_1 \cdot \bar{I}_1^*$ $P = Re(\bar{S})$
PhsAB	$\bar{S} = \sqrt{3} \cdot \bar{V}_{ab} \cdot (\bar{I}_a^* - \bar{I}_b^*)$ $P = Re(\bar{S})$
PhsBC	$\bar{S} = \sqrt{3} \cdot \bar{V}_{bc} \cdot (\bar{I}_b^* - \bar{I}_c^*)$ $P = Re(\bar{S})$
PhsCA	$\bar{S} = \sqrt{3} \cdot \bar{V}_{ca} \cdot (\bar{I}_c^* - \bar{I}_a^*)$ $P = Re(\bar{S})$
PhsA	$\bar{S} = 3 \cdot \bar{V}_a \cdot \bar{I}_a^*$ $P = Re(\bar{S})$
PhsB	$\bar{S} = 3 \cdot \bar{V}_b \cdot \bar{I}_b^*$ $P = Re(\bar{S})$
PhsC	$\bar{S} = 3 \cdot \bar{V}_c \cdot \bar{I}_c^*$ $P = Re(\bar{S})$

If all three phase voltages and phase currents are fed to the protection relay, the positive-sequence alternative is recommended (default).

Depending on the set *Measurement mode*, the power calculation calculates active power, reactive power and apparent power values from the available set of measurements. The calculated powers S, P, Q and the power factor angle, PF_ANGL, are available in the Monitored data.

Directional calculation

The Directional calculation determines the direction of the measured power. The measured power is considered to be in the forward direction if the active power is positive, else it is considered to be in the reverse direction.

If the polarity of the measured power is opposite to normal, the correction can be done by setting *Pol reversal* to "True", which rotates the apparent power by 180 degrees.

Level detector

The Level detector compares the calculated value of the active power with a set *Pickup value*. If the calculated value of the active power falls below *Pickup value* in the forward direction or if the measured power is in the reverse direction, the Level detector enables the Timer module.

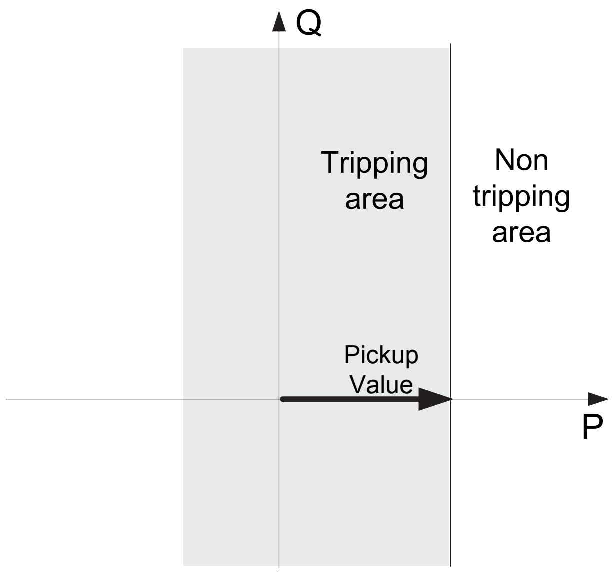


Figure 359: Operating characteristics of 32U with setting Pickup value

Timer

Once activated, the Timer activates the `PICKUP` output. The time characteristics are according to DT. When the operation timer has reached the value of *Trip delay time*, the `TRIP` output is activated. In a drop-off situation, that is, if the underpower condition disappears before the operation delay is exceeded, the timer reset state is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the `PICKUP` output is deactivated.

The Timer calculates the PICKUP_DUR value which indicates the percentage of the time elapsed since the activation of the PICKUP output with respect to *Trip delay time*. The value is available in the Monitored data.

The DISABLE input can be used to coordinate the correct operation during the generator start-up situation. By activating the DISABLE signal, both the PICKUP and TRIP outputs are blocked. Once the DISABLE signal is deactivated, the Timer remains blocked for an additional time duration as set through the setting *Disable time*.

Blocking logic

There are three operation modes in the blocking functionality. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.8.1.5 Application

The task of a generator in a power plant is to convert mechanical energy into electrical energy. Sometimes the mechanical power from the prime mover may decrease so much that it does not cover the internal losses. The task of an underpower protection is to protect the generator from very low power output conditions.

Steam turbines become easily overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. Hydro turbine of the Kaplan type may be damaged due to the fact that the turbine blade surfs on the water and sets up axial pressure on the bearing. Diesel engines may be damaged due to insufficient lubrication.

If the generator size is very large, it is uneconomical to continue running it with low generated power. In the reverse power condition, large generators draw a considerable amount of power from the rest of the system to feed their internal losses. Hence, it is desirable to disconnect the generator in such situations.

In case of the parallel-connected generators, for example, the load of one generator may be so low that it is better to disconnect it and let the remaining generators feed the network.

Where a low value of power setting is required, for example less than 2%, the correction parameters should be used to compensate for the measuring errors. The manufacturer of the measuring devices is to be contacted for information on the measuring errors.

If the measuring errors are not compensated for, the underpower setting should not be lower than the sum of the current-measuring and voltage-measuring errors.

For example, if the error of the current-measuring device is 2% and that of the voltage-measuring device is 1%, the minimum setting is (2 + 1)% = 3%.

4.8.1.6 Signals

Table 622: 32U Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I1	SIGNAL	0	Positive sequence current
V_A	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
V1	SIGNAL	0	Positive phase sequence voltage
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
DISABLE	BOOLEAN	0=False	Signal to block the function during generator startup

Table 623: 32U Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.8.1.7 Settings

Table 624: 32U Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.01...2.00	xSn	0.01	0.10	Pickup value
Trip delay time	40...300000	ms	10	40	Trip delay time

Table 625: 32U Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 626: 32U Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=PhsA, PhsB, PhsC 2=Arone 3=Pos Seq 4=PhsAB 5=PhsBC 6=PhsCA 7=PhsA 8=PhsB 9=PhsC			3=Pos Seq	Selection of power calculation method
Reset delay time	0...60000	ms	10	20	Reset delay time
Pol reversal	0=False 1=True			0=False	Reverse the definition of the power direction
Disable time	0...60000	ms	1000	0	Additional wait time after CB closing

4.8.1.8 Monitored data

Table 627: 32U Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
P	FLOAT32	-160.000...160.000	xSn	Active power
Q	FLOAT32	-160.000...160.000	xSn	Reactive power
S	FLOAT32	0.000...160.000	xSn	Apparent power
PF_ANGLE	FLOAT32	-180.00...180.00	deg	Power factor angle
32U	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.8.1.9 Technical data

Table 628: 32U Technical data

Characteristic	Value
Operation accuracy 1)	Depending on the frequency of the measured current and voltage: f_n ±2 Hz
	Power measurement accuracy ±3% of the set value or ±0.002 × S_n Phase angle: ±2°
Pickup time2)3)	Typically 45 ms
Reset time	Typically 30 ms
Reset ratio	Typically 1.04
Trip time accuracy	±1.0% of the set value of ±20 ms
Suppression of harmonics	-50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) *Measurement mode* = “Pos Seq” (default)
2) V = V_n, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
3) Includes the delay of the signal output contact

4.8.2 Reverse power/directional overpower protection 32R/32O

4.8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEE C37.2 device number
Reverse power/directional overpower protection	DOPPDPR	P>/Q>	32R/32O

4.8.2.2 Function block

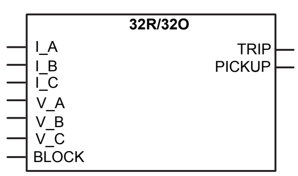


Figure 360: Function block

4.8.2.3 Functionality

The reverse power/directional overpower protection function 32R/32O can be used for generator protection against delivering an excessive power beyond the generator's capacity to the grid, against the generator running like a motor, and against the motor running like a generator and for protecting a motor which consumes more reactive power due to loss of field. It can also be used in feeder protection for indicating overload on the distribution system, to indicate that a customer is supplying power into the grid and for protecting the transformer from delivering an excessive load.

The function picks ups and trips when the measured power exceeds the set limit and in a specified direction. The operate time characteristics are according to definite time (DT).

This function contains a blocking functionality. It is possible to block the function outputs, timer or the function itself, if desired.

4.8.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 32R/32O can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

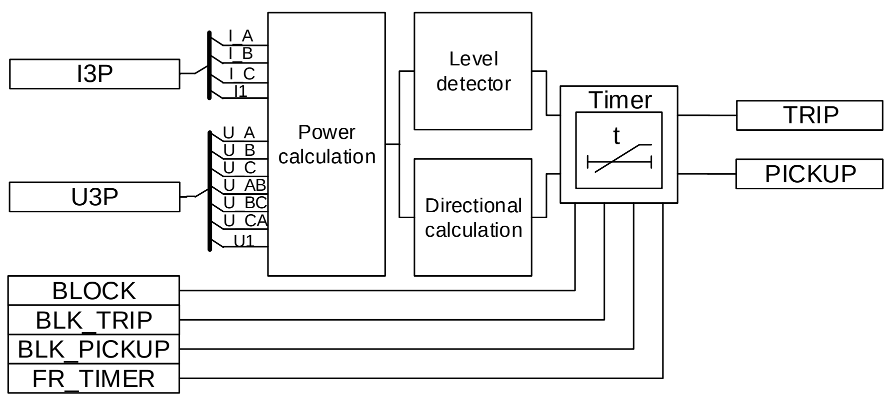


Figure 361: Functional module diagram

Power calculation

This module calculates the apparent power based on the selected voltages and currents. The *Measurement mode* setting determines which voltages and currents are used. It is also possible to use positive-sequence components for calculating the apparent power which makes the determination of power insensitive to a possible asymmetry in currents or voltages and corresponds to the real load on the prime mover of the generator.

Table 629: Power calculation

Measurement mode setting	Power calculation
PhsA, PhsB, PhsC	$\bar{S} = \bar{V}_a \cdot \bar{I}_a^* + \bar{V}_b + \bar{I}_b^* + \bar{V}_c \cdot \bar{I}_c^*$ $P = Re(\bar{S})$
Arone	$\bar{S} = \bar{V}_{ab} \cdot \bar{I}_a^* - \bar{V}_{bc} \cdot \bar{I}_c^*$ $P = Re(\bar{S})$
Pos Seq	$\bar{S} = 3 \cdot \bar{V}_1 \cdot \bar{I}_1^*$ $P = Re(\bar{S})$
PhsAB	$\bar{S} = \sqrt{3} \cdot \bar{V}_{ab} \cdot \left(\bar{I}_a^* - \bar{I}_b^*\right)$ $P = Re(\bar{S})$
PhsBC	$\bar{S} = \sqrt{3} \cdot \bar{V}_{bc} \cdot \left(\bar{I}_b^* - \bar{I}_c^*\right)$ $P = Re(\bar{S})$
PhsCA	$\bar{S} = \sqrt{3} \cdot \bar{V}_{ca} \cdot \left(\bar{I}_c^* - \bar{I}_a^*\right)$ $P = Re(\bar{S})$
PhsA	$\bar{S} = 3 \cdot \bar{V}_a \cdot \bar{I}_a^*$ $P = Re(\bar{S})$
PhsB	$\bar{S} = 3 \cdot \bar{V}_b \cdot \bar{I}_b^*$ $P = Re(\bar{S})$
PhsC	$\bar{S} = 3 \cdot \bar{V}_c \cdot \bar{I}_c^*$ $P = Re(\bar{S})$

If all three phase voltages and phase currents are fed to the protection relay, the positive-sequence alternative is recommended.

The calculated powers S, P, Q and the power factor angle PF_ANGL are available in the Monitored data view.

Level detector

The Level detector compares the magnitude of the measured apparent power to the set *Pickup value*. If the measured value exceeds the set *Pickup value*, the Level detector sends an enabling signal to the Timer module.

Directional calculation

The Directional calculation module monitors the direction of the apparent power. When the apparent power flow is in the operating area, the module sends the enabling signal to the Timer module. The directional operation can be selected with the combination of the settings *Directional mode* and *Power angle*. The selectable options for the *Directional mode* setting are "Forward" and "Reverse". The *Power angle* setting can be used to set the power direction between the reactive and active power.

A typical error is, for example, that the VT or CT poles are wrongly connected. This is seen as a power flow opposite to that of the intended direction. The *Pol Reversal* setting can be used to correct the situation. By setting the value to "True", the measured apparent power is turned 180 degrees.

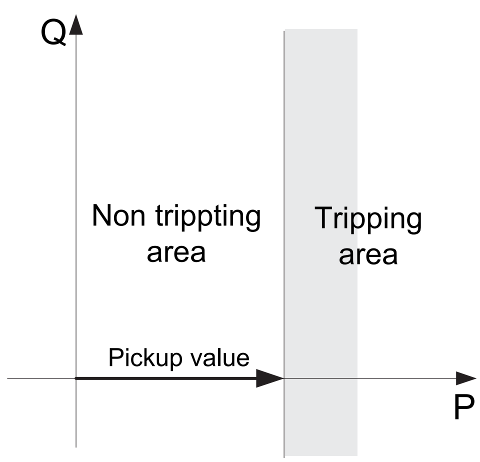


Figure 362: Operating characteristics with the Pickup Value setting, the Power angle setting being 0 and Directional mode "Forward"

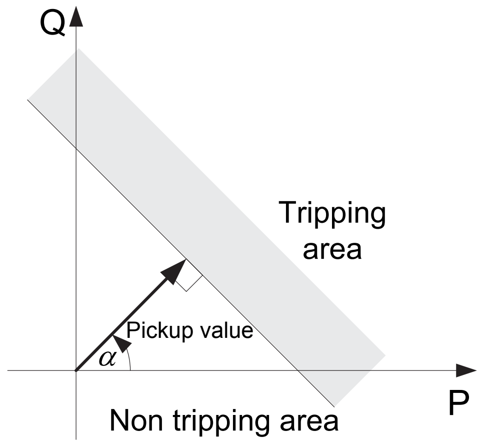


Figure 363: Operating characteristics with the Pickup Value setting, Power angle (α) being +45 and Directional mode "Forward"

Timer

Once activated, the Timer activates the `PICKUP` output. The time characteristics are according to DT. When the operation timer has reached the value of *Trip delay time*, the `TRIP` output is activated. If a drop-off situation happens, that is, the value of power drops below *Pickup value* before the trip delay is exceeded, the timer reset state is activated. If the reset timer reaches the value set by *Reset delay time*, the operate timer resets and the `PICKUP` output is deactivated.

The Timer calculates the pickup duration value PICKUP_DUR, which indicates the percentage ratio of the pickup situation and the set operating time (DT). The value is available in the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the `BLOCK` input and the global setting **Configuration/System/Blocking mode**, which selects the blocking mode. The `BLOCK` input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the `BLOCK` signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operate timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the `TRIP` output is not activated.

4.8.2.5 Application

32R/32O is used to provide protection against an excessive power flow in the set operating direction. The main application is the protection of generators and turbines. It can also be used in feeder protection applications, for example, the ring network.

32R/32O in the forward direction can be used to protect the generators or motors from delivering or consuming excess power. For example, the generator overpower protection can be used to shed a noncritical feeder load or to start parallel generators. A synchronous motor may start consuming more reactive power in case of loss of excitation, in which case the forward overpower protection is used to detect such condition.

The 32R/32O function has many applications when used as reverse power protection. A generator in a power plant converts mechanical energy to electrical energy. Sometimes the mechanical power from a prime mover may decrease to a limit that it does not cover the internal losses. The synchronous generator becomes a synchronous motor and starts importing power from the system. The effect of a generator acting as a motor implies no risk to the machine but can cause damage to the prime mover. The extent of the damage depends on the type of the prime mover.

Steam turbines become overheated easily if the steam flow drops too low or if the steam ceases to flow through the turbine. The break of a main steam pipe, damage to one or more blades in the steam turbine or an inadvertent closing of the main stop valves are typical causes for the low steam flow. The steam turbines of turbo generators can be protected during a low steam flow with the overpower protection operating in reverse direction. Hydroturbines tolerate reverse power much better than steam turbines do. There is a risk that the turbine runner moves axially and touches stationary parts. They are not always strong enough to withstand the associated stresses.

A hydroturbine that rotates in water with the closed wicket gates draws about 10% of the rated power from the rest of the power system if the intake is blocked due to ice, snow, branches or leaves. A complete blockage of the intake may cause cavitations. If there is only air in the hydroturbine, the power demand drops to about 3%. The risk of damages to the hydroturbines can justify the reverse operation of the overpower protection in unattended plants.

Whenever a low value of the reverse power setting is required, an underpower protection should also be used in conjunction with 32R/32O. The limit depends on the CT and VT accuracy.

Diesel engines should have overpower protection in reverse direction. The generator takes about 15% or more of its rated power from the system. A stiff engine may require 25% of the rated power to motor it. A well run engine may need no more than 5%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

Reverse overpower can also act as an alternative for an under excitation protection in case of small generators. If the field excitation is reduced, the generator may start importing the reactive power, making the generator run as an asynchronous generator. A synchronous generator is not designed to work asynchronously and may become damaged due to heating in the damper windings or heating in the rotor due to slip frequency current.

When operated in reverse power direction, 32R/32O can be used as an alarm if the power flowing from the industry is feeding the grid, which may not be desired as per the rules and regulations of the utility owning the grid.

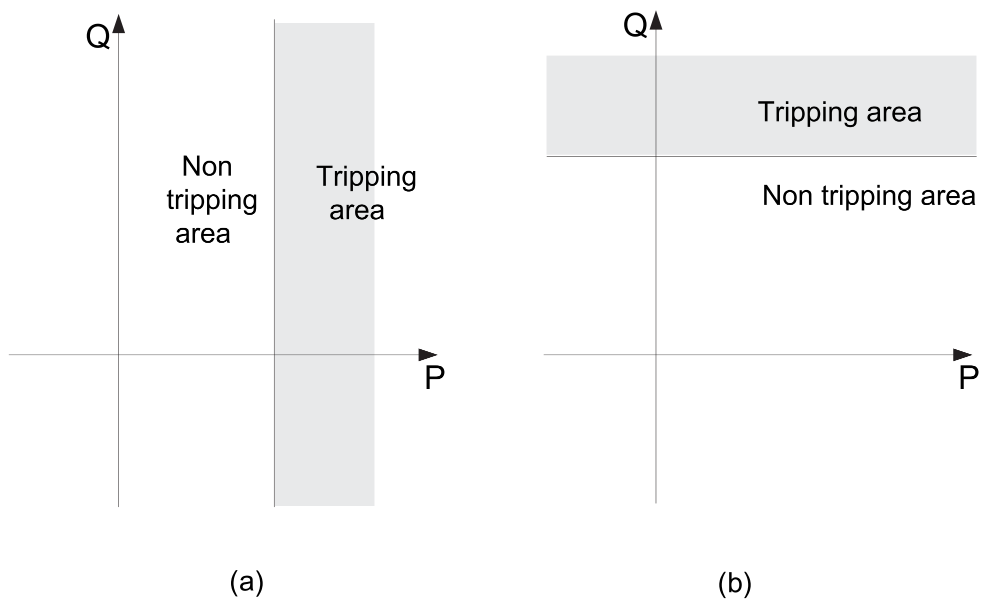


Figure 364: Forward active overpower characteristics (a) and forward reactive overpower characteristics (b)

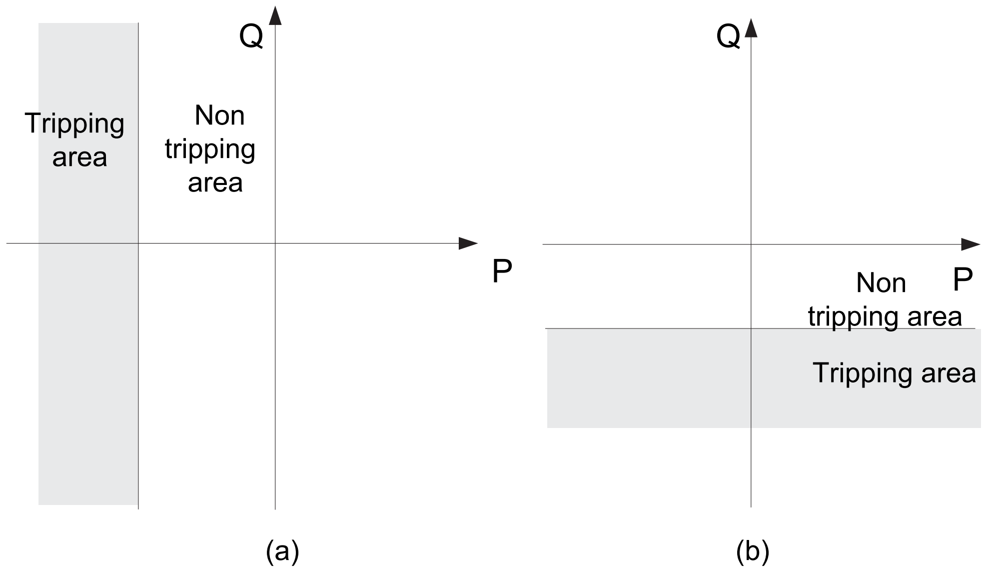


Figure 365: Reverse active overpower characteristics (a) and reverse reactive overpower characteristics (b)

4.8.2.6 Signals

Table 630: 32R/32O Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
V_A	SIGNAL	0	Phase-to-ground voltage A or phase-to-phase voltage AB
V_B	SIGNAL	0	Phase-to-ground voltage B or phase-to-phase voltage BC
V_C	SIGNAL	0	Phase-to-ground voltage C or phase-to-phase voltage CA
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 631: 32R/32O Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.8.2.7 Settings

Table 632: 32R/32O Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	0.01...2.00	xSn	0.01	1.00	Pickup value
Trip delay time	40...300000	ms	10	40	Trip delay time
Directional mode	2=Forward 3=Reverse			2=Forward	Directional mode
Power angle	-90...90	deg	1	0	Adjustable angle for power

Table 633: 32R/32O Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Measurement mode	1=PhsA, PhsB, PhsC 2=Arone 3=Pos Seq 4=PhsAB 5=PhsBC 6=PhsCA 7=PhsA 8=PhsB 9=PhsC			3=Pos Seq	Selection of power calculation method

Table 634: 32R/32O Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time
Pol reversal	0=False 1=True			0=False	Reverse the definition of the power direction

4.8.2.8 Monitored data

Table 635: 32R/32O Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
P	FLOAT32	-160.000...160.000	xSn	Active power
Q	FLOAT32	-160.000...160.000	xSn	Reactive power
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
S	FLOAT32	0.000...160.000	xSn	Apparent power
PF_ANGLE	FLOAT32	-180.00...180.00	deg	Power factor angle
32R/32O	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.8.2.9 Technical data

Table 636: 32R/32O Technical data

Characteristic	Value
Operation accuracy [1]	Depending on the frequency of the measured current and voltage: $f = f_n$ ±2 Hz
	Power measurement accuracy ±3% of the set value or ±0.002 × S_n Phase angle: ±2°
Pickup time[2)3)]	Typically 45 ms
Reset time	Typically 30 ms
Reset ratio	Typically 0.94
Trip time accuracy	±1.0% of the set value of ±20 ms
Suppression of harmonics	-50 dB at $f = n \times f_n$, where n = 2, 3, 4, 5,…

1) *Measurement mode* = “Pos Seq” (default)
2) $V = V_n$, f_n = 50 Hz, results based on statistical distribution of 1000 measurements
3) Includes the delay of the signal output contact

4.8.3 Directional reactive power undervoltage protection 32Q-27

4.8.3.1 Identification

Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional reactive power undervoltage protection	DQPTUV	Q> ->,3U<	32Q-27

4.8.3.2 Function block

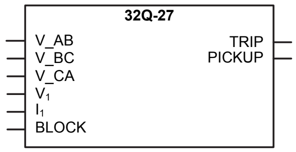


Figure 366: Function block

4.8.3.3 Functionality

The directional reactive power undervoltage protection function 32Q-27 is used at the grid connection point of distributed power generating units as stipulated by various grid codes to prevent voltage collapse of the grid due to network faults. 32Q-27 measures phase voltages and current at the grid connection point. The generating facility is disconnected from the network with a specific time delay if all phase voltages decrease and remain at or below the specified limit and if reactive power is simultaneously consumed (that is, under-excitation operation).

The function contains a blocking functionality to block function outputs, timer or the function itself.

4.8.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 32Q-27 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

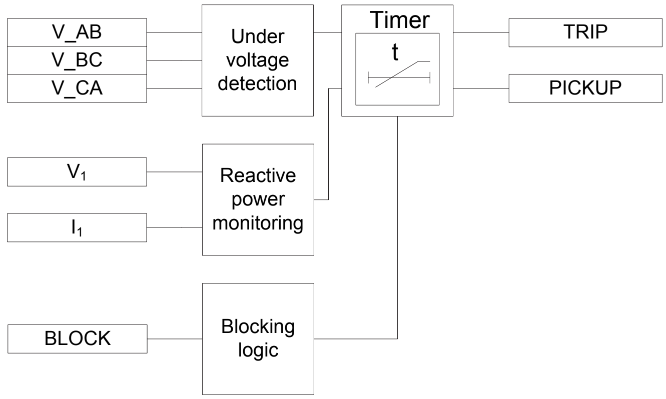


Figure 367: Functional module diagram

Under voltage detection

Under voltage detection compares the fundamental frequency component of all three phase-to-phase voltages with the set *Voltage pickup value*. When all three phase-to-phase voltages are lower than the set *Voltage pickup value*, the Under voltage detection module sends an enable signal to the Timer indicating an undervoltage condition at the grid connection point.

Reactive power monitoring

This module calculates and monitors the reactive power based on positive sequence current and voltage. The use of a positive sequence component makes the determination of power insensitive to a possible asymmetry in current and voltages. When the reactive power exceeds *Min reactive power* and flows in the operating area, the module sends an enable signal to the Timer indicating that the reactive power is being consumed at the grid connection point. A slight tilt in the curve can be obtained by the setting *Pwr sector reduction*.

To avoid false tripping, reactive power calculation is blocked if the magnitude of positive sequence current is less than the set *Min PS current*.

The magnitude of calculated reactive power Q is available in the Monitored data view.

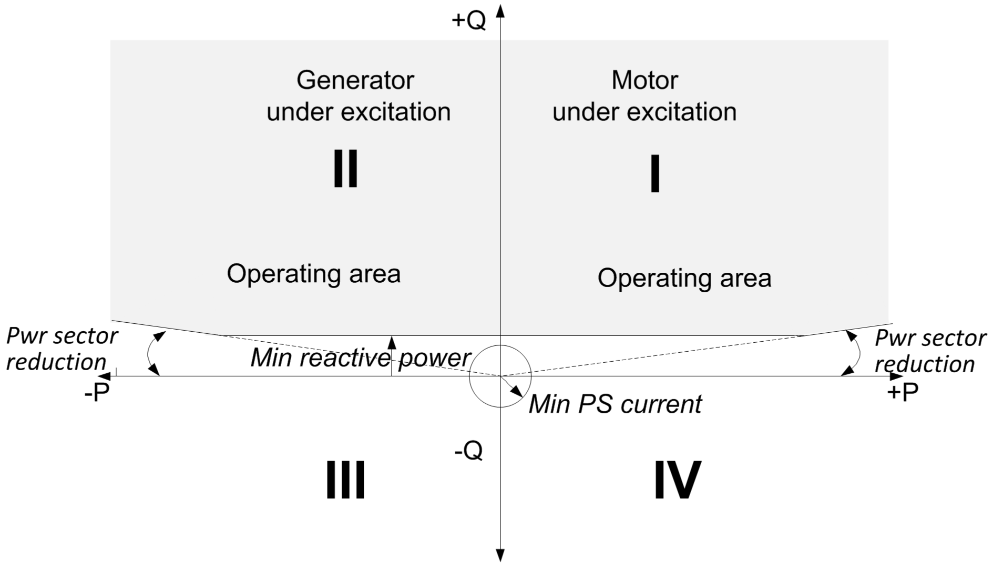


Figure 368: Operating area of 32Q-27 function

Quadrant II	Generator produces active power, but draws reactive power (under-excited)
Quadrant III	Generator produces both active and reactive power

The power direction can be reversed by setting *Pol reversal* to “True”.

Timer

Once activated by both Under voltage detection and Reactive power monitoring module, the Timer activates the PICKUP output. The Timer characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the TRIP output is activated. If the fault disappears before the module operates, the Timer is reset instantaneously.

The Timer calculates the start duration value *PICKUP_DUR* which indicates the percentage ratio of the pickup situation and the set operating time. The value is available through the Monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting **Configuration/System/Blocking**

mode which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode setting* has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.8.3.5 Application

Use of distributed power generating units (PGU) is rapidly increasing due to liberalized markets (deregulation) and the global trend to use more renewable sources of energy. As the capacity of these generating units increase, they are connected directly to medium voltage networks. Until recent years it had been a practice by grid operators to disconnect the distributed power generator from the network in case of fault in the network.

If there is a considerable loss in the power generation, it may affect the system's ability to recover. To ensure power system stability, various grid codes have revised their requirements and therefore require that the distributed PGUs have to make a contribution to network support. In case of network faults, the distributed power generator should not be immediately disconnected from the network. Instead, as a matter of principle, generating plants connected to the medium-voltage network must be capable of participating in steady-state voltage control and dynamic network support. However, if the generators stay connected, it must be ensured that they do not take reactive power from the network because this may lead to collapse of the grid. 32Q-27 is used for detecting such situations, that is, simultaneous undervoltage and reactive power (under excited generators) and trip the generators.

The protection function 32Q-27 is developed considering various grid codes. For example, in the BDEW Technical Guideline "Generating Plants Connected to the Medium-Voltage Network" (June 2008 issue, Germany), it is stated that if all three phase-to-phase voltages at the grid connection point decrease and remain at and below a value of 85% of the rated and if reactive power is simultaneously consumed at the grid connection point (under-excited operation), the generating facility must be disconnected from the network with a time delay of 0.5 s.

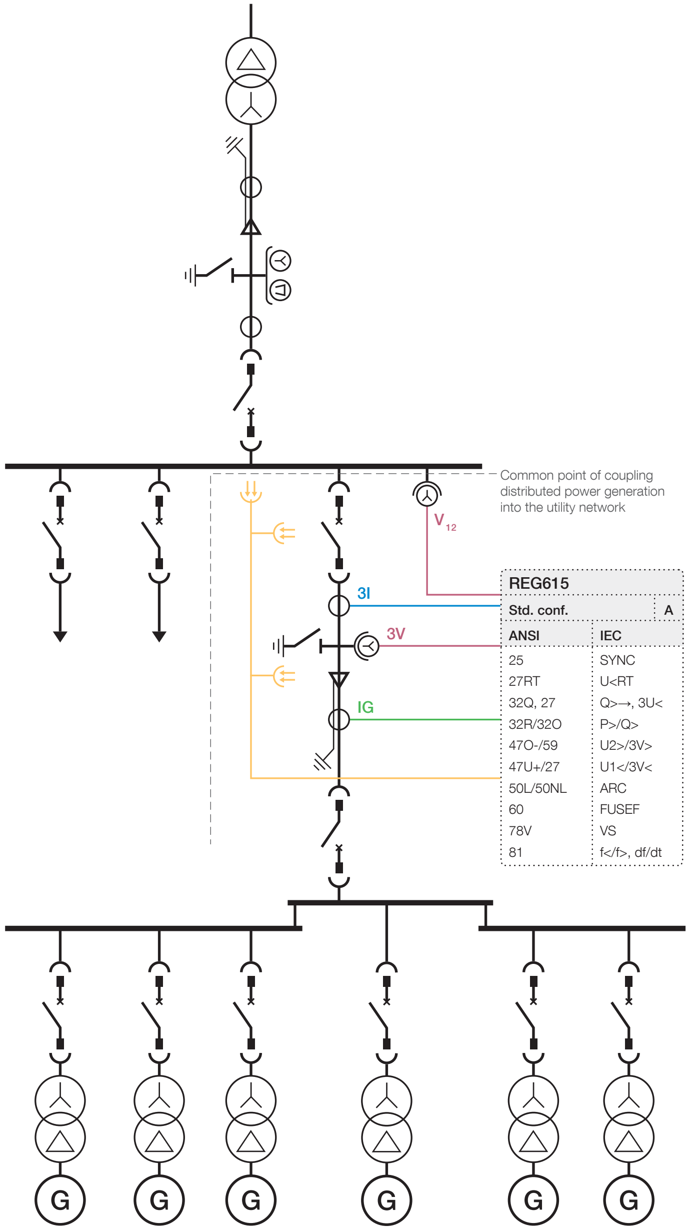


Figure 369: Application example of wind power plant as distributed power generation coupled into the utility network

4.8.3.6 Signals

Table 637: 32Q-27 Input signals

Name	Type	Default	Description
V_AB	SIGNAL	0	Phase-to-phase voltage AB
V_BC	SIGNAL	0	Phase-to-phase voltage BC
V_CA	SIGNAL	0	Phase-to-phase voltage CA
V1	SIGNAL	0	Positive phase sequence voltage
I_1	SIGNAL	0	Positive sequence current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 638: 32Q-27 Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.8.3.7 Settings

Table 639: 32Q-27 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Voltage Pickup value	0.20...1.20	xUn	0.01	0.85	Pickup value for under voltage detection
Trip delay time	100...300000	ms	10	500	Trip delay time

Table 640: 32Q-27 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 641: 32Q-27 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Min reactive power	0.01...0.50	xSn	0.01	0.05	Minimum reactive power needed for function to trip
Min Ps Seq current	0.02...0.20	xIn	0.01	0.05	Minimum positive sequence current
Pwr sector reduction	0...10	deg	1	3	Power sector reduction
Pol reversal	0=False 1=True			0=False	Reverse the definition of the positive reactive power direction

4.8.3.8 Monitored data

Table 642: 32Q-27 Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
Q	FLOAT32	-160.000...160.000	xSn	Reactive power
32Q-27	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.8.3.9 Technical data

Table 643: 32Q-27 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current and voltage: f_n ±2 Hz Reactive power range |PF| <0.71
	Power: ±3.0% or ±0.002 × Q_n Voltage: ±1.5% of the set value or ±0.002 × V_n
Pickup time[1)2)]	Typically 46 ms
Reset time	<50 ms
Reset ratio	Typically 0.96
Trip time accuracy	±1.0% of the set value or ±20 ms
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) *Pickup value* = 0.05 × S_n, reactive power before fault = 0.8 × *Pickup value*, reactive power overshoot 2 times, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.9 Arc protection AFD

4.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Arc protection	ARCSARC	ARC	AFD

4.9.2 Function block

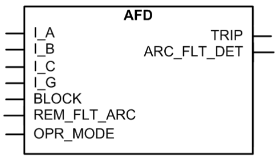


Figure 370: Function block

4.9.3 Functionality

The arc protection function AFD detects arc situations in air insulated metal-clad switchgears caused by, for example, human errors during maintenance or insulation breakdown during operation.

The function detects light from an arc either locally or via a remote light signal. The function also monitors phase and residual currents to be able to make accurate decisions on ongoing arcing situations.

The function contains a blocking functionality. Blocking deactivates all outputs and resets timers.

4.9.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of AFD can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

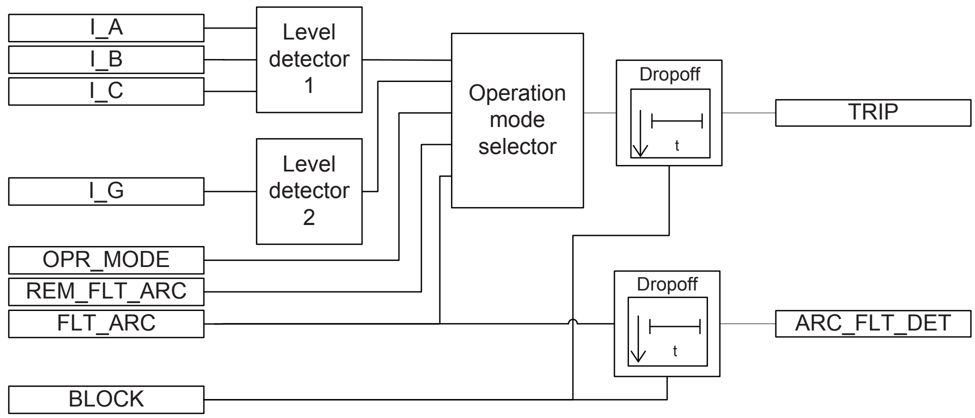


Figure 371: Functional module diagram

Level detector 1

The measured phase currents are compared phasewise to the set *Phase pickup value*. If the measured value exceeds the set *Phase pickup value*, the level detector reports the exceeding of the value to the operation mode selector.

Level detector 2

The measured residual currents are compared to the set *Ground pickup value*. If the measured value exceeds the set *Ground pickup value*, the level detector reports the exceeding of the value to the operation mode selector.

Operation mode selector

Depending on the *Operation mode* setting, the operation mode selector makes sure that all required criteria are fulfilled for a reliable decision of an arc fault situation. The user can select either "Light+current", "Light only" or "BI controlled" operation mode. The operation is based on both current and light information in “Light+current” mode, on light information only in “Light only” mode or on remotely controlled information in “BI controlled” mode. When the "BI controlled" mode is in use and the `OPR_MODE` input is activated, the operation of the function is based on light information only. When the `OPR_MODE` input is deactivated, the operation of the function is based on both light and current information. When the required criteria are met, the drop-off timer is activated.

Drop-off timer

Once activated, the drop-off timer remains active until the input is deactivated or at least during the drop-off time. The `BLOCK` signal can be used to block the `TRIP` signal or the light signal output `ARC_FLT_DET`.

4.9.5 Application

The arc protection can be realized as a stand-alone function in a single relay or as a station-wide arc protection, including several protection relays. If realized as a station-wide arc protection, different tripping schemes can be selected for the operation of the circuit breakers of the incoming and outgoing feeders. Consequently, the relays in the station can, for example, be set to trip the circuit breaker of either the incoming or the outgoing feeder, depending on the fault location in the switchgear. For maximum safety, the relays can be set to always trip both the circuit breaker of the incoming feeder and that of the outgoing feeder.

The arc protection consists of:

- Optional arc light detection hardware with automatic backlight compensation for lens type sensors
- Light signal output `ARC_FLT_DET` for routing indication of locally detected light signal to another relay
- Protection stage with phase- and ground-fault current measurement.

The function detects light from an arc either locally or via a remote light signal. Locally, the light is detected by lens sensors connected to the inputs Light sensor 1, Light sensor 2, or Light sensor 3 on the serial communication module of the relay. The lens sensors can be placed, for example, in the busbar compartment, the breaker compartment, and the cable compartment of the metal-clad cubicle.

The light detected by the lens sensors is compared to an automatically adjusted reference level. Light sensor 1, Light sensor 2, and Light sensor 3 inputs have their own reference levels. When the light exceeds the reference level of one of the inputs, the light is detected locally. When the light has been detected locally or remotely and, depending on the operation mode, if one or several phase currents exceed the set *Phase pickup value* limit, or the ground-fault current the set *Ground pickup value* limit, the arc protection stage generates a trip signal. The stage is reset in 30 ms, after all three-phase currents and the ground-fault current have fallen below the set current limits.

The light signal output from an arc protection stage `ARC_FLT_DET` is activated immediately in the detection of light in all situations. A station-wide arc protection is realized by routing the light signal output to an output contact connected to a binary input of another relay, or by routing the light signal output through the communication to an input of another relay.

It is possible to block the tripping and the light signal output of the arc protection stage with a binary input or a signal from another function block.

Cover unused inputs with dust caps.

Arc protection with one protection relay

In installations, with limited possibilities to realize signalling between protection relays protecting incoming and outgoing feeders, or if only the protection relay for the incoming feeder is to be exchanged, an arc protection with a lower protective level can be achieved with one protection relay. An arc protection with one protection relay only is realized by installing two arc lens sensors connected to the protection relay protecting the incoming feeder to detect an arc on the busbar. In arc detection, the arc protection stage trips the circuit breaker of the incoming feeder. The maximum recommended installation distance between the two lens sensors in the busbar area is six meters and the maximum distance from a lens sensor to the end of the busbar is three meters.

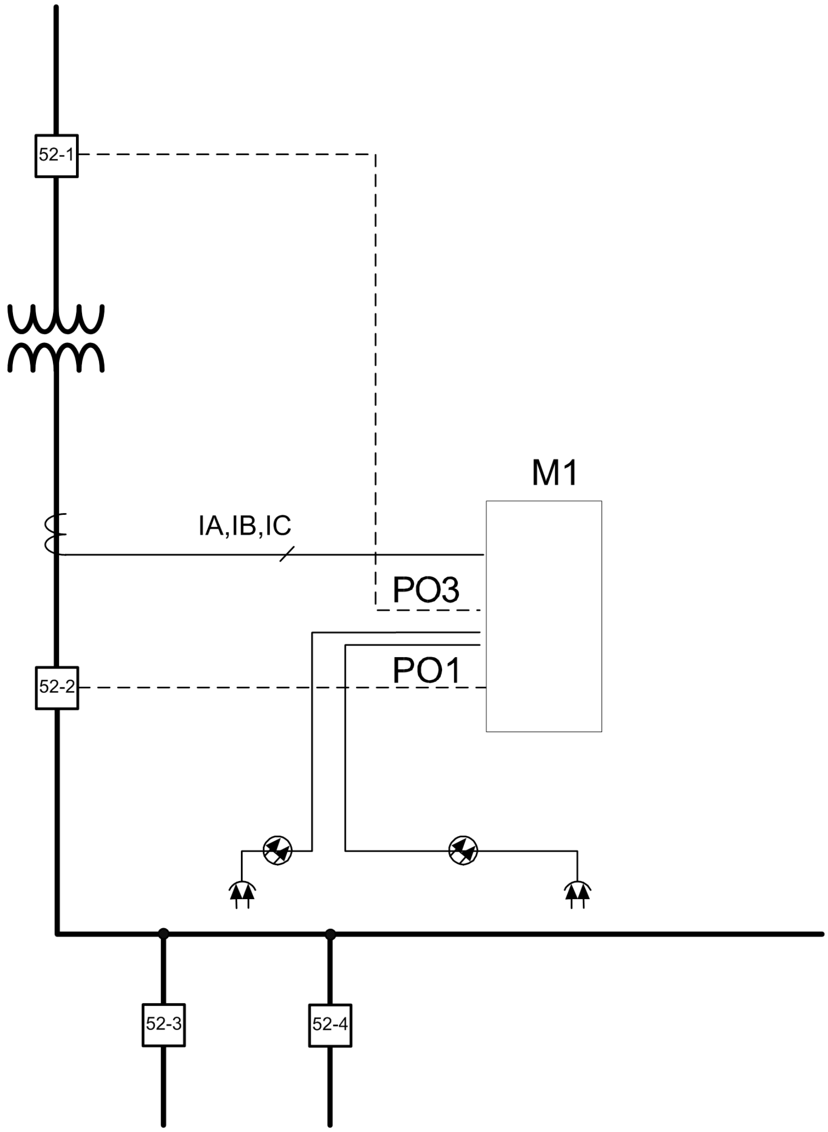


Figure 372: Arc protection with one protection relay

Arc protection with several protection relays

When using several protection relays, the protection relay protecting the outgoing feeder trips the circuit breaker of the outgoing feeder when detecting an arc at the cable terminations. If the protection relay protecting the outgoing feeder detects an arc on the busbar or in the breaker compartment via one of the other lens sensors, it will generate a signal to the protection relay protecting the incoming feeder. When detecting the signal, the protection relay protecting the incoming feeder trips the circuit breaker of the incoming feeder and generates an external trip signal to all protection relays protecting the outgoing feeders, which in turn results in tripping of all circuit breakers of the outgoing feeders. For maximum safety, the protection relays can be configured to trip all the circuit breakers regardless of where the arc is detected.

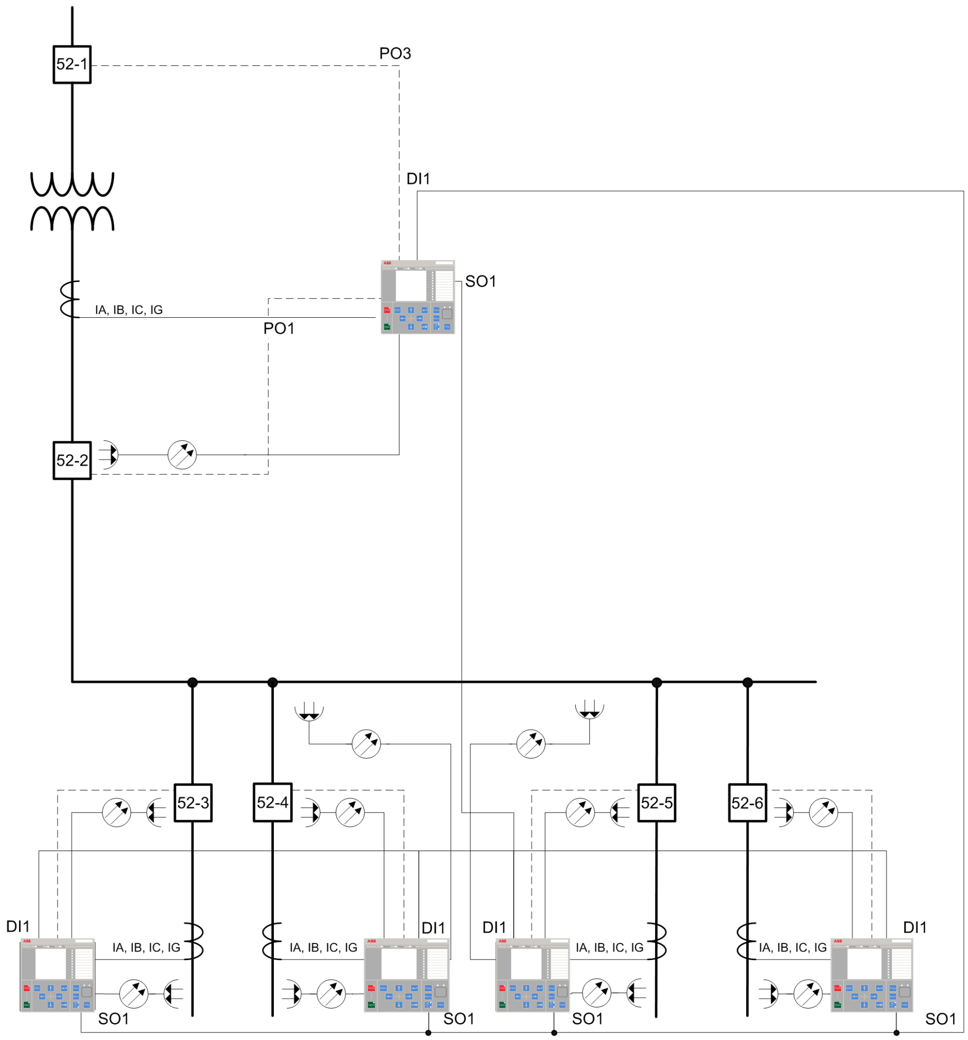


Figure 373: Arc flash detector with several protection relays

Arc protection with several protection relays and a separate arc protection system

When realizing an arc protection with both protection relays and a separate arc protection system, the cable terminations of the outgoing feeders are protected by protection relays using one lens sensor for each protection relay. The busbar and the incoming feeder are protected by the sensor loop of the separate arc protection system. With arc detection at the cable terminations, an protection relay trips the circuit breaker of the outgoing feeder. However, when detecting an arc on the busbar, the separate arc protection system trips the circuit breaker of the incoming feeder and generates an external trip signal to all protection relays protecting the outgoing feeders, which in turn results in tripping of all circuit breakers of the outgoing feeders.

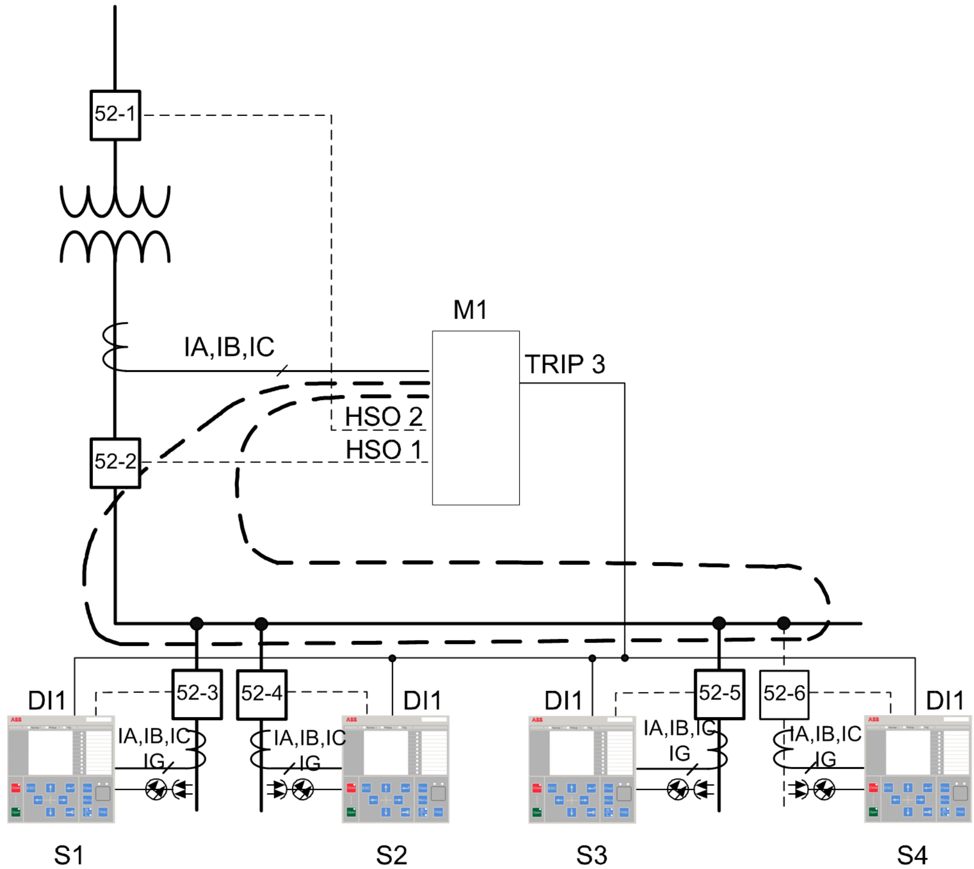


Figure 374: Arc flash detector with several protection relays and a separate arc flash detector system

4.9.6 Signals

Table 644: AFD Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_G	SIGNAL	0	Residual current
Table continues on next page			

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs
REM_FLT_ARC	BOOLEAN	0=False	Remote Fault arc detected
OPR_MODE	BOOLEAN	0=False	Operation mode input

Table 645: AFD Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
ARC_FLT_DET	BOOLEAN	Fault arc detected=light signal output

4.9.7 Settings

Table 646: AFD Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Phase pickup value	0.50...40.00	xIn	0.01	2.50	Operating phase current
Ground pickup value	0.05...8.00	xIn	0.01	0.20	Operating residual current
Operation mode	1=Light+current 2=Light only 3=BI controlled			1=Light+current	Operation mode

Table 647: AFD Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

4.9.8 Monitored data

Table 648: AFD Monitored data

Name	Type	Values (Range)	Unit	Description
AFD	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.9.9 Technical data

Table 649: AFD Technical data

Characteristic		Value		
Operation accuracy		±3% of the set value or ±0.01 × I_n		
Trip time		Minimum	Typical	Maximum
	Operation mode = "Light +current"1)2)	9 ms3) 4 ms4)	12 ms3) 6 ms4)	15 ms 3) 9 ms4)
	Operation mode = "Light only"2)	9 ms3) 4 ms4)	10 ms3) 6 ms4)	12 ms3) 7 ms4)
Reset time		Typically 40 ms		
Reset ratio		Typically 0.96		

1) *Phase pickup value* = 1.0 × I_n, current before fault = 2.0 × set *Phase pickup value*, f_n = 50 Hz, fault with nominal frequency, results based on statistical distribution of 200 measurements
2) Includes the delay of the heavy-duty output contact
3) Normal power output
4) High-speed output

4.9.10 Technical revision history

Table 650: AFD Technical revision history

Technical revision	Change
B	Internal Improvement.

4.10 Motor start-up supervision 66/51LRS

4.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Motor start-up supervision	STTPMSU	Is2t n<	66/51LRS

4.10.2 Function block

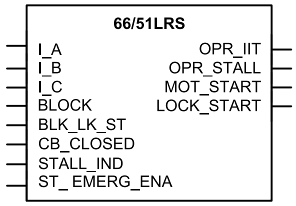


Figure 375: Function block

4.10.3 Functionality

The motor start-up supervision function 66/51LRS is designed for protection against excessive starting time and locked rotor conditions of the motor during starting. For the good and reliable operation of the motor, the thermal stress during the motor starting is maintained within the allowed limits.

The starting of the motor is supervised by monitoring the TRMS magnitude of all the phase currents or by monitoring the status of the circuit breaker connected to the motor.

During the start-up period of the motor, 66/51LRS calculates the integral of the I^2t value. If the calculated value exceeds the set value, the trip signal is activated.

66/51LRS has the provision to check the locked rotor condition of the motor using the speed switch, which means checking if the rotor is able to rotate or not. This feature trips after a predefined operating time.

66/51LRS also protects the motor from an excessive number of start-ups. Upon exceeding the specified number of start-ups within certain duration, 66/51LRS blocks further pickups. The restart of the motor is also inhibited after each start and continues to be inhibited for a set duration. When the lock of pickup of motor is enabled, 66/51LRS gives the time remaining until the restart of the motor.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

4.10.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 66/51LRS can be described with a module diagram. All the modules in the diagram are explained in the next sections.

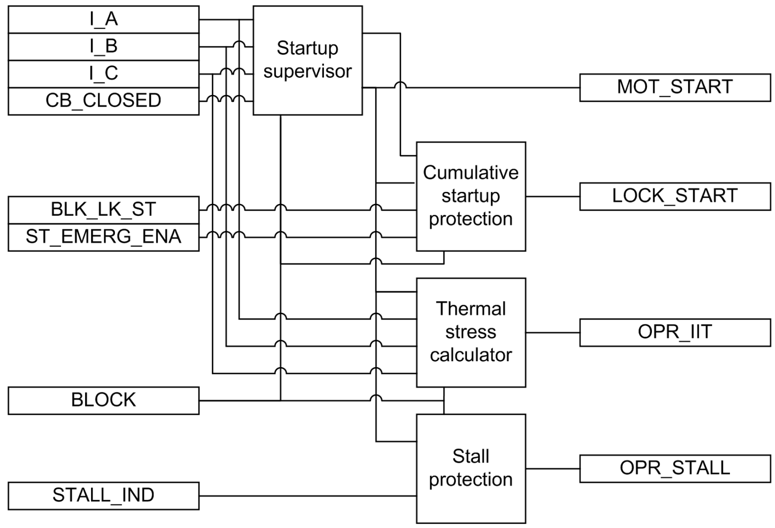


Figure 376: Functional module diagram

Startup supervisor

This module detects the starting of the motor. The starting and stalling motor conditions are detected in four different modes of operation. This is done through the *Operation mode* setting.

When the *Operation mode* setting is operated in the "IIt" mode, the function calculates the value of the thermal stress of the motor during the start-up condition. In this mode, the start-up condition is detected by monitoring the TRMS currents.

The *Operation mode* setting in the "IIt, CB" mode enables the function to calculate the value of the thermal stress when a start-up is monitored in addition to the `CB_CLOSED` input.

In the "IIt & stall" mode, the function calculates the thermal stress of the motor during the start-up condition. The start-up condition is detected by monitoring the TRMS currents.

In the "IIt & stall, CB" mode, the function calculates the thermal stress of the motor during the start-up condition but the start-up condition is detected by monitoring the TRMS current as well as the circuit breaker status.

In both the "IIt & stall" and "IIt & stall, CB" mode, the function also checks for motor stalling by monitoring the speed switch.

When the measured current value is used for start-up supervision in the "IIt" and "IIt & stall" modes, the module initially recognizes the de-energized condition of the motor when the values of all three phase currents are less than *Motor standstill A* for longer than 100 milliseconds. If any of the phase currents of the de-energized condition rises to a value equal to or greater than *Motor standstill A*, the MOT_START output signal is activated indicating that the motor start-up is in progress. The MOT_START output remains active until the values of all three phase currents drop below 90 percent of the set value of *Start detection A* and remain below that level for a time of *Str over delay time*, that is, until the start-up situation is over.

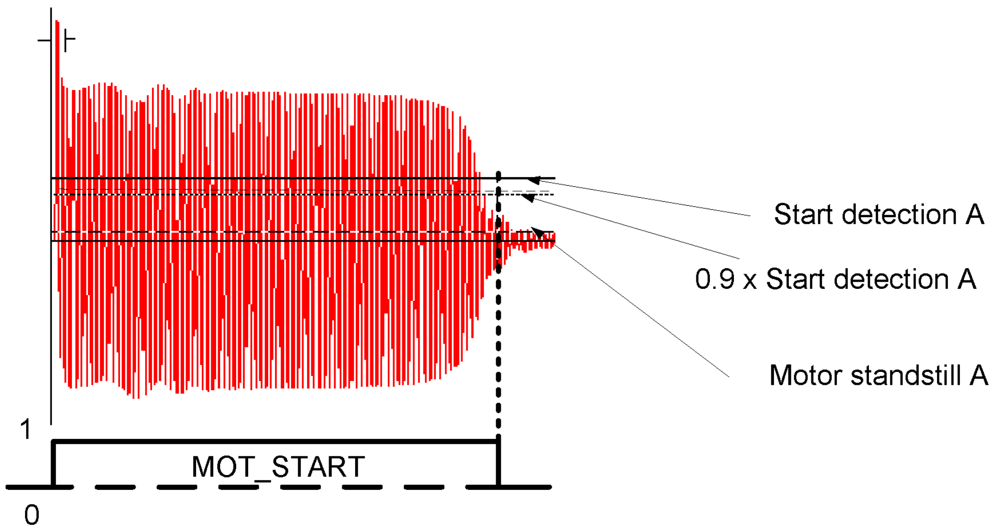


Figure 377: Functionality of start-up supervision in the "IIt and IIt&stall" mode

In case of the "IIt, CB" or "IIt & stall, CB" modes, the function initially recognizes the de-energized condition of the motor when the value of all three phase currents is below the value of the *Motor standstill A* setting for 100 milliseconds. The beginning of the motor start-up is recognized when CB is closed, that is, when the CB_CLOSED input is activated and at least one phase current value exceeds the *Motor standstill A* setting.

These two events do not take place at the same instant, that is, the CB main contact is closed first, in which case the phase current value rises above 0.1 pu and after some delay the CB auxiliary contact gives the information of the CB_CLOSED input. In some cases, the CB_CLOSED input can be active but the value of current may not be greater than the value of the *Motor standstill A* setting. To allow both possibilities, a time slot of 200 milliseconds is provided for current and the CB_CLOSED input. If both events occur during this time, the motor start-up is recognized.

The motor start-up ends either within the value of the *Str over delay time* setting from the beginning of the start-up or the opening of CB or when the CB_CLOSED input is deactivated. The operation of the MOT_START output signal in this operation mode is as illustrated in Figure 378.

This CB mode can be used in soft-started or slip ring motors for protection against a large starting current, that is, a problem in starting and so on.

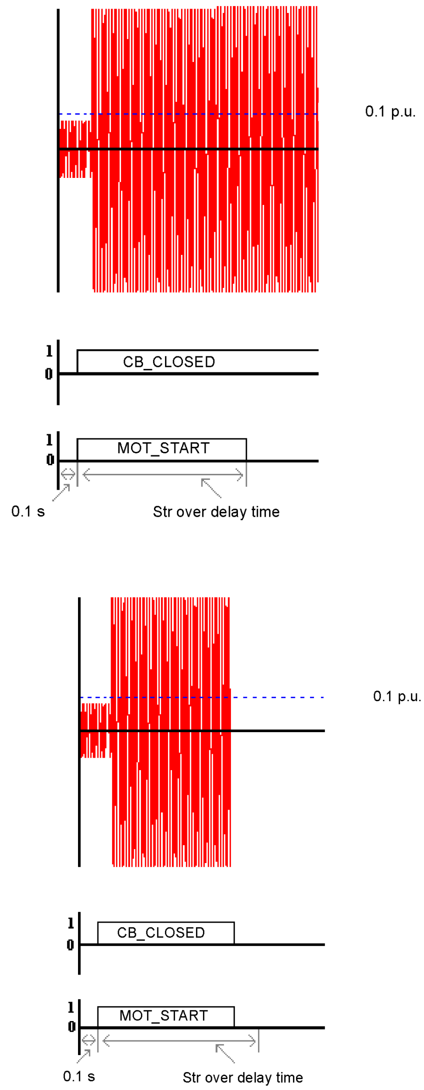


Figure 378: Functionality of start-up supervision in the "IIt, CB" mode and the "IIt and stall, CB" mode

The *Str over delay time* setting has different purposes in different modes of operation.

- In the “IIt” or “IIt & stall” modes, the aim of this setting is to check for the completion of the motor start-up period. The purpose of this time delay setting is to allow for short interruptions in the current without changing the state of the MOT_START output. In this mode of operation, the value of the setting is in the range of around 100 milliseconds.

- In the “IIt, CB” or “IIt & stall, CB” modes, the purpose of this setting is to check for the life of the protection scheme after the CB_CLOSED input has been activated. Based on the values of the phase currents, the completion of the start-up period cannot be judged. So in this mode of operation, the value of the time delay setting can even be as high as within the range of seconds, for example around 30 seconds.

The activation of the BLOCK input signal deactivates the MOT_START output.

Thermal stress calculator

Because of the high current surges during the start-up period, a thermal stress is imposed on the rotor. With less air circulation in the ventilation of the rotor before it reaches its full speed, the situation becomes even worse. Consequently, a long start-up causes a rapid heating of the rotor.

This module calculates the thermal stress developed in the motor during start-up. The heat developed during the starting can be calculated with the equation.

$$W = R_s \int_0^t i_s^2 (t)\, dt$$

(Equation 133)

R_s combined rotor and stator resistance

i_s starting current of the motor

t starting time of the motor

This equation is normally represented as the integral of I²t. It is a commonly used method in protective protection relays to protect the motor from thermal stress during starting. The advantage of this method over the traditional definite time overcurrent protection is that when the motor is started with a reduced voltage as in the star-delta starting method, the starting current is lower. This allows more starting time for the motor since the module is monitoring the integral of I²t.

The module calculates the accumulated heat continuously and compares it to the limiting value obtained from the product of the square of the values of the *Motor start-up A* and *Motor start-up time* settings. When the calculated value of the thermal stress exceeds this limit, the OPR_IIT output is activated.

The module also measures the time START_TIME required by the motor to attain the rated speed and the relative thermal stress IIT_RL. The values are available in the Monitored data view.

The activation of the BLOCK input signal resets the thermal stress calculator and deactivates the OPR_IIT output.

Stall protection

This module is activated only when the selected *Operation mode* setting value is "IIt & stall" or "IIt & stall, CB".

The start-up current is specific to each motor and depends on the start-up method used, such as direct online, autotransformer and rotor resistance insertion. The start-up time is dependent on the load connected to the motor.

Based on the motor characteristics supplied by the manufacturer, this module is required if the stalling time is shorter than or too close to the starting time. In such cases, a speed switch must be used to indicate whether a motor is accelerating during start-up or not.

At motor standstill, the STALL_IND input is active. It indicates that the rotor is not rotating. When the motor is started, at certain revolution the deactivation of the STALL_IND by the speed switch indicates that the rotor is rotating. If the input is not deactivated within *Lock rotor time*, the OPR_STALL output is activated.

The module calculates the duration of the motor in stalling condition, the STALL_RL output indicating the percent ratio of the start situation and the set value of *Lock rotor time*. The value is available in the Monitored data view.

The activation of the BLOCK input signal resets the operation time and deactivates the OPR_STALL output.

Cumulative start-up protection

This module protects the motor from an excessive number of start-ups.

Whenever the motor is started, the latest value of START_TIME is added to the existing value of T_ST_CNT and the updated cumulative start-up time is available at T_ST_CNT. If the value of T_ST_CNT is greater than the value of *Cumulative time Lim*, the LOCK_START output is activated and lockout condition for the restart of motor is enabled during the time the output is active. The LOCK_START output remains high until the T_ST_CNT value reduces to a value less than the value of *Cumulative time Lim*. The start time counter reduces at the rate of the value of *Counter Red rate*.

The LOCK_START output becomes activated at the start of MOT_START. The output remains active for a period of *Restart inhibit time*.

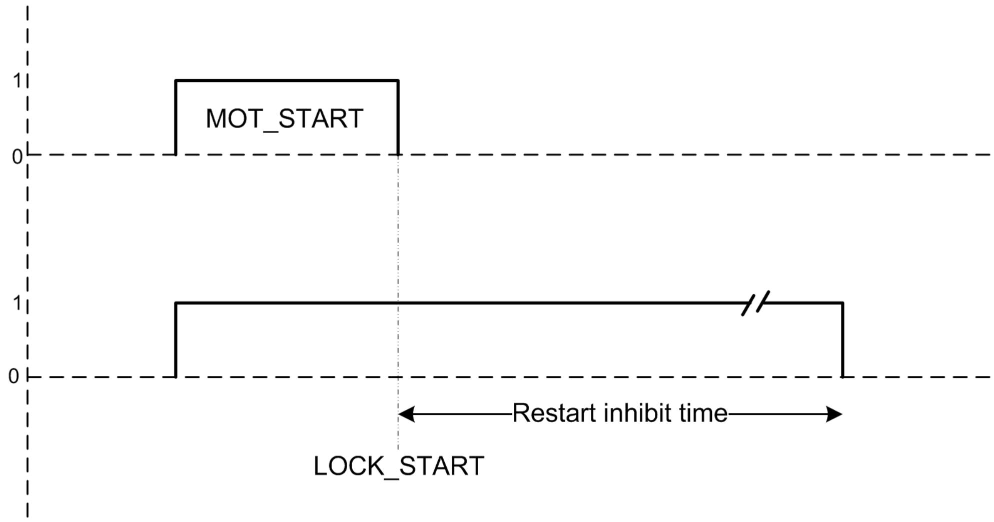


Figure 379: Time delay for cumulative start

This module also protects the motor from consecutive start-ups. When the LOCK_START output is active, T_RST_ENA shows the possible time for next restart. The value of T_RST_ENA is calculated by the difference of *Restart inhibit time* and the elapsed time from the instant LOCK_START is enabled.

When the ST_EMERG_ENA emergency start is set high, the value of the cumulative start-up time counter is set to *Cumulative time Lim* - 60s · *Emg start Red rate*. This disables LOCK_START and in turn makes the restart of the motor possible.

This module also calculates the total number of start-ups occurred, START_CNT. The value can be reset from the Clear menu.

The old *Number of motor start-ups occurred* counter value (START_CNT) can be taken into use by writing the value to the *Ini start up counter* parameter and resetting the value via the Clear menu from WHMI or LHMI.

The calculated values of T_RST_ENA, T_ST_CNT and START_CNT are available in the Monitored data view.

The activation of the BLK_LK_ST input signal deactivates the LOCK_START output. The activation of the BLOCK input signal resets the cumulative start-up counter module.

4.10.5 Application

When a motor is started, it draws a current well in excess of the motor's full-load rating throughout the period it takes for the motor to run up to the rated speed. The motor starting current decreases as the motor speed increases and the value of current remains close to the rotor-locked value for most of the acceleration period.

The full-voltage starting or the direct-on-line starting method is used out of the many methods used for starting the induction motor. If there is either an electrical or mechanical constraint, this starting method is not suitable. The full-voltage starting produces the highest starting torque. A high starting torque is generally required to start a high-inertia load to limit the acceleration time. In this method, full voltage is applied to the motor when the switch is in the "On" position. This method of starting results in a large initial current surge, which is typically four to eight times that of the full-load current drawn by the motor. If a star-delta starter is used, the value of the line current will only be about one-third of the direct-on-line starting current.

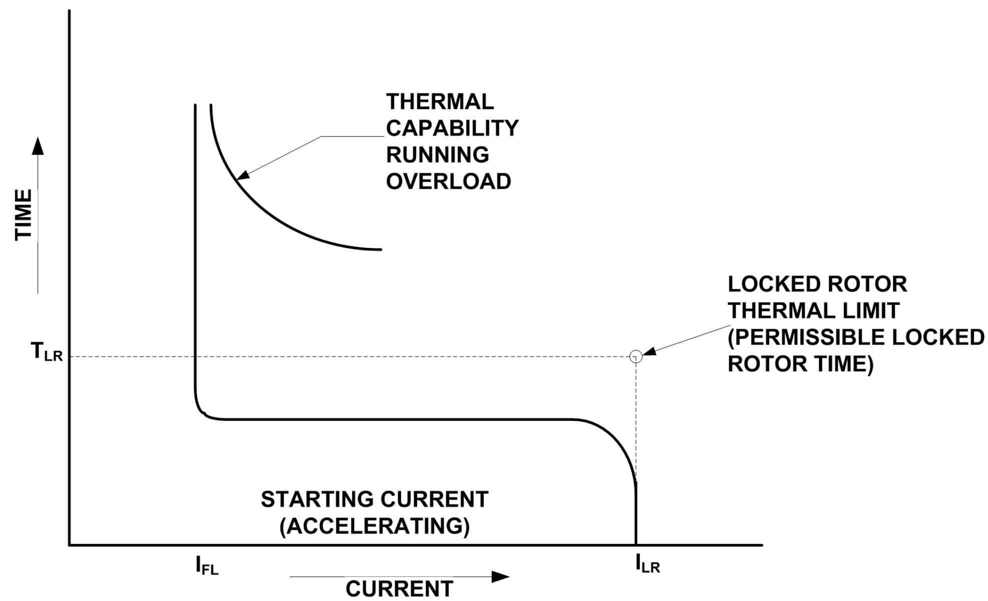


Figure 380: Typical motor starting and capability curves

The start-up supervision of a motor is an important function because of the higher thermal stress developed during starting. During the start-up, the current surge imposes a thermal strain on the rotor. This is exaggerated as the air flow for cooling is less because the fans do not rotate in their full speed. Moreover, the difference of speed between the rotating magnetic field and the rotor during the start-up time induces a high magnitude of slip current in the rotor at frequencies higher than when the motor is at full speed. The skin effect is stronger at higher frequencies and all these factors increase the losses and the generated heat. This is worse when the rotor is locked.

The starting current for slip-ring motors is less than the full load current and therefore it is advisable to use the circuit breaker in the closed position to indicate the starting for such type of motors.

The starting times vary depending on motor design and load torque characteristics. The time taken may vary from less than two seconds to more than 60 seconds. The starting time is determined for each application.

When the permissible stall time is less than the starting time of the motor, the stalling protection is used and the value of the time delay setting should be set slightly less than the permissible stall time. The speed switch on the motor shaft must be used for detecting whether the motor begins to accelerate or not. However, if the safe stall time is longer than the start-up time of the motor, the speed switch is not required.

The failure of a motor to accelerate or to reach its full nominal speed in an acceptable time when the stator is energized is caused by several types of abnormal conditions, including a mechanical failure of the motor or load bearings, low supply voltage, open circuit in one phase of a three-phase voltage supply or too high starting voltage. All these abnormal conditions result in overheating.

Repeated starts increase the temperature to a high value in the stator or rotor windings, or both, unless enough time is allowed for the heat to dissipate. To ensure a safe operation it is necessary to provide a fixed-time interval between starts or limit the number of starts within a period of time. This is why the motor manufacturers have restrictions on how many starts are allowed in a defined time interval. This function does not allow starting of the motor if the number of starts exceeds the set level in the register that calculates them. This insures that the thermal effects on the motor for consecutive starts stay within permissible levels.

For example, the motor manufacturer may state that three starts at the maximum are allowed within 4 hours and the start-up situation time is 60 seconds. By initiating three successive starts we reach the situation as illustrated. As a result, the value of the register adds up to a total of 180 seconds. Right after the third start has been initiated, the output lock of start of motor is activated and the fourth start will not be allowed, provided the time limit has been set to 121 seconds.

Furthermore, a maximum of three starts in 4 hours means that the value of the register should reach the set start time counter limit within 4 hours to allow a new start. Accordingly, the start time counter reduction should be 60 seconds in 4 hours and should thus be set to 60 s / 4 h = 15 s / h.

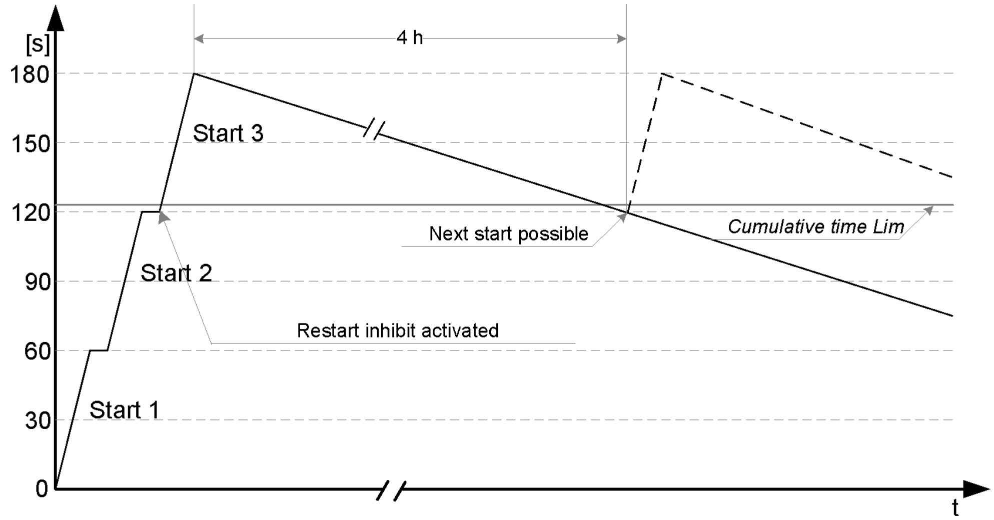


Figure 381: Typical motor-starting and capability curves

Setting of *Cumulative time Lim*

Cumulative time Lim is calculated by

$$\sum t_{si} = (n-1) \times t + margin$$

(Equation 134)

n	specified maximum allowed number of motor start-ups
t	start-up time of the motor (in seconds)
margin	safety margin (~10...20 percent)

Setting of *Counter Red rate*

Counter Red rate is calculated by

$$\Delta \sum t_s = \frac{t}{t_{reset}}$$

(Equation 135)

t	specified start time of the motor in seconds
t_{reset}	duration during which the maximum number of motor start-ups stated by the manufacturer can be made; time in hours

4.10.6 Signals

Table 651: 66/51LRS Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block of function
BLK_LK_ST	BOOLEAN	0=False	Blocks lock out condition for restart of motor
CB_CLOSED	BOOLEAN	0=False	Input showing the status of motor circuit breaker
STALL_IND	BOOLEAN	0=False	Input signal for showing the motor is not stalling
ST_EMERG_ENA	BOOLEAN	0=False	Enable emergency start to disable lock of start of motor

Table 652: 66/51LRS Output signals

Name	Type	Description
OPR_IIT	BOOLEAN	Trip signal for thermal stress.
OPR_STALL	BOOLEAN	Trip signal for stalling protection.
MOT_START	BOOLEAN	Signal to show that motor startup is in progress
LOCK_START	BOOLEAN	Lock out condition for restart of motor.

4.10.7 Settings

Table 653: 66/51LRS Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Motor start-up A	1.0...10.0	xIn	0.1	2.0	Motor starting current
Motor start-up time	1...80	s	1	5	Motor starting time
Lock rotor time	2...120	s	1	10	Permitted stalling time
Str over delay time	0...60000	ms	1	100	Time delay to check for completion of motor startup period

Table 654: 66/51LRS Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup detection A	0.1...10.0	xIn	0.1	1.5	Current value for detecting starting of motor.

Table 655: 66/51LRS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=IIt 2=IIt, CB 3=IIt + stall 4=IIt + stall, CB			1=IIt	Motor start-up operation mode
Counter Red rate	2.0...250.0	s/h	0.1	60.0	Start time counter reduction rate
Cumulative time Lim	1...500	s	1	10	Cumulative time based restart inhibit limit
Emg start Red rate	0.00...100.00	%	0.01	20.00	Start time reduction factor when emergency start is On
Restart inhibit time	0...250	min	1	30	Time delay between consecutive startups
Ini start up counter	0...999999		1	0	Initial value for the START_CNT

Table 656: 66/51LRS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Motor standstill A	0.05...0.20	xIn	0.01	0.12	Current limit to check for motor standstill condition

4.10.8 Monitored data

Table 657: 66/51LRS Monitored data

Name	Type	Values (Range)	Unit	Description
START_CNT	INT32	0...999999		Number of motor start-ups occurred
START_TIME	FLOAT32	0.0...999.9	s	Measured motor latest startup time in sec
T_ST_CNT	FLOAT32	0.0...99999.9	s	Cumulated start-up time in sec
T_RST_ENA	INT32	0...999	min	Time left for restart when lockstart is enabled in minutes
IIT_RL	FLOAT32	0.00...100.00	%	Thermal stress relative to set maximum thermal stress
STALL_RL	FLOAT32	0.00...100.00	%	Pickup time relative to the trip time for stall condition
66/51LRS	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.10.9 Technical data

Table 658: 66/51LRS Technical data

Characteristic		Value		
Operation accuracy		Depending on the frequency of the measured current: f_n ±2 Hz		
		±1.5% of the set value or ±0.002 × I_n		
Pickup time[1)2)]		Minimum	Typical	Maximum
	I_{Fault} = 1.1 × set *Pickup detection A*	27 ms	30 ms	34 ms
Trip time accuracy		±1.0% of the set value or ±20 ms		
Reset ratio		Typically 0.90		

1) Current before = 0.0 × I_n, f_n = 50 Hz, overcurrent in one phase, results based on statistical distribution of 1000 measurements
2) Includes the delay of the signal output contact

4.10.10 Technical revision history

Table 659: STTPMSU Technical revision history66/51LRS Technical revision history

Technical revision	Change
B	Internal improvement
C	Added setting *Ini start up counter*.

4.11 Multipurpose protection MAP

4.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Multipurpose protection	MAPGAPC	MAP	MAP

4.11.2 Function block

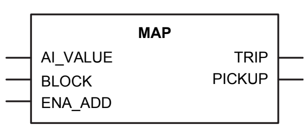


Figure 382: Function block

4.11.3 Functionality

The RTD based thermal protection function 38 is used as a general protection with many possible application areas as it has flexible measuring and setting facilities. The function can be used as an under- or overprotection with a settable absolute hysteresis limit. The function operates with the definite time (DT) characteristics.

The function contains a blocking functionality. It is possible to block function outputs, the definite timer or the function itself, if desired.

4.11.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of MAP can be described using a module diagram. All the modules in the diagram are explained in the next sections.

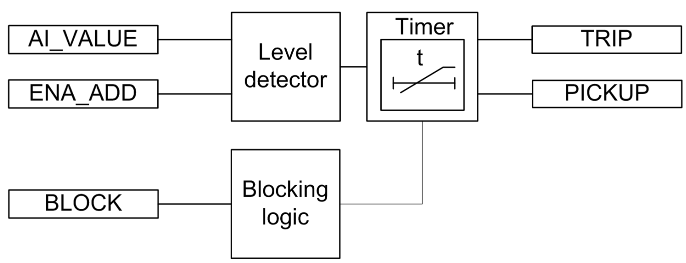


Figure 383: Functional module diagram

Level detector

The level detector compares `AI_VALUE` to the *Pickup value* setting. The *Operation mode* setting defines the direction of the level detector.

Table 660: Operation mode types

Operation Mode	Description
"Under"	If the input signal `AI_VALUE` is lower than the set value of the *Pickup value* setting, the level detector enables the timer module.
"Over"	If the input signal `AI_VALUE` exceeds the set value of the *Pickup value* setting, the level detector enables the timer module.

The *Absolute hysteresis* setting can be used for preventing unnecessary oscillations if the input signal is slightly above or below the *Pickup value* setting. After leaving the hysteresis area, the pickup condition has to be fulfilled again and it is not sufficient for the signal to only return to the hysteresis area. If the ENA_ADD input is activated, the threshold value of the internal comparator is the sum of the *Pickup value Add* and *Pickup value* settings. The resulting threshold value for the comparator can be increased or decreased depending on the sign and value of the *Pickup value Add* setting.

Timer

Once activated, the timer activates the PICKUP output. The time characteristic is according to DT. When the operation timer has reached the value set by *Trip delay time*, the TRIP output is activated. If the pickup condition disappears before the module trips, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the operation timer resets and the PICKUP output is deactivated.

The timer calculates the pickup duration value PICKUP_DUR, which indicates the ratio of the pickup situation and the set trip time. The value is available in the monitored data view.

Blocking logic

There are three operation modes in the blocking function. The operation modes are controlled by the BLOCK input and the global setting in **Configuration/System/Blocking mode** which selects the blocking mode. The BLOCK input can be controlled by a binary input, a horizontal communication input or an internal signal of the protection relay's program. The influence of the BLOCK signal activation is preselected with the global setting *Blocking mode*.

The *Blocking mode* setting has three blocking methods. In the "Freeze timers" mode, the operation timer is frozen to the prevailing value, but the TRIP output is not deactivated when blocking is activated. In the "Block all" mode, the whole function is blocked and the timers are reset. In the "Block TRIP output" mode, the function operates normally but the TRIP output is not activated.

4.11.5 Application

The function block can be used for any general analog signal protection, either underprotection or overprotection. The setting range is wide, allowing various protection schemes for the function. Thus, the absolute hysteresis can be set to a value that suits the application.

The temperature protection using the RTD sensors can be done using the function block. The measured temperature can be fed from the RTD sensor to the function input that detects too high temperatures in the motor bearings or windings, for example. When the ENA_ADD input is enabled, the threshold value of the internal comparator is the sum of the

Pickup value Add and *Pickup value* settings. This allows a temporal increase or decrease of the level detector depending on the sign and value of the *Pickup value Add* setting, for example, when the emergency start is activated. If, for example, *Pickup value* is 100, *Pickup value Add* is 20 and the ENA_ADD input is active, the input signal needs to rise above 120 before MAP trips.

4.11.6 Signals

Table 661: MAP Input signals

Name	Type	Default	Description
AI_VALUE	FLOAT32	0.0	Analogue input value
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ENA_ADD	BOOLEAN	0=False	Enable pickup added

Table 662: MAP Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip
PICKUP	BOOLEAN	Pickup

4.11.7 Settings

Table 663: MAP Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	-10000.0...10000.0		0.1	0.0	Pickup value
Pickup value Add	-100.0...100.0		0.1	0.0	Pickup value Add
Trip delay time	0...200000	ms	100	0	Trip delay time

Table 664: MAP Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=Over 2=Under			1=Over	Operation mode

Table 665: MAP Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	100	0	Reset delay time
Absolute hysteresis	0.01...100.00		0.01	0.10	Absolute hysteresis for operation

4.11.8 Monitored data

Table 666: MAP Monitored data

Name	Type	Values (Range)	Unit	Description
PICKUP_DUR	FLOAT32	0.00...100.00	%	Ratio of pickup time / trip time
MAP	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

4.11.9 Technical data

Table 667: MAP Technical data

Characteristic	Value
Operation accuracy	±1.0% of the set value or ±20 ms

4.11.10 Technical revision history

Table 668: MAP Technical revision history

Technical revision	Change
B	Internal improvement.
C	Internal improvement.

Section 5 Protection related functions

5.1 Three-phase inrush detector INR

5.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase inrush detector	INRPHAR	3I2f>	INR

5.1.2 Function block

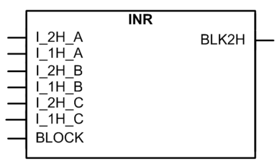


Figure 384: Function block

5.1.3 Functionality

The three-phase inrush detector function INR is used to coordinate transformer inrush situations in distribution networks.

Transformer inrush detection is based on the following principle: the output signal `BLK2H` is activated once the numerically derived ratio of second harmonic current I_2H and the fundamental frequency current I_1H exceeds the set value.

The trip time characteristic for the function is of definite time (DT) type.

The function contains a blocking functionality. Blocking deactivates all outputs and resets timers.

5.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of INR can be described using a module diagram. All the modules in the diagram are explained in the next sections.

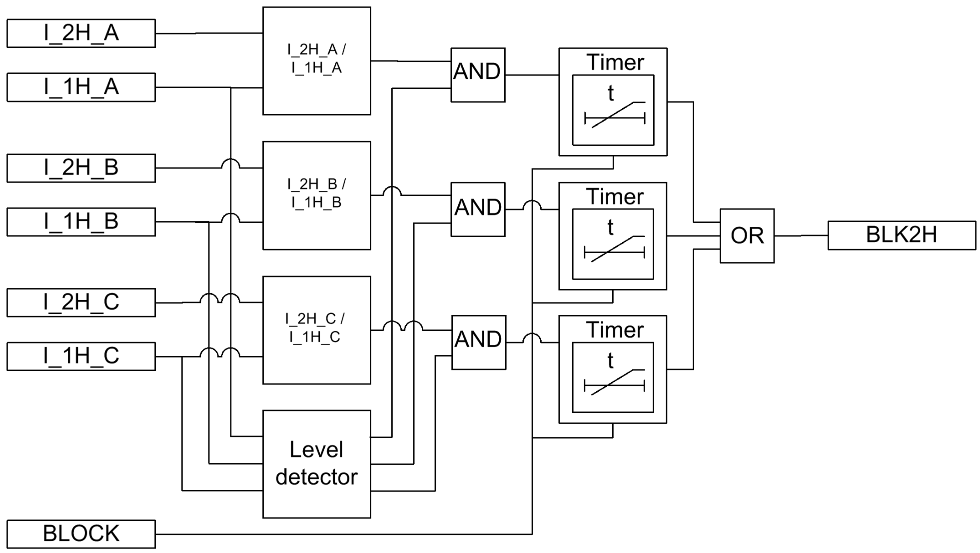


Figure 385: Functional module diagram

I_2H/I_1H

This module calculates the ratio of the second harmonic (I_2H) and fundamental frequency (I_1H) phase currents. The calculated value is compared to the set *Pickup value*. If the calculated value exceeds the set *Pickup value*, the module output is activated.

Level detector

The output of the phase specific level detector is activated when the fundamental frequency current I_1H exceeds five percent of the nominal current.

Timer

Once activated, the timer runs until the set *Trip delay time* value. The time characteristic is according to DT. When the operation timer has reached the *Trip delay time* value, the `BLK2H` output is activated. After the timer has elapsed and the inrush situation still exists, the `BLK2H` signal remains active until the I_2H/I_1H ratio drops below the value set for the ratio in all phases, that is, until the inrush situation is over. If the drop-off situation occurs within the trip time up counting, the reset timer is activated. If the drop-off time exceeds *Reset delay time*, the operation timer is reset.

The `BLOCK` input can be controlled with a binary input, a horizontal communication input or an internal signal of the relay program. The activation of the `BLOCK` input prevents the `BLK2H` output from being activated.

It is recommended to use the second harmonic and the waveform based inrush blocking from the 87T function, if available.

5.1.5 Application

Transformer protections require high stability to avoid tripping during magnetizing inrush conditions. A typical example of an inrush detector application is doubling the pickup value of an overcurrent protection during inrush detection.

The inrush detection function can be used to selectively block overcurrent and ground-fault function stages when the ratio of second harmonic component over the fundamental component exceeds the set value.

Other applications of this function include the detection of inrush in lines connected to a transformer.

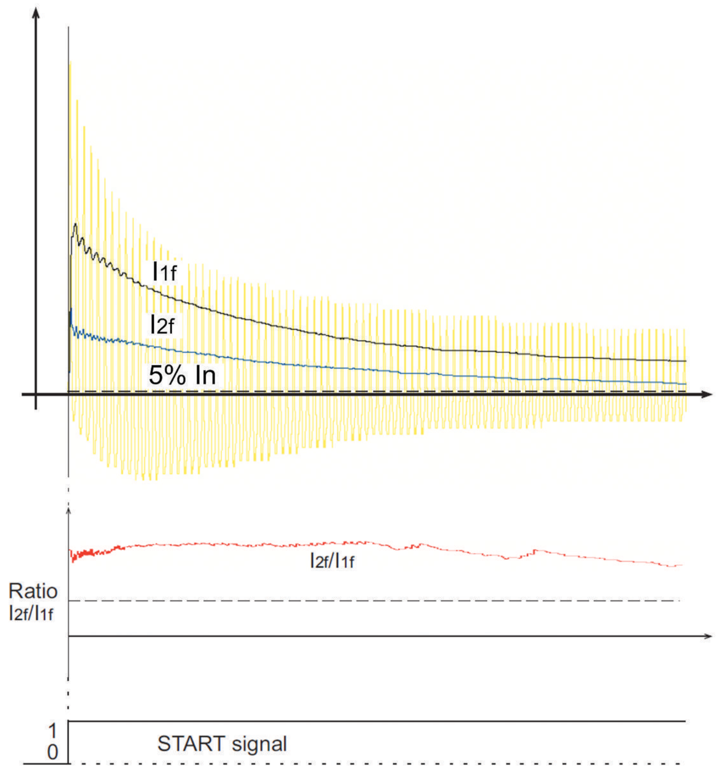


Figure 386: Inrush current in transformer

It is recommended to use the second harmonic and the waveform based inrush blocking from the 87T function, if available.

5.1.6 Signals

Table 669: INR Input signals

Name	Type	Default	Description
I_2H_A	SIGNAL	0	Second harmonic phase A current
I_1H_A	SIGNAL	0	Fundamental frequency phase A current
I_2H_B	SIGNAL	0	Second harmonic phase B current
I_1H_B	SIGNAL	0	Fundamental frequency phase B current
I_2H_C	SIGNAL	0	Second harmonic phase C current
I_1H_C	SIGNAL	0	Fundamental frequency phase C current
BLOCK	BOOLEAN	0=False	Block input status

Table 670: INR Output signals

Name	Type	Description
BLK2H	BOOLEAN	Second harmonic based block

5.1.7 Settings

Table 671: INR Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Pickup value	5...100	%	1	20	Ratio of the 2. to the 1. harmonic leading to restraint
Trip delay time	20...60000	ms	1	20	Trip delay time

Table 672: INR Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 673: INR Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	1	20	Reset delay time

5.1.8 Monitored data

Table 674: INR Monitored data

Name	Type	Values (Range)	Unit	Description
INR	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.1.9 Technical data

Table 675: INR Technical data

Characteristic	Value
Operation accuracy	At the frequency f = f_n
	Current measurement: ±1.5% of the set value or ±0.002 × I_n Ratio I2f/I1f measurement: ±5.0% of the set value
Reset time	+35 ms / -0 ms
Reset ratio	Typically 0.96
Trip time accuracy	+35 ms / -0 ms

5.1.10 Technical revision history

Table 676: INR Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

5.2 Circuit breaker failure protection 50BF

5.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit breaker failure protection	CCBRBRF	3I>/Io>BF	50BF

5.2.2 Function block

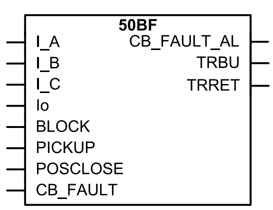


Figure 387: Function block

5.2.3 Functionality

The circuit breaker failure protection function 50BF is activated by trip commands from the protection functions. The commands are either internal commands to the terminal or external commands through binary inputs. The pickup command is always a default for three-phase operation. 50BF includes a three-phase conditional or unconditional retrip function, and also a three-phase conditional back-up trip function.

50BF uses the same levels of current detection for both retrip and back-up trip. The operating values of the current measuring elements can be set within a predefined setting range. The function has two independent timers for trip purposes: a retrip timer for the repeated tripping of its own breaker and a back-up timer for the trip logic operation for upstream breakers. A minimum trip pulse length can be set independently for the trip output.

The function contains a blocking functionality. It is possible to block the function outputs, if desired.

5.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of 50BF can be described using a module diagram. All the modules in the diagram are explained in the next sections. Also further information on the retrip and backup trip logics is given in sub-module diagrams.

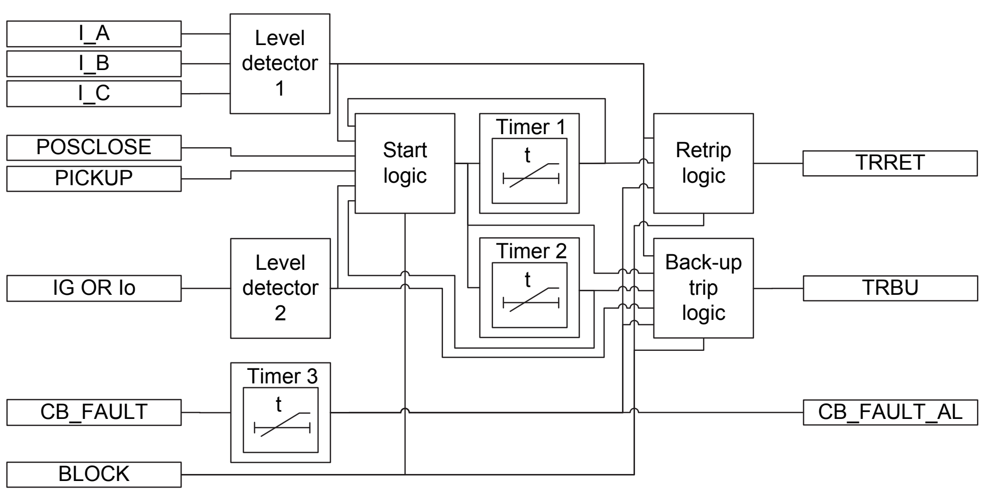


Figure 388: Functional module diagram

Level detector 1

The measured phase currents are compared phasewise to the set *Current value*. If the measured value exceeds the set *Current value*, the level detector reports the exceeding of the value to the start, retrip and backup trip logics. The parameter should be set low enough so that breaker failure situations with small fault current or high load current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection.

Level detector 2

The measured residual current is compared to the set *Current value Res*. If the measured value exceeds the set *Current value Res*, the level detector reports the exceeding of the value to the pickup and backup trip logics. In high-impedance grounded systems, the residual current at phase-to-ground faults is normally much smaller than the short circuit currents. To detect a breaker failure at single-phase ground faults in these systems, it is necessary to measure the residual current separately. In effectively grounded systems, also the setting of the ground-fault current protection can be chosen at a relatively low current level. The current setting should be chosen in accordance with the setting of the sensitive ground-fault protection.

Start logic

The start logic is used to manage the starting of the timer 1 and timer 2. It also resets the function after the circuit breaker failure is handled. On the rising edge of the `PICKUP` input, the enabling signal is send to the timer 1 and timer 2.

Function resetting is prevented during the next 150 ms. The 150 ms time elapse is provided to prevent malfunctioning due to oscillation in the starting signal.

In case the setting *Pickup latching mode* is set to "Level sensitive", the 50BF is reset immediately after the `PICKUP` signal is deactivated. The recommended setting value is "Rising edge".

The resetting of the function depends on the *CB failure mode* setting.

- If *CB failure mode* is set to "Current", the resetting logic further depends on the *CB failure trip mode* setting.

- If *CB failure trip mode* is set to "1 out of 3", the resetting logic requires that the values of all the phase currents drop below the *Current value* setting.
- If *CB failure trip mode* is set to "1 out of 4", the resetting logic requires that the values of the phase currents and the residual current drops below the *Current value* and *Current value Res* setting respectively.
- If *CB failure trip mode* is set to "2 out of 4", the resetting logic requires that the values of all the phase currents and the residual current drop below the *Current value* and *Current value Res* setting.

- If *CB failure mode* is set to the "Breaker status" mode, the resetting logic requires that the circuit breaker is in the open condition.
- If the *CB failure mode* setting is set to "Both", the resetting logic requires that the circuit breaker is in the open condition and the values of the phase currents and the residual current drops below the *Current value* and *Current value Res* setting respectively.

The activation of the `BLOCK` input resets the function.

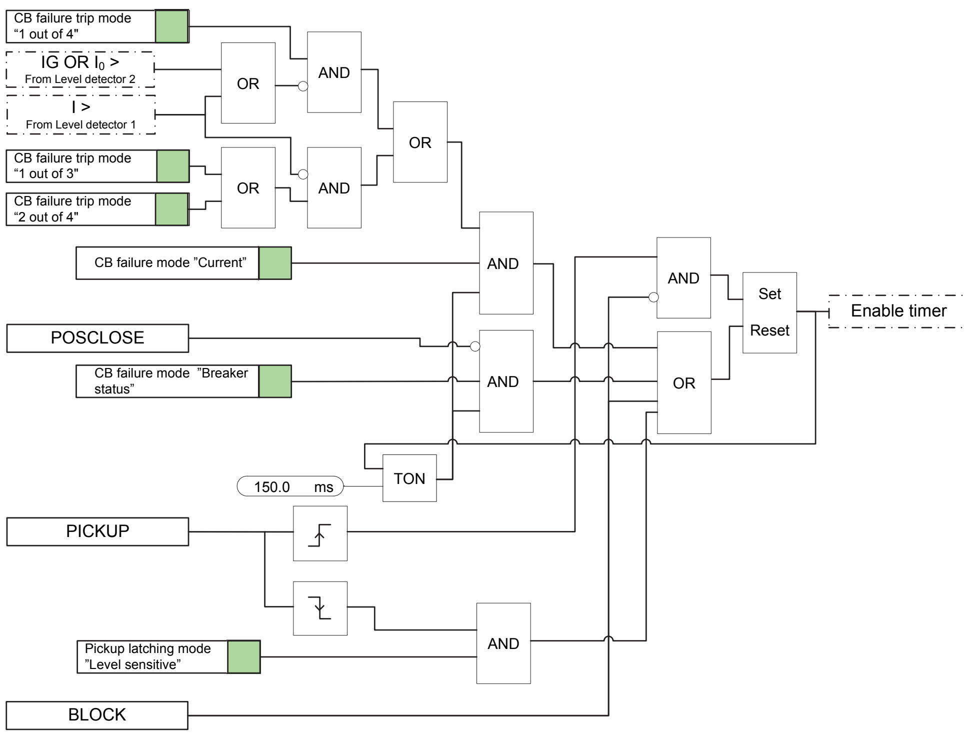


Figure 389: Start logic

Timer 1

Once activated, the timer runs until the set *Retrip time* value has elapsed. The time characteristic is according to DT. When the operation timer has reached the value set with *Retrip time*, the retrip logic is activated. A typical setting is 0...50 ms.

Timer 2

Once activated, the timer runs until the set *CB failure delay* value has elapsed. The time characteristic is according to DT. When the operation timer has reached the set maximum time value *CB failure delay*, the backup trip logic is activated. The value of this setting is made as low as possible at the same time as any unwanted operation is avoided. A typical setting is 90 - 150 ms, which is also dependent on the retrip timer.

The minimum time delay for the CB failure delay can be estimated as:

$$CBfailuredelay \geq Retriptime + t_{cbopen} + t_{BFP\_reset} + t_{margin}$$

(Equation 136)

t_{cbopen}	maximum opening time for the circuit breaker
t_{BFP_reset}	maximum time for the breaker failure protection to detect the correct breaker function (the current criteria reset)
t_{margin}	safety margin

It is often required that the total fault clearance time is less than the given critical time. This time often depends on the ability to maintain transient stability in case of a fault close to a power plant.

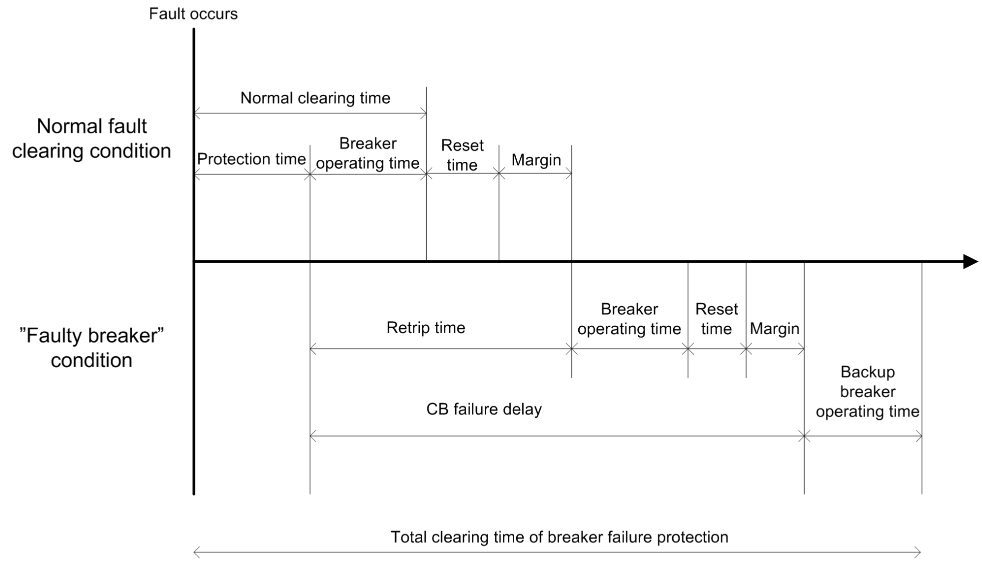


Figure 390: Timeline of the breaker failure protection

Timer 3

This module is activated by the CB_FAULT signal. Once activated, the timer runs until the set *CB fault delay* value has elapsed. The time characteristic is according to DT. When the operation timer has reached the maximum time value *CB fault delay*, the CB_FAULT_AL output is activated. After the set time, an alarm is given so that the circuit breaker can be repaired. A typical value is 5 s.

Retrip logic

The retrip logic provides the TRRET output, which can be used to give a retrip signal for the main circuit breaker. Timer 1 activates the retrip logic. The operation of the retrip logic depends on the *CB fail retrip mode* setting.

- The retrip logic is inactive if the *CB fail retrip mode* setting is set to "Disabled".
- If *CB fail retrip mode* is set to the "Current check" mode, the activation of the retrip output TRRET depends on the *CB failure mode* setting.
    - If *CB failure mode* is set to the "Current" mode, TRRET is activated when the value of any phase current exceeds the *Current value* setting. The TRRET output remains active for the time set with the *Trip pulse time* setting or until all phase current values drop below the *Current value* setting, whichever is longer.
    - If *CB failure mode* is set to the "Breaker status" mode, TRRET is activated if the circuit breaker is in the closed position. The TRRET output remains active for

    the time set with the *Trip pulse time* setting or the time the circuit breaker is in the closed position, whichever is longer.
    - If *CB failure mode* is set to "Both", TRRET is activated when either of the "Breaker status" or "Current" mode condition is satisfied.
- If *CB fail retrip mode* is set to the "Without check" mode, TRRET is activated once the timer 1 is activated without checking the current level. The TRRET output remains active for a fixed time set with the *Trip pulse time* setting.

The activation of the BLOCK input or the CB_FAULT_AL output deactivates the TRRET output.

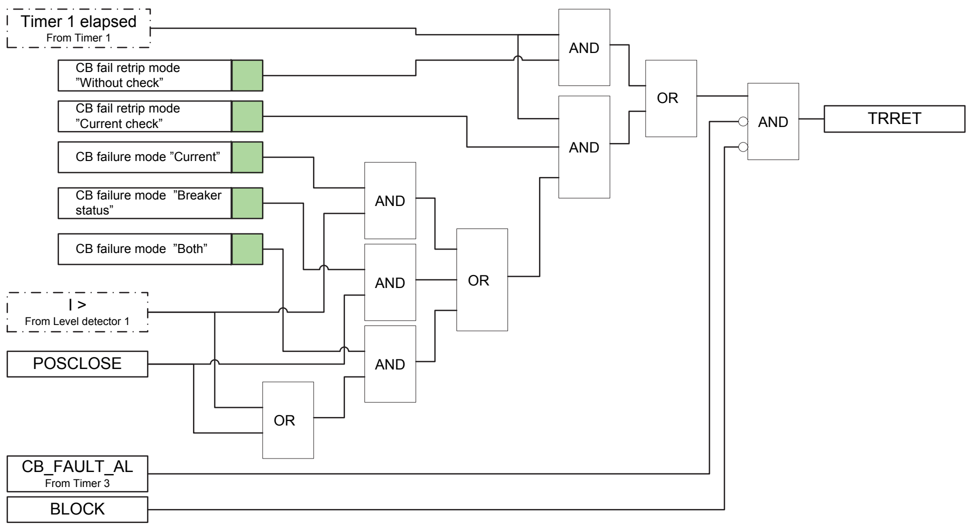


Figure 391: Retrip logic

Backup trip logic

The backup trip logic provides the TRBU output which can be used to trip the upstream backup circuit breaker when the main circuit breaker fails to clear the fault. The backup trip logic is activated by the timer 2 module or timer-enabling signal from the start logic module (rising edge of the PICKUP input detected), and simultaneously CB_FAULT_AL is active. The operation of the backup logic depends on the *CB failure mode* setting.

- If the *CB failure mode* is set to "Current", the activation of TRBU depends on the *CB failure trip mode* setting.
    - If *CB failure trip mode* is set to "1 out of 3", the failure detection is based on any of the phase currents exceeding the *Current value* setting. Once TRBU is activated, it remains active for the time set with the *Trip pulse time* setting or

    until the values of all the phase currents drop below the *Current value* setting, whichever takes longer.
    - If *CB failure trip mode* is set to "1 out of 4", the failure detection is based on either a phase current or a residual current exceeding the *Current value* or *Current value Res* setting respectively. Once TRBU is activated, it remains active for the time set with the *Trip pulse time* setting or until the values of all the phase currents or residual currents drop below the *Current value* and *Current value Res* setting respectively, whichever takes longer.
    - If *CB failure trip mode* is set to "2 out of 4", the failure detection requires that a phase current and a residual current both exceed the *Current value* and *Current value Res* setting respectively or two phase currents exceeding the *Current value*. Once TRBU is activated, it remains active for the time set with the *Trip pulse time* setting or until the values of all the phase currents drop below the *Current value*, whichever takes longer.

In most applications, "1 out of 3" is sufficient.

- If the *CB failure mode* is set to "Breaker status", the TRBU output is activated if the circuit breaker is in the closed position. Once activated, the TRBU output remains active for the time set with the *Trip pulse time* setting or the time the circuit breaker is in the closed position, whichever is longer.
- If the *CB failure mode* setting is set to "Both", TRBU is activated when the "Breaker status" or "Current" mode conditions are satisfied.

The activation of the BLOCK input deactivates the TRBU output.

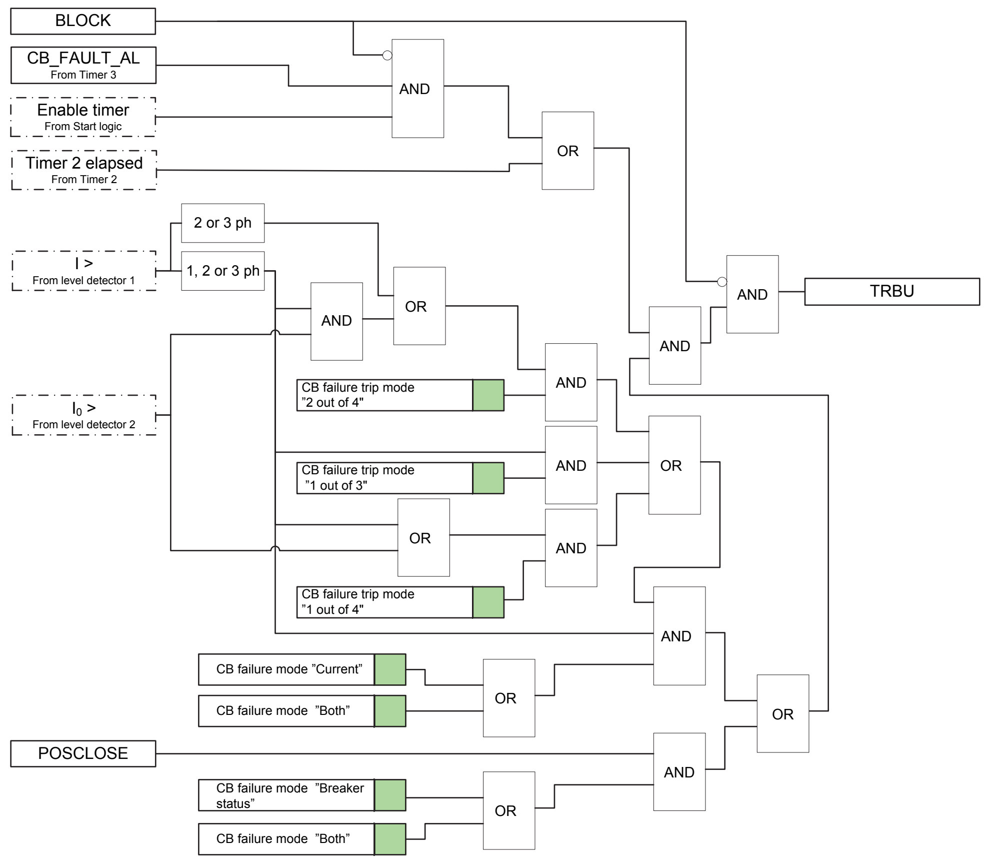


Figure 392: Backup trip logic

5.2.5 Application

The n-1 criterion is often used in the design of a fault clearance system. This means that the fault is cleared even if some component in the fault clearance system is faulty. A circuit breaker is a necessary component in the fault clearance system. For practical and economical reasons, it is not feasible to duplicate the circuit breaker for the protected component, but breaker failure protection is used instead.

The breaker failure function issues a backup trip command to up-stream circuit breakers in case the original circuit breaker fails to trip for the protected component. The detection of a failure to break the current through the breaker is made by measuring the current or by detecting the remaining trip signal (unconditional).

50BF can also retrip. This means that a second trip signal is sent to the protected circuit breaker. The retrip function is used to increase the operational reliability of the breaker.

The function can also be used to avoid backup tripping of several breakers in case mistakes occur during protection relay maintenance and tests.

50BF is initiated by operating different protection functions or digital logics inside the protection relay. It is also possible to initiate the function externally through a binary input.

50BF can be blocked by using an internally assigned signal or an external signal from a binary input. This signal blocks the function of the breaker failure protection even when the timers have started or the timers are reset.

The retrip timer is initiated after the pickup input is set to true. When the pre-defined time setting is exceeded, 50BF issues the retrip and sends a trip command, for example, to the circuit breaker's second trip coil. Both a retrip with current check and an unconditional retrip are available. When a retrip with current check is chosen, the retrip is performed only if there is a current flow through the circuit breaker.

The backup trip timer is also initiated at the same time as the retrip timer. If 50BF detects a failure in tripping the fault within the set backup delay time, which is longer than the retrip time, it sends a backup trip signal to the chosen backup breakers. The circuit breakers are normally upstream breakers which feed fault current to a faulty feeder.

The backup trip always includes a current check criterion. This means that the criterion for a breaker failure is that there is a current flow through the circuit breaker after the set backup delay time.

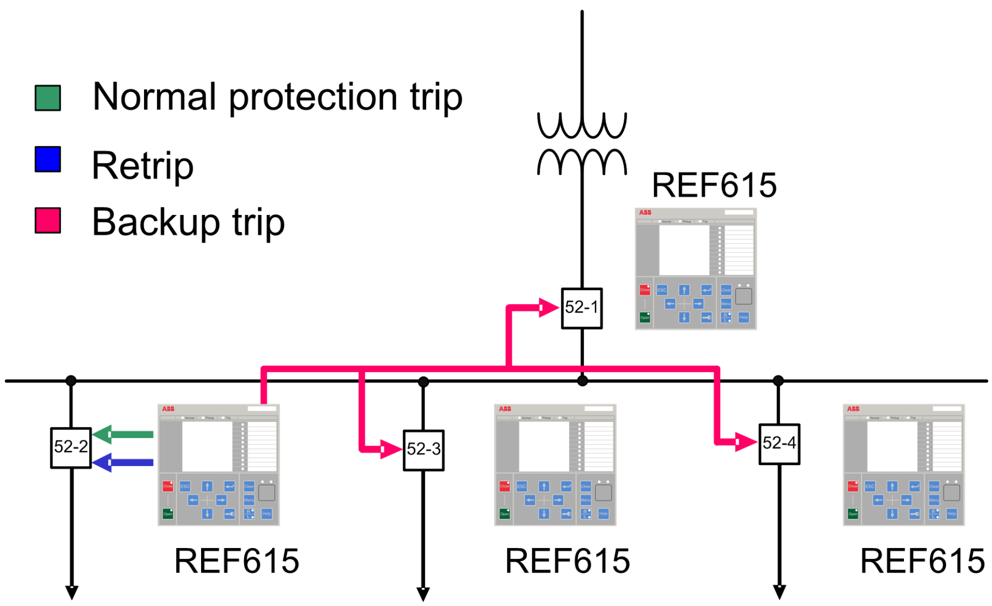


Figure 393: Typical breaker failure protection scheme in distribution substations

5.2.6 Signals

Table 677: 50BF Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
Io	SIGNAL	0	Residual current
BLOCK	BOOLEAN	0=False	Block CBFP operation
PICKUP	BOOLEAN	0=False	CBFP pickup command
POSCLOSE	BOOLEAN	0=False	CB in closed position
CB_FAULT	BOOLEAN	0=False	CB faulty and unable to trip

Table 678: 50BF Output signals

Name	Type	Description
CB_FAULT_AL	BOOLEAN	Delayed CB failure alarm
TRBU	BOOLEAN	Backup trip
TRRET	BOOLEAN	Retrip

5.2.7 Settings

Table 679: 50BF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Current value	0.05...2.00	xIn	0.05	0.30	Operating phase current
Current value Res	0.05...2.00	xIn	0.05	0.30	Operating residual current
CB failure trip mode	1=2 out of 4 2=1 out of 3 3=1 out of 4			2=1 out of 3	Backup trip current check mode
CB failure mode	1=Current 2=Breaker status 3=Both			1=Current	Operating mode of function
CB fail retrip mode	1=Disabled 2=Without Check 3=Current check			1=Disabled	Operating mode of retrip logic
Retrip time	0...60000	ms	10	120	Delay timer for retrip
CB failure delay	0...60000	ms	10	240	Delay timer for backup trip

Table 680: 50BF Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
CB fault delay	0...60000	ms	10	5000	Circuit breaker faulty delay
Measurement mode	2=DFT 3=Peak-to-Peak			3=Peak-to-Peak	Phase current measurement mode of function
Trip pulse time	0...60000	ms	10	200	Pulse length of retrip and backup trip outputs
Pickup latching mode	1=Rising edge 2=Level sensitive			1=Rising edge	Pickup reset delayed or immediately

5.2.8 Monitored data

Table 681: 50BF Monitored data

Name	Type	Values (Range)	Unit	Description
50BF	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.2.9 Technical data

Table 682: 50BF Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × I_n
Trip time accuracy	±1.0% of the set value or ±20 ms
Reset time	Typically 40 ms
Retardation time	<20 ms

5.2.10 Technical revision history

Table 683: 50BF Technical revision history

Technical revision	Change
B	Default trip pulse time changed to 150 ms
C	Added new setting parameter *Pickup latching mode*. Maximum value changed to 2.00 xIn for the *Current value* setting.
D	Internal improvement.
E	Maximum value for *Current value* and *Current value Res* changed from “1.00 x In” to “2.00 x In”.

5.3 Master trip 86/94

5.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Master trip	TRPPTRC	Master Trip	86/94

5.3.2 Function block

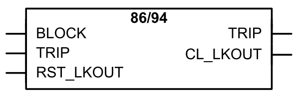


Figure 394: Function block

5.3.3 Functionality

The master trip function 86/94 is intended to be used as a trip command collector and handler after the protection functions. The features of this function influence the trip signal behavior of the circuit breaker. The minimum trip pulse length can be set when the non-latched mode is selected. It is also possible to select the latched or lockout mode for the trip signal.

5.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

When the 86/94 function is disabled, all trip outputs which are intended to go through the function to the circuit breaker trip coil are blocked.

The operation of 86/94 can be described with a module diagram. All the modules in the diagram are explained in the next sections.

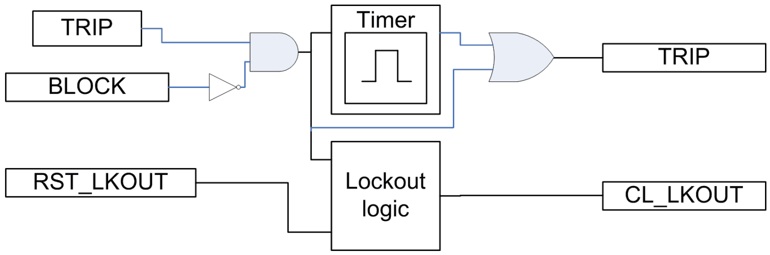


Figure 395: Functional module diagram

Timer

The duration of the TRIP output signal from 86/94 can be adjusted with the *Trip pulse time* setting when the "Non-latched" operation mode is used. The pulse length should be long enough to secure the opening of the breaker. For three-pole tripping, 86/94 has a single input TRIP, through which all trip output signals are routed from the protection functions within the protection relay, or from external protection functions via one or more of the protection relay's binary inputs. The function has a single trip output TRIP for connecting the function to one or more of the protection relay's binary outputs, and also to other functions within the protection relay requiring this signal.

The BLOCK input blocks the TRIP output and resets the timer.

Lockout logic

86/94 is provided with possibilities to activate a lockout. When activated, the lockout can be manually reset after checking the primary fault by activating the RST_LKOUT input or from the LHMI clear menu parameter. When using the "Latched" mode, the resetting of the TRIP output can be done similarly as when using the "Lockout" mode. It is also possible to reset the "Latched" mode remotely through a separate communication parameter.

The minimum pulse trip function is not active when using the "Lockout" or "Latched" modes but only when the "Non-latched" mode is selected.

The CL_LKOUT and TRIP outputs can be blocked with the BLOCK input.

Table 684: Operation modes for the 86/94 trip output

Mode	Operation
Non-latched	The *Trip pulse length* parameter gives the minimum pulse length for TRIP
Latched	TRIP is latched ; both local and remote clearing is possible.
Lockout	TRIP is locked and can be cleared only locally via menu or the RST_LKOUT input.

5.3.5 Application

All trip signals from different protection functions are routed through the trip logic. The most simplified application of the logic function is linking the trip signal and ensuring that the signal is long enough.

The tripping logic in the protection relay is intended to be used in the three-phase tripping for all fault types (3ph operating). To prevent the closing of a circuit breaker after a trip, 86/94 can block the 52 closing.

86/94 is intended to be connected to one trip coil of the corresponding circuit breaker. If tripping is needed for another trip coil or another circuit breaker which needs, for example, different trip pulse time, another trip logic function can be used. The two instances of the PTRC function are identical, only the names of the functions, 86/94-1 and 86/94-2, are different. Therefore, all references made to only 86/94-1 apply to 86/94-2 as well.

The inputs from the protection functions are connected to the `TRIP` input. Usually, a logic block OR is required to combine the different function outputs to this input. The `TRIP` output is connected to the binary outputs on the IO board. This signal can also be used for other purposes within the protection relay, for example when starting the breaker failure protection.

86/94 is used for simple three-phase tripping applications.

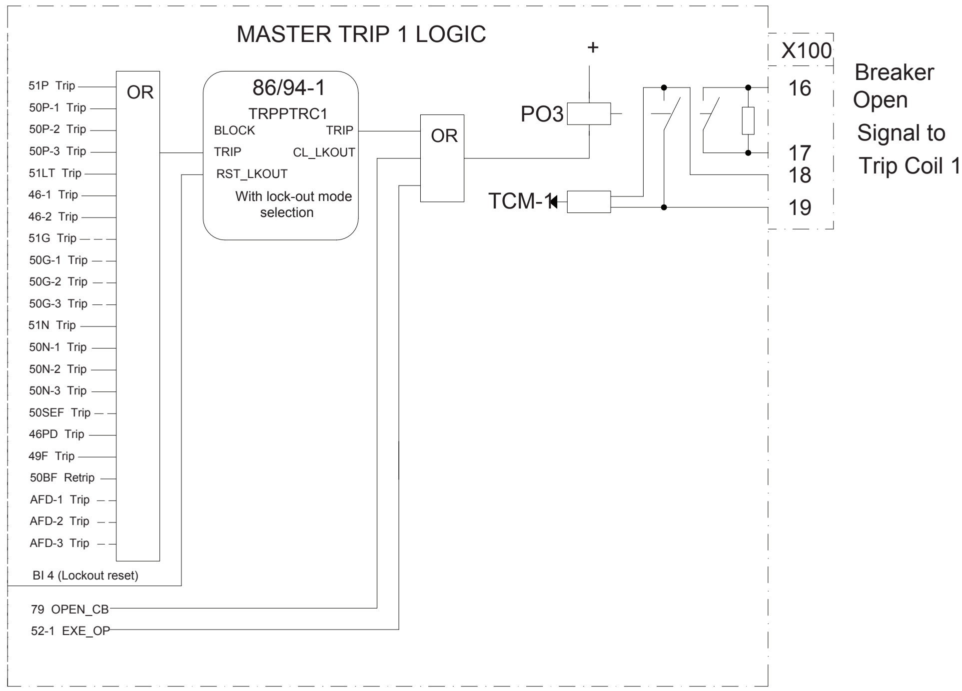


Figure 396: Typical 86/94 connection

5.3.6 Signals

Table 685: 86/94 Input signals

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block of function
TRIP	BOOLEAN	0=False	Trip
RST_LKOUT	BOOLEAN	0=False	Input for resetting the circuit breaker lockout function

Table 686: 86/94 Output signals

Name	Type	Description
TRIP	BOOLEAN	General trip output signal
CL_LKOUT	BOOLEAN	Circuit breaker lockout output (set until reset)

5.3.7 Settings

Table 687: 86/94 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Trip pulse time	20...60000	ms	1	250	Minimum duration of trip output signal
Trip output mode	1=Non-latched 2=Latched 3=Lockout			1=Non-latched	Select the operation mode for trip output

5.3.8 Monitored data

Table 688: 86/94 Monitored data

Name	Type	Values (Range)	Unit	Description
86/94	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.3.9 Technical revision history

Table 689: 86/94 Technical revision history

Technical revision	Change
B	-
C	-
D	Internal improvement.
E	Setting *Trip output mode* default setting is changed to "Latched".
F	Internal improvement.

5.4 High-impedance fault detection HIZ

5.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
High-impedance fault detection	PHIZ	HIF	HIZ

5.4.2 Function block

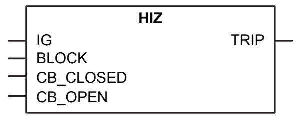


Figure 397: Function block

5.4.3 Functionality

A small percentage of ground faults have a very large impedance. They are comparable to load impedance and consequently have very little fault current. These high-impedance faults do not pose imminent danger to power system equipment. However, they are a substantial threat to humans and properties; people can touch or get close to conductors carrying large amounts of energy.

ABB has developed a patented technology (US Patent 7,069,116 B2 June 27, 2006, US Patent 7,085,659 B2 August 1, 2006) to detect a high-impedance fault.

The high-impedance fault detection function HIZ also contains a blocking functionality. It is possible to block function outputs, if desired.

HIZ is limited to be used in 60 Hz electrical networks with efficiently grounded or isolated neutral.

5.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

HIZ uses a multi-algorithm approach. Each algorithm uses various features of ground currents to detect a high-impedance fault.

Although the HIZ algorithm is very sophisticated, the setting required to operate the function is simple. The *Security Level* setting, with the setting range of 1 to 10, is set to strike a balance between the extremes of security and dependability which together constitute the reliability of any system. The setting value “10” is more secure than “1”.

The higher the *Security Level* setting, the lower the probability of false detection, but the system might miss out some genuine fault. On the other hand, a lower setting would make the system operate more dependably for high-impedance faults in the line, but the operation is more likely for other transients in the system. There are events in electrical networks which can cause similar current waveforms like high-impedance faults. These events could then be detected by the HIZ algorithm causing unnecessary detections. Normally, electrical network operator does not know the existence of these events well and those can also be happening very randomly. The effect is also always dependent on event location compared to protection relay measurement location. All these facts make the HIZ algorithm operation in certain electrical networks quite hard to measure and forecast beforehand. There is not any direct formula which can calculate the exact right setting based on known electrical network parameters.

It is hence recommended to set the value midway to “5” initially. Based on experience and confidence gained in a particular application, the setting can be moved either side. In many cases, it would be a good practice to use HIZ as an indicative function during a piloting phase, until enough experience has been gathered and a suitable setting found.

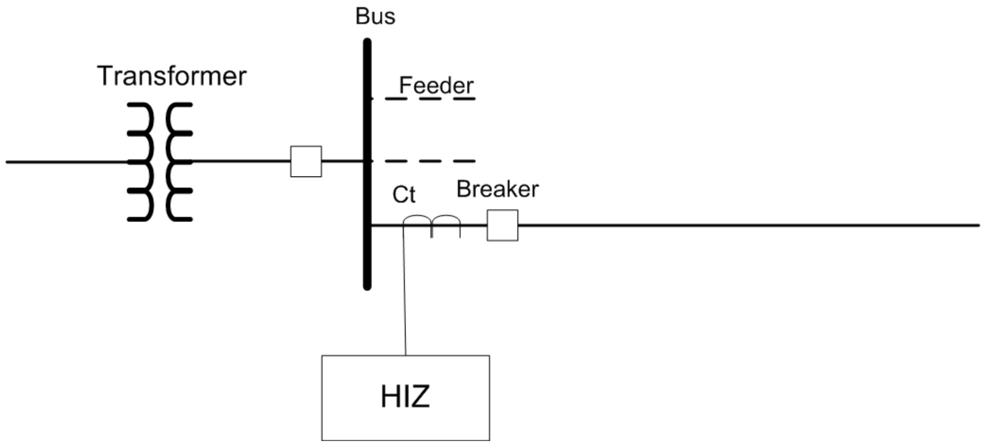


Figure 398: Electrical power system equipped with HIZ

Power system signals are acquired, filtered and then processed by individual high-impedance fault detection algorithm. The results of these individual algorithms are further processed by a decision logic to provide the detection decision. The decision logic can be modified depending on the application requirement.

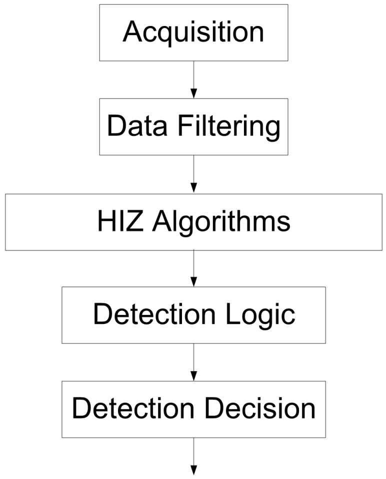


Figure 399: Block diagram of HIZ

HIZ is based on algorithms that use ground current signatures which are considered non-stationary, temporally volatile and of various burst duration. All harmonic and non-harmonic components within the available data window can play a vital role in the high-impedance fault detection. A major challenge is to develop a data model that acknowledges that high-impedance faults could take place at any time within the observation window of the signal and could be delayed randomly and attenuated substantially. The model is motivated by extensive research, actual experimental observations in the laboratory, field testing and what traditionally represents an accurate depiction of a non-stationary signal with a time-dependent spectrum.

Figure 400: Validation of HIZ on gravel

Figure 401: Validation of HIZ on concrete

Figure 402: Validation of HIZ on sand

Figure 403: Validation of HIZ on grass

5.4.5 Application

HIZ is used to detect a downed conductor dropping to a very resistive ground, causing a ground fault which is very difficult to detect by a conventional protection relay functionality. HIZ is then targeted to be used with overhead lines. HIZ is limited to be used in 60 Hz electrical networks with efficiently grounded or isolated neutral.

Electric power lines experience faults for many reasons. In most cases, electrical faults manifest in mechanical damage, which must be repaired before returning the line to service.

Most of the electrical network faults are ground faults. Conventional protection systems based on overcurrent, impedance or other principles are suitable for detecting relatively low-impedance faults which have a relatively large fault current.

However, a small percentage of the ground faults have a very large impedance. They are comparable to load impedance and consequently have very little fault current. These high-impedance faults do not pose imminent danger to power system equipment. However, they are a considerable threat to people and property. The IEEE Power System Relay Committee working group on High Impedance Fault Detection Technology defines High Impedance Faults as those that 'do not produce enough fault current to be detectable by conventional overcurrent relays or fuses.

HIZ always needs sensitive IG measurement.

High-impedance fault (HIZ) detection requires a different approach than that for conventional low-impedance faults. Reliable detection of HIZ provides safety to humans and animals. HIZ detection can also prevent fire and minimize property damage. ABB has developed innovative technology for high-impedance fault detection with over ten years of research resulting in many successful field tests.

5.4.6 Signals

Table 690: HIZ Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Ground current measured using SEF CT
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
CB_CLOSED	BOOLEAN	0=False	Circuit Breaker Closed input
CB_OPEN	BOOLEAN	0=False	Circuit Breaker Open input

Table 691: HIZ Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip

5.4.7 Settings

Table 692: HIZ Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Security Level	1...10		1	5	Security Level

Table 693: HIZ Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
System type	1=Grounded 2=Ungrounded			1=Grounded	System Type

5.4.8 Monitored data

Table 694: HIZ Monitored data

Name	Type	Values (Range)	Unit	Description
Position	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Position
HIZ	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.4.9 Technical revision history

Table 695: HIZ Technical revision history

Technical revision	Change
B	Internal improvement
C	Added inputs for Circuit Breaker Closed and Circuit Breaker Open

5.5 Binary signal transfer BST

5.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Binary signal transfer	BSTGGIO	BST	BST

5.5.2 Function block

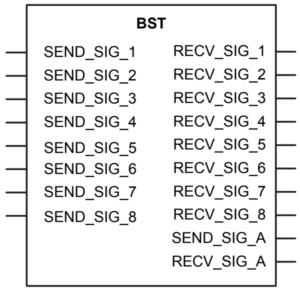


Figure 404: Function block

5.5.3 Functionality

The binary signal transfer function BST is used for transferring binary signals between the local and remote end line differential protection relays. The function includes eight binary signals that are transferred in the protection communication telegram and can be freely configured and used for any purpose in the line differential application.

BST transfers binary data continuously over the protection communication channel between the terminals. Each of the eight signals are bidirectional and the binary data sent locally is available remotely as a received signal.

BST includes a minimum pulse time functionality for the received binary signals. Each received signal has its own minimum pulse time setting parameter.

The function includes two alarm output signals. The `SEND_SIG_A` output signal is updated according to the status of the sent binary signals. The `RECV_SIG_A` output signal is updated according to the status of the received binary signals. Each signal can be separately included or excluded from the alarm logic with a setting parameter.

5.5.4 Operation principle

The *Signal 1...8 mode* setting can be used for changing the operation of the bidirectional signal channel. The signal channel can be disabled by setting the corresponding parameter value to “Not in use”. When the signal channel is disabled locally or remotely, the corresponding `RECV_SIG_1...8` signal status is always false on both ends.

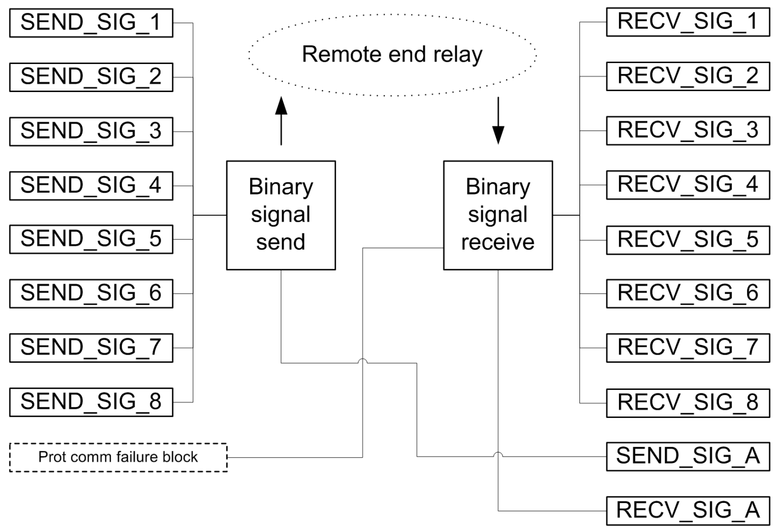


Figure 405: Functional module diagram

Binary signal send

The status of the inputs is continuously sent in the line differential protection telegrams. SEND_SIG_A can be used for alarming based on the status of SEND_SIG_1...8. By selecting the signal mode as "In use, alarm sel.", the sending status of the corresponding signal affects also the activation criteria of SEND_SIG_A. Further, in case more than one signal channels are selected into the alarm logic, the activation criteria can be defined according to "Any of selected" (OR) or "All of selected" (AND).

Binary signal receive

The function receives continuous binary data within the protection telegrams from the remote end protection relay. This received binary data status is then available as the RECV_SIG_1...8 outputs on the local end protection relay. RECV_SIG_A can be used for alarming based on the status of RECV_SIG_1...8. By selecting the signal mode as "In use, alarm sel.", the received status of the corresponding signal affects the activation criteria of RECV_SIG_A. Further, in case more than one signal channels are selected into the alarm logic, the activation criteria can be defined according to "Any of selected" (OR) or "All of selected" (AND). Each signal has also the *Pulse time 1...8* setting that defines the minimum pulse length for RECV_SIG_1...8. Also, in case the protection communication supervision detects a failure in the communication, the RECV_SIG_1...8 outputs are not set to false sooner than the minimum pulse length defined is first ensured for each signal.

5.5.5 Application

Among with the analog data, the binary data can also be exchanged with the line differential protection relays. The usage of the binary data is application specific and can vary in each separate case. The demands for the speed of the binary signals vary depending on the usage of the data. When the binary data is used as blocking signals for the line differential protection, the transfer response is extremely high. Binary signal interchange can be used in applications such as:

- Remote position indications
- Inter-tripping of the circuit breakers on both line ends
- Blocking of the line differential protection during transformer inrush or current circuit supervision failure
- Protection schemes; blocking or permissive
- Remote alarming.

The figure shows the overall chain to transfer binary data in an example application. The position indication of the local circuit breaker is connected to the protection relay's input interface and is then available for the protection relay configuration. The circuit breaker position indication is connected to the first input of BST which is used to send information to the remote end via communication. In the remote end, this information is handled as a remote circuit breaker open position and it is available from the first output of BST. This way the information can be exchanged.

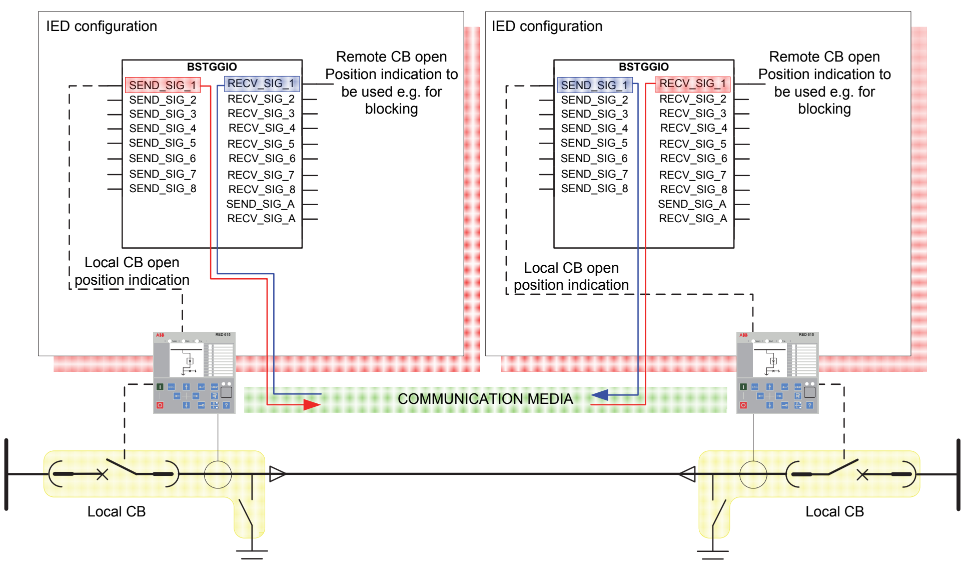


Figure 406: Example of usage of binary signal transfer for position indication change

5.5.6 Signals

Table 696: BST Input signals

Name	Type	Default	Description
SEND_SIG_1	BOOLEAN	0=False	Send signal 1 state
SEND_SIG_2	BOOLEAN	0=False	Send signal 2 state
SEND_SIG_3	BOOLEAN	0=False	Send signal 3 state
SEND_SIG_4	BOOLEAN	0=False	Send signal 4 state
SEND_SIG_5	BOOLEAN	0=False	Send signal 5 state
SEND_SIG_6	BOOLEAN	0=False	Send signal 6 state
SEND_SIG_7	BOOLEAN	0=False	Send signal 7 state
SEND_SIG_8	BOOLEAN	0=False	Send signal 8 state

Table 697: BST Output signals

Name	Type	Description
RECV_SIG_1	BOOLEAN	Receive signal 1 state
RECV_SIG_2	BOOLEAN	Receive signal 2 state
RECV_SIG_3	BOOLEAN	Receive signal 3 state
RECV_SIG_4	BOOLEAN	Receive signal 4 state
RECV_SIG_5	BOOLEAN	Receive signal 5 state
RECV_SIG_6	BOOLEAN	Receive signal 6 state
RECV_SIG_7	BOOLEAN	Receive signal 7 state
RECV_SIG_8	BOOLEAN	Receive signal 8 state
SEND_SIG_A	BOOLEAN	General logic send signal state
RECV_SIG_A	BOOLEAN	General logic receive signal state

5.5.7 Settings

Table 698: BST Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Signal 1 mode	1=on 2=on, logic included 3=off			2=on, logic included	Operation mode for signal 1
Signal 2 mode	1=on 2=on, logic included 3=off			2=on, logic included	Operation mode for signal 2
Signal 3 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 3
Signal 4 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 4
Signal 5 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 5
Signal 6 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 6
Signal 7 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 7
Signal 8 mode	1=on 2=on, logic included 3=off			1=on	Operation mode for signal 8
Pulse time 1	0...60000	ms	1	0	Minimum pulse time for received signal 1
Pulse time 2	0...60000	ms	1	0	Minimum pulse time for received signal 2
Pulse time 3	0...60000	ms	1	0	Minimum pulse time for received signal 3
Pulse time 4	0...60000	ms	1	0	Minimum pulse time for received signal 4
Pulse time 5	0...60000	ms	1	0	Minimum pulse time for received signal 6
Pulse time 6	0...60000	ms	1	0	Minimum pulse time for received signal 6
Pulse time 7	0...60000	ms	1	0	Minimum pulse time for received signal 7
Pulse time 8	0...60000	ms	1	0	Minimum pulse time for received signal 8

Table 699: BST Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Logic mode	1=Any of selected 2=All of selected			1=Any of selected	Selects the used logic mode for general send/ receive signals

5.5.8 Technical data

Table 700: BST Technical data

Characteristic		Value
Signalling delay	Fiber optic link	<5 ms
	Galvanic pilot wire link	<10 ms

5.5.9 Technical revision history

Table 701: BST Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

5.6 Emergency start-up 62EST

5.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Emergency start-up	ESMGAPC	ESTART	62EST

5.6.2 Function block

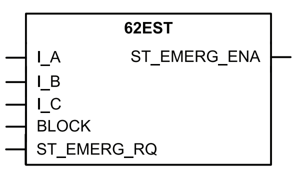


Figure 407: Function block

5.6.3 Functionality

An emergency condition can arise in cases where the motor needs to be started despite knowing that this can increase the temperature above limits or cause a thermal overload that can damage the motor. The emergency start-up function 62EST allows motor start-ups during such emergency conditions. 62EST is only to force the protection relay to allow the restarting of the motor. After the emergency start input is activated, the motor can be started normally. 62EST itself does not actually restart the motor.

The function contains a blocking functionality. It is possible to block function outputs, timer or the function itself, if desired.

5.6.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 62EST can be described using a module diagram. All the modules in the diagram are explained in the next sections.

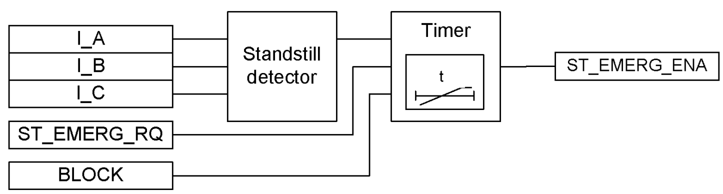


Figure 408: Functional module diagram

Standstill detector

The module detects if the motor is in a standstill condition. The standstill condition can be detected based on the phase current values. If all three phase currents are below the set value of *Motor standstill A*, the motor is considered to be in a standstill condition.

Timer

The timer is a fixed 10-minute timer that is activated when the ST_EMERG_RQ input is activated and motor standstill condition is fulfilled. Thus, the activation of the ST_EMERG_RQ input activates the ST_EMERG_ENA output, provided that the motor is in a standstill condition. The ST_EMERG_ENA output remains active for 10 minutes or as long as the ST_EMERG_RQ input is high, whichever takes longer.

The activation of the BLOCK input blocks and also resets the timer.

The function also provides the ST_EMERG_ENA output change date and time, T_ST_EMERG. The information is available in the monitored data view.

5.6.5 Application

If the motor needs to be started in an emergency condition at the risk of damaging the motor, all the external restart inhibits are ignored, allowing the motor to be restarted. Furthermore, if the calculated thermal level is higher than the restart inhibit level at an emergency start condition, the calculated thermal level is set slightly below the restart inhibit level. Also, if the register value of the cumulative start-up time counter exceeds the restart inhibit level, the value is set slightly below the restart disable value to allow at least one motor start-up.

The activation of the ST_EMERG_RQ digital input allows to perform emergency start. The protection relay is forced to a state which allows the restart of motor, and the operator can now restart the motor. A new emergency start cannot be made until the 10 minute time-out has passed or until the emergency start is released, whichever takes longer.

The last change of the emergency start output signal is recorded.

5.6.6 Signals

Table 702: 62EST Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode
ST_EMERG_RQ	BOOLEAN	0=False	Emergency start input

Table 703: 62EST Output signals

Name	Type	Description
ST_EMERG_ENA	BOOLEAN	Emergency start

5.6.7 Settings

Table 704: 62EST Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Motor standstill A	0.05...0.20	xIn	0.01	0.12	Current limit to check for motor standstill condition

Table 705: 62EST Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

5.6.8 Monitored data

Table 706: 62EST Monitored data

Name	Type	Values (Range)	Unit	Description
T_ST_EMERG	Timestamp			Emergency start activation timestamp
62EST	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.6.9 Technical data

Table 707: 62EST Technical data

Characteristic	Value
Operation accuracy	At the frequency $f = f_n$
	±1.5% of the set value or $\pm 0.002 \times U_n$

5.6.10 Technical revision history

Table 708: ESM Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

5.7 Fault locator 21FL

5.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fault locator	SCEFRFLO	FLOC	21FL

5.7.2 Function block

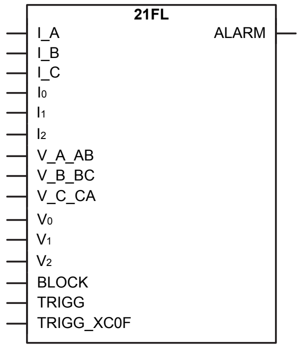


Figure 409: Function block

5.7.3 Functionality

The fault locator function 21FL provides impedance-based fault location. It is designed for radially operated distribution systems. It is applicable for locating short circuits in all kinds of distribution networks. Ground faults can be located in effectively grounded and in low-resistance or low-reactance grounded networks. Under certain limitations, 21FL can also be applied for an ground-fault location in ungrounded distribution networks.

The fault distance calculation is based on locally measured fundamental frequency current and voltage phasors. The full operation of 21FL requires that all phase currents and phase-to-ground voltages are measured.

The fault distance estimate is obtained when the function is externally or internally triggered.

5.7.4 Operation principle

The fault distance calculation is done in two steps. First, the fault type is determined with the inbuilt Phase Selection Logic (PSL). Second, based on the selected impedance measuring element (fault loop) the fault distance from the measuring point to the fault location is calculated.

As a fundamental operation criterion, the phase current and voltage magnitudes must exceed the threshold values of 2% xIn and 3% xUn, respectively.

The function can be enabled or disabled with the *Operation* setting. The corresponding parameter values are “Enable" and "Disable".

The operation of 21FL can be described with a module diagram. All the modules in the diagram are explained in the next sections.

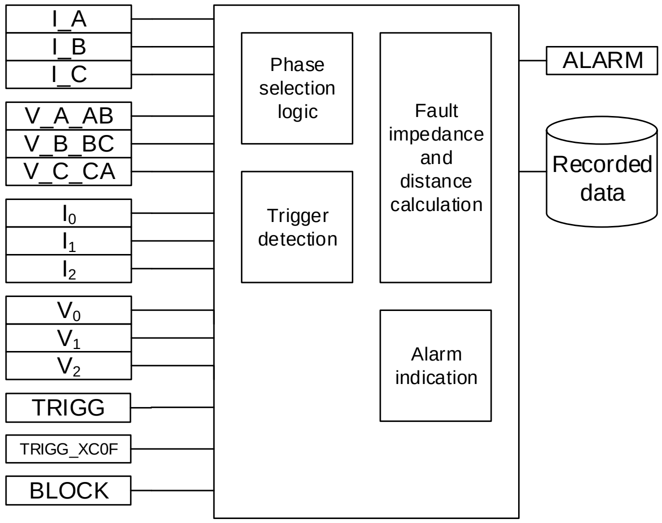


Figure 410: Functional module diagram

5.7.4.1 Phase selection logic

Identification of the faulty phases is provided by the built-in Phase Selection Logic based on combined impedance and current criterion. Phase selection logic is virtually setting-free and has only one parameter, *Z Max phase load*, for discriminating a large symmetrical load from a three-phase fault. The setting *Z Max phase load* can be calculated using the equation.

$$Z\ Max\ phase\ load = \left| 0.8 \cdot \frac{V_{xy}^2}{S_{max}} \right|$$

(Equation 137)

V_{xy}	Nominal phase-to-phase voltage
S_{max}	Maximum three-phase load

For example, if V_{xy} = 20 kV and S_{max} = 1 MVA, then *Z Max phase load* = 320.0 Ω.

The identification of the faulty phases is compulsory for the correct operation of 21FL. This is because only one of the impedance-measuring elements (fault loops) provides the correct result for a specific fault type. A three-phase fault is an exception and theoretically it can be calculated with any of the fault loops. The fault loop used in the fault distance calculation is indicated in the recorded data Flt loop as specified in Table 709.

Table 709: Fault types and corresponding fault loops

Fault type	Description	Flt loop
-	No fault	No fault
A-E	Phase A-to-ground fault	AG Fault
B-E	Phase B-to-ground fault	BG Fault
C-E	Phase C-to-ground fault	CG Fault
A-B	Phase A-to-B short circuit fault	AB Fault
B-C	Phase B-to-C short circuit fault	BC Fault
C-A	Phase C-to-A short circuit fault	AC Fault
A-B-C-(E)	Three-phase short circuit	ABC Fault

In case of two-phase-to-ground faults (A-B-E, B-C-E or C-A-E), the selected fault loop depends on the location of the individual ground faults. When the faults are located at the same feeder, the corresponding phase-to-phase loop (either “AB Fault” or “BC Fault” or “CA Fault”) is used for calculation. When the faults are located at different feeders, the phase-to-ground loop (either “AG Fault” or “BG Fault” or “CG Fault”) corresponding to the faulty phase at the protected feeder is used for calculation.

5.7.4.2 Fault impedance and distance calculation

As soon as a fault condition is recognized by the phase selection logic, the fault distance calculation is started with one of the seven impedance-measuring elements, that is, the fault loops. 21FL employs independent algorithms for each fault type to achieve optimal performance.

The inherent result from the fault distance calculation is the ohmic fault loop impedance value.

Table 710: The calculated impedance values available in the recorded data

Impedance valule	Description
Flt phase reactance	Estimated positive sequence reactance from the substation to the fault location in primary ohms.
Flt point resistance	Fault resistance value in the fault spot in primary ohms. The composition of this term depends on the fault loop as described in the following subsections.
Flt loop resistance	The total fault loop resistance from the substation to the fault location in primary ohms. Fault point resistance is included in this value. The composition of this term is different for short-circuit and ground-fault loops as described in the following subsections.
Flt loop reactance	The total fault loop reactance from the substation to the fault location in primary ohms. The composition of this term is different for short-circuit and ground-faults loops as described in the following subsections.

These impedance values can be utilized as such or they can be further processed in system level fault location applications, such as distribution management system (DMS).

Fault loops “AG Fault” or “BG Fault” or “CG Fault”

Fault loops “AG Fault”, “BG Fault” or “CG Fault” are used for single-phase-to-ground faults. When the individual ground faults are located at different feeders, they are also applied in the case of two-phase-to-ground fault. In this case, the phase-to-ground loop (either “AG Fault” or “BG Fault” or “CG Fault”) corresponding to the faulty phase at the protected feeder, is used for calculation. Figure 411 shows the phase-to-ground fault loop model. The following impedances are measured and stored in the recorded data of 21FL.

$$Flt\ point\ resistance = R_{fault}$$

(Equation 138)

$$Flt\ loop\ resistance = R_1 + R_N + R_{fault}$$

(Equation 139)

$$Flt\ loop\ reactance = X_1 + X_N$$

(Equation 140)

$$Flt\ phase\ reactance = X_1$$

(Equation 141)

R_1	Estimated positive-sequence resistance from the substation to the fault location
X_1	Estimated positive-sequence reactance from the substation to the fault location
R_0	Estimated zero-sequence resistance from the substation to the fault location
X_0	Estimated zero-sequence reactance from the substation to the fault location
R_N	Estimated the ground return path resistance (= (R0 – R1)/3) from the substation to the fault location
X_N	Estimated is the ground return path reactance (= (X0 – X1)/3) from the substation to the fault
R_{fault}	Estimated fault resistance at the fault location

The recorded data Flt phase reactance provides the estimated positive-sequence reactance from the substation to the fault location.

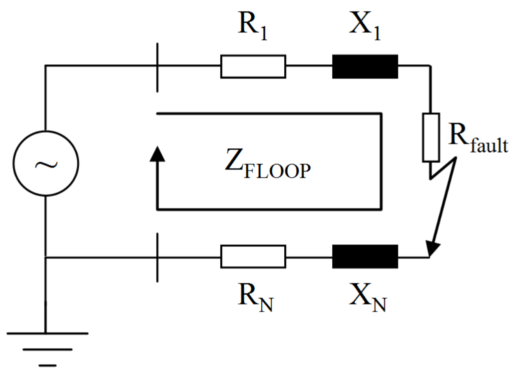


Figure 411: Fault loop impedance for phase-to-ground fault loops "AG Fault", "BG Fault" or "CG Fault"

The ground-fault distance calculation algorithm is selected with setting *EF algorithm Sel*. Options for the selection are "Load compensation" and "Load modelling". For the correct operation of both algorithms there should not be any zero-sequence current sources, for example, grounding transformers, in front of the protection relay location.

The "Load compensation" algorithm utilizes symmetrical components to compensate for the effect of load on the measured voltages and currents. In case of radial feeders, this algorithm should be selected with low-impedance/effectively grounded systems where the fault current is fed from one side only and there are no in-feeds along the protected line.

The "Load modelling" algorithm takes into account the effect of the load in the measured currents and voltages by considering it in the fault loop model. In case of radial feeders, this algorithm can be applied with low-impedance/effectively grounded systems where the fault current is fed from one side only. The "Load modelling" algorithm has been especially designed for ungrounded systems.

The "Load modelling" algorithm requires the *Equivalent load Dis* setting, that is, an equivalent load distance, as an additional parameter. The derivation and meaning of this parameter is illustrated in Figure 412, where the load is assumed to be evenly distributed along the feeder, resulting in the actual voltage drop curve as seen in the middle part of Figure 412.

In case of evenly distributed load, *Equivalent load Dis* ~ 0.5. When the load is tapped at the end of the feeder, *Equivalent load Dis* = 1.0. If the load distribution is unknown, a default value of 0.5 can be used for *Equivalent load Dis*.

The maximum value of the voltage drop, denoted as V_{drop}(real), appears at the end of the feeder. The *Equivalent load Dis* parameter is the distance at which a single load tap corresponding to the total load of the feeder would result in a voltage drop equal to V_{drop}(real). The dashed curve shows the voltage drop profile in this case.

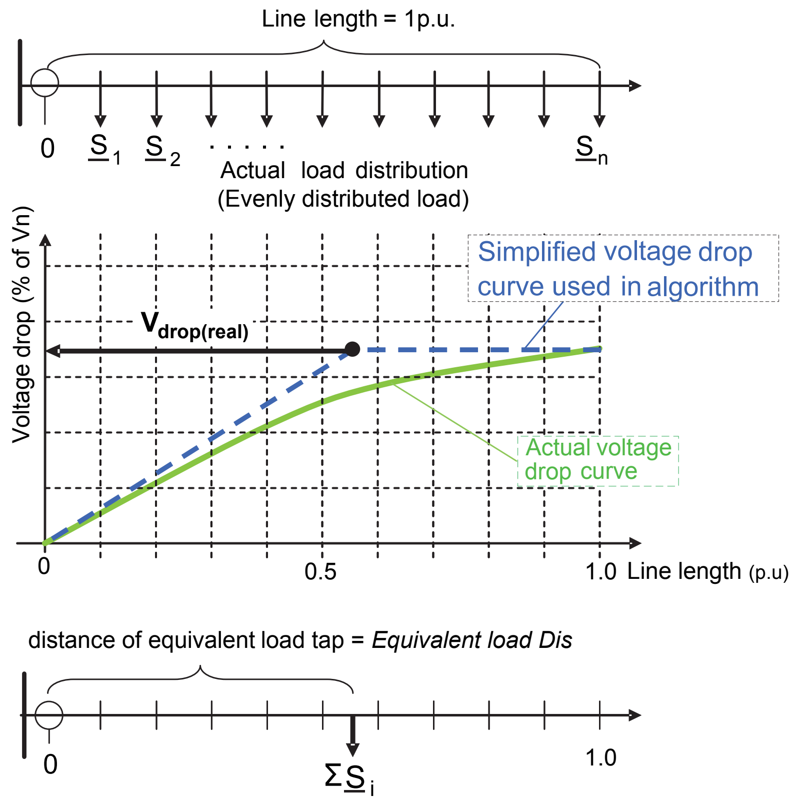


Figure 412: Description of the equivalent load distance

The exact value for *Equivalent load Dis* can be calculated based on the load flow and voltage drop calculations using data from DMS-system and the following equation.

$$Equivalent\ load\ Dis = \left| \frac{V_{d(real)}}{V_{d(tap,d=1)}} \right|$$

(Equation 142)

$V_{d(real)}$	The actual maximum voltage drop of the feeder
$V_{d(tap,d=1)}$	The fictional voltage drop, if the entire load would be tapped at the end (d=1) of the feeder (not drawn in Figure 412). The calculation of this value requires data from the DMS system.

Alternatively, the setting *Equivalent load Dis* can be determined by conducting a single-phase ground-fault test ($R_{fault} = 0\ \Omega$) at that point of the feeder where the maximum actual voltage drop takes place. This point is typically located at the end of the main line. As a result, the calculated value is stored in the recorded data Equivalent load Dis.

In addition, when the setting *EF algorithm Sel* is equal to “Load modelling”, the *EF algorithm Cur Sel* setting determines whether zero-sequence “Io based” or negative-sequence “I2 based” current based algorithm is used. The difference between “Io based” and “I2 based” methods is that “I2 based” does not require the *Ph capacitive React* and *Ph leakage Ris* settings. In case of “Io based”, these settings are needed to compensate for the influence of the line-charging capacitances of the protected feeder. This improves the accuracy of the fault location estimate when fault resistance is involved in the fault.

Under certain restrictions, the “Load modelling” algorithm can also be applied to ungrounded networks. In this case the *EF algorithm Cur Sel* setting should be set to “Io based” and thus *Ph capacitive React* and *Ph leakage Ris* settings must be determined.

The prerequisite for the operation of 21FL in ground faults in ungrounded networks is that the ground-fault current of the network corresponding to a solid fault exceeds the pre-fault load current; that is the Equation 143 is valid.

$$Flt\ to\ Lod\ Cur\ ratio = \frac{\left|I_{ef(Rfault=0)}\right|}{\left|I_{Load}\right|} \geq 1$$

(Equation 143)

This ratio is estimated by 21FL and stored in the recorded data Flt to Lod Cur ratio together with the fault distance estimate.

In case of ungrounded network, sufficient fault current magnitude resulting in Flt to Lod Cur ratio >1 can be achieved, for example, with proper switching operations in the background network, if possible, which increase the fault current. If the faulty feeder is re-energized after the switching operation, a new estimate for the fault distance can be obtained. Fault resistance decreases the fault location accuracy and the resistance should not be too high, the maximum is a few hundred ohms. Also low value of Flt to Lod Cur ratio causes inaccuracy and affects the quality of fault distance estimate. Considered inaccuracies affecting the calculated fault distance estimate are reported in the recorded result quality indicator value Flt Dist quality in Table 711.

Fault loops “AB Fault”, “BC Fault” or “CA Fault”

Fault loops “AB Fault”, “BC Fault” or “CA Fault” are used for phase-to-phase short circuit faults as well as in the case of a two-phase-to-ground fault if the individual ground faults are located at the same feeder. Figure 413 shows the phase-to-phase fault loop model. The following impedances are measured and stored in the recorded data of 21FL.

$$Flt\ point\ resistance = \frac{R_{fault}}{2}$$

(Equation 144)

$$Flt\ loop\ resistance = R_1 + \frac{R_{fault}}{2}$$

(Equation 145)

$$Flt\ loop\ reactance = Flt\ phase\ reactance = X_1$$

(Equation 146)

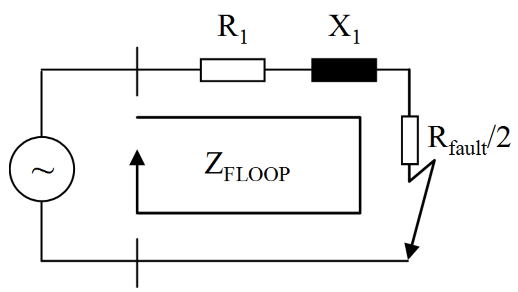


Figure 413: Fault loop impedance for phase-to-phase fault loops (either “AB Fault”, “BC Fault” or “CA Fault”)

The fault distance calculation algorithm for the phase-to-phase fault loops is defined by using settings *Load Com PP loops* and *Enable simple model*. Options for the selection are "Disabled" or "Enabled".

Load compensation can be enabled or disabled with setting *Load Com PP loops*. The load compensation should be disabled only if the ratio between the fault current and load current is large or when the value of the fault distance estimate for the short circuit fault is required from each shot of an autoreclosing sequence.

The fault distance calculation is most accurate when calculated with the fault loop model. This model requires positive sequence impedances of the protected feeder to be given as settings. If these settings are not available, valid impedance values can be calculated also without the fault loop model with setting *Enable simple model* = “TRUE”. However, valid distance estimate, that is, the conversion of measured impedance (‘’electrical fault distance’’) into a physical fault distance requires accurate positive sequence impedance settings.

Fault loop “ABC Fault”

Fault loop “ABC Fault” is used exclusively for the three-phase short circuit fault. Figure 414 shows the three-phase fault loop model. The following impedances are measured and stored in the recorded data of 21FL.

$$Flt\ point\ resistance = R_{fault}$$

(Equation 147)

$$Flt\ loop\ resistance = R_1 + R_{fault}$$

(Equation 148)

$$Flt\ loop\ reactance = Flt\ phase\ reactance = X_1$$

(Equation 149)

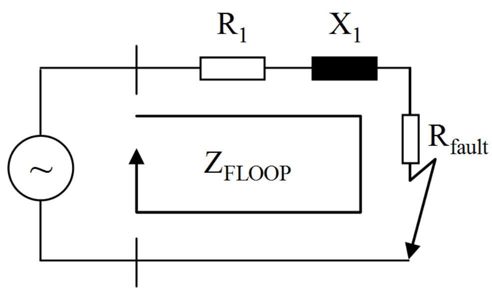


Figure 414: Fault loop impedance for a three-phase fault loop ("ABC Fault")

The three-phase fault distance is calculated with a special measuring element using positive-sequence quantities. This is advantageous especially in case of non-transposed (asymmetric) lines, as the influence of line parameter asymmetry is reduced. If the line is non-transposed, all the phase-to-phase loops have different fault loop reactances. The use of positive-sequence quantities results in the average value of phase-to-phase loop reactances, that is, the most representative estimate in case of three-phase faults.

The fault distance calculation algorithm for the three-phase fault loop is defined by using settings *Load Com PP loops* and *Enable simple model*. Options for the selection are "Disabled" or "Enabled".

Load compensation can be enabled or disabled with setting *Load Com PP loops*. The load compensation should be disabled only if the ratio between the fault current and load current is large or when the value of the fault distance estimate for the short circuit fault is required from each shot of an autoreclosing sequence.

The fault distance calculation is most accurate when the calculation is made with the fault loop model. This model requires positive sequence impedances of the protected feeder to be given as settings. If these settings are not available, valid impedance values can be calculated also without the fault loop model with setting *Enable simple model* = "TRUE". However, valid distance estimate, that is, the conversion of measured impedance (''electrical fault distance'') into a physical fault distance requires accurate positive sequence impedance settings.

Estimation of fault resistance in different fault loops

The fault point resistance value provided by the impedance calculation is available in recorded data Flt point resistance and it depends on the applied fault loop as shown in Figure 415. In case of ground faults, the estimated fault point resistance includes the total fault point resistance between the faulted phase and ground, for example, the arc and grounding resistances. In case of phase-to-phase faults, the estimated fault point resistance is half of the total fault point resistance between the phases. In case of a three-phase fault, the estimated fault point resistance equals the total fault point resistance as per phase value, for example, the arc resistance per phase.

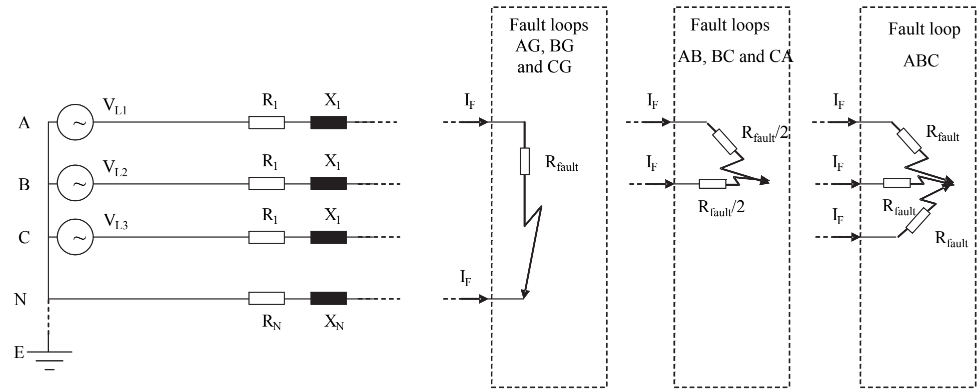


Figure 415: Definition of a physical fault point resistance in different fault loops

Steady-state asymmetry and load compensation

In reality, power systems are never perfectly symmetrical. The asymmetry produces steady-state quantities in the form of zero-sequence and negative-sequence voltages and currents. If not compensated, these are error sources for fault distance calculation especially in case of ground faults. All ground-fault distance calculation algorithms of 21FL utilize the delta-quantities which mitigate the effects of the steady-state asymmetry.

Load current is another error source for fault distance calculation. Its influence increases with higher fault resistance values. 21FL employs independent load compensation methods for each fault type to achieve optimal performance. The purpose of load compensation is to improve the accuracy of the fault distance calculation models by estimating the actual fault current in the fault location. Delta-quantities are used for this to mitigate the effect of load current on fault distance estimation. For ground faults, the load compensation is done automatically inside the fault distance calculation algorithm. For short circuit faults, load compensation is enabled with setting *Load Com PP loops*. The default value is “Enabled”. The parameter should be set to “Disabled” only if the ratio between the expected fault current and load current is large or when the fault distance estimate for short circuit fault is required for each shot of an autoreclosing sequence.

The delta-quantity describes the change in measured signal due to the fault.

$$\Delta x = x_{fault} + x_{pre\text{-}fault}$$

(Equation 150)

x_{fault}	Corresponds to the signal value during fault
$x_{pre\text{-}fault}$	Corresponds to the signal value during healthy state just before fault

Result quality indicator

The quality of the estimated fault distance is judged and reported in recorded data as the Flt Dist quality together with the fault distance estimate. The Flt Dist quality is a bit vector indicating detected sources of inaccuracy in the fault distance estimate. In case Flt Dist quality equals 1, the result is not affected by error sources. This results in good quality for fault distance estimate. If factors affecting negatively to fault distance estimation are detected, the Flt Dist quality is according to Table 711. In this case estimated fault distance, Flt distance value is given in HMI in parenthesis.

Table 711: Fault distance quality indicator Flt Dist quality

Value	Corresponding inaccuracy description
2	Estimation stability criterion has not been reached
4	Fault point resistance exceeds 500 Ω
8	Fault point resistance exceeds 5 × X_{loop} 1)
16	Fault point resistance exceeds 20 × X_{loop} 1)
32	Flt to Lod Cur ratio is below 1.00
64	Fault distance estimate outside tolerances (<-0.1 pu or >1.1 pu)
128	Distance estimate calculation is not done due to too low magnitudes of I or V
256	Distance estimate calculation cannot be performed (for example avoiding internal division by zero)

1) Xloop is the total loop reactance according to settings

For example, if fault point resistance exceeds 500 Ω and Flt to Lod Cur ratio is below 1.0, Flt Dist quality is “36”. As another example, if no error sources are found, but stability criterion is not met, the value of Flt Dist quality is “2”.

Impedance settings

The fault distance calculation in 21FL is based on the fault loop impedance modeling. The fault loop is parametrized with the impedance settings and these can be set at maximum for three line sections (A, B and C). Each section is enabled by entering a section length, which differs from zero to settings *Line Len section A*, *Line Len section B* or *Line Len section C* in the order section A-> section B-> section C.

The ground-fault loops require both positive-sequence and zero-sequence impedances, for example, *R1 line section A* and *X1 line section A*, *R0 line section A* and *X0 line section A*. For the short circuit loops, only positive-sequence impedances are needed. Even these can be omitted in the short circuit loops, if the setting *Enable simple model* equals "TRUE".

If the impedance settings are in use, it is important that the settings closely match the impedances of used conductor types. The impedance settings are given in primary ohms [ohm/pu] and the line section lengths in per unit [pu]. Thus, impedances can be either given in ohm/km and section length in km, or ohm/mile and section length in miles. The resulting Flt distance matches the units entered for the line section lengths.

Positive-sequence impedance values

Fault location requires accurate setting values for line impedances. Positive-sequence impedances are required both for location of short circuits and ground faults. As data sheet impedance per unit values are generally valid only for a certain tower configuration, the values should be adjusted according to the actual installation configuration. This minimizes the fault location errors caused by inaccurate settings.

The positive-sequence reactance per unit and per phase can be calculated with a following approximation equation which applies to symmetrically transposed three-phase aluminium overhead lines without ground wires.

$$X_1 \approx \omega_n \cdot 10^{-4} \left(2 \cdot \ln \frac{a_{en}}{r} + 0.5 \right) [\Omega / km]$$

(Equation 151)

ω_n	$2 \times \pi \times f_n$, where f_n = fundamental frequency [Hz]
a_{en}	$\sqrt[3]{\left(a_{12} \cdot a_{23} \cdot a_{31}\right)}$ the geometric average of phase distances [m]
a_{xy}	distance [m] between phases x and y
r	radius [m] for single conductor

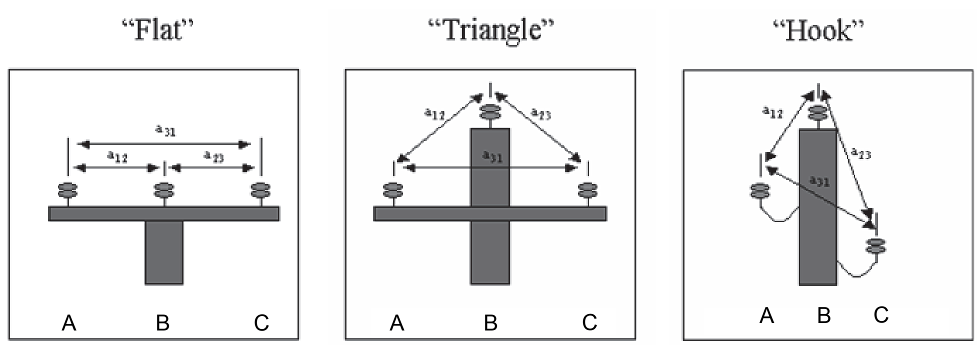


Figure 416: Typical distribution line tower configurations

Example values of positive-sequence impedances for typical medium voltage overhead-lines are given in the following tables.

Table 712: *Positive-sequence impedance values for typical 11 kV conductors, "Flat" tower configuration assumed*

Name	R1 [Ω/km]	X1 [Ω/km]
ACSR 50 SQ.mm	0.532	0.373
ACSR 500 SQ.mm	0.0725	0.270

Table 713: *Positive-sequence impedance values for typical 10/20 kV conductors, "Flat" tower configuration assumed*

Name	R1 [Ω/km]	X1 [Ω/km]
Al/Fe 36/6 Sparrow	0.915	0.383
Al/Fe 54/9 Raven	0.578	0.368
Al/Fe 85/14 Pigeon	0.364	0.354
Al/Fe 93/39 Imatra	0.335	0.344
Al/Fe 108/23 Vaasa	0.287	0.344
Al/Fe 305/39 Duck	0.103	0.314

Table 714: *Positive-sequence impedance values for typical 33 kV conductors, "Flat" tower configuration assumed*

Name	R1 [Ω/km]	X1 [Ω/km]
ACSR 50 sq.mm	0.529	0.444
ACSR 100 sq.mm	0.394	0.434
ACSR 500 sq.mm	0.0548	0.346

Zero-sequence impedance values

Location of ground faults requires both positive-sequence and zero-sequence impedances. For short circuit faults, zero-sequence impedances are not required.

The positive-sequence impedance per unit values for the lines are typically known or can easily be obtained from data sheets. The zero-sequence values are generally not as easy to obtain as they depend on the actual installation conditions and configurations. Sufficient accuracy can, however, be obtained with rather simple calculations using the following equations, which apply per phase for symmetrically transposed three-phase aluminium overhead lines without ground wires.

$$R_0\,[50Hz] \approx R1 + 0.14804\,[\Omega / km]$$

(Equation 152)

$$R_0\,[60Hz] \approx R1 + 0.17765[\Omega / km]$$

(Equation 153)

$$X_0 \approx 2 \cdot \omega_n \cdot 10^{-4} \left(3 \cdot \ln \frac{w}{r_{en}} + 0.25 \right) [\Omega / km]$$

(Equation 154)

R_1	conductor AC resistance [Ω/km]
W	$658\sqrt{\dfrac{\rho_{ground}}{f_n}}$ the equivalent depth [m] of the ground return path
ρ_{ground}	ground resistivity [Ωm]
r_{en}	$\sqrt[3]{r \cdot \sqrt[3]{a_{12}^2 \cdot a_{23}^2 \cdot a_{31}^2}}$ the equivalent radius [m] for conductor bundle
r	radius [m] for single conductor
a_{xy}	distance [m] between phases x and y

Ph leakage Ris and *Ph capacitive React* settings

The *Ph leakage Ris* and *Ph capacitive React* settings are used for improving fault distance estimation accuracy for ground faults. They are critical for an accurate fault location in ungrounded networks. In other types of networks they are less critical. The *Ph leakage Ris* setting represents the leakage losses of the protected feeder in terms of resistance per phase. The *Ph capacitive React* setting represents the total phase-to-ground capacitive reactance of the protected feeder per phase. Based on experience, a proper estimate for *Ph leakage Ris* should be about 20…40 × *Ph capacitive React*.

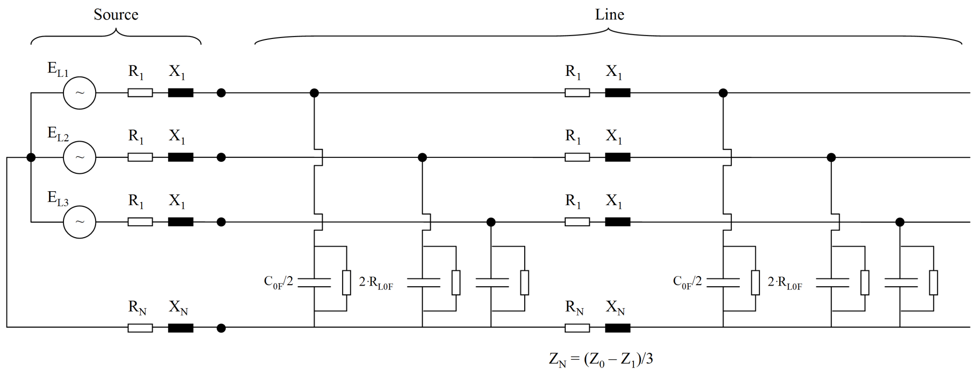


Figure 417: Equivalent diagram of the protected feeder. R_{L0F} = Ph leakage Ris.

The determination of the *Ph capacitive React* setting can be based either on network data or measurement.

If the total phase-to-ground capacitance (including all branches) per phase C_{0F} of the protected feeder is known, the setting value can be calculated.

$$Ph\ capacitive\ React = \frac{1}{(\omega_n \cdot C_{0F})}$$

(Equation 155)

In case of ungrounded network, if the ground-fault current produced by the protected feeder I_{ef} is known, the setting value can be calculated.

$$Ph\ capacitive\ React = \left| \frac{\sqrt{3} \cdot V_{xy}}{I_{ef}} \right|$$

(Equation 156)

V_{xy}	Phase-to-ground voltage

21FL can also determine the value for the *Ph capacitive React* setting by measurements. The calculation of *Ph capacitive React* is triggered by the binary signal connected to the `TRIGG_XC0F` input when a ground-fault test is conducted outside the protected feeder during commissioning, for example, at the substation busbar. The *Calculation Trg mode* has to be “External”. After the activation of the `TRIGG_XC0F` triggering input, the calculated value for setting *Ph capacitive React* is obtained from recorded data as parameter *XC0F Calc*. This value has to be manually entered for the *Ph capacitive React* setting. The calculated value matches the current switching state of the feeder and thus, if the switching state of the protected feeder changes, the value should be updated.

Figure 418 shows an example configuration, which enables the measurement of setting *Ph capacitive React*.

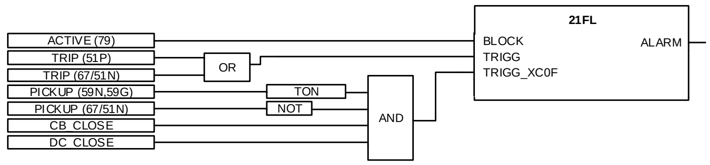


Figure 418: An example configuration, which enables the measurement of setting Ph capacitive React

If the ground fault is detected by the residual overvoltage function (PICKUP of 59N, 59G), but not seen by the forward-looking ground-fault protection function (PICKUP of 67/51N), the fault is located outside the protected feeder. This is mandatory for valid measurement of setting *Ph capacitive React*. After a set delay (TON), the input TRIGG_XC0F is activated and the parameter *XC0F Calc* in the recorded data is updated. The delay (TON) must be set longer than the pickup delay of the directional ground-fault function 67/51N, but shorter than the minimum trip time of the directional ground-fault functions in any of the feeders. For example, if the pickup delay is 100 ms and the shortest trip time 300 ms, a value of 300 ms can be used. Circuit breaker and disconnector status is used to verify that the entire feeder is measured.

Modeling a non-homogeneous line

A typical distribution feeder is built with several different types of overhead lines and cables. This means that the feeder is electrically non-homogeneous. 21FL allows the modeling of the line impedance variation in protection relay with three line sections with independent impedance settings. This improves the accuracy of physical fault distance conversion done in the protection relay, especially in cases where the line impedance non-homogeneity is severe. Each section is enabled by entering a section length, which differs from zero, to settings *Line Len section A*, *Line Len section B* or *Line Len section C* in the order section A-> section B-> section C.

Impedance model with one line section is enabled by setting *Line Len section A* to differ from zero. In this case the impedance settings *R1 line section A*, *X1 line section A*, *R0 line section A* and *X0 line section A* are used for the fault distance calculation and for conversion from reactance to physical fault distance. This option should be used only in the case of a homogeneous line, that is, when the protected feeder consists of only one conductor type.

Impedance model with two line sections is enabled by setting both *Line Len section A* and *Line Len section B* to differ from zero. In this case the impedance settings *R1 line section A*, *X1 line section A*, *R0 line section A*, *X0 line section A*, *R1 line section B*, *X1 line section B*, *R0 line section B* and *X0 line section B* are used for the fault distance calculation and for conversion from reactance to physical fault distance. This option should be used in the case of a non-homogeneous line when the protected feeder consists of two types of conductors.

Impedance model with three line sections is enabled by setting *Line Len section A*, *Line Len section B* and *Line Len section C* all differ from zero. In this case the impedance settings *R1 line section A*, *X1 line section A*, *R0 line section A*, *X0 line section A*, *R1 line section B*, *X1 line section B*, *R0 line section B*, *X0 line section B*, *R1 line section C*, *X1 line section C*, *R0 line section C* and *X0 line section C* are used for the fault distance calculation and for conversion from reactance to physical fault distance. This option should be used in the case of a non-homogeneous line when the protected feeder consists of more than two types of conductors.

The effect of line impedance non-homogeneity in the conversion of fault loop reactance into physical fault distance is demonstrated in example shown in Figure 419 with 10 kilometer long feeder with three line types. The total line impedance for the 10 km line is R1 = 6.602 Ω (0.660 Ω/km) and X1 = 3.405 Ω (0.341 Ω/km), consisting of the following sections and impedance values.

- 4 km of PAS 150 (R1 = 0.236 Ω/km, X1 = 0.276 Ω/km)
- 3 km of Al/Fe 54/9 Raven (R1 = 0.536 Ω/km, X1 = 0.369 Ω/km)
- 3 km of Al/Fe 21/4 Swan (R1 = 1.350 Ω/km, X1 = 0.398 Ω/km)

The non-homogeneity of feeder impedance can be illustrated by drawing the protected feeder in RX-diagram (in the impedance plane), as shown in Figure 419.

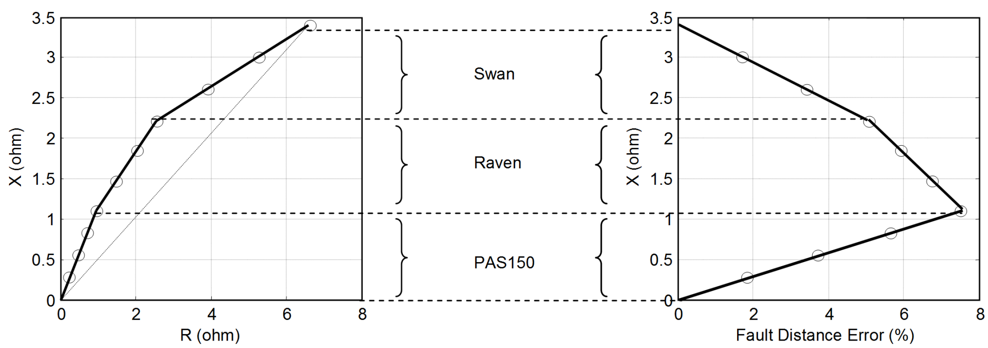


Figure 419: Example impedance diagram of an electrically non-homogeneous feeder (left), and the resulting error in fault distance if the measured fault loop reactance is converted into physical fault distance by using only one line section parameters (right).

In Figure 419 the feeder is modelled either with one or three line sections with parameters given in Table 715.

Table 715: Impedance settings

Parameter	Impedance model with one section	Impedance model with three sections
R1 line section A	0.660 Ω/pu	0.236 Ω/pu
X1 line section A	0.341 Ω/pu	0.276 Ω/pu
Line Len section A	10000 pu	4000 pu
R1 line section B	N/A	0.536 Ω/pu
X1 line section B	N/A	0.369 Ω/pu
Line Len section B	0.000 pu	3000 pu
R1 line section C	N/A	1.350 Ω/pu
X1 line section C	N/A	0.398 Ω/pu
Line Len section C	0.000 pu	3000 pu

Figure 419 illustrates the conversion error from measured fault loop reactance into physical fault distance. The fault location is varied from 1 km to 10 km in 1 km steps (marked with circles). An error of nearly eight per cent at maximum is created by the conversion procedure when modeling a non-homogenous line with only one section. By using impedance model with three line sections, there is no error in the conversion.

The previous example assumed a short circuit fault and thus, only positive-sequence impedance settings were used. The results, however, also apply for ground faults.

Taps or spurs in the feeder

If the protected feeder consists of taps or spurs, the measured fault impedance corresponds to several physical fault locations (For example, A or B in Figure 420). The actual fault location must be identified using additional information, for example, short circuit current indicators placed on tapping points.

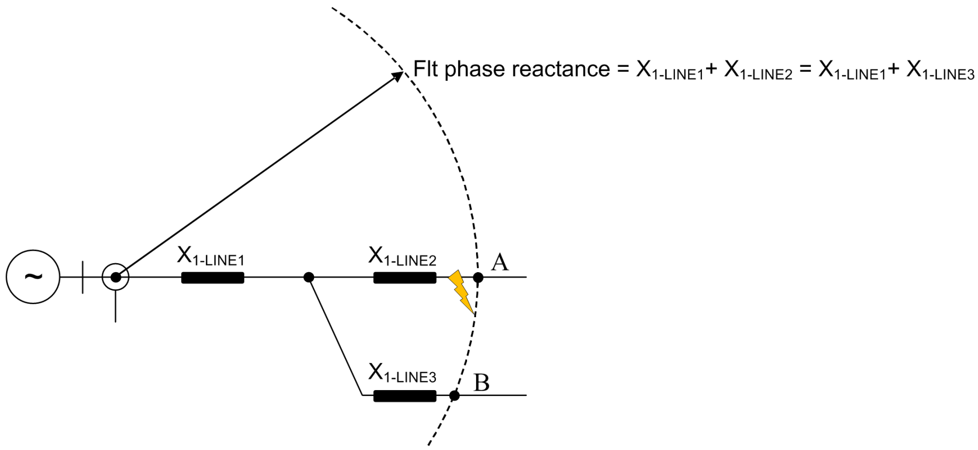


Figure 420: Fault on a distribution line with spurs

5.7.4.3 Trigger detection

The fault distance estimate is obtained when 21FL is triggered. The triggering method is defined with setting *Calculation Trg mode*. The options for selection are: “External” or “Internal”, where the default value is “External”. The TRIGG_OUT event indicates fault distance value recording moment. The fault distance estimate, Flt distance, together with the timestamp of actual triggering are saved in the recorded data of 21FL.

- In case of external triggering, an external trigger signal should be connected to the `TRIGG` input. The triggering signal is typically a trip signal from a protective function. At triggering moment the fault distance is stored into recorded data. It is important that triggering is timed suitably to provide sufficient distance estimation calculation time before tripping of the feeder circuit breaker.
- In case of internal triggering, the `TRIGG` input is not used for triggering. Instead, the trigger signal is created internally so that the estimation is started when phase selection logic detects a fault and the estimate is triggered when its value has stabilized sufficiently. This is judged by maximum variation in fault distance estimate and defined with setting *Distance estimate Va* (in the same unit as the fault distance estimate). When successive estimates during one fundamental cycle are within “final value ± *Distance estimate Va*”, the fault distance estimate (mean of successive estimates) is recorded. In case stabilization criterion has not been fulfilled, the fault distance estimate is given just before the phase currents are interrupted. The phase selection logic is a non-directional function, and thus internal triggering should not be used when directionality is required.

Generally, 21FL requires a minimum of two fundamental cycles of measuring time after the fault occurrence. Figure 421 illustrates typical behavior of fault distance estimate of 21FL as a function of time.

- Immediately after the fault occurrence, the estimate is affected by initial fault transients in voltages and currents.
- Approximately one fundamental cycle after the fault occurrence, the fault distance estimate starts to approach the final value.
- Approximately two fundamental cycles after the fault occurrence, the stability criterion for fault distance estimate is fulfilled and the TRIGG_OUT event is sent. The recorded data values are stored at this moment.

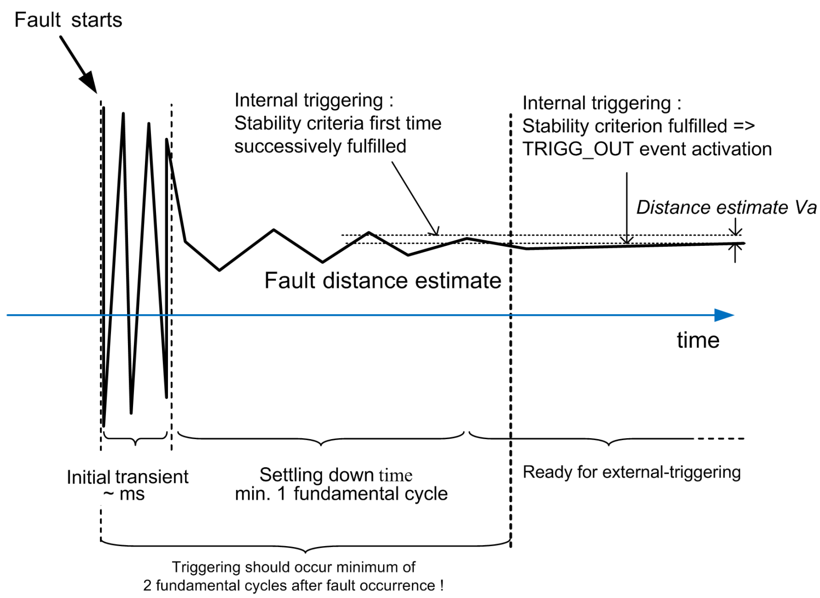


Figure 421: The behavior of fault distance estimate in time

5.7.4.4 Alarm indication

21Fl contains an alarm output for the calculated fault distance. If the calculated fault distance FLT_DISTANCE is between the settings *Low alarm Dis limit* and *High alarm Dis limit*, the ALARM output is activated.

The ALARM output can be utilized, for example, in regions with waterways or other places where knowledge of certain fault locations is of high importance.

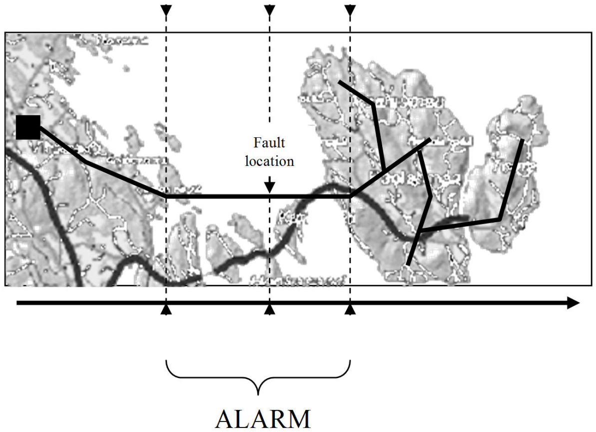


Figure 422: An example of the ALARM output use

5.7.4.5 Recorded data

All the information required for a later fault analysis is recorded to 21FL recorded data. In the protection relay, recorded data is found in **Monitoring/Recorded data/Other protection/S21FL**.

The function has also monitored data values which are used for the read-out of continuous calculation values. The cross reference table shows which of the recorded data values are available as continuous monitoring values during a fault.

Table 716: Cross reference table for recorded and monitored data values

Recorded data	Monitored data
Flt loop	FAULT_LOOP
Flt distance	FLT_DISTANCE
Flt Dist quality	FLT_DIST_Q
Flt loop resistance	RFLOOP
Flt loop reactance	XFLOOP
Flt phase reactance	XFPHASE
Flt point resistance	RF
Flt to Lod Cur ratio	IFLT_PER_ILD
Equivalent load Dis	S_CALC
XC0F Calc	XC0F_CALC

5.7.4.6 Measurement modes

The full operation of 21FL requires that all three phase-to-ground voltages are measured. The voltages can be measured with conventional voltage transformers or voltage dividers connected between the phase and ground (*VT connection* is set to “Wye”). Another alternative is to measure phase-to-phase voltages (*VT connection* is set to “Delta”) and residual voltage (V0). Both alternatives are covered by setting the configuration parameter *Phase voltage Meas* to "Accurate".

When the *Phase voltage Meas* setting is set to "Ph-to-ph without Uo" and only phase-to-phase voltages are available (but not V0), only short-circuit measuring loops (fault loops “AB Fault”, “BC Fault” or “CA Fault” or “ABC Fault”) can be measured accurately. In this case, the ground-fault loops (fault loops either “AG Fault”, “BG Fault” or “CG Fault”) cannot provide correct fault distance estimates and the triggering of the function in case of ground fault is automatically disabled.

5.7.5 Application

The main objective of the feeder terminals is a fast, selective and reliable operation in faults inside the protected feeder. In addition, information on the distance to the fault point is very important for those involved in operation and maintenance. Reliable information on the fault location greatly decreases the downtime of the protected feeders and increases the total availability of a power system.

21FL provides impedance-based fault location. It is designed for radially operated distribution systems and is applicable for locating short circuits in all kinds of distribution networks. Ground faults can be located in effectively grounded and low resistance/low-reactance grounded networks. Under certain limitations, 21FL can also be applied for ground-fault location in ungrounded distribution networks.

Configuration example

A typical configuration example for 21FL triggering is illustrated in Figure 418 where external triggering is applied, that is, *Calculation Trg mode* is set to “External”. The `TRIP` signal from non-directional overcurrent function 51P is used to provide an indication of a short circuit fault. The `TRIP` signal from the directional ground-fault function 67/51N is used to provide an indication of a ground fault at the protected feeder.

21FL with the autoreclosing function

When 21FL is used with the autoreclosing sequence, the distance estimate from the first trip is typically the most accurate one. The fault distance estimates from successive trips are possible but accuracy can be decreased due to inaccurate load compensation. During the dead time of an autoreclosing sequence, the load condition of the feeder is uncertain.

The triggering of 21FL can also be inhibited during the autoreclosing sequence. This is achieved by connecting the inverted READY signal from the autoreclosing function 79, which indicates that the autoreclosing sequence is in progress, to the BLOCK input of 21FL. Blocking of the 21FL triggering is suggested during the autoreclosing sequence when the load compensation or steady-state asymmetry elimination is based on the delta quantities. This applies to the short circuit faults when *Load Com PP loops* is set to "Enabled" or, for ground faults, when *EF algorithm Sel* is set to "Load compensation" or "Load modelling".

5.7.6 Signals

Table 717: 21FL Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
Io	SIGNAL	0	Residual current
I_1	SIGNAL	0	Positive sequence current
I_2	SIGNAL	0	Negative sequence current
V_A_AB	SIGNAL	0	Phase to ground voltage A or phase to phase voltage AB
V_B_BC	SIGNAL	0	Phase to ground voltage B or phase to phase voltage BC
V_C_CA	SIGNAL	0	Phase to ground voltage C or phase to phase voltage CA
V_0	SIGNAL	0	Residual voltage
V_1	SIGNAL	0	Positive phase sequence voltage
V_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Signal for blocking the triggering
TRIGG	BOOLEAN	0=False	Distance calculation triggering signal
TRIGG_XC0F	BOOLEAN	0=False	XC0F calculation triggering signal

Table 718: 21FL Output signals

Name	Type	Description
ALARM	BOOLEAN	Fault location alarm signal

5.7.7 Settings

Table 719: 21FL Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Z Max phase load	1.0...10000.0	ohm	0.1	80.0	Impedance per phase of max. load, overcurr./ under-imp., PSL
Ph leakage Ris	20...1000000	ohm	1	210000	Line PhE leakage resistance in primary ohms
Ph capacitive React	10...1000000	ohm	1	7000	Line PhE capacitive reactance in primary ohms
R1 line section A	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line resistance, line section A
X1 line section A	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line reactance, line section A
R0 line section A	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line resistance, line section A
X0 line section A	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line reactance, line section A
Line Len section A	0.000...1000.000	pu	0.001	0.000	Line length, section A

Table 720: 21FL Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
High alarm Dis limit	0.000...1.000	pu	0.001	0.000	High alarm limit for calculated distance
Low alarm Dis limit	0.000...1.000	pu	0.001	0.000	Low alarm limit for calculated distance
Equivalent load Dis	0.00...1.00		0.01	0.50	Equivalent load distance when EF algorithm equals to load modelling
R1 line section B	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line resistance, line section B
X1 line section B	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line reactance, line section B
R0 line section B	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line resistance, line section B
X0 line section B	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line reactance, line section B
Line Len section B	0.000...1000.000	pu	0.001	0.000	Line length, section B
R1 line section C	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line resistance, line section C
X1 line section C	0.000...1000.000	ohm / pu	0.001	1.000	Positive sequence line reactance, line section C
R0 line section C	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line resistance, line section C
X0 line section C	0.000...1000.000	ohm / pu	0.001	4.000	Zero sequence line reactance, line section C
Line Len section C	0.000...1000.000	pu	0.001	0.000	Line length, section C

Table 721: 21FL Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Phase voltage Meas	1=Accurate 2=Ph-to-ph without Uo			1=Accurate	Phase voltage measurement principle
Calculation Trg mode	1=Internal 2=External			2=External	Trigger mode for distance calculation

Table 722: 21FL Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
EF algorithm Sel	1=Load compensation 2=Load modelling			1=Load compensation	Selection for PhE-loop calculation algorithm
EF algorithm Cur Sel	1=Io based 2=I2 based			1=Io based	Selection for ground-fault current model
Load Com PP loops	0=Disabled 1=Enabled			1=Enabled	Enable load compensation for PP/3P-loops
Enable simple model	0=Disabled 1=Enabled			0=Disabled	Enable calc. without impedance settings for PP/3P-loops
Distance estimate Va	0.001...0.300		0.001	0.015	Allowed variation of short circuit distance estimate

5.7.8 Monitored data

Table 723: 21FL Monitored data

Name	Type	Values (Range)	Unit	Description
RF	FLOAT32	0.0...1000000.0	ohm	Fault point resistance in primary ohms
FAULT_LOOP	Enum	1=AG Fault 2=BG Fault 3=CG Fault 4=AB Fault 5=BC Fault 6=CA Fault 7=ABC Fault -5=No fault		Fault impedance loop
FLT_DISTANCE	FLOAT32	0.00...3000.00	pu	Fault distance in units selected by the user
FLT_DIST_Q	INT32	0...511		Fault distance quality
RFLOOP	FLOAT32	0.0...1000000.0	ohm	Fault loop resistance in primary ohms
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
XFLOOP	FLOAT32	0.0...1000000.0	ohm	Fault loop reactance in primary ohms
XFPHASE	FLOAT32	0.0...1000000.0	ohm	Positive sequence fault reactance in primary ohms
IFLT_PER_ILD	FLOAT32	0.00...60000.00		Fault to load current ratio
S_CALC	FLOAT32	0.00...1.00		Estimated equivalent load distance
XC0F_CALC	FLOAT32	0.0...1000000.0	ohm	Estimated PhE capacitive reactance of line
21FL	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
Triggering time	Timestamp			Estimate triggering time
Flt loop	Enum	1=AG Fault 2=BG Fault 3=CG Fault 4=AB Fault 5=BC Fault 6=CA Fault 7=ABC Fault -5=No fault		Fault loop
Flt distance	FLOAT32	0.00...3000.00	pu	Fault distance
Flt Dist quality	INT32	0...511		Fault distance quality
Flt loop resistance	FLOAT32	0.0...1000000.0	ohm	Fault loop resistance
Flt loop reactance	FLOAT32	0.0...1000000.0	ohm	Fault loop reactance
Flt phase reactance	FLOAT32	0.0...1000000.0	ohm	Fault phase reactance
Flt point resistance	FLOAT32	0.0...1000000.0	ohm	Fault resistance
Flt to Lod Cur ratio	FLOAT32	0.00...60000.00		Fault to load current ratio
Equivalent load Dis	FLOAT32	0.00...1.00		Estimated equivalent load distance
XC0F Calc	FLOAT32	0.0...1000000.0	ohm	Estimated PhE capacitive reactance of the line
Pre fault time	Timestamp			Pre-fault time
A Pre Flt Phs A Magn	FLOAT32	0.00...40.00	xIn	Pre-fault current phase A, magnitude
A Pre Flt Phs A Angl	FLOAT32	-180.00...180.00	deg	Pre-fault current phase A, angle
A Pre Flt Phs B Magn	FLOAT32	0.00...40.00	xIn	Pre-fault current phase B, magnitude
A Pre Flt Phs B Angl	FLOAT32	-180.00...180.00	deg	Pre-fault current phase B, angle
A Pre Flt Phs C Magn	FLOAT32	0.00...40.00	xIn	Pre-fault current phase C, magnitude

Table continues on next page

Name	Type	Values (Range)	Unit	Description
A Pre Flt Phs C Angl	FLOAT32	-180.00...180.00	deg	Pre-fault current phase C, angle
V Pre Flt Phs A Magn	FLOAT32	0.00...40.00	xIn	Pre-fault voltage phase A, magnitude
V Pre Flt Phs A Angl	FLOAT32	-180.00...180.00	deg	Pre-fault voltage phase A, angle
V Pre Flt Phs B Magn	FLOAT32	0.00...40.00	xIn	Pre-fault voltage phase B, magnitude
V Pre Flt Phs B Angl	FLOAT32	-180.00...180.00	deg	Pre-fault voltage phase B, angle
V Pre Flt Phs C Magn	FLOAT32	0.00...40.00	xIn	Pre-fault voltage phase C, magnitude
V Pre Flt Phs C Angl	FLOAT32	-180.00...180.00	deg	Pre-fault voltage phase C, angle
A Flt Phs A Magn	FLOAT32	0.00...40.00	xIn	Fault current phase A, magnitude
A Flt Phs A angle	FLOAT32	-180.00...180.00	deg	Fault current phase A, angle
A Flt Phs B Magn	FLOAT32	0.00...40.00	xIn	Fault current phase B, magnitude
A Flt Phs B angle	FLOAT32	-180.00...180.00	deg	Fault current phase B, angle
A Flt Phs C Magn	FLOAT32	0.00...40.00	xIn	Fault current phase C, magnitude
A Flt Phs C angle	FLOAT32	-180.00...180.00	deg	Fault current phase C, angle
V Flt Phs A Magn	FLOAT32	0.00...40.00	xIn	Fault voltage phase A, magnitude
V Flt Phs A angle	FLOAT32	-180.00...180.00	deg	Fault voltage phase A, angle
V Flt Phs B Magn	FLOAT32	0.00...40.00	xIn	Fault voltage phase B, magnitude
V Flt Phs B angle	FLOAT32	-180.00...180.00	deg	Fault voltage phase B, angle
V Flt Phs C Magn	FLOAT32	0.00...40.00	xIn	Fault voltage phase C, magnitude
V Flt Phs C angle	FLOAT32	-180.00...180.00	deg	Fault voltage phase C, angle

5.7.9 Technical data

Table 724: 21FL Technical data

Characteristic	Value
Measurement accuracy	At the frequency f = f_n Impedance: ±2.5% or ±0.25 Ω Distance: ±2.5% or ±0.16 km/0.1 mile XC0F_CALC: ±2.5% or ±50 Ω IFLT_PER_ILD: ±5% or ±0.05

5.7.10 Technical revision history

Table 725: 21FL Technical revision history

Technical revision	Change
B	Internal improvement.

5.8 Switch onto fault SOTF

5.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Switch onto fault	CBPSOF	SOTF	SOTF

5.8.2 Function block

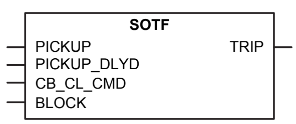


Figure 423: Function block

5.8.3 Functionality

The switch onto fault function SOTF provides an instantaneous trip or a time delayed trip when closing the breaker while a fault exists.

SOTF is activated when the `CB_CL_CMD` circuit breaker closing command is set high. The function has `PICKUP` and `PICKUP_DLYD` inputs for immediate or delayed pickup operation respectively.

The function contains a blocking functionality. It is possible to block function outputs and the reset timers, if desired.

5.8.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of SOTF can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

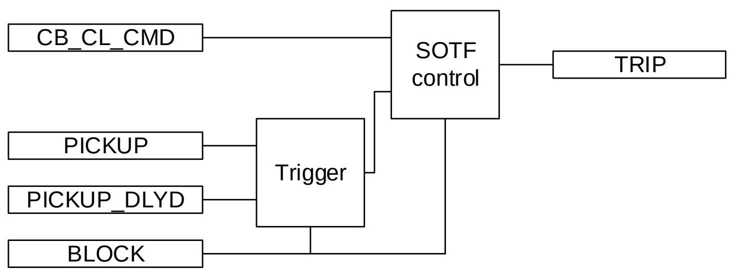


Figure 424: Functional module diagram

Trigger

This module is used for detecting possible fault immediately after closing the circuit breaker. An external protection function for example, 51P, 50P, 50P-3 or 51N, 51G, 50N, 50G, 50N-3, 50G-3 is used for fault indication. The `PICKUP` and `PICKUP_DLYD` inputs are available for feeding the detected fault.

- `PICKUP` input is used when it is required to enable SOTF control immediately after protection function indicates a fault.
- `PICKUP_DLYD` input is used when time delayed SOTF control enabling is needed. In this case, the delay can be set with a *Trip delay time* setting.

SOTF control

The SOTF control is activated when CB_CL_CMD circuit breaker closing command input is activated. The module is kept active until the set *SOTF reset time* is exceeded after the CB_CL_CMD is deactivated. The TRIP output is activated when a fault indication signal is received from the Trigger module while the SOTF control is still active.

5.8.5 Application

The CB_CL_CMD input activates SOTF. In the standard configuration, the breaker close command should be connected to this input. The *SOTF reset time* setting parameter is used for keeping SOTF active for a certain time after the CB close command is executed.

The overcurrent high and instantaneous signals, for example, the 50P-3 PICKUP signal is connected to the function PICKUP input. When the SOTF control module is active and the PICKUP input is activated, the function trips instantaneously without any delays.

The overcurrent low stage signals, for example, 51P PICKUP signal is connected to the function PICKUP_DLYD input. The setting parameter *Trip delay time* is used to delay the operation in case of inrush situation.

5.8.6 Signals

Table 726: SOTF Input signals

Name	Type	Default	Description
PICKUP	BOOLEAN	0=False	Pickup from function to be accelerated by SOTF
PICKUP_DLYD	BOOLEAN	0=False	Pickup from function to be accelerated with delay by SOTF
CB_CL_CMD	BOOLEAN	0=False	External enabling of SOTF by CB close command
BLOCK	BOOLEAN	0=False	Block of function

Table 727: SOTF Output signals

Name	Type	Description
TRIP	BOOLEAN	Trip

5.8.7 Settings

Table 728: SOTF Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Trip delay time	0...60000	ms	1	0	Time delay for pickup input

Table 729: SOTF Group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
SOTF reset time	0...60000	ms	1	1000	SOTF detection period after initialization

Table 730: SOTF Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

5.8.8 Monitored data

Table 731: SOTF Monitored data

Name	Type	Values (Range)	Unit	Description
SOTF	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

5.8.9 Technical data

Table 732: SOTF Technical data

Characteristic	Value
Trip time accuracy	±1.0% of the set value or ±20 ms

Section 6 Supervision functions

6.1 Trip circuit supervision TCM

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip circuit supervision	TCSSCBR	TCS	TCM

6.1.2 Function block

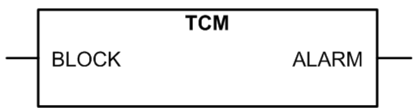


Figure 425: Function block

6.1.3 Functionality

The trip circuit supervision function TCM is designed to supervise the control circuit of the circuit breaker. The invalidity of a control circuit is detected by using a dedicated output contact that contains the supervision functionality. The failure of a circuit is reported to the corresponding function block in the relay configuration.

The function picks up and trips when TCM detects a trip circuit failure. The operating time characteristic for the function is of the definite time (DT) type. The function trips after a predefined operating time and resets when the fault disappears.

The function contains a blocking functionality. Blocking deactivates the `ALARM` output and resets the timer.

6.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of TCM can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

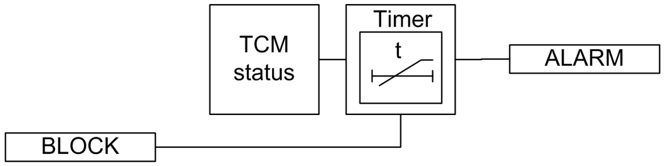


Figure 426: Functional module diagram

TCM status

This module receives the trip circuit status from the hardware. A detected failure in the trip circuit activates the timer.

Timer

Once activated, the timer runs until the set value *Trip delay time* is elapsed. The time characteristic is according to DT. When the operation timer has reached the maximum time value, the ALARM output is activated. If a drop-off situation occurs during the operate time up counting, the fixed 0.5 s reset timer is activated. After that time, the operation timer is reset.

The BLOCK input can be controlled with a binary input, a horizontal communication input or an internal signal of the relay program. The activation of the BLOCK input prevents the ALARM output to be activated.

6.1.5 Application

TCM detects faults in the electrical control circuit of the circuit breaker. The function can supervise both open and closed coil circuits. This supervision is necessary to find out the vitality of the control circuits continuously.

Figure 427 shows an application of the trip circuit supervision function use. The best solution is to connect an external R_{ext} shunt resistor in parallel with the circuit breaker internal contact. Although the circuit breaker internal contact is open, TCM can see the trip circuit through R_{ext}. The R_{ext} resistor should have such a resistance that the current through the resistance remains small, that is, it does not harm or overload the circuit breaker's trip coil.

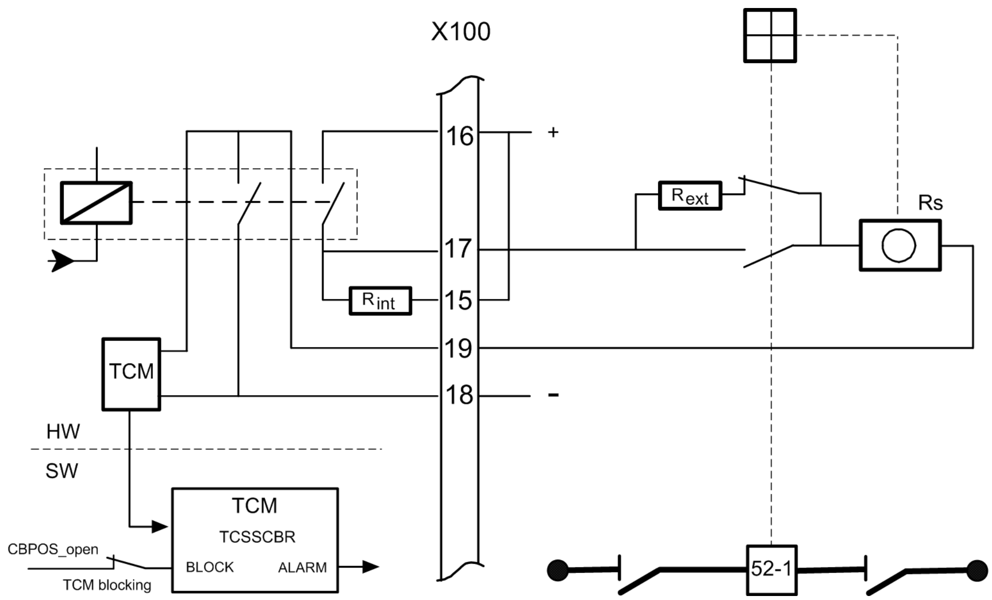


Figure 427: Operating principle of the trip-circuit supervision with an external resistor. The TCM blocking switch is not required since the external resistor is used.

If TCM is required only in a closed position, the external shunt resistance can be omitted. When the circuit breaker is in the open position, the TCM sees the situation as a faulty circuit. One way to avoid TCM operation in this situation would be to block the supervision function whenever the circuit breaker is open.

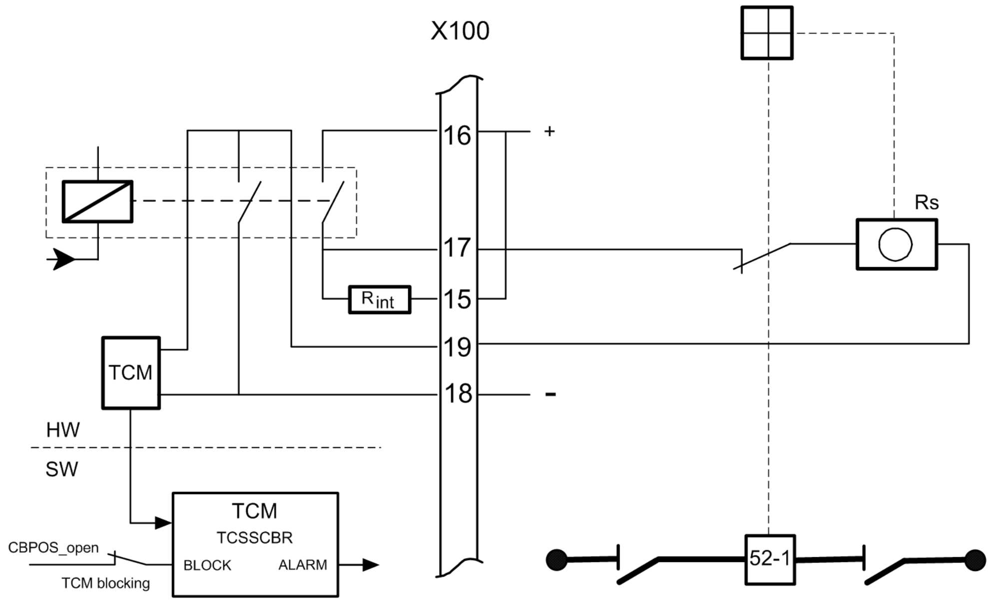


Figure 428: Operating principle of the trip-circuit supervision without an external resistor. The circuit breaker open indication is set to block TCM when the circuit breaker is open.

Trip circuit supervision and other trip contacts

It is typical that the trip circuit contains more than one trip contact in parallel, for example in transformer feeders where the trip of a Buchholz relay is connected in parallel with the feeder terminal and other relays involved. The supervising current cannot detect if one or all the other contacts connected in parallel are not connected properly.

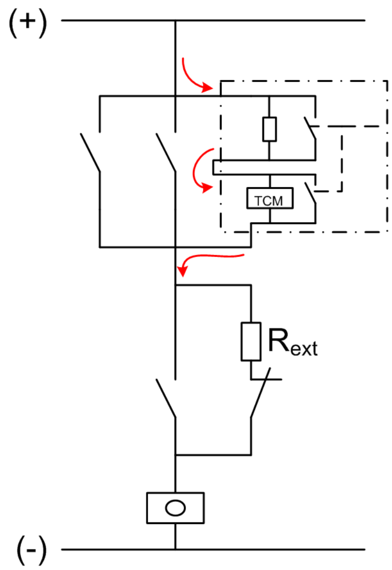


Figure 429: Constant test current flow in parallel trip contacts and trip circuit supervision

In case of parallel trip contacts, the recommended way to do the wiring is that the TCM test current flows through all wires and joints.

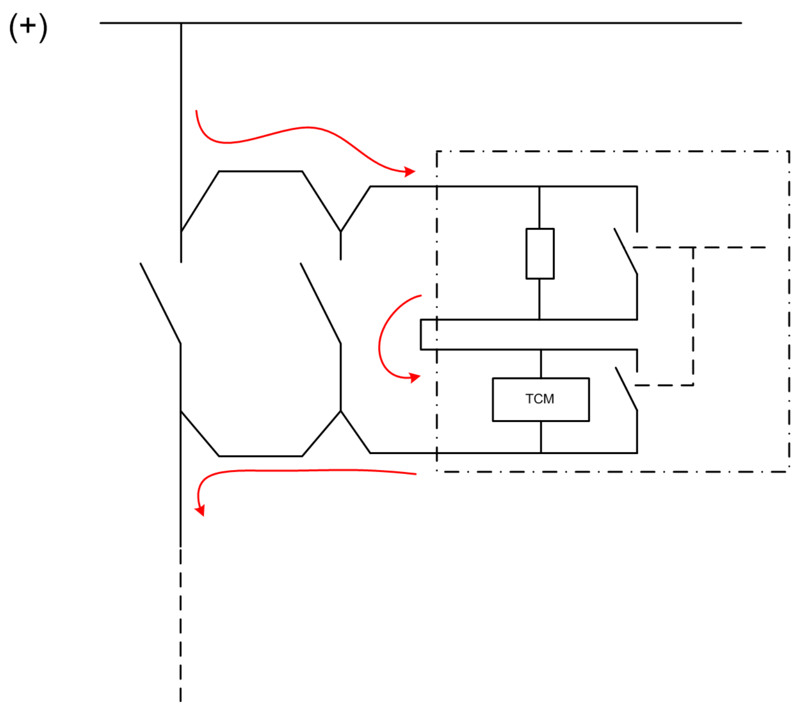


Figure 430: Improved connection for parallel trip contacts where the test current flows through all wires and joints

Several trip circuit supervision functions parallel in circuit

Not only the trip circuit often have parallel trip contacts, it is also possible that the circuit has multiple TCM circuits in parallel. Each TCM circuit causes its own supervising current to flow through the monitored coil and the actual coil current is a sum of all TCM currents. This must be taken into consideration when determining the resistance of R_{ext}.

Setting the TCM function in a protection relay not-in-use does not typically affect the supervising current injection.

Trip circuit supervision with auxiliary relays

Many retrofit projects are carried out partially, that is, the old electromechanical relays are replaced with new ones but the circuit breaker is not replaced. This creates a problem that the coil current of an old type circuit breaker can be too high for the protection relay trip contact to break.

The circuit breaker coil current is normally cut by an internal contact of the circuit breaker. In case of a circuit breaker failure, there is a risk that the protection relay trip contact is destroyed since the contact is obliged to disconnect high level of electromagnetic energy accumulated in the trip coil.

An auxiliary relay can be used between the protection relay trip contact and the circuit breaker coil. This way the breaking capacity question is solved, but the TCM circuit in the protection relay monitors the healthy auxiliary relay coil, not the circuit breaker coil. The separate trip circuit supervision relay is applicable for this to supervise the trip coil of the circuit breaker.

Dimensioning of the external resistor

Under normal operating conditions, the applied external voltage is divided between the relay's internal circuit and the external trip circuit so that at the minimum 20 V (15...20 V) remains over the relay's internal circuit. Should the external circuit's resistance be too high or the internal circuit's too low, for example due to welded relay contacts, a fault is detected.

Mathematically, the operation condition can be expressed as:

$$V_C - (\mathrm{R}_{ext} + R_{int} + R_s) \times I_c \geq 20V \quad AC / DC$$

(Equation 157)

V_c	Operating voltage over the supervised trip circuit
I_c	Measuring current through the trip circuit, appr. 1.5 mA (0.99...1.72 mA)
R_{ext}	external shunt resistance
R_{int}	internal shunt resistance, 1 kΩ
R_s	trip coil resistance

If the external shunt resistance is used, it has to be calculated not to interfere with the functionality of the supervision or the trip coil. Too high a resistance causes too high a voltage drop, jeopardizing the requirement of at least 20 V over the internal circuit, while a resistance too low can enable false operations of the trip coil.

Table 733: Values recommended for the external resistor R_{ext}

Operating voltage U_c	Shunt resistor R_{ext}
48 V AC/DC	1.2 kΩ, 5 W
60 V AC/DC	5.6 kΩ, 5 W
110 V AC/DC	22 kΩ, 5 W
220 V AC/DC	33 kΩ, 5 W

Due to the requirement that the voltage over the TCM contact must be 20 V or higher, the correct operation is not guaranteed with auxiliary operating voltages lower than 48 V DC because of the voltage drop in R_{int},R_{ext} and the operating coil or even voltage drop of the feeding auxiliary voltage system which can cause too low voltage values over the TCM contact. In this case, erroneous alarming can occur.

At lower (<48 V DC) auxiliary circuit operating voltages, it is recommended to use the circuit breaker position to block unintentional operation of TCM. The use of the position indication is described earlier in this chapter.

Using power output contacts without trip circuit supervision

If TCM is not used but the contact information of corresponding power outputs are required, the internal resistor can be by-passed. The output can then be utilized as a normal power output. When bypassing the internal resistor, the wiring between the terminals of the corresponding output X100:16-15(PO3) or X100:21-20(PO4) can be disconnected. The internal resistor is required if the complete TCM circuit is used.

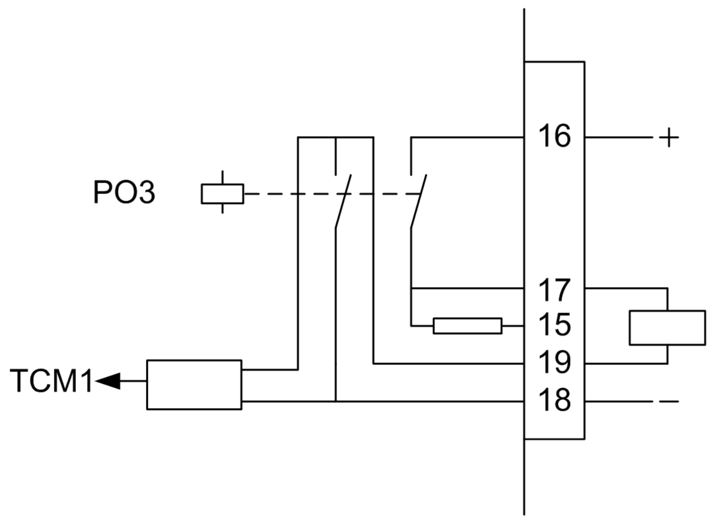


Figure 431: Connection of a power output in a case when TCM is not used and the internal resistor is disconnected

Incorrect connections and use of trip circuit supervision

Although the TCM circuit consists of two separate contacts, it must be noted that those are designed to be used as series connected to guarantee the breaking capacity given in the technical manual of the protection relay. In addition to the weak breaking capacity, the internal resistor is not dimensioned to withstand current without a TCM circuit. As a result, this kind of incorrect connection causes immediate burning of the internal resistor when the circuit breaker is in the close position and the voltage is applied to the trip circuit. The following figure shows incorrect usage of a TCM circuit when only one of the contacts is used.

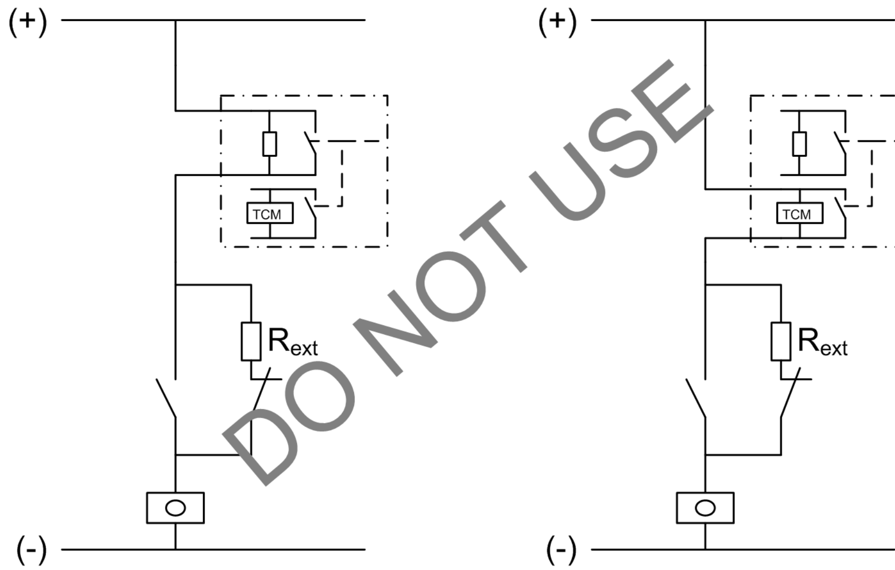


Figure 432: Incorrect connection of trip-circuit supervision

A connection of three protection relays with a double pole trip circuit is shown in the following figure. Only the protection relay R3 has an internal TCM circuit. In order to test the operation of the protection relay R2, but not to trip the circuit breaker, the upper trip contact of the protection relay R2 is disconnected, as shown in the figure, while the lower contact is still connected. When the protection relay R2 operates, the coil current starts to flow through the internal resistor of the protection relay R3 and the resistor burns immediately. As proven with the previous examples, both trip contacts must operate together. Attention should also be paid for correct usage of the trip circuit supervision while, for example, testing the protection relay.

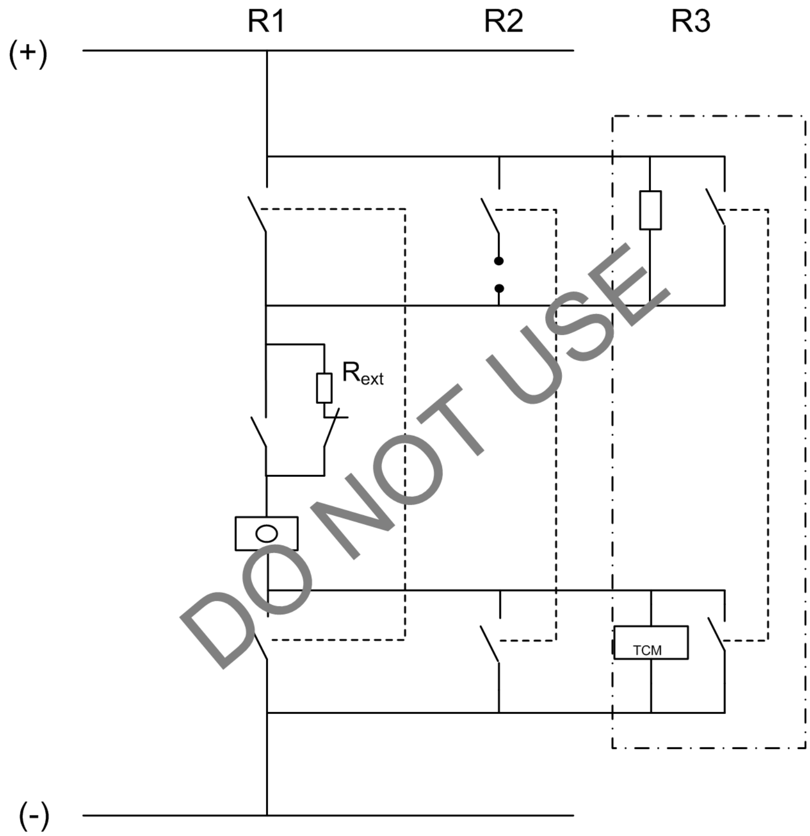


Figure 433: Incorrect testing of protection relays

6.1.6 Signals

Table 734: TCM Input signals

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block input status

Table 735: TCM Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm output

6.1.7 Settings

Table 736: TCM Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Trip delay time	20...300000	ms	1	3000	Trip delay time

Table 737: TCM Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	20...60000	ms	1	1000	Reset delay time

6.1.8 Monitored data

Table 738: TCM Monitored data

Name	Type	Values (Range)	Unit	Description
TCM	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

6.1.9 Technical revision history

Table 739: TCM Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement

6.2 Current circuit supervision CCM

6.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current circuit supervision	CCSPVC	MCS 3I	CCM

6.2.2 Function block

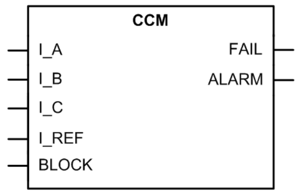


Figure 434: Function block

6.2.3 Functionality

The current circuit supervision function CCM is used for monitoring current transformer secondary circuits.

CCM calculates internally the sum of phase currents (I_A, I_B and I_C) and compares the sum against the measured single reference current (I_REF).The reference current must originate from other three-phase CT cores than the phase currents (I_A, I_B and I_C) and it is to be externally summated, that is, outside the protection relay.

CCM detects a fault in the measurement circuit and issues an alarm or blocks the protection functions to avoid unwanted tripping.

It must be remembered that the blocking of protection functions at an occurring open CT circuit means that the situation remains unchanged and extremely high voltages stress the secondary circuit.

6.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of CCM can be described with a module diagram. All the modules in the diagram are explained in the next sections.

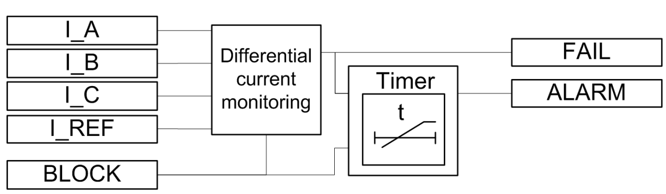


Figure 435: Functional module diagram

Differential current monitoring

Differential current monitoring supervises the difference between the summed phase currents I_A, I_B and I_C and the reference current I_REF.

The current operating characteristics can be selected with the *Pickup value* setting. When the highest phase current is less than 1.0 × In, the differential current limit is defined with *Pickup value*. When the highest phase current is more than 1.0 × In, the differential current limit is calculated with the equation.

$$MAX(I\_A, I\_B, I\_C) \times Pickup\ value$$

(Equation 158)

The differential current is limited to 1.0 × In.

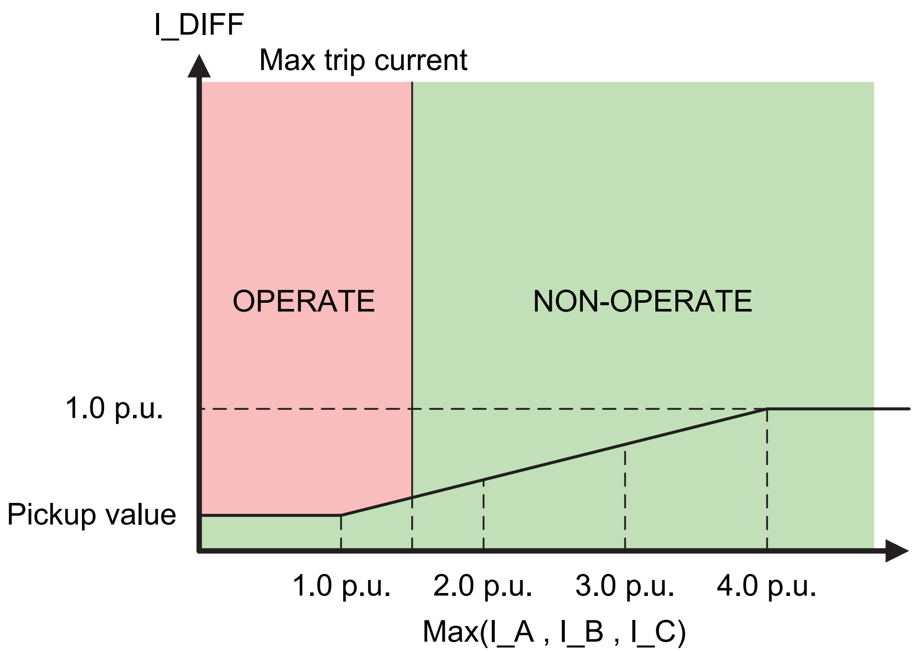


Figure 436: CCM operating characteristics

When the differential current I_DIFF is in the operating region, the `FAIL` output is activated.

The function is internally blocked if any phase current is higher than the set *Max trip current*. When the internal blocking activates, the `FAIL` output is deactivated immediately. The internal blocking is used for avoiding false operation during a fault situation when the current transformers are saturated due to high fault currents.

The value of the differential current is available in the monitored data view on the LHMI or through other communication tools. The value is calculated with the equation.

$$I\_DIFF = \left|\overline{I\_A} + \overline{I\_B} + \overline{I\_C}\right| - \left|\overline{I\_REF}\right|$$

(Equation 159)

The *Pickup value* setting is given in units of ×In of the phase current transformer. The possible difference in the phase and reference current transformer ratios is internally compensated by scaling `I_REF` with the value derived from the *Primary current* setting values. These setting parameters can be found in the Basic functions section.

The activation of the `BLOCK` input deactivates the `FAIL` output immediately.

Timer

The timer is activated with the `FAIL` signal. The `ALARM` output is activated after a fixed 200 ms delay. `FAIL` needs to be active during the delay.

When the internal blocking is activated, the `FAIL` output is deactivated immediately immediately. However, the `ALARM` output is deactivated immediately after a fixed delay of three seconds.

The function resets when the differential current is below the pickup value and the highest phase current is more than 5 percent of the nominal current (0.05 × In).

If the current falls to zero when the `FAIL` or `ALARM` outputs are active, the deactivation of these outputs is prevented.

The activation of the `BLOCK` input deactivates the `ALARM` output.

6.2.5 Application

Open or short-circuited current transformer cores can cause unwanted operation in many protection functions such as differential, ground-fault current and negative-sequence current functions. When currents from two independent three-phase sets of CTs or CT cores measuring the same primary currents are available, reliable current circuit supervision can be arranged by comparing the currents from the two sets. When an error in any CT circuit is detected, the protection functions concerned can be blocked and an alarm given.

In case of high currents, the unequal transient saturation of CT cores with a different remanence or saturation factor can result in differences in the secondary currents from the two CT cores. An unwanted blocking of protection functions during the transient stage must then be avoided.

The supervision function must be sensitive and have a short trip time to prevent unwanted tripping from fast-acting, sensitive numerical protections in case of faulty CT secondary circuits.

Open CT circuits create extremely high voltages in the circuits, which may damage the insulation and cause further problems. This must be taken into consideration especially when the protection functions are blocked.

When the reference current is not connected to the protection relay, the function should be turned off. Otherwise, the `FAIL` output is activated when unbalance occurs in the phase currents even if there was nothing wrong with the measurement circuit.

Reference current measured with core-balanced current transformer

CCM compares the sum of phase currents to the current measured with the core-balanced CT.

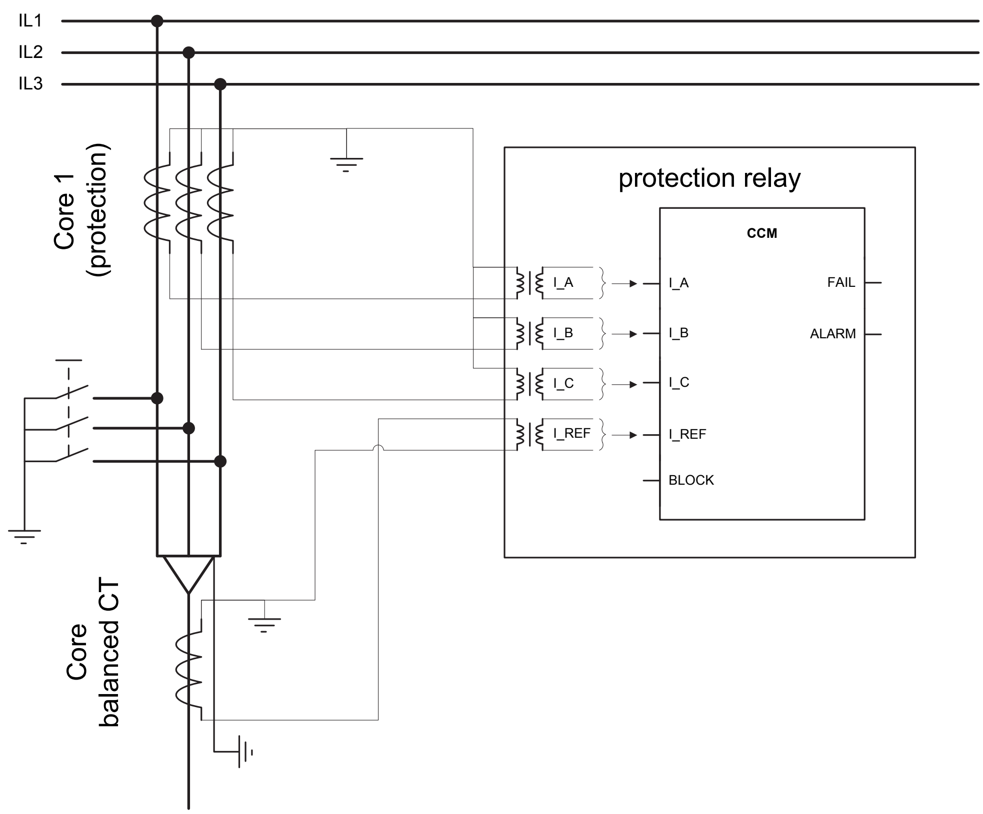


Figure 437: Connection diagram for reference current measurement with core-balanced current transformer

Current measurement with two independent three-phase sets of CT cores

Figure 438 and Figure 439 show diagrams of connections where the reference current is measured with two independent three-phase sets of CT cores.

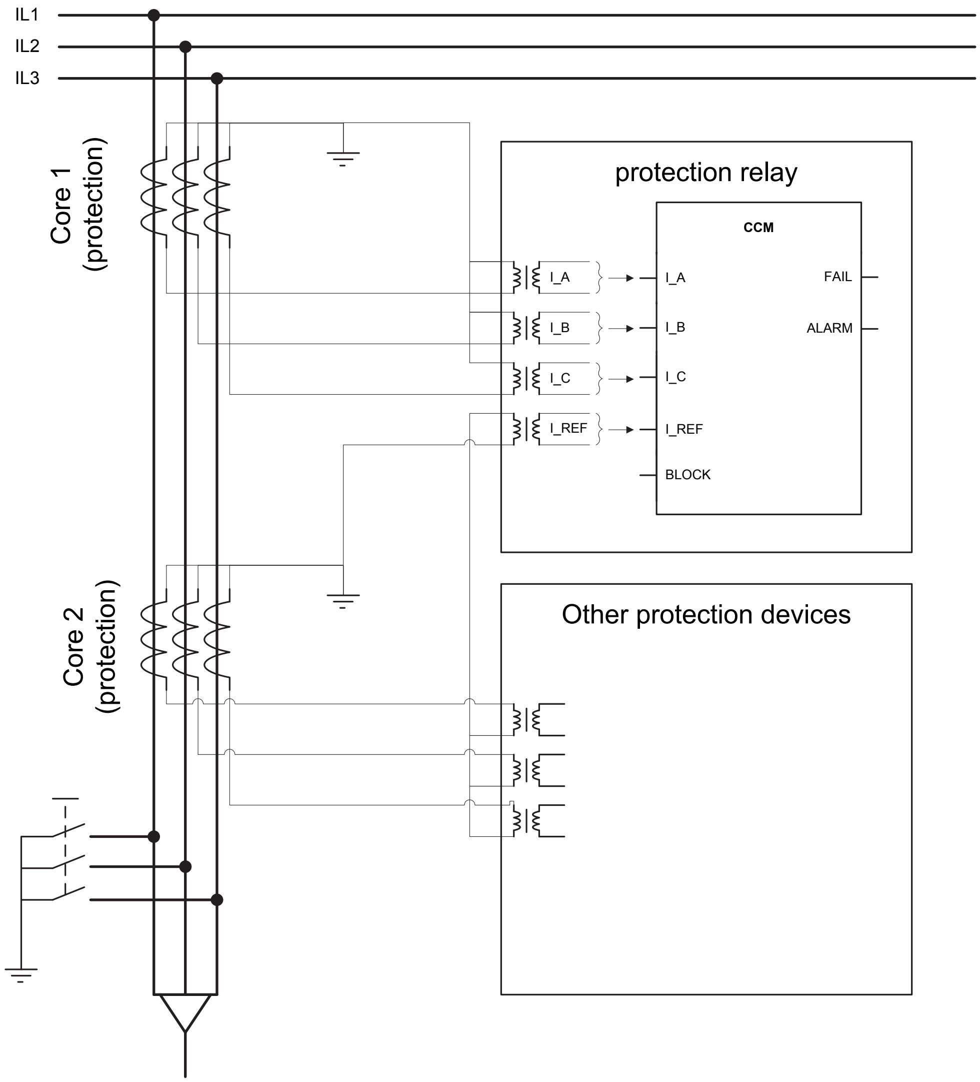


Figure 438: Connection diagram for current circuit supervision with two sets of three-phase current transformer protection cores

When using the measurement core for reference current measurement, it should be noted that the saturation level of the measurement core is much lower than with the protection core. This should be taken into account when setting the current circuit supervision function.

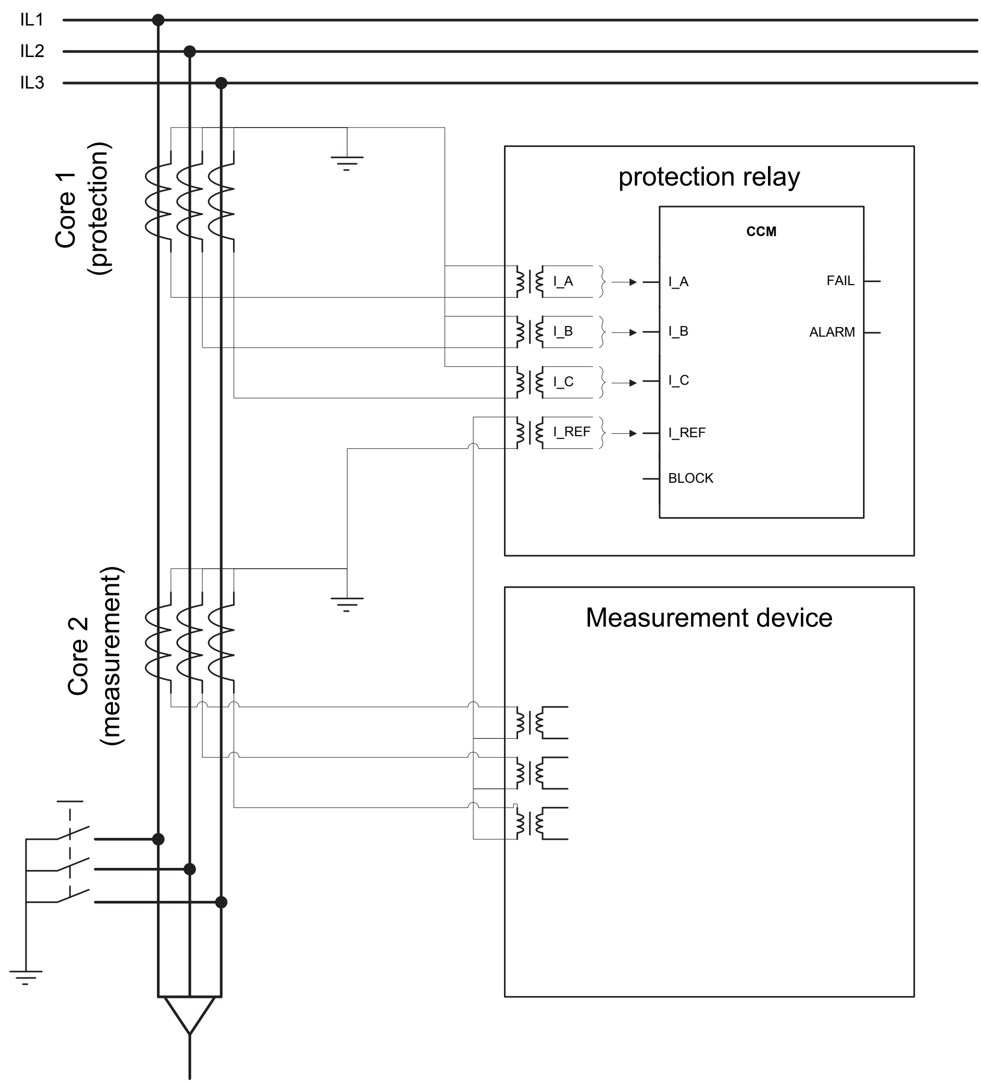


Figure 439: Connection diagram for current circuit supervision with two sets of three-phase current transformer cores (protection and measurement)

Example of incorrect connection

The currents must be measured with two independent cores, that is, the phase currents must be measured with a different core than the reference current. A connection diagram shows an example of a case where the phase currents and the reference currents are measured from the same core.

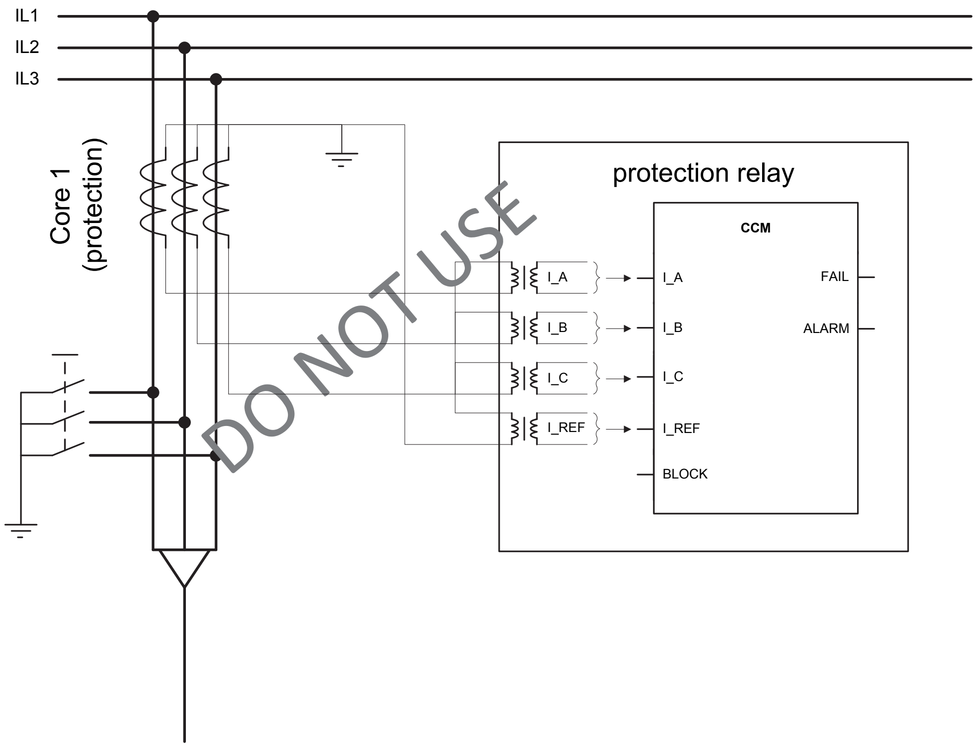


Figure 440: Example of incorrect reference current connection

6.2.6 Signals

Table 740: CCM Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_REF	SIGNAL	0	Reference current
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 741: CCM Output signals

Name	Type	Description
FAIL	BOOLEAN	Fail output
ALARM	BOOLEAN	Alarm output

6.2.7 Settings

Table 742: CCM Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Enable / Disable
Pickup value	0.05...0.20	xIn	0.01	0.05	Minimum trip current differential level

Table 743: CCM Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Max alarm current	1.00...5.00	xIn	0.01	1.50	Block of the function at high phase current

6.2.8 Monitored data

Table 744: CCM Monitored data

Name	Type	Values (Range)	Unit	Description
I_DIFF	FLOAT32	0.00...40.00	xIn	Differential current
CCM	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

6.2.9 Technical data

Table 745: CCM Technical data

Characteristic	Value
Trip time [1)]	<30 ms

1) Including the delay of the output contact

6.2.10 Technical revision history

Table 746: CCM Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement
D	Internal improvement

6.3 Current transformer supervision for high-impedance protection scheme MCS-A, MCS-B, MCS-C

6.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current transformer supervision for high-impedance protection scheme for phase A	HZCCASPVC	MCS I_A	MCS-A
Current transformer supervision for high-impedance protection scheme for phase B	HZCCBSPVC	MCS I_B	MCS-B
Current transformer supervision for high-impedance protection scheme for phase C	HZCCCSPVC	MCS I_C	MCS-C

6.3.2 Function block

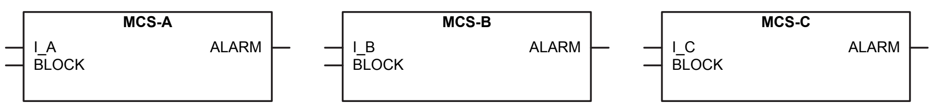


Figure 441: Function block

6.3.3 Functionality

The current transformer supervision for high-impedance protection scheme function MCS-A, MCS-B, MCS-C is a dedicated phase-segregated supervision function to be used along with the high-impedance differential protection for detecting the broken CT secondary wires. The differential current is taken as an input for the protection relay. During normal CT condition, the value of the differential current is zero. However, when the CT is broken, the secondary differential current starts flowing and it is used for generating alarms.

To avoid faulty operation, MCS-A, MCS-B, MCS-C should have a sensitive setting, compared to the high-impedance differential protection. The function is likely to pick up under through-fault conditions. However, by incorporating a high time delay (3 s or more), the downstream protection clears the fault before an alarm is generated.

MCS-A, MCS-B, MCS-C generates an alarm when the differential current exceeds the set limit. The function operates within the DT characteristic.

The function contains a blocking functionality. It is possible to block the function output, Timer or the whole function.

6.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are "Enable" and "Disable".

The operation of MCS-A, MCS-B, MCS-C can be generated with a module diagram. All the modules in the diagram are explained in the next sections.

The module diagram illustrates all the phases of the function. However, the functionality is described only for phase A. The functionality for phase B and C is identical.

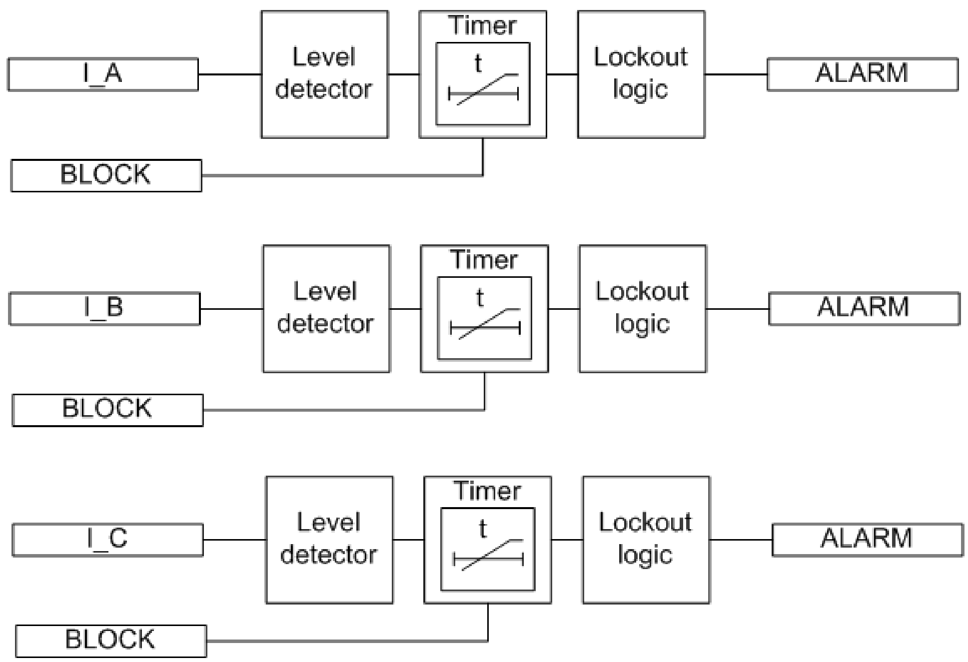


Figure 442: Functional module diagram

Level detector

This module compares the differential current `I_A` to the set *Pickup value*. The timer module is activated if the differential current exceeds the value set in the *Pickup value* setting.

Timer

The time characteristic is according to DT. When the alarm timer reaches the value set by *Alarm delay time*, the ALARM output is activated. If the fault disappears before the module generates an alarm signal, the reset timer is activated. If the reset timer reaches the value set by *Reset delay time*, the alarm timer resets. The activation of the BLOCK signal resets the Timer and deactivates the ALARM output.

Lockout logic

MCS-A, MCS-B, MCS-C is provided with the possibility to activate a lockout for the ALARM output depending on the *Alarm output mode* setting. In the "Lockout" mode, the ALARM must be reset manually from the LHMI Clear menu after checking the CT secondary circuit. In the "Non-latched" mode, the ALARM output functions normally, that is, it resets as soon as the fault is cleared.

6.3.5 Measuring modes

The function operates on two alternative measurement modes, DFT and Peak-to-Peak. The measurement mode is selected using the *Measurement mode* setting.

6.3.6 Application

MCS-A, MCS-B, MCS-C is a dedicated phase-segregated supervision function to be used along with the high-impedance differential protection for detecting the broken CT secondary wires. The operation principle of MCS-A, MCS-B, MCS-C is similar to the high-impedance differential protection function 87A, 87B, 87C. However, the current setting of MCS-A, MCS-B, MCS-C is set to be much more sensitive than 87A, 87B, 87C and it trips with a higher time delay. A typical example of the MCS-A, MCS-B, MCS-C *Pickup value* setting is 0.1 pu with an *Alarm delay time* of 3 s or more.

As the current setting of MCS-A, MCS-B, MCS-C is more sensitive than the actual differential stage, it can pick up internally under the through-fault conditions; however, a sufficient time delay prevents false alarm. If the bus wire is broken, differential current arises depending on the load of the feeder with the broken bus wire.

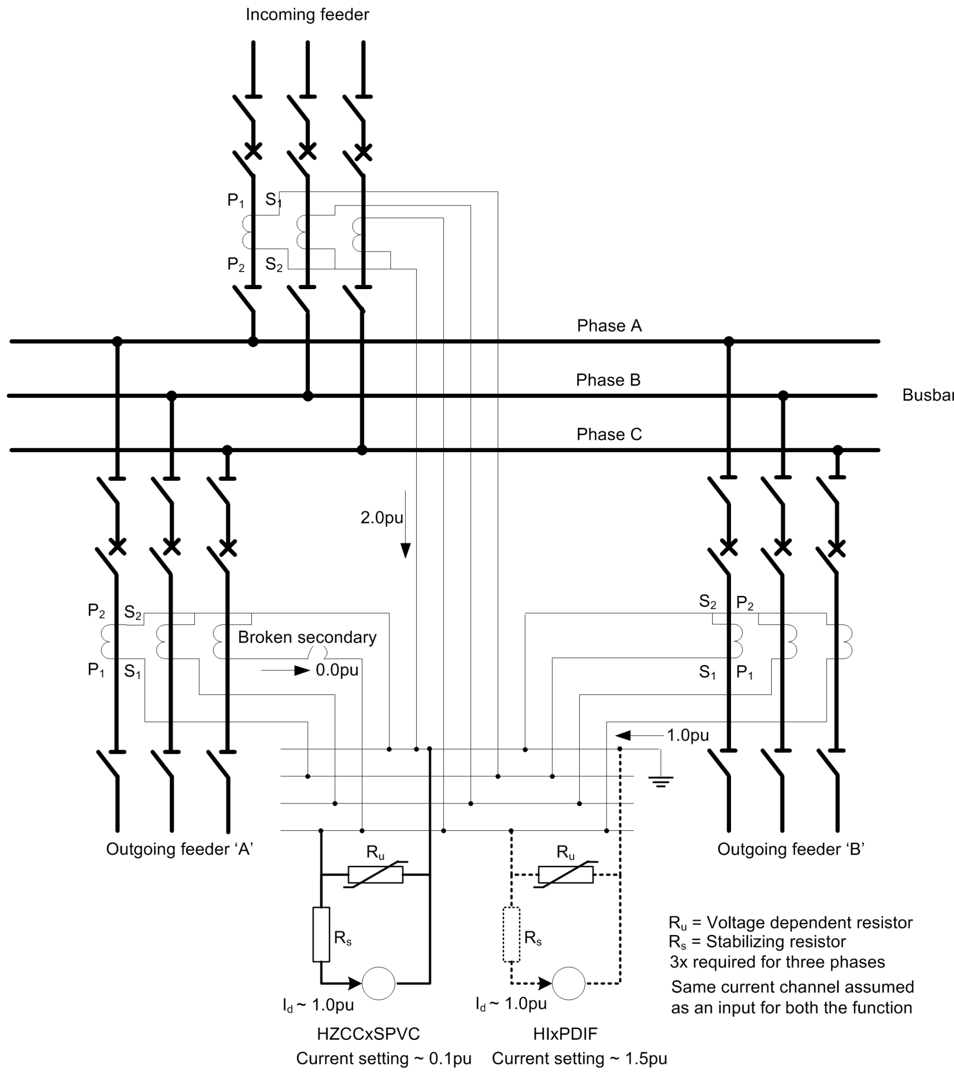


Figure 443: Broken secondary detection by MCS-A, MCS-B, MCS-C

In the example, the incoming feeder is carrying a load of 2.0 pu and both outgoing feeders carry an equal load of 1.0 pu However, both 87A, 87B, 87C and MCS-A, MCS-B, MCS-C consider the current as an increased differential or unbalance current because of the broken CT wire in phase C. Both 87A, 87B, 87C and MCS-A, MCS-B, MCS-C receive the differential current of approximately 1.0 pu The main differential protection 87A, 87B, 87C cannot trip because of the higher current setting.

All CTs must have the same ratio.

The ALARM output of the CT supervision function can be used to energize an auxiliary relay which can short-circuit the current CT wires, making the busbar differential protection inoperative. This arrangement does not prevent unwanted operation of 87A, 87B, 87C if the pickup setting is below the rated load. For example, if the pickup setting for 87A, 87B, 87C in the example is set as 0.8 pu 87A, 87B, 87C trips before MCS-A, MCS-B, MCS-C.

6.3.7 Signals

Table 747: MCS-A Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
BLOCK	BOOLEAN	0=False	Block signal for activating blocking mode

Table 748: MCS-B Input signals

Name	Type	Default	Description
I_B	SIGNAL	0	Phase B current
BLOCK	BOOLEAN	0=False	Block signal for activating blocking mode

Table 749: MCS-C Input signals

Name	Type	Default	Description
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for activating blocking mode

Table 750: MCS-A Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm output

Table 751: MCS-B Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm output

Table 752: MCS-C Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm output

6.3.8 Settings

Table 753: MCS-A Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Pickup value	1.0...100.0	%In	0.1	10.0	Pickup value, percentage of the nominal current
Alarm delay time	100...300000	ms	10	3000	Alarm delay time
Alarm output mode	1=Non-latched 3=Lockout			3=Lockout	Select the operation mode for alarm output

Table 754: MCS-A Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time
Measurement mode	2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode

Table 755: MCS-B Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Pickup value	1.0...100.0	%In	0.1	10.0	Pickup value, percentage of the nominal current
Alarm delay time	100...300000	ms	10	3000	Alarm delay time
Alarm output mode	1=Non-latched 3=Lockout			3=Lockout	Select the operation mode for alarm output

Table 756: MCS-B Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time
Measurement mode	2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode

Table 757: MCS-C Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Pickup value	1.0...100.0	%In	0.1	10.0	Pickup value, percentage of the nominal current
Alarm delay time	100...300000	ms	10	3000	Alarm delay time
Alarm output mode	1=Non-latched 3=Lockout			3=Lockout	Select the operation mode for alarm output

Table 758: MCS-C Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	0...60000	ms	10	20	Reset delay time
Measurement mode	2=DFT 3=Peak-to-Peak			2=DFT	Selects used measurement mode

6.3.9 Monitored data

Table 759: MCS-A Monitored data

Name	Type	Values (Range)	Unit	Description
MCS-A	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 760: MCS-B Monitored data

Name	Type	Values (Range)	Unit	Description
MCS-B	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

Table 761: MCS-C Monitored data

Name	Type	Values (Range)	Unit	Description
MCS-C	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

6.3.10 Technical data

Table 762: MCS-A, MCS-B, MCS-C Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the current measured: f_n ±2 Hz
	±1.5% of the set value or ±0.002 × I_n
Reset time	<40 ms
Reset ratio	Typically 0.96
Retardation time	<35 ms
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms

6.3.11 Technical revision history

Table 763: MCS-A, MCS-B, MCS-C Technical revision history

Technical revision	Change
B	Function name changed from HZCCRDIF to HZCCASPVC, HZCCBSPVC, HZCCCSPVC.

6.4 Protection communication supervision PCS

6.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Protection communication supervision	PCSITPC	PCS	PCS

6.4.2 Function block

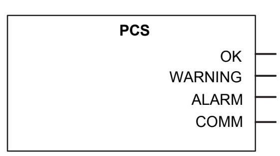


Figure 444: Function block

6.4.3 Functionality

The protection communication supervision function PCS monitors the protection communication channel. PCS blocks the line differential protection functions when interference in the protection communication channel is detected. The blocking takes place automatically for the 87L and BST functions which are dependent on the continuous availability of the protection communication channel.

The protection communication channel is continuously monitored by PCS. The function detects missing or delayed protection telegrams. Protection telegrams are used for transferring the sampled analog and other protection related data. Missing or delayed protection telegrams can jeopardize the demand operate speed of the differential protection.

When a short-term interference is detected in the protection communication channel, the function issues a warning and the line differential functions are automatically internally blocked. PCS reacts fast for the protection communication interferences. The blocking takes place at the latest when a communication interruption lasting for two fundamental network periods is detected. When a severe and long lasting interference or total interruption in the protection communication channel is detected, an alarm is issued (after a five-second delay). The protection communication supervision quality status is exchanged continuously online by the local and remote PCS instances. This ensures that both local and remote ends protection blocking is issued coordinately. This further enhances the security of the line differential protection by forcing both line end protection relays to the same blocking state during a protection communication interference, even in cases where the interference is detected with only one line end protection relay. There is also the *Reset delay time* settings parameter available which is used for changing the required interference-free time before releasing the line-differential protection back in operation after a blocking due to an interference in communication.

6.4.4 Operation principle

The operation of PCS can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

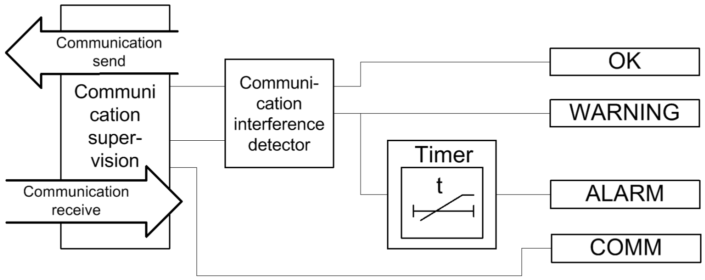


Figure 445: Functional module diagram

Communication supervision

The protection communication is supervised because the differential calculation is dependent on the refreshing of new analog phasor samples from the remote terminal within the protection telegram. The new protection telegram also updates the status of the binary signals sent by the remote terminal. The calculation of the differential current is based on comparing the remote and local terminal measured current samples. It is therefore essential that the protection communication telegrams are supervised and the result of the sample latency calculation can be used further in the differential current calculation. When the communication is able to receive telegrams correctly from the remote end via the communication media, the communication is assumed to be operating correctly and the `COMM` output is kept active.

Communication interference detector

The communication interference detector is continuously measuring and observing the sample latency of the protection telegrams. This value is also available as monitored data. The function provides three output signals of which only the corresponding one is active at a time depending on if the protection communication supervision is in `OK`, `WARNING` or `ALARM`. The `OK` state indicates the correct operation of the protection. The `WARNING` state indicates that the protection is internally blocked due to detected interference. The `WARNING` state is switched to `ALARM` if the interference lasts for a longer period. The protection communication supervision can sometimes be in the `WAITING` state. This state indicates that the terminal is waiting for the communication to start or restart from the remote end terminal.

Timer

Once activated with the `WARNING` signal, the timer has a constant time delay value of five seconds. If the communication failure exists after the delay, the `ALARM` output is activated.

6.4.5 Application

Communication principle

Analog samples, trip, pickup and user programmable signals are transferred in each protection telegram and the exchange of these protection telegrams is done eight times per power system cycle (every 2.5 ms when F_n = 50 Hz).

Master-Master communication arrangement is used in the two-terminal line differential solution. Current samples are sent from both line ends and the protection algorithms are also executed on both line ends. The direct-intertrip, however, ensures that both ends are always operated simultaneously.

Time synchronization

In numerical line differential protection, the current samples from the protections which are located geographically apart from each other must be time coordinated so that the current samples from both ends of the protected line can be compared without introducing irrelevant errors. The time coordination requires an extremely high accuracy.

As an example, an inaccuracy of 0.1 ms in a 50 Hz system gives a maximum amplitude error of approximately around 3 percent. An inaccuracy of 1 ms gives a maximum amplitude error of approximately 31 percent. The corresponding figures for a 60 Hz system are 4 and 38 percent respectively.

In the protection relay, the time coordination is done with an echo method. The protection relays create their own time reference between each other so that the system clocks do not need to synchronize.

The figure shows that in the time synchronization the transmission time to send a message from station B to station A, T1→T2, and the time to receive a message from A to B, T4→T5, are measured. The station A protection relay delay from the sampling to the start of send, T3→T4, and the local delay from receive to the station B protection relay sampling T5→T6 time, are also measured for the station B protection relay, and vice versa. This way the time alignment factor for the local and remote samples is achieved.

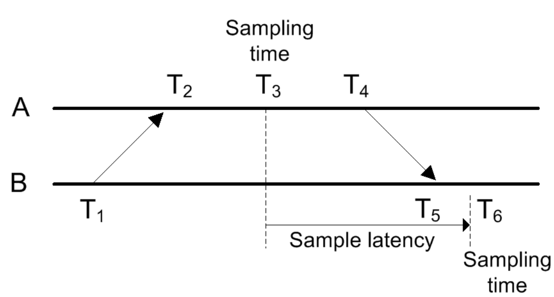


Figure 446: Measuring sampling latency

$$P_d = \frac{(T_2 - T_1) + (T_5 - T_4)}{2}$$

(Equation 160)

$$S_d = P_d + (T_4 - T_3) + (T_6 - T_5)$$

(Equation 161)

The sampling latency S_d is calculated for each telegram on both ends. The algorithm assumes that the one-way propagation delay P_d is equal for both directions.

The echo method without GPS can be used in telecommunication transmission networks as long as delay symmetry exists, that is, the sending and receiving delays are equal.

6.4.6 Signals

Table 764: PCS Output signals

Name	Type	Description
OK	BOOLEAN	Protection communication ok
WARNING	BOOLEAN	Protection communication warning
ALARM	BOOLEAN	Protection communication alarm
COMM	BOOLEAN	Communication detected

6.4.7 Settings

Table 765: PCS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Reset delay time	100...300000	ms	10	1000	Reset delay time from alarm and warning into ok state
Alarm count	0...99999		1	0	Set new alarm count value
Warning count	0...99999		1	0	Set new warning count value

6.4.8 Monitored data

Table 766: PCS Monitored data

Name	Type	Values (Range)	Unit	Description
Health	Enum	1=Ok 2=Warning 3=Alarm -2=Waiting		Communication link health
Alarm count	INT32	0...99999		Number of alarms detected
WARN_CNT	INT32	0...99999		Number of warnings detected
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
Sample latency	FLOAT32	0.000...99.999	ms	Measured sample latency
PROPAGTN_DLY	FLOAT32	0.000...99.999	ms	Measured propagation delay
RND_TRIP_DLY	FLOAT32	0.000...99.999	ms	Measured round trip delay
T_ALARM_CNT	Timestamp			Time when alarm count was last changed
T_WARN_CNT	Timestamp			Time when warning count was last changed

6.4.9 Technical revision history

Table 767: PCS Technical revision history

Technical revision	Change
B	Changes and additions to the monitored data
C	Internal improvement
D	Internal improvement
E	Function name changed from PCSRTCP to PCSITPC

6.5 Fuse failure supervision 60

6.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fuse failure supervision	SEQSPVC	FUSEF	60

6.5.2 Function block

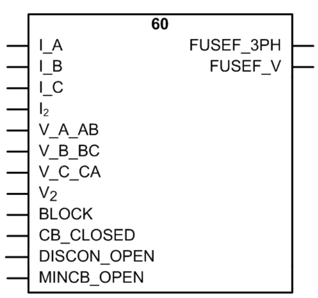


Figure 447: Function block

6.5.3 Functionality

The fuse failure supervision function 60 is used to block the voltage-measuring functions when failure occurs in the secondary circuits between the voltage transformer (or combi sensor or voltage sensor) and protection relay to avoid faulty operation of the voltage protection functions.

60 has two algorithms, a negative sequence-based algorithm and a delta current and delta voltage algorithm.

A criterion based on the delta current and the delta voltage measurements can be activated to detect three-phase fuse failures which usually are more associated with the voltage transformer switching during station operations.

6.5.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of 60 can be described with a module diagram. All the modules in the diagram are explained in the next sections.

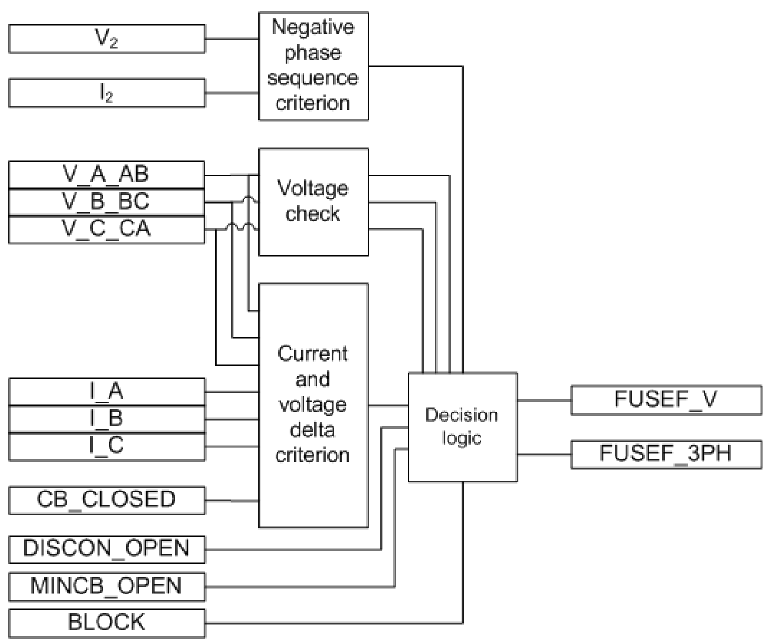


Figure 448: Functional module diagram

Negative phase-sequence criterion

A fuse failure based on the negative-sequence criterion is detected if the measured negative-sequence voltage exceeds the set *Neg Seq voltage Lev* value and the measured negative-sequence current is below the set *Neg Seq current Lev* value. The detected fuse failure is reported to the decision logic module.

Voltage check

The phase voltage magnitude is checked when deciding whether the fuse failure is a three, two or a single-phase fault.

The module makes a phase-specific comparison between each voltage input and the *Seal in voltage* setting. If the input voltage is lower than the setting, the corresponding phase is reported to the decision logic module.

Current and voltage delta criterion

The delta function can be activated by setting the *Change rate enable* parameter to "True". Once the function is activated, it operates in parallel with the negative sequence-based algorithm. The current and voltage are continuously measured in all three phases to calculate:

- Change of voltage dV/dt
- Change of current dI/dt

The calculated delta quantities are compared to the respective set values of the *Current change rate* and *Voltage change rate* settings.

The delta current and delta voltage algorithms detect a fuse failure if there is a sufficient negative change in the voltage amplitude without a sufficient change in the current amplitude in each phase separately. This is performed when the circuit breaker is closed. Information about the circuit breaker position is connected to the `CB_CLOSED` input.

There are two conditions for activating the current and voltage delta function.

- The magnitude of dV/dt exceeds the corresponding value of the *Voltage change rate* setting and magnitude of dI/dt is below the value of the *Current change rate* setting in any phase at the same time due to the closure of the circuit breaker (`CB_CLOSED` = TRUE).
- The magnitude of dV/dt exceeds the value of the *Voltage change rate* setting and the magnitude of dI/dt is below the Current change rate setting in any phase at the same time and the magnitude of the phase current in the same phase exceeds the *Min Op current delta* setting.

The first condition requires the delta criterion to be fulfilled in any phase at the same time as the circuit breaker is closed. Opening the circuit breaker at one end and energizing the line from the other end onto a fault could lead to an improper operation of 60 with an open breaker. If this is considered to be an important disadvantage, the CB_CLOSED input is to be connected to FALSE. In this way only the second criterion can activate the delta function.

The second condition requires the delta criterion to be fulfilled in one phase together with a high current for the same phase. The measured phase current is used to reduce the risk of a false fuse failure detection. If the current on the protected line is low, a voltage drop in the system (not caused by the fuse failure) is not followed by a current change and a false fuse failure can occur. To prevent this, the minimum phase current criterion is checked.

The fuse failure detection is active until the voltages return above the *Min Op voltage delta* setting. If a voltage in a phase is below the *Min Op voltage delta* setting, a new fuse failure detection for that phase is not possible until the voltage returns above the setting value.

Decision logic

If voltages are Wye-connected, it is recommended to scale the default values of voltage-based settings with 1/sqrt(3) because the default setting values apply for Delta-connected settings.

The fuse failure detection outputs FUSEF_V and FUSEF_3PH are controlled according to the detection criteria or external signals.

Table 768: Fuse failure output control

Fuse failure detection criterion	Conditions and function response
Negative-sequence criterion	If a fuse failure is detected based on the negative sequence criterion, the FUSEF_V output is activated.
	If the fuse failure detection is active for more than five seconds and at the same time all the phase voltage values are below the set value of the *Seal in voltage* setting with *Enable seal in* turned to "True", the function activates the FUSE_3PH output signal.
	The FUSEF_V output signal is also activated if all the phase voltages are above the *Seal in voltage* setting for more than 60 seconds and at the same time the negative sequence voltage is above *Neg Seq voltage Lev* for more than 5 seconds, all the phase currents are below the *Current dead Lin Val* setting and the circuit breaker is closed, that is CB_CLOSED is TRUE.
Table continues on next page	

Fuse failure detection criterion	Conditions and function response
Current and voltage delta function criterion	If the current and voltage delta criterion detects a fuse failure condition, but all the voltages are not below the *Seal in voltage* setting, only the FUSEF_V output is activated.
	If the fuse failure detection is active for more than five seconds and at the same time all the phase voltage values are below the set value of the *Seal in voltage* setting with *Enable seal in* turned to "True", the function activates the FUSE_3PH output signal.
External fuse failure detection	The MINCB_OPEN input signal is supposed to be connected through a protection relay binary input to the N.C. auxiliary contact of the miniature circuit breaker protecting the VT secondary circuit.The MINCB_OPEN signal sets the FUSEF_V output signal to block all the voltage-related functions when MCB is in the open state.
	The DISCON_OPEN input signal is supposed to be connected through a protection relay binary input to the N.C. auxiliary contact of the line disconnector.The DISCON_OPEN signal sets the FUSEF_V output signal to block the voltage-related functions when the line disconnector is in the open state.

It is recommended to always set *Enable seal in* to "True". This secures that the blocked protection functions remain blocked until normal voltage conditions are restored if the fuse failure has been active for 5 seconds, that is, the fuse failure outputs are deactivated when the normal voltage conditions are restored.

The activation of the BLOCK input deactivates both FUSEF_V and FUSEF_3PH outputs.

6.5.5 Application

Some protection functions operate on the basis of the measured voltage value in the protection relay point. These functions can fail if there is a fault in the measuring circuits between the voltage transformer (or combi sensor or voltage sensor) and protection relay.

A fault in the voltage-measuring circuit is called a fuse failure. This term is misleading since a blown fuse is just one of the many possible reasons for a broken circuit. Since incorrectly measured voltage can result in a faulty operation of some of the protection functions, it is important to detect the fuse failures. A fast fuse failure detection is one of the means to block voltage-based functions before they trip.

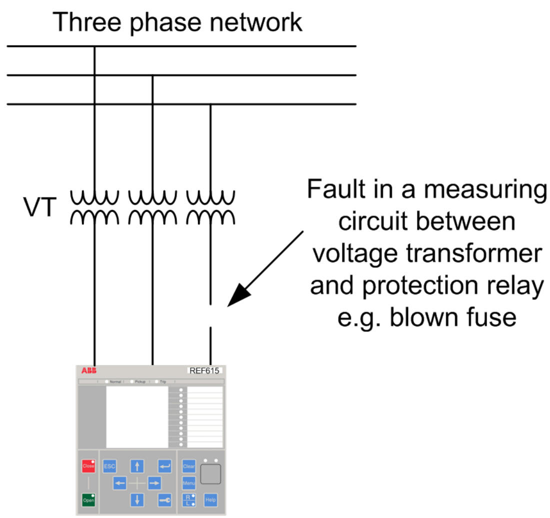


Figure 449: Fault in a circuit from the voltage transformer to the protection relay

A fuse failure occurs due to blown fuses, broken wires or intended substation operations. The negative sequence component-based function can be used to detect different types of single-phase or two-phase fuse failures. However, at least one of the three circuits from the voltage transformers must be intact. The supporting delta-based function can also detect a fuse failure due to three-phase interruptions.

In the negative sequence component-based part of the function, a fuse failure is detected by comparing the calculated value of the negative sequence component voltage to the negative sequence component current. The sequence entities are calculated from the measured current and voltage data for all three phases. The purpose of this function is to block voltage-dependent functions when a fuse failure is detected. Since the voltage dependence differs between these functions, 60 has two outputs for this purpose.

6.5.6 Signals

Table 769: 60 Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
I_2	SIGNAL	0	Negative sequence current
V_A_AB	SIGNAL	0	Phase A voltage
V_B_BC	SIGNAL	0	Phase B voltage
V_C_CA	SIGNAL	0	Phase C voltage
Table continues on next page			

Name	Type	Default	Description
V_2	SIGNAL	0	Negative phase sequence voltage
BLOCK	BOOLEAN	0=False	Block of function
CB_CLOSED	BOOLEAN	0=False	Active when circuit breaker is closed
DISCON_OPEN	BOOLEAN	0=False	Active when line disconnector is open
MINCB_OPEN	BOOLEAN	0=False	Active when external MCB opens protected voltage circuit

Table 770: 60 Output signals

Name	Type	Description
FUSEF_3PH	BOOLEAN	Three-phase pickup of function
FUSEF_V	BOOLEAN	General pickup of function

6.5.7 Settings

Table 771: 60 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable

Table 772: 60 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Neg Seq current Lev	0.03...0.20	xIn	0.01	0.03	Trip level of neg seq undercurrent element
Neg Seq voltage Lev	0.03...0.20	xUn	0.01	0.10	Trip level of neg seq overvoltage element
Current change rate	0.01...0.50	xIn	0.01	0.15	Trip level of change in phase current
Voltage change rate	0.25...0.90	xUn	0.01	0.40	Trip level of change in phase voltage
Change rate enable	0=False 1=True			0=False	Enabling operation of change based function
Min Op voltage delta	0.01...1.00	xUn	0.01	0.50	Minimum trip level of phase voltage for delta calculation
Min Op current delta	0.01...1.00	xIn	0.01	0.10	Minimum trip level of phase current for delta calculation
Seal in voltage	0.01...1.00	xUn	0.01	0.50	Trip level of seal-in phase voltage
Enable seal in	0=False 1=True			0=False	Enabling seal in functionality
Current dead Lin Val	0.05...1.00	xIn	0.01	0.05	Trip level for open phase current detection

6.5.8 Monitored data

Table 773: 60 Monitored data

Name	Type	Values (Range)	Unit	Description
60	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

6.5.9 Technical data

Table 774: 60 Technical data

Characteristic		Value	
Trip time[1)]	NPS function	V_{Fault} = 1.1 × set *Neg Seq voltage Lev*	<33 ms
		V_{Fault} = 5.0 × set *Neg Seq voltage Lev*	<18 ms
	Delta function	ΔV = 1.1 × set *Voltage change rate*	<30 ms
		ΔV = 2.0 × set *Voltage change rate*	<24 ms

1) Includes the delay of the signal output contact, f_n = 50 Hz, fault voltage with nominal frequency injected from random phase angle, results based on statistical distribution of 1000 measurements

6.5.10 Technical revision history

Table 775: 60 Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement
D	Function name changed from SEQRFUF to SEQSPVC

6.6 Runtime counter for machines and devices OPTM

6.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Runtime counter for machines and devices	MDSOPT	OPTS	OPTM

6.6.2 Function block

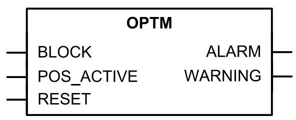


Figure 450: Function block

6.6.3 Functionality

The generic operation time counter function OPTM calculates and presents the accumulated operation time of a machine or device as the output. The unit of time for accumulation is hour. The function generates a warning and an alarm when the accumulated operation time exceeds the set limits. It utilizes a binary input to indicate the active operation condition.

The accumulated operation time is one of the parameters for scheduling a service on the equipment like motors. It indicates the use of the machine and hence the mechanical wear and tear. Generally, the equipment manufacturers provide a maintenance schedule based on the number of hours of service.

6.6.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of OPTM can be described using a module diagram. All the modules in the diagram are explained in the next sections.

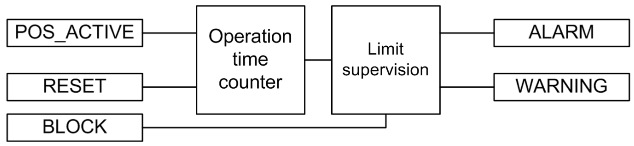


Figure 451: Functional module diagram

Operation time counter

This module counts the operation time. When POS_ACTIVE is active, the count is continuously added to the time duration until it is deactivated. At any time the OPR_TIME output is the total duration for which POS_ACTIVE is active. The unit of time duration count for OPR_TIME is hour. The value is available through the Monitored data view.

The OPR_TIME output is a continuously increasing value and it is stored in a non-volatile memory. When POS_ACTIVE is active, the OPR_TIME count starts increasing from the previous value. The count of OPR_TIME saturates at the final value of 299999, that is, no further increment is possible. The activation of RESET can reset the count to the *Initial value* setting.

Limit Supervision

This module compares the motor run-time count to the set values of *Warning value* and *Alarm value* to generate the WARNING and ALARM outputs respectively when the counts exceed the levels.

The activation of the WARNING and ALARM outputs depends on the *Operating time mode* setting. Both WARNING and ALARM occur immediately after the conditions are met if *Operating time mode* is set to “Immediate”. If *Operating time mode* is set to “Timed Warn”, WARNING is activated within the next 24 hours at the time of the day set using the *Operating time hour* setting. If *Operating time mode* is set to “Timed Warn Alm”, the WARNING and ALARM outputs are activated at the time of day set using *Operating time hour*.

The *Operating time hour* setting is used to set the hour of day in Coordinated Universal Time (UTC). The setting has to be adjusted according to the local time and local daylight-saving time.

The function contains a blocking functionality. Activation of the BLOCK input blocks both WARNING and ALARM.

6.6.5 Application

The machine operating time since commissioning indicates the use of the machine. For example, the mechanical wear and lubrication requirement for the shaft bearing of the motors depend on the use hours.

If some motor is used for long duration runs, it might require frequent servicing, while for a motor that is not used regularly the maintenance and service are scheduled less frequently. The accumulated operating time of a motor together with the appropriate settings for warning can be utilized to trigger the condition based maintenance of the motor.

The operating time counter combined with the subsequent reset of the operating-time count can be used to monitor the motor's run time for a single run.

Both the long term accumulated operating time and the short term single run duration provide valuable information about the condition of the machine and device. The information can be co-related to other process data to provide diagnoses for the process where the machine or device is applied.

6.6.6 Signals

Table 776: OPTM Input signals

Name	Type	Default	Description
BLOCK	BOOLEAN	0=False	Block input status
POS_ACTIVE	BOOLEAN	0=False	When active indicates the equipment is running
RESET	BOOLEAN	0=False	Resets the accumulated operation time to initial value

Table 777: OPTM Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm accumulated operation time exceeds Alarm value
WARNING	BOOLEAN	Warning accumulated operation time exceeds Warning value

6.6.7 Settings

Table 778: OPTM Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Warning value	0...299999	h	1	8000	Warning value for operation time supervision
Alarm value	0...299999	h	1	10000	Alarm value for operation time supervision

Table 779: OPTM Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Initial value	0...299999	h	1	0	Initial value for operation time supervision
Operating time hour	0...23	h	1	0	Time of day when alarm and warning will occur
Operating time mode	1=Immediate 2=Timed Warn 3=Timed Warn Alm			1=Immediate	Operating time mode for warning and alarm

6.6.8 Monitored data

Table 780: OPTM Monitored data

Name	Type	Values (Range)	Unit	Description
OPTM	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
OPR_TIME	INT32	0...299999	h	Total operation time in hours

6.6.9 Technical data

Table 781: OPTM Technical data

Description	Value
Motor runtime measurement accuracy1)	±0.5%

1) Of the reading, for a stand-alone relay, without time synchronization

6.6.10 Technical revision history

Table 782: OPTM Technical revision history

Technical revision	Change
B	Internal improvement.
C	Internal improvement.
D	Internal improvement.

Section 7 Condition monitoring functions

7.1 Circuit breaker condition monitoring 52CM

7.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit breaker condition monitoring	SSCBR	CBCM	52CM

7.1.2 Function block

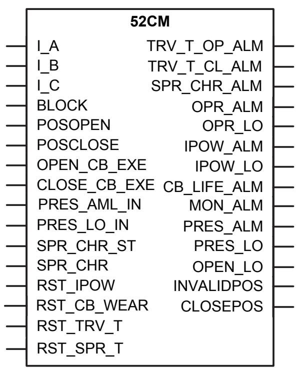


Figure 452: Function block

7.1.3 Functionality

The circuit breaker condition monitoring function 52CM is used to monitor different parameters of the circuit breaker. The breaker requires maintenance when the number of operations has reached a predefined value. The energy is calculated from the measured input currents as a sum of $I^y t$ values. Alarms are generated when the calculated values exceed the threshold settings.

The function contains a blocking functionality. It is possible to block the function outputs, if desired.

7.1.4 Operation principle

The circuit breaker condition monitoring function includes different metering and monitoring sub-functions. The functions can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”. The operation counters are cleared when *Operation* is set to “Disable”.

The operation of 52CM can be described with a module diagram. All the modules in the diagram are explained in the next sections.

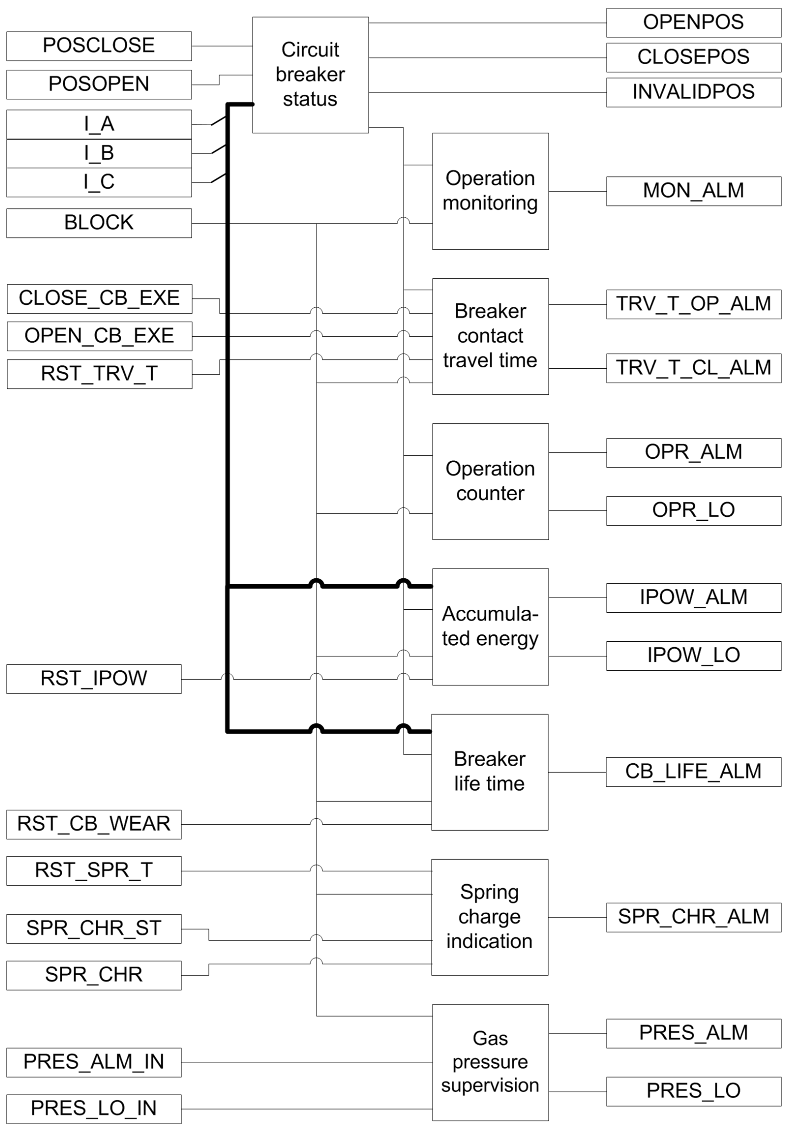


Figure 453: Functional module diagram

7.1.4.1 Circuit breaker status

The Circuit breaker status sub-function monitors the position of the circuit breaker, that is, whether the breaker is in open, closed or invalid position. The operation of the breaker status monitoring can be described by using a module diagram. All the modules in the diagram are explained in the next sections.

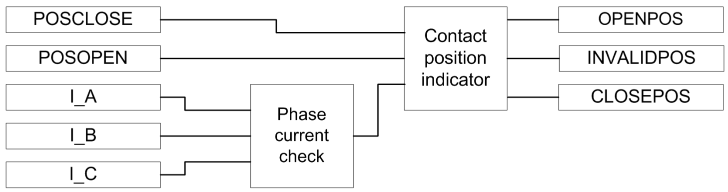


Figure 454: Functional module diagram for monitoring circuit breaker status

Phase current check

This module compares the three phase currents to the setting *Acc stop current*. If the current in a phase exceeds the set level, information about the phase is reported to the contact position indicator module.

Contact position indicator

The `OPENPOS` output is activated when the auxiliary input contact `POSCLOSE` is FALSE, the `POSOPEN` input is TRUE and all the phase currents are below the setting *Acc stop current*.

The `CLOSEPOS` output is activated when the auxiliary `POSOPEN` input is FALSE and the `POSCLOSE` input is TRUE.

The `INVALIDPOS` output is activated when both the auxiliary contacts have the same value, that is, both are in the same logical level, or if the auxiliary input contact `POSCLOSE` is FALSE and the `POSOPEN` input is TRUE and any of the phase currents exceed the setting `Acc stop current`.

The status of the breaker is indicated by the binary outputs `OPENPOS`, `INVALIDPOS` and `CLOSEPOS` for open, invalid and closed position respectively.

7.1.4.2 Circuit breaker operation monitoring

The purpose of the circuit breaker operation monitoring subfunction is to indicate if the circuit breaker has not been operated for a long time.

The operation of the circuit breaker operation monitoring can be described with a module diagram. All the modules in the diagram are explained in the next sections.

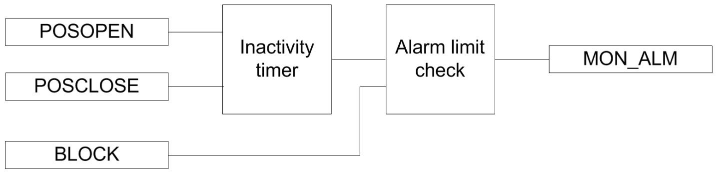


Figure 455: Functional module diagram for calculating inactive days and alarm for circuit breaker operation monitoring

Inactivity timer

The module calculates the number of days the circuit breaker has remained inactive, that is, has stayed in the same open or closed state. The calculation is done by monitoring the states of the `POSOPEN` and `POSCLOSE` auxiliary contacts.

The inactive days `INA_DAYS` is available in the monitored data view. It is also possible to set the initial inactive days with the *Ini inactive days* parameter.

Alarm limit check

When the inactive days exceed the limit value defined with the *Inactive Alm days* setting, the `MON_ALM` alarm is initiated. The time in hours at which this alarm is activated can be set with the *Inactive Alm hours* parameter as coordinates of UTC. The alarm signal `MON_ALM` can be blocked by activating the binary input `BLOCK`.

7.1.4.3 Breaker contact travel time

The Breaker contact travel time module calculates the breaker contact travel time for the closing and opening operation. The operation of the breaker contact travel time measurement can be described with a module diagram. All the modules in the diagram are explained in the next sections.

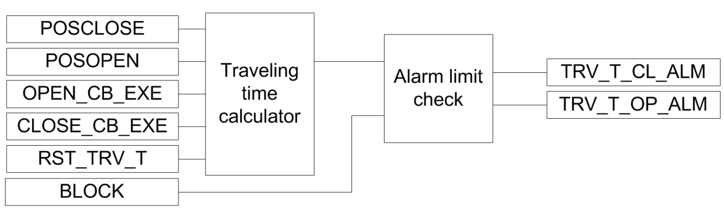


Figure 456: Functional module diagram for breaker contact travel time

Traveling time calculator

The travel time can be calculated using two different methods based on the setting *Travel time Clc mode*.

When the setting *Travel time Clc mode* is “From Pos to Pos”, the contact travel time of the breaker is calculated from the time between auxiliary contacts' state change. The opening travel time is measured between the opening of the `POSCLOSE` auxiliary contact and the closing of the `POSOPEN` auxiliary contact. The travel time is also measured between the opening of the `POSOPEN` auxiliary contact and the closing of the `POSCLOSE` auxiliary contact.

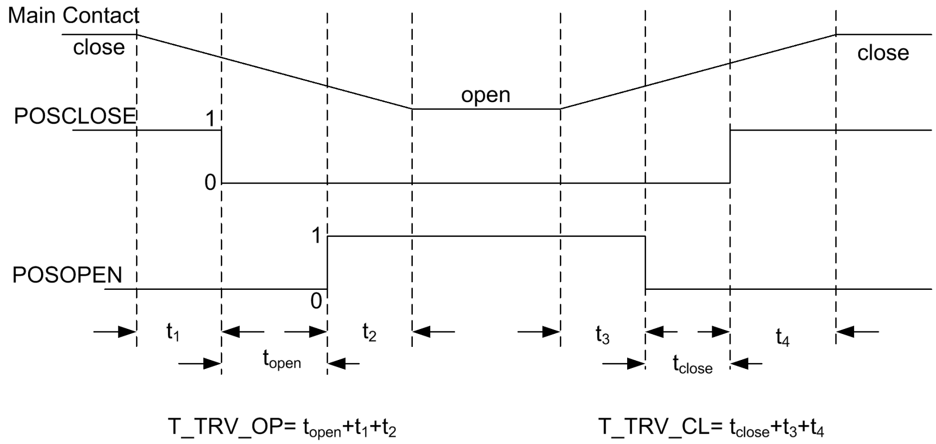


Figure 457: Travel time calculation when Travel time Clc mode is “From Pos to Pos”

There is a time difference t_1 between the start of the main contact opening and the opening of the `POSCLOSE` auxiliary contact. Similarly, there is a time gap t_2 between the time when the `POSOPEN` auxiliary contact opens and the main contact is completely open. To incorporate the time $t_1 + t_2$, a correction factor needs to be added with t_{open} to get the actual opening time. This factor is added with the *Opening time Cor* (= $t_1 + t_2$) setting. The closing time is calculated by adding the value set with the *Closing time Cor* ($t_3 + t_4$) setting to the measured closing time.

When the setting *Travel time Clc mode* is “From Cmd to Pos”, the contact travel time of the breaker is calculated from the time between the circuit breaker opening or closing command and the auxiliary contacts’ state change. The opening travel time is measured between the rising edge of the OPEN_CB_EXE command and the `POSOPEN` auxiliary contact. The closing travel time is measured between the rising edge of the CLOSE_CB_EXEC command and the POSCLOSE auxiliary contact.

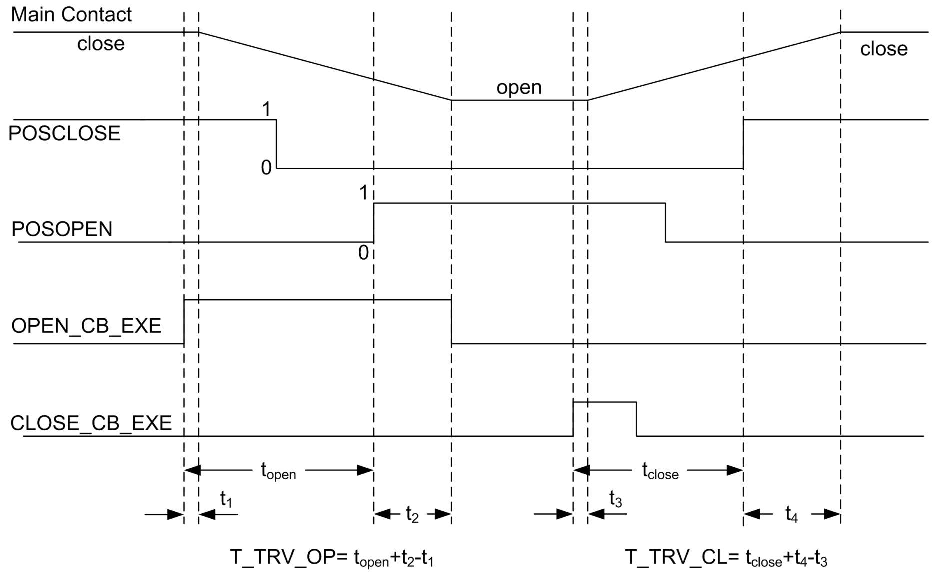


Figure 458: Travel time calculation when Travel time Clc mode is “From Cmd to Pos”

There is a time difference t_1 between the start of the main contact opening and the OPEN_CB_EXE command. Similarly, there is a time gap t_2 between the time when the `POSOPEN` auxiliary contact opens and the main contact is completely open. Therefore, to incorporate the times t_1 and t_2, a correction factor needs to be added with t_{open} to get the actual opening time. This factor is added with the *Opening time Cor* (= t_2 - t_1) setting. The closing time is calculated by adding the value set with the *Closing time Cor* (t_4 - t_3) setting to the measured closing time.

The last measured opening travel time `T_TRV_OP` and the closing travel time `T_TRV_CL` are available in the monitored data view on the LHMI or through tools via communications.

Alarm limit check

When the measured opening travel time is longer than the value set with the *Open alarm time* setting, the `TRV_T_OP_ALM` output is activated. Respectively, when the measured closing travel time is longer than the value set with the *Close alarm time* setting, the `TRV_T_CL_ALM` output is activated.

It is also possible to block the `TRV_T_CL_ALM` and `TRV_T_OP_ALM` alarm signals by activating the `BLOCK` input.

7.1.4.4 Operation counter

The operation counter subfunction calculates the number of breaker operation cycles. The opening and closing operations are both included in one operation cycle. The operation counter value is updated after each opening operation.

The operation of the subfunction can be described with a module diagram. All the modules in the diagram are explained in the next sections.

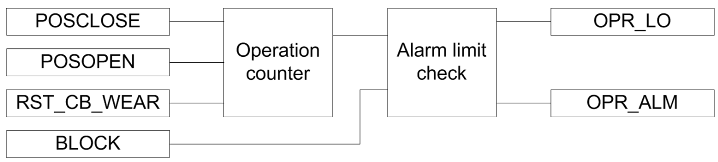


Figure 459: Functional module diagram for counting circuit breaker operations

Operation counter

The operation counter counts the number of operations based on the state change of the binary auxiliary contacts inputs POSCLOSE and POSOPEN.

The number of operations NO_OPR is available in the monitored data view on the LHMI or through tools via communications. The old circuit breaker operation counter value can be taken into use by writing the value to the *Counter initial Val* parameter and by setting the parameter *Initial CB Rmn life* in the clear menu from WHMI or LHMI.

Alarm limit check

The OPR_ALM operation alarm is generated when the number of operations exceeds the value set with the *Alarm Op number* threshold setting. However, if the number of operations increases further and exceeds the limit value set with the *Lockout Op number* setting, the OPR_LO output is activated.

The binary outputs OPR_LO and OPR_ALM are deactivated when the BLOCK input is activated.

7.1.4.5 Accumulation of I^yt

Accumulation of the I^yt module calculates the accumulated energy.

The operation of the module can be described with a module diagram. All the modules in the diagram are explained in the next sections.

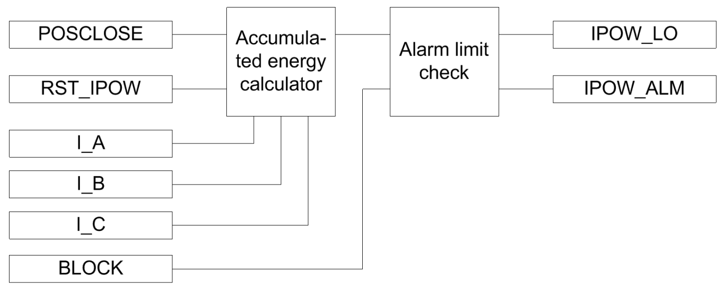


Figure 460: Functional module diagram for calculating accumulative energy and alarm

Accumulated energy calculator

This module calculates the accumulated energy I^yt [(kA)^{y}s]. The factor y is set with the *Current exponent* setting.

The calculation is initiated with the `POSCLOSE` input opening events. It ends when the RMS current becomes lower than the *Acc stop current* setting value.

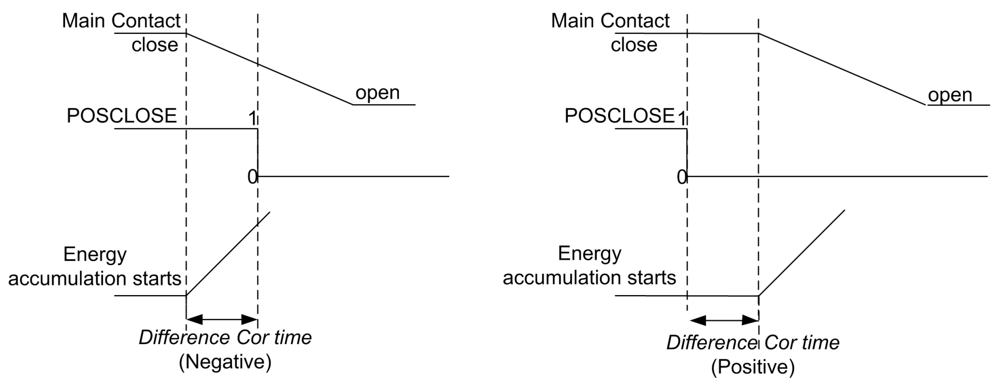


Figure 461: Significance of the Difference Cor time setting

The *Difference Cor time* setting is used instead of the auxiliary contact to accumulate the energy from the time the main contact opens. If the setting is positive, the calculation of energy starts after the auxiliary contact has opened and when the delay is equal to the value set with the *Difference Cor time* setting. When the setting is negative, the calculation starts in advance by the correction time before the auxiliary contact opens.

The accumulated energy outputs `IPOW_A (_B, _C)` are available in the monitored data view on the LHMI or through tools via communications. The values can be reset by setting the parameter *Initial CB Rmn life* setting to true in the clear menu from WHMI or LHMI.

Alarm limit check

The IPOW_ALM alarm is activated when the accumulated energy exceeds the value set with the *Alm Acc currents Pwr* threshold setting. However, when the energy exceeds the limit value set with the *LO Acc currents Pwr* threshold setting, the IPOW_LO output is activated.

The IPOW_ALM and IPOW_LO outputs can be blocked by activating the binary input BLOCK.

7.1.4.6 Remaining life of circuit breaker

Every time the breaker operates, the life of the circuit breaker reduces due to wearing. The wearing in the breaker depends on the tripping current, and the remaining life of the breaker is estimated from the circuit breaker trip curve provided by the manufacturer. The remaining life is decremented at least with one when the circuit breaker is opened.

The operation of the remaining life of the circuit breaker subfunction can be described with a module diagram. All the modules in the diagram are explained in the next sections.

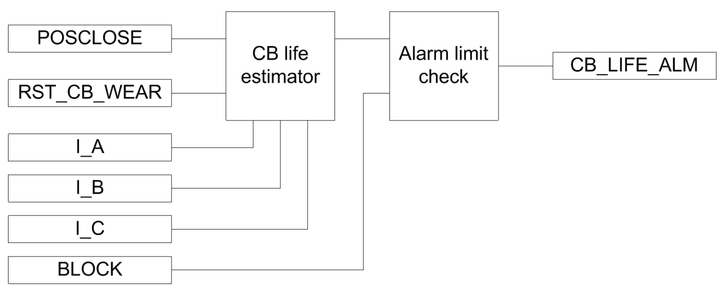


Figure 462: Functional module diagram for estimating the life of the circuit breaker

Circuit breaker life estimator

The circuit breaker life estimator module calculates the remaining life of the circuit breaker. If the tripping current is less than the rated operating current set with the *Rated Op current* setting, the remaining operation of the breaker reduces by one operation. If the tripping current is more than the rated fault current set with the *Rated fault current* setting, the possible operations are zero. The remaining life of the tripping current in between these two values is calculated based on the trip curve given by the manufacturer. The *Op number rated* and *Op number fault* parameters set the number of operations the breaker can perform at the rated current and at the rated fault current, respectively.

The remaining life is calculated separately for all three phases and it is available as a monitored data value CB_LIFE_A (_B, _C). The values can be cleared by setting the parameter *CB wear values* in the clear menu from WHMI or LHMI.

Clearing *CB wear values* also resets the operation counter.

Alarm limit check

When the remaining life of any phase drops below the *Life alarm level* threshold setting, the corresponding circuit breaker life alarm CB_LIFE_ALM is activated.

It is possible to deactivate the CB_LIFE_ALM alarm signal by activating the binary input BLOCK. The old circuit breaker operation counter value can be taken into use by writing the value to the *Initial CB Rmn life* parameter and resetting the value via the clear menu from WHMI or LHMI.

7.1.4.7 Circuit breaker spring-charged indication

The circuit breaker spring-charged indication subfunction calculates the spring charging time.

The operation of the subfunction can be described with a module diagram. All the modules in the diagram are explained in the next sections.

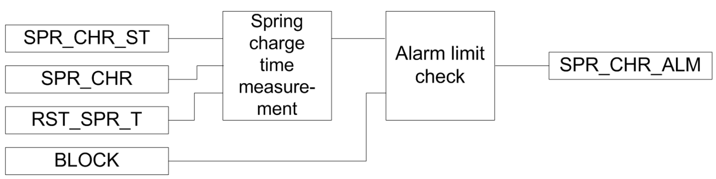


Figure 463: Functional module diagram for circuit breaker spring-charged indication and alarm

Spring charge time measurement

Two binary inputs, SPR_CHR_ST and SPR_CHR, indicate spring charging started and spring charged, respectively. The spring-charging time is calculated from the difference of these two signal timings.

The spring charging time T_SPR_CHR is available in the monitored data view on the LHMI or through tools via communications.

Alarm limit check

If the time taken by the spring to charge is more than the value set with the *Spring charge time* setting, the subfunction generates the SPR_CHR_ALM alarm.

It is possible to block the SPR_CHR_ALM alarm signal by activating the BLOCK binary input.

7.1.4.8 Gas pressure supervision

The gas pressure supervision subfunction monitors the gas pressure inside the arc chamber.

The operation of the subfunction can be described with a module diagram. All the modules in the diagram are explained in the next sections.

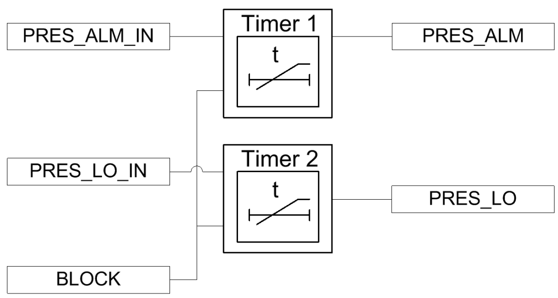


Figure 464: Functional module diagram for circuit breaker gas pressure alarm

The gas pressure is monitored through the binary input signals PRES_LO_IN and PRES_ALM_IN.

Timer 1

When the PRES_ALM_IN binary input is activated, the PRES_ALM alarm is activated after a time delay set with the *Pressure alarm time* setting. The PRES_ALM alarm can be blocked by activating the BLOCK input.

Timer 2

If the pressure drops further to a very low level, the PRES_LO_IN binary input becomes high, activating the lockout alarm PRES_LO after a time delay set with the *Pres lockout time* setting. The PRES_LO alarm can be blocked by activating the BLOCK input.

7.1.5 Application

52CM includes different metering and monitoring subfunctions.

Circuit breaker status

Circuit breaker status monitors the position of the circuit breaker, that is, whether the breaker is in an open, closed or intermediate position.

Circuit breaker operation monitoring

The purpose of the circuit breaker operation monitoring is to indicate that the circuit breaker has not been operated for a long time. The function calculates the number of days the circuit breaker has remained inactive, that is, has stayed in the same open or closed state. There is also the possibility to set an initial inactive day.

Breaker contact travel time

High traveling times indicate the need for the maintenance of the circuit breaker mechanism. Therefore, detecting excessive traveling time is needed. During the opening cycle operation, the main contact starts opening. The auxiliary contact A opens, the auxiliary contact B closes and the main contact reaches its opening position. During the closing cycle, the first main contact starts closing. The auxiliary contact B opens, the auxiliary contact A closes and the main contact reaches its closed position. The travel times are calculated based on the state changes of the auxiliary contacts and the adding correction factor to consider the time difference of the main contact's and the auxiliary contact's position change.

Operation counter

Routine maintenance of the breaker, such as lubricating breaker mechanism, is generally based on a number of operations. A suitable threshold setting to raise an alarm when the number of operation cycle exceeds the set limit helps preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

The change of state can be detected from the binary input of the auxiliary contact. There is a possibility to set an initial value for the counter which can be used to initialize this functionality after a period of operation or in case of refurbished primary equipment.

Accumulation of I^yt

Accumulation of I^yt calculates the accumulated energy ΣI^yt, where the factor y is known as the current exponent. The factor y depends on the type of the circuit breaker. For oil circuit breakers, the factor y is normally 2. In case of a high-voltage system, the factor y can be 1.4...1.5.

Remaining life of the breaker

Every time the breaker operates, the life of the circuit breaker reduces due to wearing. The wearing in the breaker depends on the tripping current, and the remaining life of the breaker is estimated from the circuit breaker trip curve provided by the manufacturer.

Example for estimating the remaining life of a circuit breaker

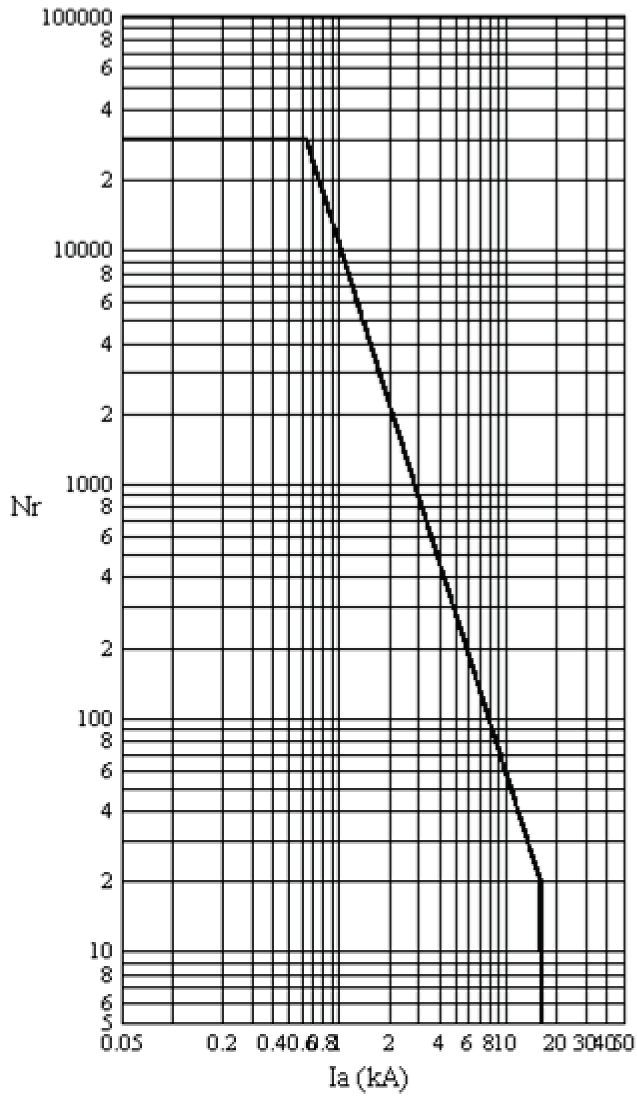


Figure 465: Trip Curves for a typical 12 kV, 630 A, 16 kA vacuum interrupter

Nr	the number of closing-opening operations allowed for the circuit breaker
Ia	the current at the time of tripping of the circuit breaker

Calculation of Directional Coef

The directional coefficient is calculated according to the formula:

$$Directional\,Coef = \frac{\log\left(\frac{B}{A}\right)}{\log\left(\frac{I_f}{I_r}\right)} = -2.2609$$

(Equation 162)

I_r	Rated operating current = 630 A
I_f	Rated fault current = 16 kA
A	Op number rated = 30000
B	Op number fault = 20

Calculation for estimating the remaining life

Figure 465 shows that there are 30,000 possible operations at the rated operating current of 630 A and 20 operations at the rated fault current 16 kA. Therefore, if the tripping current is 10 kA, one operation at 10 kA is equivalent to 30,000/60=500 operations at the rated current. It is also assumed that prior to this tripping, the remaining life of the circuit breaker is 15,000 operations. Therefore, after one operation of 10 kA, the remaining life of the circuit breaker is 15,000-500=14,500 at the rated operating current.

$$Remaining\ \ life\ \ reduction = \left(\frac{I}{I_r}\right)^{-Directional\,Coef}$$

(Equation 163)

Spring-charged indication

For normal operation of the circuit breaker, the circuit breaker spring should be charged within a specified time. Therefore, detecting long spring-charging time indicates that it is time for the circuit breaker maintenance. The last value of the spring-charging time can be used as a service value.

Gas pressure supervision

The gas pressure supervision monitors the gas pressure inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operations are locked. A binary input is available based on the pressure levels in the function, and alarms are generated based on these inputs.

7.1.6 Signals

Table 783: 52CM Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block input status
POSOPEN	BOOLEAN	0=False	Signal for open position of apparatus from I/O
POSCLOSE	BOOLEAN	0=False	Signal for close position of apparatus from I/O
OPEN_CB_EXE	BOOLEAN	0=False	Signal for open command to coil
CLOSE_CB_EXE	BOOLEAN	0=False	Signal for close command to coil
PRES_ALM_IN	BOOLEAN	0=False	Binary pressure alarm input
PRES_LO_IN	BOOLEAN	0=False	Binary pressure input for lockout indication
SPR_CHR_ST	BOOLEAN	0=False	CB spring charging started input
SPR_CHR	BOOLEAN	0=False	CB spring charged input
RST_IPOW	BOOLEAN	0=False	Reset accumulation energy
RST_CB_WEAR	BOOLEAN	0=False	Reset input for CB remaining life and operation counter
RST_TRV_T	BOOLEAN	0=False	Reset input for CB closing and opening travel times
RST_SPR_T	BOOLEAN	0=False	Reset input for the charging time of the CB spring

Table 784: 52CM Output signals

Name	Type	Description
TRV_T_OP_ALM	BOOLEAN	CB open travel time exceeded set value
TRV_T_CL_ALM	BOOLEAN	CB close travel time exceeded set value
SPR_CHR_ALM	BOOLEAN	Spring charging time has crossed the set value
OPR_ALM	BOOLEAN	Number of CB operations exceeds alarm limit
OPR_LO	BOOLEAN	Number of CB operations exceeds lockout limit
IPOW_ALM	BOOLEAN	Accumulated currents power (Iyt),exceeded alarm limit
IPOW_LO	BOOLEAN	Accumulated currents power (Iyt),exceeded lockout limit
CB_LIFE_ALM	BOOLEAN	Remaining life of CB exceeded alarm limit
MON_ALM	BOOLEAN	CB 'not tripped for long time' alarm
PRES_ALM	BOOLEAN	Pressure below alarm level
PRES_LO	BOOLEAN	Pressure below lockout level
OPENPOS	BOOLEAN	CB is in open position
INVALIDPOS	BOOLEAN	CB is in invalid position (not positively open or closed)
CLOSEPOS	BOOLEAN	CB is in closed position

7.1.7 Settings

Table 785: 52CM Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Acc stop current	5.00...500.00	A	0.01	10.00	RMS current setting below which engy acm stops
Open alarm time	0...200	ms	1	40	Alarm level setting for open travel time in ms
Close alarm time	0...200	ms	1	40	Alarm level Setting for close travel time in ms
Spring charge time	0...60000	ms	10	15000	Setting of alarm for spring charging time of CB in ms
Alarm Op number	0...99999		1	200	Alarm limit for number of operations
Lockout Op number	0...99999		1	300	Lock out limit for number of operations
Current exponent	0.00...2.00		0.01	2.00	Current exponent setting for energy calculation
Difference Cor time	-10...10	ms	1	5	Corr. factor for time dif in aux. and main contacts open time
Alm Acc currents Pwr	0.00...20000.00		0.01	2500.00	Setting of alarm level for accumulated currents power
LO Acc currents Pwr	0.00...20000.00		0.01	2500.00	Lockout limit setting for accumulated currents power
Directional Coef	-3.00...-0.50		0.01	-1.50	Directional coefficient for CB life calculation
Initial CB Rmn life	0...99999		1	5000	Initial value for the CB remaining life
Rated Op current	100.00...5000.00	A	0.01	1000.00	Rated operating current of the breaker
Rated fault current	500.00...75000.00	A	0.01	5000.00	Rated fault current of the breaker
Op number rated	1...99999		1	10000	Number of operations possible at rated current
Op number fault	1...10000		1	1000	Number of operations possible at rated fault current
Inactive Alm days	0...9999		1	2000	Alarm limit value of the inactive days counter
Travel time Clc mode	1=From Cmd to Pos 2=From Pos to Pos			2=From Pos to Pos	Travel time calculation mode selection

Table 786: 52CM Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Opening time Cor	-100...100	ms	1	10	Correction factor for open travel time in ms
Closing time Cor	-100...100	ms	1	10	Correction factor for CB close travel time in ms
Counter initial Val	0...99999		1	0	The operation numbers counter initialization value
Ini Acc currents Pwr	0.00...20000.00		0.01	0.00	Initial value for accumulation energy (Iyt)
Life alarm level	0...99999		1	500	Alarm level for CB remaining life

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Pressure alarm time	0...60000	ms	1	10	Time delay for gas pressure alarm in ms
Pres lockout time	0...60000	ms	10	10	Time delay for gas pressure lockout in ms
Ini inactive days	0...9999		1	0	Initial value of the inactive days counter
Inactive Alm hours	0...23	h	1	0	Alarm time of the inactive days counter in hours

7.1.8 Monitored data

Table 787: 52CM Monitored data

Name	Type	Values (Range)	Unit	Description
T_TRV_OP	FLOAT32	0...60000	ms	Travel time of the CB during opening operation
T_TRV_CL	FLOAT32	0...60000	ms	Travel time of the CB during closing operation
T_SPR_CHR	FLOAT32	0.00...99.99	s	The charging time of the CB spring
NO_OPR	INT32	0...99999		Number of CB operation cycle
INA_DAYS	INT32	0...9999		The number of days CB has been inactive
CB_LIFE_A	INT32	-99999...99999		CB Remaining life phase A
CB_LIFE_B	INT32	-99999...99999		CB Remaining life phase B
CB_LIFE_C	INT32	-99999...99999		CB Remaining life phase C
IPOW_A	FLOAT32	0.000...30000.000		Accumulated currents power (Iyt), phase A
IPOW_B	FLOAT32	0.000...30000.000		Accumulated currents power (Iyt), phase B
IPOW_C	FLOAT32	0.000...30000.000		Accumulated currents power (Iyt), phase C
52CM	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

7.1.9 Technical data

Table 788: 52CM Technical data

Characteristic	Value
Current measuring accuracy	±1.5% or ±0.002 × I_n (at currents in the range of 0.1…10 × I_n) ±5.0% (at currents in the range of 10…40 × I_n)
Operate time accuracy	±1.0% of the set value or ±20 ms
Travelling time measurement	+10 ms / -0 ms

7.1.10 Technical revision history

Table 789: 52CM Technical revision history

Technical revision	Change
B	Added the possibility to reset spring charge time and breaker travel times
C	Removed the DIFTRVTOPALM and DIFTRVTCLALM outputs and the corresponding *Open Dif alarm time* and *Close Dif alarm time* setting parameters
D	The *Operation cycle* setting parameter renamed to *Initial CB Rmn life*. The IPOW_A (_B, _C) range changed.
E	Maximum value of initial circuit breaker remaining life time setting (*Initial CB Rmn life*) changed from 9999 to 99999. Added support for measuring circuit breaker travelling time from opening/closing command and auxiliary contact state signal change.
F	*Alarm Op number* range increased from 9999 to 99999. *Lockout Op* number setting range increased from 9999 to 99999. *Counter initial value* setting range increased from 9999 to 99999.

Section 8 Measurement functions

8.1 Basic measurements

8.1.1 Functions

The three-phase current measurement function IA, IB, IC is used for monitoring and metering the phase currents of the power system.

The three-phase voltage measurement function VA, VB, VC is used for monitoring and metering the phase-to-phase voltages of the power system. The phase-to-ground voltages are also available in VA, VB, VC.

The ground current measurement function IG is used for monitoring and metering the ground current of the power system.

The ground voltage measurement function VG is used for monitoring and metering the ground voltage of the power system.

The sequence current measurement I1, I2, I0 is used for monitoring and metering the phase sequence currents.

The sequence voltage measurement V1, V2, V0 is used for monitoring and metering the phase sequence voltages.

The frequency measurement f is used for monitoring and metering the power system frequency.

The single-phase power and energy measurement SP, SE and the three-phase power and energy measurement P, E is used for monitoring and metering the active power P, reactive power Q, apparent power S, power factor PF and for calculating the accumulated energy separately as forward active, reverse active, forward reactive and reverse reactive. P, E calculates these quantities with the fundamental frequency phasors, that is, the DFT values of the measured phase current and phase voltage signals.

The information of the measured quantity is available for the operator both locally in LHMI or WHMI and remotely to a network control center with communication.

If the measured data in LHMI or WHMI is within parentheses, there are some problems to express the data.

8.1.2 Measurement functionality

The functions can be enabled or disabled with the *Operation* setting. The corresponding parameter values are Enable and Disable.

Some of the measurement functions operate on two alternative measurement modes: "DFT" and "RMS". The measurement mode is selected with the *X Measurement mode* setting. Depending on the measuring function if the measurement mode cannot be selected, the measuring mode is "DFT".

Demand value calculation

The demand values are calculated separately for each measurement function and per phase when applicable. The available measurement modes are "Linear" and "Logarithmic". The "Logarithmic" measurement mode is only effective for phase current and residual current demand value calculations. The demand value calculation mode is selected with the setting parameter **Configuration/Measurements/A demand Av mode**. The time interval for all demand value calculations is selected with the setting parameter **Configuration/Measurements/Demand interval**.

If the *Demand interval* setting is set to "15 minutes", for example, the demand values are updated every quarter of an hour. The demand time interval is synchronized to the real-time clock of the protection relay. When the demand time interval or calculation mode is changed, it initializes the demand value calculation. For the very first demand value calculation interval, the values are stated as invalid until the first refresh is available.

The "Linear" calculation mode uses the periodic sliding average calculation of the measured signal over the demand time interval. A new demand value is obtained once in a minute, indicating the analog signal demand over the demand time interval proceeding the update time. The actual rolling demand values are stored in the memory until the value is updated at the end of the next time interval.

The "Logarithmic" calculation mode uses the periodic calculation using a log10 function over the demand time interval to replicate thermal demand ammeters. The logarithmic demand calculates a snapshot of the analog signal every 1/15 x demand time interval.

Each measurement function has its own recorded data values. In protection relay, these are found in **Monitoring/Recorded data/Measurements**. In the technical manual these are listed in the monitored data section of each measurement function. These values are periodically updated with the maximum and minimum demand values. The time stamps are provided for both values.

Reset of Recorded data initializes a present demand value to the minimum and maximum demand values.

Value reporting

The measurement functions are capable of reporting new values for network control center (SCADA system) based on various functions.

- Zero-point clamping
- Deadband supervision
- Limit value supervision

In the three-phase voltage measurement function VA, VB, VC the supervision functions are based on the phase-to-phase voltages. However, the phase-to-ground voltage values are also reported together with the phase-to-phase voltages.

GOOSE is an event based protocol service. Analog GOOSE uses the same event generation functions as vertical SCADA communication for updating the measurement values. Update interval of 500 ms is used for data that do not have zero-point clamping, deadband supervision or limit value supervision.

Zero-point clamping

A measured value under the zero-point clamping limit is forced to zero. This allows the noise in the input signal to be ignored. The active clamping function forces both the actual measurement value and the angle value of the measured signal to zero. In the three-phase or sequence measuring functions, each phase or sequence component has a separate zero-point clamping function. The zero-value detection operates so that once the measured value exceeds or falls below the value of the zero-clamping limit, new values are reported.

Table 790: Zero-point clamping limits

Function	Zero-clamping limit
Three-phase current measurement (IA, IB, IC)	1% of nominal (In)
Three-phase voltage measurement (VA, VB, VC)	1% of nominal (Vn)
Ground current measurement (IG)	1% of nominal (In)
Ground voltage measurement (VG)	1% of nominal (Vn)
Phase sequence current measurement (I1, I2, I0)	1% of the nominal (In)
Phase sequence voltage measurement (V1, V2, V0)	1% of the nominal (Vn)
Three-phase power and energy measurement (P, E)	1.5% of the nominal (Sn)

When the frequency measurement function f is unable to measure the network frequency in the undervoltage situation, the measured values are set to the nominal and also the quality information of the data set accordingly. The undervoltage limit is fixed to 10 percent of the nominal for the frequency measurement.

Limit value supervision

The limit value supervision function indicates whether the measured value of X_INST exceeds or falls below the set limits. The measured value has the corresponding range information X_RANGE and has a value in the range of 0 to 4:

- 0: "normal"
- 1: "high"
- 2: "low"
- 3: "high-high"
- 4: "low-low"

The range information changes and the new values are reported.

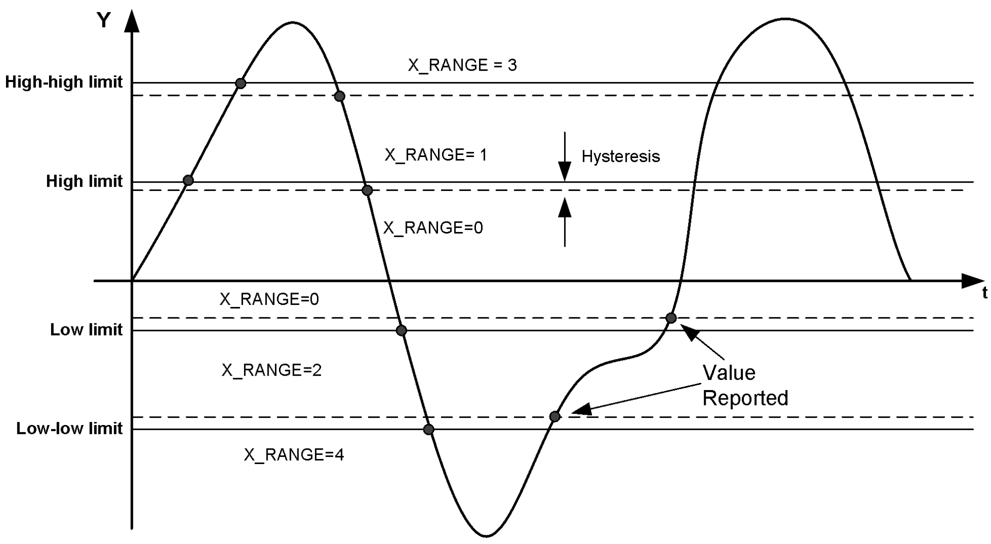


Figure 466: Presentation of operating limits

The range information can also be decoded into boolean output signals on some of the measuring functions and the number of phases required to exceed or undershoot the limit before activating the outputs and can be set with the *Num of phases* setting in the three-phase measurement functions IA, IB, IC and VA, VB, VC. The limit supervision boolean alarm and warning outputs can be blocked.

Table 791: Settings for limit value supervision

Function	Settings for limit value supervision	
Three-phase current measurement (IA, IB, IC)	High limit	*A high limit*
	Low limit	*A low limit*
	High-high limit	*A high high limit*
	Low-low limit	*A low low limit*
Three-phase voltage measurement (VA, VB, VC)	High limit	*V high limit*
	Low limit	*V low limit*
	High-high limit	*V high high limit*
	Low-low limit	*V low low limit*
Ground current measurement (IG)	High limit	*A high limit res*
	Low limit	-
	High-high limit	*A Hi high limit res*
	Low-low limit	-
Frequency measurement (f)	High limit	*F high limit*
	Low limit	*F low limit*
	High-high limit	*F high high limit*
	Low-low limit	*F low low limit*
Ground voltage measurement (VG)	High limit	*V high limit res*
	Low limit	-
	High-high limit	*V Hi high limit res*
	Low-low limit	-
Phase sequence current measurement (I1, I2, I0)	High limit	*Ps Seq A high limit*, *Ng Seq A high limit*, *Zro A high limit*
	Low limit	*Ps Seq A low limit*, *Ng Seq A low limit*, *Zro A low limit*
	High-high limit	*Ps Seq A Hi high Lim*, *Ng Seq A Hi high Lim*, *Zro A Hi high Lim*
	Low-low limit	*Ps Seq A low low Lim*, *Ng Seq A low low Lim*, *Zro A low low Lim*
Phase sequence voltage measurement (V1, V2, V0)	High limit	*Ps Seq V high limit*, *Ng Seq V high limit*, *Zro V high limit*
	Low limit	*Ps Seq V low limit*, *Ng Seq V low limit*, *Zro V low limit*
	High-high limit	*Ps Seq V Hi high Lim*, *Ng Seq V Hi high Lim*, *Zro V Hi high Lim*
	Low-low limit	*Ps Seq V low low Lim*, *Ng Seq V low low Lim*,

Table continues on next page

Function	Settings for limit value supervision	
Three-phase power and energy measurement (P, E)	High limit	-
	Low limit	-
	High-high limit	-
	Low-low limit	-

Deadband supervision

The deadband supervision function reports the measured value according to integrated changes over a time period.

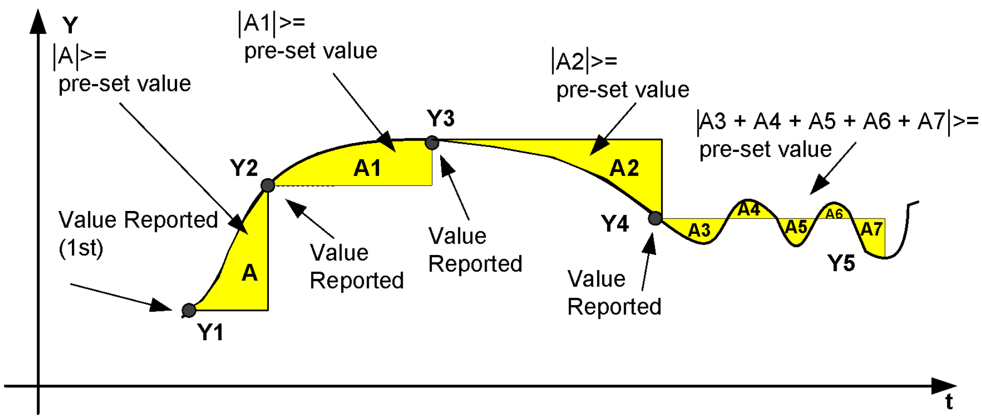


Figure 467: Integral deadband supervision

The deadband value used in the integral calculation is configured with the *X deadband* setting. The value represents the percentage of the difference between the maximum and minimum limit in the units of 0.001 percent x seconds.

The reporting delay of the integral algorithms in seconds is calculated with the formula:

$$t(s) = \frac{(\max - \min) \times deadband / 1000}{|\Delta Y| \times 100\%}$$

(Equation 164)

Example for IA, IB, IC:

A deadband = 2500 (2.5% of the total measuring range of 40)

I_INST_A = I_DB_A = 0.30

If I_INST_A changes to 0.40, the reporting delay is:

$$t(s) = \frac{(40-0)\times 2500/1000}{|0.40-0.30|\times 100\%} = 10s$$

Table 792: Parameters for deadband calculation

Function	Settings	Maximum/minimum (=range)
Three-phase current measurement (IA, IB, IC)	*A deadband*	*40/0 (=40xIn)*
Three-phase voltage measurement (VA, VB, VC)	*V Deadband*	*4/0 (=4xVn)*
Ground current measurement (IG)	*A deadband res*	*40/0 (=40xIn)*
Ground voltage measurement (VG)	*V deadband res*	*4/0 (=4xVn)*
Frequency measurement (f)	*F deadband*	*75/35 (=40 Hz)*[1)]
Phase sequence current measurement (I1, I2, I0)	*Ps Seq A deadband*, *Ng Seq A deadband*, *Zro A deadband*	*40/0 (=40xIn)*
Phase sequence voltage measurement (V1, V2, V0)	*Ps Seq V deadband*, *Ng Seq V deadband*, *Zro V deadband*	*4/0 (=4xVn)*
Three-phase power and energy measurement (P, E)	-	

1) The value provided is for REF615, RET615 and REM615 in 50 Hz network. The value for 60 Hz network is 90/36 (=54 Hz). For REG615 the values are 75/10 (=65 Hz) in 50 Hz network and 90/12 (=78 Hz) in 60 Hz network.

In the power and energy measurement functions P, E and SP, SE, the deadband supervision is done separately for apparent power S, with the preset value of fixed 10 percent of the Sn and the power factor PF, with the preset values fixed at 0.10. All the power measurement-related values P, Q, S and PF are reported simultaneously when either one of the S or PF values exceeds the preset limit.

Power and energy calculation

The single-phase and three-phase power is calculated from the phase-to-ground voltages and phase-to-ground currents. The power measurement function is capable of calculating a complex power based on the fundamental frequency component phasors (DFT).

$$\overline{S} = (\overline{V}_A \cdot \overline{I}^*_A + \overline{V}_B \cdot \overline{I}^*_B + \overline{V}_C \cdot \overline{I}^*_C)$$

(Equation 165)

Once the complex apparent power is calculated, P, Q, S and PF are calculated with the equations:

$$P = \mathrm{Re}(\overline{S})$$

(Equation 166)

$$Q = \mathrm{Im}(\overline{S})$$

(Equation 167)

$$S = \left|\overline{S}\right| = \sqrt{P^2 + Q^2}$$

(Equation 168)

$$Cos\varphi = \frac{P}{S}$$

(Equation 169)

Depending on the unit multiplier selected with *Power unit Mult*, the calculated power values are presented in units of kVA/kW/kVAr or in units of MVA/MW/MVAr.

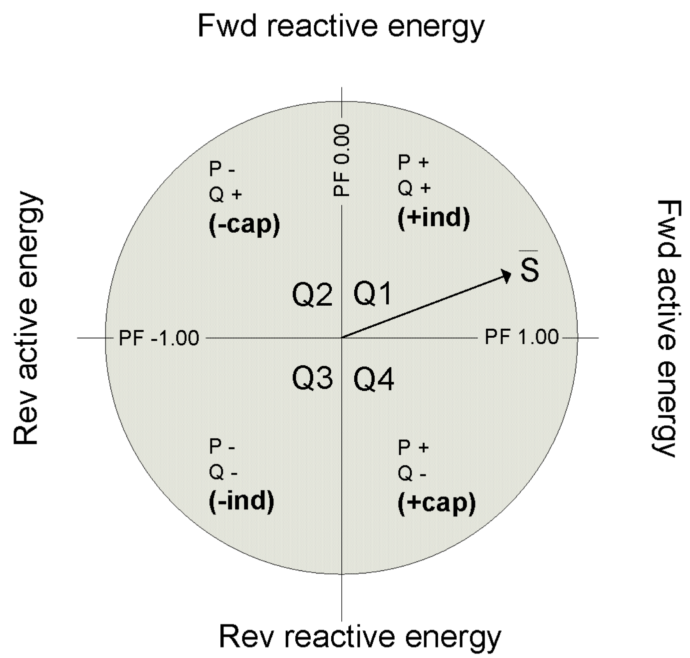


Figure 468: Complex power and power quadrants

Table 793: Power quadrants

Quadrant	Current	P	Q	PF	Power
Q1	Lagging	+	+	0…+1.00	+ind
Q2	Lagging	-	+	0…-1.00	-cap
Q3	Leading	-	-	0…-1.00	-ind
Q4	Leading	+	-	0…+1.00	+cap

The active power P direction can be selected between forward and reverse with *Active power Dir* and correspondingly the reactive power Q direction can be selected with *Reactive power Dir*. This affects also the accumulated energy directions.

The accumulated energy is calculated separately as forward active (`EA_FWD_ACM`), reverse active (`EA_RV_ACM`), forward reactive (`ER_FWD_ACM`) and reverse reactive (`ER_RV_ACM`). Depending on the value of the unit multiplier selected with *Energy unit Mult*, the calculated power values are presented in units of kWh/kVArh or in units of MWh/MVArh.

When the energy counter reaches its defined maximum value, the counter value is reset and restarted from zero. Changing the value of the *Energy unit Mult* setting resets the accumulated energy values to the initial values, that is, `EA_FWD_ACM` to *Forward Wh Initial*, `EA_RV_ACM` to *Reverse Wh Initial*, `ER_FWD_ACM` to *Forward VArh Initial* and `ER_RV_ACM` to *Reverse VArh Initial*. It is also possible to reset the accumulated energy to initial values through a parameter or with the `RSTACM` input.

Sequence components

The phase-sequence components are calculated using the phase currents and phase voltages. More information on calculating the phase-sequence components can be found in Calculated measurements in this manual.

8.1.3 Measurement function applications

The measurement functions are used for power system measurement, supervision and reporting to LHMI, a monitoring tool within PCM600, or to the station level, for example, with IEC 61850. The possibility to continuously monitor the measured values of active power, reactive power, currents, voltages, power factors and so on, is vital for efficient production, transmission, and distribution of electrical energy. It provides a fast and easy overview of the present status of the power system to the system operator. Additionally, it can be used during testing and commissioning of protection relays to verify the proper operation and connection of instrument transformers, that is, the current transformers (CTs) and voltage transformers (VTs). The proper operation of the protection relay analog measurement chain can be verified during normal service by a periodic comparison of the measured value from the protection relay to other independent meters.

When the zero signal is measured, the noise in the input signal can still produce small measurement values. The zero point clamping function can be used to ignore the noise in the input signal and, hence, prevent the noise to be shown in the user display. The zero clamping is done for the measured analog signals and angle values.

The demand values are used to neglect sudden changes in the measured analog signals when monitoring long time values for the input signal. The demand values are linear average values of the measured signal over a settable demand interval. The demand values are calculated for the measured analog three-phase current signals.

The limit supervision indicates, if the measured signal exceeds or goes below the set limits. Depending on the measured signal type, up to two high limits and up to two low limits can be set for the limit supervision.

The deadband supervision reports a new measurement value if the input signal has gone out of the deadband state. The deadband supervision can be used in value reporting between the measurement point and operation control. When the deadband supervision is properly configured, it helps in keeping the communication load in minimum and yet measurement values are reported frequently enough.

8.1.4 Three-phase current measurement IA, IB, IC

8.1.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase current measurement	CMMXU	3I	IA, IB, IC

8.1.4.2 Function block

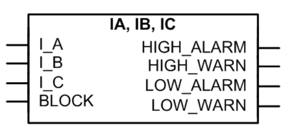


Figure 469: Function block

8.1.4.3 Signals

Table 794: IA,IB,IC Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 795: IA,IB,IC Output signals

Name	Type	Description
HIGH_ALARM	BOOLEAN	High alarm
HIGH_WARN	BOOLEAN	High warning
LOW_WARN	BOOLEAN	Low warning
LOW_ALARM	BOOLEAN	Low alarm

8.1.4.4 Settings

Table 796: IA,IB,IC Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required by limit supervision
A high high limit	0.00...40.00	xIn	1	1.40	High alarm current limit
A high limit	0.00...40.00	xIn	1	1.20	High warning current limit
A low limit	0.00...40.00	xIn	1	0.00	Low warning current limit
A low low limit	0.00...40.00	xIn	1	0.00	Low alarm current limit
A deadband	100...100000		1	2500	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 797: IA,IB,IC Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT			2=DFT	Selects used measurement mode

8.1.4.5 Monitored data

Table 798: IA,IB,IC Monitored data

Name	Type	Values (Range)	Unit	Description
IA-A	FLOAT32	0.00...40.00	xIn	Measured current amplitude phase A
IB-A	FLOAT32	0.00...40.00	xIn	Measured current amplitude phase B
IC-A	FLOAT32	0.00...40.00	xIn	Measured current amplitude phase C
Max demand IA	FLOAT32	0.00...40.00	xIn	Maximum demand for Phase A
Max demand IB	FLOAT32	0.00...40.00	xIn	Maximum demand for Phase B
Max demand IC	FLOAT32	0.00...40.00	xIn	Maximum demand for Phase C
Min demand IA	FLOAT32	0.00...40.00	xIn	Minimum demand for Phase A
Min demand IB	FLOAT32	0.00...40.00	xIn	Minimum demand for Phase B
Min demand IC	FLOAT32	0.00...40.00	xIn	Minimum demand for Phase C
Time max demand IA	Timestamp			Time of maximum demand phase A
Time max demand IB	Timestamp			Time of maximum demand phase B
Time max demand IC	Timestamp			Time of maximum demand phase C
Time min demand IA	Timestamp			Time of minimum demand phase A
Time min demand IB	Timestamp			Time of minimum demand phase B
Time min demand IC	Timestamp			Time of minimum demand phase C
BLOCK	BOOLEAN	0=False 1=True		Block signal for all binary outputs
HIGH_ALARM	BOOLEAN	0=False 1=True		High alarm
HIGH_WARN	BOOLEAN	0=False 1=True		High warning
LOW_WARN	BOOLEAN	0=False 1=True		Low warning
LOW_ALARM	BOOLEAN	0=False 1=True		Low alarm
I_INST_A	FLOAT32	0.00...40.00	xIn	IA Amplitude, magnitude of instantaneous value
I_ANGL_A	FLOAT32	-180.00...180.00	deg	IA current angle

Table continues on next page

Name	Type	Values (Range)	Unit	Description
I_DB_A	FLOAT32	0.00...40.00	xIn	IA Amplitude, magnitude of reported value
I_DMD_A	FLOAT32	0.00...40.00	xIn	Demand value of IA current
I_RANGE_A	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		IA Amplitude range
I_INST_B	FLOAT32	0.00...40.00	xIn	IB Amplitude, magnitude of instantaneous value
I_ANGL_B	FLOAT32	-180.00...180.00	deg	IB current angle
I_DB_B	FLOAT32	0.00...40.00	xIn	IB Amplitude, magnitude of reported value
I_DMD_B	FLOAT32	0.00...40.00	xIn	Demand value of IB current
I_RANGE_B	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		IB Amplitude range
I_INST_C	FLOAT32	0.00...40.00	xIn	IC Amplitude, magnitude of instantaneous value
I_ANGL_C	FLOAT32	-180.00...180.00	deg	IC current angle
I_DB_C	FLOAT32	0.00...40.00	xIn	IC Amplitude, magnitude of reported value
I_DMD_C	FLOAT32	0.00...40.00	xIn	Demand value of IC current
I_RANGE_C	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		IC Amplitude range

8.1.4.6 Technical data

Table 799: IA, IB, IC Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f_n ±2 Hz
	±0.5% or ±0.002 × I_n (at currents in the range of 0.01...4.00 × I_n)
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,… RMS: No suppression

8.1.4.7 Technical revision history

Table 800: IA, IB, IC Technical revision history

Technical revision	Change
B	Menu changes
C	Phase current angle values added to Monitored data view. Minimum demand value and time added to recorded data. Logarithmic demand calculation mode added and demand interval setting moved under Measurement menu as general setting to all demand calculations.
D	Internal improvement.
E	Internal improvement.

8.1.5 Three-phase voltage measurement VA, VB, VC

8.1.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase voltage measurement	VMMXU	3U	VA, VB, VC

8.1.5.2 Function block

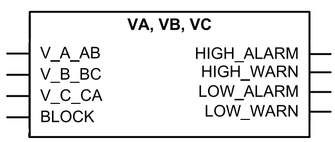


Figure 470: Function block

8.1.5.3 Signals

Table 801: VA,VB,VC Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase A voltage
V_B_BC	SIGNAL	0	Phase B voltage
V_C_CA	SIGNAL	0	Phase C voltage
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 802: VA,VB,VC Output signals

Name	Type	Description
HIGH_ALARM	BOOLEAN	High alarm
HIGH_WARN	BOOLEAN	High warning
LOW_WARN	BOOLEAN	Low warning
LOW_ALARM	BOOLEAN	Low alarm

8.1.5.4 Settings

Table 803: VA,VB,VC Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Num of phases	1=1 out of 3 2=2 out of 3 3=3 out of 3			1=1 out of 3	Number of phases required by limit supervision
V high high limit	0.00...4.00	xUn	1	1.40	High alarm voltage limit
V high limit	0.00...4.00	xUn	1	1.20	High warning voltage limit
V low limit	0.00...4.00	xUn	1	0.00	Low warning voltage limit
V low low limit	0.00...4.00	xUn	1	0.00	Low alarm voltage limit
V deadband	100...100000		1	10000	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 804: VA,VB,VC Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT			2=DFT	Selects used measurement mode

8.1.5.5 Monitored data

Table 805: VA,VB,VC Monitored data

Name	Type	Values (Range)	Unit	Description
VAB-kV	FLOAT32	0.00...4.00	xUn	Measured phase to phase voltage amplitude phase AB
VBC-kV	FLOAT32	0.00...4.00	xUn	Measured phase to phase voltage amplitude phase BC
VCA-kV	FLOAT32	0.00...4.00	xUn	Measured phase to phase voltage amplitude phase CA
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
BLOCK	BOOLEAN	0=False 1=True		Block signal for all binary outputs
HIGH_ALARM	BOOLEAN	0=False 1=True		High alarm
HIGH_WARN	BOOLEAN	0=False 1=True		High warning
LOW_WARN	BOOLEAN	0=False 1=True		Low warning
LOW_ALARM	BOOLEAN	0=False 1=True		Low alarm
V_INST_AB	FLOAT32	0.00...4.00	xUn	VAB Amplitude, magnitude of instantaneous value
V_ANGL_AB	FLOAT32	-180.00...180.00	deg	VAB angle
V_DB_AB	FLOAT32	0.00...4.00	xUn	VAB Amplitude, magnitude of reported value
V_DMD_AB	FLOAT32	0.00...4.00	xUn	Demand value of VAB voltage
V_RANGE_AB	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		VAB Amplitude range
V_INST_BC	FLOAT32	0.00...4.00	xUn	VBC Amplitude, magnitude of instantaneous value
V_ANGL_BC	FLOAT32	-180.00...180.00	deg	VBC angle
V_DB_BC	FLOAT32	0.00...4.00	xUn	VBC Amplitude, magnitude of reported value
V_DMD_BC	FLOAT32	0.00...4.00	xUn	Demand value of VBC voltage
V_RANGE_BC	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		VBC Amplitude range
V_INST_CA	FLOAT32	0.00...4.00	xUn	VCA Amplitude, magnitude of instantaneous value
V_ANGL_CA	FLOAT32	-180.00...180.00	deg	VCA angle
V_DB_CA	FLOAT32	0.00...4.00	xUn	VCA Amplitude, magnitude of reported value
V_DMD_CA	FLOAT32	0.00...4.00	xUn	Demand value of VCA voltage
V_RANGE_CA	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		VCA Amplitude range
V_INST_A	FLOAT32	0.00...5.00	xUn	VA Amplitude, magnitude of instantaneous value
V_ANGL_A	FLOAT32	-180.00...180.00	deg	VA angle

Table continues on next page

Name	Type	Values (Range)	Unit	Description
V_DMD_A	FLOAT32	0.00...5.00	xUn	Demand value of VA voltage
V_INST_B	FLOAT32	0.00...5.00	xUn	VB Amplitude, magnitude of instantaneous value
V_ANGL_B	FLOAT32	-180.00...180.00	deg	VB angle
V_DMD_B	FLOAT32	0.00...5.00	xUn	Demand value of VB voltage
V_INST_C	FLOAT32	0.00...5.00	xUn	VC Amplitude, magnitude of instantaneous value
V_ANGL_C	FLOAT32	-180.00...180.00	deg	VC angle
V_DMD_C	FLOAT32	0.00...5.00	xUn	Demand value of VC voltage

8.1.5.6 Technical data

Table 806: VA, VB, VC Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the voltage measured: f_n ±2 Hz At voltages in range 0.01…1.15 × V_n
	±0.5% or ±0.002 × V_n
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,… RMS: No suppression

8.1.5.7 Technical revision history

Table 807: VA, VB, VC Technical revision history

Technical revision	Change
B	Phase and phase-to-phase voltage angle values and demand values added to Monitored data view.
C	Internal improvement.
D	Internal improvement.

8.1.6 Residual current measurement IG

8.1.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Residual current measurement	RESCMMXU	Io	IG

8.1.6.2 Function block

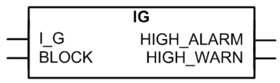


Figure 471: Function block

8.1.6.3 Signals

Table 808: IG Input signals

Name	Type	Default	Description
IG	SIGNAL	0	Ground current
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 809: IG Output signals

Name	Type	Description
HIGH_ALARM	BOOLEAN	High alarm
HIGH_WARN	BOOLEAN	High warning

8.1.6.4 Settings

Table 810: IG Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
A Hi high limit res	0.00...40.00	xIn	1	0.20	High alarm current limit
A high limit res	0.00...40.00	xIn	1	0.05	High warning current limit
A deadband res	100...100000		1	2500	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 811: IG Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT			2=DFT	Selects used measurement mode

8.1.6.5 Monitored data

Table 812: IG Monitored data

Name	Type	Values (Range)	Unit	Description
IG-A	FLOAT32	0.00...40.00	xIn	Measured residual current
BLOCK	BOOLEAN	0=False 1=True		Block signal for all binary outputs
HIGH_ALARM	BOOLEAN	0=False 1=True		High alarm
HIGH_WARN	BOOLEAN	0=False 1=True		High warning
IG_INST	FLOAT32	0.00...40.00	xIn	Ground current Amplitude, magnitude of instantaneous value
IG_ANGL	FLOAT32	-180.00...180.00	deg	Residual current angle
IG_DB	FLOAT32	0.00...40.00	xIn	Ground current Amplitude, magnitude of reported value
IG_DMD	FLOAT32	0.00...40.00	xIn	Demand value of residual current
IG_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Ground current Amplitude range
Max demand IG	FLOAT32	0.00...40.00	xIn	Maximum demand for residual current
Min demand IG	FLOAT32	0.00...40.00	xIn	Minimum demand for residual current
Time max demand IG	Timestamp			Time of maximum demand residual current
Time min demand IG	Timestamp			Time of minimum demand residual current

8.1.6.6 Technical data

Table 813: IG Technical data

Characteristic	Value
Operation accuracy	At the frequency $f = f_n$
	±0.5% or ±0.002 × I_n (at currents in the range of 0.01...4.00 × I_n)
Suppression of harmonics	DFT: -50 dB at $f = n \times f_n$, where n = 2, 3, 4, 5,… RMS: No suppression

8.1.6.7 Technical revision history

Table 814: IG Technical revision history

Technical revision	Change
B	-
C	Residual current angle and demand value added to Monitored data view. Recorded data added for minimum and maximum values with timestamps.
D	Monitored data Min demand IG maximum value range (RESCMSTA2.MinAmps.maxVal.f) is corrected to 40.00.
E	Internal improvement

8.1.7 Residual voltage measurement VG

8.1.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Residual voltage measurement	RESVMMXU	Uo	VG

8.1.7.2 Function block

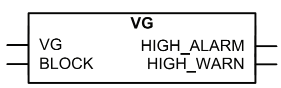


Figure 472: Function block

8.1.7.3 Signals

Table 815: VG Input signals

Name	Type	Default	Description
VG	SIGNAL	0	Ground voltage
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 816: VG Output signals

Name	Type	Description
HIGH_ALARM	BOOLEAN	High alarm
HIGH_WARN	BOOLEAN	High warning

8.1.7.4 Settings

Table 817: VG Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
V Hi high limit res	0.00...4.00	xUn	1	0.20	High alarm voltage limit
V high limit res	0.00...4.00	xUn	1	0.05	High warning voltage limit
V deadband res	100...100000		1	10000	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 818: VG Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Measurement mode	1=RMS 2=DFT			2=DFT	Selects used measurement mode

8.1.7.5 Monitored data

Table 819: VG Monitored data

Name	Type	Values (Range)	Unit	Description
VG-kV	FLOAT32	0.00...4.00	xUn	Measured residual voltage
BLOCK	BOOLEAN	0=False 1=True		Block signal for all binary outputs
HIGH_ALARM	BOOLEAN	0=False 1=True		High alarm
HIGH_WARN	BOOLEAN	0=False 1=True		High warning
VG_INST	FLOAT32	0.00...4.00	xUn	Ground voltage Amplitude, magnitude of instantaneous value
VG_ANGL	FLOAT32	-180.00...180.00	deg	Residual voltage angle
VG_DB	FLOAT32	0.00...4.00	xUn	Ground voltage Amplitude, magnitude of reported value
VG_DMD	FLOAT32	0.00...4.00	xUn	Demand value of residual voltage
VG_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Ground voltage Amplitude range

8.1.7.6 Technical data

Table 820: VG Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured voltage: f/f_n = ±2 Hz
	±0.5% or ±0.002 × V_n
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,… RMS: No suppression

8.1.7.7 Technical revision history

Table 821: VG Technical revision history

Technical revision	Change
B	-
C	Residual voltage angle and demand value added to Monitored data view
D	Internal improvement
E	Internal improvement

8.1.8 Frequency measurement f

8.1.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Frequency measurement	FMMXU	f	f

8.1.8.2 Function block

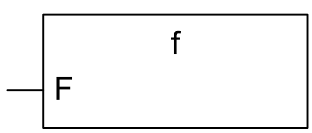


Figure 473: Function block

8.1.8.3 Functionality

The frequency measurement range is 35...75 Hz. The measured frequencies outside the measurement range are considered to be out of range and the minimum and maximum values are then shown in parentheses.

When *Frequency adaptivity* is enabled, the measurement range is extended to 10...75 Hz in a 50 Hz network and 12...90 Hz in a 60 Hz network. The measured frequencies outside 35...75 Hz are shown in parentheses.

When the frequencies cannot be measured, for example, due to too low voltage amplitude, the default value for frequency measurement can be selected with the *Def frequency Sel* setting parameter. In the “Nominal” mode the frequency is set to 50 Hz (or 60 Hz) and in “Zero” mode the frequency is set to zero and shown in parentheses.

8.1.8.4 Signals

Table 822: f Input signals

Name	Type	Default	Description
F	SIGNAL	-	Measured system frequency

8.1.8.5 Settings

Table 823: f Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
F Hi high limit	35.00...75.00	Hz	1	60.00	High alarm frequency limit
F high limit	35.00...75.00	Hz	1	55.00	High warning frequency limit
F low limit	35.00...75.00	Hz	1	45.00	Low warning frequency limit
F Lo low limit	35.00...75.00	Hz	1	40.00	Low alarm frequency limit
F deadband	100...100000		1	1000	Deadband configuration value for integral calculation. (percentage of difference between min and max as 0,001 % s)

Table 824: f Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Def frequency Sel	1=Nominal 2=Zero			1=Nominal	Default frequency selection

8.1.8.6 Monitored data

Table 825: f Monitored data

Name	Type	Values (Range)	Unit	Description
f-Hz	FLOAT32	35.00...75.00	Hz	Measured frequency
F_INST	FLOAT32	35.00...75.00	Hz	Frequency, instantaneous value
F_DB	FLOAT32	35.00...75.00	Hz	Frequency
F_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Frequency range

8.1.8.7 Technical data

Table 826: f Technical data

Characteristic	Value
Operation accuracy	±5 mHz (in measurement range 35...75 Hz)

8.1.8.8 Technical revision history

Table 827: f Technical revision history

Technical revision	Change
B	Added new setting *Def frequency Sel*. Frequency measurement range lowered from 35 Hz to 10 Hz.

8.1.9 Sequence current measurement I1, I2, I0

8.1.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Sequence current measurement	CSMSQI	I1, I2, I0	I1, I2, I0

8.1.9.2 Function block

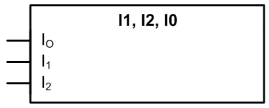


Figure 474: Function block

8.1.9.3 Signals

Table 828: I1, I2, I0 Input signals

Name	Type	Default	Description
I_0	SIGNAL	0	Zero sequence current
I_1	SIGNAL	0	Positive sequence current
I_2	SIGNAL	0	Negative sequence current

8.1.9.4 Settings

Table 829: I1,I2,I0 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Ps Seq A Hi high Lim	0.00...40.00	xIn	1	1.40	High alarm current limit for positive sequence current
Ps Seq A high limit	0.00...40.00	xIn	1	1.20	High warning current limit for positive sequence current
Ps Seq A low limit	0.00...40.00	xIn	1	0.00	Low warning current limit for positive sequence current
Ps Seq A low low Lim	0.00...40.00	xIn	1	0.00	Low alarm current limit for positive sequence current
Ps Seq A deadband	100...100000		1	2500	Deadband configuration value for positive sequence current for integral calculation. (percentage of difference between min and max as 0,001 % s)
Ng Seq A Hi high Lim	0.00...40.00	xIn	1	0.20	High alarm current limit for negative sequence current
Ng Seq A High limit	0.00...40.00	xIn	1	0.05	High warning current limit for negative sequence current
Ng Seq A low limit	0.00...40.00	xIn	1	0.00	Low warning current limit for negative sequence current

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Ng Seq A low low Lim	0.00...40.00	xIn	1	0.00	Low alarm current limit for negative sequence current
Ng Seq A deadband	100...100000		1	2500	Deadband configuration value for negative sequence current for integral calculation. (percentage of difference between min and max as 0,001 % s)
Zro A Hi high Lim	0.00...40.00	xIn	1	0.20	High alarm current limit for zero sequence current
Zro A High limit	0.00...40.00	xIn	1	0.05	High warning current limit for zero sequence current
Zro A low limit	0.00...40.00	xIn	1	0.00	Low warning current limit for zero sequence current
Zro A low low Lim	0.00...40.00	xIn	1	0.00	Low alarm current limit for zero sequence current
Zro A deadband	100...100000		1	2500	Deadband configuration value for zero sequence current for integral calculation. (percentage of difference between min and max as 0,001 % s)

8.1.9.5 Monitored data

Table 830: I1,I2,I0 Monitored data

Name	Type	Values (Range)	Unit	Description
I2-A	FLOAT32	0.00...40.00	xIn	Measured negative sequence current
I1-A	FLOAT32	0.00...40.00	xIn	Measured positive sequence current
I0-A	FLOAT32	0.00...40.00	xIn	Measured zero sequence current
I2_INST	FLOAT32	0.00...40.00	xIn	Negative sequence current amplitude, instantaneous value
I2_ANGL	FLOAT32	-180.00...180.00	deg	Negative sequence current angle
I2_DB	FLOAT32	0.00...40.00	xIn	Negative sequence current amplitude, reported value
I2_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Negative sequence current amplitude range
I1_INST	FLOAT32	0.00...40.00	xIn	Positive sequence current amplitude, instantaneous value
I1_ANGL	FLOAT32	-180.00...180.00	deg	Positive sequence current angle

Table continues on next page

Name	Type	Values (Range)	Unit	Description
I1_DB	FLOAT32	0.00...40.00	xIn	Positive sequence current amplitude, reported value
I1_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Positive sequence current amplitude range
I0_INST	FLOAT32	0.00...40.00	xIn	Zero sequence current amplitude, instantaneous value
I0_ANGL	FLOAT32	-180.00...180.00	deg	Zero sequence current angle
I0_DB	FLOAT32	0.00...40.00	xIn	Zero sequence current amplitude, reported value
I0_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Zero sequence current amplitude range

8.1.9.6 Technical data

Table 831: I1, I2, I0 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the measured current: f/f_n = ±2 Hz
	±1.0% or ±0.002 × I_n at currents in the range of 0.01...4.00 × I_n
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

8.1.9.7 Technical revision history

Table 832: I1, I2, I0 Technical revision history

Technical revision	Change
A	-
B	Sequence current angle values added to the Monitored data view.
C	Internal improvement.

8.1.10 Sequence voltage measurement V1, V2, V0

8.1.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Sequence voltage measurement	VSMSQI	U1, U2, U0	V1, V2, V0

8.1.10.2 Function block

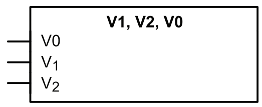


Figure 475: Function block

8.1.10.3 Signals

Table 833: V1, V2, V0 Input signals

Name	Type	Default	Description
V0	SIGNAL	0	Zero sequence voltage
V_1	SIGNAL	0	Positive phase sequence voltage
V_2	SIGNAL	0	Negative phase sequence voltage

8.1.10.4 Settings

Table 834: V1,V2,V0 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Ps Seq V Hi high Lim	0.00...4.00	xUn	1	1.40	High alarm voltage limit for positive sequence voltage
Ps Seq V high limit	0.00...4.00	xUn	1	1.20	High warning voltage limit for positive sequence voltage
Ps Seq V low limit	0.00...4.00	xUn	1	0.00	Low warning voltage limit for positive sequence voltage
Ps Seq V low low Lim	0.00...4.00	xUn	1	0.00	Low alarm voltage limit for positive sequence voltage
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Ps Seq V deadband	100...100000		1	10000	Deadband configuration value for positive sequence voltage for integral calculation. (percentage of difference between min and max as 0,001 % s)
Ng Seq V Hi high Lim	0.00...4.00	xUn	1	0.20	High alarm voltage limit for negative sequence voltage
Ng Seq V High limit	0.00...4.00	xUn	1	0.05	High warning voltage limit for negative sequence voltage
Ng Seq V low limit	0.00...4.00	xUn	1	0.00	Low warning voltage limit for negative sequence voltage
Ng Seq V low low Lim	0.00...4.00	xUn	1	0.00	Low alarm voltage limit for negative sequence voltage
Ng Seq V deadband	100...100000		1	10000	Deadband configuration value for negative sequence voltage for integral calculation. (percentage of difference between min and max as 0,001 % s)
Zro V Hi high Lim	0.00...4.00	xUn	1	0.20	High alarm voltage limit for zero sequence voltage
Zro V High limit	0.00...4.00	xUn	1	0.05	High warning voltage limit for zero sequence voltage
Zro V low limit	0.00...4.00	xUn	1	0.00	Low warning voltage limit for zero sequence voltage
Zro V low low Lim	0.00...4.00	xUn	1	0.00	Low alarm voltage limit for zero sequence voltage
Zro V deadband	100...100000		1	10000	Deadband configuration value for zero sequence voltage for integral calculation. (percentage of difference between min and max as 0,001 % s)

8.1.10.5 Monitored data

Table 835: V1,V2,V0 Monitored data

Name	Type	Values (Range)	Unit	Description
V2-kV	FLOAT32	0.00...4.00	xUn	Measured negative sequence voltage
V1-kV	FLOAT32	0.00...4.00	xUn	Measured positive sequence voltage
V0-kV	FLOAT32	0.00...4.00	xUn	Measured zero sequence voltage
V2_INST	FLOAT32	0.00...4.00	xUn	Negative sequence voltage amplitude, instantaneous value
V2_ANGL	FLOAT32	-180.00...180.00	deg	Negative sequence voltage angle
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
V2_DB	FLOAT32	0.00...4.00	xUn	Negative sequence voltage amplitude, reported value
V2_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Negative sequence voltage amplitude range
V1_INST	FLOAT32	0.00...4.00	xUn	Positive sequence voltage amplitude, instantaneous value
V1_ANGL	FLOAT32	-180.00...180.00	deg	Positive sequence voltage angle
V1_DB	FLOAT32	0.00...4.00	xUn	Positive sequence voltage amplitude, reported value
V1_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Positive sequence voltage amplitude range
V0_INST	FLOAT32	0.00...4.00	xUn	Zero sequence voltage amplitude, instantaneous value
V0_ANGL	FLOAT32	-180.00...180.00	deg	Zero sequence voltage angle
V0_DB	FLOAT32	0.00...4.00	xUn	Zero sequence voltage amplitude, reported value
V0_RANGE	Enum	0=normal 1=high 2=low 3=high-high 4=low-low		Zero sequence voltage amplitude range

8.1.10.6 Technical data

Table 836: V1, V2, V0 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the voltage measured: f_n ±2 Hz At voltages in range 0.01…1.15 × V_n
	±1.0% or ±0.002 × V_n
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

8.1.11 Three-phase power and energy measurement P, E

8.1.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Three-phase power and energy measurement	PEMMXU	P, E	P, E

8.1.11.2 Function block

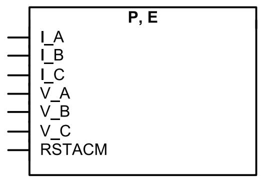


Figure 476: Function block

8.1.11.3 Signals

Table 837: P,E Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
V_A	SIGNAL	0	Phase A voltage
V_B	SIGNAL	0	Phase B voltage
V_C	SIGNAL	0	Phase C voltage
RSTACM	BOOLEAN	0=False	Reset of accumulated energy reading

8.1.11.4 Settings

Table 838: P,E Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Power unit Mult	3=Kilo 6=Mega			3=Kilo	Unit multiplier for presentation of the power related values
Energy unit Mult	3=Kilo 6=Mega			3=Kilo	Unit multiplier for presentation of the energy related values
Active power Dir	1=Forward 2=Reverse			1=Forward	Direction of active power flow: Forward, Reverse
Reactive power Dir	1=Forward 2=Reverse			1=Forward	Direction of reactive power flow: Forward, Reverse

Table 839: P,E Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Forward Wh Initial	0...999999999		1	0	Preset Initial value for forward active energy
Reverse Wh Initial	0...999999999		1	0	Preset Initial value for reverse active energy
Forward VArh Initial	0...999999999		1	0	Preset Initial value for forward reactive energy
Reverse VArh Initial	0...999999999		1	0	Preset Initial value for reverse reactive energy

8.1.11.5 Monitored data

Table 840: P,E Monitored data

Name	Type	Values (Range)	Unit	Description
S-kVA	FLOAT32	-999999.9...999999.9	kVA	Total Apparent Power
P-kW	FLOAT32	-999999.9...999999.9	kW	Total Active Power
Q-kVAr	FLOAT32	-999999.9...999999.9	kVAr	Total Reactive Power
PF	FLOAT32	-1.00...1.00		Average Power factor
RSTACM	BOOLEAN	0=False 1=True		Reset of accumulated energy reading
S-kVA	FLOAT32	-999999.9...999999.9	kVA	Total Apparent Power
S_DB	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of reported value
S_DMD	FLOAT32	-999999.9...999999.9	kVA	Demand value of apparent power
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
P-kW	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of instantaneous value
P_DB	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of reported value
P_DMD	FLOAT32	-999999.9...999999.9	kW	Demand value of active power
Q-kVAr	FLOAT32	-999999.9...999999.9	kVAr	Total Reactive Power
Q_DB	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of reported value
Q_DMD	FLOAT32	-999999.9...999999.9	kVAr	Demand value of reactive power
PF	FLOAT32	-1.00...1.00		Average Power factor
PF_DB	FLOAT32	-1.00...1.00		Power factor, magnitude of reported value
PF_DMD	FLOAT32	-1.00...1.00		Demand value of power factor
EA_RV_ACM	INT64	0...999999999	kWh	Accumulated reverse active energy value
ER_RV_ACM	INT64	0...999999999	kVArh	Accumulated reverse reactive energy value
EA_FWD_ACM	INT64	0...999999999	kWh	Accumulated forward active energy value
ER_FWD_ACM	INT64	0...999999999	kVArh	Accumulated forward reactive energy value
Max demand S	FLOAT32	-999999.9...999999.9	kVA	Maximum demand value of apparent power
Min demand S	FLOAT32	-999999.9...999999.9	kVA	Minimum demand value of apparent power
Max demand P	FLOAT32	-999999.9...999999.9	kW	Maximum demand value of active power
Min demand P	FLOAT32	-999999.9...999999.9	kW	Minimum demand value of active power
Max demand Q	FLOAT32	-999999.9...999999.9	kVAr	Maximum demand value of reactive power
Min demand Q	FLOAT32	-999999.9...999999.9	kVAr	Minimum demand value of reactive power
Time max dmd S	Timestamp			Time of maximum demand
Time min dmd S	Timestamp			Time of minimum demand
Time max dmd P	Timestamp			Time of maximum demand
Time min dmd P	Timestamp			Time of minimum demand
Time max dmd Q	Timestamp			Time of maximum demand
Time min dmd Q	Timestamp			Time of minimum demand

8.1.11.6 Technical data

Table 841: P, E Technical data

Characteristic	Value
Operation accuracy	At all three currents in range 0.10…1.20 × I_n At all three voltages in range 0.50…1.15 × V_n At the frequency f_n ±1 Hz
	±1.5% for apparent power S ±1.5% for active power P and active energy[1)] ±1.5% for reactive power Q and reactive energy[2)] ±0.015 for power factor
Suppression of harmonics	DFT: -50 dB at f = n × f_n, where n = 2, 3, 4, 5,…

1) |PF| >0.5 which equals |cosφ| >0.5
2) |PF| <0.86 which equals |sinφ| >0.5

8.1.11.7 Technical revision history

Table 842: P, E Technical revision history

Technical revision	Change
B	Demand values added to Monitored data. Recorded data added to store minimum and maximum demand values with timestamps.
C	Internal improvement.
D	Internal improvement.

8.1.12 Single-phase power and energy measurement SP, SE

8.1.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single-phase power and energy measurement	SPEMMXU	SP, SE	SP, SE

8.1.12.2 Function block

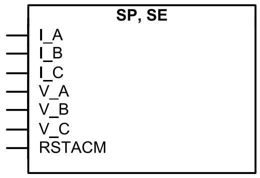


Figure 477: Function block

8.1.12.3 Signals

Table 843: SP,SE Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
V_A	SIGNAL	0	Phase A voltage
V_B	SIGNAL	0	Phase B voltage
V_C	SIGNAL	0	Phase C voltage
RSTACM	BOOLEAN	0=False	Reset of accumulated energy reading

8.1.12.4 Settings

Table 844: SP,SE Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Power unit Mult	3=k 6=M			3=k	Unit multiplier for presentation of the power related values
Energy unit Mult	3=k 6=M			3=k	Unit multiplier for presentation of the energy related values
Active power Dir	1=Forward 2=Reverse			1=Forward	Direction of active power flow: forward, reverse
Reactive power Dir	1=Forward 2=Reverse			1=Forward	Direction of reactive power flow: forward, reverse

Table 845: SP,SE Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Direction of reactive power flow: forward, reverse	0...999999999		1	0	Preset Initial value for forward active energy
Reverse Wh Initial	0...999999999		1	0	Preset Initial value for reverse active energy
Forward VArh Initial	0...999999999		1	0	Preset Initial value for forward reactive energy
Reverse VArh Initial	0...999999999		1	0	Preset Initial value for reverse reactive energy

8.1.12.5 Monitored data

Table 846: SP,SE Monitored data

Name	Type	Values (Range)	Unit	Description
SA-kVA	FLOAT32	-999999.9...999999.9	kVA	Apparent Power, Phase A
SB-kVA	FLOAT32	-999999.9...999999.9	kVA	Apparent Power, Phase B
SC-kVA	FLOAT32	-999999.9...999999.9	kVA	Apparent Power, Phase C
PA-kW	FLOAT32	-999999.9...999999.9	kW	Active Power, Phase A
PB-kW	FLOAT32	-999999.9...999999.9	kW	Active Power, Phase B
PC-kW	FLOAT32	-999999.9...999999.9	kW	Active Power, Phase C
QA-kVAr	FLOAT32	-999999.9...999999.9	kVAr	Reactive Power, Phase A
QB-kVAr	FLOAT32	-999999.9...999999.9	kVAr	Reactive Power, Phase B
QC-kVAr	FLOAT32	-999999.9...999999.9	kVAr	Reactive Power, Phase C
PFA	FLOAT32	-1.00...1.00		Average Power factor, Phase A
PFB	FLOAT32	-1.00...1.00		Average Power factor, Phase B
PFC	FLOAT32	-1.00...1.00		Average Power factor, Phase C
Max demand SL1	FLOAT32	-999999.9...999999.9	kVA	Maximum demand for phase A
Max demand SL2	FLOAT32	-999999.9...999999.9	kVA	Maximum demand for phase B
Max demand SL3	FLOAT32	-999999.9...999999.9	kVA	Maximum demand for phase C

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Min demand SL1	FLOAT32	-999999.9...999999.9	kVA	Minimum demand for phase A
Min demand SL2	FLOAT32	-999999.9...999999.9	kVA	Minimum demand for phase B
Min demand SL3	FLOAT32	-999999.9...999999.9	kVA	Minimum demand for phase C
Max demand PL1	FLOAT32	-999999.9...999999.9	kW	Maximum demand for phase A
Max demand PL2	FLOAT32	-999999.9...999999.9	kW	Maximum demand for phase B
Max demand PL3	FLOAT32	-999999.9...999999.9	kW	Maximum demand for phase C
Min demand PL1	FLOAT32	-999999.9...999999.9	kW	Minimum demand for phase A
Min demand PL2	FLOAT32	-999999.9...999999.9	kW	Minimum demand for phase B
Min demand PL3	FLOAT32	-999999.9...999999.9	kW	Minimum demand for phase C
Max demand QL1	FLOAT32	-999999.9...999999.9	kVAr	Maximum demand for phase A
Max demand QL2	FLOAT32	-999999.9...999999.9	kVAr	Maximum demand for phase B
Max demand QL3	FLOAT32	-999999.9...999999.9	kVAr	Maximum demand for phase C
Min demand QL1	FLOAT32	-999999.9...999999.9	kVAr	Minimum demand for phase A
Min demand QL2	FLOAT32	-999999.9...999999.9	kVAr	Minimum demand for phase B
Min demand QL3	FLOAT32	-999999.9...999999.9	kVAr	Minimum demand for phase B
Time max dmd SL1	Timestamp			Time of maximum demand phase A
Time max dmd SL2	Timestamp			Time of maximum demand phase B
Time max dmd SL3	Timestamp			Time of maximum demand phase C
Time max dmd PL1	Timestamp			Time of maximum demand phase A
Time max dmd PL2	Timestamp			Time of maximum demand phase B
Time max dmd PL3	Timestamp			Time of maximum demand phase C
Time max dmd QL1	Timestamp			Time of maximum demand phase A

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Time max dmd QL2	Timestamp			Time of maximum demand phase B
Time max dmd QL3	Timestamp			Time of maximum demand phase C
Time min dmd SL1	Timestamp			Time of minimum demand phase A
Time min dmd SL2	Timestamp			Time of minimum demand phase B
Time min dmd SL3	Timestamp			Time of minimum demand phase C
Time min dmd PL1	Timestamp			Time of minimum demand phase A
Time min dmd PL2	Timestamp			Time of minimum demand phase B
Time min dmd PL3	Timestamp			Time of minimum demand phase C
Time min dmd QL1	Timestamp			Time of minimum demand phase A
Time min dmd QL2	Timestamp			Time of minimum demand phase B
Time min dmd QL3	Timestamp			Time of minimum demand phase C
RSTACM	BOOLEAN	0=False 1=True		Reset of accumulated energy reading
S_INST_A	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of instantaneous value, Phase A
S_INST_B	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of instantaneous value, Phase B
S_INST_C	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of instantaneous value, Phase C
S_DB_A	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of reported value, Phase A
S_DB_B	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of reported value, Phase B
S_DB_C	FLOAT32	-999999.9...999999.9	kVA	Apparent power, magnitude of reported value, Phase C
S_DMD_A	FLOAT32	-999999.9...999999.9	kVA	Demand value of apparent power, phase A
S_DMD_B	FLOAT32	-999999.9...999999.9	kVA	Demand value of apparent power, phase B
S_DMD_C	FLOAT32	-999999.9...999999.9	kVA	Demand value of apparent power, phase C
P_INST_A	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of instantaneous value, Phase A

Table continues on next page

Name	Type	Values (Range)	Unit	Description
P_INST_B	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of instantaneous value, Phase B
P_INST_C	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of instantaneous value, Phase C
P_DB_A	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of reported value, Phase A
P_DB_B	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of reported value, Phase B
P_DB_C	FLOAT32	-999999.9...999999.9	kW	Active power, magnitude of reported value, Phase C
P_DMD_A	FLOAT32	-999999.9...999999.9	kW	Demand value of active power, phase A
P_DMD_B	FLOAT32	-999999.9...999999.9	kW	Demand value of active power, phase B
P_DMD_C	FLOAT32	-999999.9...999999.9	kW	Demand value of active power, phase C
Q_INST_A	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of instantaneous value, Phase A
Q_INST_B	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of instantaneous value, Phase B
Q_INST_C	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of instantaneous value, Phase C
Q_DB_A	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of reported value, Phase A
Q_DB_B	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of reported value, Phase B
Q_DB_C	FLOAT32	-999999.9...999999.9	kVAr	Reactive power, magnitude of reported value, Phase C
Q_DMD_A	FLOAT32	-999999.9...999999.9	kVAr	Demand value of reactive power, phase A
Q_DMD_B	FLOAT32	-999999.9...999999.9	kVAr	Demand value of reactive power, phase B
Q_DMD_C	FLOAT32	-999999.9...999999.9	kVAr	Demand value of reactive power, phase C
PF_INST_A	FLOAT32	-1.00...1.00		Power factor, magnitude of instantaneous value, Phase A
PF_INST_B	FLOAT32	-1.00...1.00		Power factor, magnitude of instantaneous value, Phase B
PF_INST_C	FLOAT32	-1.00...1.00		Power factor, magnitude of instantaneous value, Phase C
PF_DB_A	FLOAT32	-1.00...1.00		Power factor, magnitude of reported value, Phase A
PF_DB_B	FLOAT32	-1.00...1.00		Power factor, magnitude of reported value, Phase B

Table continues on next page

Name	Type	Values (Range)	Unit	Description
PF_DB_C	FLOAT32	-1.00...1.00		Power factor, magnitude of reported value, Phase C
PF_DMD_A	FLOAT32	-1.00...1.00		Demand value of power factor, phase A
PF_DMD_B	FLOAT32	-1.00...1.00		Demand value of power factor, phase B
PF_DMD_C	FLOAT32	-1.00...1.00		Demand value of power factor, phase C
EA_RV_ACM_A	INT64	0...999999999	kWh	Accumulated reverse active energy value, Phase A
EA_RV_ACM_B	INT64	0...999999999	kWh	Accumulated reverse active energy value, Phase B
EA_RV_ACM_C	INT64	0...999999999	kWh	Accumulated reverse active energy value, Phase C
ER_RV_ACM_A	INT64	0...999999999	kVArh	Accumulated reverse reactive energy value, Phase A
ER_RV_ACM_B	INT64	0...999999999	kVArh	Accumulated reverse reactive energy value, Phase B
ER_RV_ACM_C	INT64	0...999999999	kVArh	Accumulated reverse reactive energy value, Phase C
EA_FWD_ACM_A	INT64	0...999999999	kWh	Accumulated forward active energy value, Phase A
EA_FWD_ACM_B	INT64	0...999999999	kWh	Accumulated forward active energy value, Phase B
EA_FWD_ACM_C	INT64	0...999999999	kWh	Accumulated forward active energy value, Phase C
ER_FWD_ACM_A	INT64	0...999999999	kVArh	Accumulated forward reactive energy value, Phase A
ER_FWD_ACM_B	INT64	0...999999999	kVArh	Accumulated forward reactive energy value, Phase B
ER_FWD_ACM_C	INT64	0...999999999	kVArh	Accumulated forward reactive energy value, Phase C

8.1.12.6 Technical data

Table 847: SP, SE Technical data

Characteristic	Value
Operation accuracy	At all three currents in range 0.10…1.20 x I_n At all three voltages in range 0.50…1.15 x V_n At the frequency f_n ±1 Hz Active power and energy in range |PF| > 0.71 Reactive power and energy in range |PF| < 0.71
	±1.5% for power (S, P and Q) ±0.015 for power factor ±1.5% for energy
Suppression of harmonics	DFT: -50 dB at f = n x f_n, where n = 2, 3, 4, 5,…

8.2 Digital fault recorder DFR

8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance recorder	RDRE	DR	DFR

8.2.2 Functionality

The relay is provided with a disturbance recorder featuring up to 12 analog and 64 binary signal channels.The analog channels can be set to record either the waveform or the trend of the currents and voltages measured.

The analog channels can be set to trigger the recording function when the measured value falls below or exceeds the set values. The binary signal channels can be set to start a recording either on the rising or the falling edge of the binary signal or on both.

By default, the binary channels are set to record external or internal relay signals, for example, the pickup or trip signals of the relay stages, or external blocking or control signals. Binary relay signals, such as a protection pickup or trip signal, or an external relay control signal via a binary input, can be set to trigger the recording.Recorded information is stored in a non-volatile memory and can be uploaded for subsequent fault analysis.

8.2.2.1 Recorded analog inputs

The user can map any analog signal type of the protection relay to each analog channel of the disturbance recorder by setting the *Channel selection* parameter of the corresponding analog channel. In addition, the user can enable or disable each analog channel of the disturbance recorder by setting the *Operation* parameter of the corresponding analog channel to “Enable” or “Disable”.

All analog channels of the disturbance recorder that are enabled and have a valid signal type mapped are included in the recording.

8.2.2.2 Triggering alternatives

The recording can be triggered by any or several of the following alternatives:

- Triggering according to the state change of any or several of the binary channels of the disturbance recorder. The user can set the level sensitivity with the *Level trigger mode* parameter of the corresponding binary channel.
- Triggering on limit violations of the analog channels of the disturbance recorder (high and low limit)
- Manual triggering via the *Trig recording* parameter (LHMI or communication)
- Periodic triggering.

Regardless of the triggering type, each recording generates the Recording started and Recording made events. The Recording made event indicates that the recording has been stored to the non-volatile memory. In addition, every analog channel and binary channel of the disturbance recorder has its own *Channel triggered* parameter. Manual trigger has the *Manual triggering* parameter and periodic trigger has the *Periodic triggering* parameter.

Triggering by binary channels

Input signals for the binary channels of the disturbance recorder can be formed from any of the digital signals that can be dynamically mapped. A change in the status of a monitored signal triggers the recorder according to the configuration and settings. Triggering on the rising edge of a digital input signal means that the recording sequence starts when the input signal is activated. Correspondingly, triggering on the falling edge means that the recording sequence starts when the active input signal resets. It is also possible to trigger from both edges. In addition, if preferred, the monitored signal can be non-triggering. The trigger setting can be set individually for each binary channel of the disturbance recorder with the *Level trigger mode* parameter of the corresponding binary channel.

Triggering by analog channels

The trigger level can be set for triggering in a limit violation situation. The user can set the limit values with the *High trigger level* and *Low trigger level* parameters of the corresponding analog channel. Both high level and low level violation triggering can be active simultaneously for the same analog channel. If the duration of the limit violation condition exceeds the filter time of approximately 50 ms, the recorder triggers. In case of a low level limit violation, if the measured value falls below approximately 0.05 during the filter time, the situation is considered to be a circuit-breaker operation and therefore, the recorder does not trigger. This is useful especially in undervoltage situations. The filter time of approximately 50 ms is common to all the analog channel triggers of the disturbance recorder. The value used for triggering is the calculated peak-to-peak value. Either high or low analog channel trigger can be disabled by setting the corresponding trigger level parameter to zero.

Manual triggering

The recorder can be triggered manually via the LHMI or via communication by setting the *Trig recording* parameter to TRUE.

Periodic triggering

Periodic triggering means that the recorder automatically makes a recording at certain time intervals. The user can adjust the interval with the *Periodic trig time* parameter. If the value of the parameter is changed, the new setting takes effect when the next periodic triggering occurs. Setting the parameter to zero disables the triggering alternative and the setting becomes valid immediately. If a new non-zero setting needs to be valid immediately, the user should first set the *Periodic trig time* parameter to zero and then to the new value. The user can monitor the time remaining to the next triggering with the `Time to trigger` monitored data which counts downwards.

8.2.2.3 Length of recordings

The user can define the length of a recording with the *Record length* parameter. The length is given as the number of fundamental cycles.

According to the memory available and the number of analog channels used, the disturbance recorder automatically calculates the remaining amount of recordings that fit into the available recording memory. The user can see this information with the `Rem. amount of rec` monitored data. The fixed memory size allocated for the recorder can fit in two recordings that are ten seconds long. The recordings contain data from all analog and binary channels of the disturbance recorder, at the sample rate of 32 samples per fundamental cycle.

The user can view the number of recordings currently in memory with the `Number of recordings` monitored data. The currently used memory space can be viewed with the `Rec. memory used` monitored data. It is shown as a percentage value.

The maximum number of recordings is 100.

8.2.2.4 Sampling frequencies

The sampling frequency of the disturbance recorder analog channels depends on the set rated frequency. One fundamental cycle always contains the amount of samples set with the *Storage rate* parameter. Since the states of the binary channels are sampled once per task execution of the disturbance recorder, the sampling frequency of binary channels is 400 Hz at the rated frequency of 50 Hz and 480 Hz at the rated frequency of 60 Hz.

Table 848: Sampling frequencies of the digital fault recorder analog channels

Storage rate (samples per fundamental cycle)	Recording length	Sampling frequency of analog channels, when the rated frequency is 50 Hz	Sampling frequency of binary channels, when the rated frequency is 50 Hz	Sampling frequency of analog channels, when the rated frequency is 60 Hz	Sampling frequency of binary channels, when the rated frequency is 60 Hz
32	1* Record length	1600 Hz	400 Hz	1920 Hz	480 Hz
16	2* Record length	800 Hz	400 Hz	960 Hz	480 Hz
8	4 * Record length	400 Hz	400 Hz	480 Hz	480 Hz

8.2.2.5 Uploading of recordings

The protection relay stores COMTRADE files to the `C:\COMTRADE\` folder. The files can be uploaded with the PCM600 or any appropriate computer software that can access the `C:\COMTRADE\` folder.

One complete disturbance recording consists of two COMTRADE file types: the configuration file and the data file. The file name is the same for both file types. The configuration file has .CFG and the data file .DAT as the file extension.

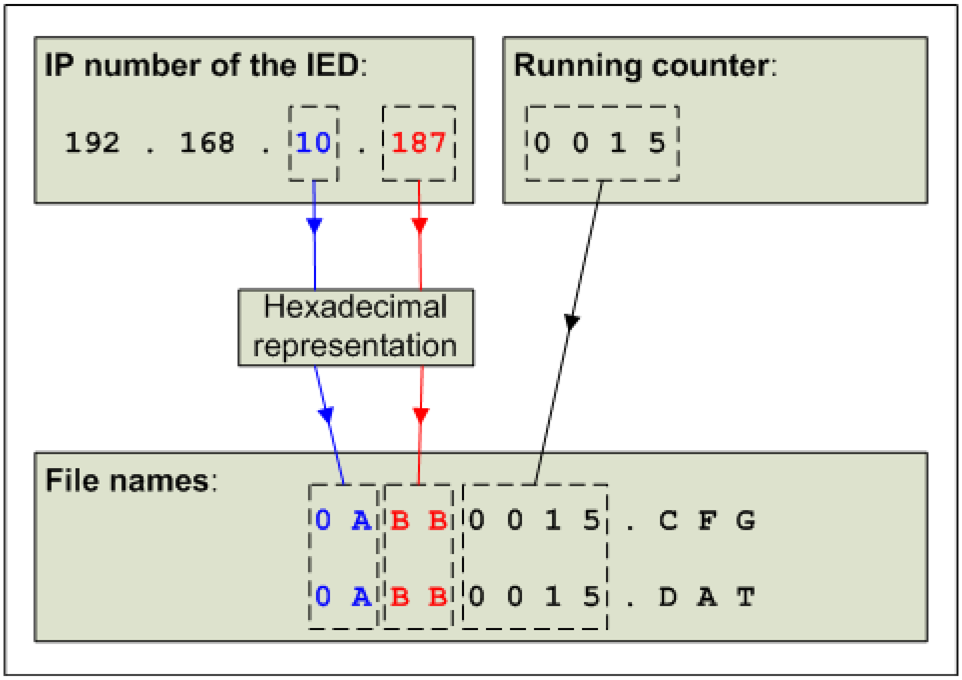


Figure 478: Disturbance recorder file naming

The naming convention of 8+3 characters is used in COMTRADE file naming. The file name is composed of the last two octets of the protection relay's IP number and a running counter, which has a range of 1...9999. A hexadecimal representation is used for the IP number octets. The appropriate file extension is added to the end of the file name.

8.2.2.6 Deletion of recordings

There are several ways to delete disturbance recordings. The recordings can be deleted individually or all at once.

Individual disturbance recordings can be deleted with PCM600 or any appropriate computer software, which can access the protection relay's `C:\COMTRADE` folder. The disturbance recording is not removed from the protection relay's memory until both of the corresponding COMTRADE files, .CFG and .DAT, are deleted. The user may have to delete both of the files types separately, depending on the software used.

Deleting all disturbance recordings at once is done either with PCM600 or any appropriate computer software, or from the LHMI via the **Clear/Digital fault recorder** menu. Deleting all disturbance recordings at once also clears the pre-trigger recording in progress.

8.2.2.7 Storage mode

The disturbance recorder can capture data in two modes: waveform and trend mode. The user can set the storage mode individually for each trigger source with the *Storage mode* parameter of the corresponding analog channel or binary channel, the *Stor. mode manual* parameter for manual trigger and the *Stor. mode periodic* parameter for periodic trigger.

In the waveform mode, the samples are captured according to the *Storage rate* and *Pre-trg length* parameters.

In the trend mode, one value is recorded for each enabled analog channel, once per fundamental cycle. The recorded values are RMS values, which are scaled to peak level. The binary channels of the disturbance recorder are also recorded once per fundamental cycle in the trend mode.

Only post-trigger data is captured in trend mode.

The trend mode enables recording times of 32 * *Record length*.

8.2.2.8 Pre-trigger and post-trigger data

The waveforms of the disturbance recorder analog channels and the states of the disturbance recorder binary channels are constantly recorded into the history memory of the recorder. The user can adjust the percentage of the data duration preceding the triggering, that is, the so-called pre-trigger time, with the *Pre-trg length* parameter. The duration of the data following the triggering, that is, the so-called post-trigger time, is the difference between the recording length and the pre-trigger time. Changing the pre-trigger time resets the history data and the current recording under collection.

8.2.2.9 Operation modes

Disturbance recorder has two operation modes: saturation and overwrite mode. The user can change the operation mode of the disturbance recorder with the *Operation mode* parameter.

Saturation mode

In saturation mode, the captured recordings cannot be overwritten with new recordings. Capturing the data is stopped when the recording memory is full, that is, when the maximum number of recordings is reached. In this case, the event is sent via the state change (TRUE) of the *Memory full* parameter. When there is memory available again, another event is generated via the state change (FALSE) of the *Memory full* parameter.

Overwrite mode

When the operation mode is "Overwrite" and the recording memory is full, the oldest recording is overwritten with the pre-trigger data collected for the next recording. Each time a recording is overwritten, the event is generated via the state change of the *Overwrite of rec.* parameter. The overwrite mode is recommended, if it is more important to have the latest recordings in the memory. The saturation mode is preferred, when the oldest recordings are more important.

New triggerings are blocked in both the saturation and the overwrite mode until the previous recording is completed. On the other hand, a new triggering can be accepted before all pre-trigger samples are collected for the new recording. In such a case, the recording is as much shorter as there were pre-trigger samples lacking.

8.2.2.10 Exclusion mode

Exclusion mode is on, when the value set with the *Exclusion time* parameter is higher than zero. During the exclusion mode, new triggerings are ignored if the triggering reason is the same as in the previous recording. The *Exclusion time* parameter controls how long the exclusion of triggerings of same type is active after a triggering. The exclusion mode only applies to the analog and binary channel triggerings, not to periodic and manual triggerings.

When the value set with the *Exclusion time* parameter is zero, the exclusion mode is disabled and there are no restrictions on the triggering types of the successive recordings.

The exclusion time setting is global for all inputs, but there is an individual counter for each analog and binary channel of the disturbance recorder, counting the remaining exclusion time. The user can monitor the remaining exclusion time with the *Exclusion time rem* parameter (only visible via communication, IEC 61850 data ExclTmRmn) of the corresponding analog or binary channel. The *Exclusion time rem* parameter counts downwards.

8.2.3 Configuration

The disturbance recorder can be configured with PCM600 or any tool supporting the IEC 61850 standard.

The disturbance recorder can be enabled or disabled with the *Operation* parameter under the **Configuration/Digital fault recorder/General** menu.

One analog signal type of the protection relay can be mapped to each of the analog channels of the disturbance recorder. The mapping is done with the *Channel selection* parameter of the corresponding analog channel. The name of the analog channel is user-configurable. It can be modified by writing the new name to the *Channel id text* parameter of the corresponding analog channel.

Any external or internal digital signal of the protection relay which can be dynamically mapped can be connected to the binary channels of the disturbance recorder. These signals can be, for example, the pickup and trip signals from protection function blocks or the external binary inputs of the protection relay. The connection is made with dynamic mapping to the binary channel of the disturbance recorder using, for example, SMT of PCM600. It is also possible to connect several digital signals to one binary channel of the disturbance recorder. In that case, the signals can be combined with logical functions, for example AND and OR. The name of the binary channel can be configured and modified by writing the new name to the *Channel id text* parameter of the corresponding binary channel.

Note that the *Channel id text* parameter is used in COMTRADE configuration files as a channel identifier.

The recording always contains all binary channels of the disturbance recorder. If one of the binary channels is disabled, the recorded state of the channel is continuously FALSE and the state changes of the corresponding channel are not recorded. The corresponding channel name for disabled binary channels in the COMTRADE configuration file is Unused BI.

To enable or disable an analog or a binary channel of the disturbance recorder, the *Operation* parameter of the corresponding analog or binary channel is set to “Enable” or “Disable”.

The states of manual triggering and periodic triggering are not included in the recording, but they create a state change to the *Periodic triggering* and *Manual triggering* status parameters, which in turn create events.

The `TRIGGERED` output can be used to control the indication LEDs of the protection relay. The `TRIGGERED` output is TRUE due to the triggering of the disturbance recorder, until all the data for the corresponding recording has been recorded.

The IP number of the protection relay and the content of the *Bay name* parameter are both included in the COMTRADE configuration file for identification purposes.

8.2.4 Application

The disturbance recorder is used for post-fault analysis and for verifying the correct operation of protection relays and circuit breakers. It can record both analog and binary signal information. The analog inputs are recorded as instantaneous values and converted to primary peak value units when the protection relay converts the recordings to the COMTRADE format.

COMTRADE is the general standard format used in storing disturbance recordings.

The binary channels are sampled once per task execution of the disturbance recorder. The task execution interval for the disturbance recorder is the same as for the protection functions. During the COMTRADE conversion, the digital status values are repeated so that the sampling frequencies of the analog and binary channels correspond to each other. This is required by the COMTRADE standard.

The disturbance recorder follows the 1999 version of the COMTRADE standard and uses the binary data file format.

8.2.5 Settings

Table 849: DFR Non-group general settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=Enable 5=Disable		1	1=Enable	DFR Enabled / Disabled
Record length	10...500	fundamental cycles	1	50	Size of the recording in fundamental cycles
Pre-trg length	0...100	%	1	50	Length of the recording preceding the triggering
Operation mode	1=Saturation 2=Overwrite		1	1	Operation mode of the recorder
Exclusion time	0...1 000 000	ms	1	0	The time during which triggerings of same type are ignored
Storage rate	32, 16, 8	samples per fundamental cycle		32	Storage rate of the waveform recording
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
Periodic trig time	0...604 800	s	10	0	Time between periodic triggerings
Stor. mode periodic	0=Waveform 1=Trend / cycle		1	0	Storage mode for periodic triggering
Stor. mode manual	0=Waveform 1=Trend / cycle		1	0	Storage mode for manual triggering

Table 850: RDRE Non-group channel settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=on 5=off		1	1=on	Analog channel is enabled or disabled
Channel selection	0=Disabled 1=IG 2=IA-A 3=IB-A 4=IC-A 5=IG2-A 6=IA2-A 7=IB2-A 8=IC2-A 9=VG-A 10=VA-A 11=VB-A 12=VC-A 13=VG2-A 14=VA2-A 15=VB2-A 16=VC2-A 17=CI0 18=SI1[1)] 19=SI2[1)] 20=SU0 21=SU1[1)] 22=SU2[1)] 23=CI0B 24=SI1B[1)] 25=SI2B[1)] 26=SUoB 27=SU1B[1)] 28=SU2B[1)] 29=V12 30=V23 31=V31 32=VA 33=VB 34=VC 35=V12B 36=V23B 37=V31B 38=VA-B 39=VB-B 40=VC-B		0	0=Disabled	Select the signal to be recorded by this channel. Applicable values for this parameter are product variant dependent. Every product variant includes only the values that are applicable to that particular variant
Channel id text	0 to 64 characters, alphanumeric			DR analog channel X	Identification text for the analog channel used in the COMTRADE format

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
High trigger level	0.00...60.00	pu	0.01	10.00	High trigger level for the analog channel
Low trigger level	0.00...2.00	pu	0.01	0.00	Low trigger level for the analog channel
Storage mode	0=Waveform 1=Trend / cycle		1	0	Storage mode for the analog channel

1) Recordable values are available only in trend mode. In waveform mode, samples for this signal type are constant zeroes. However, these signal types can be used to trigger the recorder on limit violations of the corresponding analog channel.

Table 851: DFR Non-group binary channel settings

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=Enable 5=Disable		1	5=Disable	Binary channel is enabled or disabled
Level trigger mode	1=Positive or Rising 2=Negative or Falling 3=Both 4=Level trigger off		1	1=Rising	Level trigger mode for the binary channel
Storage mode	0=Waveform 1=Trend / cycle		1	0	Storage mode for the binary channel
Channel id text	0 to 64 characters, alphanumeric			DR binary channel X	Identification text for the analog channel used in the COMTRADE format

Table 852: DFR Control data

Parameter	Values (Range)	Unit	Step	Default	Description
Trig recording	0=Cancel 1=Trig				Trigger the disturbance recording
Clear recordings	0=Cancel 1=Clear				Clear all recordings currently in memory

8.2.6 Monitored data

Table 853: DFR Monitored data

Parameter	Values (Range)	Unit	Step	Default	Description
Number of recordings	0...100				Number of recordings currently in memory
Rem. amount of rec.	0...100				Remaining amount of recordings that fit into the available recording memory, when current settings are used
Rec. memory used	0...100	%			Storage mode for the binary channel
Time to trigger	0...604 800	s			Time remaining to the next periodic triggering

8.2.7 Technical revision history

Table 854: DFR Technical revision history

Technical revision	Change
B	ChNum changed to EChNum (RADR's) RADR9...12 added (Analog channels 9...12) RBDR33...64 added (Binary channels 33...64)
C	New channels added to parameter *Channel selection* Selection names for *Trig Recording* and *Clear Recordings updated*
D	Symbols in the *Channel selection* setting are updated
E	New channels IL1C, IL2C and IL3C added to *Channel selection* parameter
F	Internal improvement
G	Internal improvement

8.3 Tap changer position indication 84T

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tap changer position indication	TPOSYLTC	TPOSM	84T

8.3.2 Function block

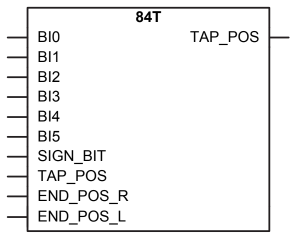


Figure 479: Function block

8.3.3 Functionality

The tap changer position indication function 84T is used for transformer tap position supervision. The binary inputs can be used for converting a binary-coded tap changer position to a tap position status indication. The X130 (RTD) card, available as an option, provides the RTD sensor information to be used and the versatile analog inputs enabling the tap position supervision through mA.

There are three user-selectable conversion modes available for the 7-bit binary inputs where MSB is used as the SIGN bit: the natural binary-coded boolean input to the signed integer output, binary coded decimal BCD input to the signed integer output and binary reflected GRAY coded input to the signed integer output.

8.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”. When the function is disabled, the tap position quality information is changed accordingly. When the tap position information is not available, it is recommended to disable this function with the *Operation* setting.

The operation of 84T can be described using a module diagram. All the modules in the diagram are explained in the next sections.

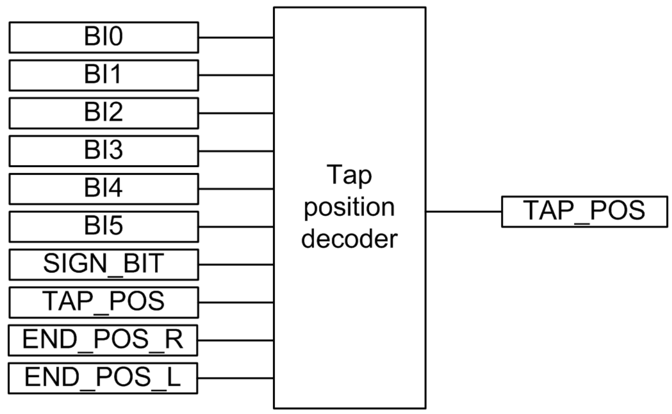


Figure 480: Functional module diagram

Tap position decoder

When there is a wired connection to the TAP_POS input connector, the corresponding tap changer position is decoded from the mA or RTD input. When there is no wired connection to the TAP_POS connector, the binary inputs are expected to be used for the tap changer position information. The tap changer position value and quality are internally shared to other functions. The value is available in the Monitored data view or as a TAP_POS output signal.

The function has three alternative user selectable operation modes: "NAT2INT", "BCD2INT" and "GRAY2INT". The operation mode is selected with the *Operation mode* setting. Each operation mode can be used to convert a maximum of 6–bit coded input to an 8–bit signed short integer output. For less than 6–bit input, for example 19 positions with 5 bits when the BCD coding is used, the rest of the bits can be set to FALSE (0).

The operation mode "NAT2INT" is selected when the natural binary coding is used for showing the position of the transformer tap changer. The basic principle of the natural binary coding is to calculate the sum of the bits set to TRUE (1). The LSB has the factor 1. Each following bit has the previous factor multiplied by 2. This is also called dual coding.

The operation mode "BCD2INT" is selected when the binary-coded decimal coding is used for showing the position of the transformer tap changer. The basic principle with the binary-coded decimal coding is to calculate the sum of the bits set to TRUE (1). The four bits nibble (BI3...BI0) have a typical factor to the natural binary coding. The sum of the values should not be more than 9. If the nibble sum is greater than 9, the tap position output validity is regarded as bad.

The operation mode “GRAY2INT” is selected when the binary-reflected Gray coding is used for showing the position of the transformer tap changer. The basic principle of the Gray coding is that only one actual bit changes value with consecutive positions. This function is based on the common binary-reflected Gray code which is used with some tap changers. Changing the bit closest to the right side bit gives a new pattern.

An additional separate input, SIGN_BIT, can be used for negative values. If the values are positive, the input is set to FALSE (0). If the SIGN_BIT is set to TRUE (1) making the number negative, the remaining bits are identical to those of the coded positive number.

The tap position validity is set to good in all valid cases. The quality is set to bad in invalid combinations in the binary inputs. For example, when the “BCD2INT” mode is selected and the input binary combination is “0001101”, the quality is set to bad. For negative values, when the SIGN_BIT is set to TRUE (1) and the input binary combination is “1011011”, the quality is set to bad.

If the tap changer has auxiliary contacts for indicating the extreme positions of the tap changer, their status can be connected to END_POS_R and END_POS_L inputs. The END_POS_R (End position raise or highest allowed tap position reached) status refers to the extreme position that results in the highest number of the taps in the tap changer. Similarly, END_POS_L (End position lower or lowest allowed tap position reached) status refers to the extreme position that results in the lowest number of the taps in the tap changer. TAP_POS output is dedicated for transferring the validated tap position for the functions that need tap position information, for example 87T. It includes both the actual position information and the status of reached end positions, assuming that inputs END_POS_R and END_POS_L are connected.

Table 855: Truth table of the decoding modes

Inputs							TAP_POS outputs		
SIGN_BIT	BI5	BI4	BI3	BI2	BI1	BI0	NAT2INT	BCD2INT	GRAY2INT
...		...		...		...	...	...	...
1	0	0	0	0	1	1	-3	-3	-2
1	0	0	0	0	1	0	-2	-2	-3
1	0	0	0	0	0	1	-1	-1	-1
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	1	1	1	1
0	0	0	0	0	1	0	2	2	3
0	0	0	0	0	1	1	3	3	2
0	0	0	0	1	0	0	4	4	7
0	0	0	0	1	0	1	5	5	6

Table continues on next page

Inputs							TAP_POS outputs		
0	0	0	0	1	1	0	6	6	4
0	0	0	0	1	1	1	7	7	5
0	0	0	1	0	0	0	8	8	15
0	0	0	1	0	0	1	9	9	14
0	0	0	1	0	1	0	10	9	12
0	0	0	1	0	1	1	11	9	13
0	0	0	1	1	0	0	12	9	8
0	0	0	1	1	0	1	13	9	9
0	0	0	1	1	1	0	14	9	11
0	0	0	1	1	1	1	15	9	10
0	0	1	0	0	0	0	16	10	31
0	0	1	0	0	0	1	17	11	30
0	0	1	0	0	1	0	18	12	28
0	0	1	0	0	1	1	19	13	29
0	0	1	0	1	0	0	20	14	24
0	0	1	0	1	0	1	21	15	25
0	0	1	0	1	1	0	22	16	27
0	0	1	0	1	1	1	23	17	26
0	0	1	1	0	0	0	24	18	16
0	0	1	1	0	0	1	25	19	17
0	0	1	1	0	1	0	26	19	19
0	0	1	1	0	1	1	27	19	18
0	0	1	1	1	0	0	28	19	23
0	0	1	1	1	0	1	29	19	22
0	0	1	1	1	1	0	30	19	20
0	0	1	1	1	1	1	31	19	21
0	1	0	0	0	0	0	32	20	63
0	1	0	0	0	0	1	33	21	62
0	1	0	0	0	1	0	34	22	60
0	1	0	0	0	1	1	35	23	61
0	1	0	0	1	0	0	36	24	56
...		...		...		...	...	...	...

8.3.5 Application

84T provides tap position information for other functions as a signed integer value that can be fed to the tap position input.

The position information of the tap changer can be coded in various methods for many applications, for example, the differential protection algorithms. In this function, the binary inputs in the transformer terminal connector are used as inputs to the function. The coding method can be chosen by setting the mode parameter. The available coding methods are BCD, Gray and Natural binary coding. Since the number of binary inputs are limited to seven, the coding functions are limited to seven bits including the sign bit and thus the six bits are used in the coding functions. The position limits for the tap positions at BCD, Gray and Natural binary coding are ±39, ±63 and ±63 respectively.

In this example, the transformer tap changer position indication is wired as a mA signal from the corresponding measuring transducer. The position indication is connected to input 1 (`AI_VAL1`) of the X130 (RTD) card. The tap changer operating range from the minimum to maximum turns of the tap and a corresponding mA signal for the tap position are set in X130(RTD). Since the values of the X130(RTD) outputs are floating point numbers, the float to integer (T_F32_INT8) conversion is needed before the tap position information can be fed to 84T. When there is a wired connection to the `TAP_POS` connector, the validated tap changer position is presented in the `TAP_POS` output that is connected to other functions. When there is no wired connection to the `TAP_POS` connector, the binary inputs are expected to be used for the tap changer position information.

8.3.6 Signals

Table 856: 84T Input signals

Name	Type	Default	Description
BI0	BOOLEAN	0=False	Binary input 1
BI1	BOOLEAN	0=False	Binary input 2
BI2	BOOLEAN	0=False	Binary input 3
BI3	BOOLEAN	0=False	Binary input 4
BI4	BOOLEAN	0=False	Binary input 5
BI5	BOOLEAN	0=False	Binary input 6
SIGN_BIT	BOOLEAN	0=False	Binary input sign bit
END_POS_R	BOOLEAN	0=False	End position raise or highest allowed tap position reached
END_POS_L	BOOLEAN	0=False	End position lower or lowest allowed tap position reached
TAP_POS	INT8	0	Tap position indication

Table 857: 84T Output signals

Name	Type	Description
TAP_POS	INT8	Tap position indication

8.3.7 Settings

Table 858: 84T Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Operation mode	1=NAT2INT 2=BCD2INT 3=GRAY2INT			2=BCD2INT	Operation mode selection

8.3.8 Monitored data

Table 859: 84T Monitored data

Name	Type	Values (Range)	Unit	Description
BI0	BOOLEAN	0=False 1=True		Binary input 1
BI1	BOOLEAN	0=False 1=True		Binary input 2
BI2	BOOLEAN	0=False 1=True		Binary input 3
BI3	BOOLEAN	0=False 1=True		Binary input 4
BI4	BOOLEAN	0=False 1=True		Binary input 5
BI5	BOOLEAN	0=False 1=True		Binary input 6
SIGN_BIT	BOOLEAN	0=False 1=True		Binary input sign bit
END_POS_R	BOOLEAN	0=False 1=True		End position raise or highest allowed tap position reached
END_POS_L	BOOLEAN	0=False 1=True		End position lower or lowest allowed tap position reached
TAP_POS	INT8	-63...63		Tap position indication

8.3.9 Technical data

Table 860: 84T Technical data

Descrpition	Value
Response time for binary inputs	Typically 100 ms

8.3.10 Technical revision history

Table 861: 84T Technical revision history

Technical revision	Change
B	Added new input `TAP_POS`
C	Internal improvement
D	Added new inputs `END_TPOS_R` and `END_TPOS_L` Added a new output `TAP_POS`

Section 9 Control functions

9.1 Circuit breaker control 52, Disconnector control 29DS and Grounding switch control 29GS

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit-breaker control	CBXCBR	I<->O CB	52
Disconnector control	DCXSWI	I <-> O DCC	29DS
Grounding switch control	ESXSWI	I <-> O ESC (1)	29GS

9.1.2 Function block

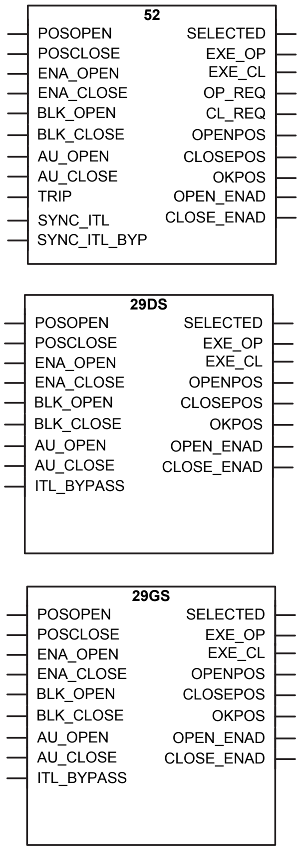


Figure 481: Function block

9.1.3 Functionality

52, 29DS and 29GS are intended for circuit breaker, disconnector and grounding switch control and status information purposes. These functions execute commands and evaluate block conditions and different time supervision conditions. The functions perform an execution command only if all conditions indicate that a switch operation is allowed. If erroneous conditions occur, the functions indicate an appropriate cause value. The functions are designed according to the IEC 61850-7-4 standard with logical nodes CILO, CSWI and XSWI/XCBR.

The circuit breaker, disconnector and grounding switch control functions have an operation counter for closing and opening cycles. The counter value can be read and written remotely from the place of operation or via LHMI.

9.1.4 Operation principle

Status indication and validity check

The object state is defined by two digital inputs, POSOPEN and POSCLOSE, which are also available as outputs OPENPOS and CLOSEPOS together with the OKPOS information. The debouncing and short disturbances in an input are eliminated by filtering. The binary input filtering time can be adjusted separately for each digital input used by the function block. The validity of the digital inputs that indicate the object state is used as additional information in indications and event logging. The reporting of faulty or intermediate position of the apparatus occurs after the *Event delay* setting, assuming that the circuit breaker is still in a corresponding state.

Table 862: Status indication

Input		Status	Output		
POSOPEN	POSCLOSE	POSITION (Monitored data)	OKPOS	OPENPOS	CLOSEPOS
1=True	0=False	1=Open	1=True	1=True	0=False
0=False	1=True	2=Closed	1=True	0=False	1=True
1=True	1=True	3=Faulty/Bad (11)	0=False	0=False	0=False
0=False	0=False	0=Intermediate (00)	0=False	0=False	0=False

Enabling and blocking

52, 29DS and 29GS have an enabling and blocking functionality for interlocking and synchrocheck purposes.

Circuit breaker control 52

Normally, the CB closing is enabled (that is, CLOSE_ENAD signal is TRUE) by activating both ENA_CLOSE and SYNC_OK inputs. Typically, the ENA_CLOSE comes from the interlocking, and SYNC_OK comes from the synchronism and energizing check. The input SYNC_ITL_BYP can be used for bypassing this control. The SYNC_ITL_BYP input can be used to activate CLOSE_ENAD discarding the ENA_CLOSE and SYNC_OK input states. However, the BLK_CLOSE input always blocks the CLOSE_ENAD output.

The CB opening (OPEN_ENAD) logic is the same as CB closing logic, except that SYNC_OK is used only in closing. The SYNC_ITL_BYP input is used in both CLOSE_ENAD and OPEN_ENAD logics.

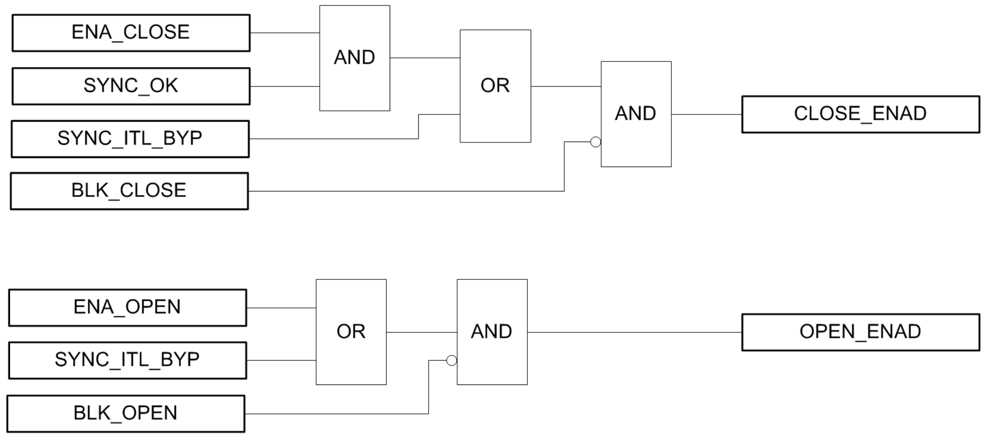


Figure 482: Enabling and blocking logic for CLOSE_ENAD and OPEN_ENAD signals

Disconnector control 29DS and grounding switch control 29GS

Normally, the switch closing is enabled (that is, the `CLOSE_ENAD` signal is TRUE) by activating the `ENA_CLOSE` input. The input `ITL_BYPASS` can be used for bypassing this control. The `ITL_BYPASS` input can be used to activate the `CLOSE_ENAD` discarding the `ENA_CLOSE` input state. However, the `BLK_CLOSE` input always blocks the `CLOSE_ENAD` output.

The CB opening (`OPEN_ENAD`) logic is identical to CB closing logic. The `ITL_BYPASS` input is used in both `CLOSE_ENAD` and `OPEN_ENAD` logics.

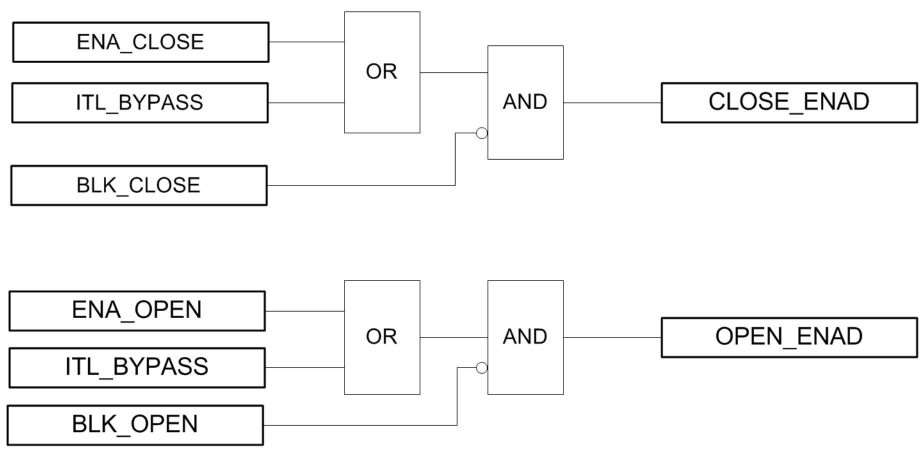


Figure 483: Enabling and blocking logic for CLOSE_ENAD and OPEN_ENAD signals

Opening and closing operations

The opening and closing operations are available via communication, binary inputs or LHMI commands. As a prerequisite for control commands, there are enabling and blocking functionalities for both opening and closing commands (CLOSE_ENAD and OPEN_ENAD signals). If the control command is executed against the blocking or if the enabling of the corresponding command is not valid, 52 generates an error message.

When close command is given from communication, via LHMI or activating the AU_CLOSE input, it is carried out (the EXE_CL output) only if CLOSE_ENAD is TRUE.

If the 25 function is used in "Command" mode, the CL_REQ output can be used in 52. Initially, the SYNC_OK input is FALSE. When the close command given, it activates the CL_REQ output, which should be routed to 25. The close command is then processed only after SYNC_OK is received from 25.

When using 25 in the "Command" mode, the 52 setting *Operation timeout* should be set longer than 25 setting *Maximum Syn time*.

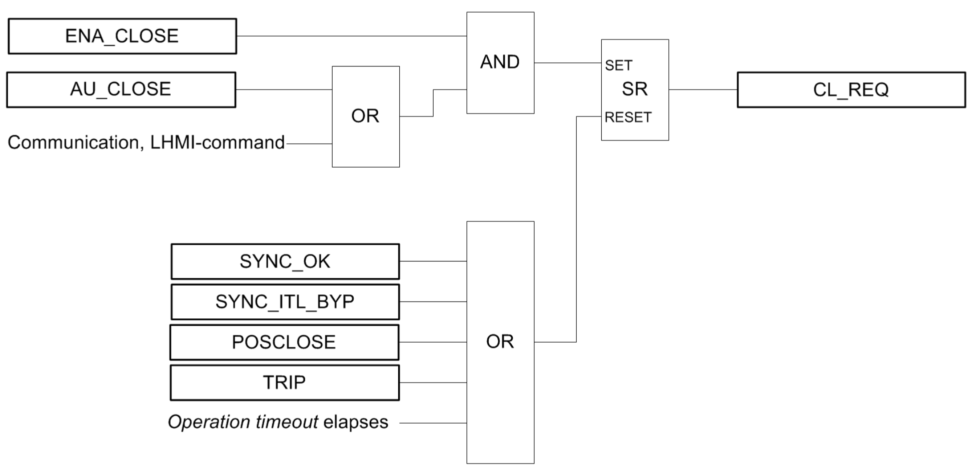


Figure 484: Condition for enabling the close request (CL_REQ) for 52

When the open command is given from communication, via LHMI or activating the AU_OPEN input, it is processed only if OPEN_ENAD is TRUE. OP_REQ output is also available.

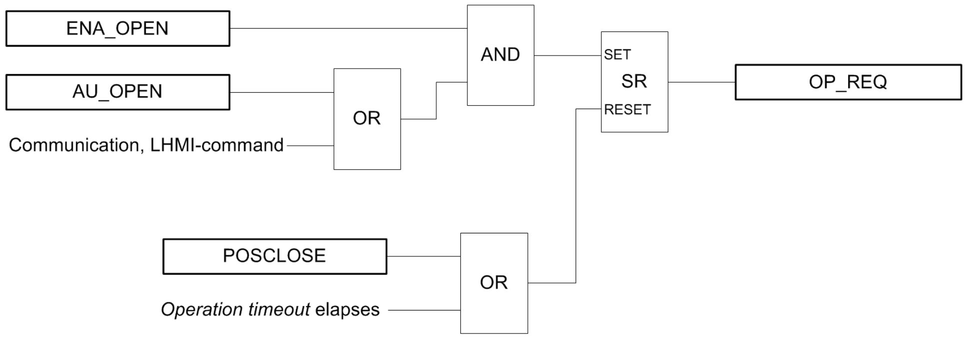


Figure 485: Condition for enabling the open request (OP_REQ) for 52

OPEN and CLOSE outputs

The `EXE_OP` output is activated when the open command is given (`AU_OPEN`, via communication or from LHMI) and `OPEN_ENAD` signal is TRUE. In addition, the protection trip commands can be routed through the 52 function by using the `TRIP` input. When the `TRIP` input is TRUE, the `EXE_OP` output is activated immediately and bypassing all enabling or blocking conditions.

The `EXE_CL` output is activated when the close command is given (`AU_CLOSE`, via communication or from LHMI) and `CLOSE_ENAD` signal is TRUE. When the `TRIP` input is "TRUE", CB closing is not allowed.

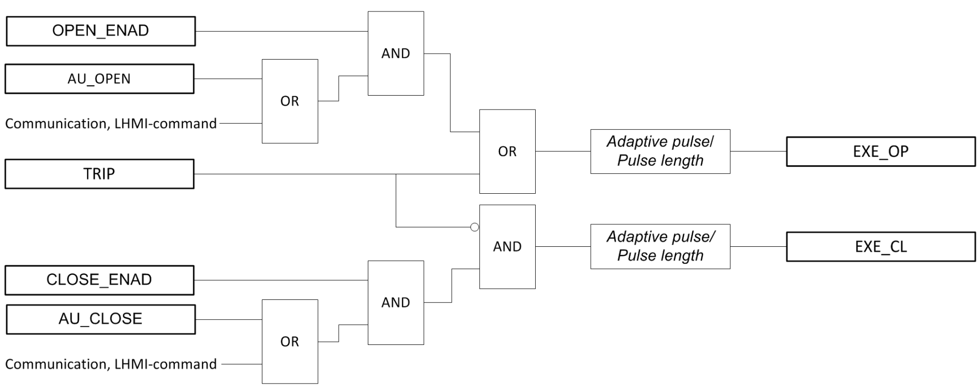


Figure 486: OPEN and CLOSE outputs logic for 52

Opening and closing pulse widths

The pulse width type can be defined with the *Adaptive pulse* setting. The function provides two modes to characterize the opening and closing pulse widths. When the *Adaptive pulse* is set to "TRUE", it causes a variable pulse width, which means that the output pulse is deactivated when the object state shows that the apparatus has entered the correct state. If apparatus fails to enter the correct state, the output pulse is deactivated after the set *Operation timeout* setting, and an error message is displayed. When the *Adaptive pulse* is set to “FALSE”, the functions always use the maximum pulse width, defined by the user-configurable *Pulse length* setting. The *Pulse length* setting is the same for both the opening and closing commands. When the apparatus already is in the right position, the maximum pulse length is given.

The *Pulse length* setting does not affect the length of the trip pulse.

Control methods

The command execution mode can be set with the *Control model* setting. The alternatives for command execution are direct control and secured object control, which can be used to secure controlling.

The secured object control SBO is an important feature of the communication protocols that support horizontal communication, because the command reservation and interlocking signals can be transferred with a bus. All secured control operations require two-step commands: a selection step and an execution step. The secured object control is responsible for the several tasks.

- Command authority: ensures that the command source is authorized to operate the object
- Mutual exclusion: ensures that only one command source at a time can control the object
- Interlocking: allows only safe commands
- Execution: supervises the command execution
- Command canceling: cancels the controlling of a selected object.

In direct operation, a single message is used to initiate the control action of a physical device. The direct operation method uses less communication network capacity and bandwidth than the SBO method, because the procedure needs fewer messages for accurate operation.

The “status-only” mode means that control is not possible (non-controllable) via communication or from LHMI. However, it is possible to control a disconnector (29DC) from `AU_OPEN` and `AU_CLOSE` inputs.

`AU_OPEN` and `AU_CLOSE` control the object directly regardless of the set *Control model*. These inputs can be used when control is wanted to be implemented purely based on ACT logic and no additional exception handling is needed. However, in case of simultaneous open and close control, the open control is always prioritized.

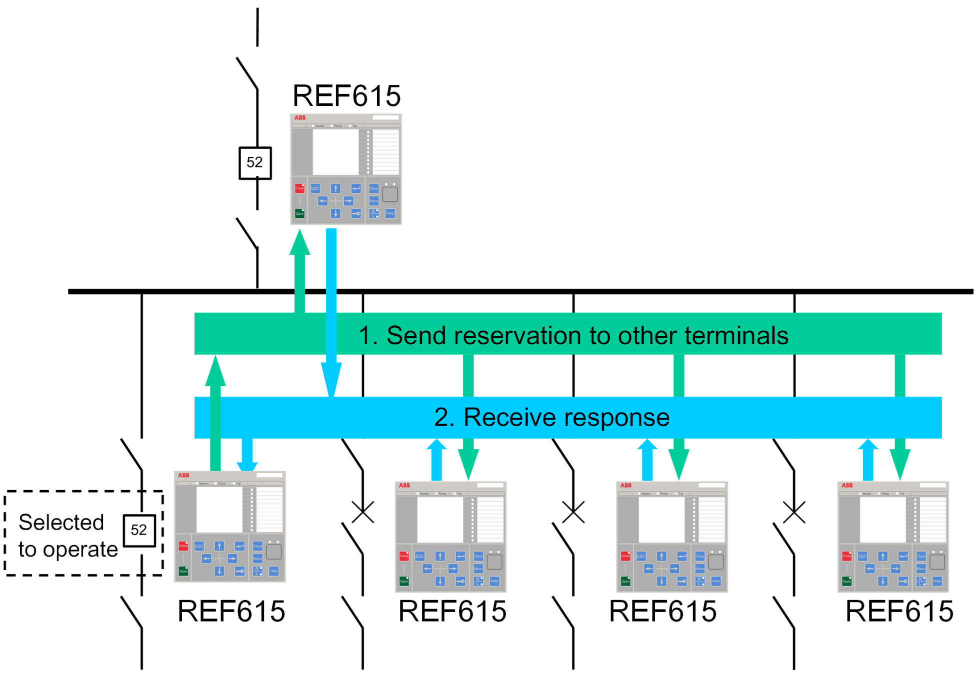


Figure 487: Control procedure in SBO method

Local/Remote operations

The local/remote selection affects the 52, 29DS and 29GS.

- Local: the opening and closing via communication is disabled.
- Remote: the opening and closing via LHMI is disabled.
- `AU_OPEN` and `AU_CLOSE` inputs function regardless of the local/remote selection.

9.1.5 Application

In the field of distribution and sub-transmission automation, reliable control and status indication of primary switching components both locally and remotely is in a significant role. They are needed especially in modern remotely controlled substations.

Control and status indication facilities are implemented in the same package with 52, 29DS and 29GS. When primary components are controlled in the energizing phase, for example, the correct execution sequence of the control commands must be ensured. This can be achieved, for example, with interlocking based on the status indication of the related primary components. The interlocking on substation level can be applied using the IEC 61850 GOOSE messages between feeders.

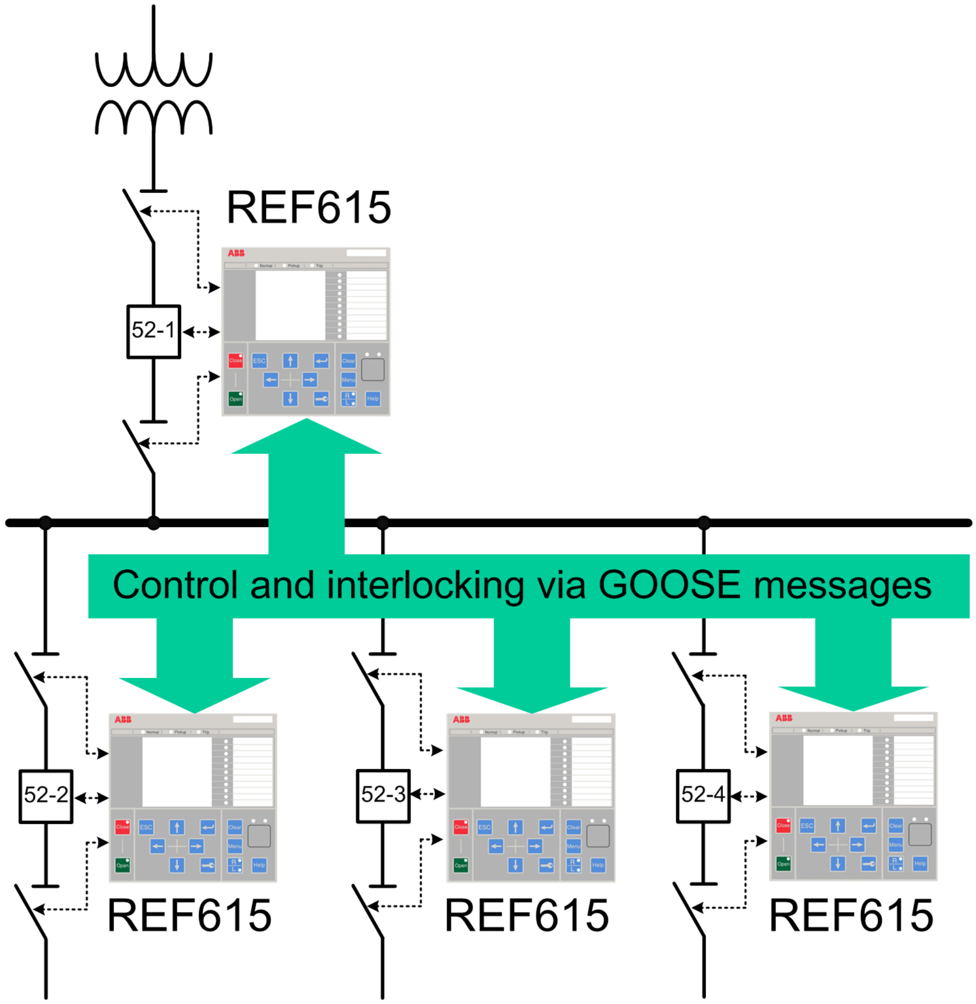


Figure 488: Status indication-based interlocking via the GOOSE messaging

9.1.6 Signals

Table 863: 52 Input signals

Name	Type	Default	Description
POSOPEN	BOOLEAN	0=False	Signal for open position of apparatus from I/O[1)]
POSCLOSE	BOOLEAN	0=False	Signal for close position of apparatus from I/O[1)]
ENA_OPEN	BOOLEAN	1=True	Enables opening
ENA_CLOSE	BOOLEAN	1=True	Enables closing
Table continues on next page			

Name	Type	Default	Description
BLK_OPEN	BOOLEAN	0=False	Blocks opening
BLK_CLOSE	BOOLEAN	0=False	Blocks closing
AU_OPEN	BOOLEAN	0=False	Auxiliary open1)
AU_CLOSE	BOOLEAN	0=False	Auxiliary close1)2)
TRIP	BOOLEAN	0=False	Trip signal
SYNC_OK	BOOLEAN	1=True	Synchronism-check OK
SYNC_ITL_BYP	BOOLEAN	0=False	Discards ENA_OPEN and ENA_CLOSE interlocking when TRUE

1) Not available for monitoring
2) Always direct operation

Table 864: 29DS Input signals

Name	Type	Default	Description
POSOPEN	BOOLEAN	0=False	Apparatus open position
POSCLOSE	BOOLEAN	0=False	Apparatus close position
ENA_OPEN	BOOLEAN	1=True	Enables opening
ENA_CLOSE	BOOLEAN	1=True	Enables closing
BLK_OPEN	BOOLEAN	0=False	Blocks opening
BLK_CLOSE	BOOLEAN	0=False	Blocks closing
AU_OPEN	BOOLEAN	0=False	Executes the command for open direction1)2)
AU_CLOSE	BOOLEAN	0=False	Executes the command for close direction1)2)
ITL_BYPASS	BOOLEAN	0=False	Discards ENA_OPEN and ENA_CLOSE interlocking when TRUE

1) Not available for monitoring
2) Always direct operation

Table 865: 29GS Input signals

Name	Type	Default	Description
POSOPEN	BOOLEAN	0=False	Apparatus open position
POSCLOSE	BOOLEAN	0=False	Apparatus close position
ENA_OPEN	BOOLEAN	1=True	Enables opening
ENA_CLOSE	BOOLEAN	1=True	Enables closing
BLK_OPEN	BOOLEAN	0=False	Blocks opening
BLK_CLOSE	BOOLEAN	0=False	Blocks closing

Table continues on next page

Name	Type	Default	Description
AU_OPEN	BOOLEAN	0=False	Executes the command for open direction[1)2)]
AU_CLOSE	BOOLEAN	0=False	Executes the command for close direction[1)2)]
ITL_BYPASS	BOOLEAN	0=False	Discards ENA_OPEN and ENA_CLOSE interlocking when TRUE

1) Not available for monitoring
2) Always direct operation

Table 866: 52 Output signals

Name	Type	Description
SELECTED	BOOLEAN	Object selected
EXE_OP	BOOLEAN	Executes the command for open direction
EXE_CL	BOOLEAN	Executes the command for close direction
OP_REQ	BOOLEAN	Open request
CL_REQ	BOOLEAN	Close request
OPENPOS	BOOLEAN	Signal for open position of apparatus from I/O
CLOSEPOS	BOOLEAN	Signal for close position of apparatus from I/O
OKPOS	BOOLEAN	Apparatus position is ok
OPEN_ENAD	BOOLEAN	Opening is enabled based on the input status
CLOSE_ENAD	BOOLEAN	Closing is enabled based on the input status

Table 867: 29DS Output signals

Name	Type	Description
SELECTED	BOOLEAN	Object selected
EXE_OP	BOOLEAN	Executes the command for open direction
EXE_CL	BOOLEAN	Executes the command for close direction
OPENPOS	BOOLEAN	Apparatus open position
CLOSEPOS	BOOLEAN	Apparatus closed position
OKPOS	BOOLEAN	Apparatus position is ok
OPEN_ENAD	BOOLEAN	Opening is enabled based on the input status
CLOSE_ENAD	BOOLEAN	Closing is enabled based on the input status

Table 868: 29GS Output signals

Name	Type	Description
SELECTED	BOOLEAN	Object selected
EXE_OP	BOOLEAN	Executes the command for open direction
EXE_CL	BOOLEAN	Executes the command for close direction
OPENPOS	BOOLEAN	Apparatus open position
CLOSEPOS	BOOLEAN	Apparatus closed position
OKPOS	BOOLEAN	Apparatus position is ok
OPEN_ENAD	BOOLEAN	Opening is enabled based on the input status
CLOSE_ENAD	BOOLEAN	Closing is enabled based on the input status

9.1.7 Settings

Table 869: 52 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation mode disable / disable
Select timeout	10000...300000	ms	10000	30000	Select timeout in ms
Pulse length	10...60000	ms	1	200	Open and close pulse length
Control model	0=status-only 1=direct-with-normal-security 4=sbo-with-enhanced-security			4=sbo-with-enhanced-security	Select control model
Operation timeout	10...60000	ms	1	500	Timeout for negative termination
Identification				CBXCBR1 switch position	Control Object identification

Table 870: 52 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation counter	0...10000		1	0	Breaker operation cycles
Adaptive pulse	0=False 1=True			1=True	Stop in right position
Event delay	0...10000	ms	1	200	Event delay of the intermediate position
Vendor				0	External equipment vendor
Serial number				0	External equipment serial number
Model				0	External equipment model

Table 871: 29DS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation mode disable / disable
Select timeout	10000...300000	ms	10000	30000	Select timeout in ms
Pulse length	10...60000	ms	1	100	Open and close pulse length
Control model	0=status-only 1=direct-with-normal-security 4=sbo-with-enhanced-security			4=sbo-with-enhanced-security	Select control model
Operation timeout	10...60000	ms	1	30000	Timeout for negative termination
Identification				DCXSWI1 switch position	Control Object identification

Table 872: 29DS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation counter	0...10000		1	0	Breaker operation cycles
Adaptive pulse	0=False 1=True			1=True	Stop in right position
Event delay	0...60000	ms	1	10000	Event delay of the intermediate position
Vendor				0	External equipment vendor
Serial number				0	External equipment serial number
Model				0	External equipment model

Table 873: 29GS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation mode disable / disable
Select timeout	10000...300000	ms	10000	30000	Select timeout in ms
Pulse length	10...60000	ms	1	100	Open and close pulse length
Control model	0=status-only 1=direct-with-normal-security 4=sbo-with-enhanced-security			4=sbo-with-enhanced-security	Select control model
Operation timeout	10...60000	ms	1	30000	Timeout for negative termination
Identification				ESXSWI1 switch position	Control Object identification

Table 874: 29GS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation counter	0...10000		1	0	Breaker operation cycles
Adaptive pulse	0=False 1=True			1=True	Stop in right position
Event delay	0...60000	ms	1	10000	Event delay of the intermediate position
Vendor				0	External equipment vendor
Serial number				0	External equipment serial number
Model				0	External equipment model

9.1.8 Monitored data

Table 875: 52 Monitored data

Name	Type	Values (Range)	Unit	Description
POSITION	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Apparatus position indication

Table 876: 29DS Monitored data

Name	Type	Values (Range)	Unit	Description
POSITION	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Apparatus position indication

Table 877: 29GS Monitored data

Name	Type	Values (Range)	Unit	Description
POSITION	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Apparatus position indication

9.1.9 Technical revision history

Table 878: 52 Technical revision history

Technical revision	Change
B	Interlocking bypass input (ITL_BYPASS) and opening enabled (OPEN_ENAD)/closing enabled (CLOSE_ENAD) outputs added. ITL_BYPASS bypasses the ENA_OPEN and ENA_CLOSE states.
C	Internal improvement.
D	Added inputs TRIP and SYNC_OK. Renamed input ITL_BYPASS to SYNC_ITL_BYP. Added outputs CL_REQ and OP_REQ. Outputs OPENPOS and CLOSEPOS are forced to “FALSE” in case status is Faulty (11).

Table 879: 29DS Technical revision history

Technical revision	Change
B	Maximum and default values changed to 60 s and 10 s respectively for *Event delay* settings. Default value changed to 30 s for *Operation timeout* setting.
C	Outputs OPENPOS and CLOSEPOS are forced to “FALSE” in case status is Faulty (11).

Table 880: 29GS Technical revision history

Technical revision	Change
B	Maximum and default values changed to 60 s and 10 s respectively for *Event delay* settings. Default value changed to 30 s for *Operation timeout* setting.
C	Outputs OPENPOS and CLOSEPOS are forced to “FALSE” in case status is Faulty (11).

9.2 Disconnector position indication 52-TOC, 29DS and Grounding switch indication 29GS

9.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disconnector position indication	DCSXSWI	I<->O DC	52-TOC, 29DS
Grounding switch indication	ESSXSWI	I<->O ES	29GS

9.2.2 Function block

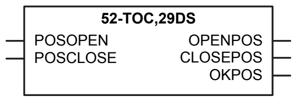


Figure 489: Function block

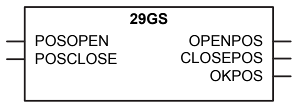


Figure 490: Function block

9.2.3 Functionality

The functions 52-TOC, 29DS and 29GS indicate remotely and locally the open, close and undefined states of the disconnector and grounding switch. The functionality of both is identical, but each one is allocated for a specific purpose visible in the function names. For example, the status indication of disconnectors or circuit breaker truck can be monitored with the 52-TOC, 29DS function.

The functions are designed according to the IEC 61850-7-4 standard with the logical node XSWI.

9.2.4 Operation principle

Status indication and validity check

The object state is defined by the two digital inputs `POSOPEN` and `POSCLOSE`, which are also available as outputs `OPENPOS` and `CLOSEPOS` together with the `OKPOS` according to Table 881. The debounces and short disturbances in an input are eliminated by filtering. The binary input filtering time can be adjusted separately for each digital input used by the function block. The validity of digital inputs that indicate the object state is used as additional information in indications and event logging.

Table 881: Status indication

Input		Status	Output		
POSOPEN	POSCLOSE	POSITION (Monitored data)	OKPOS	OPENPOS	CLOSEPOS
1=True	0=False	1=Open	1=True	1=True	0=False
0=False	1=True	2=Closed	1=True	0=False	1=True
1=True	1=True	3=Faulty/Bad (11)	0=False	0=False	0=False
0=False	0=False	0=Intermediate (00)	0=False	0=False	0=False

9.2.5 Application

In the field of distribution and sub-transmission automation, the reliable control and status indication of primary switching components both locally and remotely is in a significant role. These features are needed especially in modern remote controlled substations. The application area of 52-TOC, 29DS and 29GS functions covers remote and local status indication of, for example, disconnectors, air-break switches and grounding switches, which represent the lowest level of power switching devices without short-circuit breaking capability.

9.2.6 Signals

Table 882: 52-TOC,29DS Input signals

Name	Type	Default	Description
POSOPEN	BOOLEAN	0=False	Signal for open position of apparatus from I/O[1)]
POSCLOSE	BOOLEAN	0=False	Signal for close position of apparatus from I/O[1)]

1) Not available for monitoring

Table 883: 29GS Input signals

Name	Type	Default	Description
POSOPEN	BOOLEAN	0=False	Signal for open position of apparatus from I/O[1)]
POSCLOSE	BOOLEAN	0=False	Signal for close position of apparatus from I/O[1)]

1) Not available for monitoring

Table 884: 52-TOC,29DS Output signals

Name	Type	Description
OPENPOS	BOOLEAN	Apparatus open position
CLOSEPOS	BOOLEAN	Apparatus closed position
OKPOS	BOOLEAN	Apparatus position is ok

Table 885: 29GS Output signals

Name	Type	Description
OPENPOS	BOOLEAN	Apparatus open position
CLOSEPOS	BOOLEAN	Apparatus closed position
OKPOS	BOOLEAN	Apparatus position is ok

9.2.7 Settings

Table 886: 52-TOC,29DS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Identification				DCSXSWI1 switch position	Control Object identification

Table 887: 52-TOC,29DS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Event delay	0...60000	ms	1	30000	Event delay of the intermediate position
Vendor				0	External equipment vendor
Serial number				0	External equipment serial number
Model				0	External equipment model

Table 888: 29GS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Identification				ESSXSWI1 switch position	Control Object identification

Table 889: 29GS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Event delay	0...60000	ms	1	30000	Event delay of the intermediate position
Vendor				0	External equipment vendor
Serial number				0	External equipment serial number
Model				0	External equipment model

9.2.8 Monitored data

Table 890: 52-TOC,29DS Monitored data

Name	Type	Values (Range)	Unit	Description
POSITION	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Apparatus position indication

Table 891: 29GS Monitored data

Name	Type	Values (Range)	Unit	Description
POSITION	Dbpos	0=intermediate 1=open 2=closed 3=faulty		Apparatus position indication

9.2.9 Technical revision history

Table 892: 52-TOC, 29DS Technical revision history

Technical revision	Change
B	Maximum and default values changed to 60 s and 30 s respectively for *Event delay* settings.
C	Outputs `OPENPOS` and `CLOSEPOS` are forced to “FALSE” in case status is Faulty (11).

Table 893: 29GS Technical revision history

Technical revision	Change
B	Maximum and default values changed to 60 s and 30 s respectively for *Event delay* settings.
C	Outputs `OPENPOS` and `CLOSEPOS` are forced to “FALSE” in case status is Faulty (11).

9.3 Synchronism and energizing check 25

9.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Synchronism and energizing check	SECRSYN	SYNC	25

9.3.2 Function block

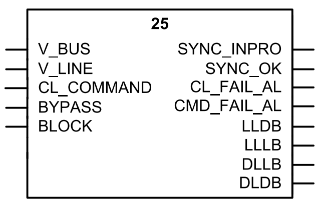


Figure 491: Function block

9.3.3 Functionality

The synchronism and energizing check function 25 checks the condition across the circuit breaker from separate power system parts and gives the permission to close the circuit breaker. 25 includes the functionality of synchrocheck and energizing check.

Asynchronous operation mode is provided for asynchronously running systems. The main purpose of the asynchronous operation mode is to provide a controlled closing of circuit breakers when two asynchronous systems are connected.

The synchrocheck operation mode checks that the voltages on both sides of the circuit breaker are perfectly synchronized. It is used to perform a controlled reconnection of two systems which are divided after islanding and it is also used to perform a controlled reconnection of the system after reclosing.

The energizing check function checks that at least one side is dead to ensure that closing can be done safely.

The function contains a blocking functionality. It is possible to block function outputs and timers if desired.

9.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

25 has two parallel functionalities, the synchro check and energizing check functionality. The operation of 25 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

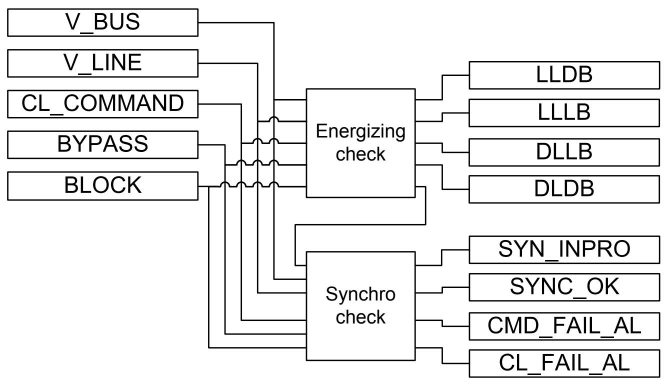


Figure 492: Functional module diagram

If Energizing check is passed, no further conditions need to be fulfilled to permit closing. Otherwise, Synchro check function can operate either with the V_AB or V_A voltages. The selection of used voltages is defined with the *VT connection* setting of the line voltage general parameters.

By default, voltages V_BUS and V_LINE are connected as presented in Figure 501. If necessary, connections can be switched by setting *Voltage source switch* to “True”.

Energizing check

The Energizing check function checks the energizing direction. Energizing is defined as a situation where a dead network part is connected to an energized section of the network. The conditions of the network sections to be controlled by the circuit breaker, that is, which side has to be live and which side dead, are determined by the setting. A situation where both sides are dead is possible as well. The actual value for defining the dead line or bus is given with the *Dead bus value* and *Dead line value* settings. Similarly, the actual values of live line or bus are defined with the *Live bus value* and *Live line value* settings.

Table 894: Live dead mode of operation under which switching can be carried out

Live dead mode	Description
Both Dead	Both line and bus de-energized
Live L, Dead B	Bus de-energized and line energized
Dead L, Live B	Line de-energized and bus energized
Dead Bus, L Any	Both line and bus de-energized or bus de-energized and line energized
Dead L, Bus Any	Both line and bus de-energized or line de-energized and bus energized
One Live, Dead	Bus de-energized and line energized or line de-energized and bus energized
Not Both Live	Both line and bus de-energized or bus de-energized and line energized or line de-energized and bus energized

When the energizing direction corresponds to the settings, the situation has to be constant for a time set with the *Energizing time* setting before the circuit breaker closing is permitted. The purpose of this time delay is to ensure that the dead side remains de-energized and also that the situation is not caused by a temporary interference. If the conditions do not persist for a specified operation time, the timer is reset and the procedure is restarted when the conditions allow. The circuit breaker closing is not permitted if the measured voltage on the live side is greater than the set value of *Max energizing V*.

The measured energized state is available as a monitored data value ENERG_STATE and as four function outputs `LLDB` (live line / dead bus), `LLLB` (live line / live bus), `DLLB` (dead line / live bus) and `DLDB` (dead line / dead bus), of which only one can be active at a time. It is also possible that the measured energized state indicates “Unknown” if at least one of the measured voltages is between the limits set with the dead and live setting parameters.

Synchro check

The Synchro check function measures the difference between the line voltage and bus voltage. The function permits the closing of the circuit breaker when certain conditions are simultaneously fulfilled.

- The measured line and bus voltages are higher than the set values of *Live bus value* and *Live line value* (ENERG_STATE equals to "Both Live").
- The measured bus and line frequency are both within the range of 95 to 105 percent of the value of f_n.
- The measured voltages for the line and bus are less than the set value of *Max energizing V*.

In case *Syncro check mode* is set to "Syncronous", the additional conditions must be fulfilled.

- In the synchronous mode, the closing is attempted so that the phase difference at closing is close to zero.
- The synchronous mode is only possible when the frequency slip is below 0.1 percent of the value of f_n.
- The voltage difference must not exceed the 1 percent of the value of V_n.

In case *Syncro check mode* is set to “Asyncronous”, the additional conditions must be fulfilled.

- The measured difference of the voltages is less than the set value of *Difference voltage*.
- The measured difference of the phase angles is less than the set value of *Difference angle*.
- The measured difference in frequency is less than the set value of *Frequency difference*.
- The estimated breaker closing angle is decided to be less than the set value of *Difference angle*.

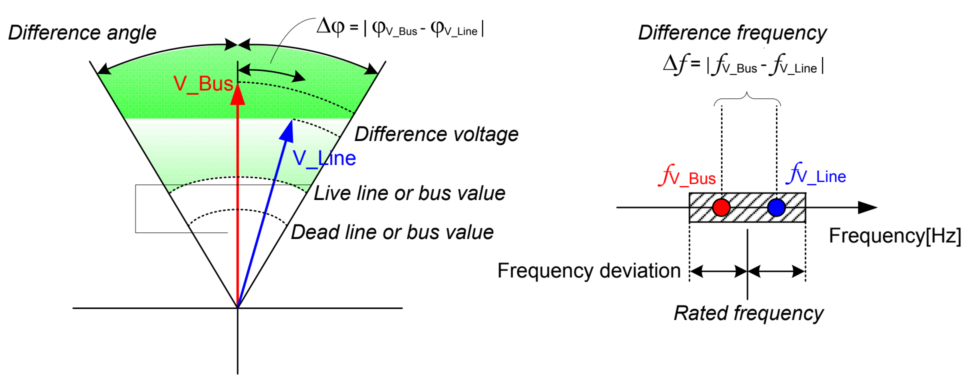


Figure 493: Conditions to be fulfilled when detecting synchronism between systems

When the frequency, phase angle and voltage conditions are fulfilled, the duration of the synchronism conditions is checked so as to ensure that they are still met when the condition is determined on the basis of the measured frequency and phase difference. Depending on the circuit breaker and the closing system, the delay from the moment the closing signal is given until the circuit breaker finally closes is about 50...250 ms. The selected *Closing time of CB* informs the function how long the conditions have to persist. The Synchro check function compensates for the measured slip frequency and the circuit breaker closing delay. The phase angle advance is calculated continuously with the formula.

$$Closing\ angle = \left|\left(\angle V_{Bus} - \angle V_{Line}\right)° + \left(\left(f_{Bus} - f_{line}\right) \times \left(T_{CB} + T_{PL}\right) \times 360°\right)\right|$$

(Equation 170)

$\angle V_{Bus}$	Measured bus voltage phase angle
$\angle V_{Line}$	Measured line voltage phase angle
f_{Bus}	Measured bus frequency
f_{line}	Measured line frequency
T_{CB}	Total circuit breaker closing delay, including the delay of the protection relay output contacts defined with the *Closing time of CB* setting parameter value

The closing angle is the estimated angle difference after the breaker closing delay.

The *Minimum Syn time* setting time can be set, if required, to demand the minimum time within which conditions must be simultaneously fulfilled before the `SYNC_OK` output is activated.

The measured voltage, frequency and phase angle difference values between the two sides of the circuit breaker are available as monitored data values V_DIFF_MEAS, FR_DIFF_MEAS and PH_DIFF_MEAS. Also, the indications of the conditions that are not fulfilled and thus preventing the breaker closing permission are available as monitored data values V_DIFF_SYNC, PH_DIF_SYNC and FR_DIFF_SYNC. These monitored data values are updated only when the Synchro check enabled with the *Synchro check mode* setting and the measured ENERG_STATE is "Both Live".

Continuous mode

The continuous mode is activated by setting the parameter *Control mode* to "Continuous". In the continuous control mode, Synchro check is continuously checking the synchronism. When synchronism is detected (according to the settings), the `SYNC_OK` output is set to TRUE (logic '1') and it stays TRUE as long as the conditions are fulfilled. The command input is ignored in the continuous control mode. The mode is used for situations where Synchro check only gives the permission to the control block that executes the CB closing.

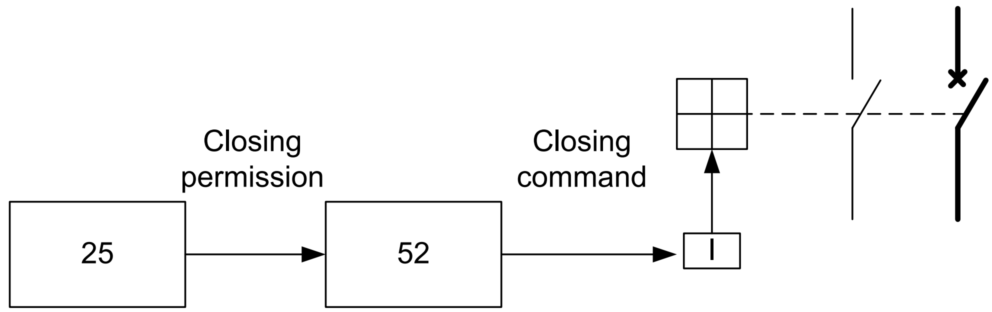


Figure 494: A simplified block diagram of the Synchro check function in the continuous mode operation

Command mode

If *Control mode* is set to "Command", the purpose of the Synchro check functionality in the command mode is to find the instant when the voltages on both sides of the circuit breaker are in synchronism. The conditions for synchronism are met when the voltages on both sides of the circuit breaker have the same frequency and are in phase with a magnitude that makes the concerned busbars or lines such that they can be regarded as live.

In the command mode operation, an external command signal `CL_COMMAND`, besides the normal closing conditions, is needed for delivering the closing signal. In the command control mode operation, the Synchro check function itself closes the breaker via the `SYNC_OK` output when the conditions are fulfilled. In this case, the control function block delivers the command signal to close the Synchro check function for the releasing of a closing-signal pulse to the circuit breaker. If the closing conditions are fulfilled during a permitted check time set with *Maximum Syn time*, the Synchro check function delivers a closing signal to the circuit breaker after the command signal is delivered for closing.

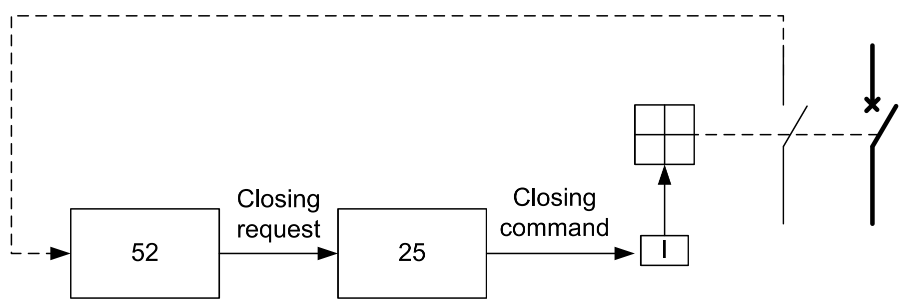


Figure 495: A simplified block diagram of 25 in the command mode operation

The closing signal is delivered only once for each activated external closing command signal. The pulse length of the delivered closing is set with the *Close pulse* setting.

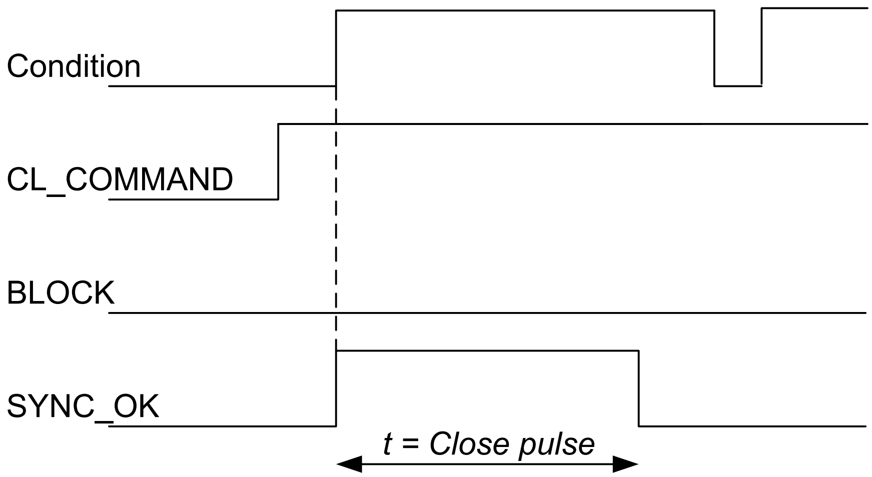


Figure 496: Determination of the pulse length of the closing signal

In the command control mode operation, there are alarms for a failed closing attempt (CL_FAIL_AL) and for a command signal that remains active too long (CMD_FAIL_AL).

If the conditions for closing are not fulfilled within the set time of *Maximum Syn time*, a failed closing attempt alarm is given. The CL_FAIL_AL alarm output signal is pulse-shaped and the pulse length is 500 ms. If the external command signal is removed too early, that is, before conditions are fulfilled and the closing pulse is given, the alarm timer is reset.

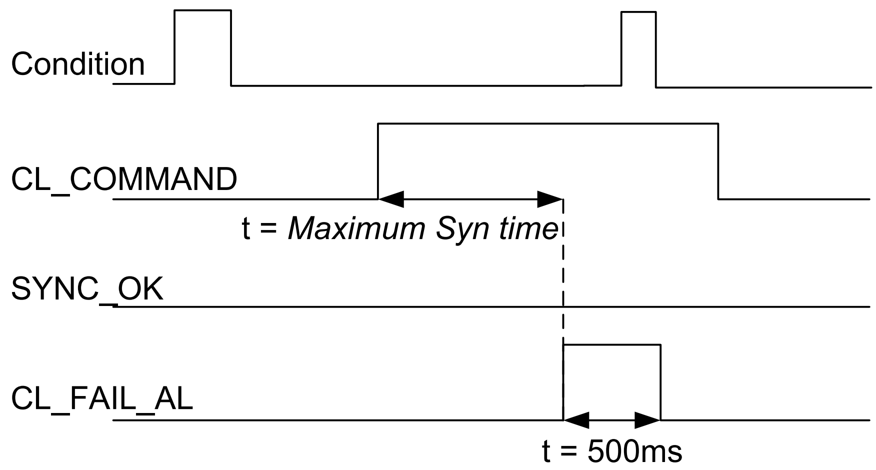


Figure 497: Determination of the checking time for closing

The control module receives information about the circuit breaker status and thus is able to adjust the command signal to be delivered to the Synchro check function. If the external command signal CL_COMMAND is kept active longer than necessary, the `CMD_FAIL_AL` alarm output is activated. The alarm indicates that the control module has not removed the external command signal after the closing operation. To avoid unnecessary alarms, the duration of the command signal should be set in such a way that the maximum length of the signal is always below *Maximum Syn time* + 5s.

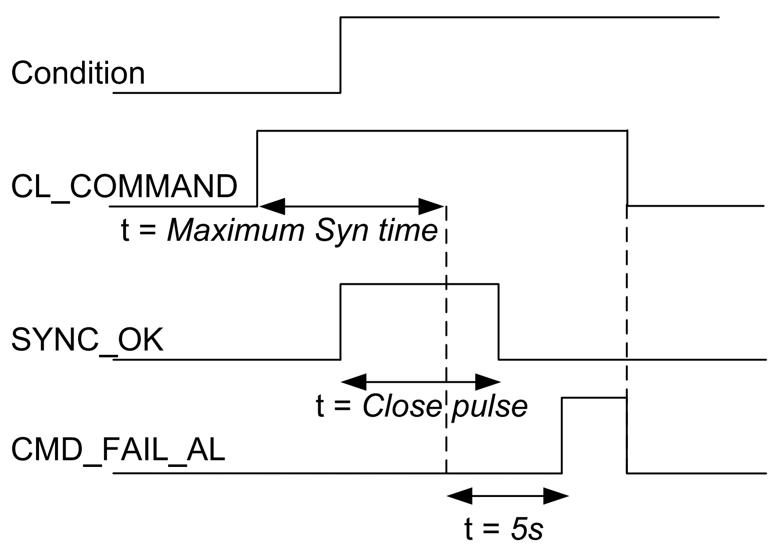


Figure 498: Determination of the alarm limit for a still-active command signal

Closing is permitted during *Maximum Syn time*, starting from the moment the external command signal CL_COMMAND is activated. The CL_COMMAND input must be kept active for the whole time that the closing conditions are waited to be fulfilled. Otherwise, the procedure is cancelled. If the closing-command conditions are fulfilled during *Maximum Syn time*, a closing pulse is delivered to the circuit breaker. If the closing conditions are not fulfilled during the checking time, the alarm CL_FAIL_AL is activated as an indication of a failed closing attempt. The closing pulse is not delivered if the closing conditions become valid after *Maximum Syn time* has elapsed. The closing pulse is delivered only once for each activated external command signal, and a new closing-command sequence cannot be started until the external command signal is reset and reactivated. The SYNC_INPRO output is active when the closing-command sequence is in progress and it is reset when the CL_COMMAND input is reset or *Maximum Syn time* has elapsed.

Bypass mode

25 can be set to the bypass mode by setting the parameters *Synchrocheck mode* and *Live dead mode* to "Disable" or alternatively by activating the BYPASS input.

In the bypass mode, the closing conditions are always considered to be fulfilled by 25. Otherwise, the operation is similar to the normal mode.

Voltage angle difference adjustment

In application where the power transformer is located between the voltage measurement and the vector group connection gives phase difference to the voltages between the high- and low-voltage sides, the angle adjustment can be used to meet synchronism.

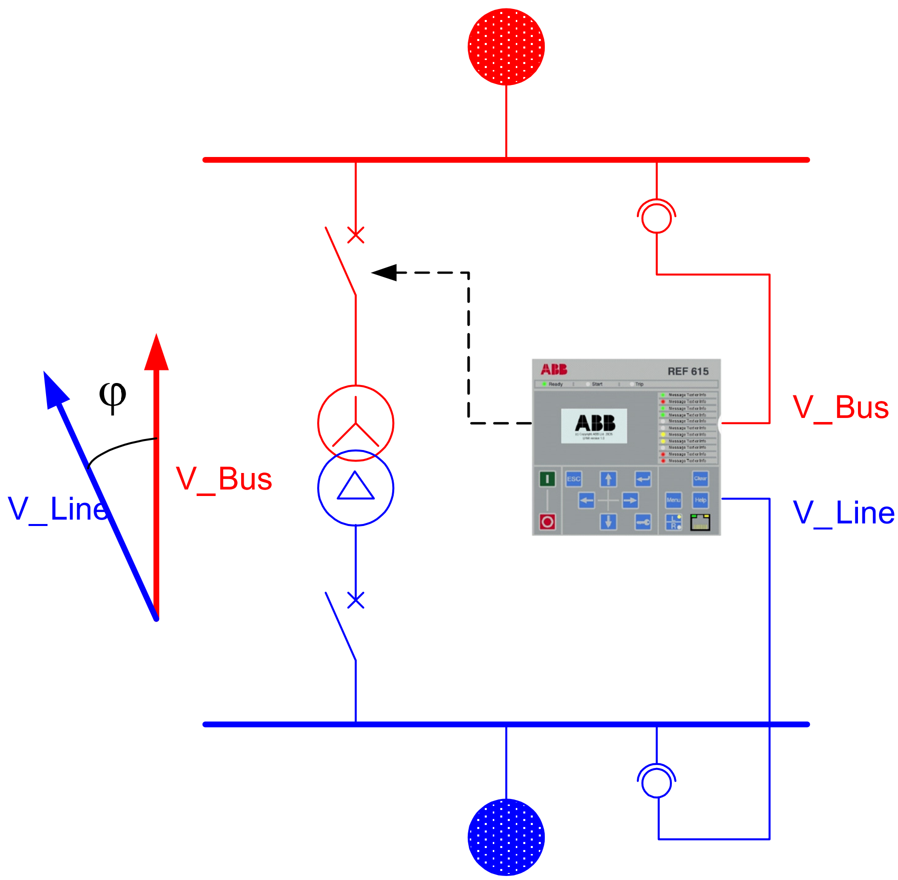


Figure 499: Angle difference when power transformer is in sychrocheck zone

The vector group of the power transformer is defined with clock numbers, where the value of the hour pointer defines the low-voltage-side phasor and the high-voltage-side phasor is always fixed to the clock number 12, which is same as zero. The angle between clock numbers is 30 degrees. When comparing phase angles, the `V_BUS` input is always the reference. This means that when the Yd11 power transformer is used, the low-voltage-side voltage phasor leads by 30 degrees or lags by 330 degrees the high-voltage-side phasor. The rotation of the phasors is counterclockwise.

The generic rule is that a low-voltage-side phasor lags the high-voltage-side phasor by clock number * 30º. This is called angle difference adjustment and can be set for 25 with the *Phase shift* setting.

9.3.5 Application

The main purpose of the synchrocheck function is to provide control over the closing of the circuit breakers in power networks to prevent the closing if the conditions for synchronism are not detected. This function is also used to prevent the reconnection of two systems which are divided after islanding and a three-pole reclosing.

The Synchro check function block includes both the synchronism check function and the energizing function to allow closing when one side of the breaker is dead.

Network and the generator running in parallel with the network are connected through the line AB. When a fault occurs between A and B, the protection relay protection opens the circuit breakers A and B, thus isolating the faulty section from the network and making the arc that caused the fault extinguish. The first attempt to recover is a delayed autoreclosure made a few seconds later. Then, the autoreclose function 79 gives a command signal to the synchrocheck function to close the circuit breaker A. 25 performs an energizing check, as the line AB is de-energized (V_BUS> *Live bus value*, V_LINE< *Dead line value*). After verifying the line AB is dead and the energizing direction is correct, the protection relay energizes the line (V_BUS -> V_LINE) by closing the circuit breaker A. The PLC of the power plant discovers that the line has been energized and sends a signal to the other synchrocheck function to close the circuit breaker B. Since both sides of the circuit breaker B are live (V_BUS > *Live bus value*, V_LINE > *Live bus value*), the synchrocheck function controlling the circuit breaker B performs a synchrocheck and, if the network and the generator are in synchronism, closes the circuit breaker.

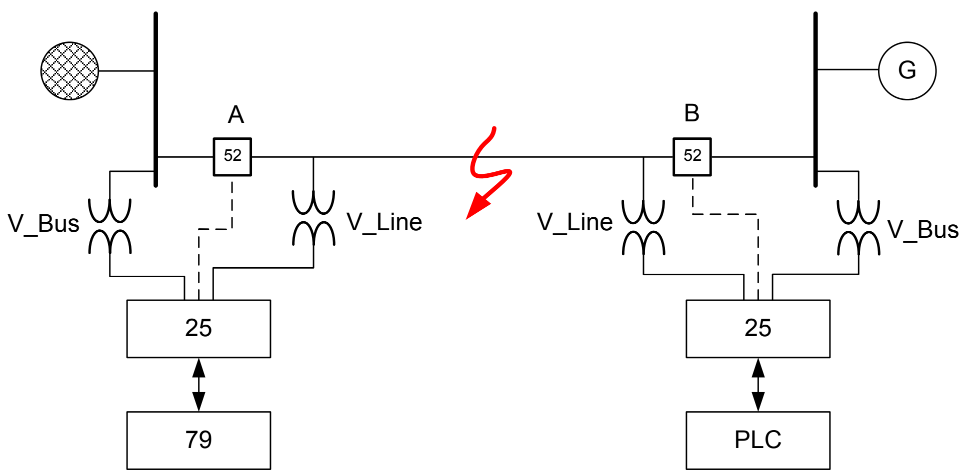


Figure 500: Synchrocheck function 79 checking energizing conditions and synchronism

Connections

A special attention is paid to the connection of the protection relay. Furthermore it is checked that the primary side wiring is correct.

A faulty wiring of the voltage inputs of the protection relay causes a malfunction in the synchrocheck function. If the wires of an energizing input have changed places, the polarity of the input voltage is reversed (180°). In this case, the protection relay permits the circuit breaker closing in a situation where the voltages are in opposite phases. This can damage the electrical devices in the primary circuit. Therefore, it is extremely important that the wiring from the voltage transformers to the terminals on the rear of the protection relay is consistent regarding the energizing inputs `V_BUS` (bus voltage) and `V_LINE` (line voltage).

The wiring should be verified by checking the reading of the phase difference measured between the `V_BUS` and `V_LINE` voltages. The phase difference measured by the protection relay has to be close to zero within the permitted accuracy tolerances. The measured phase differences are indicated in the LHMI. At the same time, it is recommended to check the voltage difference and the frequency differences presented in the monitored data view. These values should be within the permitted tolerances, that is, close to zero.

Figure 501 shows an example where the synchrocheck is used for the circuit breaker closing between a busbar and a line. The phase-to-phase voltages are measured from the busbar and also one phase-to-phase voltage from the line is measured.

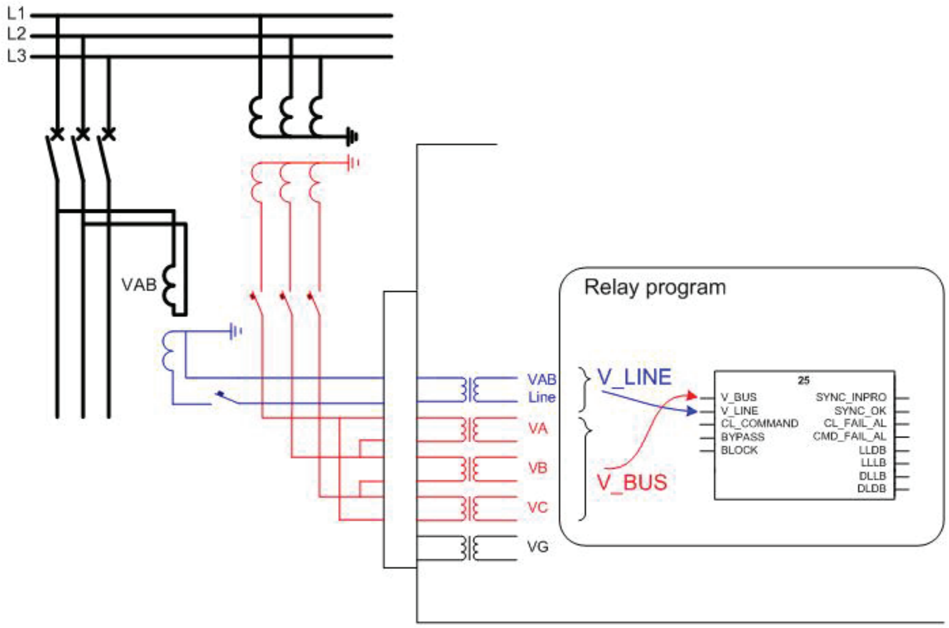


Figure 501: Connection of voltages for the protection relay and signals used in synchrocheck

9.3.6 Signals

Table 895: 25 Input signals

Name	Type	Default	Description
V_BUS	SIGNAL	0=False	Busbar Voltage
V_LINE	SIGNAL	0=False	Line Voltage
CL_COMMAND	BOOLEAN	0=False	External closing request
BYPASS	BOOLEAN	0=False	Request to bypass synchronism check and voltage check
BLOCK	BOOLEAN	0=False	Blocking signal of the synchro check and voltage check function

Table 896: 25 Output signals

Name	Type	Description
SYNC_INPRO	BOOLEAN	Synchronizing in progress
SYNC_OK	BOOLEAN	Systems in synchronism
CL_FAIL_AL	BOOLEAN	CB closing failed
Table continues on next page		

Name	Type	Description
CMD_FAIL_AL	BOOLEAN	CB closing request failed
LLDB	BOOLEAN	Live Line, Dead Bus
LLLB	BOOLEAN	Live Line, Live Bus
DLLB	BOOLEAN	Dead Line, Live Bus
DLDB	BOOLEAN	Dead Line, Dead Bus

9.3.7 Settings

Table 897: 25 Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Live dead mode	-1=Disable 1=Both Dead 2=Live L, Dead B 3=Dead L, Live B 4=Dead Bus, L Any 5=Dead L, Bus Any 6=One Live, Dead 7=Not Both Live			1=Both Dead	Energizing check mode
Difference voltage	0.01...0.50	xUn	0.01	0.05	Maximum voltage difference limit
Difference frequency	0.001...0.100	xFn	0.001	0.001	Maximum frequency difference limit
Difference angle	5...90	deg	1	5	Maximum angle difference limit

Table 898: 25 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Synchro check mode	1=Disable 2=Synchronous 3=Asynchronous			3=Asynchronous	Synchro check operation mode
Dead line value	0.1...0.8	xUn	0.1	0.2	Voltage low limit line for energizing check
Live line value	0.2...1.0	xUn	0.1	0.8	Voltage high limit line for energizing check
Dead bus value	0.1...0.8	xUn	0.1	0.2	Voltage low limit bus for energizing check
Live bus value	0.2...1.0	xUn	0.1	0.5	Voltage high limit bus for energizing check
Max energizing V	0.50...1.15	xUn	0.01	1.05	Maximum voltage for energizing

Table 899: 25 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Control mode	1=Continuous 2=Command			1=Continuous	Selection of synchro check command or Continuous control mode
Close pulse	200...60000	ms	10	200	Breaker closing pulse duration
Phase shift	-180...180	deg	1	0	Correction of phase difference between measured U_BUS and U_LINE
Minimum Syn time	0...60000	ms	10	0	Minimum time to accept synchronizing
Maximum Syn time	100...6000000	ms	10	2000	Maximum time to accept synchronizing
Energizing time	100...60000	ms	10	100	Time delay for energizing check
Closing time of CB	40...250	ms	10	60	Closing time of the breaker
Voltage source switch	0=False 1=True			0=False	Voltage source switch

9.3.8 Monitored data

Table 900: 25 Monitored data

Name	Type	Values (Range)	Unit	Description
ENERG_STATE	Enum	0=Unknown 1=Both Live 2=Live L, Dead B 3=Dead L, Live B 4=Both Dead		Energization state of Line and Bus
U_DIFF_MEAS	FLOAT32	0.00...1.00	xUn	Calculated voltage amplitude difference
FR_DIFF_MEAS	FLOAT32	0.000...0.100	xFn	Calculated voltage frequency difference
PH_DIFF_MEAS	FLOAT32	0.00...180.00	deg	Calculated voltage phase angle difference
U_DIFF_SYNC	BOOLEAN	0=False 1=True		Voltage difference out of limit for synchronizing
PH_DIF_SYNC	BOOLEAN	0=False 1=True		Phase angle difference out of limit for synchronizing
FR_DIFF_SYNC	BOOLEAN	0=False 1=True		Frequency difference out of limit for synchronizing
25	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

9.3.9 Technical data

Table 901: 25 Technical data

Characteristic	Value
Operation accuracy	Depending on the frequency of the voltage measured: f_n ±1 Hz
	Voltage: ±3.0% of the set value or ±0.01 × V_n Frequency: ±10 mHz Phase angle: ±3°
Reset time	<50 ms
Reset ratio	Typically 0.96
Trip time accuracy in definite time mode	±1.0% of the set value or ±20 ms

9.3.10 Technical revision history

Table 902: 25 Technical revision history

Technical revision	Change
B	Internal improvement
C	Added new setting *Voltage source switch* to switch the input signals `V_BUS` (bus voltage) and `V_LINE` (line voltage) between each other.

9.4 Autoreclosing 79

9.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Autoreclosing	DARREC	O -> I	79

9.4.2 Function block

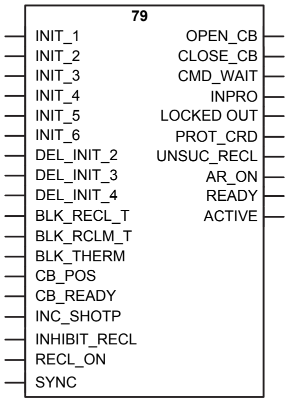


Figure 502: Function block

9.4.3 Functionality

About 80 to 85 percent of faults in the MV overhead lines are transient and automatically cleared with a momentary de-energization of the line. The rest of the faults, 15 to 20 percent, can be cleared by longer interruptions. The de-energization of the fault location for a selected time period is implemented through automatic reclosing, during which most of the faults can be cleared.

In case of a permanent fault, the automatic reclosing is followed by final tripping. A permanent fault must be located and cleared before the fault location can be re-energized.

The autoreclosing function 79 can be used with any circuit breaker suitable for autoreclosing. The function provides five programmable autoreclosing shots which can perform one to five successive autoreclosings of desired type and duration, for instance one high-speed and one delayed autoreclosing.

When the reclosing is initiated with pickup of the protection function, the autoreclosing function can execute the final trip of the circuit breaker in a short trip time, provided that the fault still persists when the last selected reclosing has been carried out.

9.4.3.1 Protection signal definition

The *Control line* setting defines which of the initiation signals are protection pickup and trip signals and which are not. With this setting, the user can distinguish the blocking signals from the protection signals. The *Control line* setting is a bit mask, that is, the lowest bit controls the `INIT_1` line and the highest bit the `INIT_6` line. Some example combinations of the *Control line* setting are as follows:

Table 903: Control line setting definition

Control line setting	INIT_1	INIT_2 DEL_INIT_2	INIT_3 DEL_INIT_3	INIT_4 DEL_INIT_4	INIT_5	INIT_6
0	other	other	other	other	other	other
1	prot	other	other	other	other	other
2	other	prot	other	other	other	other
3	prot	prot	other	other	other	other
4	other	other	prot	other	other	other
5	prot	other	prot	other	other	other
...63	prot	prot	prot	prot	prot	prot

prot = protection signal

other = non-protection signal

When the corresponding bit or bits in both the *Control line* setting and the INIT_X line are TRUE:

- The CLOSE_CB output is blocked until the protection is reset
- If the INIT_X line defined as the protection signal is activated during the discrimination time, the AR function goes to lockout
- If the INIT_X line defined as the protection signal stays active longer than the time set by the *Max trip time* setting, the AR function goes to lockout (long trip)
- The UNSUC_RECL output is activated after a pre-defined two minutes (alarming ground-fault).

9.4.3.2 Zone coordination

Zone coordination is used in the zone sequence between local protection units and downstream devices. At the falling edge of the INC_SHOTP line, the value of the shot pointer is increased by one, unless a shot is in progress or the shot pointer already has the maximum value.

The falling edge of the INC_SHOTP line is not accepted if any of the shots are in progress.

9.4.3.3 Master and slave scheme

With the cooperation between the AR units in the same protection relay or between protection relays, sequential reclosings of two breakers at a line end in a 1½-breaker, double breaker or ring-bus arrangement can be achieved. One unit is defined as a master and it executes the reclosing first. If the reclosing is successful and no trip takes place, the second unit, that is the slave, is released to complete the reclose shot. With persistent faults, the breaker reclosing is limited to the first breaker.

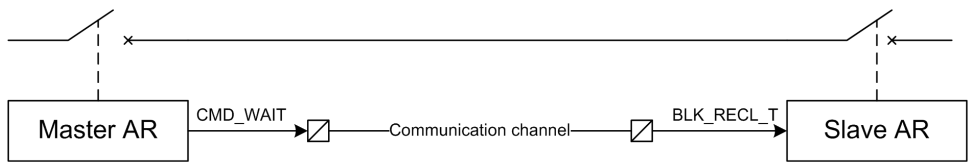


Figure 503: Master and slave scheme

If the AR unit is defined as a master by setting its terminal priority to high:

- The unit activates the CMD_WAIT output to the low priority slave unit whenever a shot is in progress, a reclosing is unsuccessful or the BLK_RCLM_T input is active
- The CMD_WAIT output is reset one second after the reclose command is given or if the sequence is unsuccessful when the reclaim time elapses.

If the AR unit is defined as a slave by setting its terminal priority to low:

- The unit waits until the master releases the BLK_RECL_T input (the CMD_WAIT output in the master). Only after this signal has been deactivated, the reclose time for the slave unit can be started.
- The slave unit is set to a lockout state if the BLK_RECL_T input is not released within the time defined by the *Max wait time* setting , which follows the initiation of an autoreclosing shot.

If the terminal priority of the AR unit is set to "none", the AR unit skips all these actions.

9.4.3.4 Thermal overload blocking

An alarm or pickup signal from the thermal overload protection 49F can be routed to the input BLK_THERM to block and hold the reclose sequence. The BLK_THERM signal does not affect the starting of the sequence. When the reclose time has elapsed and the BLK_THERM input is active, the shot is not ready until the BLK_THERM input deactivates. Should the BLK_THERM input remain active longer than the time set by the setting *Max Thm block time*, the AR function goes to lockout.

If the BLK_THERM input is activated when the auto wait timer is running, the auto wait timer is reset and the timer restarted when the BLK_THERM input deactivates.

9.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”. Setting *Operation* to "Disable" resets non-volatile counters.

The reclosing operation can be enabled and disabled with the *Reclosing operation* setting. This setting does not disable the function, only the reclosing functionality. The setting has three parameter values: “Enable”, “External Ctl” and ”Disable”. The setting value “Enable” enables the reclosing operation and “Disable” disables it. When the setting value “External Ctl” is selected, the reclosing operation is controlled with the `RECL_ON` input. `AR_ON` is activated when reclosing operation is enabled.

The operation of 79 can be described using a module diagram. All the modules in the diagram are explained in the next sections.

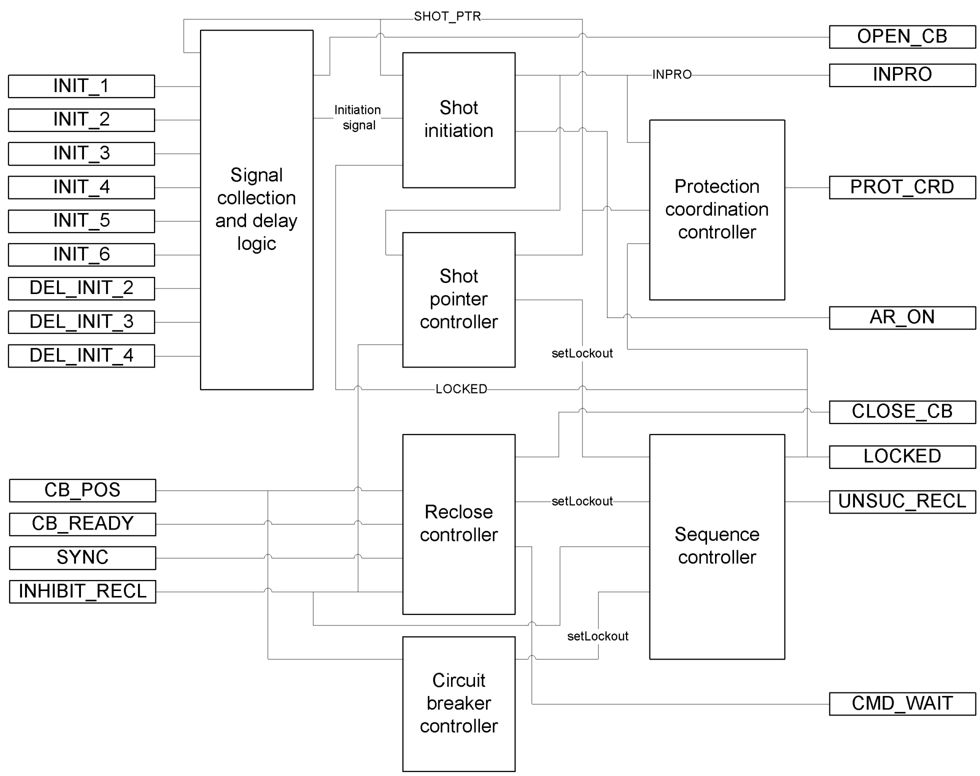


Figure 504: Functional module diagram

9.4.4.1 Signal collection and delay logic

When the protection trips, the initiation of autoreclosing shots is in most applications executed with the `INIT_1...6` inputs. The `DEL_INIT2...4` inputs are not used. In some countries, pickup of the protection stage is also used for the shot initiation. This is the only time when the `DEL_INIT` inputs are used.

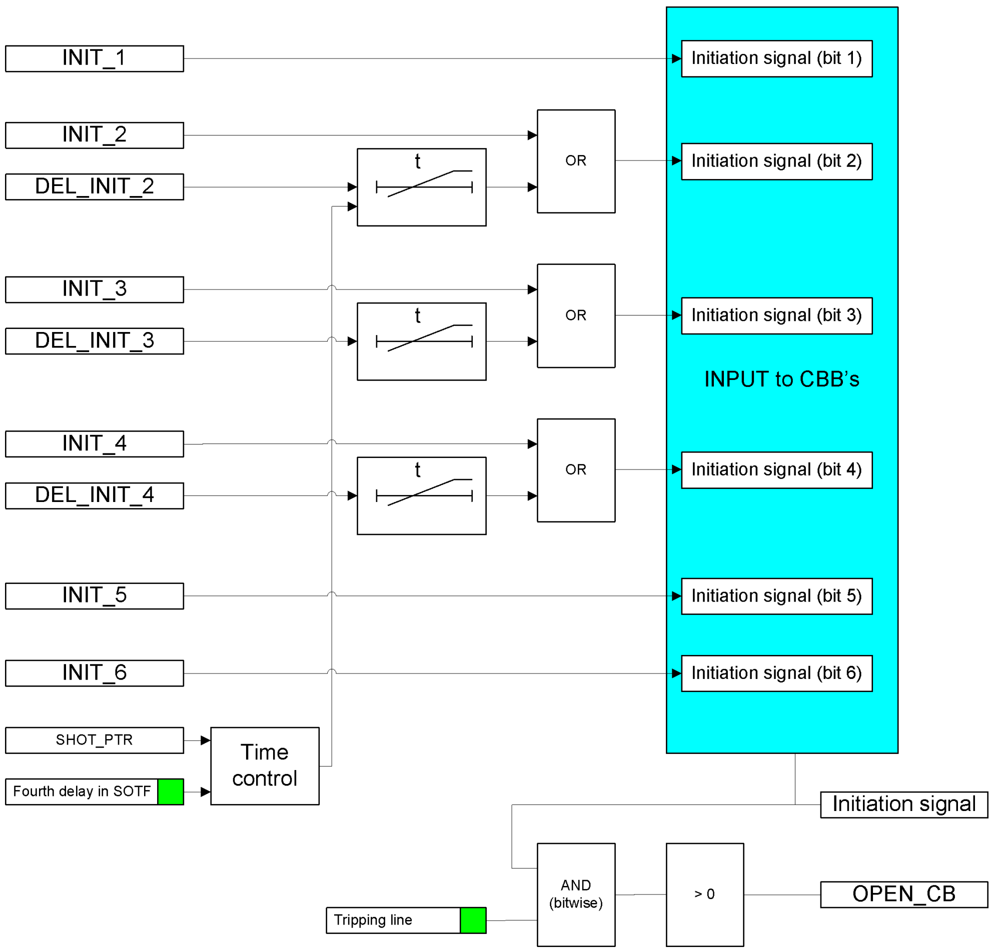


Figure 505: Schematic diagram of delayed initiation input signals

In total, the AR function contains six separate initiation lines used for the initiation or blocking of the autoreclosing shots. These lines are divided into two types of channels. In three of these channels, the signal to the AR function can be delayed, whereas the other three channels do not have any delaying capability.

Each channel that is capable of delaying a pickup signal has four time delays. The time delay is selected based on the shot pointer in the AR function. For the first reclose attempt, the first time delay is selected; for the second attempt, the second time delay and so on. For the fourth and fifth attempts, the time delays are the same.

Time delay settings for the DEL_INIT_2 signal

- *Str 2 delay shot 1*
- *Str 2 delay shot 2*
- *Str 2 delay shot 3*
- *Str 2 delay shot 4*

Time delay settings for the DEL_INIT_3 signal

- *Str 3 delay shot 1*
- *Str 3 delay shot 2*
- *Str 3 delay shot 3*
- *Str 3 delay shot 4*

Time delay settings for the DEL_INIT_4 signal

- *Str 4 delay shot 1*
- *Str 4 delay shot 2*
- *Str 4 delay shot 3*
- *Str 4 delay shot 4*

Normally, only two or three reclosing attempts are made. The third and fourth attempts are used to provide the so-called fast final trip to lockout.

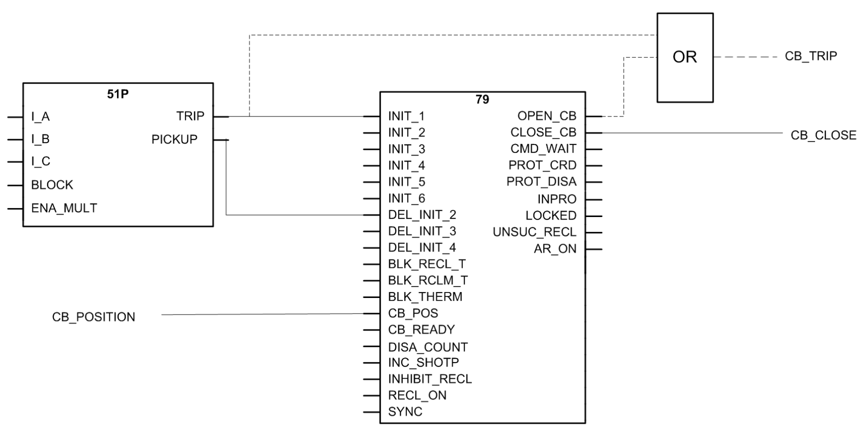


Figure 506: Autoreclosing configuration example

Delayed `DEL_INIT_2...4` signals are used only when the autoreclosing shot is initiated with the pickup signal of a protection stage. After a pickup delay, the AR function opens the circuit breaker and an autoreclosing shot is initiated. When the shot is initiated with the trip signal of the protection, the protection function trips the circuit breaker and simultaneously initiates the autoreclosing shot.

If the circuit breaker is manually closed against the fault, that is, if SOTF is used, the fourth time delay can automatically be taken into use. This is controlled with the internal logic of the AR function and the *Fourth delay in SOTF* parameter.

A typical autoreclose situation is where one autoreclosing shot has been performed after the fault was detected. There are two types of such cases: operation initiated with protection pickup signal and operation initiated with protection trip signal. In both cases, the autoreclosing sequence is successful: the reclaim time elapses and no new sequence is picked up.

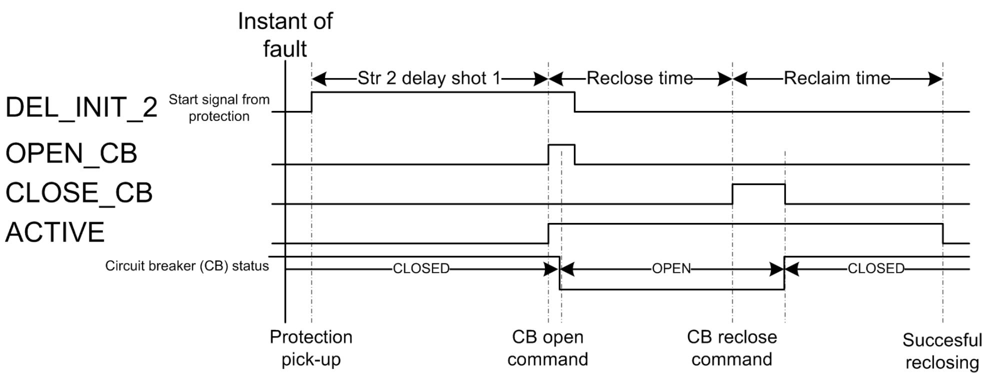


Figure 507: Signal scheme of autoreclosing operation initiated with protection pickup signal

The autoreclosing shot is initiated with a trip signal of the protection function after the pickup delay time has elapsed. The autoreclosing picks up when the *Str 2 delay shot 1* setting elapses.

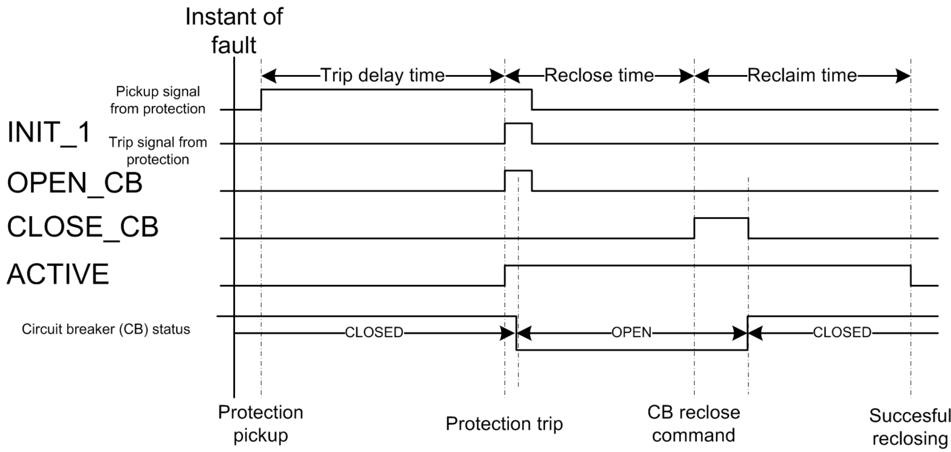


Figure 508: Signal scheme of autoreclosing operation initiated with protection trip signal

The autoreclosing shot is initiated with a trip signal of the protection function. The autoreclosing picks up when the protection trip delay time elapses.

Normally, all trip and pickup signals are used to initiate an autoreclosing shot and trip the circuit breaker. `ACTIVE` output indicates reclosing sequence in progress. If any of the input signals `INIT_X` or `DEL_INIT_X` are used for blocking, the corresponding bit in the *Tripping line* setting must be FALSE. This is to ensure that the circuit breaker does not trip from that signal, that is, the signal does not activate the `OPEN_CB` output. The default value for the setting is "63", which means that all initiation signals activate the `OPEN_CB` output. The lowest bit in the *Tripping line* setting corresponds to the `INIT_1` input, the highest bit to the `INIT_6` line.

9.4.4.2 Shot initiation

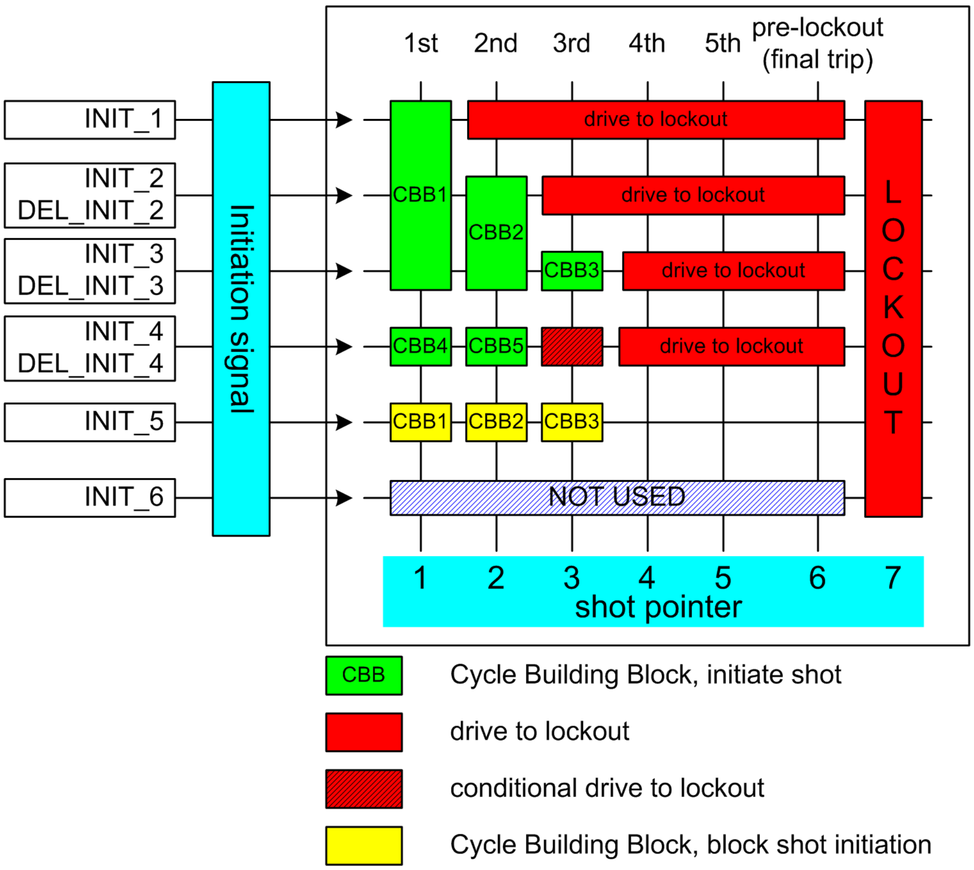


Figure 509: Example of an autoreclosing program with a reclose scheme matrix

In the AR function, each shot can be programmed to locate anywhere in the reclose scheme matrix. The shots are like building blocks used to design the reclose program. The building blocks are called CBBs. All blocks are alike and have settings which give the attempt number (columns in the matrix), the initiation or blocking signals (rows in the matrix) and the reclose time of the shot.

The settings related to CBB configuration are:

- *First...Seventh reclose time*
- *Init signals CBB1…CBB7*
- *Blk signals CBB1…CBB7*
- *Shot number CBB1…CBB7*

The reclose time defines the open and dead times, that is, the time between the `OPEN_CB` and the `CLOSE_CB` commands. The *Init signals CBBx* setting defines the initiation signals. The *Blk signals CBBx* setting defines the blocking signals that are related to the CBB (rows in the matrix). The *Shot number CBB1…CBB7* setting defines which shot is related to the CBB (columns in the matrix). For example, CBB1 settings are:

- *First reclose time* = 1.0s
- *Init signals CBB1* = 7 (three lowest bits: 111000 = 7)
- *Blk signals CBB1* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB1* = 1

CBB2 settings are:

- *Second reclose time* = 10s
- *Init signals CBB2* = 6 (the second and third bits: 011000 = 6)
- *Blk signals CBB2* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB2* = 2

CBB3 settings are:

- *Third reclose time* = 30s
- *Init signals CBB3* = 4 (the third bit: 001000 = 4)
- *Blk signals CBB3* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB3* = 3

CBB4 settings are:

- *Fourth reclose time* = 0.5s
- *Init signals CBB4* = 8 (the fourth bit: 000100 = 8)
- *Blk signals CBB4* = 0 (no blocking signals related to this CBB)
- *Shot number CBB4* = 1

If a shot is initiated from the `INIT_1` line, only one shot is allowed before lockout. If a shot is initiated from the `INIT_3` line, three shots are allowed before lockout.

A sequence initiation from the `INIT_4` line leads to a lockout after two shots. In a situation where the initiation is made from both the `INIT_3` and `INIT_4` lines, a third shot is allowed, that is, CBB3 is allowed to start. This is called conditional lockout. If the initiation is made from the `INIT_2` and `INIT_3` lines, an immediate lockout occurs.

The `INIT_5` line is used for blocking purposes. If the `INIT_5` line is active during a sequence start, the reclose attempt is blocked and the AR function goes to lockout.

If more than one CBBs are started with the shot pointer, the CBB with the smallest individual number is always selected. For example, if the

`INIT_2` and `INIT_4` lines are active for the second shot, that is, the shot pointer is 2, CBB2 is started instead of CBB5.

Even if the initiation signals are not received from the protection functions, the AR function can be set to continue from the second to the fifth reclose shot. The AR function can, for example, be requested to automatically continue with the sequence when the circuit breaker fails to close when requested. In such a case, the AR function issues a `CLOSE_CB` command. When the wait close time elapses, that is, the closing of the circuit breaker fails, the next shot is automatically started. Another example is the embedded generation on the power line, which can make the synchronism check fail and prevent the reclosing. If the autoreclose sequence is continued to the second shot, a successful synchronous reclosing is more likely than with the first shot, since the second shot lasts longer than the first one.

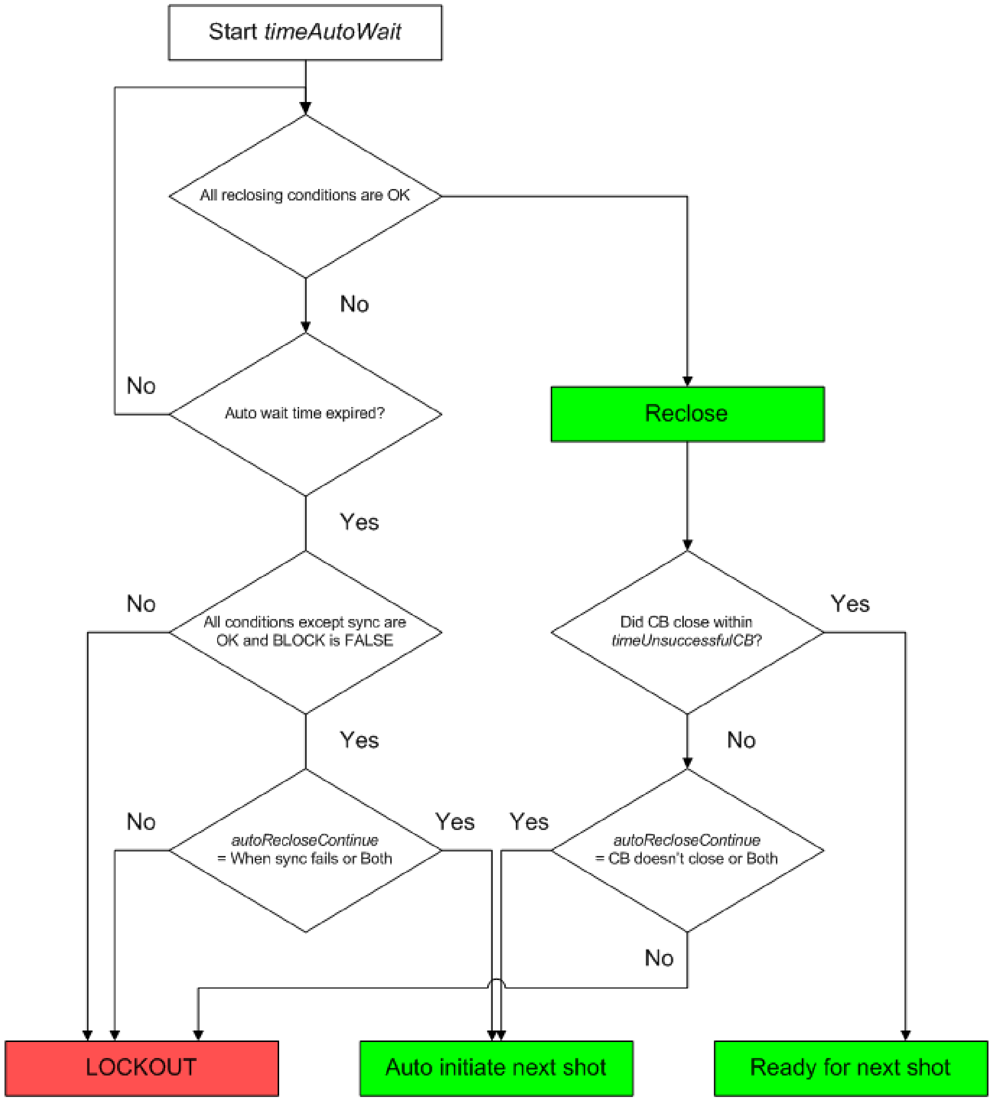


Figure 510: Logic diagram of auto-initiation sequence detection

Automatic initiation can be selected with the *Auto initiation Cnd* setting to be the following:

- Not allowed: no automatic initiation is allowed
- When the synchronization fails, the automatic initiation is carried out when the auto wait time elapses and the reclosing is prevented due to a failure during the synchronism check
- When the circuit breaker does not close, the automatic initiation is carried out if the circuit breaker does not close within the wait close time after issuing the reclose command
- Both: the automatic initiation is allowed when synchronization fails or the circuit breaker does not close.

The *Auto init* parameter defines which INIT_X lines are activated in the auto-initiation. The default value for this parameter is "0", which means that no auto-initiation is selected.

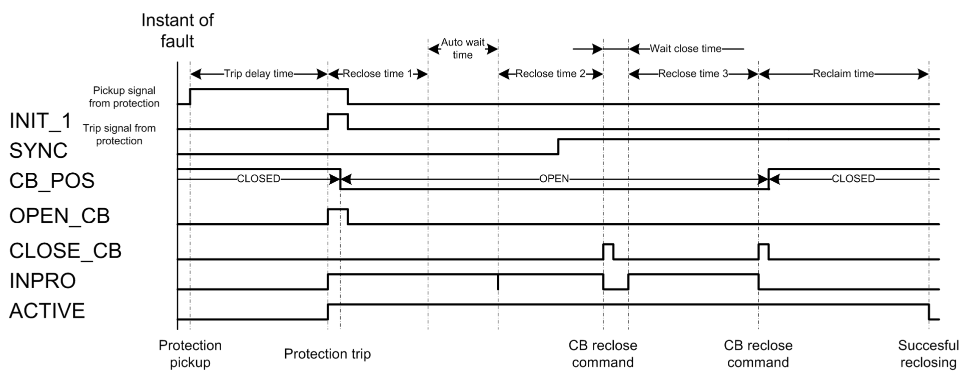


Figure 511: Example of an auto-initiation sequence with synchronization failure in the first shot and circuit breaker closing failure in the second shot

In the first shot, the synchronization condition is not fulfilled (SYNC is FALSE). When the auto wait timer elapses, the sequence continues to the second shot. During the second reclosing, the synchronization condition is fulfilled and the close command is given to the circuit breaker after the second reclose time has elapsed.

After the second shot, the circuit breaker fails to close when the wait close time has elapsed. The third shot is started and a new close command is given after the third reclose time has elapsed. The circuit breaker closes normally and the reclaim time starts. When the reclaim time has elapsed, the sequence is concluded successful.

9.4.4.3 Shot pointer controller

The execution of a reclose sequence is controlled by a shot pointer. It can be adjusted with the SHOT_PTR monitored data.

The shot pointer starts from an initial value "1" and determines according to the settings whether or not a certain shot is allowed to be initiated. After every shot, the shot pointer value increases. This is carried out until a successful reclosing or lockout takes place after a complete shot sequence containing a total of five shots.

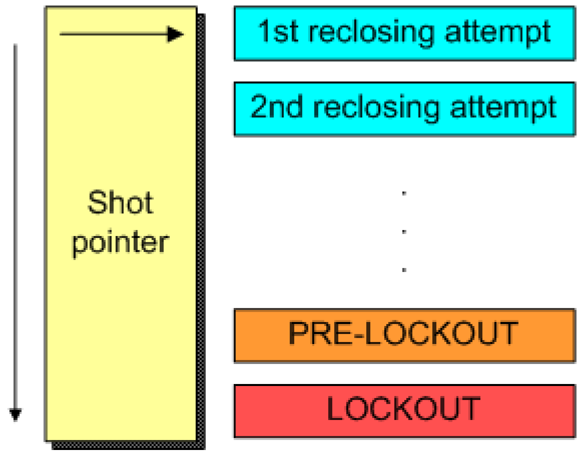


Figure 512: Shot pointer function

Every time the shot pointer increases, the reclaim time starts. When the reclaim time ends, the shot pointer sets to its initial value, unless no new shot is initiated. The shot pointer increases when the reclose time elapses or at the falling edge of the `INC_SHOTP` signal.

When `SHOT_PTR` has the value six, the AR function is in a so called pre-lockout state. If a new initiation occurs during the pre-lockout state, the AR function goes to lockout. Therefore, a new sequence initiation during the pre-lockout state is not possible.

The AR function goes to the pre-lockout state in the following cases:

- During SOTF
- When the AR function is active, it stays in a pre-lockout state for the time defined by the reclaim time
- When all five shots have been executed
- When the frequent operation counter limit is reached. A new sequence initiation forces the AR function to lockout.

9.4.4.4 Reclose controller

The reclose controller calculates the reclose, discrimination and reclaim times. The reclose time is started when the `INPRO` signal is activated, that is, when the sequence starts and the activated CBB defines the reclose time.

When the reclose time has elapsed, the CLOSE_CB output is not activated until the following conditions are fulfilled:

- The SYNC input must be TRUE if the particular CBB requires information about the synchronism
- All AR initiation inputs that are defined protection lines (using the *Control line* setting) are inactive
- The circuit breaker is open
- The circuit breaker is ready for the close command, that is, the CB_READY input is TRUE. This is indicated by active READY output.

If at least one of the conditions is not fulfilled within the time set with the *Auto wait time* parameter, the autoreclose sequence is locked.

The synchronism requirement for the CBBs can be defined with the *Synchronisation set* setting, which is a bit mask. The lowest bit in the *Synchronisation set* setting is related to CBB1 and the highest bit to CBB7. For example, if the setting is set to "1", only CBB1 requires synchronism. If the setting is it set to "7", CBB1, CBB2 and CBB3 require the SYNC input to be TRUE before the reclosing command can be given.

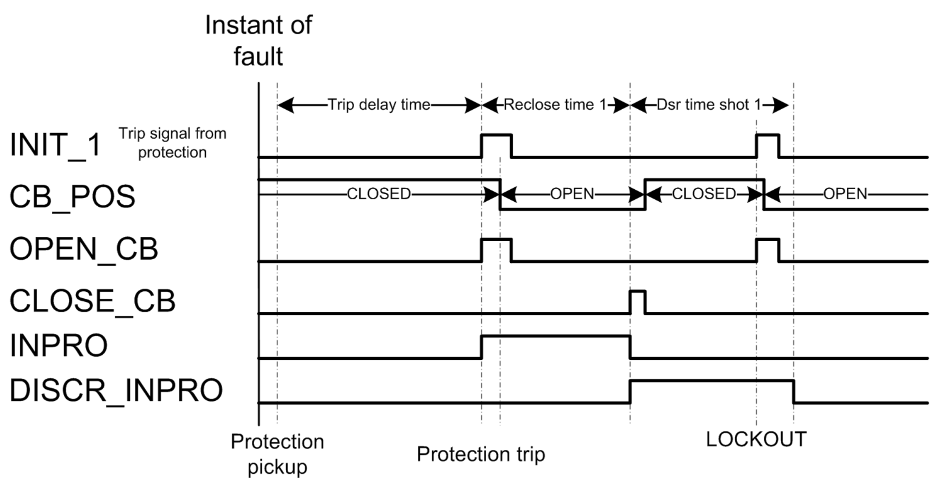


Figure 513: Initiation during discrimination time - AR function goes to lockout

The discrimination time starts when the close command CLOSE_CB has been given. If a pickup input is activated before the discrimination time has elapsed, the AR function goes to lockout. The default value for each discrimination time is zero. The discrimination time can be adjusted with the *Dsr time shot 1…4* parameter.

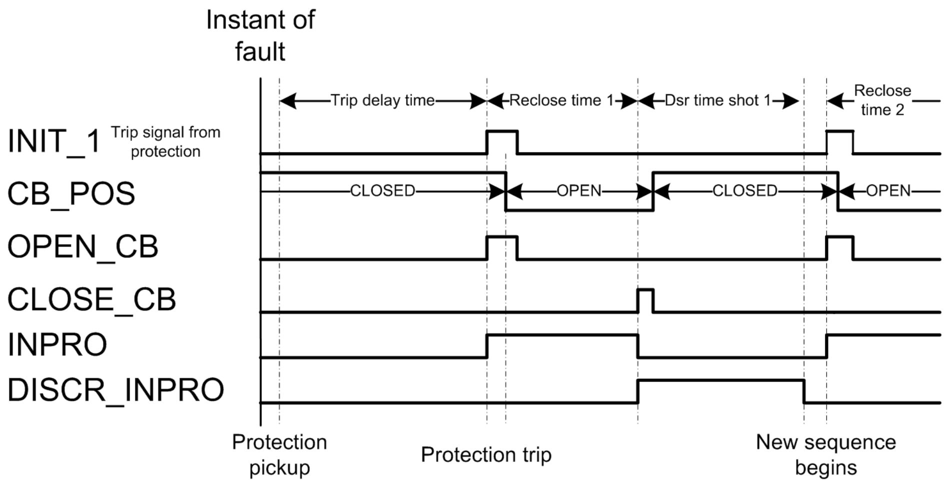


Figure 514: Initiation after elapsed discrimination time - new shot begins

9.4.4.5 Sequence controller

When the `LOCKED` output is active, the AR function is in lockout. This means that new sequences cannot be initialized, because AR is insensitive to initiation commands. It can be released from the lockout state in the following ways.

- The function is reset through communication with the *RecRs* parameter. The same functionality can also be found in the Clear menu (79 reset).
- The lockout is automatically reset after the reclaim time, if the *Auto lockout reset* setting is in use.

If the *Auto lockout reset* setting is not in use, the lockout can be released only with the *RecRs* parameter.

The AR function can go to lockout for many reasons.

- The `INHIBIT_RECL` input is active.
- All shots have been executed and a new initiation is made (final trip).
- The time set with the *Auto wait time* parameter expires and the automatic sequence initiation is not allowed because of a synchronization failure.
- The time set with the *Wait close time* parameter expires, that is, the circuit breaker does not close or the automatic sequence initiation is not allowed due to a closing failure of the circuit breaker.
- A new shot is initiated during the discrimination time.
- The time set with the *Max wait time* parameter expires, that is, the master unit does not release the slave unit.

- The frequent operation counter limit is reached and new sequence is initiated. The lockout is released when the recovery timer elapses.
- The protection trip signal has been active longer than the time set with the *Max wait time* parameter since the shot initiation.
- The circuit breaker is closed manually during an autoreclosing sequence and the manual close mode is FALSE.

9.4.4.6 Protection coordination controller

The `PROT_CRD` output is used for controlling the protection functions. In several applications, such as fuse-saving applications involving down-stream fuses, tripping and initiation of shot 1 should be fast (instantaneous or short-time delayed). The tripping and initiation of shots 2, 3 and definite tripping time should be delayed.

In this example, two overcurrent elements 51P and 50P-2 are used. 50P-2 is given an instantaneous characteristic and 51P is given a time delay.

The `PROT_CRD` output is activated, if the `SHOT_PTR` value is same or higher than the value defined with the *Protection crd limit* setting and all initialization signals have been reset. The `PROT_CRD` output is reset under the following conditions:

- If the cut-out time elapses
- If the reclaim time elapses and the AR function is ready for a new sequence
- If the AR function is in lockout or disabled, that is, if the value of the *Protection crd mode* setting is "AR inoperative" or "AR inop, CB man".

The `PROT_CRD` output can also be controlled with the *Protection crd mode* setting. The setting has the following modes:

- "no condition": the `PROT_CRD` output is controlled only with the *Protection crd limit* setting
- "AR inoperative": the `PROT_CRD` output is active, if the AR function is disabled or in the lockout state, or if the `INHIBIT_RECL` input is active
- "CB close manual": the `PROT_CRD` output is active for the reclaim time if the circuit breaker has been manually closed, that is, the AR function has not issued a close command
- "AR inop, CB man": both the modes "AR inoperative" and "CB close manual" are effective
- "always": the `PROT_CRD` output is constantly active

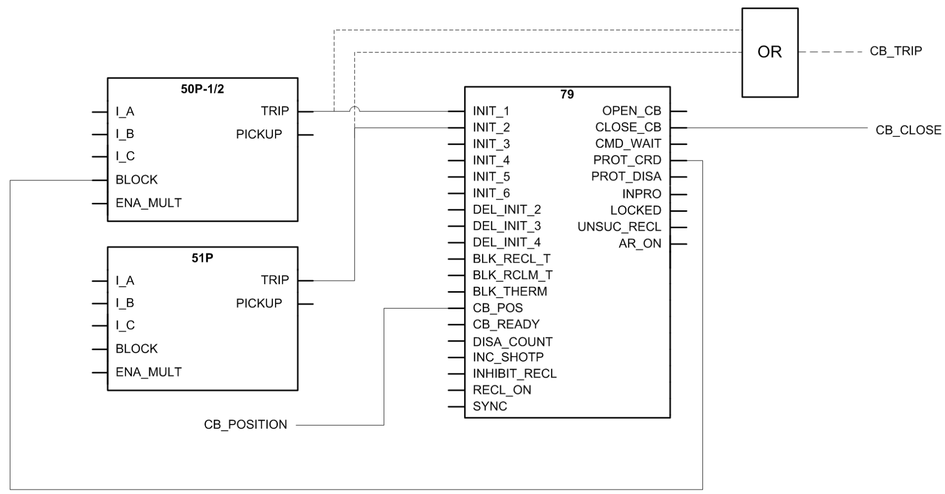


Figure 515: Configuration example of using the `PROT_CRD` output for protection blocking

If the *Protection crd limit* setting has the value "1", the instantaneous three-phase overcurrent protection function 50P-3 is disabled or blocked after the first shot.

9.4.4.7 Circuit breaker controller

Circuit breaker controller contains two features: SOTF and frequent-operation counter. SOTF protects the AR function in permanent faults.

The circuit breaker position information is controlled with the *CB closed Pos status* setting. The setting value "TRUE" means that when the circuit breaker is closed, the `CB_POS` input is TRUE. When the setting value is "FALSE", the `CB_POS` input is FALSE, provided that the circuit breaker is closed. The reclose command pulse time can be controlled with the *Close pulse time* setting: the `CLOSE_CB` output is active for the time set with the *Close pulse time* setting. The `CLOSE_CB` output is deactivated also when the circuit breaker is detected to be closed, that is, when the `CB_POS` input changes from open state to closed state. The *Wait close time* setting defines the time after the `CLOSE_CB` command activation, during which the circuit breaker should be closed. If the closing of circuit breaker does not happen during this time, the autoreclosing function is driven to lockout or, if allowed, an auto-initiation is activated.

The main motivation for autoreclosing to begin with is the assumption that the fault is temporary by nature, and that a momentary de-energizing of the power line and an automatic reclosing restores the power supply. However, when the power line is manually energized and an immediate protection trip is detected, it is very likely that the fault is of a permanent type. A permanent fault is, for example, energizing a power line into a forgotten grounding after a maintenance work along the power line. In such cases, SOTF is activated, but only for the reclaim time after energizing the power line and only when the circuit breaker is closed manually and not by the AR function.

SOTF disables any initiation of an autoreclosing shot. The energizing of the power line is detected from the `CB_POS` information.

SOTF is activated when the AR function is enabled or when the AR function is started and the SOTF should remain active for the reclaim time.

When SOTF is detected, the parameter *SOTF* is active.

If the *Manual close mode* setting is set to FALSE and the circuit breaker has been manually closed during an autoreclosing shot, the AR unit goes to an immediate lockout.

If the *Manual close mode* setting is set to TRUE and the circuit breaker has been manually closed during an autoreclosing shot (the `INPRO` is active), the shot is considered as completed.

When SOTF starts, reclaim time is restarted, provided that it is running.

The frequent-operation counter is intended for blocking the autoreclosing function in cases where the fault causes repetitive autoreclosing sequences during a short period of time. For instance, if a tree causes a short circuit and, as a result, there are autoreclosing shots within a few minutes interval during a stormy night. These types of faults can easily damage the circuit breaker if the AR function is not locked by a frequent-operation counter.

The frequent-operation counter has three settings:

- *Frq Op counter limit*
- *Frq Op counter time*
- *Frq Op recovery time*

The *Frq Op counter limit* setting defines the number of reclose attempts that are allowed during the time defined with the *Frq Op counter time* setting. If the set value is reached within a pre-defined period defined with the *Frq Op counter time* setting, the AR function goes to lockout when a new shot begins, provided that the counter is still above the set limit. The lockout is released after the recovery time has elapsed. The recovery time can be defined with the *Frq Op recovery time* setting .

If the circuit breaker is manually closed during the recovery time, the reclaim time is activated after the recovery timer has elapsed.

9.4.5 Counters

The AR function contains six counters. Their values are stored in a semi-retain memory. The counters are increased at the rising edge of the reclosing command. The counters count the following situations.

- `COUNTER`: counts every reclosing command activation
- `CNT_SHOT1`: counts reclosing commands that are executed from shot 1
- `CNT_SHOT2`: counts reclosing commands that are executed from shot 2
- `CNT_SHOT3`: counts reclosing commands that are executed from shot 3
- `CNT_SHOT4`: counts reclosing commands that are executed from shot 4
- `CNT_SHOT5`: counts reclosing commands that are executed from shot 5

The counters are disabled through communication with the *DsaCnt* parameter. When the counters are disabled, the values are not updated.

The counters are reset through communication with the *CntRs* parameter.The same functionality can also be found in the clear menu (79 counters).

9.4.6 Application

Modern electric power systems can deliver energy to users very reliably. However, different kind of faults can occur. Protection relays play an important role in detecting failures or abnormalities in the system. They detect faults and give commands for corresponding circuit breakers to isolate the defective element before excessive damage or a possible power system collapse occurs. A fast isolation also limits the disturbances caused for the healthy parts of the power system.

The faults can be transient, semi-transient or permanent. For example, a permanent fault in power cables means that there is a physical damage in the fault location that must first be located and repaired before the network voltage can be restored.

In overhead lines, the insulating material between phase conductors is air. The majority of the faults are flash-over arcing faults caused by lightning, for example. Only a short interruption is needed for extinguishing the arc. These faults are transient by nature.

A semi-transient fault can be caused for example by a bird or a tree branch falling on the overhead line. The fault disappears on its own if the fault current burns the branch or the wind blows it away.

Transient and semi-transient faults can be cleared by momentarily de-energizing the power line. Using the autoreclose function minimizes interruptions in the power system service and brings the power back on-line quickly and effortlessly.

The basic idea of the autoreclose function is simple. In overhead lines, where the possibility of self-clearing faults is high, the autoreclose function tries to restore the power by reclosing the breaker. This is a method to get the power system back into normal operation by removing the transient or semi-transient faults. Several trials, that is, autoreclose shots are allowed. If none of the trials is successful and the fault persists, definite final tripping follows.

The autoreclose function can be used with every circuit breaker that has the ability for a reclosing sequence. In 79 autoreclose function the implementing method of autoreclose sequences is patented by ABB

Table 904: Important definitions related to autoreclosing

autoreclose shot	an operation where after a preset time the breaker is closed from the breaker tripping caused by protection
autoreclose sequence	a predefined method to do reclose attempts (shots) to restore the power system
SOTF	If the protection detects a fault immediately after an open circuit breaker has been closed, it indicates that the fault was already there. It can be, for example, a forgotten grounding after maintenance work. Such closing of the circuit breaker is known as switch on to fault. Autoreclosing in such conditions is prohibited.
final trip	Occurs in case of a permanent fault, when the circuit breaker is opened for the last time after all programmed autoreclose operations. Since no auto-reclosing follows, the circuit breaker remains open. This is called final trip or definite trip.

9.4.6.1 Shot initiation

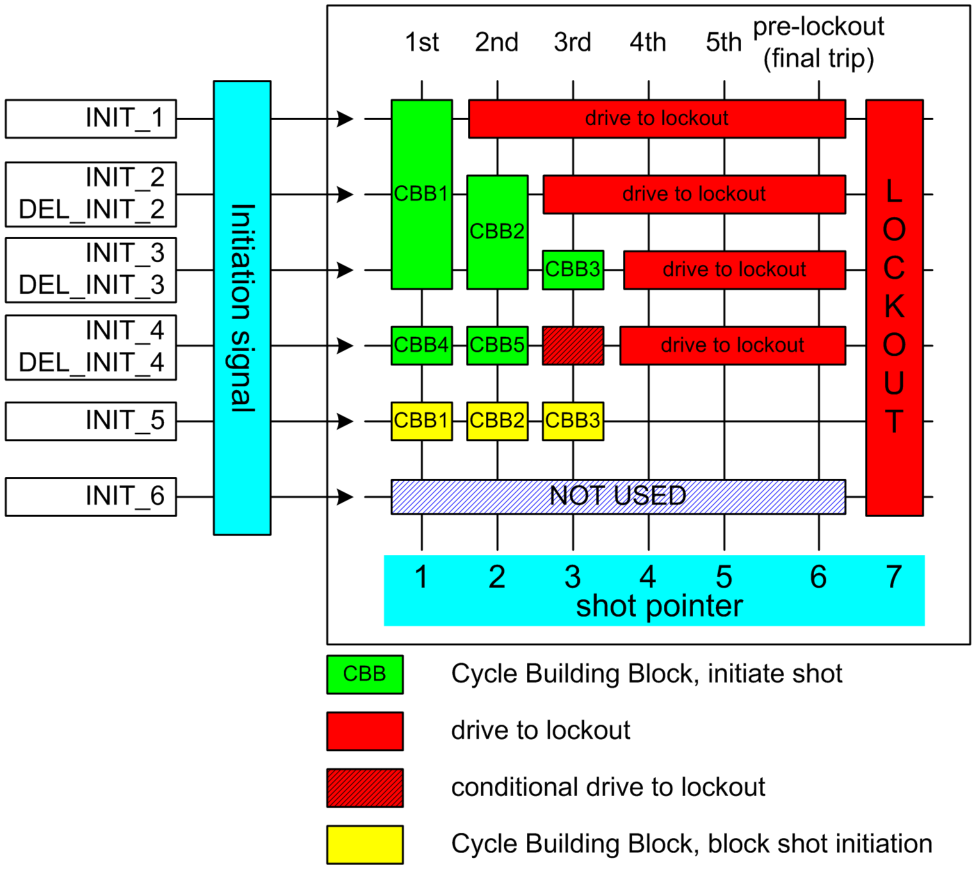


Figure 516: Example of an autoreclosing program with a reclose scheme matrix

In the AR function, each shot can be programmed to locate anywhere in the reclose scheme matrix. The shots are like building blocks used to design the reclose program. The building blocks are called CBBs. All blocks are alike and have settings which give the attempt number (columns in the matrix), the initiation or blocking signals (rows in the matrix) and the reclose time of the shot.

The settings related to CBB configuration are:

- *First...Seventh reclose time*
- *Init signals CBB1…CBB7*
- *Blk signals CBB1…CBB7*
- *Shot number CBB1…CBB7*

The reclose time defines the open and dead times, that is, the time between the `OPEN_CB` and the `CLOSE_CB` commands. The *Init signals CBBx* setting defines the initiation signals. The *Blk signals CBBx* setting defines the blocking signals that are related to the CBB (rows in the matrix). The *Shot number CBB1…CBB7* setting defines which shot is related to the CBB (columns in the matrix). For example, CBB1 settings are:

- *First reclose time* = 1.0s
- *Init signals CBB1* = 7 (three lowest bits: 111000 = 7)
- *Blk signals CBB1* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB1* = 1

CBB2 settings are:

- *Second reclose time* = 10s
- *Init signals CBB2* = 6 (the second and third bits: 011000 = 6)
- *Blk signals CBB2* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB2* = 2

CBB3 settings are:

- *Third reclose time* = 30s
- *Init signals CBB3* = 4 (the third bit: 001000 = 4)
- *Blk signals CBB3* = 16 (the fifth bit: 000010 = 16)
- *Shot number CBB3* = 3

CBB4 settings are:

- *Fourth reclose time* = 0.5s
- *Init signals CBB4* = 8 (the fourth bit: 000100 = 8)
- *Blk signals CBB4* = 0 (no blocking signals related to this CBB)
- *Shot number CBB4* = 1

If a shot is initiated from the `INIT_1` line, only one shot is allowed before lockout. If a shot is initiated from the `INIT_3` line, three shots are allowed before lockout.

A sequence initiation from the `INIT_4` line leads to a lockout after two shots. In a situation where the initiation is made from both the `INIT_3` and `INIT_4` lines, a third shot is allowed, that is, CBB3 is allowed to start. This is called conditional lockout. If the initiation is made from the `INIT_2` and `INIT_3` lines, an immediate lockout occurs.

The `INIT_5` line is used for blocking purposes. If the `INIT_5` line is active during a sequence start, the reclose attempt is blocked and the AR function goes to lockout.

If more than one CBBs are started with the shot pointer, the CBB with the smallest individual number is always selected. For example, if the

INIT_2 and INIT_4 lines are active for the second shot, that is, the shot pointer is 2, CBB2 is started instead of CBB5.

Even if the initiation signals are not received from the protection functions, the AR function can be set to continue from the second to the fifth reclose shot. The AR function can, for example, be requested to automatically continue with the sequence when the circuit breaker fails to close when requested. In such a case, the AR function issues a CLOSE_CB command. When the wait close time elapses, that is, the closing of the circuit breaker fails, the next shot is automatically started. Another example is the embedded generation on the power line, which can make the synchronism check fail and prevent the reclosing. If the autoreclose sequence is continued to the second shot, a successful synchronous reclosing is more likely than with the first shot, since the second shot lasts longer than the first one.

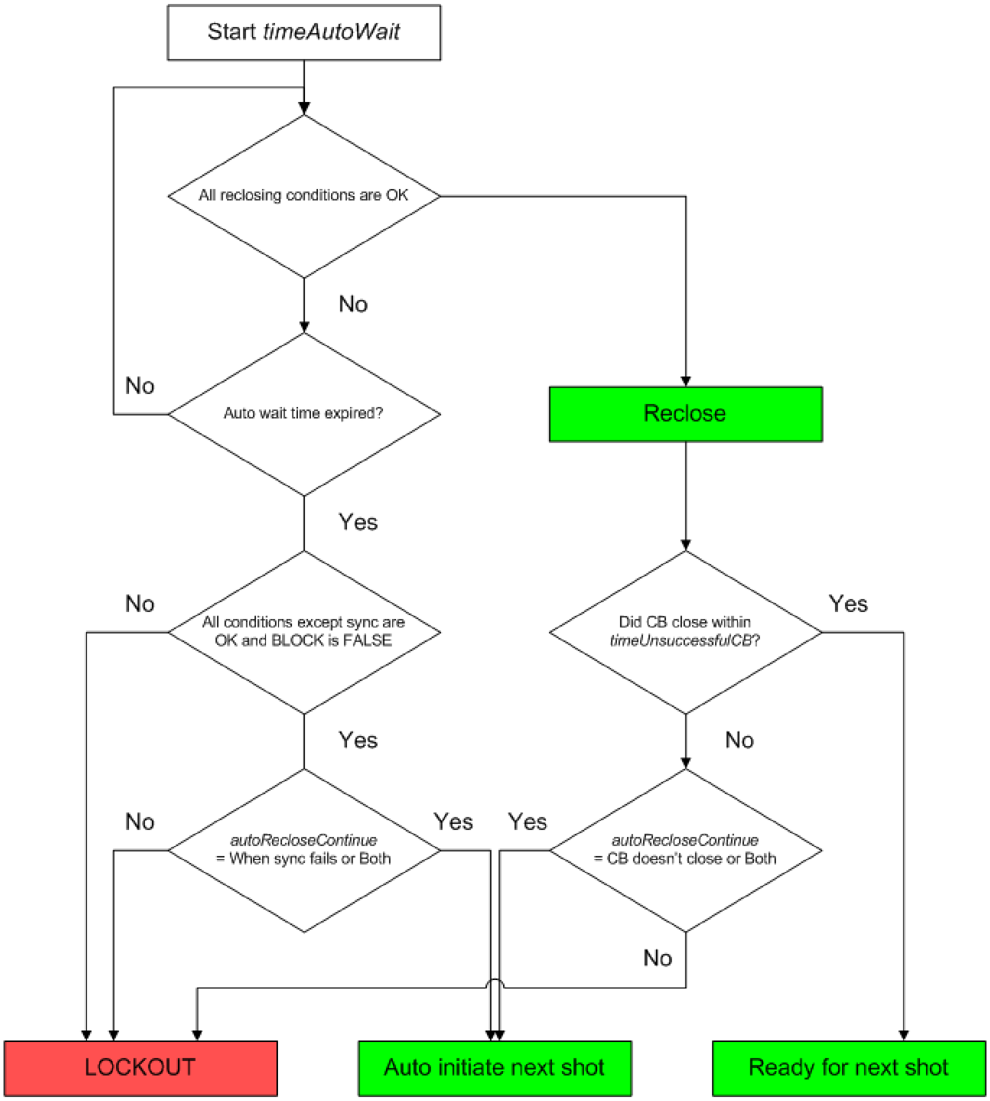


Figure 517: Logic diagram of auto-initiation sequence detection

Automatic initiation can be selected with the *Auto initiation Cnd* setting to be the following:

- Not allowed: no automatic initiation is allowed
- When the synchronization fails, the automatic initiation is carried out when the auto wait time elapses and the reclosing is prevented due to a failure during the synchronism check
- When the circuit breaker does not close, the automatic initiation is carried out if the circuit breaker does not close within the wait close time after issuing the reclose command
- Both: the automatic initiation is allowed when synchronization fails or the circuit breaker does not close.

The *Auto init* parameter defines which `INIT_X` lines are activated in the auto-initiation. The default value for this parameter is "0", which means that no auto-initiation is selected.

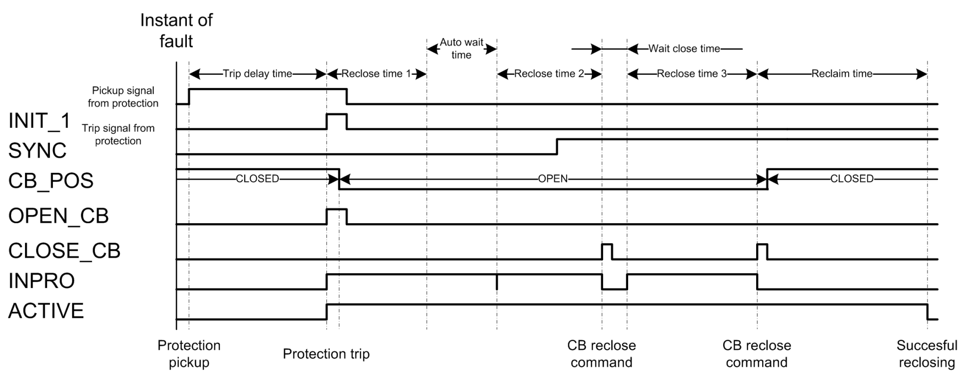


Figure 518: Example of an auto-initiation sequence with synchronization failure in the first shot and circuit breaker closing failure in the second shot

In the first shot, the synchronization condition is not fulfilled (`SYNC` is FALSE). When the auto wait timer elapses, the sequence continues to the second shot. During the second reclosing, the synchronization condition is fulfilled and the close command is given to the circuit breaker after the second reclose time has elapsed.

After the second shot, the circuit breaker fails to close when the wait close time has elapsed. The third shot is started and a new close command is given after the third reclose time has elapsed. The circuit breaker closes normally and the reclaim time starts. When the reclaim time has elapsed, the sequence is concluded successful.

9.4.6.2 Sequence

The autoreclose sequence is implemented by using up to seven CBBs. For example, if the user wants a sequence of three shots then only the first three CBBs are needed. Using building blocks instead of fixed shots gives enhanced flexibility, allowing multiple and adaptive sequences.

Each CBB is identical. The *Shot number CBB_* setting defines at which point in the autoreclose sequence the CBB should be performed, that is, whether the particular CBB is going to be the first, second, third, fourth or fifth shot.

During the initiation of a CBB, the conditions of initiation and blocking are checked. This is done for all CBBs simultaneously. Each CBB that fulfils the initiation conditions requests an execution.

The function also keeps track of shots already performed. That is, at which point the autoreclose sequence is from shot 1 to lockout. For example, if shots 1 and 2 have already been performed, only shots 3 to 5 are allowed.

Additionally, the *Enable shot jump* setting gives two possibilities:

- Only such CBBs that are set for the next shot in the sequence can be accepted for execution. For example, if the next shot in the sequence should be shot 2, a request from CBB set for shot 3 is rejected.
- Any CBB that is set for the next shot or any of the following shots can be accepted for execution. For example, if the next shot in the sequence should be shot 2, also CBBs that are set for shots 3, 4 and 5 are accepted. In other words, shot 2 can be ignored.

In case there are multiple CBBs allowed for execution, the CBB with the smallest number is chosen. For example, if CBB2 and CBB4 request an execution, CBB2 is allowed to execute the shot.

The autoreclose function can perform up to five autoreclose shots or cycles.

9.4.6.3 Configuration examples

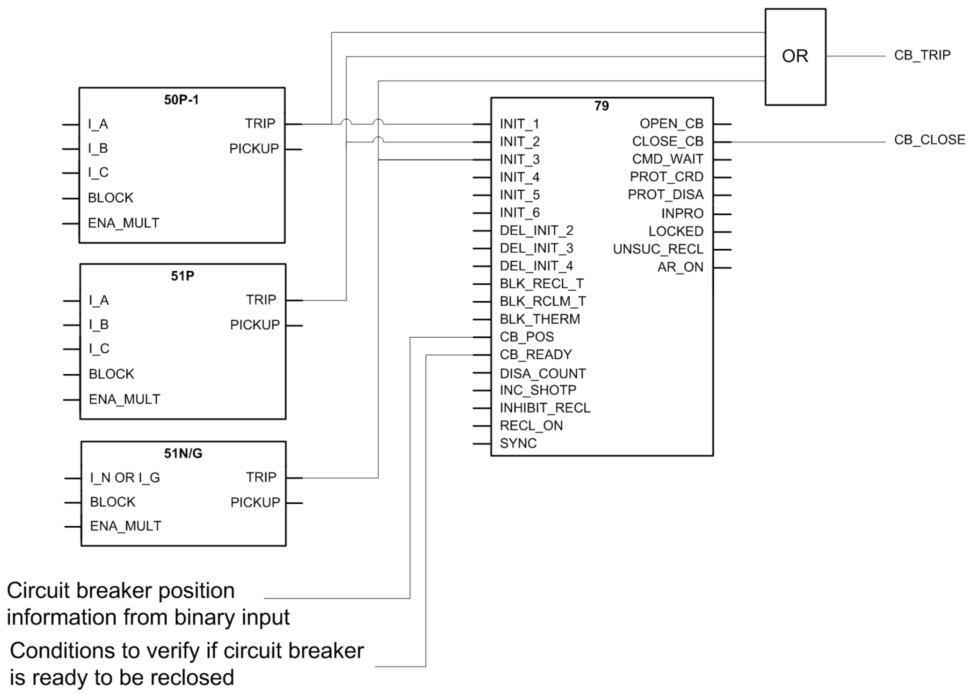


Figure 519: Example connection between protection and autoreclosing functions in protection relay configuration

It is possible to create several sequences for a configuration.

Autoreclose sequences for overcurrent and non-directional ground-fault protection applications where high speed and delayed autoreclosings are needed can be as follows:

Example 1.

The sequence is implemented by two shots which have the same reclose time for all protection functions, namely 50P-1, 51P and 51N/G. The initiation of the shots is done by activating the trip signals of the protection functions.

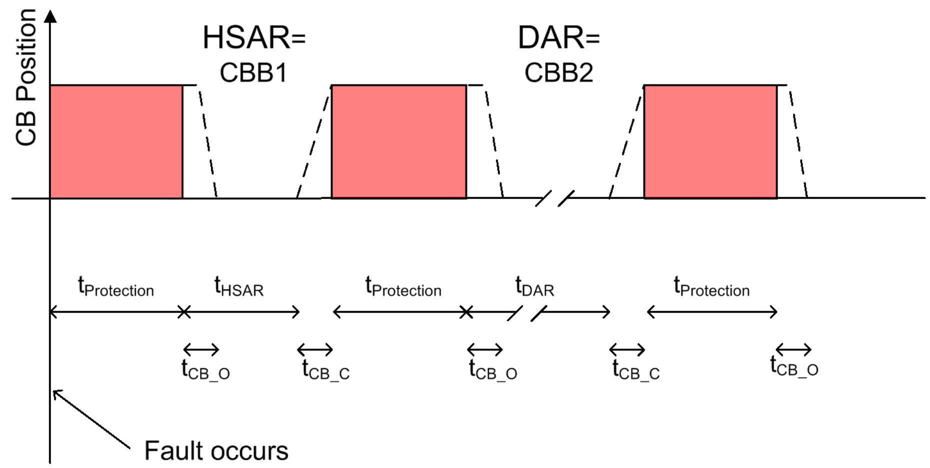


Figure 520: Autoreclosing sequence with two shots

t_{HSAR}	Time delay of high-speed autoreclosing, here: *First reclose time*
t_{DAR}	Time delay of delayed autoreclosing, here: *Second reclose time*
$t_{Protection}$	Operating time for the protection stage to clear the fault
t_{CB_O}	Operating time for opening the circuit breaker
t_{CB_C}	Operating time for closing the circuit breaker

In this case, the sequence needs two CBBs. The reclosing times for shot 1 and shot 2 are different, but each protection function initiates the same sequence. The CBB sequence is described in Table 905 as follows:

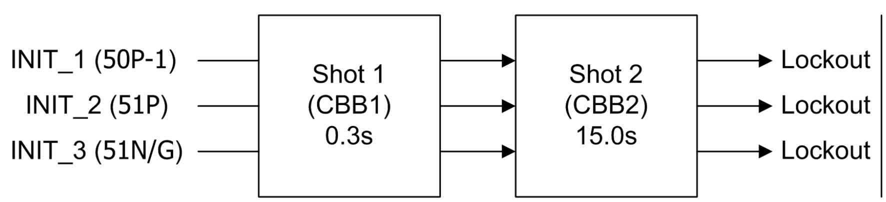


Figure 521: Two shots with three initiation lines

Table 905: Settings for configuration example 1

Setting name	Setting value
Shot number CBB1	1
Init signals CBB1	7 (lines 1, 2 and 3 = 1+2+4 = 7)
First reclose time	0.3s (an example)
Shot number CBB2	2
Init signals CBB2	7 (lines 1, 2 and 3 = 1+2+4 = 7)
Second reclose time	15.0s (an example)

Example 2

There are two separate sequences implemented with three shots. Shot 1 is implemented by CBB1 and it is initiated with the high stage of the overcurrent protection (50P-1). Shot 1 is set as a high-speed autoreclosing with a short time delay. Shot 2 is implemented with CBB2 and meant to be the first shot of the autoreclose sequence initiated by the low stage of the overcurrent protection (51P) and the low stage of the non-directional ground-fault protection (51N/G). It has the same reclose time in both situations. It is set as a high-speed autoreclosing for corresponding faults. The third shot, which is the second shot in the autoreclose sequence initiated by 51P or 51N/G, is set as a delayed autoreclosing and executed after an unsuccessful high-speed autoreclosing of a corresponding sequence.

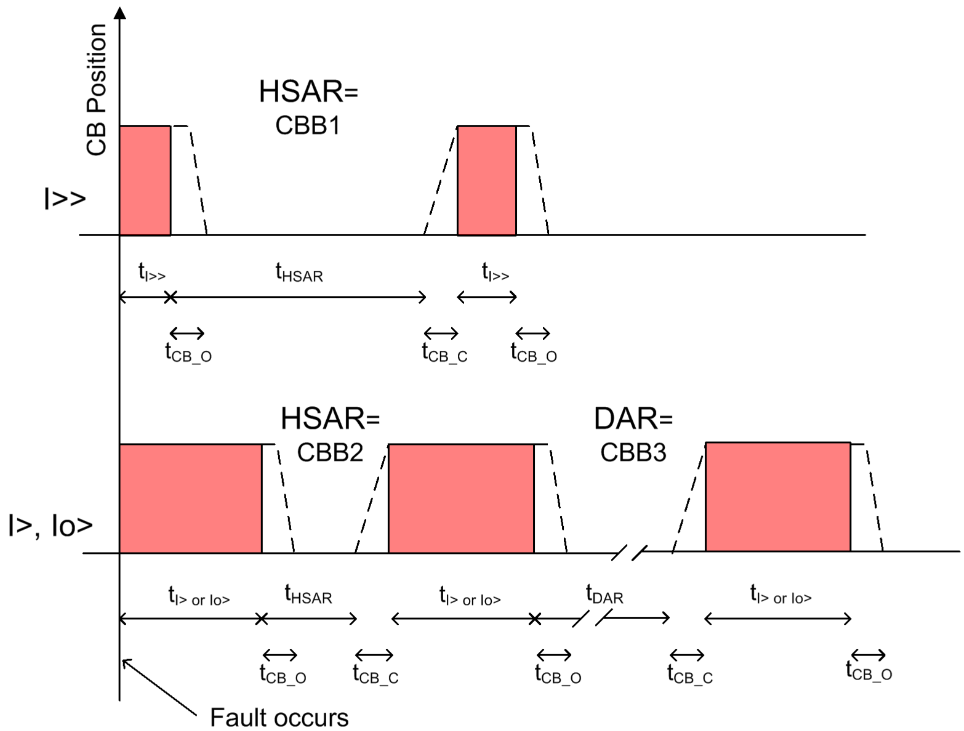


Figure 522: Autoreclosing sequence with two shots with different shot settings according to initiation signal

t_{HSAR}	Time delay of high-speed autoreclosing, here: *First reclose time*
t_{DAR}	Time delay of delayed autoreclosing, here: *Second reclose time*
$t_{I>>}$	Operating time for the 50P-1 protection stage to clear the fault
$t_{I>}$ or $_{Io>}$	Operating time for the 51P or 51N/G protection stage to clear the fault
t_{CB_O}	Operating time for opening the circuit breaker
t_{CB_C}	Operating time for closing the circuit breaker

In this case, the number of needed CBBs is three, that is, the first shot's reclosing time depends on the initiation signal.

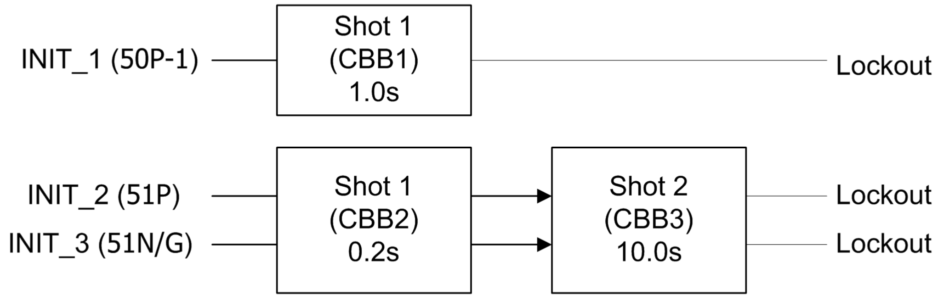


Figure 523: Three shots with three initiation lines

If the sequence is initiated from the INIT_1 line, that is, the overcurrent protection high stage, the sequence is one shot long. If the sequence is initiated from the INIT_2 or INIT_3 lines, the sequence is two shots long.

Table 906: Settings for configuration example 2

Setting name	Setting value
Shot number CBB1	1
Init signals CBB1	1 (line 1)
First reclose time	0.0s (an example)
Shot number CBB2	1
Init signals CBB2	6 (lines 2 and 3 = 2+4 = 6)
Second reclose time	0.2s (an example)
Shot number CBB3	2
Init signals CBB3	6 (lines 2 and 3 = 2+4 = 6)
Third reclose time	10.0s

9.4.6.4 Delayed initiation lines

The autoreclose function consists of six individual autoreclose initiation lines INIT_1...INIT 6 and three delayed initiation lines:

- DEL_INIT_2
- DEL_INIT_3
- DEL_INIT_4

DEL_INIT_2 and INIT_2 are connected together with an OR-gate, as are inputs 3 and 4. Inputs 1, 5 and 6 do not have any delayed input. From the autoreclosing point of view, it does not matter whether INIT_x or DEL_INIT_x line is used for shot initiation or blocking.

The autoreclose function can also open the circuit breaker from any of the initiation lines. It is selected with the *Tripping line* setting. As a default, all initiation lines activate the OPEN_CB output.

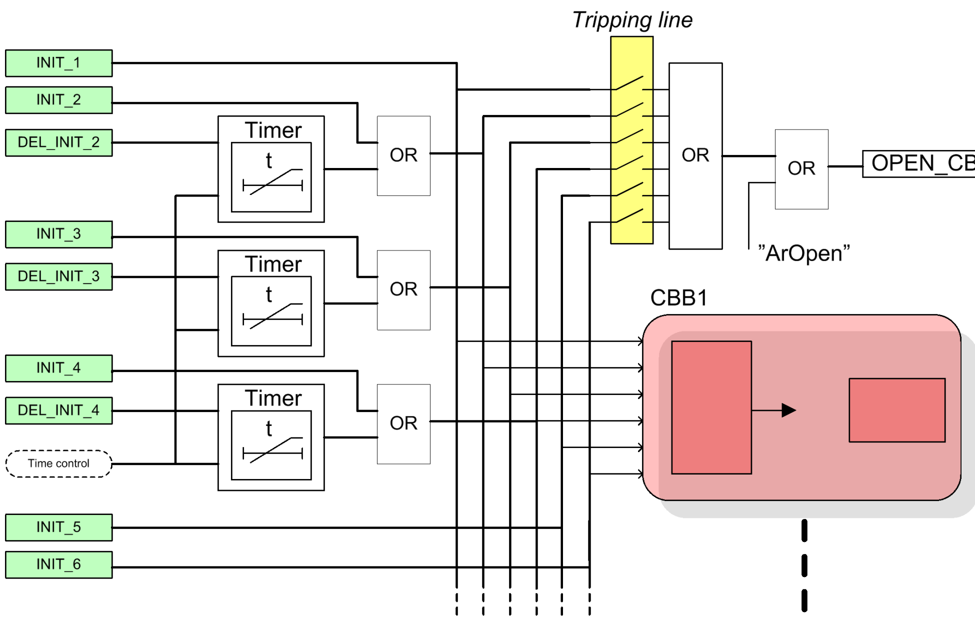


Figure 524: Simplified logic diagram of initiation lines

Each delayed initiation line has four different time settings:

Table 907: Settings for delayed initiation lines

Setting name	Description and purpose
Str x delay shot 1	Time delay for the DEL_INIT_x line, where x is the number of the line 2, 3 or 4. Used for shot 1.
Str x delay shot 2	Time delay for the DEL_INIT_x line, used for shot 2.
Str x delay shot 3	Time delay for the DEL_INIT_x line, used for shot 3.
Str x delay shot 4	Time delay for the DEL_INIT_x line, used for shots 4 and 5. Optionally, can also be used with SOTF.

9.4.6.5 Shot initiation from protection pickup signal

All autoreclose shots are initiated by protection trips. As a result, all trip times in the sequence are the same. This is why using protection trips may not be the optimal solution. Using protection pickup signals instead of protection trips for initiating shots shortens the trip times.

Example 1

When a two-shot-sequence is used, the pickup information from the protection function is routed to the DEL_INIT 2 input and the trip information to the INIT_2 input. The following conditions have to apply:

- protection trip time = 0.5s
- *Str 2 delay shot 1* = 0.05s
- *Str 2 delay shot 2* = 60s
- *Str 2 delay shot 3* = 60s

Operation in a permanent fault:

1. Protection picks up and activates the DEL_INIT 2 input.
2. After 0.05 seconds, the first autoreclose shot is initiated. The function opens the circuit breaker: the OPEN_CB output activates. The total trip time is the protection pickup delay + 0.05 seconds + the time it takes to open the circuit breaker.
3. After the first shot, the circuit breaker is reclosed and the protection picks up again.
4. Because the delay of the second shot is 60 seconds, the protection is faster and trips after the set operation time, activating the INIT 2 input. The second shot is initiated.
5. After the second shot, the circuit breaker is reclosed and the protection picks up again.
6. Because the delay of the second shot is 60 seconds, the protection is faster and trips after the set operation time. No further shots are programmed after the final trip. The function is in lockout and the sequence is considered unsuccessful.

Example 2

The delays can be used also for fast final trip. The conditions are the same as in Example 1, with the exception of *Str 2 delay shot 3* = 0.10 seconds.

The operation in a permanent fault is the same as in Example 1, except that after the second shot when the protection picks up again, *Str 2 delay shot 3* elapses before the protection trip time and the final trip follows. The total trip time is the protection pickup delay + 0.10 seconds + the time it takes to open the circuit breaker.

9.4.6.6 Fast trip in Switch on to fault

The *Str _ delay shot 4* parameter delays can also be used to achieve a fast and accelerated trip with SOTF. This is done by setting the *Fourth delay in SOTF* parameter to "1" and connecting the protection pickup information to the corresponding DEL_INIT_ input.

When the function detects a closing of the circuit breaker, that is, any other closing except the reclosing done by the function itself, it always prohibits shot initiation for the time set with the *Reclaim time* parameter. Furthermore, if the *Fourth delay in SOTF* parameter is "1", the *Str _ delay shot 4* parameter delays are also activated.

Example 1

The protection operation time is 0.5 seconds, the *Fourth delay in SOTF* parameter is set to "1" and the *Str 2 delay shot 4* parameter is 0.05 seconds. The protection pickup signal is connected to the `DEL_INIT_2` input.

If the protection picks up after the circuit breaker closes, the fast trip follows after the set 0.05 seconds. The total trip time is the protection pickup delay + 0.05 seconds + the time it takes to open the circuit breaker.

9.4.7 Signals

Table 908: 79 Input signals

Name	Type	Default	Description
INIT_1	BOOLEAN	0=False	AR initialization / blocking signal 1
INIT_2	BOOLEAN	0=False	AR initialization / blocking signal 2
INIT_3	BOOLEAN	0=False	AR initialization / blocking signal 3
INIT_4	BOOLEAN	0=False	AR initialization / blocking signal 4
INIT_5	BOOLEAN	0=False	AR initialization / blocking signal 5
INIT_6	BOOLEAN	0=False	AR initialization / blocking signal 6
DEL_INIT_2	BOOLEAN	0=False	Delayed AR initialization / blocking signal 2
DEL_INIT_3	BOOLEAN	0=False	Delayed AR initialization / blocking signal 3
DEL_INIT_4	BOOLEAN	0=False	Delayed AR initialization / blocking signal 4
BLK_RECL_T	BOOLEAN	0=False	Blocks and resets reclose time
BLK_RCLM_T	BOOLEAN	0=False	Blocks and resets reclaim time
BLK_THERM	BOOLEAN	0=False	Blocks and holds the reclose shot from the thermal overload
CB_POS	BOOLEAN	0=False	Circuit breaker position input
CB_READY	BOOLEAN	1=True	Circuit breaker status signal
INC_SHOTP	BOOLEAN	0=False	A zone sequence coordination signal
INHIBIT_RECL	BOOLEAN	0=False	Interrupts and inhibits reclosing sequence
RECL_ON	BOOLEAN	0=False	Level sensitive signal for allowing (high) / not allowing (low) reclosing
SYNC	BOOLEAN	0=False	Synchronizing check fulfilled

Table 909: 79 Output signals

Name	Type	Description
OPEN_CB	BOOLEAN	Open command for circuit breaker
CLOSE_CB	BOOLEAN	Close (reclose) command for circuit breaker
CMD_WAIT	BOOLEAN	Wait for master command
INPRO	BOOLEAN	Reclosing shot in progress, activated during dead time
LOCKED OUT	BOOLEAN	Signal indicating that AR is locked out
PROT_CRD	BOOLEAN	A signal for coordination between the AR and the protection
UNSUC_RECL	BOOLEAN	Indicates an unsuccessful reclosing sequence
AR_ON	BOOLEAN	Autoreclosing allowed
READY	BOOLEAN	Indicates that the AR is ready for a new sequence
ACTIVE	BOOLEAN	Reclosing sequence is in progress

9.4.8 Settings

Table 910: 79 Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable/Enable
Reclosing operation	1=Disable 2=External Ctl 3=Enable			1=Disable	Reclosing operation (Disable, External Ctl / Enable
Close pulse time	10...10000	ms	10	200	CB close pulse time
Reclaim time	100...1800000	ms	100	10000	Reclaim time
Terminal priority	1=None 2=Low (follower) 3=High (master)			1=None	Terminal priority
Synchronisation set	0...127		1	0	Selection for synchronizing requirement for reclosing
Auto initiation cnd	1=Not allowed 2=When sync fails 3=CB doesn't close 4=Both			2=When sync fails	Auto initiation condition
Tripping line	0...63		1	0	Tripping line, defines INIT inputs which cause OPEN_CB activation
Fourth delay in SOTF	0=False 1=True			0=False	Sets 4th delay into use for all DEL_INIT signals during SOTF
First reclose time	0...300000	ms	10	5000	Dead time for CBB1
Second reclose time	0...300000	ms	10	5000	Dead time for CBB2
Third reclose time	0...300000	ms	10	5000	Dead time for CBB3

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Fourth reclose time	0...300000	ms	10	5000	Dead time for CBB4
Fifth reclose time	0...300000	ms	10	5000	Dead time for CBB5
Sixth reclose time	0...300000	ms	10	5000	Dead time for CBB6
Seventh reclose time	0...300000	ms	10	5000	Dead time for CBB7
Init signals CBB1	0...63		1	0	Initiation lines for CBB1
Init signals CBB2	0...63		1	0	Initiation lines for CBB2
Init signals CBB3	0...63		1	0	Initiation lines for CBB3
Init signals CBB4	0...63		1	0	Initiation lines for CBB4
Init signals CBB5	0...63		1	0	Initiation lines for CBB5
Init signals CBB6	0...63		1	0	Initiation lines for CBB6
Init signals CBB7	0...63		1	0	Initiation lines for CBB7
Shot number CBB1	0...5		1	0	Shot number for CBB1
Shot number CBB2	0...5		1	0	Shot number for CBB2
Shot number CBB3	0...5		1	0	Shot number for CBB3
Shot number CBB4	0...5		1	0	Shot number for CBB4
Shot number CBB5	0...5		1	0	Shot number for CBB5
Shot number CBB6	0...5		1	0	Shot number for CBB6
Shot number CBB7	0...5		1	0	Shot number for CBB7
Frq Op counter limit	0...250		1	0	Frequent operation counter lockout limit
Frq Op counter time	1...250	min	1	1	Frequent operation counter time
Frq Op recovery time	1...250	min	1	1	Frequent operation counter recovery time
Auto init	0...63		1	0	Defines INIT lines that are activated at auto initiation

Table 911: 79 Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Manual close mode	0=False 1=True			0=False	Manual close mode
Wait close time	50...10000	ms	50	250	Allowed CB closing time after reclose command
Max wait time	100...1800000	ms	100	10000	Maximum wait time for haltDeadTime release
Max trip time	100...10000	ms	100	10000	Maximum wait time for deactivation of protection signals
Max Thm block time	100...1800000	ms	100	10000	Maximum wait time for thermal blocking signal deactivation
Cut-out time	0...1800000	ms	100	10000	Cutout time for protection coordination
Dsr time shot 1	0...10000	ms	100	0	Discrimination time for first reclosing
Dsr time shot 2	0...10000	ms	100	0	Discrimination time for second reclosing

Table continues on next page

Parameter	Values (Range)	Unit	Step	Default	Description
Dsr time shot 3	0...10000	ms	100	0	Discrimination time for third reclosing
Dsr time shot 4	0...10000	ms	100	0	Discrimination time for fourth reclosing
Auto wait time	0...60000	ms	10	2000	Wait time for reclosing condition fullfilling
Auto lockout reset	0=False 1=True			1=True	Automatic lockout reset
Protection crd limit	1...5		1	1	Protection coordination shot limit
Protection crd mode	1=No condition 2=AR inoperative 3=CB close manual 4=AR inop, CB man 5=Always			4=AR inop, CB man	Protection coordination mode
Control line	0...63		1	63	Control line, defines INIT inputs which are protection signals
Enable shot jump	0=False 1=True			1=True	Enable shot jumping
CB closed Pos status	0=False 1=True			0=False	Circuit breaker closed position status
Blk signals CBB1	0...63		1	0	Blocking lines for CBB1
Blk signals CBB2	0...63		1	0	Blocking lines for CBB2
Blk signals CBB3	0...63		1	0	Blocking lines for CBB3
Blk signals CBB4	0...63		1	0	Blocking lines for CBB4
Blk signals CBB5	0...63		1	0	Blocking lines for CBB5
Blk signals CBB6	0...63		1	0	Blocking lines for CBB6
Blk signals CBB7	0...63		1	0	Blocking lines for CBB7
Str 2 delay shot 1	0...300000	ms	10	0	Delay time for start2, 1st reclose
Str 2 delay shot 2	0...300000	ms	10	0	Delay time for start2 2nd reclose
Str 2 delay shot 3	0...300000	ms	10	0	Delay time for start2 3rd reclose
Str 2 delay shot 4	0...300000	ms	10	0	Delay time for start2, 4th reclose
Str 3 delay shot 1	0...300000	ms	10	0	Delay time for start3, 1st reclose
Str 3 delay shot 2	0...300000	ms	10	0	Delay time for start3 2nd reclose
Str 3 delay shot 3	0...300000	ms	10	0	Delay time for start3 3rd reclose
Str 3 delay shot 4	0...300000	ms	10	0	Delay time for start3, 4th reclose
Str 4 delay shot 1	0...300000	ms	10	0	Delay time for start4, 1st reclose
Str 4 delay shot 2	0...300000	ms	10	0	Delay time for start4 2nd reclose
Str 4 delay shot 3	0...300000	ms	10	0	Delay time for start4 3rd reclose
Str 4 delay shot 4	0...300000	ms	10	0	Delay time for start4, 4th reclose

9.4.9 Monitored data

Table 912: 79 Monitored data

Name	Type	Values (Range)	Unit	Description
DISA_COUNT	BOOLEAN	0=False 1=True		Signal for counter disabling
FRQ_OPR_CNT	INT32	0...2147483647		Frequent operation counter
FRQ_OPR_AL	BOOLEAN	0=False 1=True		Frequent operation counter alarm
STATUS	Enum	-1=Bad 1=Ready 2=InProgress 3=Successful 4=WaitingForTrip 5=TripFromProtection 6=FaultDisappeared 7=WaitToComplete 8=CBclosed 9=CycleUnsuccessful 10=Unsuccessful 11=Aborted		AR status signal for IEC61850
INPRO_1	BOOLEAN	0=False 1=True		Reclosing shot in progress, shot 1
INPRO_2	BOOLEAN	0=False 1=True		Reclosing shot in progress, shot 2
INPRO_3	BOOLEAN	0=False 1=True		Reclosing shot in progress, shot 3
INPRO_4	BOOLEAN	0=False 1=True		Reclosing shot in progress, shot 4
INPRO_5	BOOLEAN	0=False 1=True		Reclosing shot in progress, shot 5
DISCR_INPRO	BOOLEAN	0=False 1=True		Signal indicating that discrimination time is in progress
CUTOUT_INPRO	BOOLEAN	0=False 1=True		Signal indicating that cut-out time is in progress
SUC_RECL	BOOLEAN	0=False 1=True		Indicates a successful reclosing sequence
UNSUC_CB	BOOLEAN	0=False 1=True		Indicates an unsuccessful CB closing
CNT_SHOT1	INT32	0...2147483647		Resetable operation counter, shot 1

Table continues on next page

Name	Type	Values (Range)	Unit	Description
CNT_SHOT2	INT32	0...2147483647		Resetable operation counter, shot 2
CNT_SHOT3	INT32	0...2147483647		Resetable operation counter, shot 3
CNT_SHOT4	INT32	0...2147483647		Resetable operation counter, shot 4
CNT_SHOT5	INT32	0...2147483647		Resetable operation counter, shot 5
COUNTER	INT32	0...2147483647		Resetable operation counter, all shots
SHOT_PTR	INT32	1...7		Shot pointer value
MAN_CB_CL	BOOLEAN	0=False 1=True		Indicates CB manual closing during reclosing sequence
SOTF	BOOLEAN	0=False 1=True		Switch-onto-fault
79	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

9.4.10 Technical data

Table 913: 79 Technical data

Characteristic	Value
Trip time accuracy	±1.0% of the set value or ±20 ms

9.4.11 Technical revision history

Table 914: 79 Technical revision history

Technical revision	Change
B	The `PROT_DISA` output removed and removed the related settings
C	The default value of the *CB closed Pos status* setting changed from "True" to "False"
D	SHOT_PTR output range 0...7 (earlier 0...6)
E	Monitored data ACTIVE transferred to be ACT visible output. SHOT_PTR output range 1...7.
F	Internal improvement

Section 10 Power quality measurement functions

10.1 Current total demand distortion PQI

10.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current total demand distortion	CMHAI	PQM3I	PQI

10.1.2 Function block

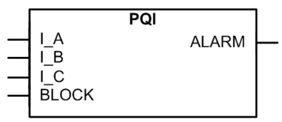


Figure 525: Function block

10.1.3 Functionality

The current total demand distortion function PQI is used for monitoring the current total demand distortion TDD.

10.1.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of PQI can be described with a module diagram. All the modules in the diagram are explained in the next sections.

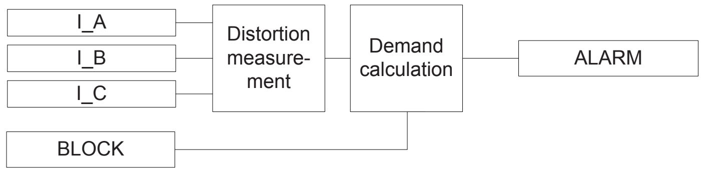


Figure 526: Functional module diagram

Distortion measurement

The distortion measurement module measures harmonics up to the 11th harmonic. The total demand distortion TDD is calculated from the measured harmonic components with the formula

$$TDD = \frac{\sqrt{\sum_{k=2}^{N} I_k^2}}{I_{max\_demand}}$$

(Equation 171)

I_k	k^{th} harmonic component
I_{max_demand}	The maximum demand current measured by IA, IB, IC

If IA, IB, IC are not available in the configuration or the measured maximum demand current is less than the *Initial Dmd current* setting, *Initial Dmd current* is used for I_{max_demand}.

Demand calculation

The demand value for TDD is calculated separately for each phase. If any of the calculated total demand distortion values is above the set alarm limit *TDD alarm limit*, the ALARM output is activated.

The demand calculation window is set with the *Demand interval* setting. It has seven window lengths from "1 minute" to "180 minutes". The window type can be set with the *Demand window* setting. The available options are "Sliding" and "Non-sliding".

The activation of the BLOCK input blocks the ALARM output.

10.1.5 Application

In standards, the power quality is defined through the characteristics of the supply voltage. Transients, short-duration and long-duration voltage variations, unbalance and waveform distortions are the key characteristics describing power quality. Power quality is, however, a customer-driven issue. It could be said that any power problem concerning voltage or current that results in a failure or misoperation of customer equipment is a power quality problem.

Harmonic distortion in a power system is caused by nonlinear devices. Electronic power converter loads constitute the most important class of nonlinear loads in a power system. The switch mode power supplies in a number of single-phase electronic equipment, such as personal computers, printers and copiers, have a very high third-harmonic content in the current. Three-phase electronic power converters, that is, dc/ac drives, however, do not generate third-harmonic currents. Still, they can be significant sources of harmonics.

Power quality monitoring is an essential service that utilities can provide for their industrial and key customers. Not only can a monitoring system provide information about system disturbances and their possible causes, it can also detect problem conditions throughout the system before they cause customer complaints, equipment malfunctions and even equipment damage or failure. Power quality problems are not limited to the utility side of the system. In fact, the majority of power quality problems are localized within customer facilities. Thus, power quality monitoring is not only an effective customer service strategy but also a way to protect a utility's reputation for quality power and service.

PQI provides a method for monitoring the power quality by means of the current waveform distortion. PQI provides a short-term 3-second average and a long-term demand for TDD.

10.1.6 Signals

Table 915: PQI Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current
I_B	SIGNAL	0	Phase B current
I_C	SIGNAL	0	Phase C current
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 916: PQI Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm signal for TDD

10.1.7 Settings

Table 917: PQI Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Demand interval	0=1 minute 1=5 minutes 2=10 minutes 3=15 minutes 4=30 minutes 5=60 minutes 6=180 minutes			2=10 minutes	Time interval for demand calculation
Demand window	1=Sliding 2=Non-sliding			1=Sliding	Demand calculation window type
TDD alarm limit	1.0...100.0	%	0.1	50.0	TDD alarm limit

Table 918: PQI Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Initial Dmd current	0.10...1.00	xIn	0.01	1.00	Initial demand current

10.1.8 Monitored data

Table 919: PQI Monitored data

Name	Type	Values (Range)	Unit	Description
Max demand TDD IA	FLOAT32	0.00...500.00	%	Maximum demand TDD for phase A
Max demand TDD IB	FLOAT32	0.00...500.00	%	Maximum demand TDD for phase B
Max demand TDD IC	FLOAT32	0.00...500.00	%	Maximum demand TDD for phase C
Time max dmd TDD IA	Timestamp			Time of maximum demand TDD phase A
Time max dmd TDD IB	Timestamp			Time of maximum demand TDD phase B
Time max dmd TDD IC	Timestamp			Time of maximum demand TDD phase C
3SMHTDD_A	FLOAT32	0.00...500.00	%	3 second mean value of TDD for phase A
DMD_TDD_A	FLOAT32	0.00...500.00	%	Demand value for TDD for phase A
3SMHTDD_B	FLOAT32	0.00...500.00	%	3 second mean value of TDD for phase B

Table continues on next page

Name	Type	Values (Range)	Unit	Description
DMD_TDD_B	FLOAT32	0.00...500.00	%	Demand value for TDD for phase B
3SMHTDD_C	FLOAT32	0.00...500.00	%	3 second mean value of TDD for phase C
DMD_TDD_C	FLOAT32	0.00...500.00	%	Demand value for TDD for phase C

10.1.9 Technical revision history

Table 920: PQI Technical revision history

Technical revision	Change
B	Internal improvement.
C	Internal improvement.
D	Internal improvement.

10.2 Voltage total harmonic distortion PQVPH

10.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage total harmonic distortion	VMHAI	PQM3U	PQVPH

10.2.2 Function block

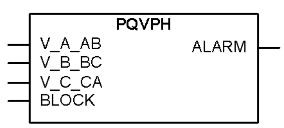


Figure 527: Function block

10.2.3 Functionality

The voltage total harmonic distortion function PQVPH is used for monitoring the voltage total harmonic distortion THD.

10.2.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of PQVPH can be described with a module diagram. All the modules in the diagram are explained in the next sections.

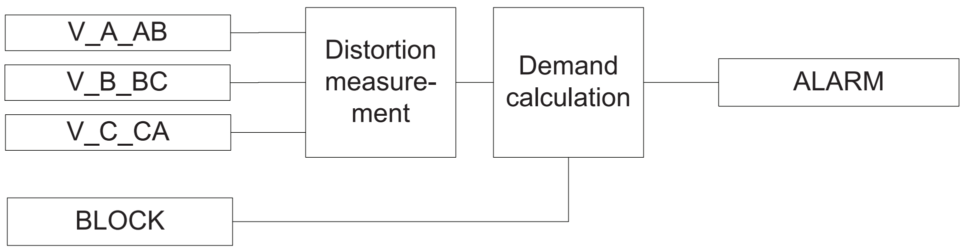


Figure 528: Functional module diagram

Distortion measurement

The distortion measurement module measures harmonics up to the 11th harmonic. The total harmonic distortion THD for voltage is calculated from the measured harmonic components with the formula

$$THD = \frac{\sqrt{\sum_{k=2}^{N} V_k^2}}{V_1}$$

(Equation 172)

V_k k^{th} harmonic component

V_1 the voltage fundamental component amplitude

Demand calculation

The demand value for THD is calculated separately for each phase. If any of the calculated demand THD values is above the set alarm limit *THD alarm limit*, the `ALARM` output is activated.

The demand calculation window is set with the *Demand interval* setting. It has seven window lengths from "1 minute" to "180 minutes". The window type can be set with the *Demand window* setting. The available options are "Sliding" and "Non-sliding".

The activation of the `BLOCK` input blocks the `ALARM` output.

10.2.5 Application

PQVPH provides a method for monitoring the power quality by means of the voltage waveform distortion. PQVPH provides a short-term three-second average and long-term demand for THD.

10.2.6 Signals

Table 921: PQVPH Input signals

Name	Type	Default	Description
V_A_AB	SIGNAL	0	Phase A voltage
V_B_BC	SIGNAL	0	Phase B voltage
V_C_CA	SIGNAL	0	Phase C voltage
BLOCK	BOOLEAN	0=False	Block signal for all binary outputs

Table 922: PQVPH Output signals

Name	Type	Description
ALARM	BOOLEAN	Alarm signal for THD

10.2.7 Settings

Table 923: PQVPH Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Demand interval	0=1 minute 1=5 minutes 2=10 minutes 3=15 minutes 4=30 minutes 5=60 minutes 6=180 minutes			2=10 minutes	Time interval for demand calculation
Demand window	1=Sliding 2=Non-sliding			1=Sliding	Demand calculation window type
THD alarm limit	1.0...100.0	%	0.1	50.0	THD alarm limit

10.2.8 Monitored data

Table 924: PQVPH Monitored data

Name	Type	Values (Range)	Unit	Description
Max demand THD VA	FLOAT32	0.00...500.00	%	Maximum demand THD for phase A
Max demand THD VB	FLOAT32	0.00...500.00	%	Maximum demand THD for phase B
Max demand THD VC	FLOAT32	0.00...500.00	%	Maximum demand THD for phase C
Time max dmd THD VA	Timestamp			Time of maximum demand THD phase A
Time max dmd THD VB	Timestamp			Time of maximum demand THD phase B
Time max dmd THD VC	Timestamp			Time of maximum demand THD phase C
3SMHTHD_A	FLOAT32	0.00...500.00	%	3 second mean value of THD for phase A
DMD_THD_A	FLOAT32	0.00...500.00	%	Demand value for THD for phase A
3SMHTHD_B	FLOAT32	0.00...500.00	%	3 second mean value of THD for phase B
DMD_THD_B	FLOAT32	0.00...500.00	%	Demand value for THD for phase B
3SMHTHD_C	FLOAT32	0.00...500.00	%	3 second mean value of THD for phase C
DMD_THD_C	FLOAT32	0.00...500.00	%	Demand value for THD for phase C

10.2.9 Technical revision history

Table 925: PQVPH Technical revision history

Technical revision	Change
B	Internal improvement.
C	Internal improvement.

10.3 Voltage variation PQSS

10.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage variation	PHQVVR	PQMU PQ 3U<>	PQSS

10.3.2 Function block

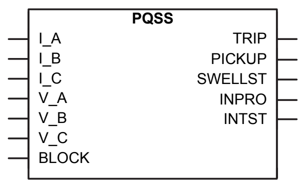


Figure 529: Function block

10.3.3 Functionality

The voltage variation function PQSS is used for measuring the short-duration voltage variations in distribution networks.

Power quality in the voltage waveform is evaluated by measuring voltage swells, dips and interruptions. PQSS includes single-phase and three-phase voltage variation modes.

Typically, short-duration voltage variations are defined to last more than half of the nominal frequency period and less than one minute. The maximum magnitude (in the case of a voltage swell) or depth (in the case of a voltage dip or interruption) and the duration of the variation can be obtained by measuring the RMS value of the voltage for each phase. International standard 61000-4-30 defines the voltage variation to be implemented using the RMS value of the voltage. IEEE standard 1159-1995 provides recommendations for monitoring the electric power quality of the single-phase and polyphase ac power systems.

PQSS contains a blocking functionality. It is possible to block a set of function outputs or the function itself, if desired.

10.3.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of PQSS can be described with a module diagram. All the modules in the diagram are explained in the next sections.

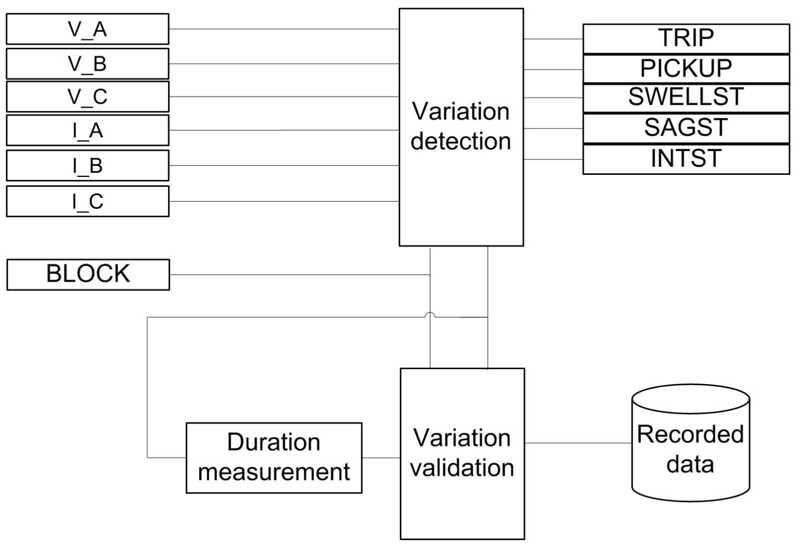


Figure 530: Functional module diagram

10.3.4.1 Phase mode setting

PQSS is designed for both single-phase and polyphase ac power systems, and selection can be made with the *Phase mode* setting, which can be set either to the "Single Phase" or "Three Phase" mode. The default setting is "Single Phase".

The basic difference between these alternatives depends on how many phases are needed to have the voltage variation activated. When the *Phase mode* setting is "Single Phase", the activation is straightforward. There is no dependence between the phases for variation pickup. The `PICKUP` output and the corresponding phase pickup are activated when the limit is exceeded or undershot. The corresponding phase pickup deactivation takes place when the limit (includes small hysteresis) is undershot or exceeded. The `PICKUP` output is deactivated when there are no more active phases.

However, when *Phase mode* is "Three Phase", all the monitored phase signal magnitudes, defined with *Phase supervision*, have to fall below or rise above the limit setting to activate the PICKUP output and the corresponding phase output, that is, all the monitored phases have to be activated. Accordingly, the deactivation occurs when the activation requirement is not fulfilled, that is, one or more monitored phase signal magnitudes return beyond their limits. Phases do not need to be activated by the same variation type to activate the PICKUP output. Another consequence is that if only one or two phases are monitored, it is sufficient that these monitored phases activate the PICKUP output.

10.3.4.2 Variation detection

The module compares the measured voltage against the limit settings. If there is a permanent undervoltage or overvoltage, the *Reference voltage* setting can be set to this voltage level to avoid the undesired voltage dip or swell indications. This is accomplished by converting the variation limits with the *Reference voltage* setting in the variation detection module, that is, when there is a voltage different from the nominal voltage, the *Reference voltage* setting is set to this voltage.

The *Variation enable* setting is used for enabling or disabling the variation types. By default, the setting value is "Swell+dip+Int" and all the alternative variation types are indicated. For example, for setting "Swell+dip", the interruption detection is not active and only swell or dip events are indicated.

In a case where *Phase mode* is "Single Phase" and the dip functionality is available, the output DIPST is activated when the measured TRMS value drops below the *Voltage dip set 3* setting in one phase and also remains above the *Voltage Int set* setting. If the voltage drops below the *Voltage Int set* setting, the output INTST is activated. INTST is deactivated when the voltage value rises above the setting *Voltage Int set*. When the same measured TRMS magnitude rises above the setting *Voltage swell set 3*, the SWELLST output is activated.

There are three setting value limits for dip (*Voltage dip set 1..3*) and swell activation (*Voltage swell set 1..3*) and one setting value limit for interruption.

If *Phase mode* is "Three Phase", the DIPST and INTST outputs are activated when the voltage levels of all monitored phases, defined with the parameter *Phase supervision*, drop below the *Voltage Int set* setting value. An example for the detection principle of voltage interruption for "Three Phase" when *Phase supervision* is "Ph A + B + C", and also the corresponding pickup signals when *Phase mode* is "Single Phase", are as shown in the example for the detection of a three-phase interruption.

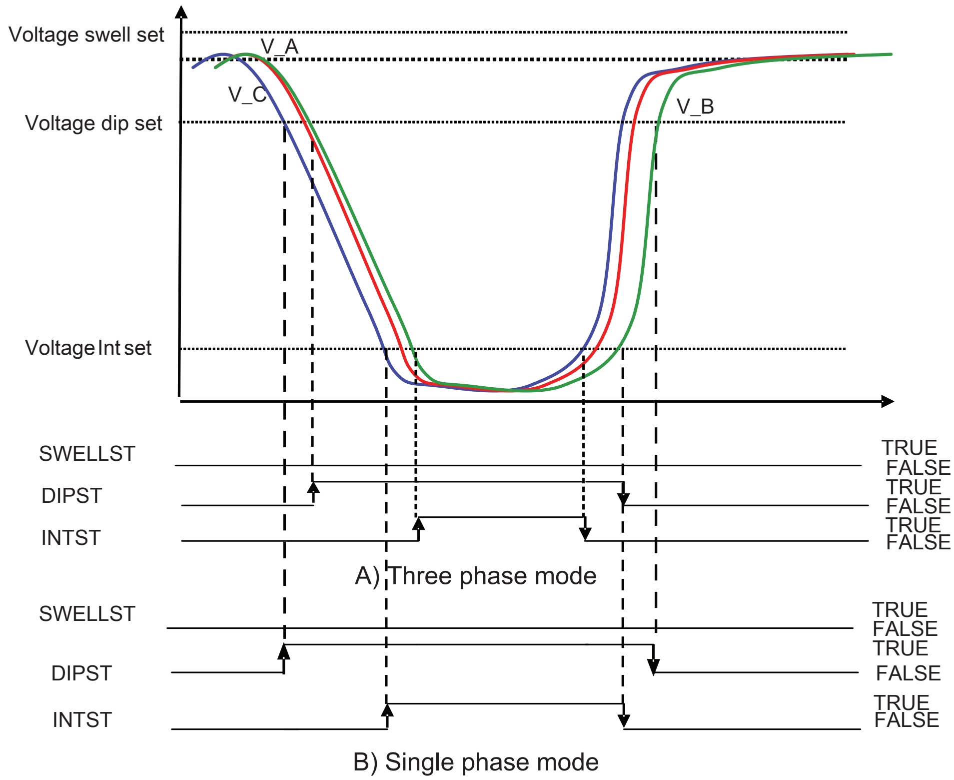


Figure 531: Detection of three-phase voltage interruption

The module measures voltage variation magnitude on each phase separately, that is, there are phase-segregated outputs `ST_A`, `ST_B` and `ST_C` for voltage variation indication. The configuration parameter *Phase supervision* defines which voltage phase or phases are monitored. If a voltage phase is selected to be monitored, the function assumes it to be connected to a voltage measurement channel. In other words, if an unconnected phase is monitored, the function falsely detects a voltage interruption in that phase.

The maximum magnitude and depth are defined as percentage values calculated from the difference between the reference and the measured voltage. For example, a dip to 70 percent means that the minimum voltage dip magnitude variation is 70 percent of the reference voltage amplitude.

The activation of the `BLOCK` input resets the function and outputs.

10.3.4.3 Variation validation

The validation criterion for voltage variation is that the measured total variation duration is between the set minimum and maximum durations (Either one of *VVa dip time 1*, *VVa* *swell time 1* or *VVa Int time 1*, depending on the variation type, and *VVa Dur Max*). The maximum variation duration setting is the same for all variation types.

Figure 532 shows voltage dip operational regions. In Figure 531, only one voltage dip/swell/Int set is drawn, whereas in this figure there are three sub-limits for the dip operation. When *Voltage dip set 3* is undershot, the corresponding `ST_x` and also the `DIPST` outputs are activated. When the TRMS voltage magnitude remains between *Voltage dip set 2* and *Voltage dip set 1* for a period longer than *VVa dip time 2* (shorter time than *VVa dip time 3*), a momentary dip event is detected. Furthermore, if the signal magnitude stays between the limits longer than *VVa dip time 3* (shorter time than *VVa Dur max*), a temporary dip event is detected. If the voltage remains below *Voltage dip set 1* for a period longer than *VVa dip time 1* but a shorter time than *VVa dip time 2*, an instantaneous dip event is detected.

For an event detection, the `TRIP` output is always activated for one task cycle. The corresponding counter and only one of them (INSTDIPCNT, MOMDIPCNT or TEMPDIPCNT) is increased by one. If the dip limit undershooting duration is shorter than *VVa dip time 1*, *VVa swell time 1* or *VVa Int time 1*, the event is not detected at all, and if the duration is longer than *VVa Dur Max*, MAXDURDIPCNT is increased by one but no event detection resulting in the activation of the `TRIP` output and recording data update takes place. These counters are available through the monitored data view on the LHMI or through tools via communications. There are no phase-segregated counters but all the variation detections are registered to a common time/magnitude-classified counter type. Consequently, a simultaneous multiphase event, that is, the variation-type event detection time moment is exactly the same for two or more phases, is counted only once also for single-phase power systems.

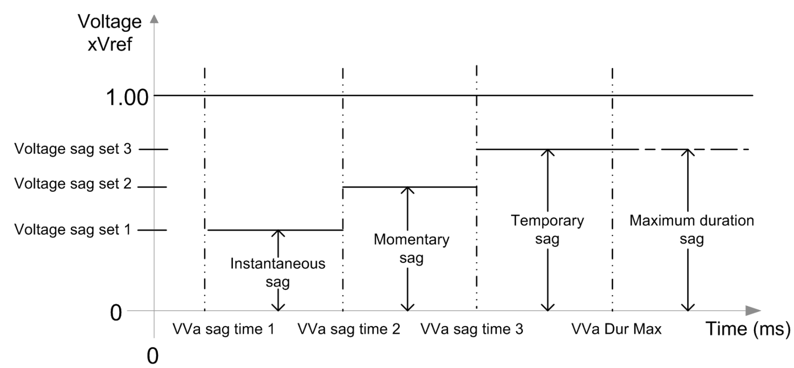


Figure 532: Voltage dip operational regions

In Figure 533, the corresponding limits regarding the swell operation are provided with the inherent magnitude limit order difference. The swell functionality principle is the same as for dips, but the different limits for the signal magnitude and times and the inherent operating zone change (here, *Voltage swell set x* > 1.0 xVn) are applied.

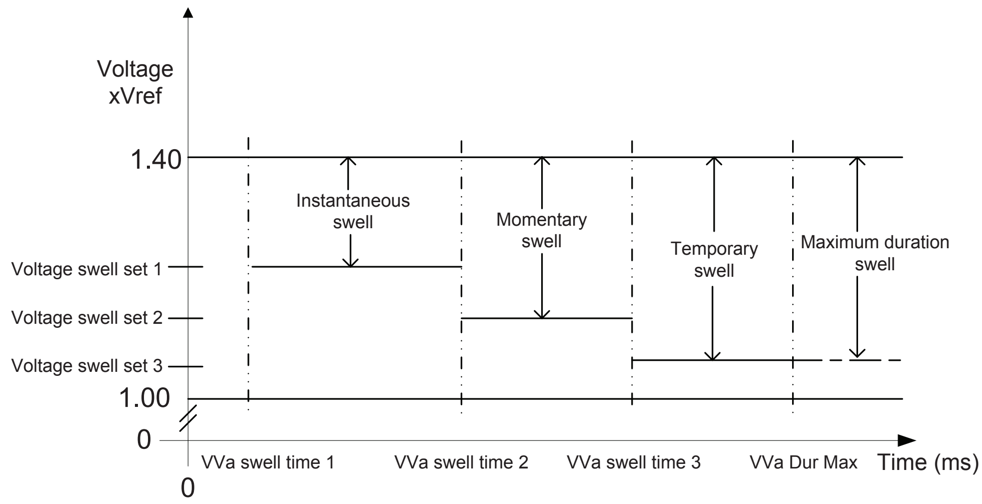


Figure 533: Voltage swell operational regions

For interruption, as shown in Figure 534, there is only one magnitude limit but four duration limits for interruption classification. Now the event and counter type depends only on variation duration time.

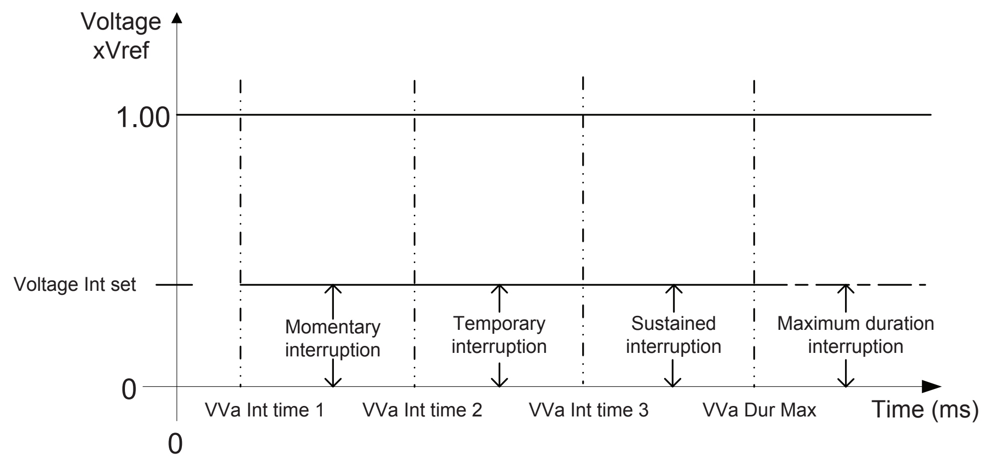


Figure 534: Interruption operating regions

Generally, no event detection is done if both the magnitude and duration requirements are not fulfilled. For example, the dip event does not indicate if the TRMS voltage magnitude remains between *Voltage dip set 3* and *Voltage dip set 2* for a period shorter than *VVa dip time 3* before rising back above *Voltage dip set 3*.

The event indication ends and possible detection is done when the TRMS voltage returns above (for dip and interruption) or below (for swell) the activation pickup limit. For example, after an instantaneous dip, the event indication when the voltage magnitude exceeds *Voltage dip set 1* is not detected (and recorded) immediately but only if no longer dip indication for the same dip variation takes place and the maximum duration time for dip variation is not exceeded before the signal magnitude rises above *Voltage dip set 3*. There is a small hysteresis for all these limits to avoid the oscillation of the output activation. No drop-off approach is applied here due to the hysteresis.

Consequently, only one event detection and recording of the same variation type can take place for one voltage variation, so the longest indicated variation of each variation type is detected. Furthermore, it is possible that another instantaneous dip event replaces the one already indicated if the magnitude again undershoots *Voltage dip set 1* for the set time after the first detection and the signal magnitude or time requirement is again fulfilled. Another possibility is that if the time condition is not fulfilled for an instantaneous dip detection but the signal rises above *Voltage dip set 1*, the already elapsed time is included in the momentary dip timer. Especially the interruption time is included in the dip time. If the signal does not exceed *Voltage dip set 2* before the timer *VVa dip time 2* has elapsed when the momentary dip timer is also started after the magnitude undershooting *Voltage dip set 2*, the momentary dip event instead is detected. Consequently, the same dip occurrence with a changing variation depth can result in several dip event indications but only one detection. For example, if the magnitude has undershot *Voltage dip set 1* but remained above *Voltage Intr set* for a shorter time than the value of *VVa dip time 1* but the signal rises between *Voltage dip set 1* and *Voltage dip set 2* so that the total duration of the dip activation is longer than *VVa dip time 2* and the maximum time is not overshot, this is detected as a momentary dip even though a short instantaneous dip period has been included. In text, the terms "deeper" and "higher" are used for referring to dip or interruption.

Although examples are given for dip events, the same rules can be applied to the swell and interruption functionality too. For swell indication, "deeper" means that the signal rises even more and "higher" means that the signal magnitude becomes lower respectively.

The adjustable voltage thresholds adhere to the relationships:

VVa dip time 1 ≤ VVa dip time 2 ≤ VVa dip time 3.

VVa swell time 1 ≤ VVa swell time 2 ≤ VVa swell time 3.

VVa Int time 1 ≤ VVa Int time 2 ≤ VVa Int time 3.

There is a validation functionality built-in function that checks the relationship adherence so that if *VVa x time 1* is set higher than *VVa x time 2* or *VVa x time 3*, *VVa x time 2* and *VVa x time 3* are set equal to the new *VVa x time 1*. If *VVa x time 2* is set higher than *VVa x time 3*, *VVa x time 3* is set to the new *VVa x time 2*. If *VVa x time 2* is set lower than *VVa x time 1*, the entered *VVa x time 2* is rejected. If *VVa x time 3* is set lower than *VVa x time 2*, the entered *VVa x time 3* is rejected.

10.3.4.4 Duration measurement

The duration of each voltage phase corresponds to the period during which the measured TRMS values remain above (swell) or below (dip, interruption) the corresponding limit.

Besides the three limit settings for the variation types dip and swell, there is also a specific duration setting for each limit setting. For interruption, there is only one limit setting common for the three duration settings. The maximum duration setting is common for all variation types.

The duration measurement module measures the voltage variation duration of each phase voltage separately when the *Phase mode* setting is "Single Phase". The phase variation durations are independent. However, when the *Phase mode* setting is "Three Phase", voltage variation may pick up only when all the monitored phases are active. An example of variation duration when *Phase mode* is "Single Phase" can be seen in Figure 535. The voltage variation in the example is detected as an interruption for the phase B and a dip for the phase A, and also the variation durations are interpreted as independent `V_B` and `V_A` durations. In case of single-phase interruption, the `DIPST` output is active when either `PICKUP_A` or `PICKUP_B` is active. The measured variation durations are the times measured between the activation of the `PICKUP_A` or `PICKUP_B` outputs and deactivation of the `PICKUP_A` or `PICKUP_B` outputs. When the *Phase mode* setting is "Three Phase", the example case does not result in any activation.

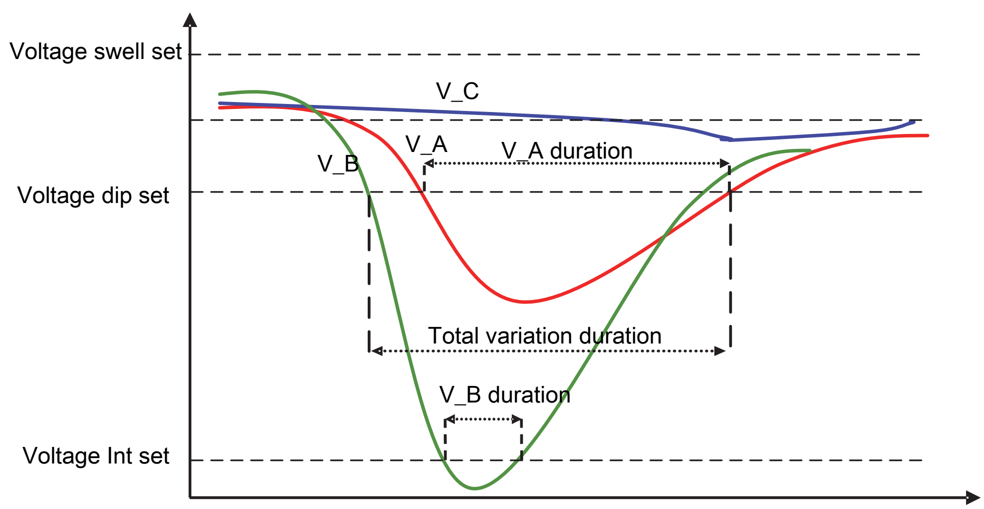


Figure 535: Single-phase interruption for the Phase mode value "Single Phase"

10.3.4.5 Three/single-phase selection variation examples

The provided rules always apply for single-phase (*Phase Mode* is "Single Phase") power systems. However, for three-phase power systems (where *Phase Mode* is "Three Phase"), it is required that all the phases have to be activated before the activation of the `PICKUP` output. Interruption event indication requires all three phases to undershoot *Voltage Int set* simultaneously, as shown in Figure 531. When the requirement for interruption for "Three Phase" is no longer fulfilled, variation is indicated as a dip as long as all phases are active.

In case of a single-phase interruption of Figure 535, when there is a dip indicated in another phase but the third phase is not active, there is no variation indication pickup when *Phase Mode* is "Three Phase". In this case, only the *Phase Mode* value "Single Phase" results in the `PICKUP_B` interruption and the `PICKUP_A` dip.

It is also possible that there are simultaneously a dip in one phase and a swell in other phases. The functionality of the corresponding event indication with one inactive phase is shown in Figure 536. Here, the "Swell + dip" variation type of *Phase mode* is "Single Phase". For the selection "Three Phase" of *Phase mode*, no event indication or any activation takes place due to a non-active phase.

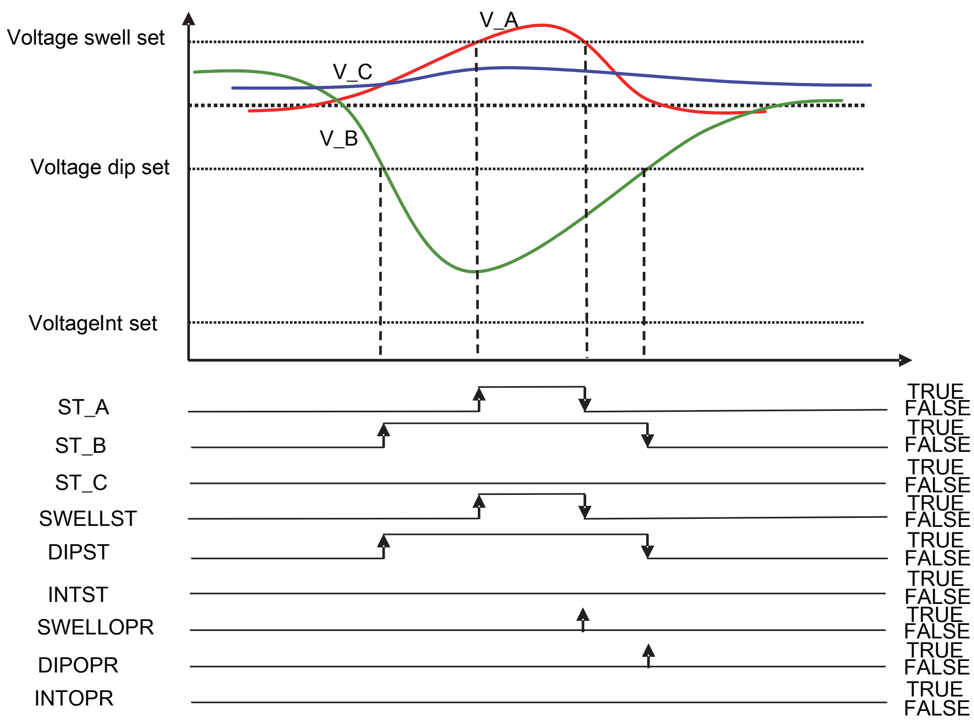


Figure 536: Concurrent dip and swell when Phase mode is "Single Phase"

In Figure 537, one phase is in dip and two phases have a swell indication. For the *Phase Mode Dip* value "Three Phase", the activation occurs only when all the phases are active. Furthermore, both swell and dip variation event detections take place simultaneously. In case of a concurrent voltage dip and voltage swell, both SWELLCNT and DIPCNT are incremented by one.

Also Figure 537 shows that for the *Phase Mode* value "Three Phase", two different time moment variation event swell detections take place and, consequently, DIPCNT is incremented by one but SWELLCNT is totally incremented by two. Both in Figure 536 and Figure 537 it is assumed that variation durations are sufficient for detections to take place.

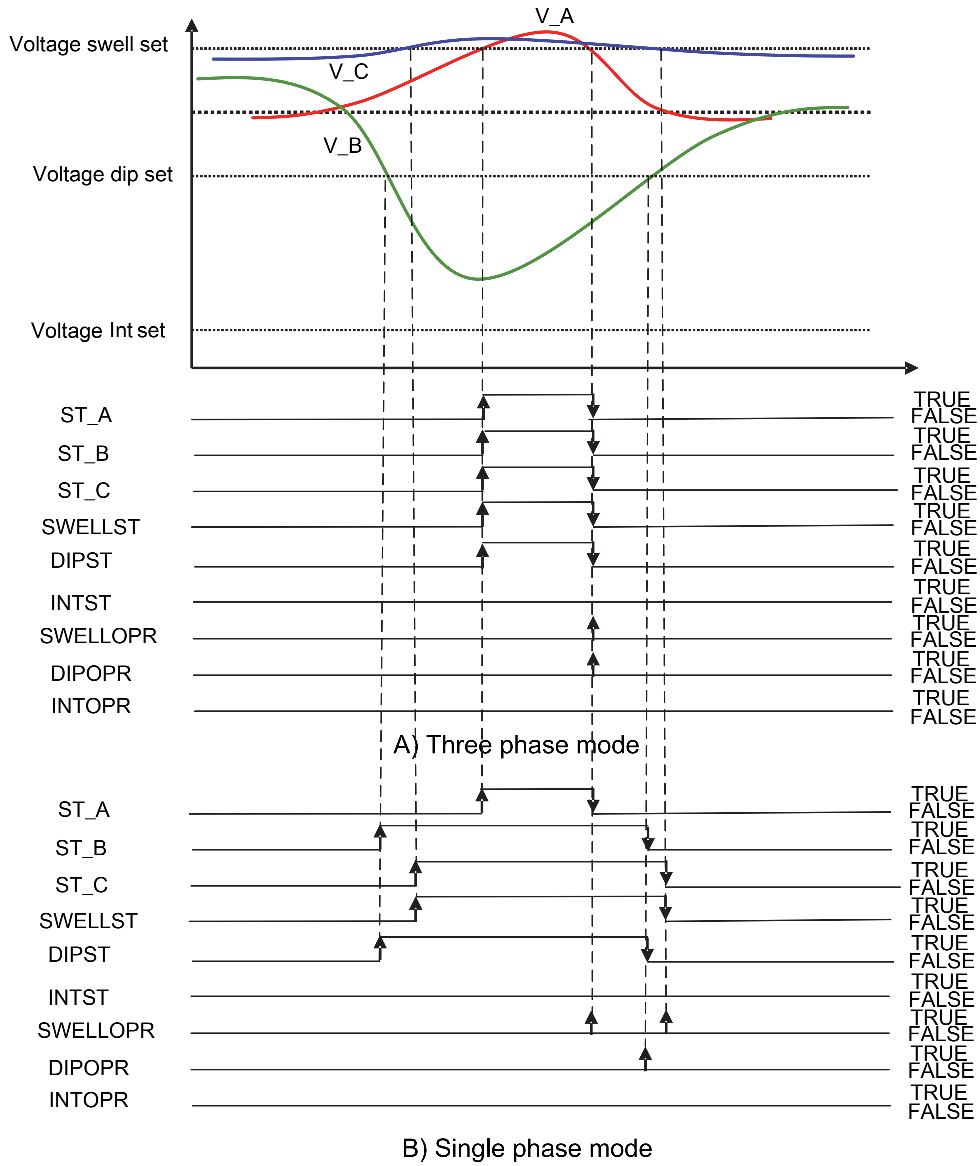


Figure 537: Concurrent dip and two-phase swell

10.3.5 Recorded data

Besides counter increments, the information required for a later fault analysis is stored after a valid voltage variation is detected.

Recorded data information

When voltage variation starts, the phase current magnitudes preceding the activation moment are stored. Also, the initial voltage magnitudes are temporarily stored at the variation pickup moment. If the variation is, for example, a two-phase voltage dip, the voltage magnitude of the non-active phase is stored from this same moment, as shown in Figure 538. The function tracks each variation-active voltage phase, and the minimum or maximum magnitude corresponding to swell or dip/interruption during variation is temporarily stored. If the minimum or maximum is found in tracking and a new magnitude is stored, also the inactive phase voltages are stored at the same moment, that is, the inactive phases are not magnitude-tracked. The time instant (time stamp) at which the minimum or maximum magnitude is measured is also temporarily stored for each voltage phase where variation is active. Finally, variation detection triggers the recorded data update when the variation activation ends and the maximum duration time is not exceeded.

The data objects to be recorded for PQSS are given in Table 926. There are totally three data banks, and the information given in the table refers to one data bank content.

The three sets of recorded data available are saved in data banks 1-3. The data bank 1 holds always the most recent recorded data, and the older data sets are moved to the next banks (1→2 and 2→3) when a valid voltage variation is detected. When all three banks have data and a new variation is detected, the newest data are placed into bank 1 and the data in bank 3 are overwritten by the data from bank 2.

Figure 538 shows a valid recorded voltage interruption and two dips for the *Phase mode* value "Single Phase". The first dip event duration is based on the `V_A` duration, while the second dip is based on the time difference between the dip stop and start times. The first detected event is an interruption based on the `V_B` duration given in Figure 538. It is shown also with dotted arrows how voltage time stamps are taken before the final time stamp for recording, which is shown as a solid arrow. Here, the `V_B` timestamp is not taken when the `V_A` activation starts.

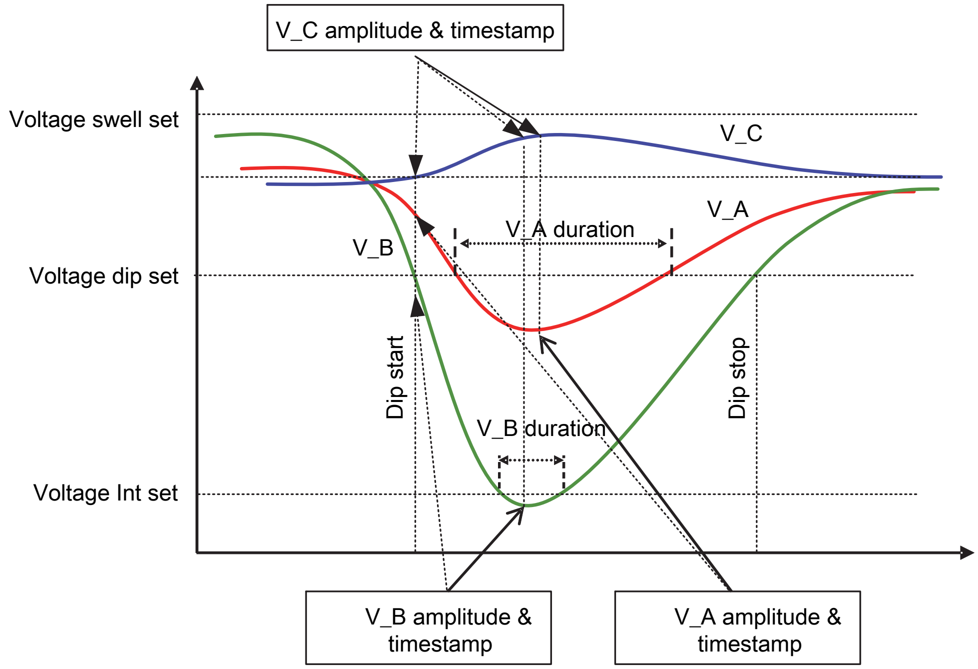


Figure 538: Valid recorded voltage interruption and two dips

Table 926: PQSS recording data bank parameters

Parameter description	Parameter name
Event detection triggering time stamp	Time
Variation type	Variation type
Variation magnitude Ph A	Variation Ph A
Variation magnitude Ph A time stamp (maximum/ minimum magnitude measuring time moment during variation)	Var Ph A rec time
Variation magnitude Ph B	Variation Ph B
Variation magnitude Ph B time stamp (maximum/ minimum magnitude measuring time moment during variation)	Var Ph B rec time
Variation magnitude Ph C	Variation Ph C
Variation magnitude Ph C time stamp (maximum/ minimum magnitude measuring time moment during variation)	Var Ph C rec time
Variation duration Ph A	Variation Dur Ph A
Variation Ph A start time stamp (phase A variation start time moment)	Var Dur Ph A time
Variation duration Ph B	Variation Dur Ph B
Table continues on next page	

Parameter description	Parameter name
Variation Ph B start time stamp (phase B variation start time moment)	Var Dur Ph B time
Variation duration Ph C	Variation Dur Ph C
Variation Ph C start time stamp (phase C variation start time moment)	Var Dur Ph C time
Current magnitude Ph A preceding variation	Var current Ph A
Current magnitude Ph B preceding variation	Var current Ph B
Current magnitude Ph C preceding variation	Var current Ph C

Table 927: Enumeration values for the recorded data parameters

Setting name	Enum name	Value
Variation type	Swell	1
Variation type	Dip	2
Variation type	Swell + dip	3
Variation type	Interruption	4
Variation type	Swell + Int	5
Variation type	Dip + Int	6
Variation type	Swell+dip+Int	7

10.3.6 Application

Voltage variations are the most typical power quality variations on the public electric network. Typically, short-duration voltage variations are defined to last more than half of the nominal frequency period and less than one minute (European Standard EN 50160 and IEEE Std 1159-1995).

These short-duration voltage variations are almost always caused by a fault condition. Depending on where the fault is located, it can cause either a temporary voltage rise (swell) or voltage drop (dip). A special case of voltage drop is the complete loss of voltage (interruption).

PQSS is used for measuring short-duration voltage variations in distribution networks. The power quality is evaluated in the voltage waveform by measuring the voltage swells, dips and interruptions.

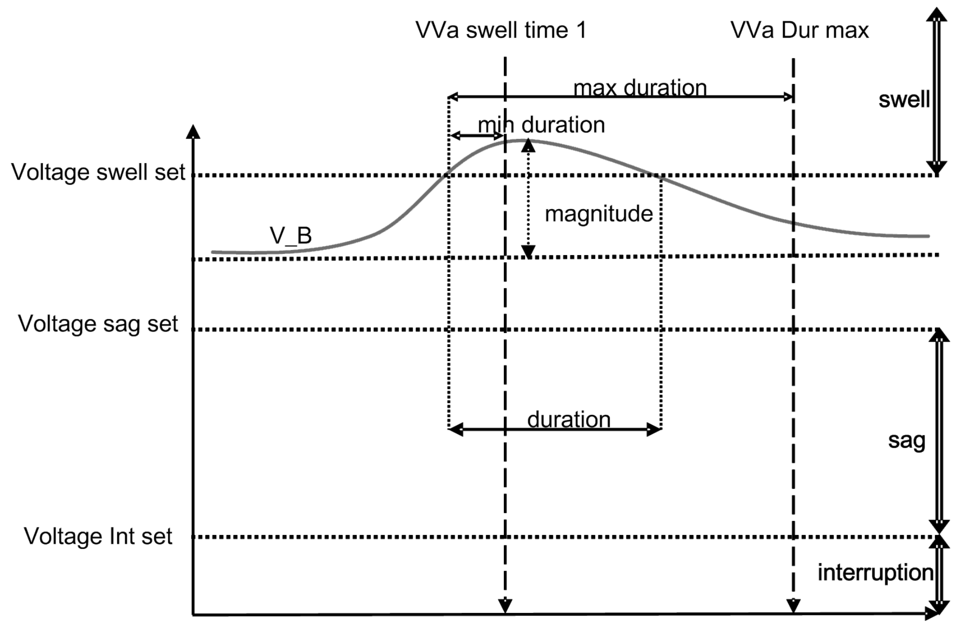


Figure 539: Duration and voltage magnitude limits for swell, dip and interruption measurement

Voltage dips disturb the sensitive equipment such as computers connected to the power system and may result in the failure of the equipment. Voltage dips are typically caused by faults occurring in the power distribution system. Typical reasons for the faults are lightning strikes and tree contacts. In addition to fault situations, the switching of heavy loads and starting of large motors also cause dips.

Voltage swells cause extra stress for the network components and the devices connected to the power system. Voltage swells are typically caused by the ground faults that occur in the power distribution system.

Voltage interruptions are typically associated with the switchgear operation related to the occurrence and termination of short circuits. The operation of a circuit breaker disconnects a part of the system from the source of energy. In the case of overhead networks, automatic reclosing sequences are often applied to the circuit breakers that interrupt fault currents. All these actions result in a sudden reduction of voltages on all voltage phases.

Due to the nature of voltage variations, the power quality standards do not specify any acceptance limits. There are only indicative values for, for example, voltage dips in the European standard EN 50160. However, the power quality standards like the international standard IEC 61000-4-30 specify that the voltage variation event is characterized by its duration and magnitude. Furthermore, IEEE Std 1159-1995 gives the recommended practice for monitoring the electric power quality.

Voltage variation measurement can be done to the phase-to-ground and phase-to-phase voltages. The power quality standards do not specify whether the measurement should be done to phase or phase-to-phase voltages. However, in some cases it is preferable to use phase-to-ground voltages for measurement. The measurement mode is always TRMS.

10.3.7 Signals

Table 928: PQSS Input signals

Name	Type	Default	Description
I_A	SIGNAL	0	Phase A current magnitude
I_B	SIGNAL	0	Phase B current magnitude
I_C	SIGNAL	0	Phase C current magnitude
V_A	SIGNAL	0	Phase-to-ground voltage A
V_B	SIGNAL	0	Phase-to-ground voltage B
V_C	SIGNAL	0	Phase-to-ground voltage C
BLOCK	BOOLEAN	0=False	Block signal for activating the blocking mode

Table 929: PQSS Output signals

Name	Type	Description
TRIP	BOOLEAN	Voltage variation detected
PICKUP	BOOLEAN	Voltage variation present
SWELLST	BOOLEAN	Voltage swell active
DIPST	BOOLEAN	Voltage dip active
INTST	BOOLEAN	Voltage interruption active

10.3.8 Settings

Table 930: PQSS Group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Reference voltage	10.0...200.0	%Un	0.1	57.7	Reference supply voltage in %
Voltage dip set 1	10.0...100.0	%	0.1	80.0	Dip limit 1 in % of reference voltage
VVa dip time 1	0.5...54.0	cycles	0.1	3.0	Voltage variation dip duration 1
Voltage dip set 2	10.0...100.0	%	0.1	80.0	Dip limit 2 in % of reference voltage
VVa dip time 2	10.0...180.0	cycles	0.1	30.0	Voltage variation dip duration 2
Voltage dip set 3	10.0...100.0	%	0.1	80.0	Dip limit 3 in % of reference voltage
VVa dip time 3	2000...60000	ms	10	3000	Voltage variation dip duration 3
Voltage swell set 1	100.0...140.0	%	0.1	120.0	Swell limit 1 in % of reference voltage
Table continues on next page					

Parameter	Values (Range)	Unit	Step	Default	Description
VVa swell time 1	0.5...54.0	cycles	0.1	0.5	Voltage variation swell duration 1
Voltage swell set 2	100.0...140.0	%	0.1	120.0	Swell limit 2 in % of reference voltage
VVa swell time 2	10.0...80.0	cycles	0.1	10.0	Voltage variation swell duration 2
Voltage swell set 3	100.0...140.0	%	0.1	120.0	Swell limit 3 in % of reference voltage
VVa swell time 3	2000...60000	ms	10	2000	Voltage variation swell duration 3
Voltage Int set	0.0...100.0	%	0.1	10.0	Interruption limit in % of reference voltage
VVa Int time 1	0.5...30.0	cycles	0.1	3.0	Voltage variation Int duration 1
VVa Int time 2	10.0...180.0	cycles	0.1	30.0	Voltage variation Int duration 2
VVa Int time 3	2000...60000	ms	10	3000	Voltage variation interruption duration 3
VVa Dur Max	100...3600000	ms	100	60000	Maximum voltage variation duration

Table 931: PQSS Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Operation Disable / Enable
Variation enable	1=Swell 2=Dip 3=Swell + dip 4=Interruption 5=Swell + Int 6=Dip + Int 7=Swell+dip+Int			7=Swell+dip+Int	Enable variation type

Table 932: PQSS Non group settings (Advanced)

Parameter	Values (Range)	Unit	Step	Default	Description
Phase supervision	1=Ph A 2=Ph B 3=Ph A + B 4=Ph C 5=Ph A + C 6=Ph B + C 7=Ph A + B + C			7=Ph A + B + C	Monitored voltage phase
Phase mode	1=Three Phase 2=Single Phase			2=Single Phase	Three/Single phase mode

10.3.9 Monitored data

Table 933: PQSS Monitored data

Name	Type	Values (Range)	Unit	Description
ST_A	BOOLEAN	0=False 1=True		Pickup Phase A (Voltage Variation Event in progress)
ST_B	BOOLEAN	0=False 1=True		Pickup Phase B (Voltage Variation Event in progress)
ST_C	BOOLEAN	0=False 1=True		Pickup Phase C (Voltage Variation Event in progress)
INSTSWELLCNT	INT32	0...2147483647		Instantaneous swell operation counter
MOMSWELLCNT	INT32	0...2147483647		Momentary swell operation counter
TEMPSWELLCNT	INT32	0...2147483647		Temporary swell operation counter
MAXDURSWELLCNT	INT32	0...2147483647		Maximum duration swell operation counter
INSTDIPCNT	INT32	0...2147483647		Instantaneous dip operation counter
MOMDIPCNT	INT32	0...2147483647		Momentary dip operation counter
TEMPDIPCNT	INT32	0...2147483647		Temporary dip operation counter
MAXDURDIPCNT	INT32	0...2147483647		Maximum duration dip operation counter
MOMINTCNT	INT32	0...2147483647		Momentary interruption operation counter
TEMPINTCNT	INT32	0...2147483647		Temporary interruption operation counter
SUSTINTCNT	INT32	0...2147483647		Sustained interruption operation counter
MAXDURINTCNT	INT32	0...2147483647		Maximum duration interruption operation counter
PQSS	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status
Time	Timestamp			Time
Table continues on next page				

Name	Type	Values (Range)	Unit	Description
Variation type	Enum	0=No variation 1=Swell 2=Dip 3=Swell + dip 4=Interruption 5=Swell + Int 6=Dip + Int 7=Swell+dip+Int		Variation type
Variation Ph A	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase A
Var Ph A rec time	Timestamp			Variation magnitude Phase A time stamp
Variation Ph B	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase B
Var Ph B rec time	Timestamp			Variation magnitude Phase B time stamp
Variation Ph C	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase C
Var Ph C rec time	Timestamp			Variation magnitude Phase C time stamp
Variation Dur Ph A	FLOAT32	0.000...3600.000	s	Variation duration Phase A
Var Dur Ph A time	Timestamp			Variation Ph A start time stamp
Variation Dur Ph B	FLOAT32	0.000...3600.000	s	Variation duration Phase B
Var Dur Ph B time	Timestamp			Variation Ph B start time stamp
Variation Dur Ph C	FLOAT32	0.000...3600.000	s	Variation duration Phase C
Var Dur Ph C time	Timestamp			Variation Ph C start time stamp
Var current Ph A	FLOAT32	0.00...60.00	xIn	Current magnitude Phase A preceding variation
Var current Ph B	FLOAT32	0.00...60.00	xIn	Current magnitude Phase B preceding variation
Var current Ph C	FLOAT32	0.00...60.00	xIn	Current magnitude Phase C preceding variation
Time	Timestamp			Time
Variation type	Enum	0=No variation 1=Swell 2=Dip 3=Swell + dip 4=Interruption 5=Swell + Int 6=Dip + Int 7=Swell+dip+Int		Variation type
Variation Ph A	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase A
Var Ph A rec time	Timestamp			Variation magnitude Phase A time stamp
Variation Ph B	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase B

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Var Ph B rec time	Timestamp			Variation magnitude Phase B time stamp
Variation Ph C	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase C
Var Ph C rec time	Timestamp			Variation magnitude Phase C time stamp
Variation Dur Ph A	FLOAT32	0.000...3600.000	s	Variation duration Phase A
Var Dur Ph A time	Timestamp			Variation Ph A start time stamp
Variation Dur Ph B	FLOAT32	0.000...3600.000	s	Variation duration Phase B
Var Dur Ph B time	Timestamp			Variation Ph B start time stamp
Variation Dur Ph C	FLOAT32	0.000...3600.000	s	Variation duration Phase C
Var Dur Ph C time	Timestamp			Variation Ph C start time stamp
Var current Ph A	FLOAT32	0.00...60.00	xIn	Current magnitude Phase A preceding variation
Var current Ph B	FLOAT32	0.00...60.00	xIn	Current magnitude Phase B preceding variation
Var current Ph C	FLOAT32	0.00...60.00	xIn	Current magnitude Phase C preceding variation
Time	Timestamp			Time
Variation type	Enum	0=No variation 1=Swell 2=Dip 3=Swell + dip 4=Interruption 5=Swell + Int 6=Dip + Int 7=Swell+dip+Int		Variation type
Variation Ph A	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase A
Var Ph A rec time	Timestamp			Variation magnitude Phase A time stamp
Variation Ph B	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase B
Var Ph B rec time	Timestamp			Variation magnitude Phase B time stamp
Variation Ph C	FLOAT32	0.00...5.00	xUn	Variation magnitude Phase C
Var Ph C rec time	Timestamp			Variation magnitude Phase C time stamp
Variation Dur Ph A	FLOAT32	0.000...3600.000	s	Variation duration Phase A
Var Dur Ph A time	Timestamp			Variation Ph A start time stamp
Variation Dur Ph B	FLOAT32	0.000...3600.000	s	Variation duration Phase B
Var Dur Ph B time	Timestamp			Variation Ph B start time stamp

Table continues on next page

Name	Type	Values (Range)	Unit	Description
Variation Dur Ph C	FLOAT32	0.000...3600.000	s	Variation duration Phase C
Var Dur Ph C time	Timestamp			Variation Ph C start time stamp
Var current Ph A	FLOAT32	0.00...60.00	xIn	Current magnitude Phase A preceding variation
Var current Ph B	FLOAT32	0.00...60.00	xIn	Current magnitude Phase B preceding variation
Var current Ph C	FLOAT32	0.00...60.00	xIn	Current magnitude Phase C preceding variation

10.3.10 Technical data

Table 934: PQSS Technical data

Characteristic	Value
Operation accuracy	±1.5% of the set value or ±0.2% of reference voltage
Reset ratio	Typically 0.96 (Swell), 1.04 (Dip, Interruption)

10.3.11 Technical revision history

Table 935: PQSS Technical revision history

Technical revision	Change
B	Internal improvement
C	Internal improvement
D	Internal improvement

10.4 Voltage unbalance PQVUB

10.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Voltage unbalance	VSQVUB	PQUUB	PQVUB

10.4.2 Function block

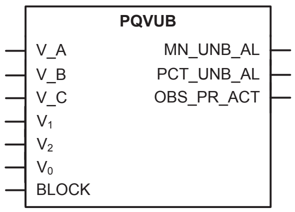


Figure 540: Function block

10.4.3 Functionality

The voltage unbalance function PQVUB monitors voltage unbalance conditions in power transmission and distribution networks. It can be applied to identify a network and load unbalance that can cause sustained voltage unbalance. PQVUB is also used to monitor the commitment of the power supply utility of providing a high-quality, that is, a balanced voltage supply on a continuous basis.

PQVUB uses five different methods for calculating voltage unbalance. The methods are the negative-sequence voltage magnitude, zero-sequence voltage magnitude, ratio of the negative-sequence voltage magnitude to the positive-sequence voltage magnitude, ratio of the zero-sequence voltage magnitude to the positive-sequence voltage magnitude and ratio of maximum phase voltage magnitude deviation from the mean voltage magnitude to the mean of the phase voltage magnitude.

PQVUB provides statistics which can be used to verify the compliance of the power quality with the European standard EN 50160 (2000). The statistics over selected period include a freely selectable percentile for unbalance. PQVUB also includes an alarm functionality providing a maximum unbalance value and the date and time of occurrence.

The function contains a blocking functionality. It is possible to block a set of function outputs or the function itself, if desired.

10.4.4 Operation principle

The function can be enabled and disabled with the *Operation* setting. The corresponding parameter values are “Enable” and “Disable”.

The operation of PQVUB can be described with a module diagram. All the modules in the diagram are explained in the next sections.

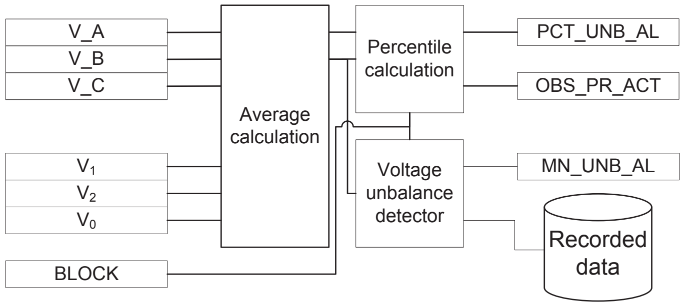


Figure 541: Functional module diagram

Average calculation

PQVUB calculates two sets of measured voltage unbalance values, a three-second and a ten-minute non-sliding average value. The three-second average value is used for continuous monitoring. The ten-minute average is used for percentile calculation for a longer period.

The Average calculation module uses five different methods for the average calculation. The required method can be selected with the *Unb detection method* parameter.

When the "Neg Seq" mode is selected with *Unb detection method*, the voltage unbalance is calculated based on the negative-sequence voltage magnitude. Similarly, when the "Zero Seq" mode is selected, the voltage unbalance is calculated based on the zero-sequence voltage magnitude. When the "Neg to Pos Seq" mode is selected, the voltage unbalance is calculated based on the ratio of the negative-sequence voltage magnitude to the positive-sequence magnitude. When the "Zero to Pos Seq" mode is selected, the voltage unbalance is calculated based on the ratio of the zero-sequence voltage magnitude to the positive-sequence magnitude. When the "Ph vectors Comp" mode is selected, the ratio of the maximum phase voltage magnitude deviation from the mean voltage magnitude to the mean of the phase voltage magnitude is used for voltage unbalance calculation.

The calculated three-second value and ten-minute value are available in the Monitored data view through the outputs `3S_MN_UNB` and `10MN_MN_UNB`.

For VT connection = "Delta", the calculated zero-sequence voltage is always zero, hence, the setting *Unb detection method* = "Zero Seq" is not applicable in this VT configuration.

Voltage unbalance detector

The three-second average value is calculated and compared to the set value *Unbalance pickup val*. If the voltage unbalance exceeds this limit, the `MN_UNB_AL` output is activated.

The activation of the `BLOCK` input blocks `MN_UNB_AL` output.

Percentile calculation

The Percentile calculation module performs the statistics calculation for the level of voltage unbalance value for a settable duration. The operation of the Percentile calculation module can be described with a module diagram.

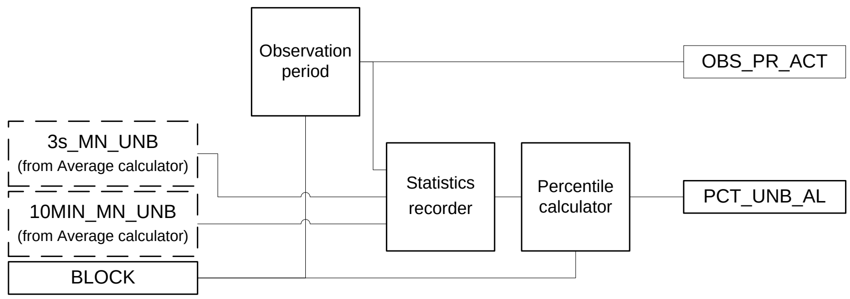


Figure 542: Percentile calculation

Observation period

The Observation period module calculates the length of the observation time for the Statistics recorder sub-module as well as determines the possible start of a new one. A new period can be started by timed activation using calendar time settings *Obs period Str year*, *Obs period Str month*, *Obs period Str day* and *Obs period Str hour*.

The observation period start time settings *Obs period Str year*, *Obs period Str month*, *Obs period Str day* and *Obs period Str hour* are used to set the calendar time in UTC. These settings have to be adjusted according to the local time and local daylight saving time.

A preferable way of continuous statistics recordings can be selected over a longer period (months, years). With the *Trigger mode* setting, the way the next possible observation time is activated after the former one has finished can be selected.

Table 936: Trigger mode observation times

Trigger mode	Observation time
Single	Only one period of observation time is activated.
Periodic	The time gap between the two trigger signals is seven days.
Continuous	The next period starts right after the previous observation period is completed.

The length of the period is determined by the settings *Obs period selection* and *User Def Obs period*. The OBS_PR_ACT output is an indication signal which exhibits rising edge (TRUE) when the observation period starts and falling edge (FALSE) when the observation period ends.

If the *Percentile unbalance*, *Trigger mode* or *Obs period duration* settings change when OBS_PR_ACT is active, OBS_PR_ACT deactivates immediately.

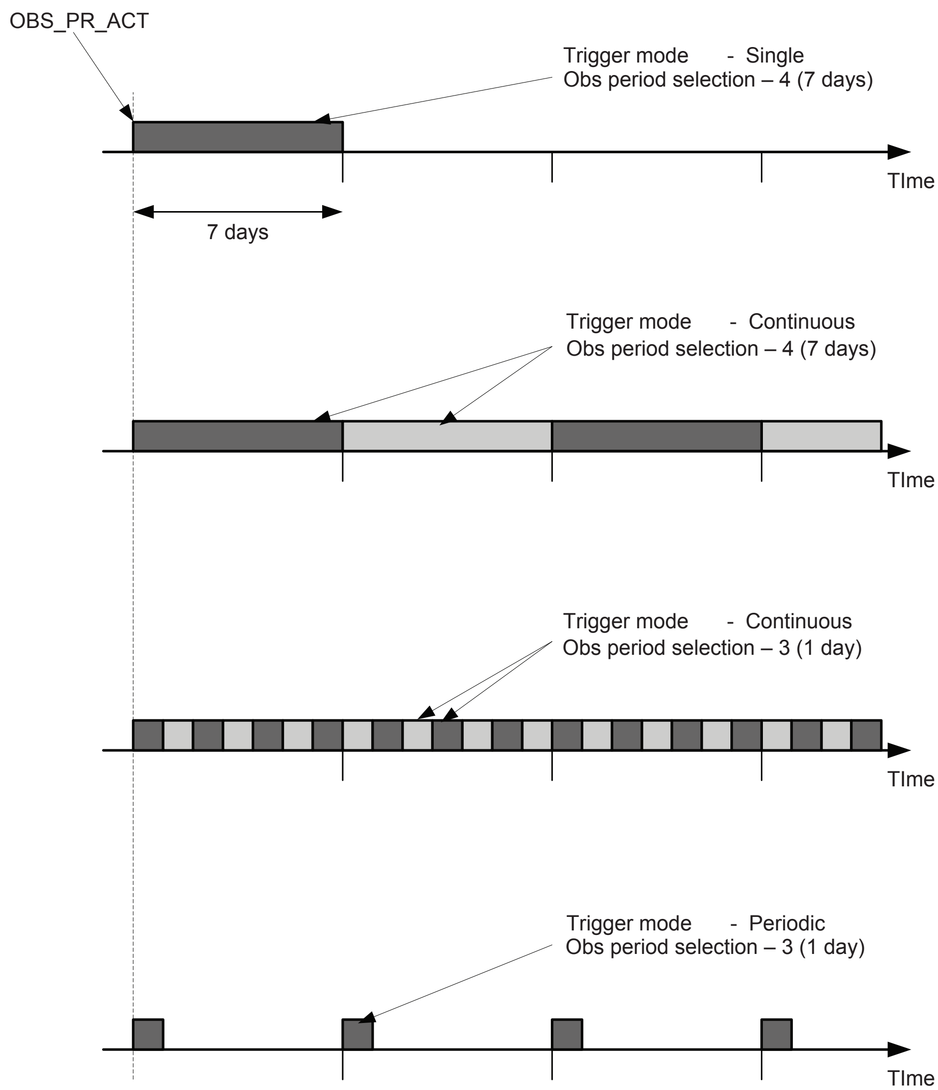


Figure 543: Periods for statistics recorder with different trigger modes and period settings

The `BLOCK` input blocks the `OBS_PR_ACT` output, which then disables the maximum value calculation of the Statistics recorder module. If the trigger mode is selected "Periodic" or "Continuous" and the blocking is deactivated before the next observation period is due to start, the scheduled period starts normally.

Statistics recorder

The Statistics recorder module provides readily calculated three-second or ten-minute values of the selected phase to the percentile calculator module based on the length of the active observation period. If the observation period is less than one day, the three-second average values are used. If the observation period is one day or longer, the ten-minute average values are used.

The maximum three-second or ten-minute mean voltage unbalance is recorded during the active observation period. The observation period start time *PR_STR_TIME*, observation period end time *PR_END_TIME*, maximum voltage unbalance value during observation period active, *MAX_UNB_VAL* and time of occurrence *MAX_UNB_TIME* are available through the Monitored data view. These outputs are updated once `OBS_PR_ACT` deactivates.

Percentile calculator

The purpose of the Percentile calculator module is to find the voltage unbalance level so that during the observation time 95 percent (default value of the *Percentile unbalance* setting) of all the measured voltage unbalance amplitudes are less than or equal to the calculated percentile.

The computed output value `PCT_UNB_VAL`, below which the percentile of the values lies, is available in the Monitored data view. The `PCT_UNB_VAL` output value is updated at the end of the observation period.

If the output `PCT_UNB_VAL` is higher than the defined setting *Unbalance pickup val* at the end of the observation period, an alarm output `PCT_UNB_AL` is activated. The `PCT_UNB_AL` output remains active for the whole period before the next period completes.

The `BLOCK` input blocks the output `PCT_UNB_VAL`.

Recorded data

The information required for a later fault analysis is stored when the Recorded data module is triggered. This happens when a voltage unbalance is detected by the Voltage unbalance detector module.

Three sets of recorded data are available in total. The sets are saved in data banks 1...3. The data bank 1 holds the most recent recorded data. Older data are moved to the subsequent banks (1 to 2 and 2 to 3) when a voltage unbalance is detected. When all three banks have data and a new variation is detected, the latest data set is placed into bank 1 and the data in bank 3 is overwritten by the data from bank 2.

The recorded data can be reset with the RESET binary input signal by navigating to the HMI reset (**Main menu/Clear/Reset recorded data/PQVUBx**) or through tools via communications.

When voltage unbalance is detected in the system, PQVUB responds with the MN_UNB_AL alarm signal. During the alarm situation, PQVUB stores the maximum magnitude and the time of occurrence and the duration of alarm MN_UNB_AL. The recorded data is stored when MN_UNB_AL is deactivated.

Table 937: Recorded data

Parameter	Description
Alarm high mean Dur	Time duration for alarm high mean unbalance
Max unbalance Volt	Maximum three-second voltage
Time Max Unb Volt	Time stamp of voltage unbalance

10.4.5 Application

Voltage unbalance is one of the basic power quality parameters.

Ideally, in a three-phase or multiphase power system, the frequency and voltage magnitude of all the phases are equal and the phase displacement between any two consecutive phases is also equal. This is called a balanced source. Apart from the balanced source, usually the power system network and loads are also balanced, implying that network impedance and load impedance in each phase are equal. In some cases, the condition of a balance network and load is not met completely, which leads to a current and voltage unbalance in the system. Providing unbalanced supply voltage has a detrimental effect on load operation. For example, a small magnitude of a negative-sequence voltage applied to an induction motor results in a significant heating of the motor.

A balanced supply, balanced network and balanced load lead to a better power quality. When one of these conditions is disturbed, the power quality is deteriorated. PQVUB monitors such voltage unbalance conditions in power transmission and distribution networks. PQVUB calculates two sets of measured values, a three-second and a ten-minute non-sliding average value. The three-second average value is used for continuous monitoring while the ten-minute average value is used for percentile calculation for a longer period of time. It can be applied to identify the network and load unbalance that may cause sustained voltage unbalance. A single-phase or phase-to-phase fault in the network or load side can create voltage unbalance but, as faults are usually isolated in a short period of time, the voltage unbalance is not a sustained one. Therefore, the voltage unbalance may not be covered by PQVUB.

Another major application is the long-term power quality monitoring. This can be used to confirm a compliance to the standard power supply quality norms. The function provides a voltage unbalance level which corresponds to the 95^{th} percentile of the ten minutes' average values of voltage unbalance recorded over a period of up to one week. It means that for 95 percent of time during the observation period the voltage unbalance was less than or equal to the calculated percentile. An alarm can be obtained if this value exceeds the value that can be set.

The function uses five different methods for calculating voltage unbalance.

- Negative-sequence voltage magnitude
- Zero-sequence voltage magnitude
- Ratio of negative-sequence to positive-sequence voltage magnitude
- Ratio of zero-sequence to positive-sequence voltage magnitude
- Ratio of maximum phase voltage magnitude deviation from the mean voltage magnitude to the mean of phase voltage magnitude.

Usually, the ratio of the negative-sequence voltage magnitude to the positive-sequence voltage magnitude is selected for monitoring the voltage unbalance. However, other methods may also be used if required.

10.4.6 Signals

Table 938: PQVUB Input signals

Name	Type	Default	Description
V_A	SIGNAL	0	Phase A voltage
V_B	SIGNAL	0	Phase B voltage
V_C	SIGNAL	0	Phase C voltage
V_1	SIGNAL	0	Positive phase sequence voltage
V_2	SIGNAL	0	Negative phase sequence voltage
V_0	SIGNAL	0	Zero sequence voltage
BLOCK	BOOLEAN	0=False	Block all outputs except measured values

Table 939: PQVUB Output signals

Name	Type	Description
MN_UNB_AL	BOOLEAN	Alarm active when 3 sec voltage unbalance exceeds the limit
PCT_UNB_AL	BOOLEAN	Alarm active when percentile unbalance exceeds the limit
OBS_PR_ACT	BOOLEAN	Observation period is active

10.4.7 Settings

Table 940: PQVUB Non group settings (Basic)

Parameter	Values (Range)	Unit	Step	Default	Description
Operation	1=enable 5=disable			1=enable	Opeartion Enable/Disable
Unb detection method	1=Neg Seq 2=Zero Seq 3=Neg to Pos Seq 4=Zero to Pos Seq 5=Ph vectors Comp			3=Neg to Pos Seq	Set the operation mode for voltage unbalance calculation
Unbalance pickup Val	1...100	%	1	1	Voltage unbalance pickup value
Trigger mode	1=Single 2=Periodic 3=Continuous			3=Continuous	Specifies the observation period triggering mode
Percentile unbalance	1...100	%	1	95	The percent to which percentile value PCT_UNB_VAL is calculated
Obs period selection	1=1 Hour 2=12 Hours 3=1 Day 4=7 Days 5=User defined			5=User defined	Observation period for unbalance calculation
User Def Obs period	1...168	h	1	168	User define observation period for statistic calculation
Obs period Str year	2008...2076			2011	Calendar time for observation period start year in YYYY
Obs period Str month	0=reserved 1=January 2=February 3=March 4=April 5=May 6=June 7=July 8=August 9=September 10=October 11=November 12=December			1=January	Calendar time for observation period start month
Obs period Str day	1...31			1	Calendar time for observation period start day
Obs period Str hour	0...23	h		0	Calendar time for observation period start hour

10.4.8 Monitored data

Table 941: PQVUB Monitored data

Name	Type	Values (Range)	Unit	Description
3S_MN_UNB	FLOAT32	0.00...150.00	%	Non sliding 3 second mean value of voltage unbalance
10MIN_MN_UNB	FLOAT32	0.00...150.00	%	Sliding 10 minutes mean value of voltage unbalance
PCT_UNB_VAL	FLOAT32	0.00...150.00	%	Limit below which percentile unbalance of the values lie
MAX_UNB_VAL	FLOAT32	0.00...150.00	%	Maximum voltage unbalance measured in the observation period
MAX_UNB_TIME	Timestamp			Time stamp at which maximum voltage unbalance measured in the observation period
PR_STR_TIME	Timestamp			Time stamp of starting of the previous observation period
PR_END_TIME	Timestamp			Time stamp of end of previous observation period
Alarm high mean Dur	FLOAT32	0.000...3600.000	s	Time duration for alarm high mean unbalance
Max unbalance Volt	FLOAT32	0.00...150.00	%	Maximum 3 seconds unbalance voltage
Time Max Unb Volt	Timestamp			Time stamp of maximum voltage unbalance
Alarm high mean Dur	FLOAT32	0.000...3600.000	s	Time duration for alarm high mean unbalance
Max unbalance Volt	FLOAT32	0.00...150.00	%	Maximum 3 seconds unbalance voltage
Time Max Unb Volt	Timestamp			Time stamp of maximum voltage unbalance
Alarm high mean Dur	FLOAT32	0.000...3600.000	s	Time duration for alarm high mean unbalance
Max unbalance Volt	FLOAT32	0.00...150.00	%	Maximum 3 seconds unbalance voltage
Time Max Unb Volt	Timestamp			Time stamp of maximum voltage unbalance
PQVUB	Enum	1=Enabled 2=blocked 3=test 4=test/blocked 5=Disabled		Status

10.4.9 Technical data

Table 942: PQVUB Technical data

Characteristic	Value
Operation accuracy	±1.5% of the set value or ±0.002 × V_n
Reset ratio	Typically 0.96

Section 11 General function block features

11.1 Definite time characteristics

11.1.1 Definite time operation

The DT mode is enabled when the *Operating curve type* setting is selected either as "ANSI Def. Time" or "IEC Def. Time". In the DT mode, the TRIP output of the function is activated when the time calculation exceeds the set *Trip delay time*.

The user can determine the reset in the DT mode with the *Reset delay time* setting, which provides the delayed reset property when needed.

The *Type of reset curve* setting has no effect on the reset method when the DT mode is selected, but the reset is determined solely with the *Reset delay time* setting.

The purpose of the delayed reset is to enable fast clearance of intermittent faults, for example self-sealing insulation faults, and severe faults which may produce high asymmetrical fault currents that partially saturate the current transformers. It is typical for an intermittent fault that the fault current contains so called drop-off periods, during which the fault current falls below the set start current, including hysteresis. Without the delayed reset function, the operation timer would reset when the current drops off. In the same way, an apparent drop-off period of the secondary current of the saturated current transformer can also reset the operation timer.

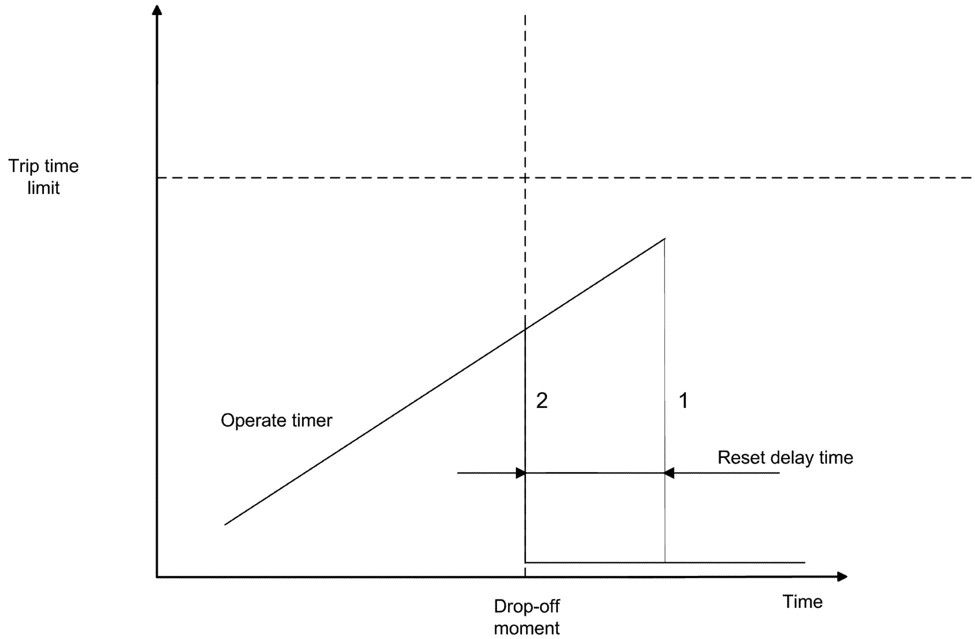


Figure 544: Operation of the counter in drop-off

In case 1, the reset is delayed with the *Reset delay time* setting and in case 2, the counter is reset immediately, because the *Reset delay time* setting is set to zero.

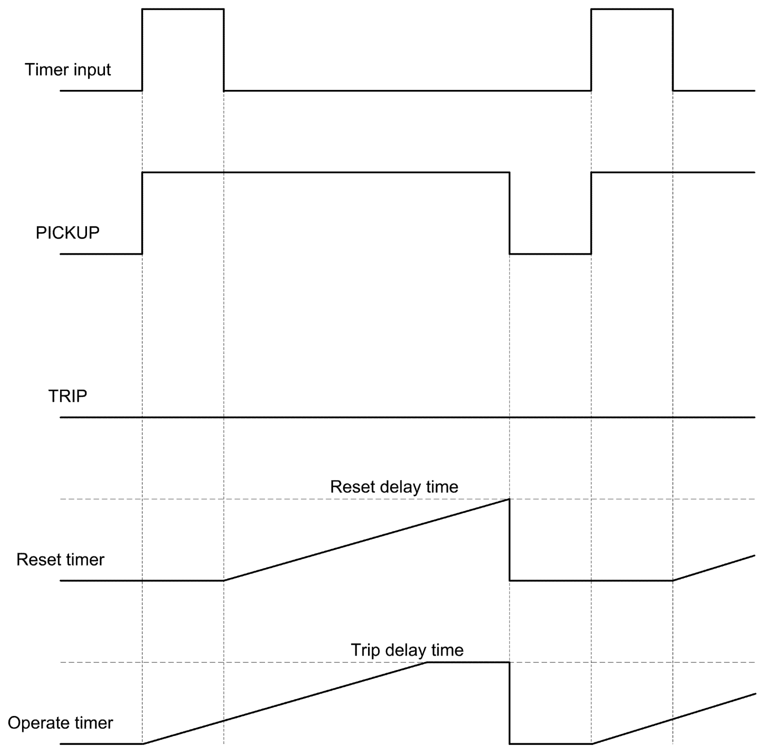


Figure 545: Drop-off period is longer than the set Reset delay time

When the drop-off period is longer than the set *Reset delay time*, as described in Figure 545, the input signal for the definite timer (here: timer input) is active, provided that the current is above the set *Pickup value*. The input signal is inactive when the current is below the set *Pickup value* and the set hysteresis region. The timer input rises when a fault current is detected. The definite timer activates the PICKUP output and the operation timer starts elapsing. The reset (drop-off) timer starts when the timer input falls, that is, the fault disappears. When the reset (drop-off) timer elapses, the operation timer is reset. Since this happens before another pickup occurs, the TRIP output is not activated.

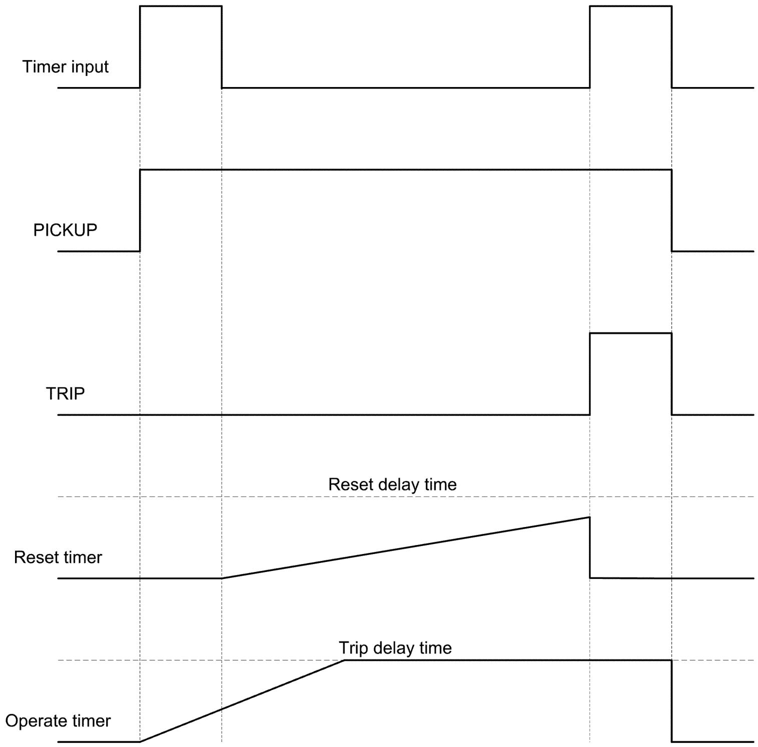


Figure 546: Drop-off period is shorter than the set Reset delay time

When the drop-off period is shorter than the set *Reset delay time*, as described in Figure 546, the input signal for the definite timer (here: timer input) is active, provided that the current is above the set *Pickup value*. The input signal is inactive when the current is below the set *Pickup value* and the set hysteresis region. The timer input rises when a fault current is detected. The definite timer activates the `PICKUP` output and the operation timer starts elapsing. The reset (drop-off) timer starts when the timer input falls, that is, the fault disappears. Another fault situation occurs before the reset (drop-off) timer has elapsed. This causes the activation of the `TRIP` output, since the operation timer already has elapsed.

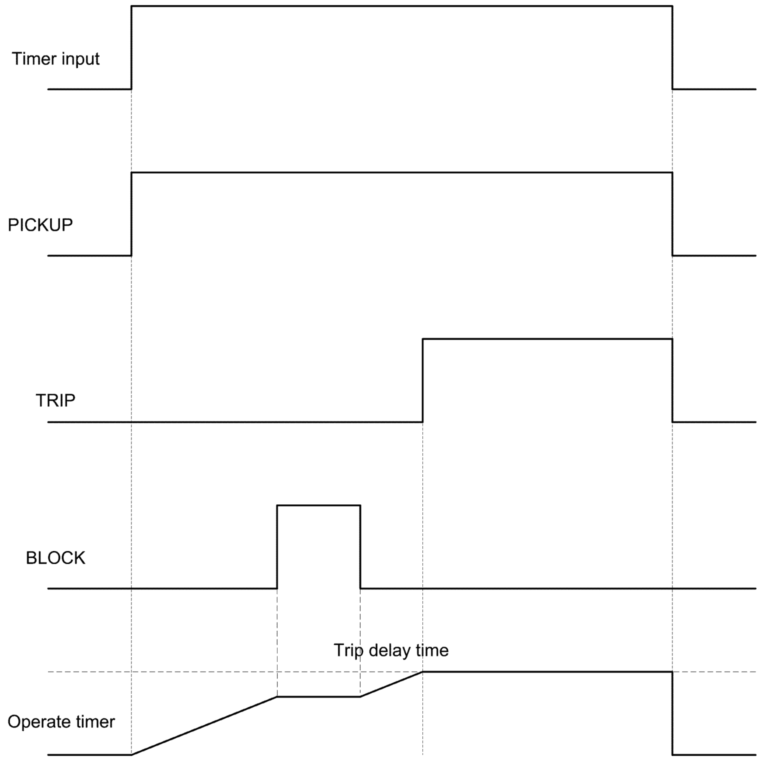


Figure 547: Operating effect of the `BLOCK` *input when the selected blocking mode is "Freeze timer"*

If the `BLOCK` input is activated when the operation timer is running, as described in Figure 547, the timer is frozen during the time `BLOCK` remains active. If the timer input is not active longer than specified by the *Reset delay time* setting, the operation timer is reset in the same way as described in Figure 545, regardless of the `BLOCK` input.

The selected blocking mode is "Freeze timer".

11.2 Current based inverse definite minimum time characteristics

11.2.1 IDMT curves for overcurrent protection

In inverse-time modes, the trip time depends on the momentary value of the current: the higher the current, the faster the trip time. The trip time calculation or integration starts immediately when the current exceeds the set *Pickup value* and the `PICKUP` output is activated.

The `TRIP` output of the component is activated when the cumulative sum of the integrator calculating the overcurrent situation exceeds the value set by the inverse-time mode. The set value depends on the selected curve type and the setting values used. The curve scaling is determined with the *Time multiplier* setting.

There are two methods to level out the inverse-time characteristic.

- The *Minimum trip time* setting defines the minimum operating time for the IDMT curve, that is, the operation time is always at least the *Minimum trip time* setting.
- Alternatively, the *IDMT Sat point* is used for giving the leveling-out point as a multiple of the *Pickup value* setting. (Global setting: **Configuration/System/*IDMT Sat point***). The default parameter value is 50. This setting affects only the overcurrent and ground-fault IDMT timers.

IDMT operation time at currents over 50 x In is not guaranteed.

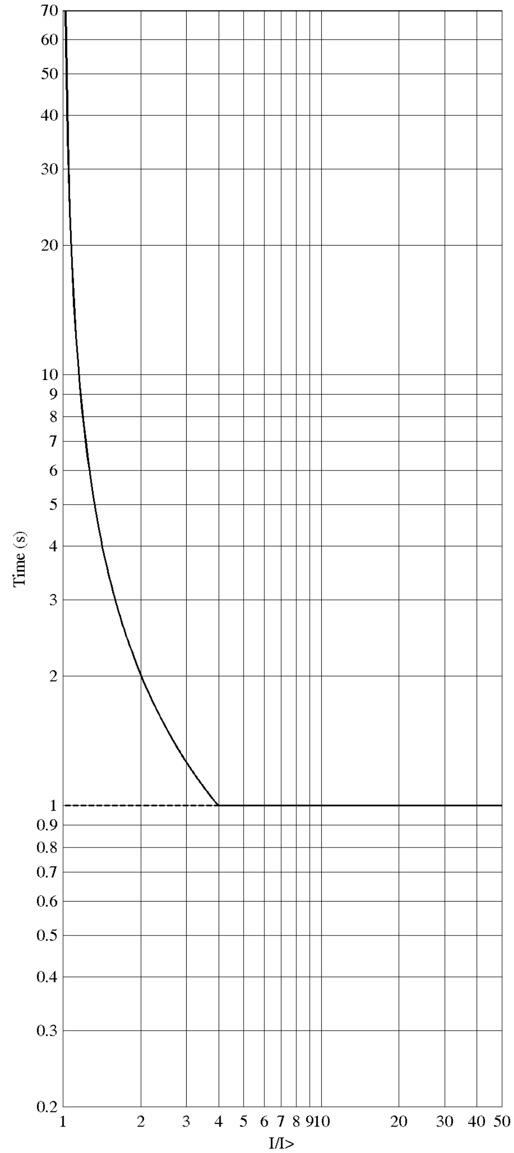


Figure 548: Operation time curve based on the IDMT characteristic leveled out with the Minimum trip time setting is set to 1000 milliseconds (the IDMT Sat point setting is set to maximum).

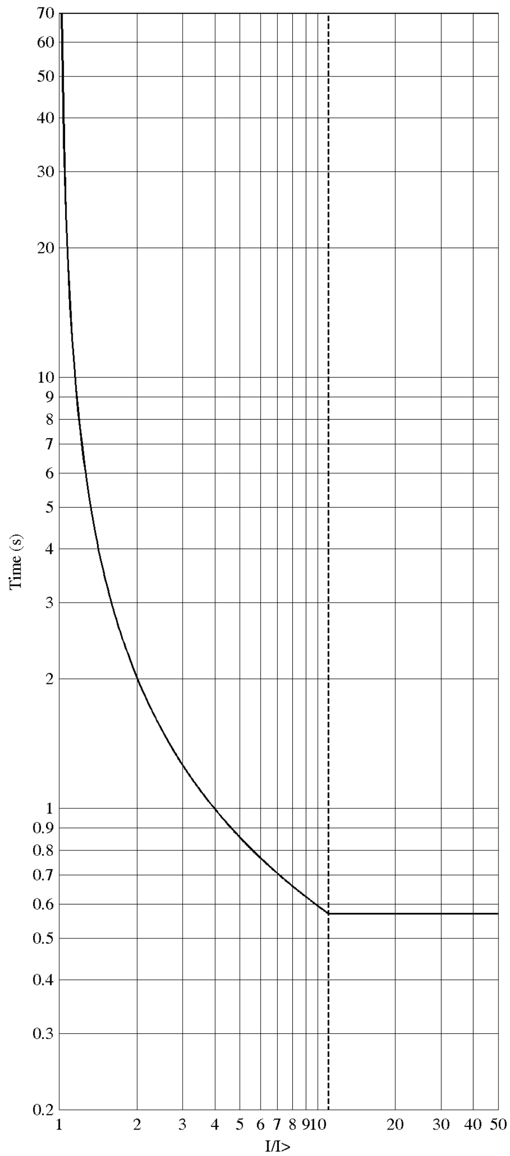


Figure 549: Operation time curve based on the IDMT characteristic leveled out with IDMT Sat point setting value “11” (the Minimum trip time setting is set to minimum).

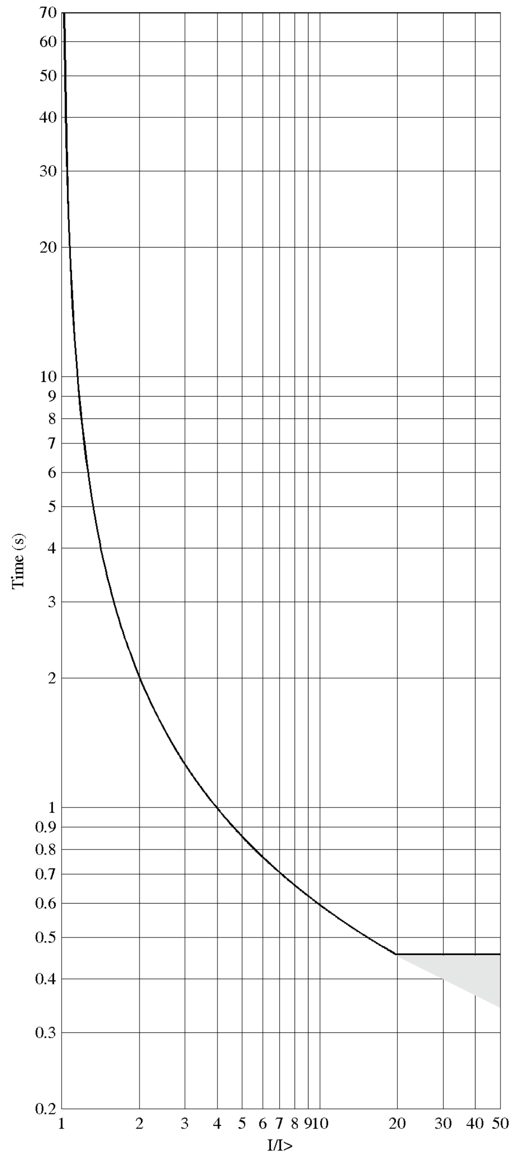


Figure 550: Example of how the inverse time characteristic is leveled out with currents over 50 x In and the Setting Pickup value setting “2.5 x In”. (the IDMT Sat point setting is set to maximum and the Minimum trip time setting is set to minimum).

The grey zone in Figure 550 shows the behavior of the curve in case the measured current is outside the guaranteed measuring range. Also, the maximum measured current of 50 x In gives the leveling-out point 50/2.5 = 20 x I/I>.

11.2.1.1 Standard inverse-time characteristics

For inverse-time operation, both IEC and ANSI/IEEE standardized inverse-time characteristics are supported.

The trip times for the ANSI and IEC IDMT curves are defined with the coefficients A, B and C.

The values of the coefficients can be calculated according to the formula:

$$t[s] = \left(\frac{A}{\left(\frac{I}{I>} \right)^{c} - 1} + B \right) \cdot k$$

(Equation 173)

t[s]	t[s] = Trip time in seconds
I	measured current
I>	set *Pickup value*
k	set *Time multiplier*

Table 943: Curve parameters for ANSI and IEC IDMT curves

Curve name	A	B	C
(1) ANSI Extremely Inverse	28.2	0.1217	2.0
(2) ANSI Very Inverse	19.61	0.491	2.0
(3) ANSI Normal Inverse	0.0086	0.0185	0.02
(4) ANSI Moderately Inverse	0.0515	0.1140	0.02
(6) Long Time Extremely Inverse	64.07	0.250	2.0
(7) Long Time Very Inverse	28.55	0.712	2.0
(8) Long Time Inverse	0.086	0.185	0.02
(9) IEC Normal Inverse	0.14	0.0	0.02
(10) IEC Very Inverse	13.5	0.0	1.0
(11) IEC Inverse	0.14	0.0	0.02

Table continues on next page

Curve name	A	B	C
(12) IEC Extremely Inverse	80.0	0.0	2.0
(13) IEC Short Time Inverse	0.05	0.0	0.04
(14) IEC Long Time Inverse	120	0.0	1.0

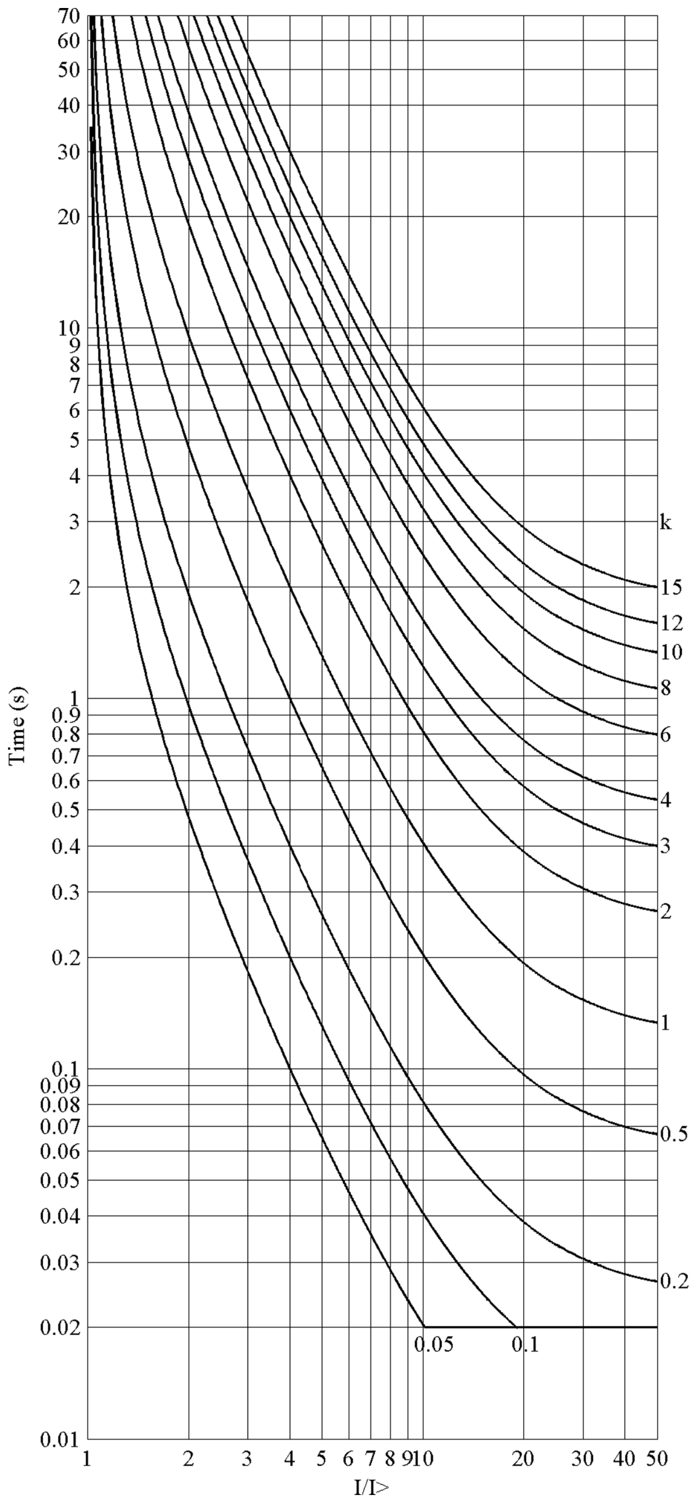


Figure 551: ANSI extremely inverse-time characteristics

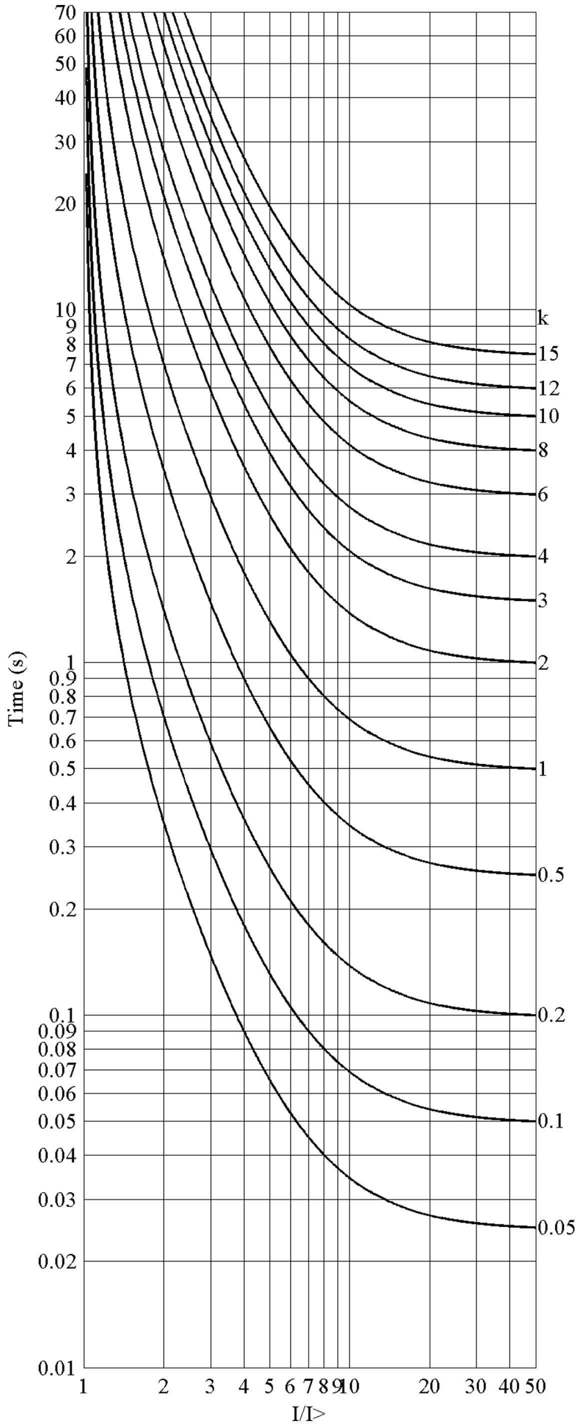


Figure 552: ANSI very inverse-time characteristics

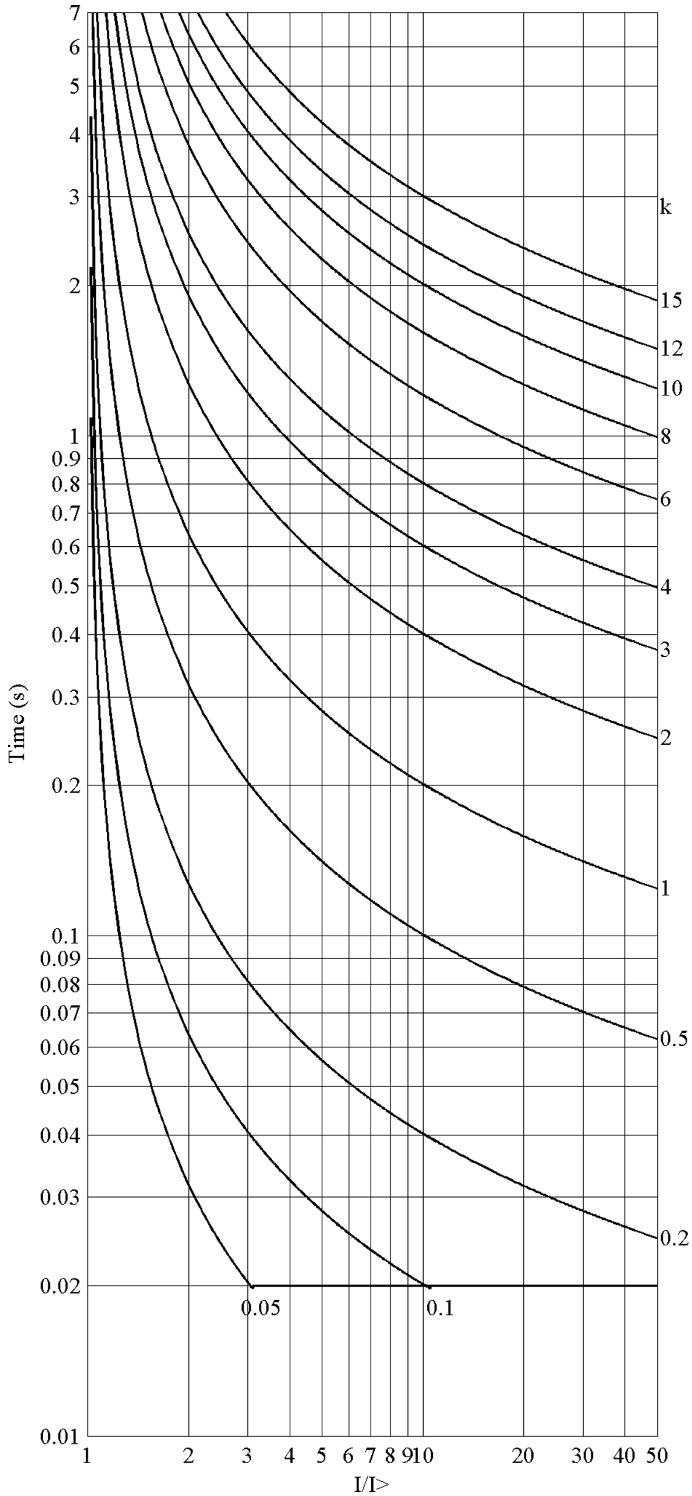


Figure 553: ANSI normal inverse-time characteristics

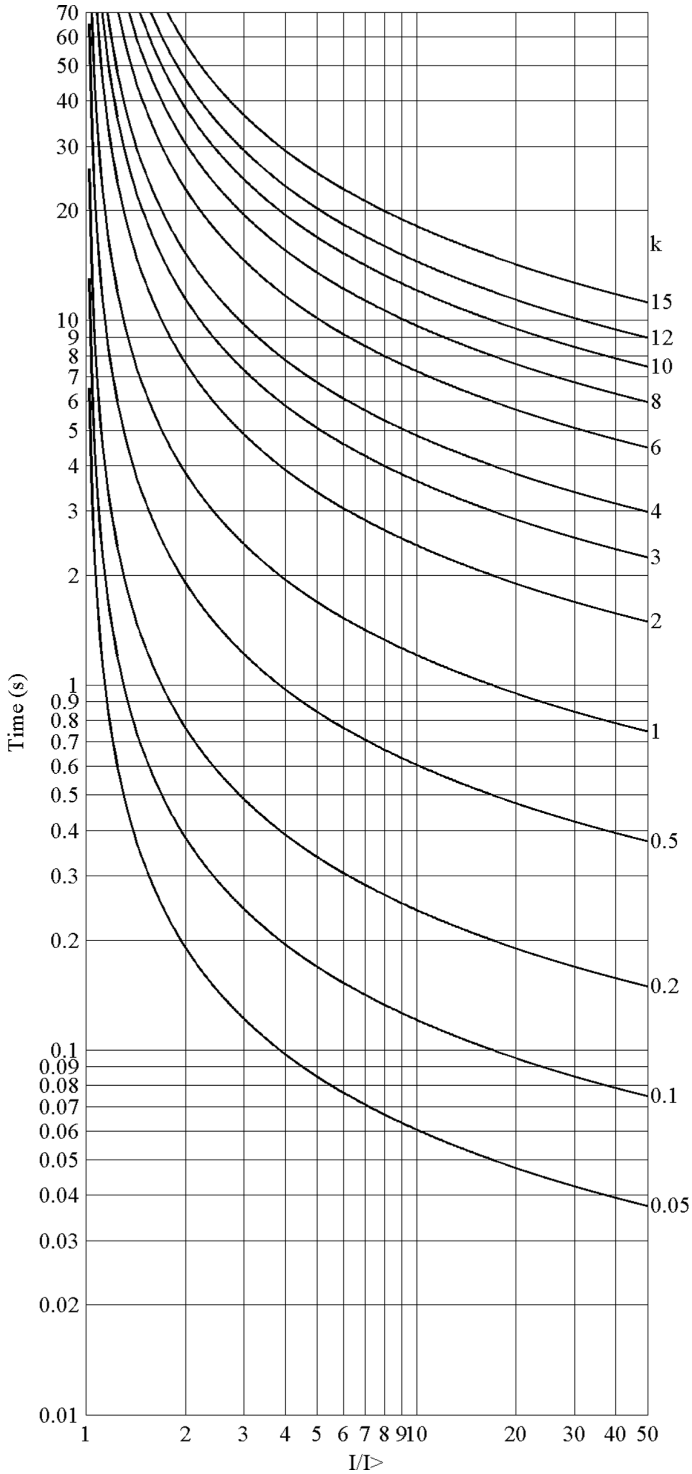


Figure 554: ANSI moderately inverse-time characteristics

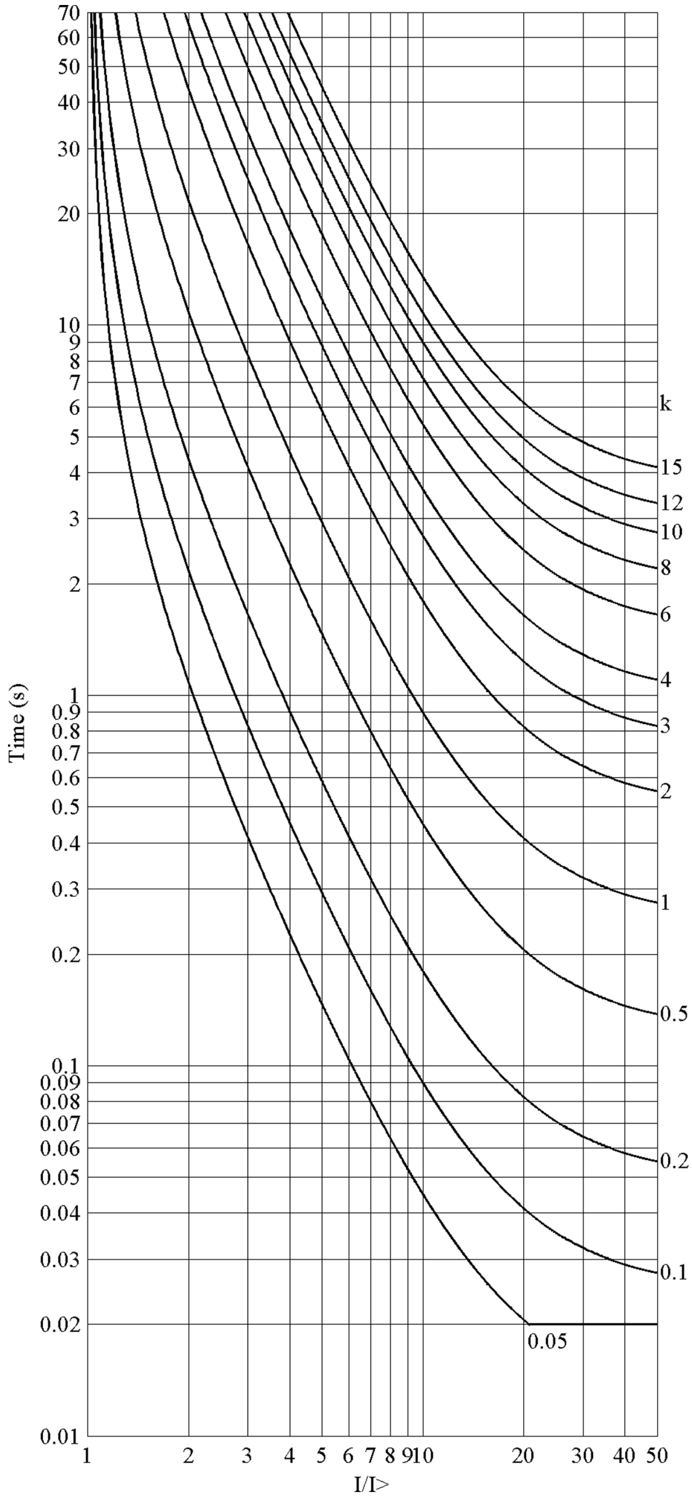


Figure 555: ANSI long-time extremely inverse-time characteristics

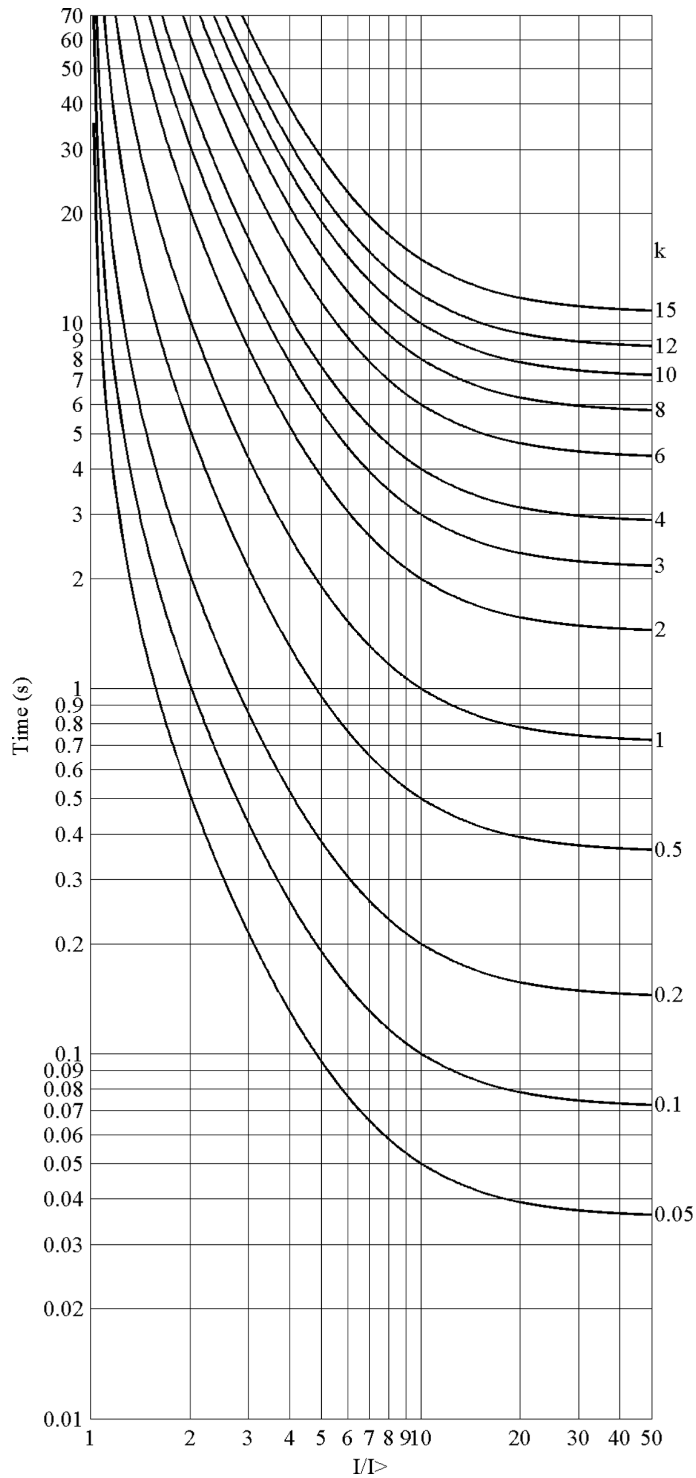


Figure 556: ANSI long-time very inverse-time characteristics

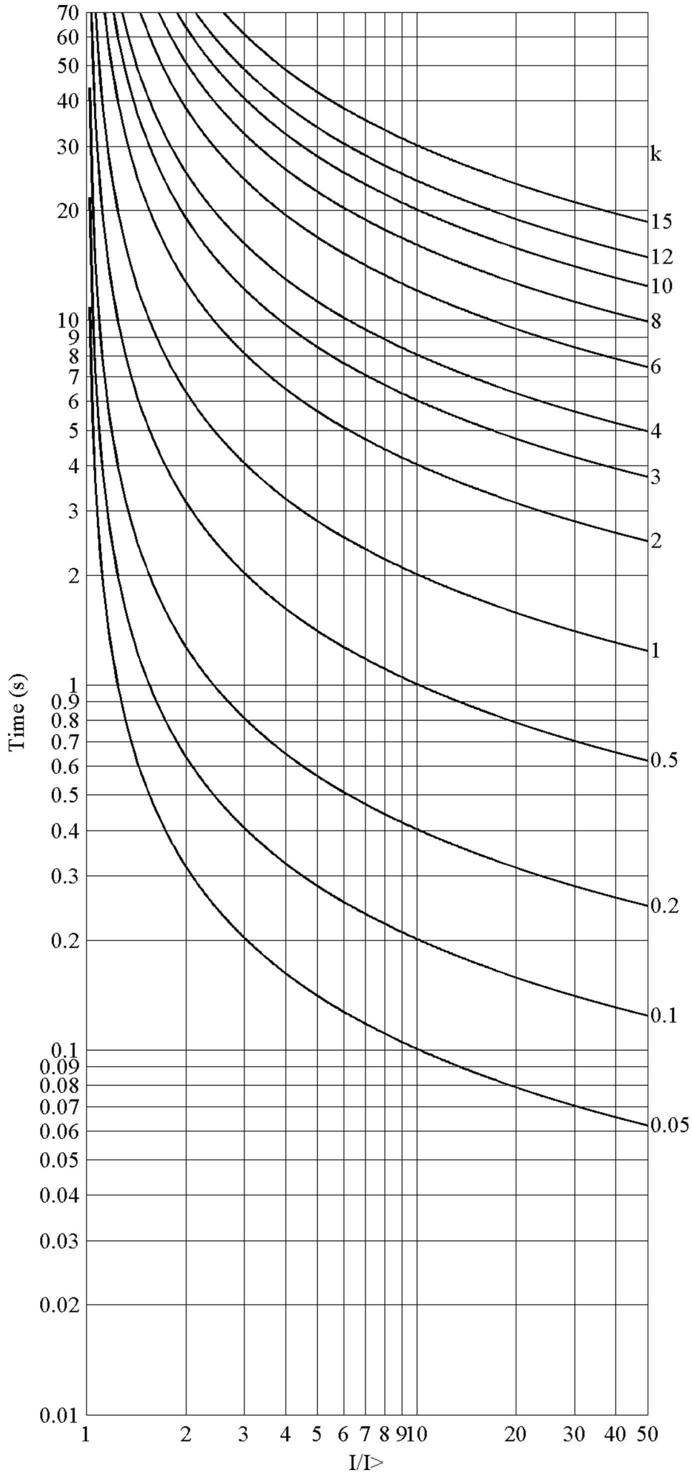


Figure 557: ANSI long-time inverse-time characteristics

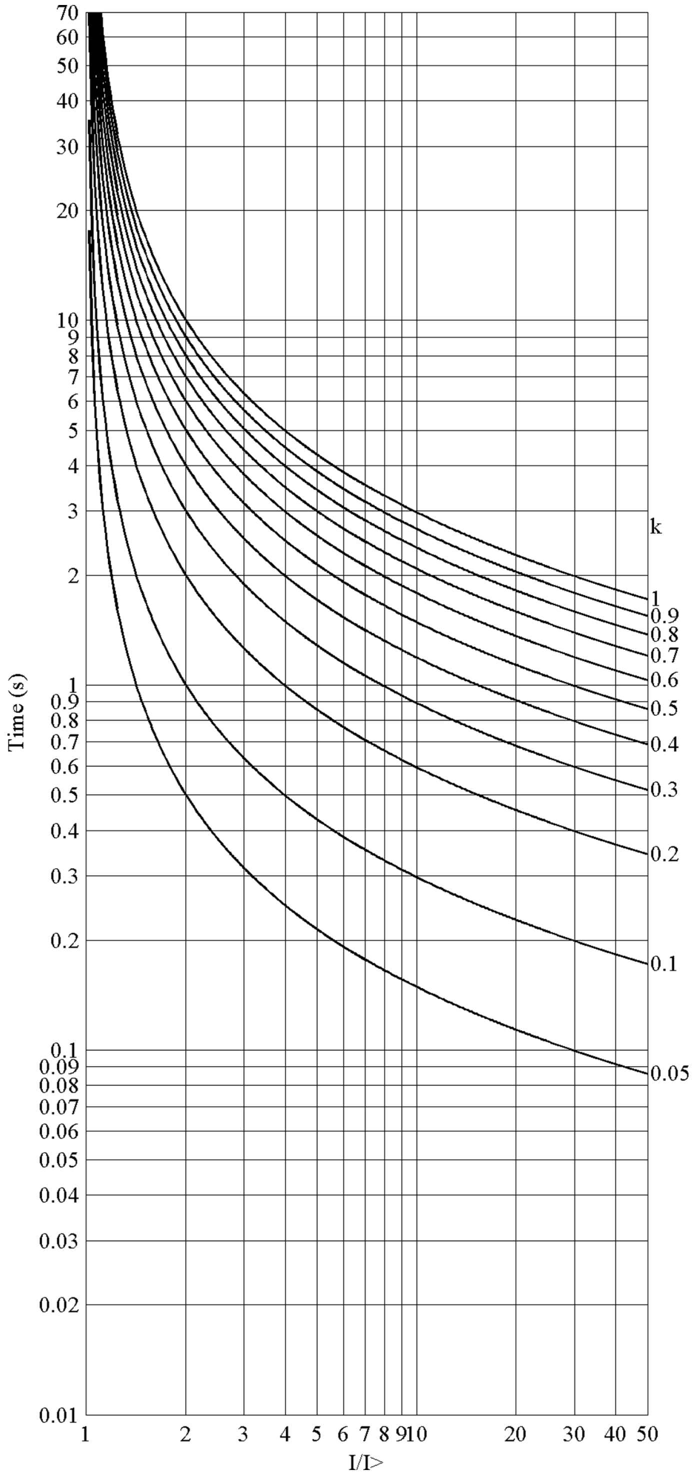


Figure 558: IEC normal inverse-time characteristics

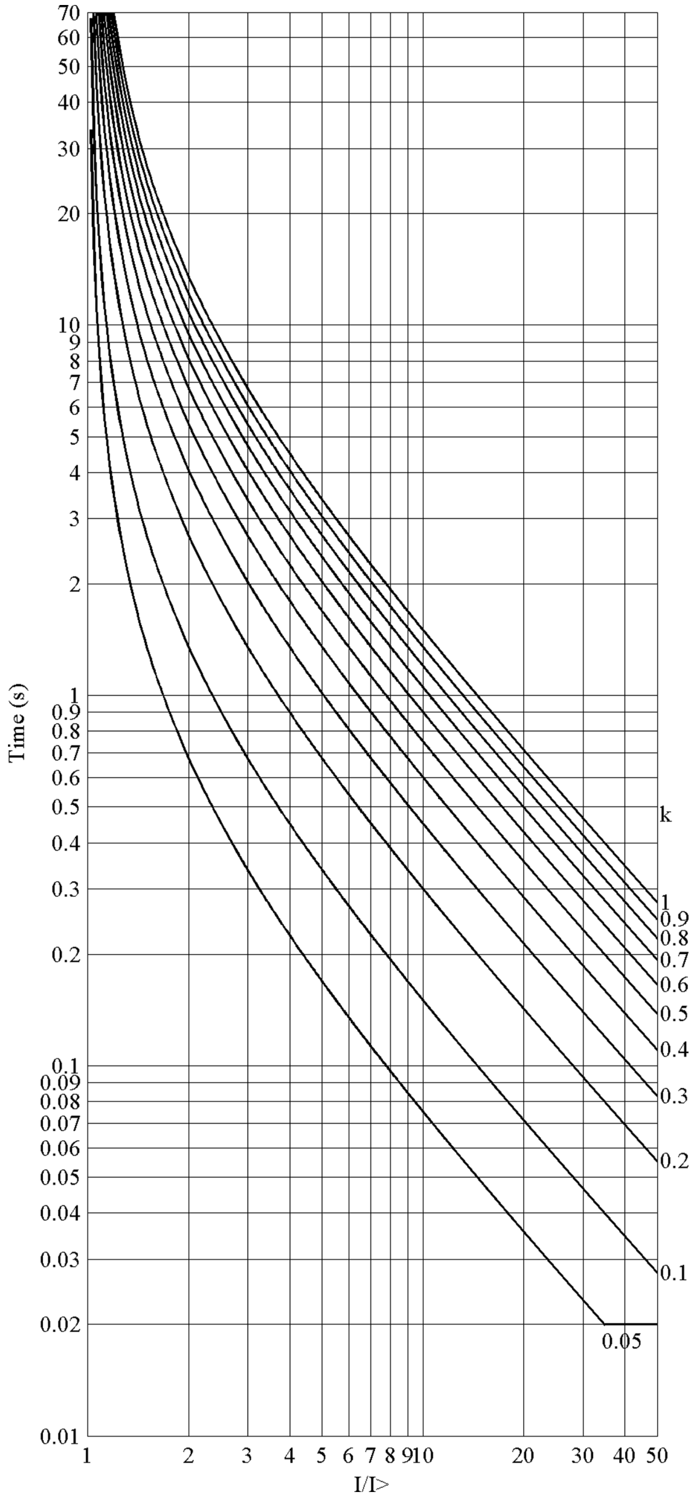


Figure 559: IEC very inverse-time characteristics

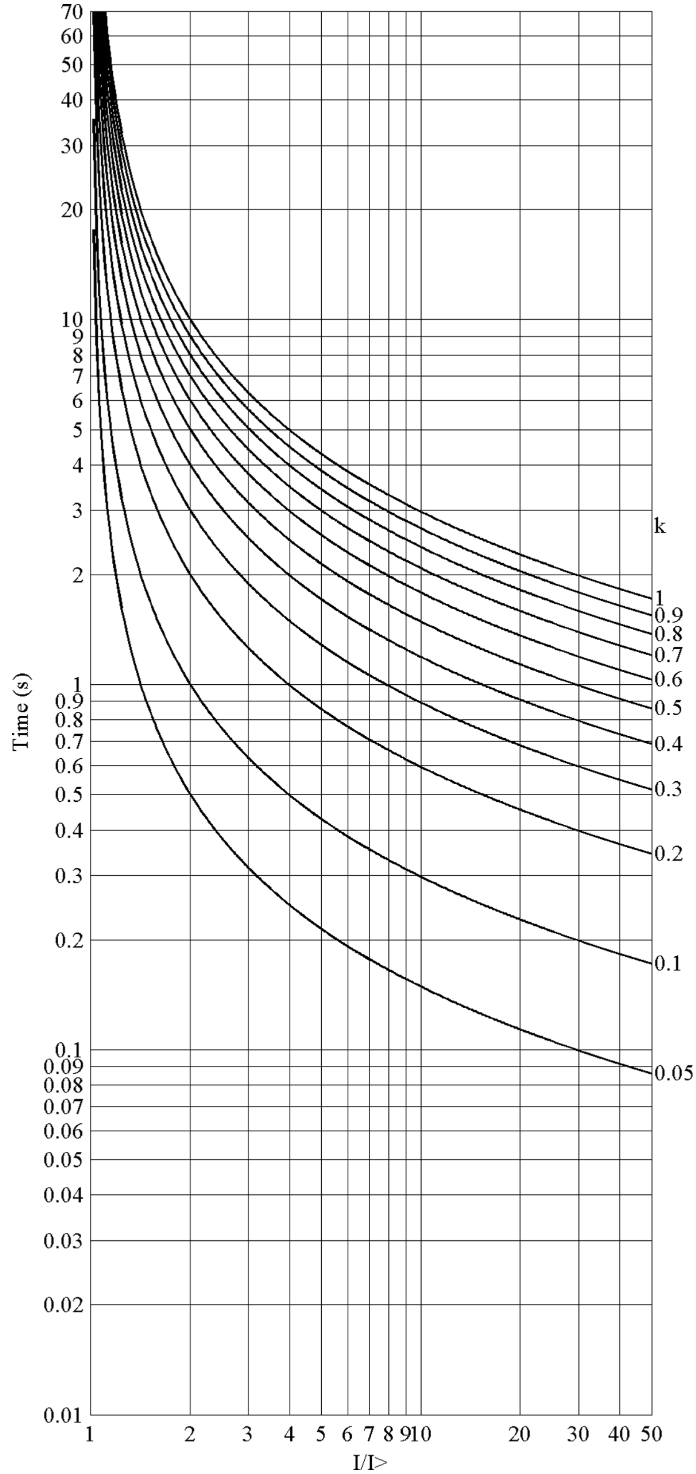


Figure 560: IEC inverse-time characteristics

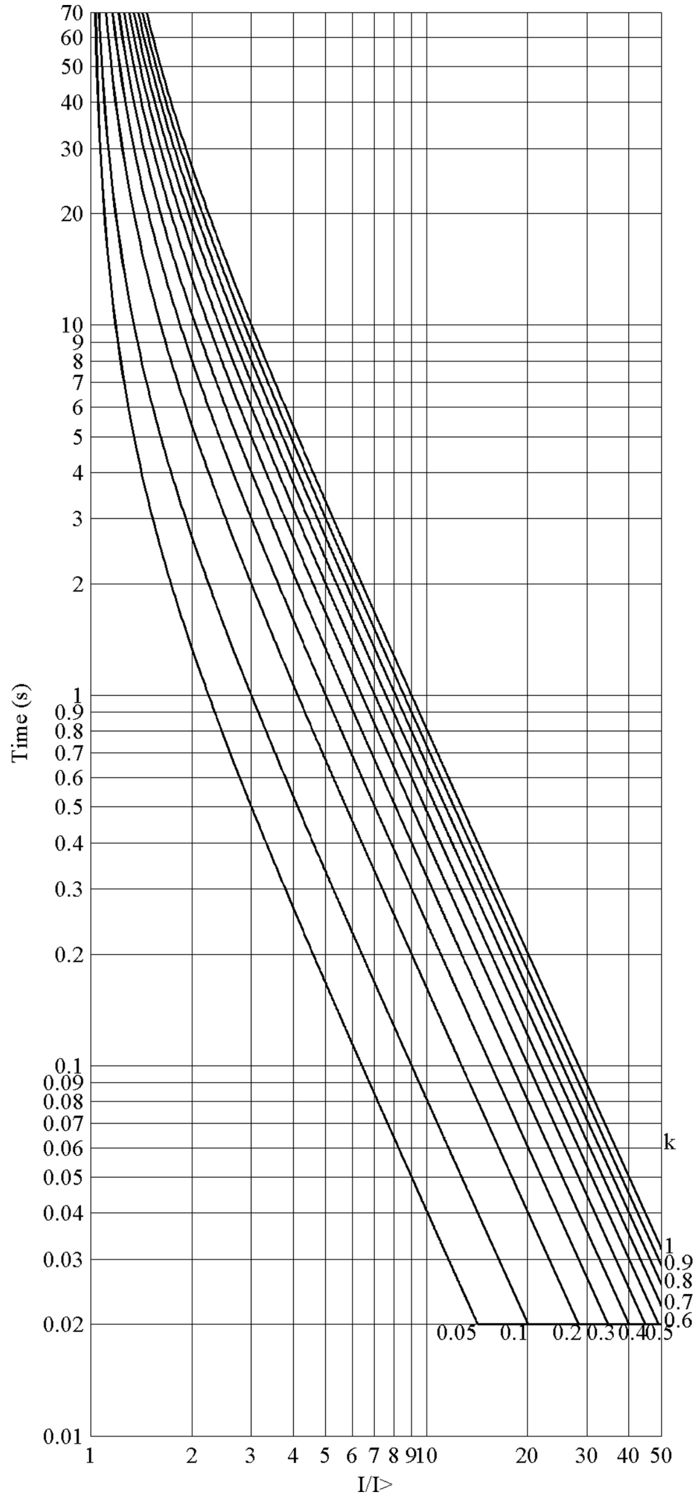


Figure 561: IEC extremely inverse-time characteristics

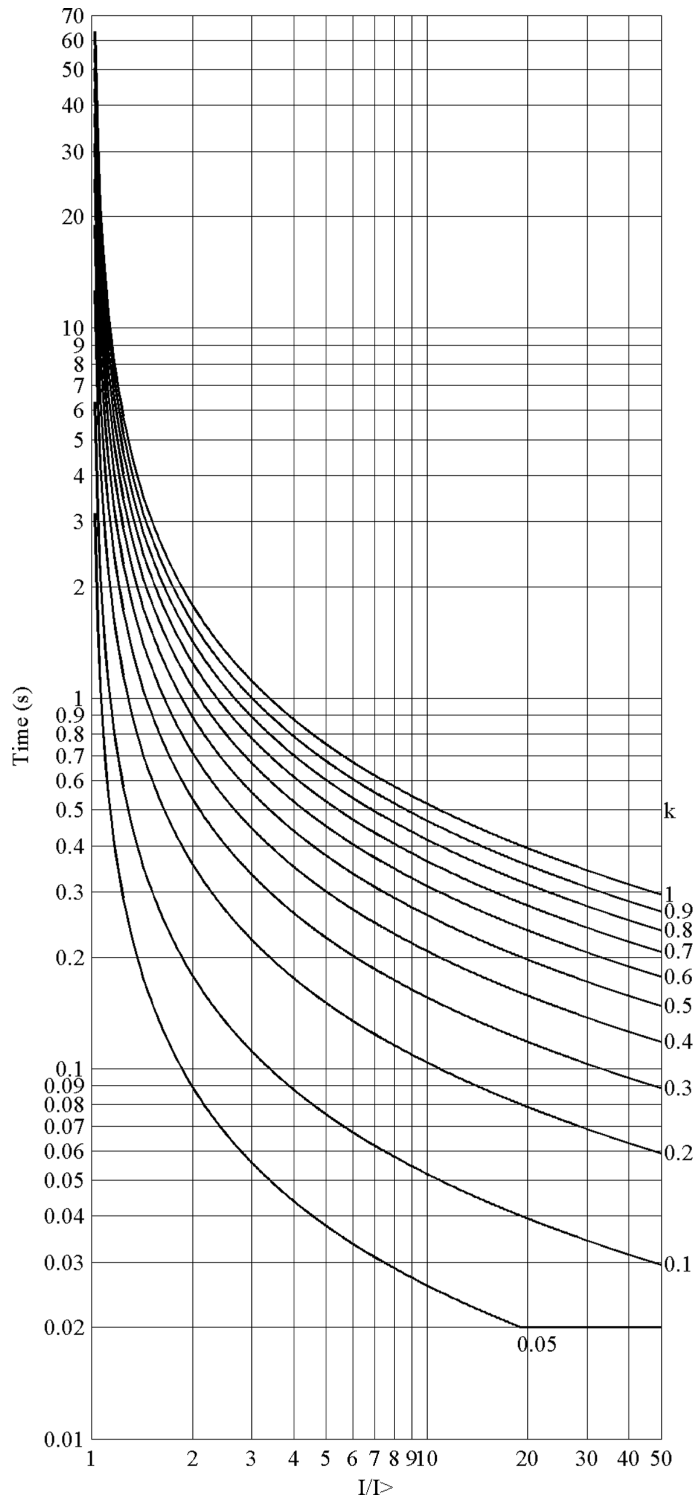


Figure 562: IEC short-time inverse-time characteristics

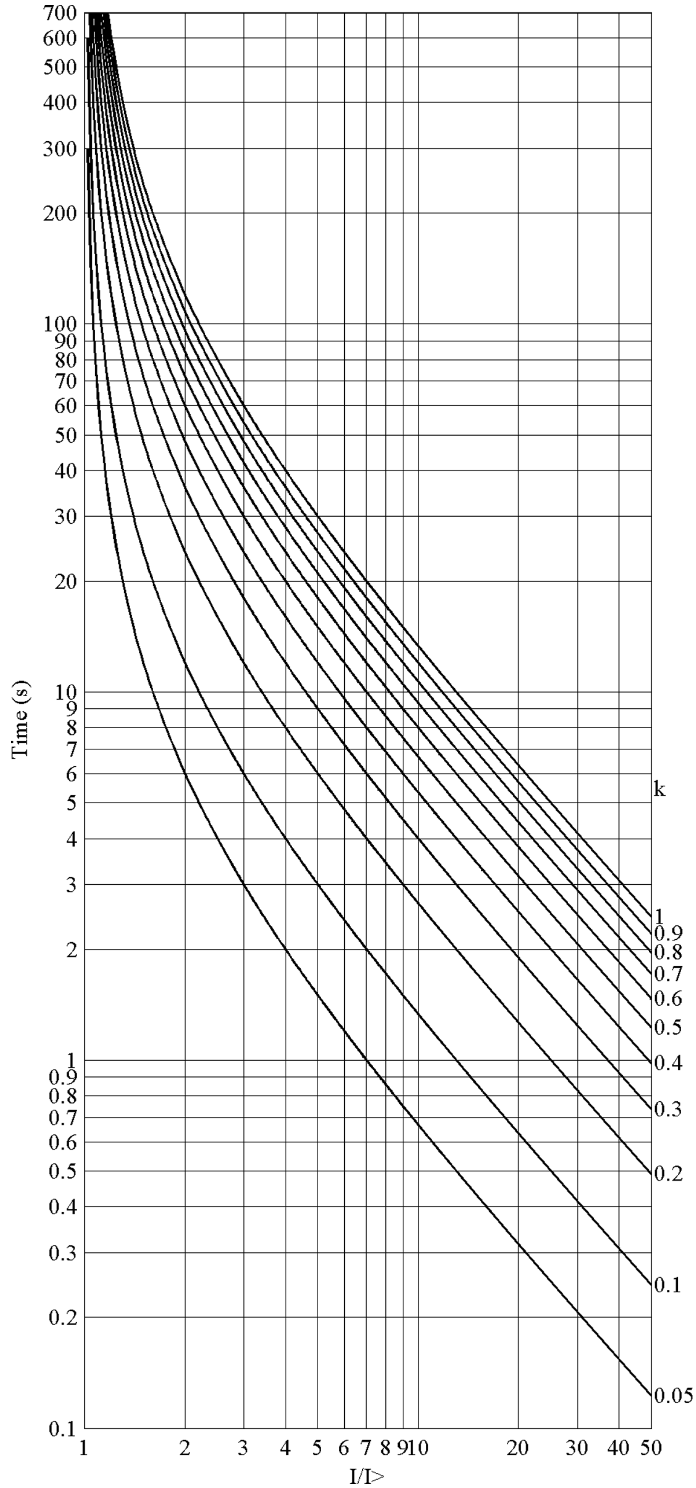


Figure 563: IEC long-time inverse-time characteristics

11.2.1.2 User-programmable inverse-time characteristics

The user can define curves by entering parameters into the following standard formula:

$$t[s] = \left(\frac{A}{\left(\frac{I}{I>}\right)^{c} - E} + B \right) \cdot k$$

(Equation 174)

t[s]	Trip time (in seconds)
A	set *Curve parameter A*
B	set *Curve parameter B*
C	set *Curve parameter C*
E	set *Curve parameter E*
I	Measured current
I>	set *Pickup value*
k	set *Time multiplier*

11.2.1.3 RI and RD-type inverse-time characteristics

The RI-type simulates the behavior of electromechanical relays. The RD-type is a ground-fault specific characteristic.

The RI-type is calculated using the formula

$$t[s] = \left(\frac{k}{0.339 - 0.236 \times \frac{I>}{I}} \right)$$

(Equation 175)

The RD-type is calculated using the formula

$$t[s] = 5.8 - 1.35 \times \text{In}\left(\frac{I}{k \times I>} \right)$$

(Equation 176)

t[s]	Trip time (in seconds)
k	set *Time multiplier*
I	Measured current
I>	set *Pickup value*

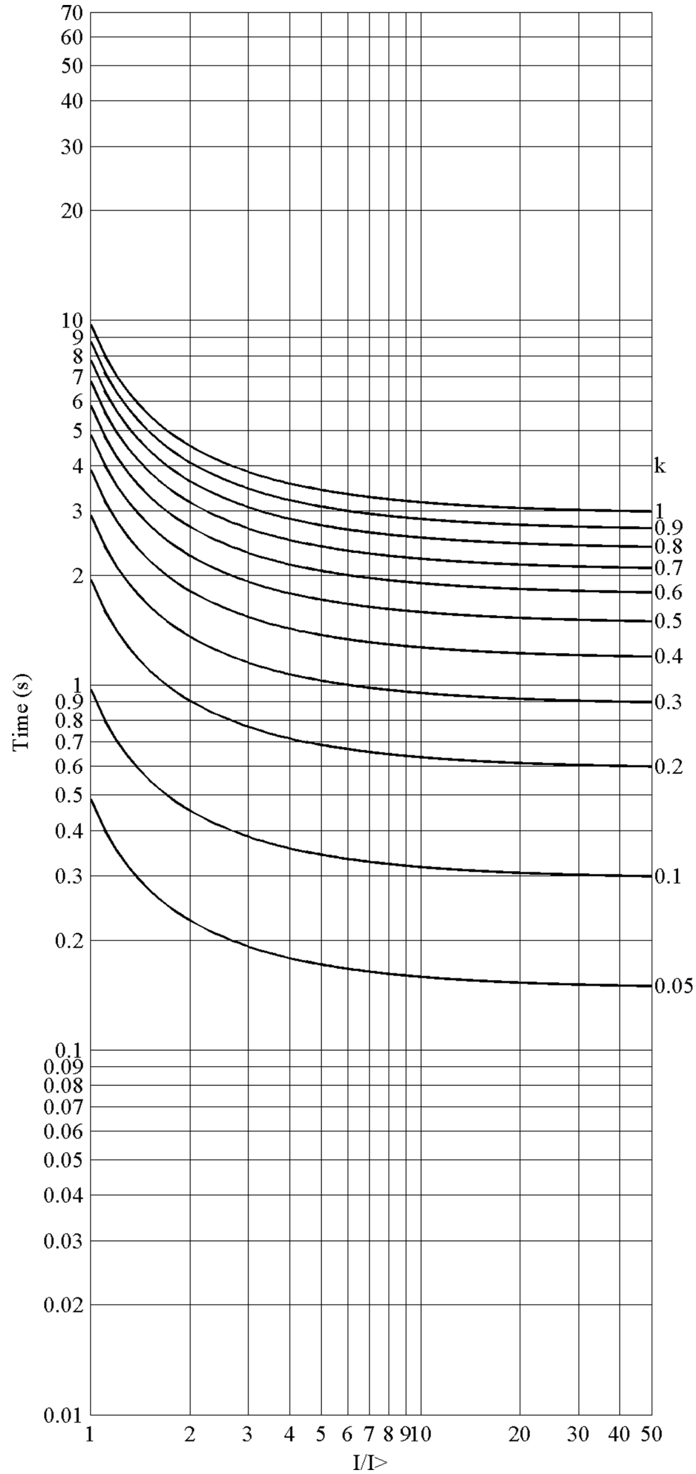


Figure 564: RI-type inverse-time characteristics

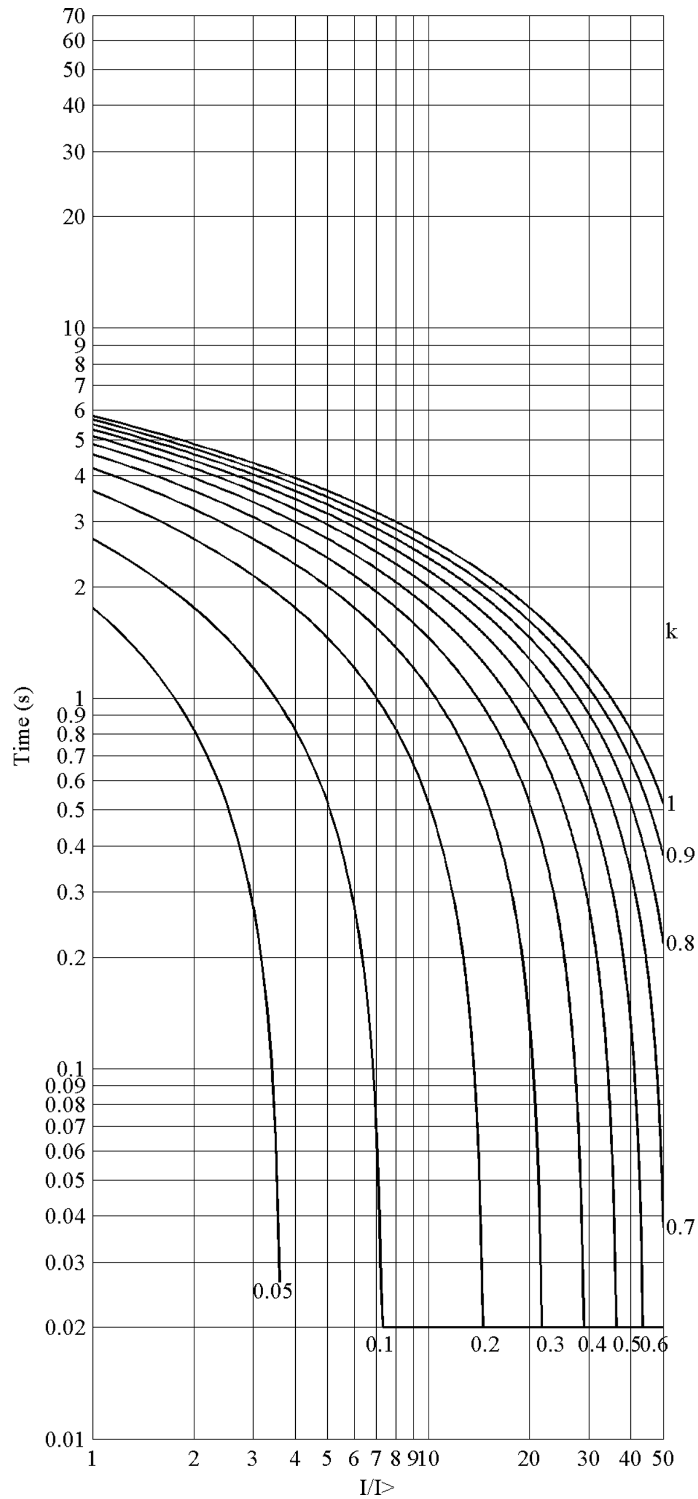


Figure 565: RD-type inverse-time characteristics

11.2.2 Reset in inverse-time modes

The user can select the reset characteristics by using the *Type of reset curve* setting.

Table 944: Values for reset mode

Setting name	Possible values
Type of reset curve	1=Immediate 2=Def time reset 3=Inverse reset

Immediate reset

If the *Type of reset curve* setting in a drop-off case is selected as "Immediate", the inverse timer resets immediately.

Definite time reset

The definite type of reset in the inverse-time mode can be achieved by setting the *Type of reset curve* parameter to “Def time reset”. As a result, the trip inverse-time counter is frozen for the time determined with the *Reset delay time* setting after the current drops below the set *Pickup value*, including hysteresis.The integral sum of the inverse-time counter is reset, if another pickup does not occur during the reset delay.

If the *Type of reset curve* setting is selected as “Def time reset”, the current level has no influence on the reset characteristic.

Inverse reset

Inverse reset curves are available only for ANSI and user-programmable curves. If you use other curve types, immediate reset occurs.

Standard delayed inverse reset

The reset characteristic required in ANSI (IEEE) inverse-time modes is provided by setting the *Type of reset curve* parameter to “Inverse reset”. In this mode, the time delay for reset is given with the following formula using the coefficient D, which has its values defined in the table below.

$$t[s] = \left(\frac{D}{\left(\frac{I}{I>} \right)^2 - 1} \right) \cdot k$$

(Equation 177)

t[s] Reset time (in seconds)

k set *Time multiplier*

I Measured current

I> set *Pickup value*

Table 945: Coefficients for ANSI delayed inverse reset curves

Curve name	D
(1) ANSI Extremely Inverse	29.1
(2) ANSI Very Inverse	21.6
(3) ANSI Normal Inverse	0.46
(4) ANSI Moderately Inverse	4.85
(6) Long Time Extremely Inverse	30
(7) Long Time Very Inverse	13.46
(8) Long Time Inverse	4.6

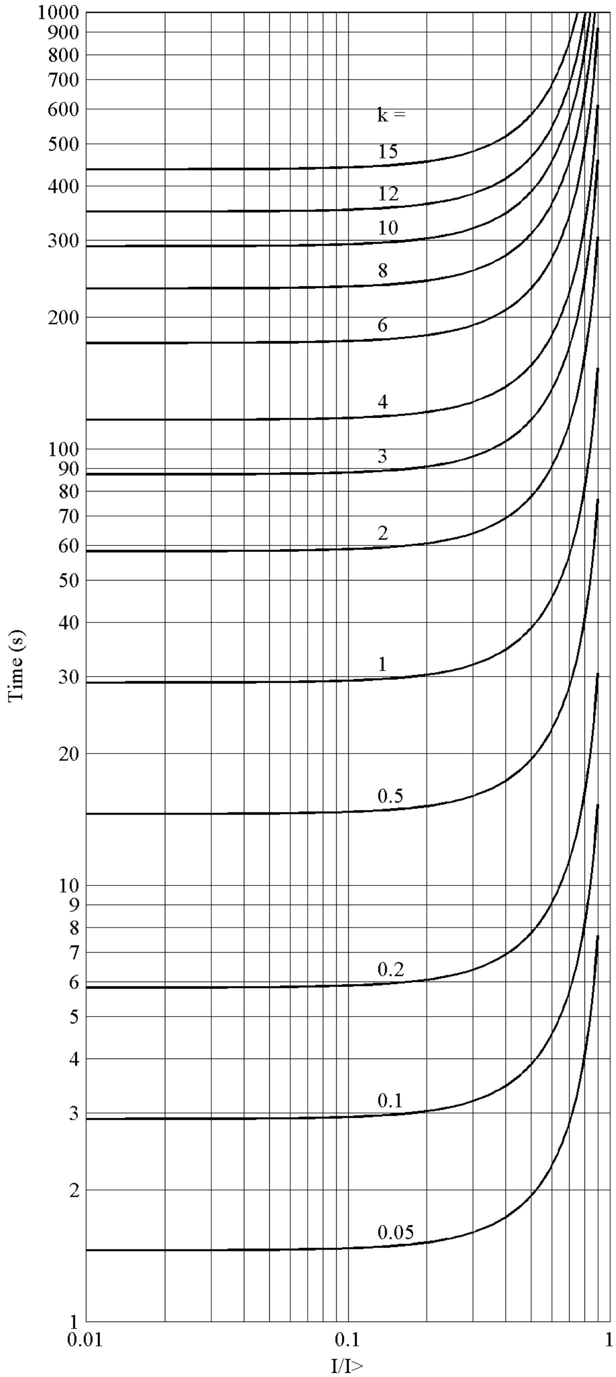


Figure 566: ANSI extremely inverse reset time characteristics

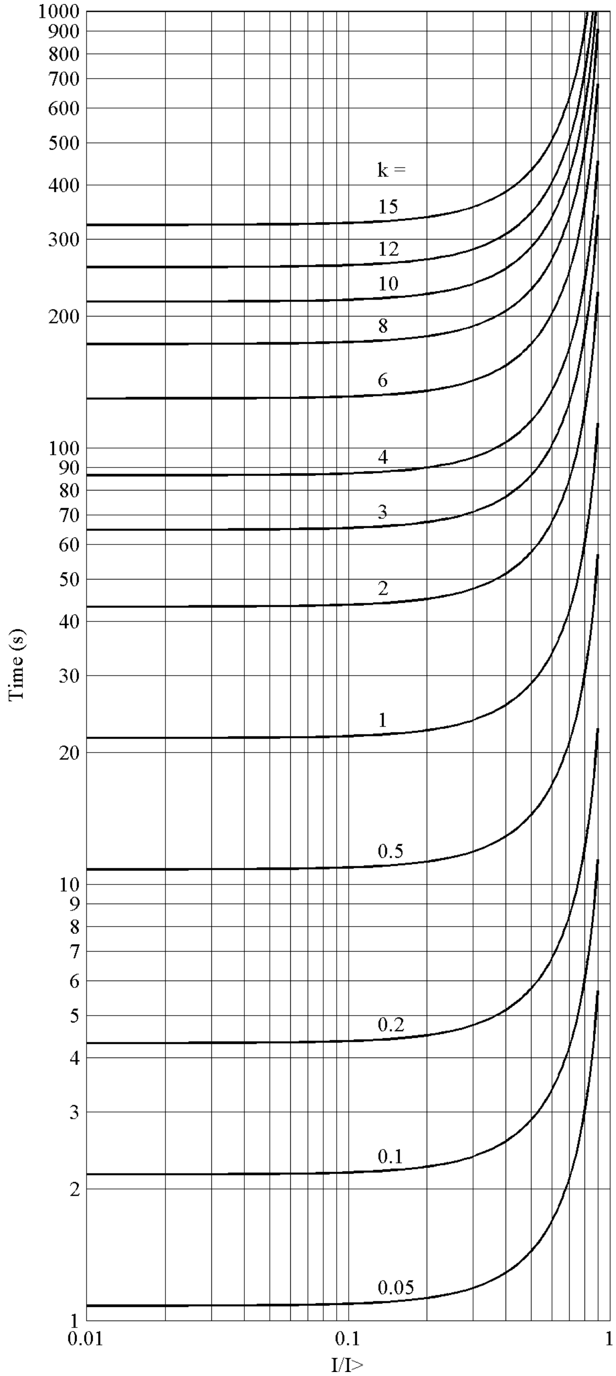


Figure 567: ANSI very inverse reset time characteristics

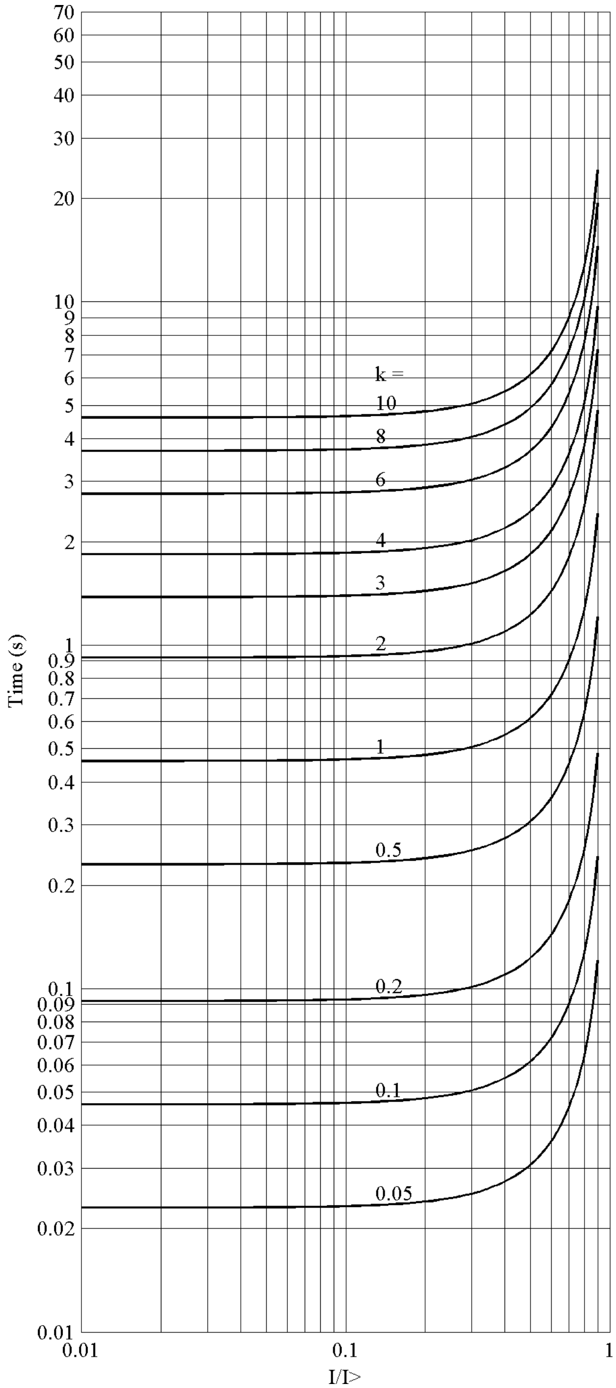


Figure 568: ANSI normal inverse reset time characteristics

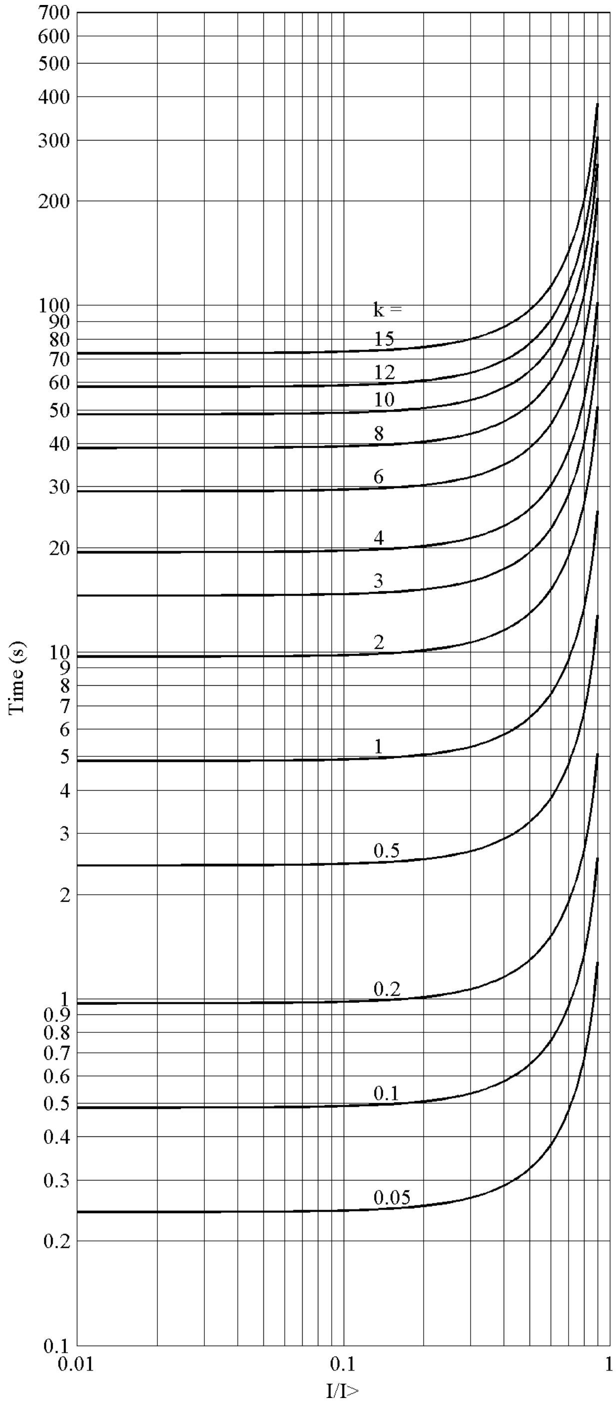


Figure 569: ANSI moderately inverse reset time characteristics

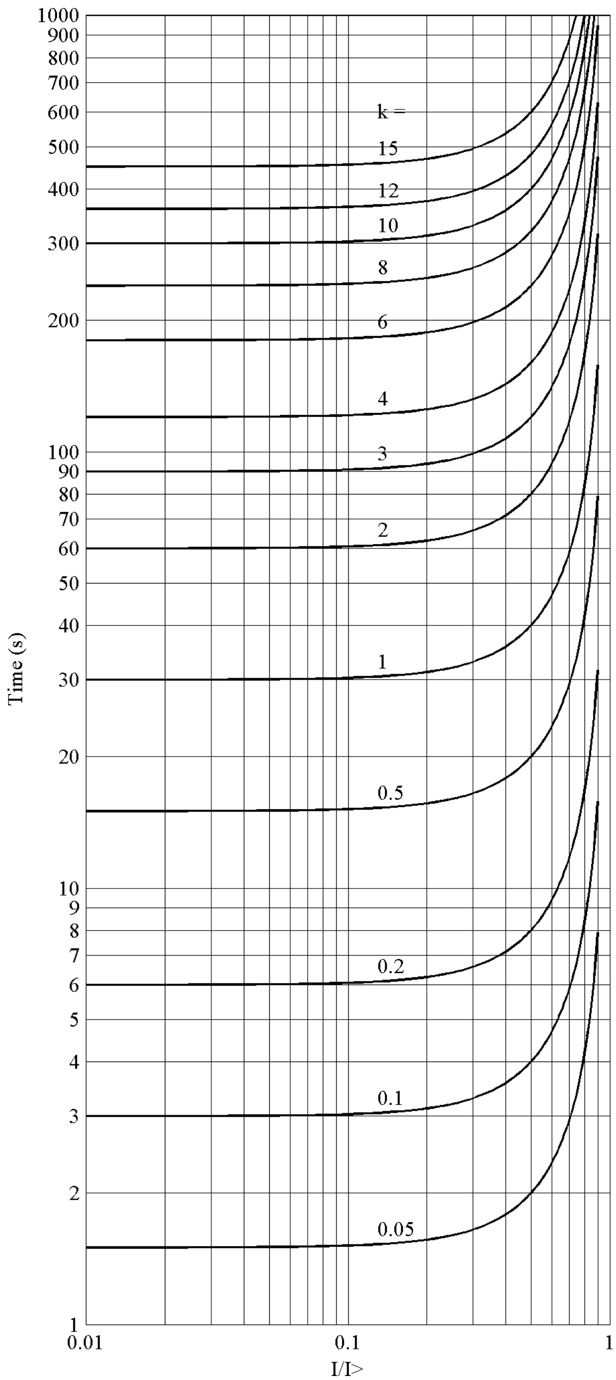


Figure 570: ANSI long-time extremely inverse reset time characteristics

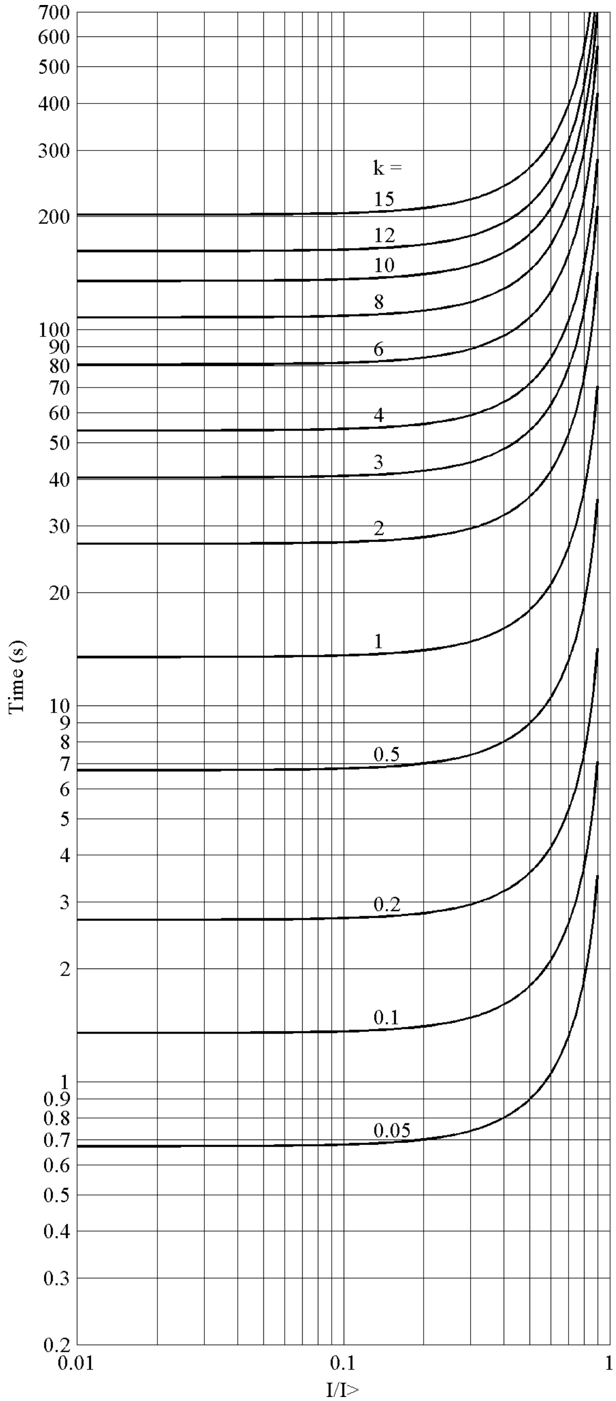


Figure 571: ANSI long-time very inverse reset time characteristics

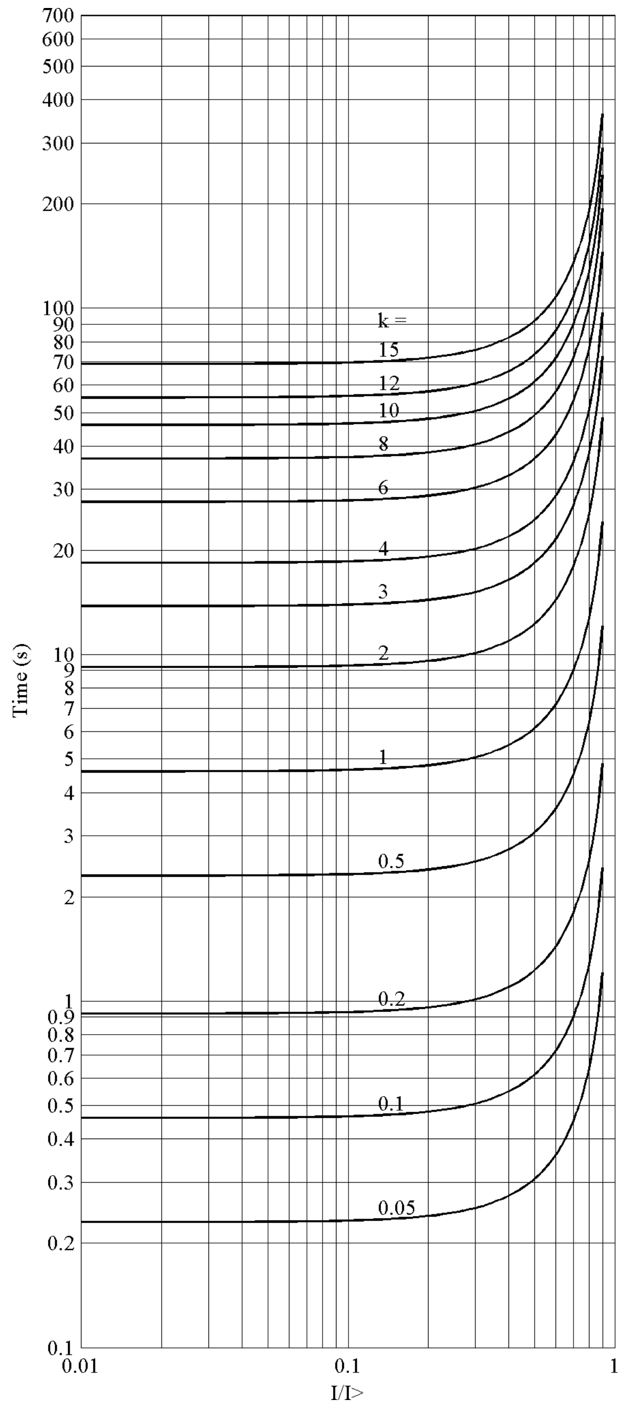


Figure 572: ANSI long-time inverse reset time characteristics

The delayed inverse-time reset is not available for IEC-type inverse time curves.

User-programmable delayed inverse reset

The user can define the delayed inverse reset time characteristics with the following formula using the set *Curve parameter D*.

$$t[s] = \left(\frac{D}{\left(\frac{I}{I>} \right)^2 - 1} \right) \cdot k$$

(Equation 178)

t[s]	Reset time (in seconds)
k	set *Time multiplier*
D	set *Curve parameter D*
I	Measured current
I>	set *Pickup value*

11.2.3 Inverse-timer freezing

When the BLOCK input is active, the internal value of the time counter is frozen at the value of the moment just before the freezing. Freezing of the counter value is chosen when the user does not wish the counter value to count upwards or to be reset. This may be the case, for example, when the inverse-time function of a protection relay needs to be blocked to enable the definite-time operation of another protection relay for selectivity reasons, especially if different relaying techniques (old and modern relays) are applied.

The selected blocking mode is "Freeze timer".

The activation of the BLOCK input also lengthens the minimum delay value of the timer.

Activating the BLOCK input alone does not affect the operation of the PICKUP output. It still becomes active when the current exceeds the set *Pickup value*, and inactive when the current falls below the set *Pickup value* and the set *Reset delay time* has expired.

11.3 Voltage based inverse definite minimum time characteristics

11.3.1 IDMT curves for overvoltage protection

In inverse-time modes, the trip time depends on the momentary value of the voltage, the higher the voltage, the faster the trip time. The trip time calculation or integration starts immediately when the voltage exceeds the set value of the *Pickup value* setting and the PICKUP output is activated.

The TRIP output of the component is activated when the cumulative sum of the integrator calculating the overvoltage situation exceeds the value set by the inverse time mode. The set value depends on the selected curve type and the setting values used. The user determines the curve scaling with the *Time multiplier* setting.

The *Minimum trip time* setting defines the minimum trip time for the IDMT mode, that is, it is possible to limit the IDMT based trip time for not becoming too short. For example:

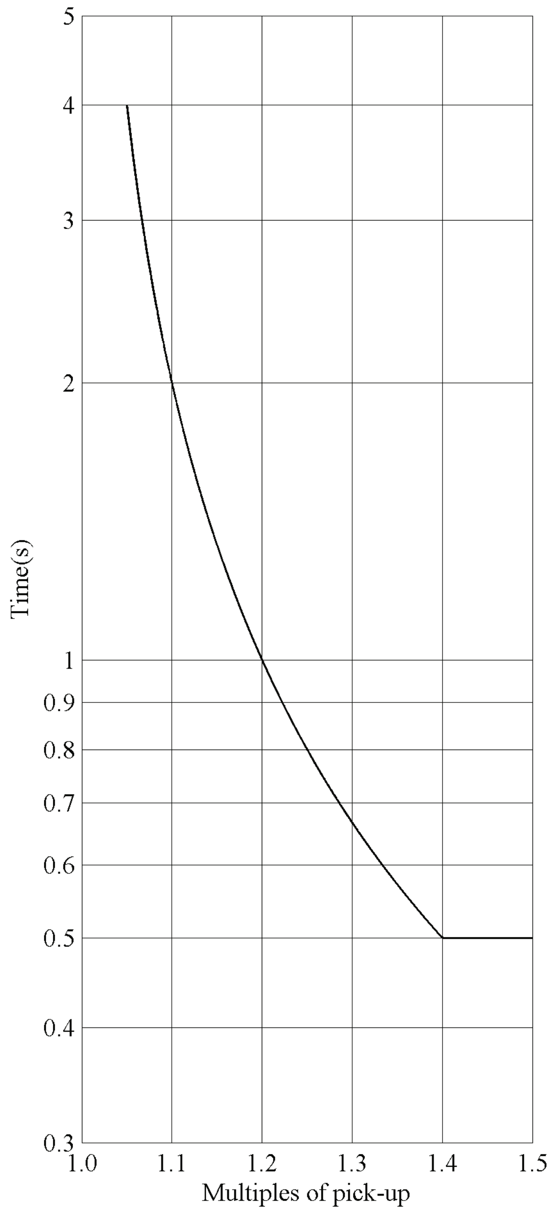


Figure 573: Trip time curve based on IDMT characteristic with Minimum trip time set to 0.5 second

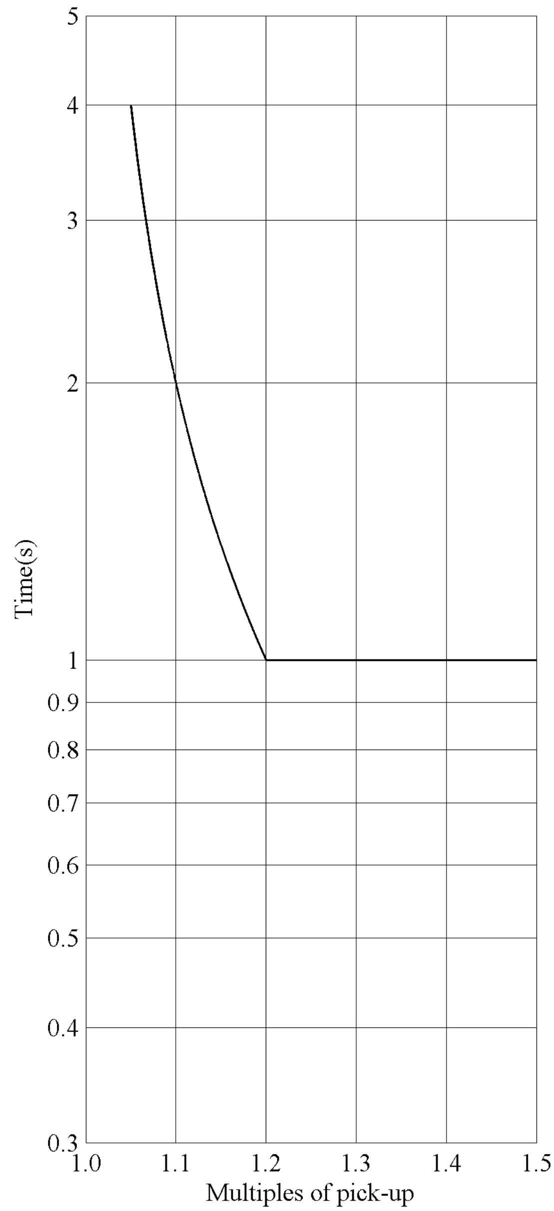


Figure 574: Trip time curve based on IDMT characteristic with Minimum trip time set to 1 second

11.3.1.1 Standard inverse-time characteristics for overvoltage protection

The trip times for the standard overvoltage IDMT curves are defined with the coefficients A, B, C, D and E.

The inverse trip time can be calculated with the formula:

$$t\left[s\right] = \frac{k \cdot A}{\left(B \times \frac{V - V>}{V>} - C\right)^{E}} + D$$

(Equation 179)

t [s] trip time in seconds

V measured voltage

V> the set value of *Pickup value*

k the set value of *Time multiplier*

Table 946: Curve coefficients for the standard overvoltage IDMT curves

Curve name	A	B	C	D	E
(17) Inverse Curve A	1	1	0	0	1
(18) Inverse Curve B	480	32	0.5	0.035	2
(19) Inverse Curve C	480	32	0.5	0.035	3

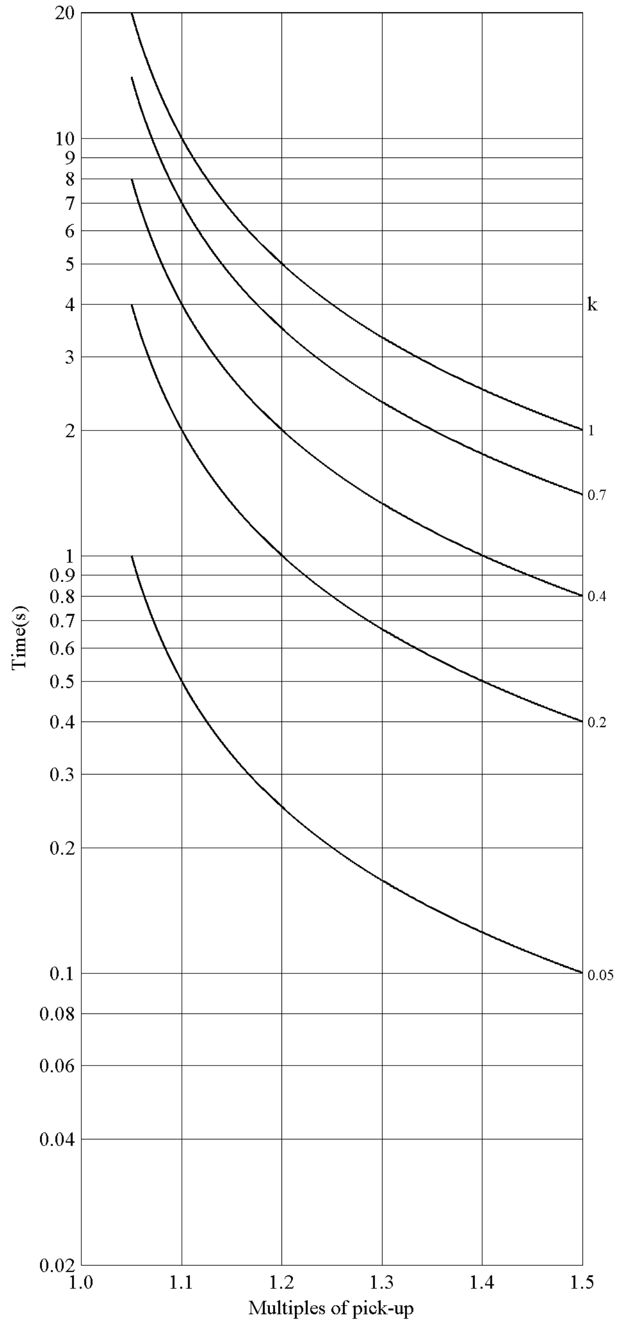


Figure 575: Inverse curve A characteristic of overvoltage protection

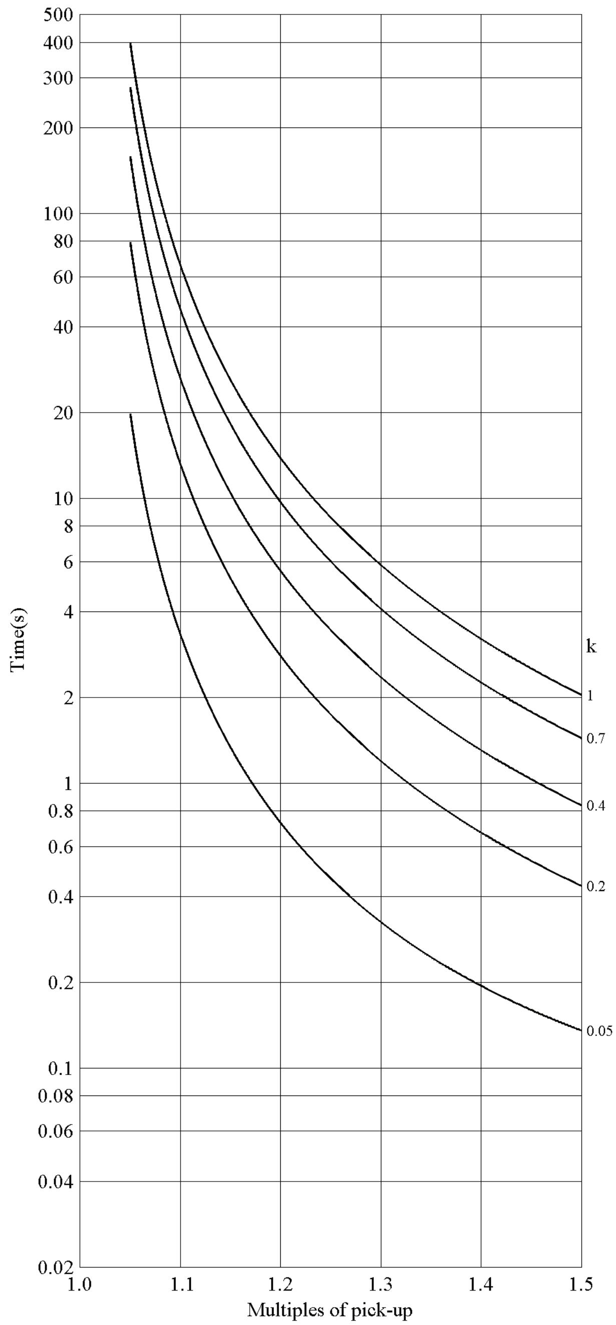


Figure 576: Inverse curve B characteristic of overvoltage protection

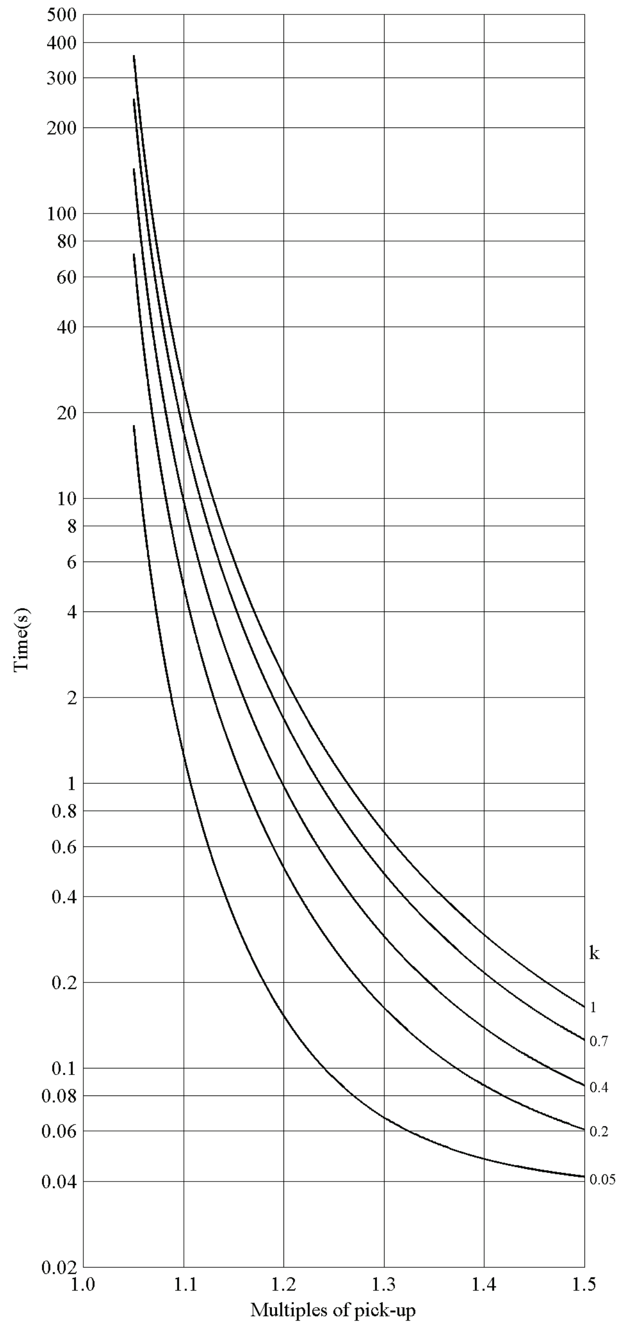


Figure 577: Inverse curve C characteristic of overvoltage protection

11.3.1.2 User programmable inverse-time characteristics for overvoltage protection

The user can define the curves by entering the parameters using the standard formula:

$$t\left[s\right] = \frac{k \cdot A}{\left(B \times \frac{V - V>}{V>} - C\right)^{E}} + D$$

(Equation 180)

t[s]	trip time in seconds
A	the set value of *Curve parameter A*
B	the set value of *Curve parameter B*
C	the set value of *Curve parameter C*
D	the set value of *Curve parameter D*
E	the set value of *Curve parameter E*
V	measured voltage
V>	the set value of *Pickup value*
k	the set value of *Time multiplier*

11.3.1.3 IDMT curve saturation of overvoltage protection

For the overvoltage IDMT mode of operation, the integration of the trip time does not start until the voltage exceeds the value of *Pickup value*. To cope with discontinuity characteristics of the curve, a specific parameter for saturating the equation to a fixed value is created. The *Curve Sat Relative* setting is the parameter and it is given in percents compared to *Pickup value*. For example, due to the curve equation B and C, the characteristics equation output is saturated in such a way that when the input voltages are in the range of *Pickup value* to *Curve Sat Relative* in percent over *Pickup value*, the equation uses *Pickup value* * (1.0 + *Curve Sat Relative* / 100) for the measured voltage. Although, the curve A has no discontinuities when the ratio V/V> exceeds the unity, *Curve Sat Relative* is also set for it. The *Curve Sat Relative* setting for curves A, B and C is 2.0 percent. However, it should be noted that the user must carefully calculate the curve characteristics concerning the discontinuities in the curve when the programmable curve equation is used. Thus, the *Curve Sat Relative* parameter gives another degree of freedom to move the inverse curve on the voltage ratio axis and it effectively sets the maximum trip time for the IDMT curve because for the voltage ratio values affecting by this setting, the operation time is fixed, that is, the definite time, depending on the parameters but no longer the voltage.

11.3.2 IDMT curves for undervoltage protection

In the inverse-time modes, the trip time depends on the momentary value of the voltage, the lower the voltage, the faster the trip time. The trip time calculation or integration starts immediately when the voltage goes below the set value of the *Pickup value* setting and the `PICKUP` output is activated.

The `TRIP` output of the component is activated when the cumulative sum of the integrator calculating the undervoltage situation exceeds the value set by the inverse-time mode. The set value depends on the selected curve type and the setting values used. The user determines the curve scaling with the *Time multiplier* setting.

The *Minimum trip time* setting defines the minimum trip time possible for the IDMT mode. For setting a value for this parameter, the user should carefully study the particular IDMT curve.

11.3.2.1 Standard inverse-time characteristics for undervoltage protection

The trip times for the standard undervoltage IDMT curves are defined with the coefficients A, B, C, D and E.

The inverse trip time can be calculated with the formula:

$$t\left[s\right] = \frac{k \cdot A}{\left(B \times \frac{V< - V}{V<} - C\right)^{E}} + D$$

(Equation 181)

t [s]	trip time in seconds
V	measured voltage
V<	the set value of the *Pickup value* setting
k	the set value of the *Time multiplier* setting

Table 947: Curve coefficients for standard undervoltage IDMT curves

Curve name	A	B	C	D	E
(21) Inverse Curve A	1	1	0	0	1
(22) Inverse Curve B	480	32	0.5	0.055	2

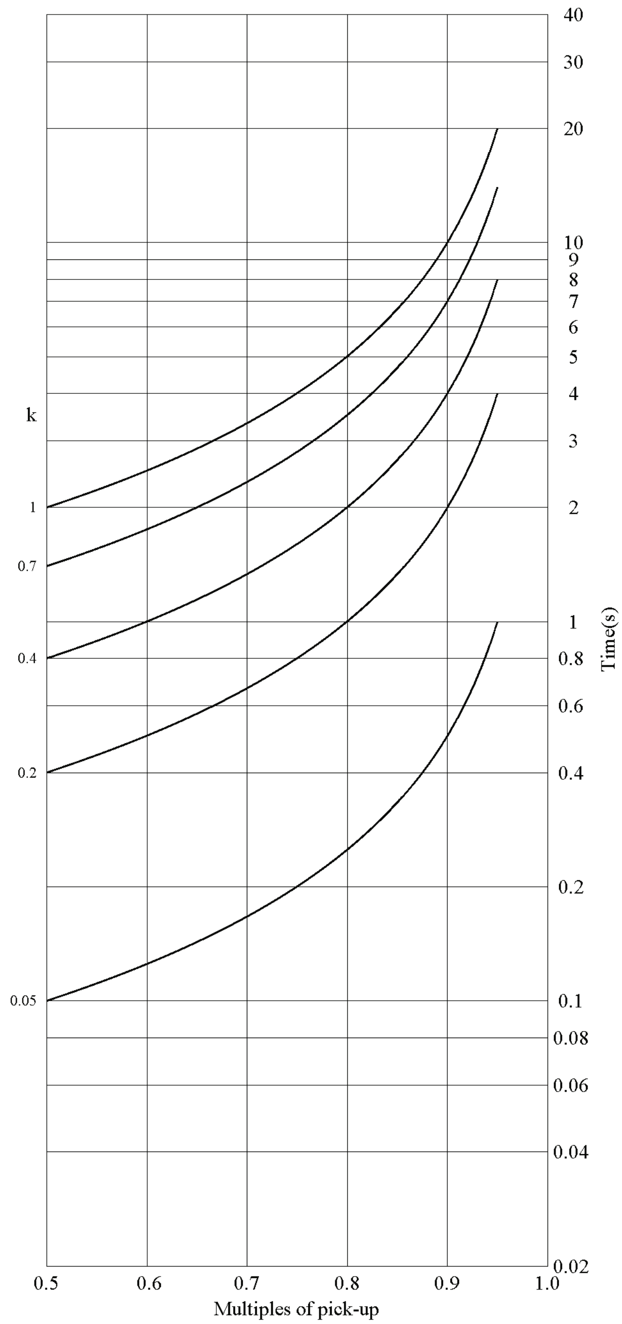


Figure 578: : Inverse curve A characteristic of undervoltage protection

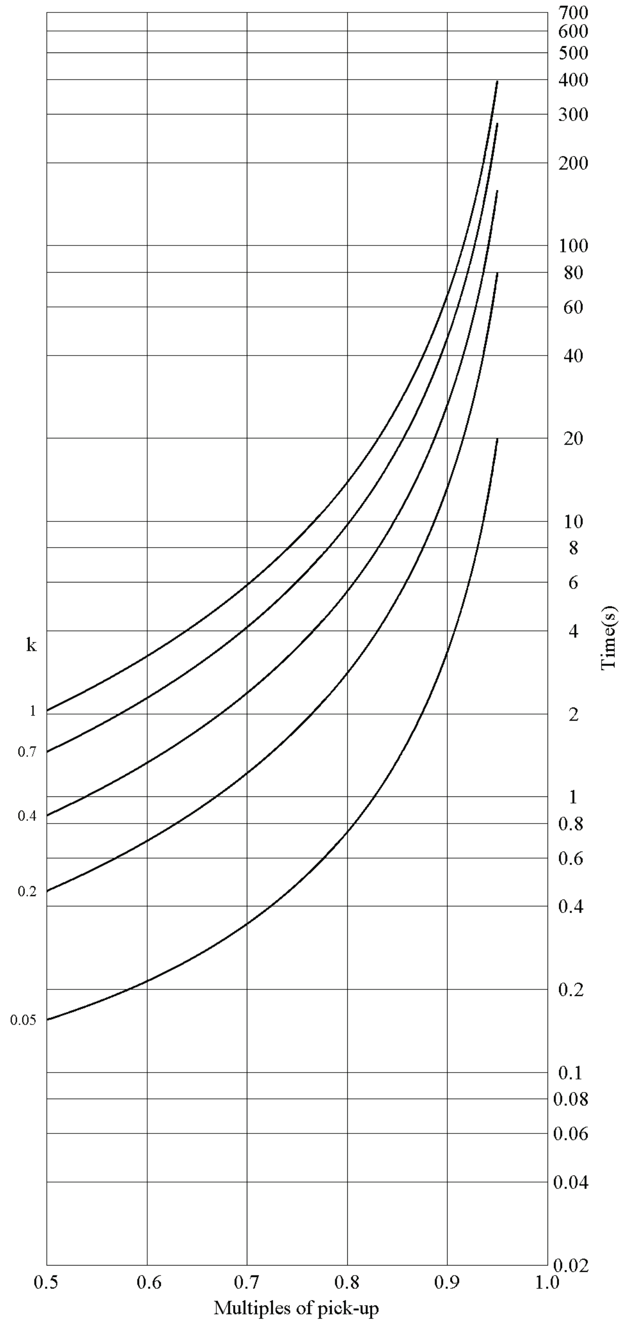


Figure 579: Inverse curve B characteristic of undervoltage protection

11.3.2.2 User-programmable inverse-time characteristics for undervoltage protection

The user can define curves by entering parameters into the standard formula:

$$t\left[s\right] = \frac{k \cdot A}{\left(B \times \frac{V< -V}{V<} - C\right)^{E}} + D$$

(Equation 182)

t[s]	trip time in seconds
A	the set value of *Curve parameter A*
B	the set value of *Curve parameter B*
C	the set value of *Curve parameter C*
D	the set value of *Curve parameter D*
E	the set value of *Curve parameter E*
V	measured voltage
V<	the set value of *Pickup value*
k	the set value of *Time multiplier*

11.3.2.3 IDMT curve saturation of undervoltage protection

For the undervoltage IDMT mode of operation, the integration of the trip time does not start until the voltage falls below the value of *Pickup value*. To cope with discontinuity characteristics of the curve, a specific parameter for saturating the equation to a fixed value is created. The *Curve Sat Relative* setting is the parameter and it is given in percents compared with *Pickup value*. For example, due to the curve equation B, the characteristics equation output is saturated in such a way that when input voltages are in the range from *Pickup value* to *Curve Sat Relative* in percents under *Pickup value*, the equation uses *Pickup value* * (1.0 - *Curve Sat Relative* / 100) for the measured voltage. Although, the curve A has no discontinuities when the ratio V/V> exceeds the unity, *Curve Sat Relative* is set for it as well. The *Curve Sat Relative* setting for curves A, B and C is 2.0 percent. However, it should be noted that the user must carefully calculate the curve characteristics concerning also discontinuities in the curve when the programmable curve equation is used. Thus, the *Curve Sat Relative* parameter gives another degree of freedom to move the inverse curve on the voltage ratio axis and it effectively sets the maximum trip time for the IDMT curve because for the voltage ratio values affecting by this setting, the operation time is fixed, that is, the definite time, depending on the parameters but no longer the voltage.

11.4 Frequency measurement and protection

All the function blocks that use frequency quantity as their input signal share the common features related to the frequency measurement algorithm. The frequency estimation is done from one phase (phase-to-phase or phase voltage) or from the positive phase sequence (PPS). The voltage groups with three-phase inputs use PPS as the source. The frequency measurement range is 0.6...1.5 × F_n. (For REG615 the range is 0.2...1.4 × F_n when *Frequency adaptivity* is enabled.) The df/dt measurement range always starts from 0.6 × F_n. When the frequency exceeds these limits, it is regarded as out of range and a minimum or maximum value is held as the measured value respectively with appropriate quality information. The frequency estimation requires 160 ms to stabilize after a bad quality signal. Therefore, a delay of 160 ms is added to the transition from the bad quality. The bad quality of the signal can be due to restrictions like:

- The source voltage is below 0.02 × Vn at f_n.
- The source voltage waveform is discontinuous.
- The source voltage frequency rate of change exceeds 15 Hz/s (including stepwise frequency changes).

When the bad signal quality is obtained, the nominal or zero (depending on the *Def frequency Sel* setting) frequency value is shown with appropriate quality information in the measurement view. The frequency protection functions are blocked when the quality is bad, thus the timers and the function outputs are reset. When the frequency is out of the function block’s setting range but within the measurement range, the protection blocks are running. However, the `TRIP` outputs are blocked until the frequency restores to a valid range.

11.5 Frequency adaptivity and generator start-up protection

Frequency adaptivity enables sensitive and selective protection during the start-up and shutdown phase of the generator when low frequency and low voltage amplitude exist at the same time. Sensitive protection is necessary because, for example, the fault current level in generator internal fault during start-up or shutdown (when field excitation is not present) may not exceed even the nominal current level. Frequency adaptivity, available only in REG615, can be enabled by setting *Frequency adaptivity*. When selected, the operation range of the relay measurements is extended to 0.2...1.5 xFn (10...75 Hz when *Rated frequency* = 50 Hz or 12...90 Hz when *Rated frequency* = 60 Hz).

The frequency adaptivity uses the positive-sequence voltage in the frequency tracking and adapts the DFT, RMS, peak-to-peak and peak measurement accuracies of the current and voltage inputs by using the tracked frequency in the operation range of 0.2...1.5 xFn.

Frequency adaptation starts when the generator terminal positive-sequence voltage level exceeds 0.04 xUn (minimum level). As the Synchronism and energizing check (25) bus voltage U12b voltage input always expects *Rated frequency*, the frequency adaptivity does not apply for this input.

If the generator terminal positive-sequence voltage is below the minimum level, the relay is not able to maintain frequency adaptation. The non-adaptive situation is indicated by function PROTECTION output FRQ_ADP_FAIL. The tracked frequency is retained for 3 seconds until the FRQ_ADP_FAIL output is activated and *Rated frequency* is expected. The FRQ_ADP_FAIL output can be utilized in the application configuration, if necessary.

The operation accuracy of the protection functions in the range of 0.2...1.5 xFn can be assumed to be according to the technical data given separately for each function. Operate time accuracy and reset times given in technical data are only valid in the frequency range specified for each function. Typical operate time examples at low frequencies are given in Table.

Table 948: Protection operate time examples at low frequency

Function	Characteristic	Value[1)]
51P, 50P	*Trip delay time* = 40 ms I_{Fault} = 1.1 × set *Pickup value*, 10 Hz *Measurement mode* = “RMS” or “DFT” *Measurement mode* = “Peak-to-Peak”	 Typically 130 ms Typically 110 ms
	Trip delay time = 40 ms I_{Fault} = 2.0 × set *Pickup value*, 12 Hz *Measurement mode* = “DFT”	 Typically 85 ms
	Trip delay time = 40 ms I_{Fault} = 2.0 × set *Pickup value*, 20 Hz *Measurement mode* = “DFT”	 Typically 70 ms
50P-3	*Trip delay time* = 20 ms *Measurement mode* = “P-to-P+backup” I_{Fault} = 1.1 × set *Pickup value*, 10 Hz I_{Fault} = 2.0 × set *Pickup value*, 10 Hz	 Typically 45...100 ms Typically 20...40 ms
67/51N, 67/50N	*Trip delay time* = 50 ms I_{Fault} = 2.0 × set *Pickup value*, 10 Hz *Measurement mode* = “DFT”	 Typically 110 ms
50N, 50G	*Trip delay time* = 40 ms I_{Fault} = 2.0 × set *Pickup value*, 10 Hz *Measurement mode* = “DFT”	 Typically 100 ms

Table continues on next page

Function	Characteristic	Value[1]
87G	Biased low stage I_{Fault} = 1.5 × set *Low trip value*, 10 Hz	Typically 90...120 ms
	Instantaneous high stage I_{Fault} = 1.5 × set *High trip value*, 10 Hz	Typically 70...95 ms
27/59THN	*Trip delay time* = 20 ms U_{Fault} = 1.1 × 3. harmonic bias voltage, 10 Hz U_{Fault} = 1.1 × 3. harmonic bias voltage, 20 Hz	Typically 55 ms Typically 40 ms
59N, 59G	*Trip delay time* = 40 ms U_{Fault} = 1.1 × set *Pickup value*, 10 Hz U_{Fault} = 2.0 × set *Pickup value*, 10 Hz	Typically 135 ms Typically 95 ms
59	*Trip delay time* = 40 ms U_{Fault} = 1.1 × set *Pickup value*, 10 Hz U_{Fault} = 2.0 × set *Pickup value*, 10Hz	Typically 105 ms Typically 65 ms
24	*Trip delay time* = 200 ms Voltage change, 11 Hz	Typically 240 ms

1) Voltages present before the fault condition. Includes the delay of the output contact

Frequency adaptivity depends on the availability of voltages. The generator start-up protection can be also extended by using wide peak-to-peak measurement mode (operational from 2 Hz upward) with designated start-up overcurrent protection function (51P). Before the generator is connected with the rest of the network by closing the circuit breaker, the designated start-up overcurrent function should be either blocked or its start value increased, as the *Pickup value* setting is typically lower than the nominal current.

11.6 Measurement modes

In many current or voltage dependent function blocks, there are various alternative measuring principles.

- RMS
- DFT which is a numerically calculated fundamental component of the signal
- Peak-to-peak
- Peak-to-peak with peak backup

Consequently, the measurement mode can be selected according to the application.

In extreme cases, for example with high overcurrent or harmonic content, the measurement modes function in a slightly different way. The operation accuracy is defined with the frequency range of f/fn=0.95...1.05. In peak-to-peak and RMS measurement modes, the harmonics of the phase currents are not suppressed, whereas in the fundamental frequency measurement the suppression of harmonics is at least -50 dB at the frequency range of f= n x fn, where n = 2, 3, 4, 5,...

RMS

The RMS measurement principle is selected with the *Measurement mode* setting using the value "RMS". RMS consists of both AC and DC components. The AC component is the effective mean value of the positive and negative peak values. RMS is used in applications where the effect of the DC component must be taken into account.

RMS is calculated according to the formula:

$$I_{RMS} = \sqrt{\frac{1}{n}\sum_{i=1}^{n} I_i^2}$$

(Equation 183)

n The number of samples in a calculation cycle

I_i The current sample value

DFT

The DFT measurement principle is selected with the *Measurement mode* setting using the value "DFT". In the DFT mode, the fundamental frequency component of the measured signal is numerically calculated from the samples. In some applications, for example, it can be difficult to accomplish sufficiently sensitive settings and accurate operation of the low stage, which may be due to a considerable amount of harmonics on the primary side currents. In such a case, the operation can be based solely on the fundamental frequency component of the current. In addition, the DFT mode has slightly higher CT requirements than the peak-to-peak mode, if used with high and instantaneous stages.

Peak-to-peak

The peak-to-peak measurement principle is selected with the *Measurement mode* setting using the value "Peak-to-Peak". It is the fastest measurement mode, in which the measurement quantity is made by calculating the average from the positive and negative peak values. The DC component is not included. The retardation time is short. The damping of the harmonics is quite low and practically determined by the characteristics of the anti-aliasing filter of the protection relay inputs. Consequently, this mode is usually used in conjunction with high and instantaneous stages, where the suppression of harmonics is not so important. In addition, the peak-to-peak mode allows considerable CT saturation without impairing the performance of the operation.

Peak-to-peak with peak backup

The peak-to-peak with peak backup measurement principle is selected with the *Measurement mode* setting using the value "P-to-P+backup". It is similar to the peak-to-peak mode, with the exception that it has been enhanced with the peak backup. In the peak-to-peak with peak backup mode, the function starts with two conditions: the peak-to-peak value is above the set pickup current or the peak value is above two times the set *Pickup value*. The peak backup is enabled only when the function is used in the DT mode in high and instantaneous stages for faster operation.

Wide peak-to-peak

The wide peak-to-peak measurement mode is available only in the three-phase overcurrent protection function 51P in REG615 standard configurations C and D. The wide peak-to-peak measurement principle is available in products where it is necessary for overcurrent protection to operate already starting from as low frequency as 2 Hz during the generator start-up or shutdown phase. The wide peak-to-peak measurement principle is selected with the *Measurement mode* setting "Wide P-to-P".

The measurement mode calculates the average from the positive and negative peak values over the 500 ms wide measurement window, independently of the *Frequency adaptivity* setting value. Retardation and reset times are longer due to the length of the measurement window. The frequency of the fault current affects the operate time. The damping of the harmonics is quite low and practically determined by the characteristics of the anti-aliasing filter of the protection relay current inputs.

When using measurement mode “Wide P-to-P”, the protection relay accepts only *Trip delay time* setting value 800 ms or longer and *Operating curve type* 5=”ANSI Def. Time” or 15=”IEC Def. Time”.

Operation accuracy in the frequency range 2...85 Hz is ±1.5% or ±0.003 × I_n. Operate time accuracy in definite time mode is ±1.0% of the set value or ±60 ms when I_{Fault} = 2 × set *Pickup value* and the fault current frequency is 10...85 Hz.

11.7 Calculated measurements

Calculated residual current and voltage

The residual current is calculated from the phase currents according to equation:

$$\overline{Io} = -(\overline{I}_A + \overline{I}_B + \overline{I}_C)$$

(Equation 184)

The residual voltage is calculated from the phase-to-ground voltages when the VT connection is selected as “Wye” with the equation:

$$\overline{Vo} = (\overline{V}_A + \overline{V}_B + \overline{V}_C)$$

(Equation 185)

Sequence components

The phase-sequence current components are calculated from the phase currents according to:

$$\overline{I}_0 = (\overline{I}_A + \overline{I}_B + \overline{I}_C)/3$$

(Equation 186)

$$\overline{I}_1 = (\overline{I}_A + a \cdot \overline{I}_B + a^2 \cdot \overline{I}_C)/3$$

(Equation 187)

$$\overline{I}_2 = (\overline{I}_A + a^2 \cdot \overline{I}_B + a \cdot \overline{I}_C)/3$$

(Equation 188)

The phase-sequence voltage components are calculated from the phase-to-ground voltages when *VT connection* is selected as “Wye” with the formulae:

$$\overline{V}_0 = (\overline{V}_A + \overline{V}_B + \overline{V}_C)/3$$

(Equation 189)

$$\overline{V}_1 = (\overline{V}_A + a \cdot \overline{V}_B + a^2 \cdot \overline{V}_C)/3$$

(Equation 190)

$$\overline{V}_2 = (\overline{V}_A + a^2 \cdot \overline{V}_B + a \cdot \overline{V}_C)/3$$

(Equation 191)

When *VT connection* is selected as “Delta”, the positive and negative phase sequence voltage components are calculated from the phase-to-phase voltages according to the equations:

$$\overline{V}_1 = (\overline{V}_{AB} - a^2 \cdot \overline{V}_{BC})/3$$

(Equation 192)

$$\overline{V}_2 = (\overline{V}_{AB} - a \cdot \overline{V}_{BC})/3$$

(Equation 193)

The phase-to-ground voltages are calculated from the phase-to-phase voltages when *VT connection* is selected as "Delta" according to the equations.

$$\overline{V}_A = \overline{V}_0 + \left(\overline{V}_{AB} - \overline{V}_{CA}\right)/3$$

(Equation 194)

$$\overline{V}_B = \overline{V}_0 + \left(\overline{V}_{BC} - \overline{V}_{AB}\right) / 3$$

(Equation 195)

$$\overline{V}_C = \overline{V}_0 + \left(\overline{V}_{CA} - \overline{V}_{BC}\right) / 3$$

(Equation 196)

If the $\overline{V}o$ channel is not valid, it is assumed to be zero.

The phase-to-phase voltages are calculated from the phase-to-ground voltages when *VT connection* is selected as "Wye" according to the equations.

$$\overline{V}_{AB} = \overline{V}_A - \overline{V}_B$$

(Equation 197)

$$\overline{V}_{BC} = \overline{V}_B - \overline{V}_C$$

(Equation 198)

$$\overline{V}_{CA} = \overline{V}_C - \overline{V}_A$$

(Equation 199)

Section 12 Requirements for measurement transformers

12.1 Current transformers

12.1.1 Current transformer requirements for overcurrent protection

For reliable and correct operation of the overcurrent protection, the CT has to be chosen carefully. The distortion of the secondary current of a saturated CT may endanger the operation, selectivity, and co-ordination of protection. However, when the CT is correctly selected, a fast and reliable short circuit protection can be enabled.

The selection of a CT depends not only on the CT specifications but also on the network fault current magnitude, desired protection objectives, and the actual CT burden. The protection settings of the protection relay should be defined in accordance with the CT performance as well as other factors.

12.1.1.1 Current transformer accuracy class and accuracy limit factor

The rated accuracy limit factor (F_n) is the ratio of the rated accuracy limit primary current to the rated primary current. For example, a protective current transformer of type 5P10 has the accuracy class 5P and the accuracy limit factor 10. For protective current transformers, the accuracy class is designed by the highest permissible percentage composite error at the rated accuracy limit primary current prescribed for the accuracy class concerned, followed by the letter "P" (meaning protection).

Table 949: Limits of errors according to IEC 60044-1 for protective current transformers

Accuracy class	Current error at rated primary current (%)	Phase displacement at rated primary current		Composite error at rated accuracy limit primary current (%)
		minutes	centiradians	
5P	±1	±60	±1.8	5
10P	±3	-	-	10

The accuracy classes 5P and 10P are both suitable for non-directional overcurrent protection. The 5P class provides a better accuracy. This should be noted also if there are accuracy requirements for the metering functions (current metering, power metering, and so on) of the protection relay.

The CT accuracy primary limit current describes the highest fault current magnitude at which the CT fulfils the specified accuracy. Beyond this level, the secondary current of the CT is distorted and it might have severe effects on the performance of the protection relay.

In practise, the actual accuracy limit factor (F_a) differs from the rated accuracy limit factor (F_n) and is proportional to the ratio of the rated CT burden and the actual CT burden.

The actual accuracy limit factor is calculated using the formula:

$$F_a \approx F_n \times \frac{|S_{in} + S_n|}{|S_{in} + S|}$$

F_n	the accuracy limit factor with the nominal external burden S_n
S_{in}	the internal secondary burden of the CT
S	the actual external burden

12.1.1.2 Non-directional overcurrent protection

The current transformer selection

Non-directional overcurrent protection does not set high requirements on the accuracy class or on the actual accuracy limit factor (F_a) of the CTs. It is, however, recommended to select a CT with F_a of at least 20.

The nominal primary current I_{1n} should be chosen in such a way that the thermal and dynamic strength of the current measuring input of the protection relay is not exceeded. This is always fulfilled when

$I_{1n} > I_{kmax} / 100$,

I_{kmax} is the highest fault current.

The saturation of the CT protects the measuring circuit and the current input of the protection relay. For that reason, in practice, even a few times smaller nominal primary current can be used than given by the formula.

Recommended pickup current settings

If I_{kmin} is the lowest primary current at which the highest set overcurrent stage is to trip, the pickup current should be set using the formula:

Current pickup value $< 0.7 \times (I_{kmin} / I_{1n})$

I_{1n} is the nominal primary current of the CT.

The factor 0.7 takes into account the protection relay inaccuracy, current transformer errors, and imperfections of the short circuit calculations.

The adequate performance of the CT should be checked when the setting of the high set stage overcurrent protection is defined. The trip time delay caused by the CT saturation is typically small enough when the overcurrent setting is noticeably lower than F_a.

When defining the setting values for the low set stages, the saturation of the CT does not need to be taken into account and the pickup current setting is simply according to the formula.

Delay in operation caused by saturation of current transformers

The saturation of CT may cause a delayed protection relay operation. To ensure the time selectivity, the delay must be taken into account when setting the trip times of successive protection relays.

With definite time mode of operation, the saturation of CT may cause a delay that is as long as the time constant of the DC component of the fault current, when the current is only slightly higher than the pickup current. This depends on the accuracy limit factor of the CT, on the remanence flux of the core of the CT, and on the trip time setting.

With inverse time mode of operation, the delay should always be considered as being as long as the time constant of the DC component.

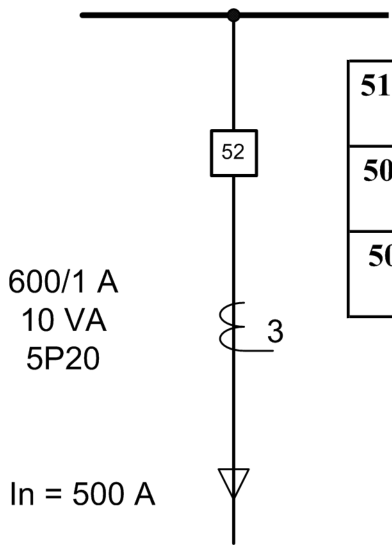
With inverse time mode of operation and when the high-set stages are not used, the AC component of the fault current should not saturate the CT less than 20 times the pickup current. Otherwise, the inverse operation time can be further prolonged. Therefore, the accuracy limit factor F_a should be chosen using the formula:

$F_a > 20 \times \textit{Current pickup value} / I_{1n}$

The *Current pickup value* is the primary pickup current setting of the protection relay.

12.1.1.3 Example for non-directional overcurrent protection

The following figure describes a typical medium voltage feeder. The protection is implemented as three-stage definite time non-directional overcurrent protection.



51P	**1200 A** **0.75 s**	**2.00 x I_{2n}** **0.75 s**
50P-1/2	**1800A** **0.50 s**	**3.00 x I_{2n}** **0.50 s**
50P-3	**3500 A** **0.20 s**	**5.83 x I_{2n}** **0.20 s**

Figure 580: Example of three-stage overcurrent protection

The maximum three-phase fault current is 41.7 kA and the minimum three-phase short circuit current is 22.8 kA. The actual accuracy limit factor of the CT is calculated to be 59.

The pickup current setting for low-set stage (51P) is selected to be about twice the nominal current of the cable. The trip time is selected so that it is selective with the next protection relay (not visible in Figure 580). The settings for the high-set stage and instantaneous stage are defined also so that grading is ensured with the downstream protection. In addition, the pickup current settings have to be defined so that the protection relay operates with the minimum fault current and it does not trip with the maximum load current. The settings for all three stages are as in Figure 580.

For the application point of view, the suitable setting for instantaneous stage (50P-3) in this example is 3 500 A (5.83 × I_{2n}). I_{2n} is the 1.2 multiple with nominal primary current of the CT. For the CT characteristics point of view, the criteria given by the current transformer selection formula is fulfilled and also the protection relay setting is considerably below the F_a. In this application, the CT rated burden could have been selected much lower than 10 VA for economical reasons.

12.1.2 Current transformer requirements for transformer differential protection

The more important the object to be protected, the more attention has to be paid to the current transformers. It is not normally possible to dimension the current transformer so that they repeat the currents with high DC components without saturating when the residual flux of the current transformer is high. 87T operates reliably even though the current transformers are partially saturated.

The accuracy class recommended for current transformers to be used with 87T is 5P, in which the limit of the current error at the rated primary current is 1 percent and the limit of the phase displacement is 60 minutes. The limit of the composite error at the rated accuracy limit primary current is 5 percent.

The approximate value of the accuracy limit factor F_a corresponding to the actual current transformer burden can be calculated on the basis of the rated accuracy limit factor F_n at the rated burden, the rated burden S_n, the internal burden $S_{in}$and the actual burden S_a of the current transformer.

$$F_a = F_n \times \frac{S_{in} + S_n}{S_{in} + S_a}$$

(Equation 200)

F_a	The approximate value of the accuracy limit factor (ALF) corresponding to the actual CT burden
F_n	The rated accuracy limit factor at the rated burden of the current transformer
S_n	The rated burden of the current transformer
S_{in}	The internal burden of the current transformer
S_a	The actual burden of the current transformer

Example 1

The rated burden S_n of the current transformer 5P20 is 10 VA, the secondary rated current is 5A, the internal resistance R_{in}= 0.07 Ω and the accuracy limit factor F_n corresponding to the rated burden is 20 (5P20). Thus the internal burden of the current transformer is S_{in}= $(5A)^2$ * 0.07 Ω = 1.75 VA. The input impedance of the protection relay at a rated current of 5A is < 20 mΩ. If the measurement conductors have a resistance of 0.113 Ω, the actual burden of the current transformer is S_a=$(5A)^2$ * (0.113 + 0.020) Ω = 3.33 VA. Thus the accuracy limit factor F_a corresponding to the actual burden is approximately 46.

The CT burden can grow considerably at the rated current 5A. The actual burden of the current transformer decreases at the rated current of 1A while the repeatability simultaneously improves.

At faults occurring in the protected area, the currents may be very high compared to the rated currents of the current transformers. Due to the instantaneous stage of the differential function block, it is sufficient that the current transformers are capable of repeating the current required for instantaneous tripping during the first cycle.

Thus the current transformers usually are able to reproduce the asymmetric fault current without saturating within the next 10 ms after the occurrence of the fault to secure that the trip times of the protection relay comply with the retardation time.

The accuracy limit factors corresponding to the actual burden of the phase current transformer to be used in differential protection fulfill the requirement.

$$F_a > K_r \times Ik_{\max} \times (T_{dc} \times \omega \times (1 - e^{-T_m / T_{dc}}) + 1)$$

(Equation 201)

Ik_{max}	The maximum through-going fault current (in I_R) at which the protection is not allowed to trip
T_{dc}	The primary DC time constant related to Ik_{max}
ω	The angular frequency, that is, 2*π*fn
T_m	The time-to-saturate, that is, the duration of the saturation free transformation
K_r	The remanence factor 1/(1-r), where r is the maximum remanence flux in p.u. from saturation flux

The accuracy limit factors corresponding to the actual burden of the phase current transformer is used in differential protection.

The parameter *r* is the maximum remanence flux density in the CT core in p.u. from saturation flux density. The value of the parameter *r* depends on the magnetic material used and on the construction of the CT. For instance, if the value of *r* = 0.4, the remanence flux density can be 40 percent of the saturation flux density. The manufacturer of the CT has to be contacted when an accurate value for the parameter *r* is needed. The value *r* = 0.4 is recommended to be used when an accurate value is not available.

The required minimum time-to-saturate T_m in 87T is half fundamental cycle period (10 ms when fn = 50Hz).

Two typical cases are considered for the determination of the sufficient accuracy limit factor (F_a):

1. A fault occurring at the substation bus:
   The protection must be stable at a fault arising during a normal operating situation. Re-energizing the transformer against a bus fault leads to very high fault currents and thermal stress and therefore re-energizing is not preferred in this case. Thus, the remanence can be neglected.
   The maximum through-going fault current Ik_{max} is typically 10 I_r for a substation main transformer. At a short circuit fault close to the supply transformer, the DC time constant (T_{dc}) of the fault current is almost the same as that of the transformer, the typical value being 100 ms.

Ik_{max}	10 I_r
T_{dc}	100 ms
ω	100π Hz
T_m	10 ms

K_r	1

When the values are substituted in Equation 201, the result is:

$$F_a > K_r \times Ik_{\max} \times (T_{dc} \times \omega \times (1 - e^{-T_m / T_{dc}}) + 1) \approx 40$$

2. Re-energizing against a fault occurring further down in the network:
   The protection must be stable also during re-energization against a fault on the line. In this case, the existence of remanence is very probable. It is assumed to be 40 percent here.
   On the other hand, the fault current is now smaller and since the ratio of the resistance and reactance is greater in this location, having a full DC offset is not possible. Furthermore, the DC time constant (T_{dc}) of the fault current is now smaller, assumed to be 50 ms here.
   Assuming a maximum fault current being 30 percent lower than in the bus fault and a DC offset 90 percent of the maximum.

Ik_{max}	0.7* 10 = 7 (I_r)
T_{dc}	50 ms
ω	100π Hz
T_m	10 ms
K_r	1/(1-0.4) = 1.6667

When the values are substituted in the equation, the result is:

$$F_a > K_r \times Ik_{\max} \times 0.9 \times (T_{dc} \times \omega \times (1 - e^{-T_m / T_{dc}}) + 1) \approx 40$$

If the actual burden of the current transformer (S_a) in Equation 200 cannot be reduced low enough to provide a sufficient value for F_a, there are two alternatives to deal with the situation:

- a CT with a higher rated burden S_n can be chosen (which also means a higher rated accuracy limit F_n)
- a CT with a higher nominal primary current I_{1n} (but the same rated burden) can be chosen

Example 2

Assuming that the actions according to alternative two above are taken in order to improve the actual accuracy limit factor:

$$F_a = \frac{IrCT}{IrTR} \times F_n$$

(Equation 202)

IrTR	1000 A (rated secondary side current of the power transformer)
IrCT	1500 A (rated primary current of the CT on the transformer secondary side)
F_n	30 (rated accuracy limit factor of the CT)
F_a	(IrCT / IrTR) * Fn (actual accuracy limit factor due to oversizing the CT) = (1500/1000) * 30 = 45

In 87T, it is important that the accuracy limit factors F_a of the phase current transformers at both sides correspond with each other, that is, the burdens of the current transformers on both sides are to be as equal as possible. If high inrush or pickup currents with high DC components pass through the protected object when it is connected to the network, special attention is required for the performance and the burdens of the current transformers and for the settings of the function block.

Section 13 Protection relay's physical connections

13.1 Module slot numbering

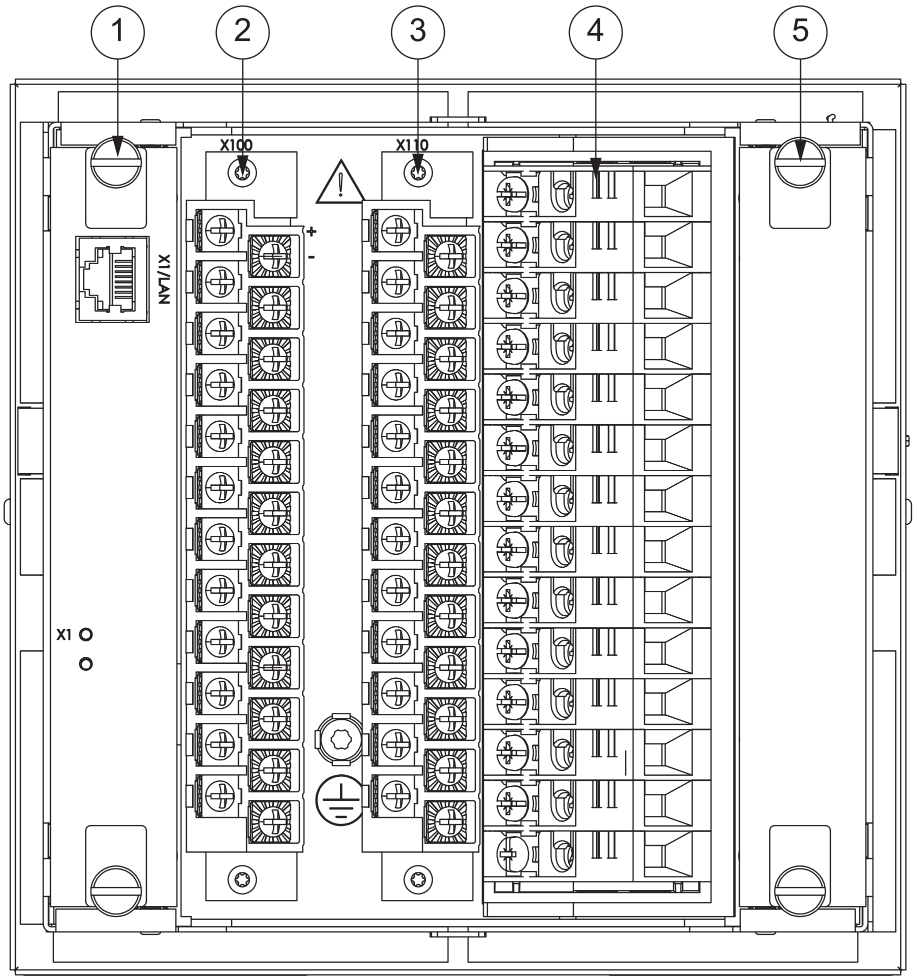


Figure 581: Module slot numbering

1 X000

2 X100

3 X110

4 X120

5 X130

13.2 Protective ground connections

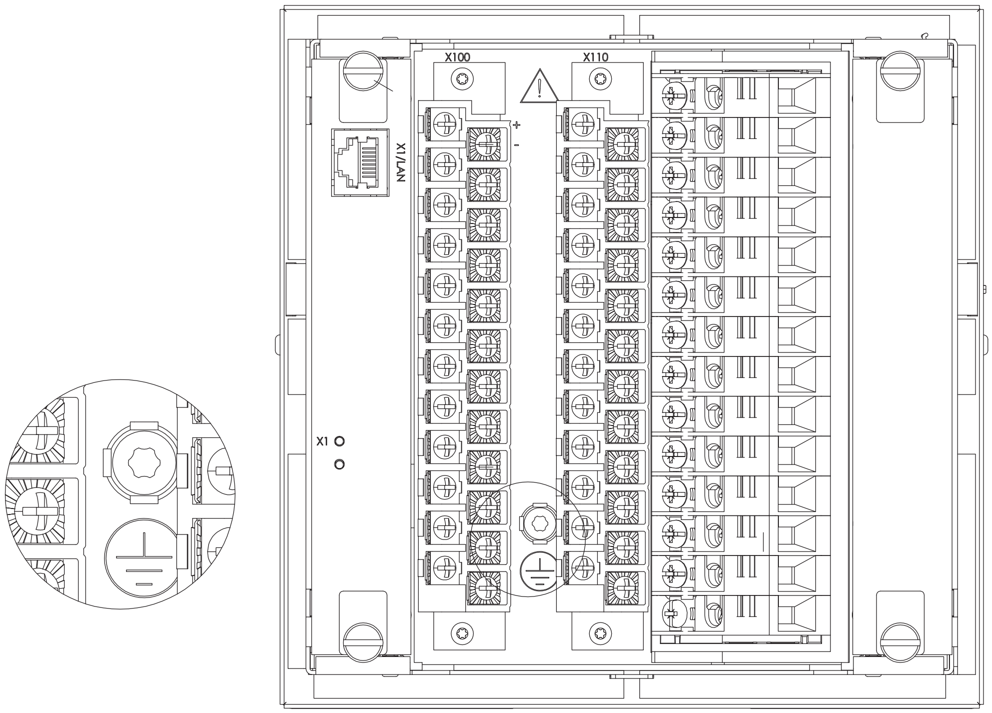


Figure 582: The protective ground screw is located between connectors X100 and X110

The ground lead must be at least a 12 Gauge wire and as short as possible.

13.3 Binary and analog connections

All binary and analog connections are described in the product specific application manuals.

13.4 Communication connections

The front communication connection is an RJ-45 type connector used mainly for configuration and setting.

For RED615, the rear communication module is mandatory due to the connection needed for the line-differential protection communication. If station communication is needed for REF615, REG615, REM615 or RET615, an optional rear communication module is required. Several optional communication connections are available.

- Galvanic RJ-45 Ethernet connection
- Optical LC Ethernet connection
- ST-type glass fiber serial connection
- EIA-485 serial connection
- EIA-232 serial connection

Never touch the end face of an optical fiber connector.

Always install dust caps on unplugged fiber connectors.

If contaminated, clean optical connectors only with fiber-optic cleaning products.

13.4.1 Ethernet RJ-45 front connection

The protection relay is provided with an RJ-45 connector on the LHMI. The connector is intended for configuration and setting purposes. The interface on the PC side has to be configured in a way that it obtains the IP address automatically. There is a DHCP server inside protection relay for the front interface only.

The events and setting values and all input data such as memorized values and disturbance records can be read via the front communication port.

Only one of the possible clients can be used for parametrization at a time.

- PCM600
- LHMI
- WHMI

The default IP address of the protection relay through this port is 192.168.0.254.

The front port supports TCP/IP protocol. A standard Ethernet CAT 5 crossover cable is used with the front port.

The speed of the front connector interface is limited to 10 Mbps.

13.4.2 Ethernet rear connections

The Ethernet station bus communication module is provided with either galvanic RJ-45 connection or optical multimode LC type connection, depending on the product variant and the selected communication interface option. A shielded twisted-pair cable CAT 5e is used with the RJ-45 connector and an optical multi-mode cable (≤2 km) with the LC type connector.

In addition, communication modules with multiple Ethernet connectors enable the forwarding of Ethernet traffic. These variants include an internal Ethernet switch that handles the Ethernet traffic between an protection relay and a station bus. In this case, the used network can be a ring or daisy-chain type of network topology. In loop type topology, a self-healing Ethernet loop is closed by a managed switch supporting rapid spanning tree protocol. In daisy-chain type of topology, the network is bus type and it is either without switches, where the station bus starts from the station client, or with a switch to connect some devices and the protection relays of this product series to the same network.Internal Ethernet switch MAC table size is 512 entries. All Ethernet ports share this one common MAC table.

Communication modules including Ethernet connectors X1, X2, and X3 can utilize the third port for connecting any other device (for example, an SNTP server, that is visible for the whole local subnet) to a station bus. In RED615, the first Ethernet port X16 is dedicated to the line differential communication and it cannot be used for station bus communication.

The protection relay's default IP address through rear Ethernet port is 192.168.2.10 with the TCP/IP protocol. The data transfer rate is 10 or 100 Mbps full duplex.

13.4.3 EIA-232 serial rear connection

The EIA-232 connection follows the TIA/EIA-232 standard and is intended to be used with a point-to-point connection. The connection supports hardware flow control (RTS, CTS, DTR, DSR), full-duplex and half-duplex communication.

13.4.4 EIA-485 serial rear connection

The EIA-485 communication module follows the TIA/EIA-485 standard and is intended to be used in a daisy-chain bus wiring scheme with 2-wire half-duplex or 4-wire full-duplex, multi-point communication.

The maximum number of devices (nodes) connected to the bus where the protection relay is used is 32, and the maximum length of the bus is 1200 meters.

13.4.5 Line differential protection communication connection

The dedicated line differential protection communication link uses either a single mode or a multimode connection with an LC type connector. The line differential communication connector (X16/LD) is always the topmost in the communication module. Line differential communication cards COM0008 and COM0036 are provided with multimode optical LC connector. Line differential communication cards COM0010 and COM0035 are provided with single mode optical LC connector.

The port cannot be used with any other Ethernet communication network. The interface speed is 100 Mbps.

Use direct link. Switches, hubs or routers are not allowed between the protection relays.

If galvanic pilot wire is used as protection communication link, the pilot wire modem RPW600 is required. The protection communication link always requires two modems in a protection scheme, thus delivered in pairs of master (RPW600M) and follower (RPW600F) units. A single-mode fiber optic cable with dual LC type connectors is used to connect RED615 with RPW600 modem. The recommended minimum length for this cable is 3 m.

Communication port X16/LD of RED615 is used both for direct fiber optic link and connection with the pilot wire modem.

The RPW600 modem has a built-in 5 kVAC (RMS, 1 min) level insulation against ground potential in the pilot wire connection.

13.4.6 Optical ST serial rear connection

Serial communication can be used optionally through an optical connection either in loop or star topology. The connection idle state is light on or light off.

Using ST loop mode requires an ST serial converter that supports detecting and removing of duplicate request after transmission trough full circle.

13.4.7 Communication interfaces and protocols

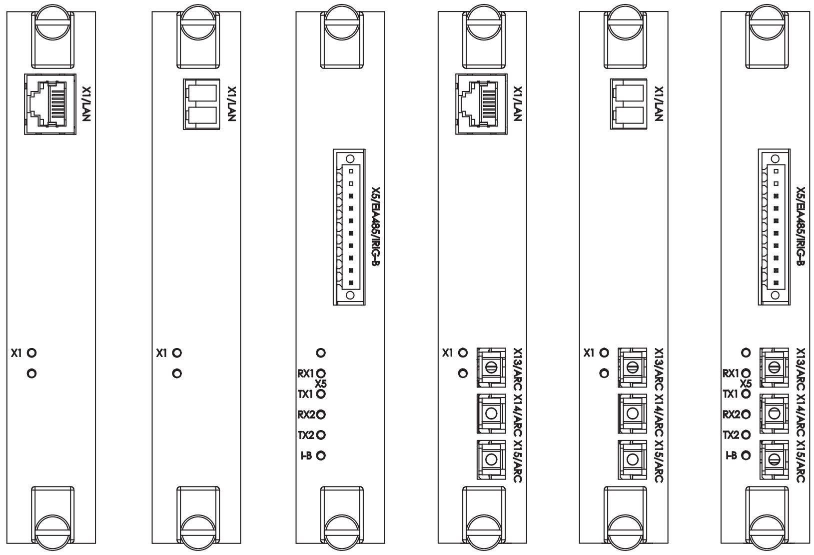
The communication protocols supported depend on the optional rear communication module.

Table 950: Supported station communication interfaces and protocols

Interfaces/Protocols	Ethernet		Serial	
	100BASE-TX RJ-45	100BASE-FX LC	EIA-232/EIA-485	Fiber optic ST
IEC 61850-8-1	●	●	-	-
IEC 61850-9-2 LE	●[1)]	●	-	-
MODBUS RTU/ ASCII	-	-	●	●
MODBUS TCP/IP	●	●	-	-
DNP3 (serial)	-	-	●	●
DNP3 TCP/IP	●	●	-	-
IEC 60870-5-103	-	-	●	●
● = Supported				

1) Not available for RED615 line differential communication connection

13.4.8 Rear communication modules



COM0001
RJ-45

COM0002
LC

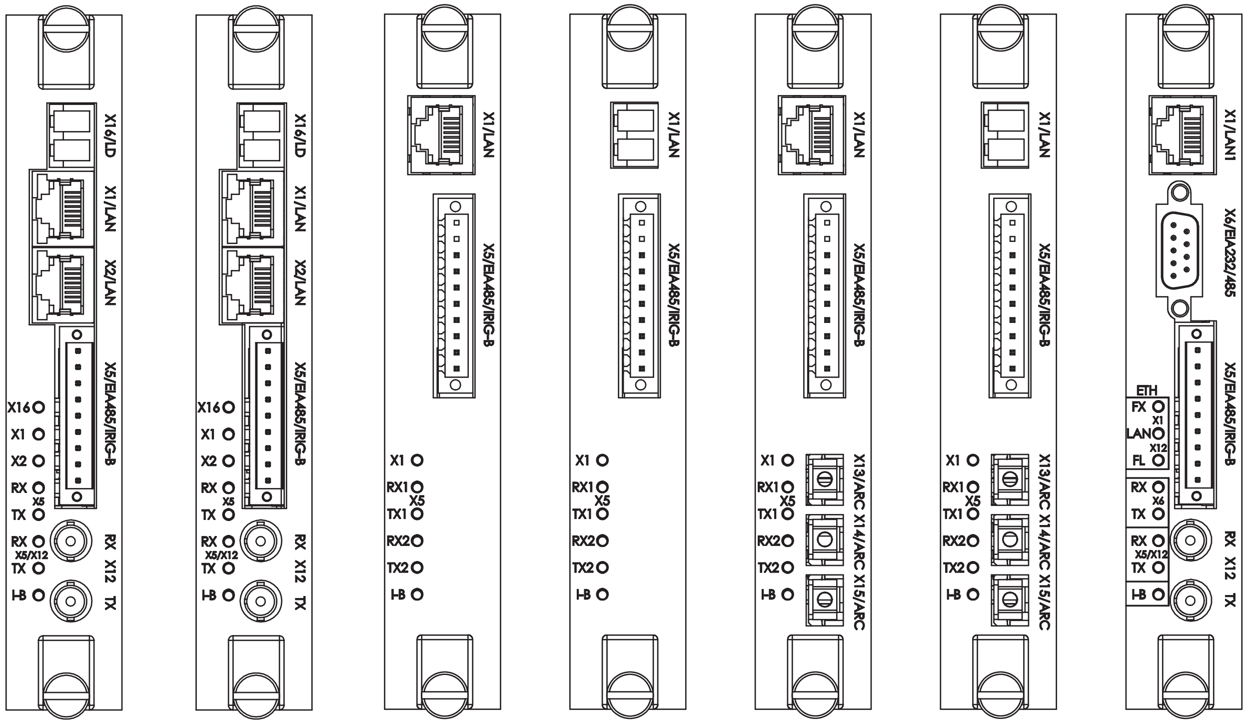
COM0003
RS-485+
IRIG-B

COM0005
RJ-45+ARC

COM0006
LC+ARC

COM0007
RS-485+
IRIG-B+ARC

Figure 583: Communication module options



COM0008
LC+2xRJ-45+
RS485+ST+IRIG-B

COM0010
LC+2xRJ-45+
RS485+ST+IRIG-B

COM0011
RJ-45+RS485+
IRIG-B

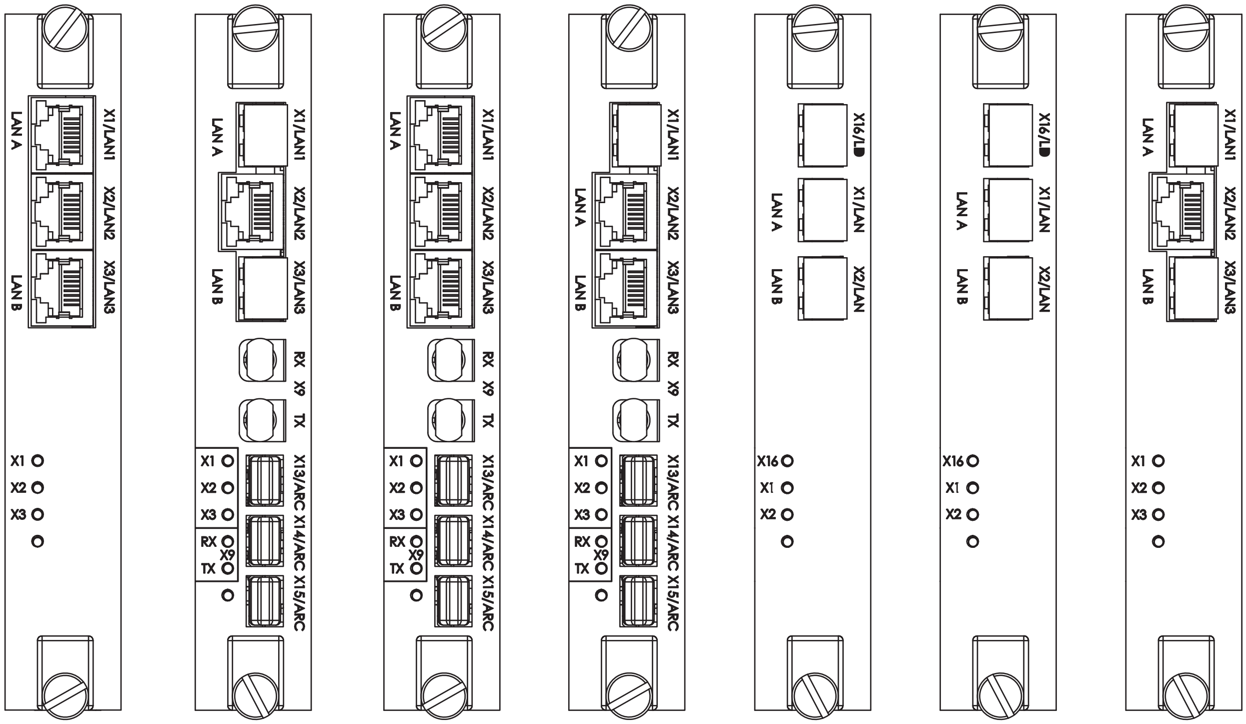
COM0012
LC+RS485+
IRIG-B

COM0013
RJ-45+RS485+
IRIG-B+ARC

COM0014
LC+RS485+
IRIG-B+ARC

COM0023
RJ-45+RS232/485+
RS485+ST+IRIG-B

Figure 584: Communication module options



COM0031 3xRJ-45	COM0032 2xLC+RJ-45+ ST+ARC	COM0033 3xRJ-45+ ST+ARC	COM0034 LC+2xRJ-45+ ST+ARC	COM0035 3xLC	COM0036 3xLC	COM0037 2xLC+RJ-45

Figure 585: Communication module options

Ethernet ports marked with LAN A and LAN B are used with redundant Ethernet protocols HSR and PRP. The third port without the LAN A or LAN B label is an interlink port which is used as a redundancy box connector with redundant Ethernet protocols.

Table 951: Station bus communication interfaces included in communication modules

Module ID	RJ-45	LC	EIA-485	EIA-232	ST
COM0001	1	-	-	-	-
COM0002	-	1	-	-	-
COM0003	-	-	1	-	-
COM0005	1	-	-	-	-
COM0006	-	1	-	-	-
COM0007	-	-	1	-	-
COM0008[1)]	2	-	1	-	1
COM0010[1)]	2	-	1	-	1
COM0011	1	-	1	-	-
Table continues on next page					

Module ID	RJ-45	LC	EIA-485	EIA-232	ST
COM0012	-	1	1	-	-
COM0013	1	-	1	-	-
COM0014	-	1	1	-	-
COM0023	1	-	1	1	1
COM0031	3	-	-	-	-
COM0032	1	2	-	-	1
COM0033	3	-	-	-	1
COM0034	2	1	-	-	1
COM0035[1)]	-	3	-	-	-
COM0036[1)]	-	3	-	-	-
COM0037	1	2	-	-	-

1) Available only for RED615

Table 952: LED descriptions for COM0001-COM0014

LED	Connector	Description[1)]
X1	X1	X1/LAN link status and activity (RJ-45 and LC)
RX1	X5	COM2 2-wire/4-wire receive activity
TX1	X5	COM2 2-wire/4-wire transmit activity
RX2	X5	COM1 2-wire receive activity
TX2	X5	COM1 2-wire transmit activity
I-B	X5	IRIG-B signal activity

1) Depending on the COM module and jumper configuration

Table 953: LED descriptions for COM0008 and COM0010

LED	Connector	Description[1)]
X16	X16	X16/LD link status and activity
X1	X1	X1/LAN link status and activity
X2	X2	X2/LAN link status and activity
RX	X5	COM1 2-wire receive activity/COM2 4-wire receive activity
TX	X5	COM1 2-wire transmit activity/COM2 4-wire transmit activity
RX	X5/X12	COM2 2-wire receive activity/COM2 4-wire receive activity
TX	X5/X12	COM2 2-wire transmit activity/COM2 4-wire transmit activity
I-B	X5	IRIG-B signal activity

1) Depending on the jumper configuration

Table 954: LED descriptions for COM0023

LED	Connector	Description[1)]
FX	X12	Not used by COM0023
X1	X1	LAN Link status and activity (RJ-45 and LC)
FL	X12	Not used by COM0023
RX	X6	COM1 2-wire / 4-wire receive activity
TX	X6	COM1 2-wire / 4-wire transmit activity
RX	X5 / X12	COM2 2-wire / 4-wire or fiber-optic receive activity
TX	X5 / X12	COM2 2-wire / 4-wire or fiber-optic transmit activity
I-B	X5	IRIG-B signal activity

1) Depending on the jumper configuration

Table 955: LED descriptions for COM0031-COM0034 and COM0037

LED	Connector	Description
X1	X1	X1/LAN1 link status and activity
X2	X2	X2/LAN2 link status and activity
X3	X3	X3/LAN3 link status and activity
RX	X9	COM1 fiber-optic receive activity
TX	X9	COM1 fiber-optic transmit activity

Table 956: LED descriptions for COM0035 and COM0036

LED	Connector	Description
X1	X1	X1/LAN link status and activity
X2	X2	X2/LAN link status and activity
X16	X16	X16/LD link status and activity

13.4.8.1 COM0001-COM0014 jumper locations and connections

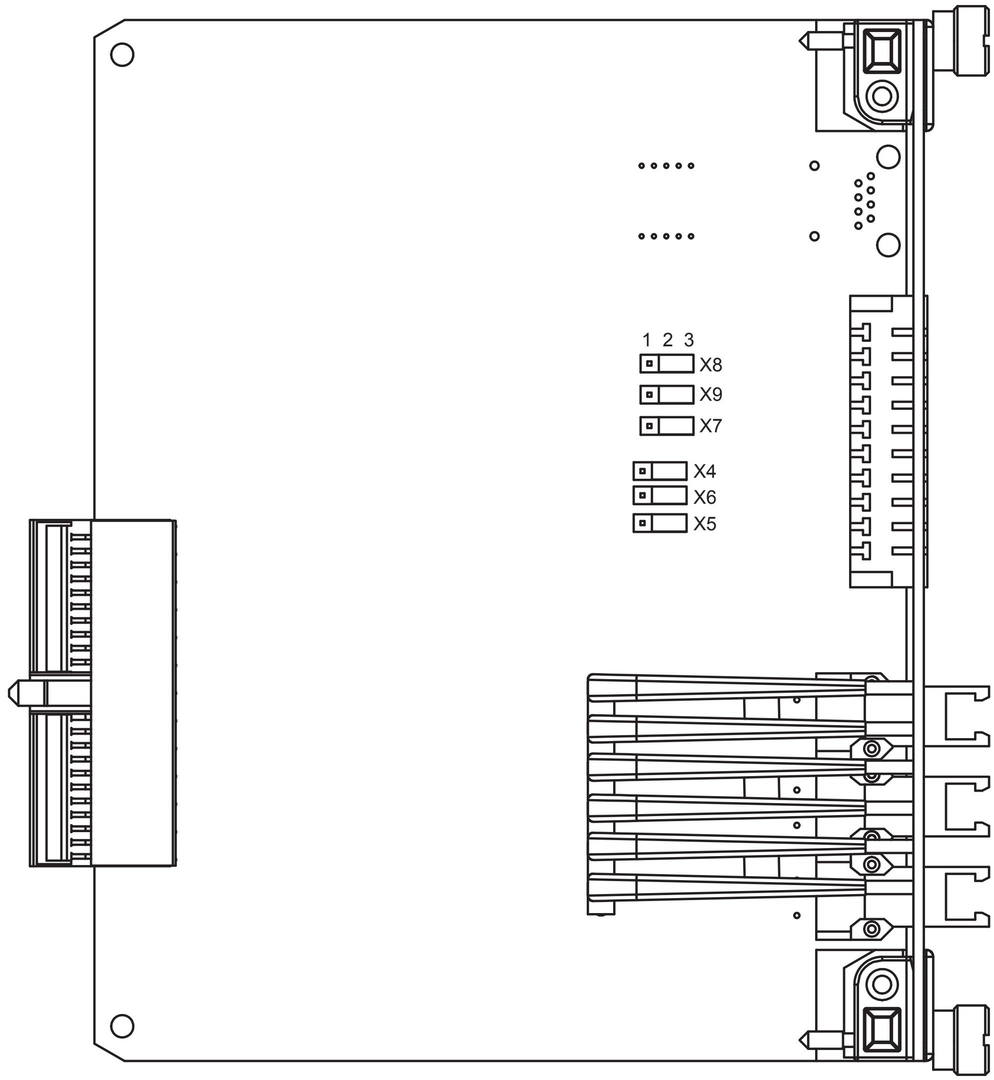


Figure 586: Jumper connectors on communication module

Table 957: 2-wire EIA-485 jumper connectors

Group	Jumper connection	Description	Notes
X4	1-2	A+ bias enabled	COM2 2-wire connection
	2-3	A+ bias disabled	
X5	1-2	B- bias enabled	
	2-3	B- bias disabled	
X6	1-2	Bus termination enabled	
	2-3	Bus termination disabled	
X7	1-2	B- bias enabled	COM1 2-wire connection
	2-3	B- bias disabled	
X8	1-2	A+ bias enabled	
	2-3	A+ bias disabled	
X9	1-2	Bus termination enabled	
	2-3	Bus termination disabled	

The bus is to be biased at one end to ensure fail-safe operation, which can be done using the pull-up and pull-down resistors on the communication module. In 4-wire connection the pull-up and pull-down resistors are selected by setting jumpers X4, X5, X7 and X8 to enabled position. The bus termination is selected by setting jumpers X6 and X9 to enabled position.

The jumpers have been set to no termination and no biasing as default.

Table 958: 4-wire EIA-485 jumper connectors for COM2

Group	Jumper connection	Description	Notes
X4	1-2	A+ bias enabled	COM2 4-wire TX channel
	2-3	A+ bias disabled 1)	
X5	1-2	B- bias enabled	
	2-3	B- bias disabled1)	
X6	1-2	Bus termination enabled	
	2-3	Bus termination disabled1)	
X7	1-2	B- bias enabled	COM2 4-wire RX channel
	2-3	B- bias disabled1)	
X8	1-2	A+ bias enabled	
	2-3	A+ bias disabled1)	
X9	1-2	Bus termination enabled	
	2-3	Bus termination disabled1)	

1) Default setting

It is recommended to enable biasing only at one end of the bus.

It is recommended to enable termination at each end of the bus.

It is recommended to ground the signal directly to earth from one node using a GND pin and through capacitor from other nodes using a GNDC pin.

Signal grounding should be used with all devices in RS-485 bus having an isolated communication port. Grounding ensures that different RS-485 nodes have the same signal reference ground. Without grounding the differential RS-485 signal might be superimposed between different nodes with respect to the node's local ground. For signal grounding it is recommended to connect to AGND pin in RS-485 connector an additional ground wire which runs inside the shielded serial cable.

The optional communication modules include support for EIA-485 serial communication (X5 connector). Depending on the configuration, the communication modules can host either two 2-wire ports or one 4-wire port.

The two 2-wire ports are called COM1 and COM2. Alternatively, if there is only one 4-wire port configured, the port is called COM2. The fiber optic ST connection uses the COM1 port.

Table 959: EIA-485 connections for COMB01A-COMB014A

Pin	2-wire mode		4-wire mode	
10	COM1	A/+	COM2	Rx/+
9		B/-		Rx/-
8	COM2	A/+		Tx/+
7		B/-		Tx/-
6	AGND (isolated ground)			
5	IRIG-B +			
4	IRIG-B -			
3	-			
2	GNDC (case via capacitor)			
1	GND (case)			

13.4.8.2 COM0023 jumper locations and connections

The optional communication module supports EIA-232/EIA-485 serial communication (X6 connector), EIA-485 serial communication (X5 connector) and optical ST serial communication (X12 connector).

Two independent communication ports are supported. The two 2-wire ports are called COM1 and COM2. Alternatively, if only one 4-wire port is configured, the port is called COM2. The fiber optic ST connection uses the COM1 port.

Table 960: Configuration options of the two independent communication ports

COM1 connector X6	COM2 connector X5 or X12
EIA-232	Optical ST (X12)
EIA-485 2-wire	EIA-485 2-wire (X5)
EIA-485 4-wire	EIA-485 4-wire (X5)

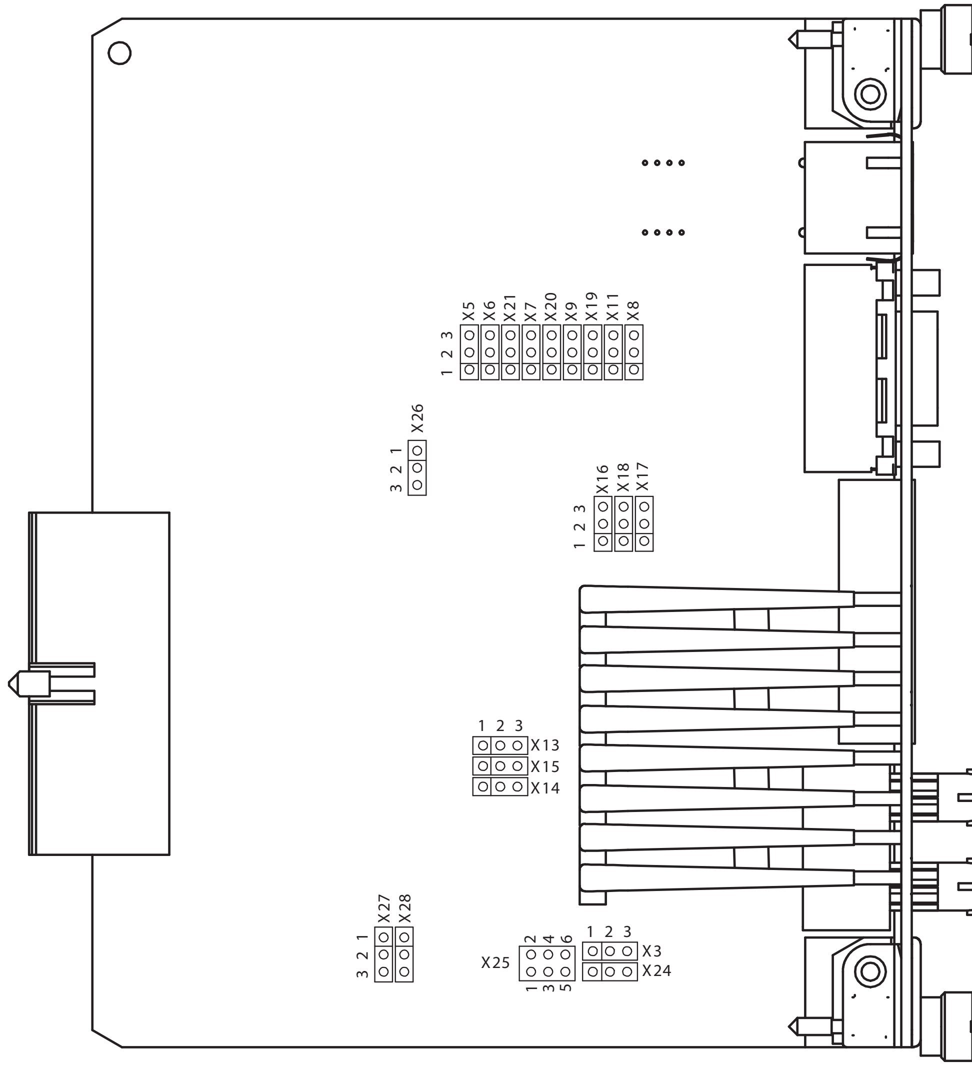


Figure 587: Jumper connections on communication module COM0023 revisions A-F

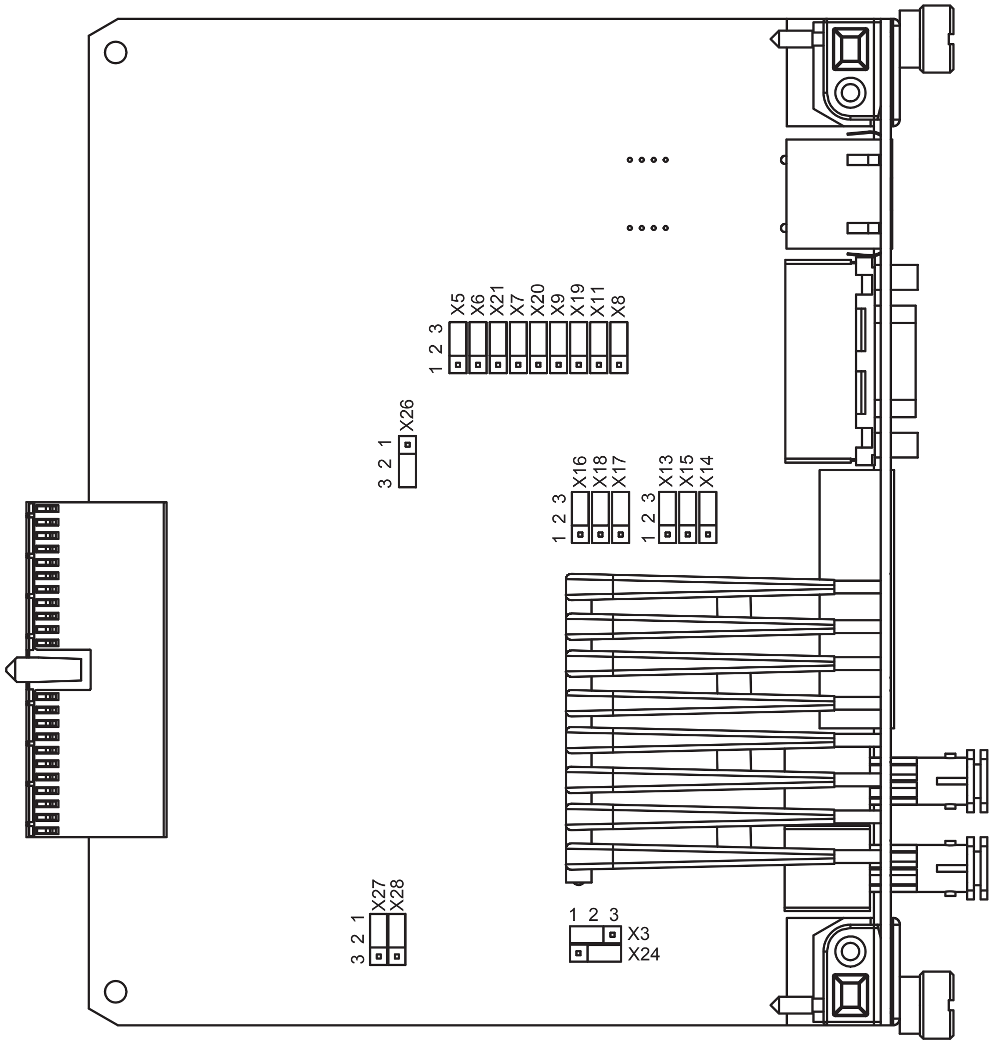


Figure 588: Jumper connections on communication module COM0023 revision G

COM1 port connection type can be either EIA-232 or EIA-485. Type is selected by setting jumpers X19, X20, X21 and X26.

The jumpers are set to EIA-232 by default.

Table 961: EIA-232 and EIA-485 jumper connectors for COM1

Group	Jumper connection	Description
X19	1-2 2-3	EIA-485 EIA-232
X20	1-2 2-3	EIA-485 EIA-232
X21	1-2 2-3	EIA-485 EIA-232
X26	1-2 2-3	EIA-485 EIA-232

To ensure fail-safe operation, the bus is to be biased at one end using the pull-up and pull-down resistors on the communication module. In the 4-wire connection, the pull-up and pull-down resistors are selected by setting jumpers X5, X6, X8 and X9 to enabled position. The bus termination is selected by setting jumpers X7 and X11 to enabled position.

The jumpers have been set to no termination and no biasing as default.

Table 962: 2-wire EIA-485 jumper connectors for COM1

Group	Jumper connection	Description	Notes
X5	1-2 2-3	A+ bias enabled A+ bias disabled[1)]	COM1 Rear connector X6 2-wire connection
X6	1-2 2-3	B- bias enabled B- bias disabled[1)]	
X7	1-2 2-3	Bus termination enabled Bus termination disabled[1)]	

1) Default setting

Table 963: 4–wire EIA-485 jumper connectors for COM1

Group	Jumper connection	Description	Notes
X5	1-2 2-3	A+ bias enabled A+ bias disabled[1)]	COM1 Rear connector X6 4-wire TX channel
X6	1-2 2-3	B- bias enabled B- bias disabled[1)]	
X7	1-2 2-3	Bus termination enabled Bus termination disabled[1)]	
Table continues on next page			

Group	Jumper connection	Description	Notes
X9	1-2 2-3	A+ bias enabled A+ bias disabled[1)]	4-wire RX channel
X8	1-2 2-3	B- bias enabled B- bias disabled[1)]	
X11	1-2 2-3	Bus termination enabled Bus termination disabled[1)]	

1) Default setting

COM2 port connection can be either EIA-485 or optical ST. Connection type is selected by setting jumpers X27 and X28.

Table 964: COM2 serial connection X5 EIA-485/ X12 Optical ST

Group	Jumper connection	Description
X27	1-2 2-3	EIA-485 Optical ST
X28	1-2 2-3	EIA-485 Optical ST

Table 965: 2-wire EIA-485 jumper connectors for COM2

Group	Jumper connection	Description
X13	1-2 2-3	A+ bias enabled A+ bias disabled
X14	1-2 2-3	B- bias enabled B- bias disabled
X15	1-2 2-3	Bus termination enabled Bus termination disabled

Table 966: 4-wire EIA-485 jumper connectors for COM2

Group	Jumper connection	Description	Notes
X13	1-2 2-3	A+ bias enabled A+ bias disabled	COM2 4-wire TX channel
X14	1-2 2-3	B- bias enabled B- bias disabled	
X15	1-2 2-3	Bus termination enabled Bus termination disabled	
X16	1-2 2-3	Bus termination enabled Bus termination disabled	4-wire RX channel
X17	1-2 2-3	A+ bias enabled A+ bias disabled	
X18	1-2 2-3	B- bias enabled B- bias disabled	

Table 967: X12 Optical ST connection

Group	Jumper connection	Description
X3	1-2 2-3	Star topology Loop topology
X24	1-2 2-3	Idle state = Light on Idle state = Light off

Table 968: EIA-232 connections for COM0023 (X6)

Pin	EIA-232
1	DCD
2	RxD
3	TxD
4	DTR
5	AGND
6	-
7	RTS
8	CTS

Table 969: EIA-485 connections for COM0023 (X6)

Pin	2-wire mode	4-wire mode
1	-	Rx/+
6	-	Rx/-
7	B/-	Tx/-
8	A/+	Tx/+

Table 970: EIA-485 connections for COM0023 (X5)

Pin	2-wire mode	4-wire mode
9	-	Rx/+
8	-	Rx/-
7	A/+	Tx/+
6	B/-	Tx/-
5	AGND (isolated ground)	
4	IRIG-B +	
3	IRIG-B -	
2	-	
1	GND (case)	

13.4.8.3 COM0008 and COM0010 jumper locations and connections

The EIA-485 communication module follows the TIA/EIA-485 standard and is intended to be used in a daisy-chain bus wiring scheme with 2-wire or 4-wire, half-duplex, multi-point communication. Serial communication can be also used through optical connection which is used either in loop or star topology.

Two parallel 2-wire serial communication channels can be used at the same time. Also optical serial connector can be used in parallel with one 2-wire or 4-wire serial channel.

The maximum number of devices (nodes) connected to the bus where the protection relay is being used is 32, and the maximum length of the bus is 1200 meters.

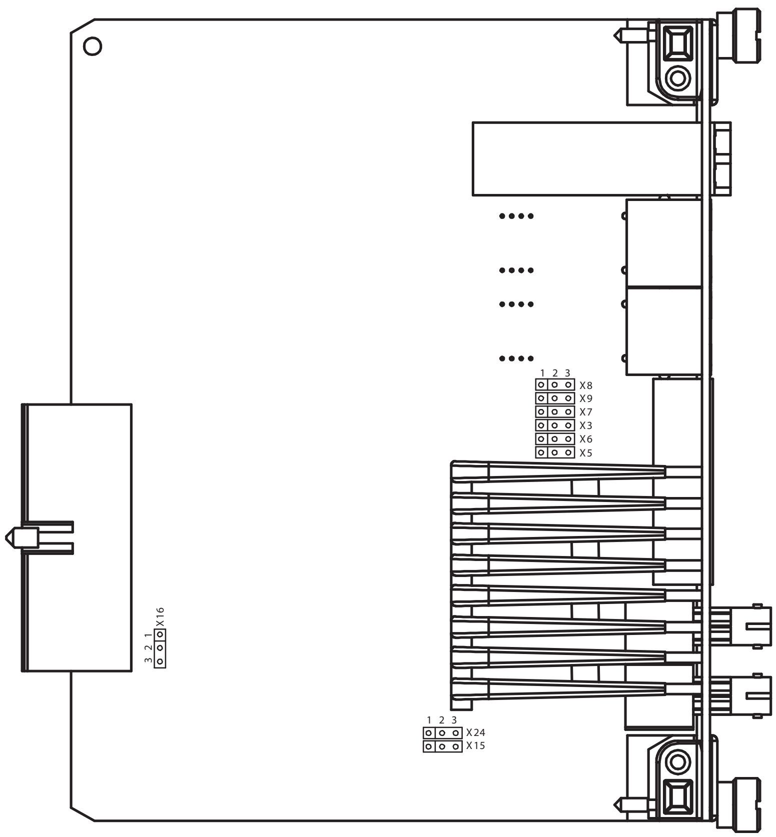


Figure 589: Jumper connectors on communication module

Table 971: 2-wire EIA-485 jumper connectors

Group	Jumper connection	Description	Notes
X3	1-2	A+ Bias enabled	COM1 2-wire connection
	2-3	A+ Bias Disabled	
X5	1-2	B- Bias enabled	
	2-3	B- Bias Disabled	
X6	1-2	Bus termination enabled	
	2-3	Bus termination disabled	
X7	1-2	B- Bias enabled	COM2 2-wire connection
	2-3	B- Bias Disabled	
X8	1-2	A+ Bias enabled	
	2-3	A+ Bias Disabled	
X9	1-2	Bus termination enabled	
	2-3	Bus termination disabled	

The bus is to be biased at one end to ensure fail-safe operation, which can be done using the pull-up and pull-down resistors on the communication module. In 4-wire connection the pull-up and pull-down resistors are selected by setting jumpers X3, X5, X7 and X8 to enabled position. The bus termination is selected by setting jumpers X6 and X9 to enabled position.

The jumpers have been set to no termination and no biasing as default.

Table 972: 4-wire EIA-485 jumper connectors for COM2

Group	Jumper connection	Description	Notes
X3	1-2	A+ Bias enabled	COM2 4-wire TX channel
	2-3	A+ Bias Disabled	
X5	1-2	B- Bias enabled	
	2-3	B- Bias Disabled	
X6	1-2	Bus termination enabled	
	2-3	Bus termination disabled	
X7	1-2	B- Bias enabled	COM2 4-wire RX channel
	2-3	B- Bias Disabled	
X8	1-2	A+ Bias enabled	
	2-3	A+ Bias Disabled	
X9	1-2	Bus termination enabled	
	2-3	Bus termination disabled	

Table 973: Jumper connectors for COM1 serial connection type

Group	Jumper connection	Description
X16	1-2	EIA-485 selected for COM1
	2-3	FO_UART selected for COM1
X15	1-2	Star topology selected for FO_UART
	2-3	Loop topology selected for FO_UART
X24	1-2	FO_UART channel idle state: Light on
	2-3	FO_UART channel idle state: Light off

It is recommended to enable biasing only at one end of the bus.

Termination is enabled at each end of the bus

It is recommended to ground the signal directly to ground from one node and through capacitor from other nodes.

The optional communication modules include support for EIA-485 serial communication (X5 connector). Depending on the configuration the communication modules can host either two 2-wire ports or one 4-wire port.

The two 2-wire ports are called as COM1 and COM2. Alternatively, if there is only one 4-wire port configured, the port is called COM2. The fiber optic ST connection uses the COM1 port.

Table 974: EIA-485 connections for COM0008 and COM0010

Pin	2-wire mode		4-wire mode	
9	COM1	A/+	COM2	Rx/+
8		B/-		Rx/-
7	COM2	A/+		Tx/+
6		B/-		Tx/-
5	AGND (isolated ground)			

Table continues on next page

Pin	2-wire mode	4-wire mode
4	IRIG-B +	
3	IRIG-B -	
2	GNDC (case via capasitor)	
1	GND (case)	

13.4.8.4 COM0032-COM0034 jumper locations and connections

The optional communication modules include support for optical ST serial communication (X9 connector). The fiber optic ST connection uses the COM1 port.

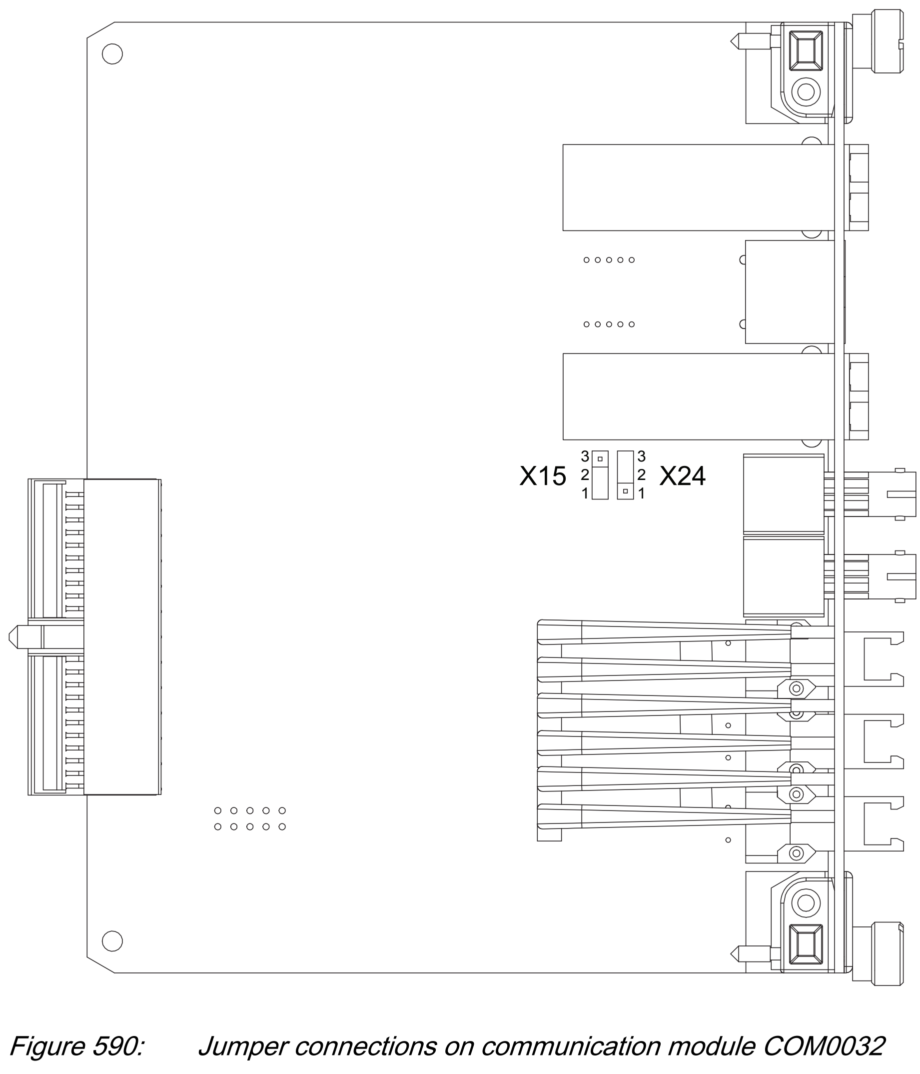


Figure 590: Jumper connections on communication module COM0032

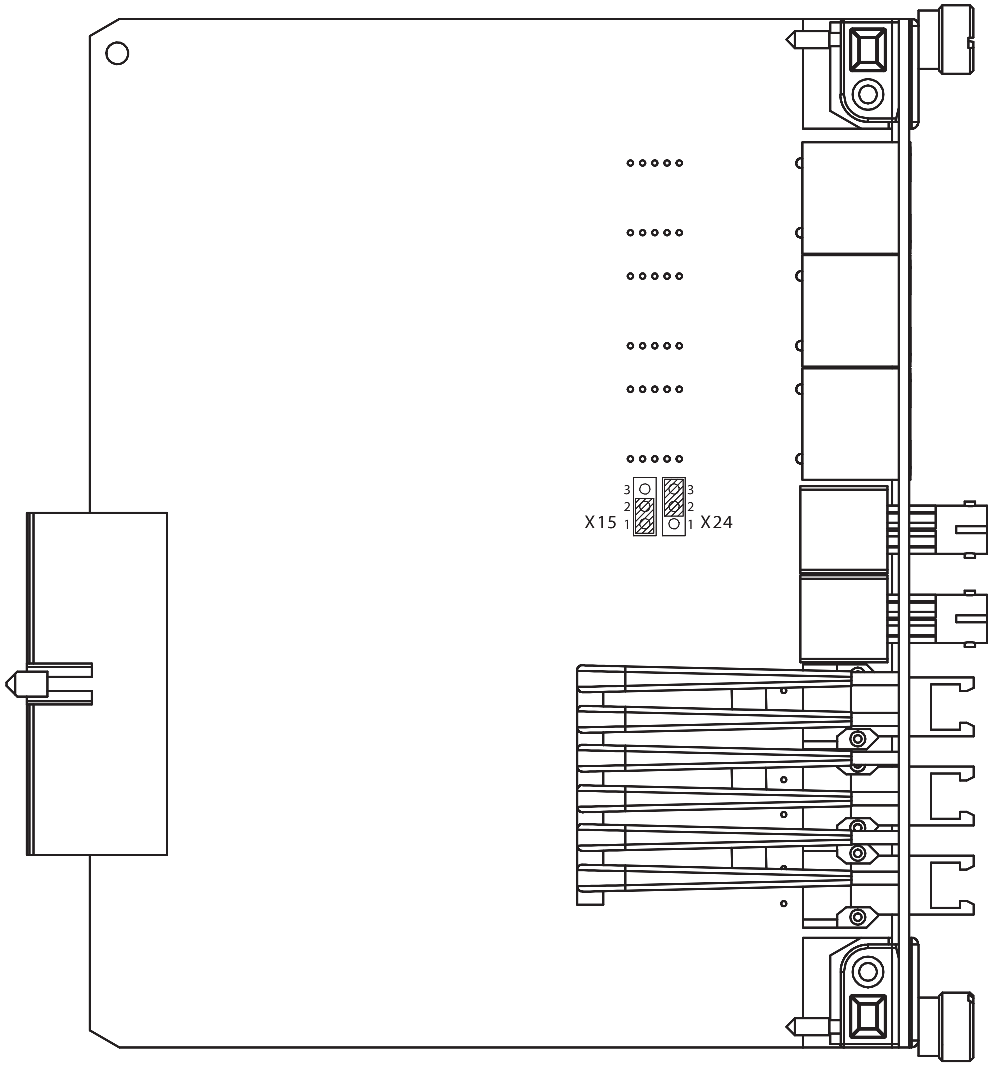


Figure 591: Jumper connections on communication module COM0033

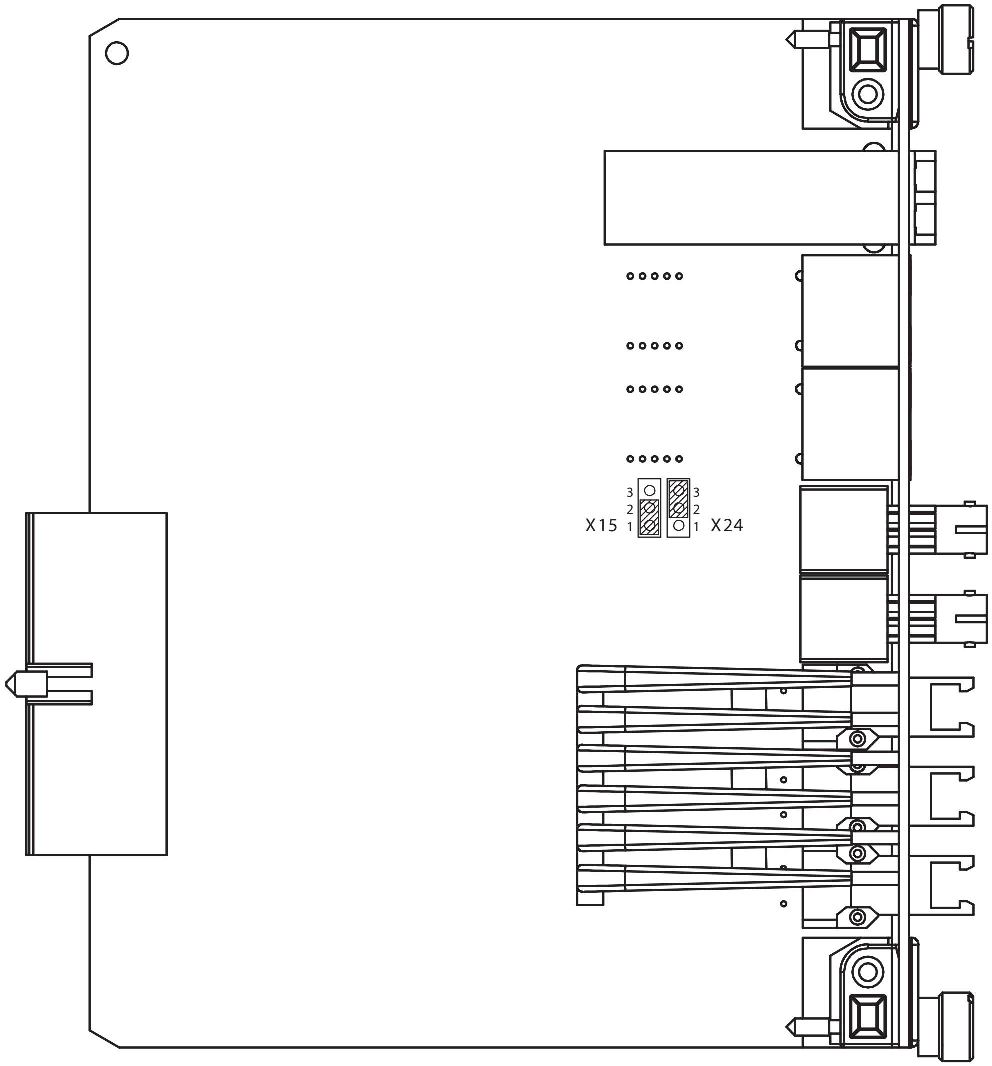


Figure 592: Jumper connections on communication module COM0034

Table 975: X9 Optical ST jumper connectors

Group	Jumper connection	Description
X15	1-2 2-3	Star topology Loop topology
X24	1-2 2-3	Idle state = Light on Idle state = Light off

Section 14 Technical data

Table 976: Dimensions

Description	Value	
Width	Frame	6.97 inches (177 mm)
	Case	6.46 inches (164 mm)
Height	Frame	6.97 inches (177 mm), 4U
	Case	6.30 inches (160 mm)
Depth		7.92 inches (201 mm)
Weight	Complete protection relay	9.0 lbs (4.1 kg)
	Plug-in unit only	4.6 lbs (2.1 kg)

Table 977: Power supply

Description	Type 1	Type 2
Nominal auxiliary voltage V_n	100, 110, 120, 220, 240 V AC, 50 and 60 Hz	24, 30, 48, 60 V DC
	48, 60, 110, 125, 220, 250 V DC	
Maximum interruption time in the auxiliary DC voltage without resetting the relay	50 ms at V_n	
Auxiliary voltage variation	38...110% of V_n (38...264 V AC)	50...120% of V_n (12...72 V DC)
	80...120% of V_n (38.4...300 V DC)	
Start-up threshold		19.2 V DC (24 V DC × 80%)
Burden of auxiliary voltage supply under quiescent (P_q)/operating condition	DC <13.0 W (nominal)/<18.0 W (max.) AC <16.0 W (nominal)/<21.0 W (max.)	DC <13.0 W (nominal)/<18.0 W (max.)
Ripple in the DC auxiliary voltage	Max 15% of the DC value (at frequency of 100 Hz)	
Fuse type	T4A/250 V	

Table 978: *Energizing inputs*

Description		Value	
Rated frequency		50/60 Hz	
Current inputs	Rated current, I_n	0.2/1 A[1][2]	1/5 A[3]
	Thermal withstand capability: • Continuously • For 1 s	 4 A 100 A	 20 A 500 A
	Dynamic current withstand: • Half-wave value	 250 A	 1250 A
	Input impedance	<100 mΩ	<20 mΩ
Voltage inputs	Rated voltage	60...210 V AC	
	Voltage withstand: • Continuous • For 10 s	 240 V AC 360 V AC	
	Burden at rated voltage	<0.05 VA	

1) Ordering option for residual current input
2) Not available for RET615
3) Ground current and/or phase current

Table 979: *Energizing inputs (sensors)*

Description		Value
Current sensor input	Rated current voltage (in secondary side)	75 mV...9000 mV[1]
	Continuous voltage withstand	125 V
	Input impedance at 50/60 Hz	2...3 MΩ[2]
Voltage sensor input	Rated voltage	6 kV...30 kV[3]
	Continuous voltage withstand	50 V
	Input impedance at 50/60 Hz	3 MΩ

1) Equals the current range of 40...4000 A with a 80 A, 3 mV/Hz Rogowski
2) Depending on the used nominal current (hardware gain)
3) This range is covered (up to 2*rated) with sensor division ratio of 10 000:1

Table 980: Binary inputs

Description	Value
Operating range	±20% of the rated voltage
Rated voltage	24...250 V DC
Current drain	1.6...1.9 mA
Power consumption	31.0...570.0 mW
Threshold voltage	16...176 V DC
Reaction time	<3 ms

Adjust the binary input threshold voltage correctly. The threshold voltage should be set to 70% of the nominal auxiliary voltage. The factory default is 16 V to ensure the binary inputs' operation regardless of the auxiliary voltage used (24, 48, 60, 110, 125, 220 or 250 V DC). However, the default value is not optimal for the higher auxiliary voltages. The binary input threshold voltage should be set as high as possible to prevent any inadvertent activation of the binary inputs due to possible external disturbances. At the same time, the threshold should be set so that the correct operation is not jeopardized in case of undervoltage of the auxiliary voltage.

Table 981: RTD/mA inputs

Description		Value	
RTD inputs	Supported RTD sensors	100 Ω platinum 250 Ω platinum 100 Ω nickel 120 Ω nickel 250 Ω nickel 10 Ω copper	TCR 0.00385 (DIN 43760) TCR 0.00385 TCR 0.00618 (DIN 43760) TCR 0.00618 TCR 0.00618 TCR 0.00427
	Supported resistance range	0...2 kΩ	
	Maximum lead resistance (three-wire measurement)	25 Ω per lead	
	Isolation	2 kV (inputs to protective ground)	
	Response time	<4 s	
	RTD/resistance sensing current	Maximum 0.33 mA rms	
	Operation accuracy	Resistance	Temperature
		± 2.0% or ±1 Ω	±1°C 10 Ω copper: ±2°C

Table continues on next page

Description		Value
mA inputs	Supported current range	0…20 mA
	Current input impedance	44 Ω ± 0.1%
	Operation accuracy	±0.5% or ±0.01 mA

Table 982: Signal output X100: SO1

Description	Value
Rated voltage	250 V AC/DC
Continuous contact carry	5 A
Make and carry for 3.0 s	15 A
Make and carry for 0.5 s	30 A
Breaking capacity when the control-circuit time constant L/R<40 ms, at 48/110/220 V DC	1 A/0.25 A/0.15 A
Minimum contact load	100 mA at 24 V AC/DC

Table 983: Signal outputs and IRF output

Description	Value
Rated voltage	250 V AC/DC
Continuous contact carry	5 A
Make and carry for 3.0 s	10 A
Make and carry 0.5 s	15 A
Breaking capacity when the control-circuit time constant L/R<40 ms, at 48/110/220 V DC	1 A/0.25 A/0.15 A
Minimum contact load	10 mA at 5 V AC/DC

Table 984: Double-pole power output relays with TCM function

Description	Value
Rated voltage	250 V AC/DC
Continuous contact carry	8 A
Make and carry for 3.0 s	15 A
Make and carry for 0.5 s	30 A
Breaking capacity when the control-circuit time constant L/R<40 ms, at 48/110/220 V DC (two contacts connected in series)	5 A/3 A/1 A
Minimum contact load	100 mA at 24 V AC/DC
Trip-circuit monitoring (TCM):	

Table continues on next page

Description	Value
• Control voltage range	20...250 V AC/DC
• Current drain through the supervision circuit	~1.5 mA
• Minimum voltage over the TCM contact	20 V AC/DC (15...20 V)

Table 985: Single-pole power output relays

Description	Value
Rated voltage	250 V AC/DC
Continuous contact carry	8 A
Make and carry for 3.0 s	15 A
Make and carry for 0.5 s	30 A
Breaking capacity when the control-circuit time constant L/R<40 ms, at 48/110/220 V DC	5 A/3 A/1 A
Minimum contact load	100 mA at 24 V AC/DC

Table 986: High-speed output HSO with BIO0007

Description	Value
Rated voltage	250 V AC/DC
Continuous contact carry	6 A
Make and carry for 3.0 s	15 A
Make and carry for 0.5 s	30 A
Breaking capacity when the control-circuit time constant L/R <40 ms, at 48/110/220 V DC	5 A/3 A/1 A
Trip time	<1 ms
Reset	<20 ms, resistive load

Table 987: Ethernet interfaces

Ethernet interface	Protocol	Cable	Data transfer rate
Front	TCP/IP protocol	Standard Ethernet CAT 5 cable with RJ-45 connector	10 MBits/s
Rear	TCP/IP protocol	Shielded twisted pair CAT 5e cable with RJ-45 connector or fiber optic cable with LC connector	100 MBits/s

Table 988: Serial rear interface

Type	Counter connector
Serial port (X5)	10-pin counter connector Weidmüller BL 3.5/10/180F AU OR BEDR or 9-pin counter connector Weidmüller BL 3.5/9/180F AU OR BEDR[1)]
Serial port (X16)	9-pin D-sub connector DE-9
Serial port (X12)	Optical ST-connector

1) Depending on the optional communication module

Table 989: Fiber optic communication link

Connector	Fiber type	Wave length	Typical max. length[1)]	Permitted path attenuation[2)]
LC	MM 62.5/125 or 50/125 μm glass fiber core	1300 nm	2 km	<8 dB
ST	MM 62.5/125 or 50/125 μm glass fiber core	820...900 nm	1 km	<11 dB

1) Maximum length depends on the cable attenuation and quality, the amount of splices and connectors in the path.
2) Maximum allowed attenuation caused by connectors and cable together

Table 990: Fiber optic protection communication link available in RED615

Connector	Fibre type	Wave length	Typical max. length[1)]	Permitted path attenuation[2)]
LC	MM 62.5/125 or 50/125 μm	1300 nm	2 km	<8 dB
LC	SM 9/125 μm[3)]	1300 nm	20 km	<8 dB

1) Maximum length depends on the cable attenuation and quality, the amount of splices and connectors in the path.
2) Maximum allowed attenuation caused by connectors and cable altogether
3) Use single-mode fiber with recommended minimum length of 3 m to connect RED615 to the pilot wire modem RPW600.

Table 991: IRIG-B

Description	Value
IRIG time code format	B004, B005[1)]
Isolation	500V 1 min
Modulation	Unmodulated
Table continues on next page	

Description	Value
Logic level	5 V TTL
Current consumption	<4 mA
Power consumption	<20 mW

1) According to the 200-04 IRIG standard

Table 992: Lens sensor and optical fiber for arc protection

Description	Value
Fiber optic cable including lens	1.5 m, 3.0 m or 5.0 m
Normal service temperature range of the lens	-40...+100°C
Maximum service temperature range of the lens, max 1 h	+140°C
Minimum permissible bending radius of the connection fiber	3.94 inches (100 mm)

Table 993: Degree of protection of flush-mounted protection relay

Description	Value
Front side	IP 54
Rear side, connection terminals	IP 10
Left and right side	IP 20
Top and bottom	IP 20

Table 994: Environmental conditions

Description	Value
Operating temperature range	-25...+55ºC (continuous)
Short-time service temperature range	• REF615, REG615, REM615 and RET615: -40...+85ºC (<16 h)[1)2)] • RED615: -40...+70ºC (<16 h)[1)2)]
Relative humidity	<93%, non-condensing
Atmospheric pressure	12.47...15.37 psi (86...106 kPa)
Altitude	Up to 6561.66 feet (2000 m)
Transport and storage temperature range	-40...+85ºC

1) Degradation in MTBF and HMI performance outside the temperature range of -25...+55 ºC
2) For relays with an LC communication interface the maximum operating temperature is +70 ºC

Section 15 Protection relay and functionality tests

Table 995: Electromagnetic compatibility tests

Description	Type test value	Reference
1 MHz/100 kHz burst disturbance test • Common mode • Differential mode	 2.5 kV 2.5 kV	IEC 61000-4-18 IEC 60255-26, class III IEEE C37.90.1-2002
3 MHz, 10 MHz and 30 MHz burst disturbance test • Common mode	 2.5 kV	IEC 61000-4-18 IEC 60255-26, class III
Electrostatic discharge test • Contact discharge • Air discharge	 8 kV 15 kV	IEC 61000-4-2 IEC 60255-26 IEEE C37.90.3-2001
Radio frequency interference test	10 V (rms) f = 150 kHz...80 MHz	IEC 61000-4-6 IEC 60255-26, class III
	10 V/m (rms) f = 80...2700 MHz	IEC 61000-4-3 IEC 60255-26, class III
	10 V/m f = 900 MHz	ENV 50204 IEC 60255-26, class III
	20 V/m (rms) f = 80...1000 MHz	IEEE C37.90.2-2004
Fast transient disturbance test • All ports	 4 kV	IEC 61000-4-4 IEC 60255-26 IEEE C37.90.1-2002
Surge immunity test • Communication • Other ports	 1 kV, line-to-ground 4 kV, line-to-ground, 2 kV, line-to-line	IEC 61000-4-5 IEC 60255-26

Table continues on next page

Description	Type test value	Reference
Power frequency (50 Hz) magnetic field immunity test • Continuous • 1...3 s	 300 A/m 1000 A/m	IEC 61000-4-8
Pulse magnetic field immunity test	1000 A/m 6.4/16 μs	IEC 61000-4-9
Damped oscillatory magnetic field immunity test • 2 s • 1 MHz	 100 A/m 400 transients/s	IEC 61000-4-10
Voltage dips and short interruptions	30%/10 ms 60%/100 ms 60%/1000 ms >95%/5000 ms	IEC 61000-4-11
Power frequency immunity test • Common mode • Differential mode	Binary inputs only 300 V rms 150 V rms	IEC 61000-4-16 IEC 60255-26, class A
Conducted common mode disturbances	15 Hz...150 kHz Test level 3 (10/1/10 V rms)	IEC 61000-4-16
Emission tests • Conducted 0.15...0.50 MHz 0.5...30 MHz • Radiated 30...230 MHz 230...1000 MHz 1…3 GHz 3…6 GHz	 <79 dB (μV) quasi peak <66 dB (μV) average <73 dB (μV) quasi peak <60 dB (μV) average <40 dB (μV/m) quasi peak, measured at 10 m distance <47 dB (μV/m) quasi peak, measured at 10 m distance <76 dB (μV/m) peak <56 dB (μV/m) average, measured at 3 m distance <80 dB (μV/m) peak <60 dB (μV/m) average, measured at 3 m distance	EN 55011, class A IEC 60255-26 CISPR 11 CISPR 12

Table 996: Insulation tests

Description	Type test value	Reference
Dielectric tests	2 kV, 50 Hz, 1 min 500 V, 50 Hz, 1 min, communication	IEC 60255-27 IEEE C37.90-2005
Impulse voltage test	5 kV, 1.2/50 μs, 0.5 J 1 kV, 1.2/50 μs, 0.5 J, communication	IEC 60255-27 IEEE C37.90-2005
Insulation resistance measurements	>100 MΩ, 500 V DC	IEC 60255-27
Protective bonding resistance	<0.1 Ω, 4 A, 60 s	IEC 60255-27

Table 997: Mechanical tests

Description	Requirement	Reference
Vibration tests (sinusoidal)	Class 2	IEC 60068-2-6 (test Fc) IEC 60255-21-1
Shock and bump test	Class 2	IEC 60068-2-27 (test Ea shock) IEC 60068-2-29 (test Eb bump) IEC 60255-21-2
Seismic test	Class 2	IEC 60255-21-3
Mechanical durability	• 200 withdrawals and insertions of the plug-in unit • 200 adjustments of protection relay's setting controls	IEEE C37.90-2005

Table 998: Environmental tests

Description	Type test value	Reference
Dry heat test	• 96 h at +55ºC • 16 h at +85ºC[1)2)]	IEC 60068-2-2 IEEE C37.90-2005
Dry cold test	• 96 h at -25ºC • 16 h at -40ºC	IEC 60068-2-1 IEEE C37.90-2005
Damp heat test	• 6 cycles (12 h + 12 h) at +25°C…+55°C, humidity >93%	IEC 60068-2-30
	• +55°C, Rh = 95%, 96h	IEEE C37.90-2005
Change of temperature test	• 5 cycles (3 h + 3 h) at -25°C...+55°C	IEC60068-2-14
Storage test	• 96 h at -40ºC • 96 h at +85ºC	IEC 60068-2-1 IEC 60068-2-2 IEEE C37.90-2005

1) For relays with an LC communication interface the maximum operating temperature is +70ºC
2) For RED615 +70ºC, 16 h

Table 999: Product safety

Description	Reference
LV directive	2006/95/EC
Standard	EN 60255-27 (2013) EN 60255-1 (2009)

Table 1000: EMC compliance

Description	Reference
EMC directive	2004/108/EC
Standard	EN 60255-26 (2013)

Section 16 Applicable standards and regulations

EN 60255-1

EN 60255-26

EN 60255-27

EMC council directive 2004/108/EC

EU directive 2002/96/EC/175

IEC 60255

Low-voltage directive 2006/95/EC

IEC 61850

IEEE C37.90-2005

Section 17 Glossary

615 series	Series of numerical protection and control relays for protection and supervision applications of utility substations, and industrial switchgear and equipment
AC	Alternating current
ACT	1. Application Configuration tool in PCM600 2. Trip status in IEC 61850
ANSI	American National Standards Institute
AVR	Automatic voltage regulator
CAT 5	A twisted pair cable type designed for high signal integrity
CAT 5e	An enhanced version of CAT 5 that adds specifications for far end crosstalk
CB	Circuit breaker
CBB	Cycle building block
COMTRADE	Common format for transient data exchange for power systems. Defined by the IEEE Standard.
CPU	Central processing unit
CT	Current transformer
CTS	Clear to send
DAN	Doubly attached node
DC	1. Direct current 2. Disconnector 3. Double command
DCD	Data carrier detect
DFR	Digital fault recorder
DFT	Discrete Fourier transform
DG	Distributed generation
DHCP	Dynamic Host Configuration Protocol

DNP3	A distributed network protocol originally developed by Westronic. The DNP3 Users Group has the ownership of the protocol and assumes responsibility for its evolution.
DSR	Data set ready
DT	Definite time
DTR	Data terminal ready
EEPROM	Electrically erasable programmable read-only memory
EF	Ground fault
EIA-232	Serial communication standard according to Electronics Industries Association
EIA-485	Serial communication standard according to Electronics Industries Association
EMC	Electromagnetic compatibility
Ethernet	A standard for connecting a family of frame-based computer networking technologies into a LAN
FLC	Full load current
FPGA	Field-programmable gate array
FTP	File transfer protocol
FTPS	FTP Secure
GFC	General fault criteria
GOOSE	Generic Object-Oriented Substation Event
GPS	Global Positioning System
HMI	Human-machine interface
HSO	High-speed output
HSR	High-availability seamless redundancy
HTTPS	Hypertext Transfer Protocol Secure
HV	High voltage
HW	Hardware
IDMT	Inverse definite minimum time
IEC 61850	International standard for substation communication and modeling
IEC 61850-9-2 LE	Lite Edition of IEC 61850-9-2 offering process bus interface

IED	Intelligent electronic device
IEEE 1588 v2	Standard for a Precision Clock Synchronization Protocol for networked measurement and control systems
IP	Internet protocol
IP address	A set of four numbers between 0 and 255, separated by periods. Each server connected to the Internet is assigned a unique IP address that specifies the location for the TCP/IP protocol.
IRF	1. Internal fault 2. Internal relay fault
IRIG-B	Inter-Range Instrumentation Group's time code format B
LAN	Local area network
LC	Connector type for glass fiber cable
LCD	Liquid crystal display
LED	Light-emitting diode
LHMI	Local human-machine interface
LOG	Loss of grid
LOM	Loss of mains
LV	Low voltage
MAC	Media access control
MCB	Miniature circuit breaker
MM	1. Multimode 2. Multimode optical fiber
MMS	1. Manufacturing message specification 2. Metering management system
MV	Medium voltage
Modbus	A serial communication protocol developed by the Modicon company in 1979. Originally used for communication in PLCs and RTU devices.
NC	Normally closed
OSB	Out of step blocking
P2P	peer-to-peer
PC	1. Personal computer 2. Polycarbonate

PCM600	Protection and Control IED Manager
PGU	Power generating unit
PLC	Programmable logic controller
PPS	Pulse per second
PRP	Parallel redundancy protocol
Peak-to-peak	1. The amplitude of a waveform between its maximum positive value and its maximum negative value 2. A measurement principle where the measurement quantity is made by calculating the average from the positive and negative peak values without including the DC component. The peak-to-peak mode allows considerable CT saturation without impairing the performance of the operation.
Peak-to-peak with peak backup	A measurement principle similar to the peak-to-peak mode but with the function picking up on two conditions: the peak-to-peak value is above the set pickup current or the peak value is above two times the set pickup value
RAM	Random access memory
RCA	Also known as MTA or base angle. Characteristic angle.
RED615	Line differential protection and control relay
REF615	Feeder protection and control relay
REM615	Motor protection and control relay
RET615	Transformer protection and control relay
RJ-45	Galvanic connector type
RMS	Root-mean-square (value)
ROM	Read-only memory
RSTP	Rapid spanning tree protocol
RTC	Real-time clock
RTD	Resistance temperature detector
RTS	Ready to send
Rx	Receive/Received
SAN	Single attached node
SBO	Select-before-operate
SCADA	Supervision, control and data acquisition

SCL	XML-based substation description configuration language defined by IEC 61850
SLD	Single-line diagram
SM	1. Single mode 2. Single-mode optical fiber
SMT	Signal Matrix tool in PCM600
SMV	Sampled measured values
SNTP	Simple Network Time Protocol
SOTF	Switch onto fault
ST	Connector type for glass fiber cable
SW	Software
Single-line diagram	Simplified notation for representing a three-phase power system. Instead of representing each of three phases with a separate line or terminal, only one conductor is represented.
TCM	Trip-circuit monitoring
TCP	Transmission Control Protocol
TCP/IP	Transmission Control Protocol/Internet Protocol
TCS	Trip-circuit supervision
TLV	Type length value
Tx	Transmit/Transmitted
UDP	User datagram protocol
UTC	Coordinated universal time
VT	Voltage transformer
WAN	Wide area network
WHMI	Web human-machine interface

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