RELION® PROTECTION AND CONTROL

REX640

Application Manual

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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 2014/30/EU) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2014/35/EU). This conformity is the result of tests conducted by the third party testing laboratory Intertek in accordance with the product standard 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.

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Section 1 Introduction

1.1 This manual

The application manual presents a number of protection and control applications which can be realized using the relay. The approach is based on selected use cases which are discussed in detail, including relay configuration and recommended parameter setting values. The target of the manual is to present examples which serve as a guideline when considering engineering the relay for an actual installation at hand. Each section in the manual focuses strictly on the needs of a certain application and does not cover the complete functionality of the relay.

1.2 Intended audience

This manual addresses the protection and control engineer responsible for planning, pre-engineering and engineering.

The protection and control engineer must be experienced in electrical power engineering and have knowledge of related technology, such as protection schemes and principles.

1.3 Product documentation

1.3.1 Product documentation set

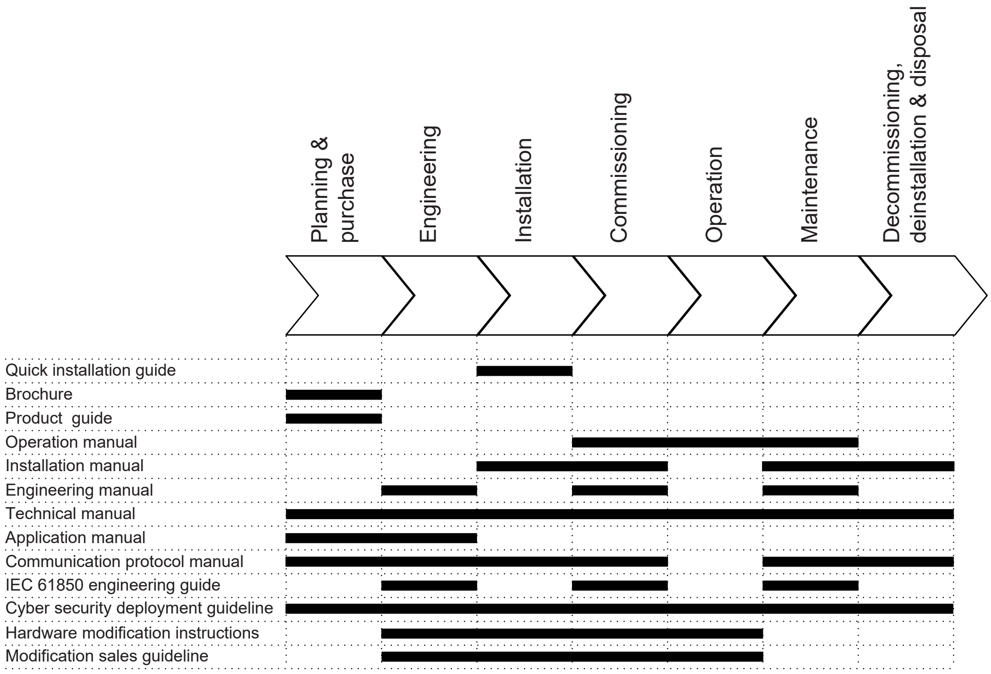

Figure 1: The intended use of documents during the product life cycle

1.3.2 Document revision history

Document revision/date	Product connectivity level	History
A/2019-03-06	PCL1	First release
B/2020-02-13	PCL2	Content updated to correspond to the product connectivity level
C/2020-12-09	PCL3	Content updated to correspond to the product connectivity level

1.3.3 Related documentation

Download the latest documents from the ABB Web site www.abb.com/mediumvoltage.

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.
- Menu paths are presented in bold.
  Select **Main menu/Settings**.
- 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 "On" and "Off".
- Input/output messages and monitored data names are shown in Courier font.
  When the function starts, the `START` output is set to TRUE.

- Values of quantities are expressed with a number and an SI unit. The corresponding imperial units may be given in parentheses.
- This document assumes that the parameter setting visibility is "Advanced".
- In the application examples, relay inputs and outputs are marked with generic labels that are not specific to any product variant.

1.4.3 Functions, codes and symbols

Table 1: Functions included in the relay

Function	IEC 61850	IEC 60617	ANSI
Protection			
Distance protection	DSTPDIS	Z<	21P,21N
Local acceleration logic	DSTPLAL	LAL	21LAL
Scheme communication logic	DSOCPSCH	CL	85 21SCHLGC
Current reversal and weak-end infeed logic	CRWPSCH	CLCRW	85 21CREV,WEI
Communication logic for residual overcurrent	RESCPSCH	CLN	85 67G/N SCHLGC
Current reversal and weak-end infeed logic for residual overcurrent	RCRWPSCH	CLCRWN	85 67G/N CREV,WEI
Line differential protection with inzone power transformer	LNPLDF	3Id/I>	87L
Binary signal transfer	BSTGAPC	BST	BST
Switch-onto-fault protection	CVPSOF	CVPSOF	SOTF
Three-phase non-directional overcurrent protection, low stage	PHLPTOC	3I>	51P-1
Three-phase non-directional overcurrent protection, high stage	PHHPTOC	3I>>	51P-2
Three-phase non-directional overcurrent protection, instantaneous stage	PHIPTOC	3I>>>	50P
Three-phase directional overcurrent protection, low stage	DPHLPDOC	3I> ->	67P/51P-1
Three-phase directional overcurrent protection, high stage	DPHHPDOC	3I>> ->	67P/51P-2
Non-directional earth-fault protection, low stage	EFLPTOC	Io>	51G/51N-1
Table continues on next page			

Function	IEC 61850	IEC 60617	ANSI
Non-directional earth-fault protection, high stage	EFHPTOC	Io>>	51G/51N-2
Non-directional earth-fault protection, instantaneous stage	EFIPTOC	Io>>>	50G/50N
Directional earth-fault protection, low stage	DEFLPDEF	Io> ->	67G/N-1 51G/N-1
Directional earth-fault protection, high stage	DEFHPDEF	Io>> ->	67G/N-1 51G/N-2
Three-phase power directional element	DPSRDIR	I1 ->	67P-TC
Neutral power directional element	DNZSRDIR	I2 ->, Io ->	67N-TC
Admittance-based earth-fault protection	EFPADM	Yo> ->	21NY
Multifrequency admittance-based earth-fault protection	MFADPSDE	Io> -> Y	67NYH
Wattmetric-based earth-fault protection	WPWDE	Po> ->	32N
Transient/intermittent earth-fault protection	INTRPTEF	Io> -> IEF	67NTEF/NIEF
Harmonics-based earth-fault protection	HAEFPTOC	Io>HA	51NH
Negative-sequence overcurrent protection	NSPTOC	I2>M	46M
Phase discontinuity protection	PDNSPTOC	I2/I1>	46PD
Residual overvoltage protection	ROVPTOV	Uo>	59G/59N
Three-phase undervoltage protection	PHPTUV	3U<	27
Three-phase overvoltage variation protection	PHVPTOV	3Urms>	59.S1
Three-phase overvoltage protection	PHPTOV	3U>	59
Positive-sequence overvoltage protection	PSPTOV	U1>	59PS
Positive-sequence undervoltage protection	PSPTUV	U1<	27PS
Negative-sequence overvoltage protection	NSPTOV	U2>	59NS
Frequency protection	FRPFRQ	f>/f<,df/dt	81
Three-phase voltage-dependent overcurrent protection	PHPVOC	3I(U)>	51V

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Overexcitation protection	OEPVPH	U/f>	24
Three-phase thermal protection for feeders, cables and distribution transformers	T1PTTR	3Ith>F	49F
Three-phase thermal overload protection, two time constants	T2PTTR	3Ith>T/G/C	49T/G/C
Three-phase overload protection for shunt capacitor banks	COLPTOC	3I> 3I<	51,37,86C
Current unbalance protection for shunt capacitor banks	CUBPTOC	dI>C	60N
Three-phase current unbalance protection for shunt capacitor banks	HCUBPTOC	3dI>C	60P
Shunt capacitor bank switching resonance protection, current based	SRCPTOC	TD>	55ITHD
Compensated neutral unbalance voltage protection	CNUPTOV	CNU>	59NU
Directional negative-sequence overcurrent protection	DNSPDOC	I2> ->	67Q
Low-voltage ride-through protection	LVRTPTUV	UU	27RT
Voltage vector shift protection	VVSPPAM	VS	78VS
Directional reactive power undervoltage protection	DQPTUV	Q> -> ,3U<	32Q,27
Reverse power/ directional overpower protection	DOPPDPR	P>/Q>	32R/32O
Underpower protection	DUPPDPR	P<	32U
Three-phase underimpedance protection	UZPDIS	ZZ	21G
Three-phase underexcitation protection	UEXPDIS	X<	40
Third harmonic-based stator earth-fault protection	H3EFPSEF	dUo>/Uo3H	64TN
Rotor earth-fault protection (injection method)	MREFPTOC	Io>R	64R

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
High-impedance or flux-balance based differential protection	MHZPDIF	3dIHi>M	87HIM
Out-of-step protection with double blinders	OOSRPSB	OOS	78PS
Negative-sequence overcurrent protection for machines	MNSPTOC	I2>M	46M
Loss of phase, undercurrent	PHPTUC	3I<	37
Loss of load supervision	LOFLPTUC	3I<	37
Motor load jam protection	JAMPTOC	Ist>	50TDJAM
Motor start-up supervision	STTPMSU	Is2t n<	49,66,48,50TDLR
Motor start counter	MSCPMRI	n<	66
Phase reversal protection	PREVPTOC	I2>>	46R
Thermal overload protection for motors	MPTTR	3Ith>M	49M
Stabilized and instantaneous differential protection for machines	MPDIF	3dI>M/G	87M/87G
Underpower factor protection	MPUPF	PF<	55U
Stabilized and instantaneous differential protection for two- or three-winding transformers	TR3PTDF	3dI>3W	87T3
Stabilized and instantaneous differential protection for two-winding transformers	TR2PTDF	3dI>T	87T
Numerical stabilized low-impedance restricted earth-fault protection	LREFPNDF	dIoLo>	87NLI
High-impedance based restricted earth-fault protection	HREFPDIF	dIoHi>	87NHI
High-impedance differential protection for phase A	HIAPDIF	dHi_A>	87_A
High-impedance differential protection for phase B	HIBPDIF	dHi_B>	87_B
High-impedance differential protection for phase C	HICPDIF	dHi_C>	87_C

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Circuit breaker failure protection	CCBRBRF	3I>/Io>BF	50BF
Three-phase inrush detector	INRPHAR	3I2f>	68HB
Master trip	TRPPTRC	Master Trip	94/86
Arc protection	ARCSARC	ARC	AFD
High-impedance fault detection	PHIZ	HIF	HIZ
Fault locator	SCEFRFLO	FLOC	FLOC
Load-shedding and restoration	LSHDPFRQ	UFLS/R	81LSH
Multipurpose protection	MAPGAPC	MAP	MAP
Accidental energization protection	GAEPVOC	U<,I>	27/50
Control			
Circuit-breaker control	CBXCBR	I <-> O CB	52
Three-state disconnector control	P3SXSWI	I<->O P3S	29DS/GS
Disconnector control	DCXSWI	I <-> O DCC	29DS
Earthing switch control	ESXSWI	I <-> O ESC	29GS
Three-state disconnector position indication	P3SSXSWI	I<->O P3SS	29DS/GS
Disconnector position indication	DCSXSWI	I <-> O DC	29DS
Earthing switch position indication	ESSXSWI	I <-> O ES	29GS
Emergency start-up	ESMGAPC	ESTART	EST,62
Autoreclosing	DARREC	O -> I	79
Autosynchronizer for generator breaker	ASGCSYN	AUTOSYNCG	25AUTOSYNCG
Autosynchronizer for network breaker	ASNSCSYN	AUTOSYNCBT/T	25AUTOSYNCBT/T
Autosynchronizer co-ordinator	ASCGAPC	AUTOSYNC	25AUTOSYNC
Synchronism and energizing check	SECRSYN	SYNC	25
Tap changer control with voltage regulator	OL5ATCC	COLTC	90V
Transformer data combiner	OLGAPC	OLGAPC	OLGAPC
Petersen coil controller	PASANCR	ANCR	90
Condition monitoring and supervision			
Circuit-breaker condition monitoring	SSCBR	CBCM	52CM

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Hot-spot and insulation ageing rate monitoring for transformers	HSARSPTR	3Ihp>T	26/49HS
Trip circuit supervision	TCSSCBR	TCS	TCM
Current circuit supervision	CCSPVC	MCS 3I	CCM
Current circuit supervision for transformers	CTSRCTF	MCS 3I,I2	CCM 3I,I2
Current transformer supervision for high-impedance protection scheme for phase A	HZCCASPVC	MCS I_A	CCM_A
Current transformer supervision for high-impedance protection scheme for phase B	HZCCBSPVC	MCS I_B	CCM_B
Current transformer supervision for high-impedance protection scheme for phase C	HZCCCSPVC	MCS I_C	CCM_C
Fuse failure supervision	SEQSPVC	FUSEF	VCM, 60
Protection communication supervision	PCSITPC	PCS	PCS
Runtime counter for machines and devices	MDSOPT	OPTS	OPTM
Three-phase remanent undervoltage supervision	MSVPR	3U<R	27R
Measurement			
Three-phase current measurement	CMMXU	3I	IA, IB, IC
Sequence current measurement	CSMSQI	I1, I2, I0	I1, I2, I0
Residual current measurement	RESCMMXU	Io	IG
Three-phase voltage measurement	VMMXU	3U	VA, VB, VC
Single-phase voltage measurement	VAMMXU	U_A	V_A
Residual voltage measurement	RESVMMXU	Uo	VG/VN
Sequence voltage measurement	VSMSQI	U1, U2, U0	V1, V2, V0
Three-phase power and energy measurement	PEMMXU	P, E	P, E
Load profile recorder	LDPRLRC	LOADPROF	LOADPROF

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Frequency measurement	FMMXU	f	f
Tap changer position indication	TPOSYLTC	TPOSM	84T
Power quality			
Current total demand, harmonic distortion, DC component (TDD, THD, DC) and individual harmonics	CHMHAI	PQM3IH	PQM ITHD,IDC
Voltage total harmonic distortion, DC component (THD, DC) and individual harmonics	VHMHAI	PQM3VH	PQM VTHD,VDC
Voltage variation	PHQVVR	PQMU	PQMV SWE,SAG,INT
Voltage unbalance	VSQVUB	PQUUB	PQMV UB
Traditional LED indication			
LED indication control	LEDPTRC	LEDPTRC	LEDPTRC
Individual virtual LED control	LED	LED	LED
Logging functions			
Disturbance recorder (common functionality)	RDRE	DR	DFR
Disturbance recorder, analog channels 1...12	A1RADR	A1RADR	A1RADR
Disturbance recorder, analog channels 13...24	A2RADR	A2RADR	A2RADR
Disturbance recorder, binary channels 1...32	B1RBDR	B1RBDR	B1RBDR
Disturbance recorder, binary channels 33...64	B2RBDR	B2RBDR	B2RBDR
Fault recorder	FLTRFRC	FAULTREC	FR
Other functionality			
Parameter setting groups	PROTECTION	PROTECTION	PROTECTION
Time master supervision	GNRLLTMS	GNRLLTMS	GNRLLTMS
Serial port supervision	SERLCCH	SERLCCH	SERLCCH
IEC 61850-1 MMS	MMSLPRT	MMSLPRT	MMSLPRT
IEC 61850-1 GOOSE	GSELPRT	GSELPRT	GSELPRT
IEC 60870-5-103 protocol	I3CLPRT	I3CLPRT	I3CLPRT
IEC 60870-5-104 protocol	I5CLPRT	I5CLPRT	I5CLPRT
DNP3 protocol	DNPLPRT	DNPLPRT	DNPLPRT

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Modbus protocol	MBSLPRT	MBSLPRT	MBSLPRT
OR gate with two inputs	OR	OR	OR
OR gate with six inputs	OR6	OR6	OR6
OR gate with twenty inputs	OR20	OR20	OR20
AND gate with two inputs	AND	AND	AND
AND gate with six inputs	AND6	AND6	AND6
AND gate with twenty inputs	AND20	AND20	AND20
XOR gate with two inputs	XOR	XOR	XOR
NOT gate	NOT	NOT	NOT
Real maximum value selector	MAX3R	MAX3R	MAX3R
Real minimum value selector	MIN3R	MIN3R	MIN3R
Rising edge detector	R_TRIG	R_TRIG	R_TRIG
Falling edge detector	F_TRIG	F_TRIG	F_TRIG
Real switch selector	SWITCHR	SWITCHR	SWITCHR
Integer 32-bit switch selector	SWITCHI32	SWITCHI32	SWITCHI32
SR flip-flop, volatile	SR	SR	SR
RS flip-flop, volatile	RS	RS	RS
Minimum pulse timer, two channels	TPGAPC	TP	62TP
Minimum pulse timer second resolution, two channels	TPSGAPC	TPS	62TPS
Minimum pulse timer minutes resolution, two channels	TPMGAPC	TPM	62TPM
Pulse counter for energy measurement	PCGAPC	PCGAPC	PCGAPC
Pulse timer, eight channels	PTGAPC	PT	62PT
Time delay off, eight channels	TOFGAPC	TOF	62TOF
Time delay on, eight channels	TONGAPC	TON	62TON
Daily timer	DTMGAPC	DTM	DTM
Calendar function	CALGAPC	CAL	CAL
SR flip-flop, eight channels, nonvolatile	SRGAPC	SR	SR

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Boolean value event creation	MVGAPC	MV	MV
Integer value event creation	MVI4GAPC	MVI4	MVI4
Analog value event creation with scaling	SCA4GAPC	SCA4	SCA4
Generic control points	SPCGAPC	SPC	SPCG
Generic up-down counter	UDFCNT	UDCNT	UDCNT
Local/Remote control	CONTROL	CONTROL	CONTROL
External HMI wake-up	EIHMI	EIHMI	EIHMI
Real addition	ADDR	ADDR	ADDR
Real subtraction	SUBR	SUBR	SUBR
Real multiplication	MULR	MULR	MULR
Real division	DIVR	DIVR	DIVR
Real equal comparator	EQR	EQR	EQR
Real not equal comparator	NER	NER	NER
Real greater than or equal comparator	GER	GER	GER
Real less than or equal comparator	LER	LER	LER
Voltage switch	VMSWI	VSWI	VSWI
Current sum	CMSUM	CSUM	CSUM
Current switch	CMSWI	CMSWI	CMSWI
Phase current preprocessing	ILTCTR	ILTCTR	ILTCTR
Residual current preprocessing	RESTCTR	RESTCTR	RESTCTR
Phase and residual voltage preprocessing	UTVTR	UTVTR	UTVTR
SMV stream receiver (IEC 61850-9-2LE)	SMVRCV	SMVRCV	SMVRCV
SMV stream sender (IEC 61850-9-2LE)	SMVSENDER	SMVSENDER	SMVSENDER
Redundant Ethernet channel supervison	RCHLCCH	RCHLCCH	RCHLCCH
Ethernet channel supervision	SCHLCCH	SCHLCCH	SCHLCCH
HMI Ethernet channel supervision	HMILCCH	HMILCCH	HMILCCH
Received GOOSE binary information	GOOSERCV_BIN	GOOSERCV_BIN	GOOSERCV_BIN
Received GOOSE double binary information	GOOSERCV_DP	GOOSERCV_DP	GOOSERCV_DP

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Received GOOSE measured value information	GOOSERCV_MV	GOOSERCV_MV	GOOSERCV_MV
Received GOOSE 8-bit integer value information	GOOSERCV_INT8	GOOSERCV_INT8	GOOSERCV_INT8
Received GOOSE 32-bit integer value information	GOOSERCV_INT32	GOOSERCV_INT32	GOOSERCV_INT32
Received GOOSE interlocking information	GOOSERCV_INTL	GOOSERCV_INTL	GOOSERCV_INTL
Received GOOSE measured value (phasor) information	GOOSERCV_CMV	GOOSERCV_CMV	GOOSERCV_CMV
Received GOOSE enumerator value information	GOOSERCV_ENUM	GOOSERCV_ENUM	GOOSERCV_ENUM
Bad signal quality	QTY_BAD	QTY_BAD	QTY_BAD
Good signal quality	QTY_GOOD	QTY_GOOD	QTY_GOOD
Received GOOSE Test mode	QTY_GOOSE_TEST	QTY_GOOSE_TEST	QTY_GOOSE_TEST
GOOSE communication quality	QTY_GOOSE_COMM	QTY_GOOSE_COMM	QTY_GOOSE_COMM
GOOSE data health	T_HEALTH	T_HEALTH	T_HEALTH
Fault direction evaluation	T_DIR	T_DIR	T_DIR
Enumerator to boolean conversion	T_TCMD	T_TCMD	T_TCMD
32-bit integer to binary command conversion	T_TCMD_BIN	T_TCMD_BIN	T_TCMD_BIN
Binary command to 32-bit integer conversion	T_BIN_TCMD	T_BIN_TCMD	T_BIN_TCMD
Switching device status decoder - CLOSE position	T_POS_CL	T_POS_CL	T_POS_CL
Switching device status decoder - OPEN position	T_POS_OP	T_POS_OP	T_POS_OP
Switching device status decoder - OK status	T_POS_OK	T_POS_OK	T_POS_OK
Controllable gate, 8 Channels	GATEGAPC	GATEGAPC	GATEGAPC
Security application	GSAL	GSAL	GSAL
Hotline tag	HLTGAPC	HLTGAPC	HLTGAPC
16 settable 32-bit integer values	SETI32GAPC	SETI32GAPC	SETI32GAPC
16 settable real values	SETRGAPC	SETRGAPC	SETRGAPC

Table continues on next page

Function	IEC 61850	IEC 60617	ANSI
Boolean to integer 32-bit conversion	T_B16_TO_I32	T_B16_TO_I32	T_B16_TO_I32
Integer 32-bit to boolean conversion	T_I32_TO_B16	T_I32_TO_B16	T_I32_TO_B16
Integer 32-bit to real conversion	T_I32_TO_R	T_I32_TO_R	T_I32_TO_R
Real to integer 8-bit conversion	T_R_TO_I8	T_R_TO_I8	T_R_TO_I8
Real to integer 32-bit conversion	T_R_TO_I32	T_R_TO_I32	T_R_TO_I32
Constant FALSE	FALSE	FALSE	FALSE
Constant TRUE	TRUE	TRUE	TRUE

Section 2 REX640 overview

2.1 Overview

REX640 is a powerful all-in-one protection and control relay for use in advanced power distribution and generation applications with unmatched flexibility available during the complete life cycle of the device – from ordering of the device, through testing and commissioning to upgrading the functionality of the modular software and hardware as application requirements change.

The modular design of both hardware and software elements facilitates the coverage of any comprehensive protection application requirement that may arise during the complete life cycle of the relay and substation.

REX640 makes modification and upgrading easy and pushes the limits of what can be achieved with a single device.

2.1.1 PCM600 and relay connectivity package version

- Protection and Control IED Manager PCM600 Ver.2.10 Hotfix 3 or later
- REX640 Connectivity Package Ver.1.2.0 or later
    - Disturbance Handling
    - Event Viewer
    - Parameter Setting
    - Application Configuration
    - Signal Matrix
    - Graphical Display Editor
    - Switchgear HMI Configuration
    - HMI Event Filtering
    - Migrate Configuration
    - IED Users
    - IED Compare
    - IEC 61850 Configuration
    - Communication Management
    - Ethernet Configuration
    - IED Summary
    - Account Management
    - Update IED
    - License Update
    - Fault Records
    - Load Profiles
    - Differential Characteristics

- Lifecycle Handling
- Configuration Wizard
- AR Sequence Visualizer

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

2.2 Application packages

REX640 offers comprehensive base functionality. However, it is possible to further adapt the product to meet special installation needs by including any number of the available optional application packages into a single REX640 relay. For the selected application packages, the functionality can be extended by including the related add-on package. The REX640 connectivity package guides the engineer in optimizing the application configuration and its performance.

Table 2: Application packages

Description	ID
Feeder earth-fault protection extension package	APP1
Feeder fault locator package	APP2
Line distance protection package	APP3
Line differential protection package	APP4
Shunt capacitor protection package	APP5
Interconnection protection package	APP6
Machine protection package	APP7
Power transformer protection package	APP8
Busbar protection package	APP9
OLTC control package	APP10
Generator autosynchronizer package	APP11
Network autosynchronizer package	APP12
Petersen coil control package	APP13
Synchronous machine add-on	ADD1
3-winding transformer add-on	ADD2

Table 3: Base and optional functionality

IEC 61850	Pcs	Base	APP 1	APP 2	APP 3	APP 4	APP 5	APP 6	APP 7	APP 8	APP 9	APP 10	APP 11	APP 12	APP 13	ADD 1	ADD 2
Protection																	
DSTPDIS	1				•												
DSTPLAL	1				•												
DSOCPSCH	1				•												
CRWPSCH	1				•												
RESCPSCH	1				•												
RCRWPSCH	1				•												
LNPLDF	1					•											
BSTGAPC	2				•	•											
CVPSOF	1	•															
PHLPTOC	3	•															
PHHPTOC	3	•															
PHIPTOC	3	•															
DPHLPDOC	3	•															
DPHHPDOC	3	•															
EFLPTOC	3	•															
EFHPTOC	3	•															
EFIPTOC	3	•															
DEFLPDEF	4	•															
DEFHPDEF	4	•															
DPSRDIR	2							•				•					
DNZSRDIR	2		•														
EFPADM	3		•														
MFADPSDE	3		•														
WPWDE	3		•														
INTRPTEF	1		•														
HAEFPTOC	1		•														
NSPTOC	3	•															
PDNSPTOC	1	•															
ROVPTOV	4	•															
PHPTUV	4	•															
PHVPTOV	2							•									
PHPTOV	4	•															
PSPTOV	4	•															
PSPTUV	4	•															
NSPTOV	4	•															
FRPFRQ	12	•															
PHPVOC	2	•															
OEPVPH	2									•						•	
T1PTTR	1	•															
T2PTTR	1									•						•	
COLPTOC	1						•										
CUBPTOC	3						•										
HCUBPTOC	2						•										
SRCPTOC	1						•										
CNUPTOV	2						•										
DNSPDOC	2	•															
LVRTPTUV	3							•									
VVSPPAM	1							•									
DQPTUV	2							•									
DOPPDPR	3							•	•	•							

Table continues on next page

IEC 61850	Pcs	Base	APP 1	APP 2	APP 3	APP 4	APP 5	APP 6	APP 7	APP 8	APP 9	APP 10	APP 11	APP 12	APP 13	ADD 1	ADD 2
DUPPDPR	3									•						•	
UZPDIS	2									•						•	
UEXPDIS	2															•	
H3EFPSEF	1															•	
MREFPTOC	2															•	
MHZPDIF	1								•								
OOSRPSB	1				•											•	
MNSPTOC	2								•								
PHPTUC	3	•															
LOFLPTUC	1								•								
JAMPTOC	1								•								
STTPMSU	1								•								
MSCPMRI	1								•								
PREVPTOC	1								•								
MPTTR	1								•								
MPDIF	1								•								
MPUPF	2							•								•	
TR3PTDF	1																•
TR2PTDF	1									•							
LREFPNDF	2	•															
HREFPDIF	2	•															
HIAPDIF	3								•	•	•						
HIBPDIF	3								•	•	•						
HICPDIF	3								•	•	•						
CCBRBRF	3	•															
INRPHAR	2	•															
TRPPTRC	6	•															
ARCSARC	4	•															
PHIZ	1		•														
SCEFRFLO	1			•													
LSHDPFRQ	6	•															
MAPGAPC	24	•															
GAEPVOC	1															•	
Control																	
CBXCBR	3	•															
P3SXSWI	6	•															
DCXSWI	8	•															
ESXSWI	3	•															
P3SSXSWI	6	•															
DCSXSWI	8	•															
ESSXSWI	3	•															
ESMGAPC	1								•								
DARREC	2	•															
ASGCSYN	1												•				
ASNSCSYN	3													•			
ASCGAPC	1	•															
SECRSYN	3	•															
OL5ATCC	1											•					
OLGAPC	5											•					
PASANCR	1														•		
Condition monitoring and supervision																	
SSCBR	3	•															
Table continues on next page																	

IEC 61850	Pcs	Base	APP 1	APP 2	APP 3	APP 4	APP 5	APP 6	APP 7	APP 8	APP 9	APP 10	APP 11	APP 12	APP 13	ADD 1	ADD 2
HSARSPTR	1									•							
TCSSCBR	6	•															
CCSPVC	5	•															
CTSRCTF	1									•							
HZCCASPVC	3										•						
HZCCBSPVC	3										•						
HZCCCSPVC	3										•						
SEQSPVC	7	•															
PCSITPC	1				•	•											
MDSOPT	2	•															
MSVPR	2	•															
Measurement																	
CMMXU	8	•															
CSMSQI	8	•															
RESCMMXU	8	•															
VMMXU	8	•															
VAMMXU	4	•															
RESVMMXU	8	•															
VSMSQI	8	•															
PEMMXU	3	•															
LDPRLRC	1	•															
FMMXU	5	•															
TPOSYLTC	1									•		•					
Power quality																	
CHMHAI	1	•															
VHMHAI	1	•															
PHQVVR	2	•															
VSQVUB	2	•															
Traditional LED indication																	
LEDPTRC	1	•															
LED	33	•															
Logging functions																	
RDRE	1	•															
A1RADR	1	•															
A2RADR	1	•															
B1RBDR	1	•															
B2RBDR	1	•															
FLTRFRC	1	•															
Other functionality																	
PROTECTION	1	•															
GNRLLTMS	1	•															
SERLCCH	2	•															
MMSLPRT	1	•															
GSELPRT	1	•															
I3CLPRT	2	•															
I5CLPRT	5	•															
DNPLPRT	5	•															
MBSLPRT	5	•															
OR	400	•															
OR6	400	•															
OR20	20	•															
AND	400	•															

Table continues on next page

IEC 61850	Pcs	Base	APP 1	APP 2	APP 3	APP 4	APP 5	APP 6	APP 7	APP 8	APP 9	APP 10	APP 11	APP 12	APP 13	ADD 1	ADD 2
AND6	400	•															
AND20	20	•															
XOR	400	•															
NOT	400	•															
MAX3R	20	•															
MIN3R	20	•															
R_TRIG	10	•															
F_TRIG	10	•															
SWITCHR	30	•															
SWITCHI32	30	•															
SR	10	•															
RS	10	•															
TPGAPC	4	•															
TPSGAPC	2	•															
TPMGAPC	2	•															
PCGAPC	4	•															
PTGAPC	5	•															
TOFGAPC	5	•															
TONGAPC	5	•															
DTMGAPC	4	•															
CALGAPC	4	•															
SRGAPC	4	•															
MVGAPC	10	•															
MVI4GAPC	4	•															
SCA4GAPC	4	•															
SPCGAPC	5	•															
UDFCNT	12	•															
CONTROL	1	•															
EIHMI	1	•															
ADDR	10	•															
SUBR	10	•															
MULR	10	•															
DIVR	10	•															
EQR	10	•															
NER	10	•															
GER	10	•															
LER	10	•															
VMSWI	3	•															
CMSUM	1	•															
CMSWI	3	•															
ILTCTR	8	•															
RESTCTR	8	•															
UTVTR	8	•															
SMVRCV	4	•															
SMVSENDER	1	•															
RCHLCCH	1	•															
SCHLCCH	5	•															
HMILCCH	1	•															
GOOSERCV_BIN	200	•															
GOOSERCV_DP	100	•															
GOOSERCV_MV	50	•															
GOOSERCV_INT8	50	•															

Table continues on next page

IEC 61850	Pcs	Base	APP 1	APP 2	APP 3	APP 4	APP 5	APP 6	APP 7	APP 8	APP 9	APP 10	APP 11	APP 12	APP 13	ADD 1	ADD 2
GOOSERCV_INT32	50	•															
GOOSERCV_INTL	100	•															
GOOSERCV_CMV	9	•															
GOOSERCV_ENUM	100	•															
QTY_BAD	20	•															
QTY_GOOD	20	•															
QTY_GOOSE_COMM	100	•															
T_HEALTH	100	•															
T_DIR	50	•															
T_TCMD	100	•															
T_TCMD_BIN	100	•															
T_BIN_TCMD	100	•															
T_POS_CL	150	•															
T_POS_OP	150	•															
T_POS_OK	150	•															
GATEGAPC	1	•															
GSAL	1	•															
HLTGAPC	1	•															
SETI32GAPC	2	•															
SETRGAPC	2	•															
T_B16_TO_I32	10	•															
T_I32_TO_B16	10	•															
T_I32_TO_R	10	•															
T_R_TO_I8	10	•															
T_R_TO_I32	10	•															
FALSE	10	•															
TRUE	10	•															

2.3 Relay hardware

The relay includes a Ready LED on the power supply module that indicates the relay's status. In normal situations, the Ready LED has a steady green light. Any other situation that requires the operator’s attention is indicated with a flashing light.

The relay has mandatory and optional slots. A mandatory slot always contains a module but an optional slot may be empty, depending on the composition variant ordered.

Table 4: Module slots

Module	Slot A1	Slot A2	Slot B	Slot C	Slot D	Slot E	Slot F	Slot G
ARC1001	o							
COM1001		•						
COM1002		•						
COM1003		•						
COM1004		•						

Table continues on next page

Module	Slot A1	Slot A2	Slot B	Slot C	Slot D	Slot E	Slot F	Slot G
COM1005		•						
BIO1001			•	o	o			
BIO1002			•	o	o			
BIO1003						o		
BIO1004						o		
RTD1001				o	o			
AIM1001						o	•	
AIM1002						o	•	
SIM1901						o	•	
PSM1001								•
PSM1002								•
PSM1003								•
• = Mandatory to have one of the allocated modules in the slot o = Optional to have one of the allocated modules in the slot. The population (order) of the modules in the optional slots depends on the composition variant ordered.								

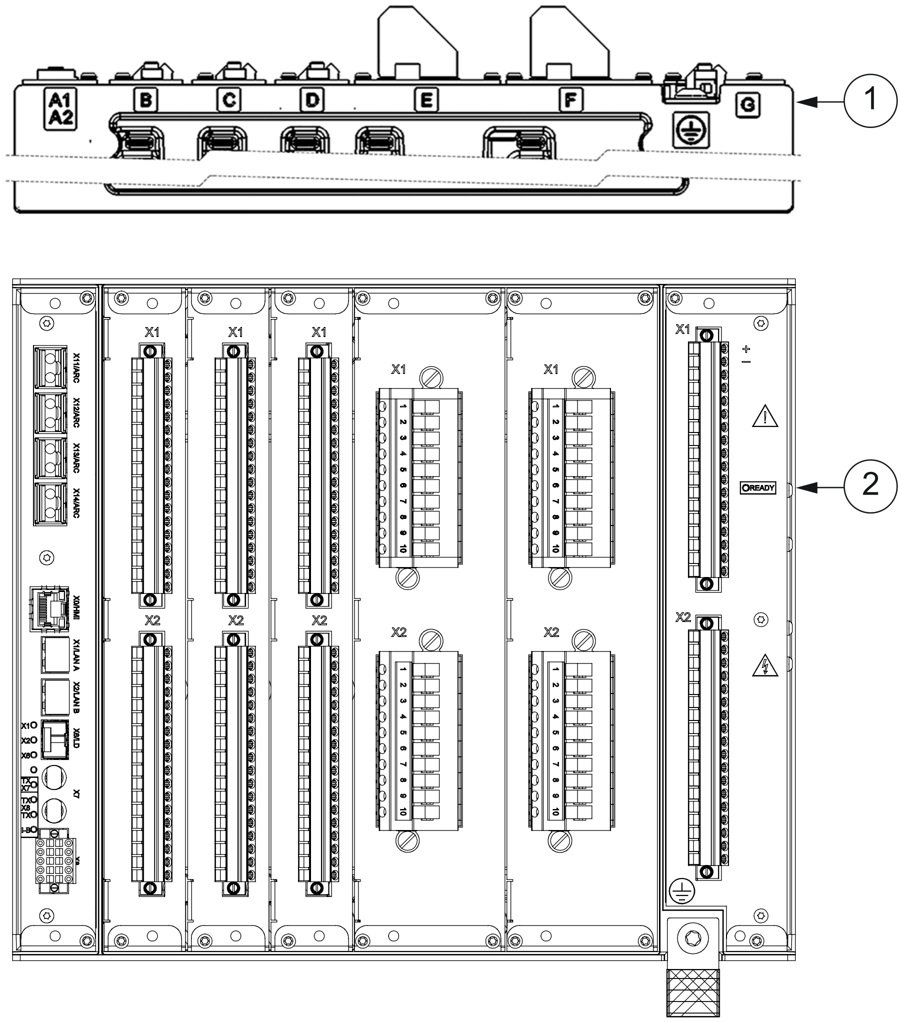

Figure 2: Hardware module slot overview of the REX640 relay

1 Slot markings in enclosure (top and bottom)

2 Ready LED

Table 5: Module description

Module	Description
ARC1001	4 × ARC sensor inputs (lense, loop or mixed)
COM1001	1 × RJ-45 (LHMI port) + 3 × RJ-45 + 1 × LD-SFP[1]
COM1002	1 × RJ-45 (LHMI port) + 2 × LC + 1 × RJ-45 + 1 × LD-SFP
COM1003	1 × RJ-45 (LHMI port) + 3 × LC + 1 × LD-SFP
COM1004	1 × RJ-45 (LHMI port) + 2 × RJ-45 + 1 × LD-SFP + 1 × RS-485/IRIG-B + 1 × FO UART
COM1005	1 × RJ-45 (LHMI port) + 2 × LC + 1 × LD-SFP + 1 × RS-485/IRIG-B + 1 × FO UART

Table continues on next page

Module	Description
BIO1001/ BIO1003	14 × BI + 8 × SO
BIO1002/ BIO1004	6 × SPO + 2 × SPO (TCS) + 9 × BI
RTD1001	10 × RTD channels + 2 × mA channels (input/output)
AIM1001	4 × CT + 1 × CT (sensitive, for residual current only) + 5 × VT
AIM1002	6 × CT + 4 × VT
SIM1901	3 × combi sensor inputs (RJ-45) + 1 × CT (sensitive, for residual current only) + 1 × VT
PSM1001	24...60 VDC, 3 × PO (TCS) + 2 × PO + 3 × SO + 2 × SSO
PSM1002	48...250 VDC / 100...240 VAC, 3 × PO (TCS) + 2 × PO + 3 × SO + 2 × SSO
PSM1003	110/125 VDC (77...150 VDC), 3 × PO (TCS) + 2 × PO + 3 × SO + 2 × SSO
PO = Power Output SO = Signal Output SPO = Static Power Output SSO = Static Signal Output	

1) Line distance/line differential protection communication + binary signal transfer, optical multimode or single-mode LC small form-factor pluggable transceiver (SFP)

The relay has a nonvolatile memory which does not need any periodical maintenance. The nonvolatile memory stores all events, recordings and logs to a memory which retains data if the relay loses its auxiliary supply.

2.4 Local HMI

The LHMI is used for setting, monitoring and controlling the protection relay and the related process. It comprises a 7-inch color screen with capacitive touch sensing and a Home button at the bottom of the LHMI.

The LHMI must be paired with the protection relay to enable all the functionalities in it. See the operation manual for the pairing procedure.

The LHMI is an accessory for the relay which is fully operational even without the LHMI.

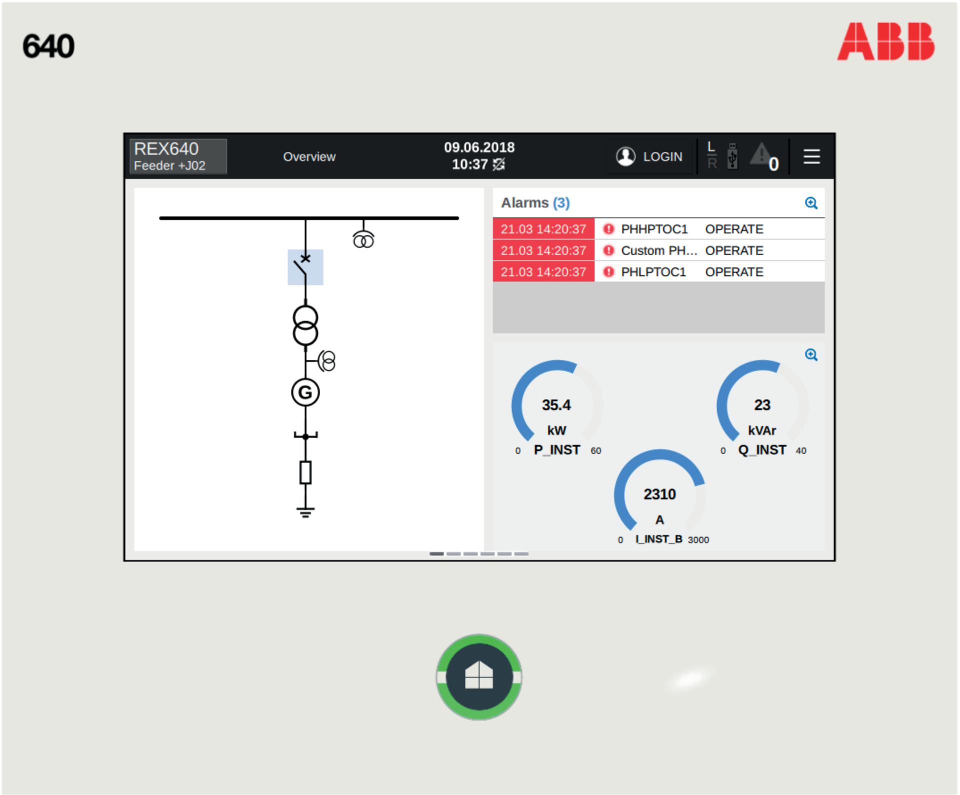

Figure 3: Example of a local HMI page

The LHMI presents pages in two categories.

- Operator pages are typically required as a part of an operator's normal activities, such as a single-line diagram, controls, measurements, events or alarms
- Engineer pages are specifically designed pages supporting relay parametrization, troubleshooting, testing and commissioning activities

The Operator pages can be scrolled either by pressing the Home button or by swiping the actual pages. The Engineer pages are accessible by tapping the menu button in the menu bar on the top of the LHMI display.

The Home button indicates the relay's status at a glance. In normal situations, the Home button shows a steady green light. Any other situation that requires the operator's attention is indicated with a flashing light, a red light or a combination of these.

Table 6: Power supply module Ready LED and local HMI Home button LED

State	Power supply module Ready LED	LHMI Home button	Alarm acknowledged
Relay under normal operation and LHMI connected	Steady green	Steady green	N/A
Relay's IRF activated, but communicates with LHMI	High frequency blinking green[1)]	High frequency blinking red[1)]	N/A
Communication lost between Relay and LHMI, but no IRF	Steady green	High frequency blinking green[1)]	N/A
LHMI not running normally or in start-up initialization phase	Steady green	High frequency blinking green[1)]	N/A
Process related alarm active	Steady green	Low frequency blinking red[2)]	No
Process related alarm active	Steady green	Steady red	Yes
Process related alarm has been active earlier, but is not any more active.	Steady green	Low frequency blinking red[2)]	No
Process related alarm has been active earlier, but is not any more active.	Steady green	Steady green	Yes
Relay set to Test Mode	Low frequency blinking green[2)]	Low frequency blinking green[2)]	No

1) High frequency = 3 Hz
2) Low frequency = 1 Hz

The Operator pages can be used as such or customized according to the project's requirements using Graphical Display Editor in PCM600. The Engineer pages are fixed and cannot be customized.

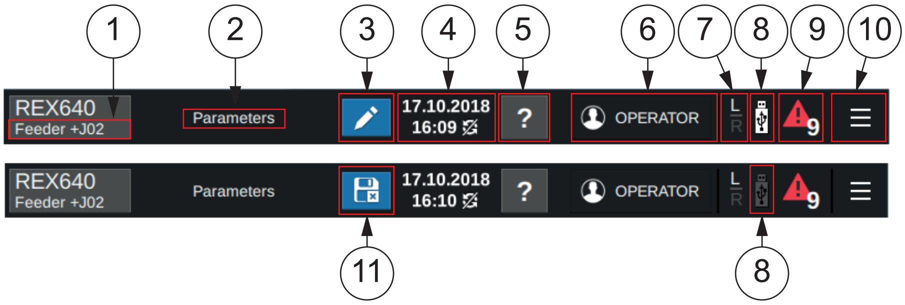

Figure 4: Menu bar elements

1	Bay name for the relay
2	Page name
3	Edit mode active (parameter editing)
4	Date, time and time synchronization status
5	Page help (visible if help is available for the page)
6	Login button/logged in user indication
7	Local/remote indication
8	USB memory not connected/connected (visible only if USB port is enabled)
9	Number of active alarms
10	Menu button for Engineer pages
11	Store or reject changed parameters indication

Table 7: Local HMI default pages

Page category	Pages	Subpages
Operator pages	Overview	Alarms
	Events	
	Fault Records	
	Timeline	
	Measurements	Phasors Load Profile Records

Table continues on next page

Page category	Pages	Subpages
Engineer pages	Parameters	
	Testing and Commissioning	Force Functions Force Outputs Simulate Inputs View I/O Send Events Secondary Injection Monitoring Protection Measurement Direction Coil Controller Commissioning[1)] View GOOSE sending View GOOSE receiving View SMV sending View SMV receiving
	Relay Status	Monitoring
	Clear	
	Disturbance Records	
	Alarms	
	Device Information	
	USB Actions	

1) Available with the Petersen coil control application package

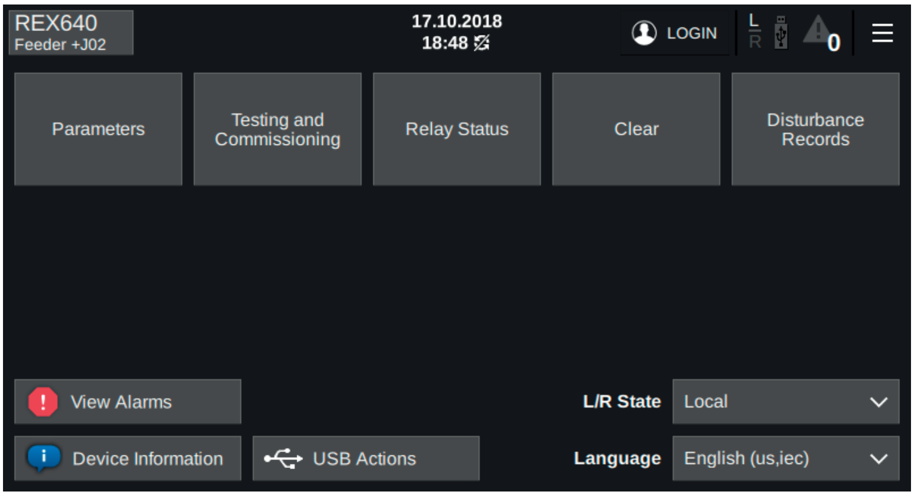

Figure 5: Engineer pages menu

2.5 Switchgear HMI

The SHMI is used for setting, monitoring and controlling up to 20 REX640 protection relays and the related processes. It comprises a 7-inch color screen with capacitive touch sensing and a Home button at the bottom of the SHMI. All features of standard HMI are also available in the SHMI.

The SHMI is an accessory for the relay which is fully operational even without the SHMI.

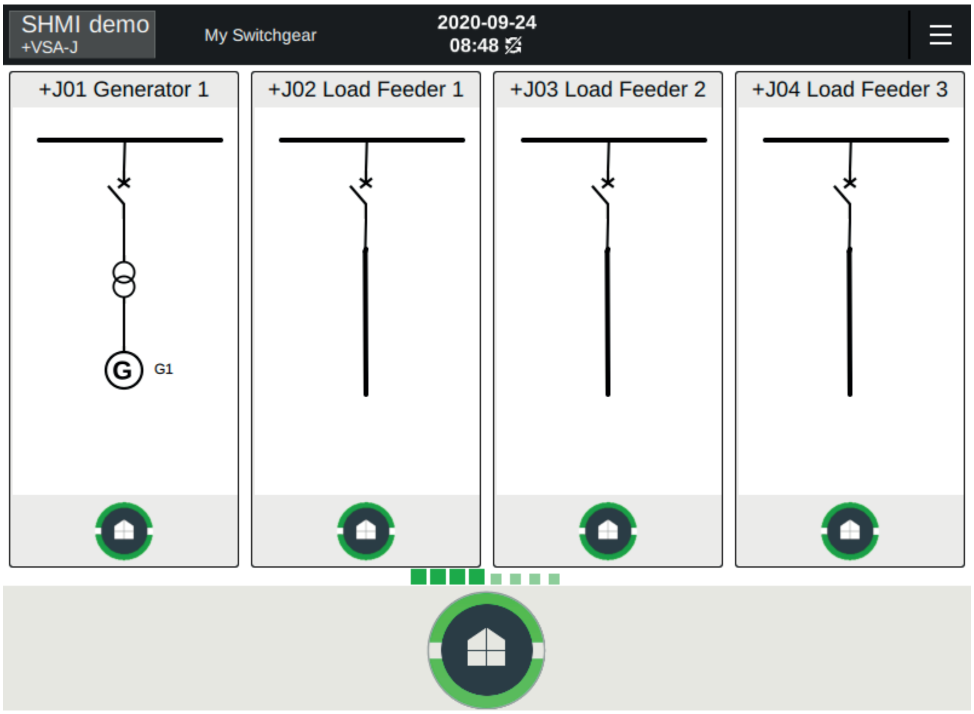

Figure 6: Example of a switchgear HMI navigation page

The SHMI has a navigation page which presents the physical switchgear lineup installation and indicates the status of each REX640 within the system. The area presenting a single switchgear bay has a small user-configurable bay overview section and a virtual Home button showing the status of the connected relay. By tapping the selected bay overview area, the SHMI connects with the related REX640 and works as normal LHMI for that relay.

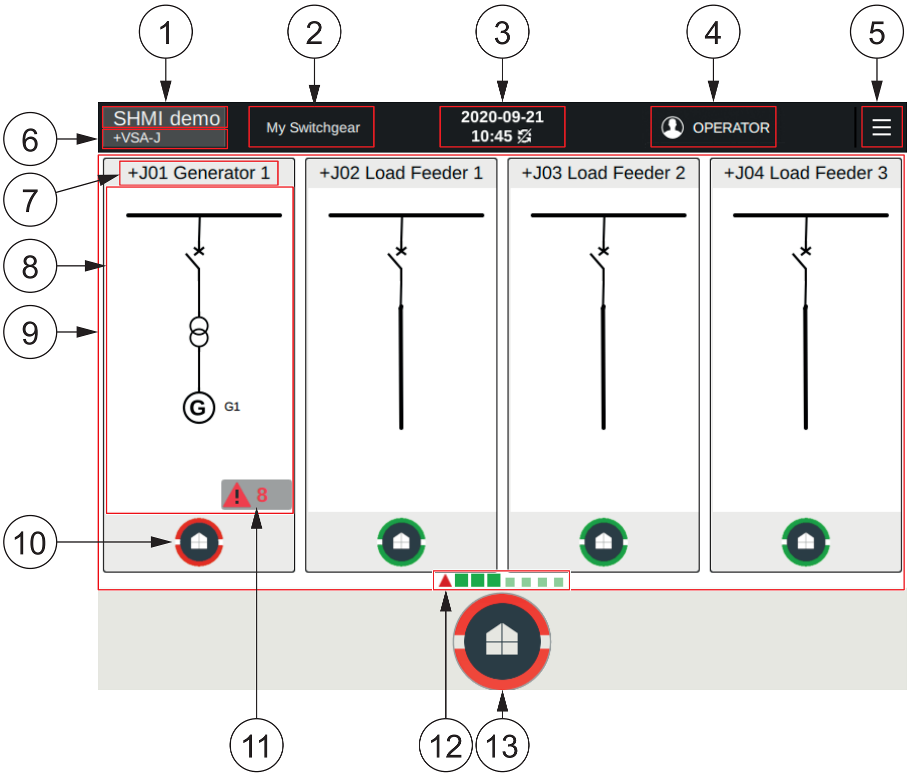

Figure 7: Navigation page elements

1	User-defined substation name
2	User-defined name for the switchgear or sub-part of switchgear lineup controlled by the SHMI
3	Date, time and time synchronization status
4	Logout button and authentication status
5	Menu button
6	User-defined voltage level name
7	User defined bay name and voltage level extension
8	Bay overview area showing static or dynamic information for a bay and functioning as a navigation point to launch the HMI view for the respective relay, user-defined content
9	SHMI navigation page
10	Virtual Home button representing the status of the respective relay’s physical Home button
11	Number of active alarms
12	Panel lineup overview showing the current status of all connected relays and the current position of navigation page
13	SHMI’s physical Home button

Bay overview area

Bay overview area consists either of a static picture or a dynamic SLD. They are configured with Graphical Display Editor in PCM600. One relay can have two overview pages.

Static picture may be, for example, a drawing or a photo of switchgear lineup. Maximum size of the picture is 186 × 320 px.

SLD does not support control operations. The following features are available.

- Static symbols such as connections, measurement devices, transformers and reactors
- Dynamic status for switching devices, but no control operations
- Dynamic and static text objects
    - Boolean state text
    - Integer state text
    - Label (translation not supported)
    - Numeric value
    - String value
- Custom symbols
- Busbar coloring

Physical and virtual Home buttons

On the SHMI navigation page, the virtual Home button shows the status of each relay as it would be shown with the physical Home button on a normal LHMI panel. In normal situations, the virtual Home button shows a steady green light. All other situations in which the relay requires operator’s attention are indicated with a flashing light, a red light or a combination of these.

SHMI’s physical Home button has two operation modes.

- On the SHMI navigation page, the Home button indicates the combined status of all connected relays. If multiple relays have different statuses, the Home button shows the indication with the highest priority.
- On the HMI view, the Home button indicates the status of the respective relay as described in Table 6.

Navigation

Navigation page is the default view for the SHMI. The navigation page shows bay overviews areas which are lined up to represent the actual panel installations. The navigation page can be scrolled by swiping the screen horizontally or by pressing the physical Home button to move the page from left to right one bay overview at a time.

Bay overview area is the configured view for one relay. It may show static or dynamic information but all control operations are disabled. The whole bay overview area works as a navigation point to the relay’s HMI view. Tapping this area opens the HMI view of the respective relay.

Panel lineup overview shows the position of the navigation page by highlighting the visible bay overviews. It also shows the status of all connected relays and helps in identifying which relay requires operator’s attention when the bay overview is not visible on the navigation page.

When the HMI view is opened for a relay, the SHMI works exactly like a normal HMI. All the same features are available, and the Home button switches between the configured home pages and indicates the alarm status for the respective relay.

Navigation area on the top left corner of the HMI view is used to navigate back to the SHMI’s navigation page. The navigation area shows the bay name on the button to identify which relay’s HMI is open.

2.6 Web HMI

The WHMI allows secure access to the protection relay via a Web browser. The WHMI is verified with Google Chrome, Mozilla Firefox, Internet Explorer 11.0 and Microsoft Edge.

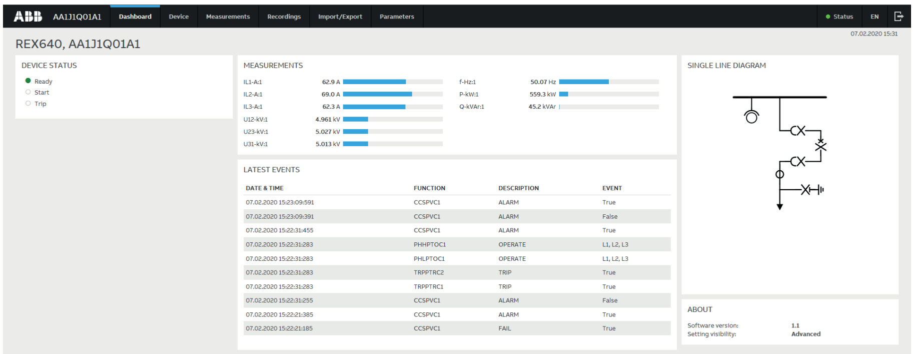

Figure 8: Example view of the Web HMI

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

Table 8: Web HMI main groups and submenus

Main groups	Submenus	Description
Dashboard		Used to see an overview of the protection relay including status, measurements, single-line diagram and latest events
Device	Monitoring Information Self-supervision Single Line Diagram Clear Change Password About	Used to navigate to monitoring, information, self-supervision, single-line diagram or clear pages
Measurements	Measurements Phasor Diagrams	Used to navigate to the measurements or phasor diagrams
Recordings	Events Disturbance records Fault records Load Profile Record Alarm List	Used to view the events, disturbance records, fault records, load profile records and alarms
Import/Export	Report Summary Import/Export Settings Parameter List	Used to export a parameter list or a report summary, and to import and export settings
Parameters		Used to view the menu tree structure for the protection relay's setting parameters
Language selection		Used to change the language
Logout		Used to end the session

The WHMI can be accessed locally and remotely.

- Locally by connecting the laptop to the protection relay
- Remotely over LAN/WAN

2.7 User authorization

The user management for the protection relay can be handled in two possible ways. Only one user management way can be enabled in the protection relay at a time.

For more information, see the cyber security deployment guideline.

Local user account management

Four factory default user accounts (VIEWER, OPERATOR, ENGINEER and ADMINISTRATOR) have been predefined for the LHMI and the WHMI, each with different rights and default passwords. The roles for these user accounts are the same as the username. Additional user accounts can be added for the protection relay.

IED Users in PCM600 is used to manage the user accounts. Each protection relay supports eight fixed roles and 50 user accounts belonging to any one of these roles. Each user account can be mapped to a maximum of eight roles.

The factory default passwords can be changed with Administrator user rights or by the users themselves. Relay user passwords can be changed using the LHMI, IED Users in PCM600 or the WHMI. Only Administrator can create user accounts and update the roles-to-rights mapping. Administrator can also reset the passwords of the users.

User authorization is disabled by default for the LHMI and can be enabled with the *Local override* parameter via the menu path **Configuration/Authorization/Passwords**. WHMI always requires authentication. Changes in user management settings do not cause the protection relay to reboot. The changes are taken into use immediately after committing the changed settings.

Central account management

The user accounts and roles can be created and authenticated centrally in a CAM server. CAM needs to be activated in the protection relay from Account Management in PCM600.

A CAM server can be a tool such as SDM600 or it can be an Active Directory server such as Windows AD. There can also be a secondary or redundant CAM server configured which can act as a backup CAM server if the primary CAM server is not accessible.

The protection relay is the CAM client and can maintain its own replica database of the user accounts and roles configured in the CAM server. This CAM replica database acts as a backup authentication mechanism if primary and secondary CAM servers are not accessible from the protection relay.

Each protection relay supports eight roles and 50 user accounts in the CAM replica database. Each user account can be mapped to a maximum of eight roles.

For more information on user management and security logging, see the cyber security deployment guideline.

For user authorization for PCM600, see the PCM600 documentation.

2.8 Station communication

Operational information and controls are available through a wide range of communication protocols including IEC 61850 Edition 2, IEC 61850-9-2 LE, IEC

60870-5-103, IEC 60870-5-104, Modbus® and DNP3. Full communication capabilities, for example, horizontal communication between the relays, are only enabled by IEC 61850.

The relay provides the possibility for a second IP address and a second subnetwork when the communication modules with three Ethernet ports (COM1001...1003) are used. However, only one IP network can be used as the default route. Using two IP addresses, communication networks can be separated based on the dominant user's needs. For example, one IP address can serve the dispatchers and the other one can serve the service engineers' needs.

The IEC 61850 protocol is a core part of the relay as the protection and control application is fully based on standard modelling. The relay supports Edition 2 and Edition 1 versions of the standard. With Edition 2 support, the relay has the latest functionality modelling for substation applications and the best interoperability for modern substations. The relay supports flexible product naming (FPN) facilitating the mapping of relay's IEC 61850 data model to a customer defined IEC 61850 data model.

2.9 Modification Sales

Modification Sales is a concept that provides modification support for already delivered relays. Under Modification Sales it is possible to modify both the hardware and software capabilities of the existing relay. The same options are available as when a new relay variant is configured and ordered from the factory: it is possible to add new hardware modules into empty slots, change the type of the existing modules within the slots or add software functions by adding application and, if necessary, add-on packages. If it is needed to use the possibilities provided by the Modification Sales concept, please contact your local ABB unit.

Section 3 Multifrequency admittance-based earth-fault protection

3.1 Introduction to application

Earth-fault detection and direction determination are difficult due to the variety of possible fault conditions. The widespread use of resonant earthing for improving the quality and reliability of the energy supply further complicates the matter. Earth faults in compensated networks with underground cables often have an intermittent characteristic and are typically low ohmic. Also, the mixed use of overhead lines and underground cables in modern power networks presents high-ohmic earth faults. To detect different types of earth faults and get comprehensive protection, it is often necessary to use multiple relays or protection functions in parallel.

Multifrequency admittance-based earth-fault protection MFADPSDE is a single-function solution for earth-fault protection. MFADPSDE provides extremely secure, dependable and selective directional earth-fault protection for high-impedance earthed networks, that is, compensated, unearthed and high-resistance earthed systems. Because of its high reliability and sensitivity, MFADPSDE can avoid the need for using multiple dedicated relays or functions in parallel for detecting earth faults, especially in compensated networks. It can be applied to the earth-fault protection of overhead lines and underground cables and it can operate with low-ohmic and high-ohmic earth faults with permanent or intermittent characteristics.

The transient detection capability of MFADPSDE also makes it effective in detecting transient, intermittent and restriking earth faults. Therefore, it can be used as an alternative solution to transient/intermittent earth-fault protection INTRPTEF.

Table 9: Typical earth-fault conditions in feeders and protection functions

Faults and conditions	Protection functions
Low-ohmic faults	Multifrequency admittance-based earth-fault protection MFADPSDE
Transient, intermittent and restriking faults	
Cable termination faults	
Double earth faults	Non-directional earth-fault protection, high stage EFHPTOC
High-ohmic faults	Multifrequency admittance-based earth-fault protection MFADPSDE, Residual overvoltage protection ROVPTOV as backup

3.2 Description of the example case

To explain the application of MFADPSDE, a generic network is taken as an example. Figure 9 shows a representative network configuration (20 kV, 50 Hz system) with five feeders compensated centrally at the substation. The network has resonance current at 50 A and is overcompensated by 5 A. There is a permanently connected parallel resistor in the power auxiliary winding of the Petersen coil, which introduces 8.6 A of resistive current at primary voltage level. The network's natural losses are approximately equal to 2.4 A. The healthy-state residual voltage U_0 level is 5% of the nominal phase-to-earth voltage.

The example case focuses on the multifrequency admittance-based protection of the feeder J1. Other feeders can be similarly protected using MFADPSDE with the same settings. Figure 9 has a core balance current transformer (CBCT) (recommended class: 0.5S/5P10, 1VA) to measure the residual current I_0 of feeder J1 and phase CTs and VTs connected in open-delta connection to measure the residual voltage U_0. The phase CTs in the example case are used for getting the calculated residual current, which is needed for double earth-fault protection. Similar arrangements to measure the residual current, phase currents and the residual voltage along with relays (not shown in the figure) should be present in individual feeders to protect them.

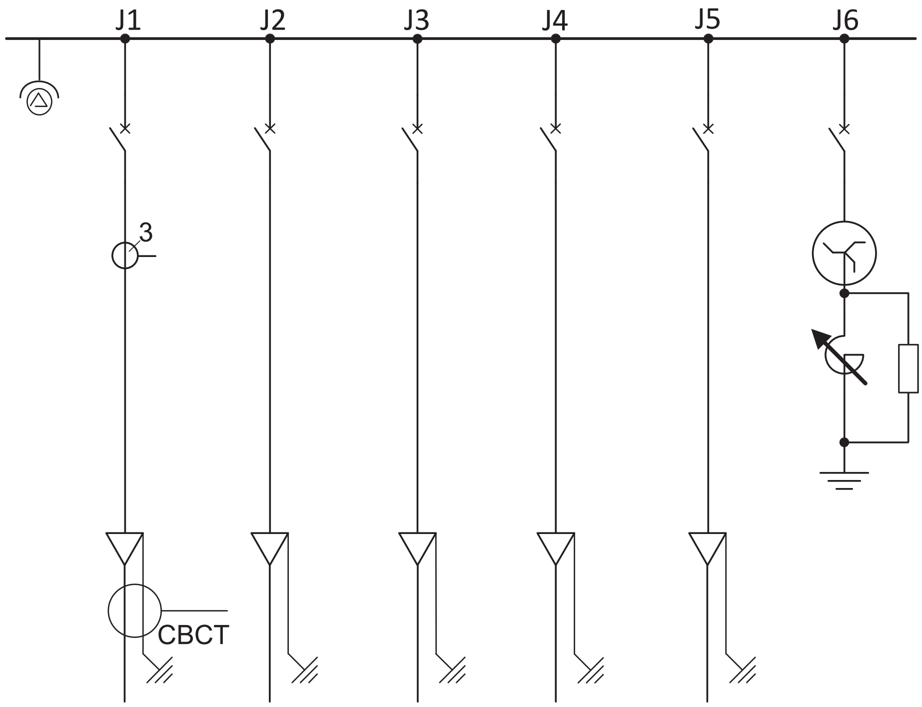

Figure 9: Single-line diagram of the example case

3.3 Multifrequency admittance-based earth-fault relay

This chapter provides detailed information about the configuration of the relay used in this application example: the relay interfaces, the ACT diagram and parameter settings and information on how the MFADPSDE protection can be achieved for the given example.

3.3.1 Relay interface, configuration and settings

Figure 10 shows the connection details of the relay's analog inputs (AI) and binary outputs (BO). The CT and VT connections required for realizing the example case are also shown in the figure for the MFADPSDE protection of feeder J1. A CBCT should be used for measuring the residual current. The residual voltage U_0 is typically measured with open-delta connected VTs.

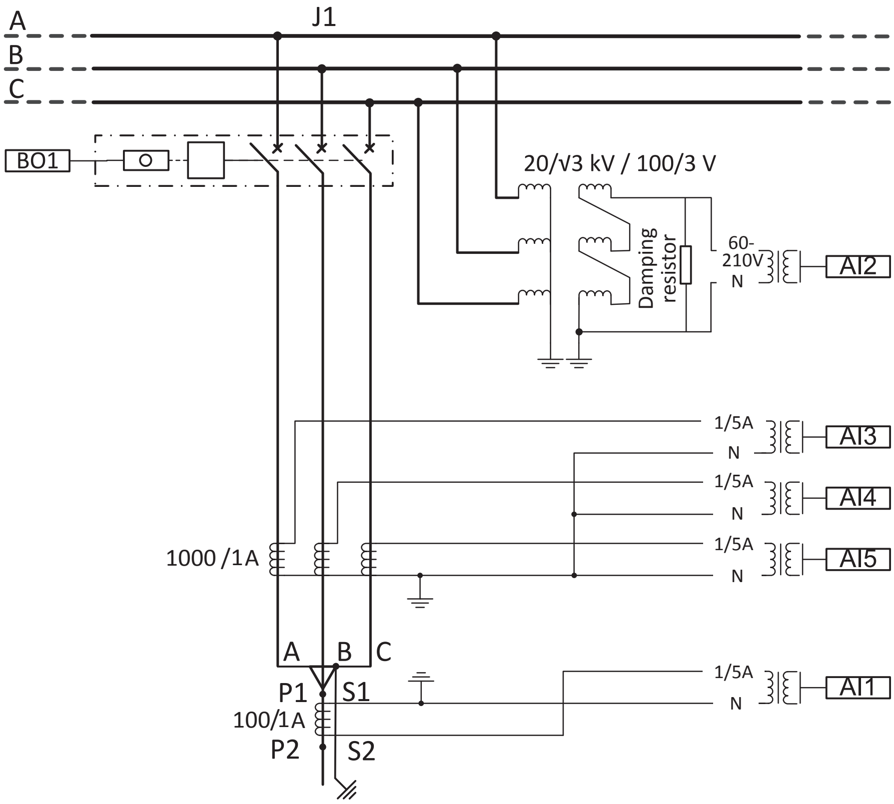

Figure 10: Relay interfaces and CT/VT connections for the example case

3.3.1.1 Analog input signals

Table 10: Physical analog input signals for implementing the application example

Analog input	Description
AI1	Feeder J1 residual current
AI2	Bus open delta voltage
AI3	Feeder J1 I_A current
AI4	Feeder J1 I_B current
AI5	Feeder J1 I_C current

3.3.1.2 Binary output signals

Table 11: Physical binary output signal for implementing the application example

Binary output	Description
BO1	Open the feeder circuit breaker

3.3.1.3 Recommended alarms

Table 12: Alarm list for implementing the application example

Event container	Event	Description
MFADPSDE1	OPERATE	Operate signal
MFADPSDE1	START	Start signal
MFADPSDE1	INTR_EF	Intermittent earth-fault indication
MFADPSDE2	OPERATE	Operate signal
MFADPSDE2	START	Start signal
MFADPSDE2	INTR_EF	Intermittent earth-fault indication
ROVPTOV1	OPERATE	Operate signal
EFHPTOC1	OPERATE	Operate signal

3.3.1.4 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 13: Function blocks used in the relay configuration

Function block	Description
ILTCTR1 UTVTR1 RESTCTR1	Analog signal preprocessing block
TRPPTRC1	Trip command collector/handler with lockout/ latching feature
MFADPSDE1 MFADPSDE2	Multifrequency admittance-based earth-fault protection
ROVPTOV1	Residual overvoltage protection. This function is used for providing backup for earth-fault protection.
EFHPTOC1	Non-directional earth-fault protection. This function is used for earth-fault protection of the feeder (especially, double earth fault).

Table 14: Physical analog channels of the function

Function block	Feeder residual current, AI1	Bus open delta voltage, AI2	Feeder phase currents, AI3, AI4, AI5
MFADPSDE1	x	x	
MFADPSDE2			x[1)]
ROVPTOV1		x	
EFHPTOC1			x[1)]

1) I_0 is calculated from phase currents by the ILTCTR1 block

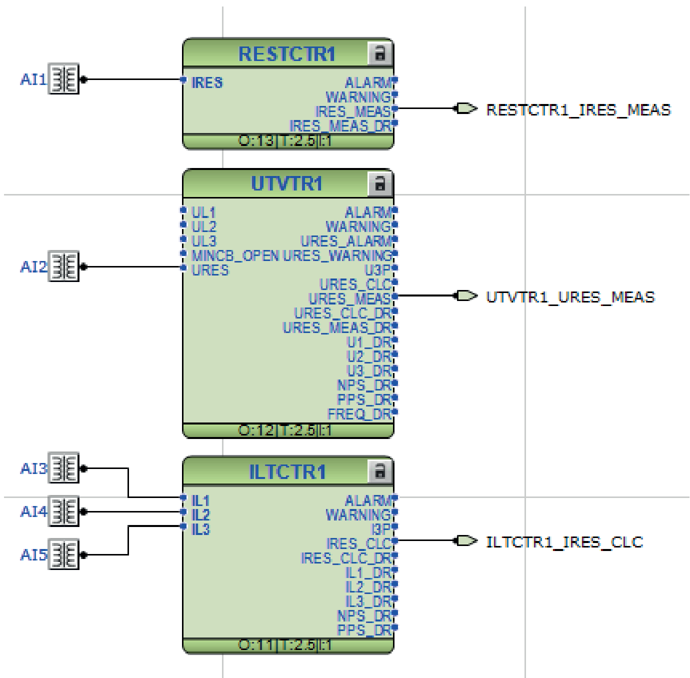

Figure 11: Relay inputs and preprocessing connections

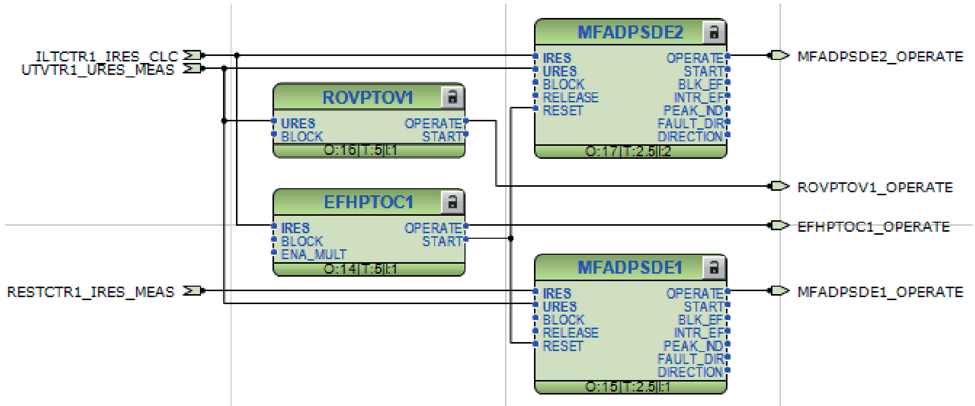

Figure 12: Application function block connections

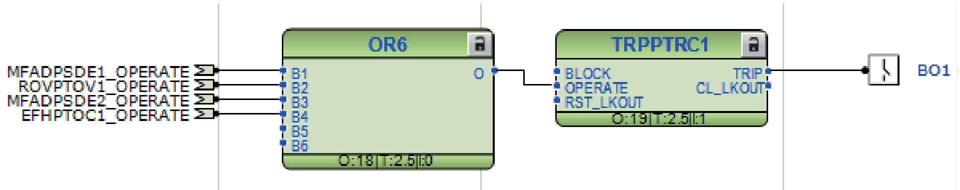

Figure 13: Relay output connections

3.3.1.5 Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 15 shows recommended setting values; all other settings can be kept at default values.

Table 15: ILTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	1000	Primary current value
Secondary current	1	Secondary current value

RESTCTR1 – Residual current preprocessing

RESTCTR1 is the analog signal preprocessing function for the residual current signal. Table 16 shows recommended setting values; all other settings can be kept at default values.

Table 16: RESTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	100 A	Primary current
Secondary current	1 A	Secondary current

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 17 shows recommended setting values; all other settings can be kept at default values.

Table 17: UTVTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	11.547 kV	Primary rated voltage
Secondary voltage	100 V	Secondary rated voltage

TRPPTRC1 - Master trip

Master trip TRPPTRC1 is used as a trip command collector and handler after the protection functions. All settings of TRPPTRC1 function blocks are kept at default values for this example case.

ROVPTOV1 - Residual overvoltage protection

ROVPTOV1 provides earth-fault protection by detecting an abnormal level of residual voltage. In the application example, it is used as a backup protection. Table 18 shows recommended setting values; all other settings can be kept at default values.

Table 18: ROVPTOV1 settings for the relay in the example case

Setting	Suggested values	Description
Start value	$0.08 \times U_n$[1)]	Start value
Operate delay time	600 ms[2)]	Operate delay time
Reset delay time	500 ms[3)]	Reset delay time

1) Since ROVPTOV1 is a backup for MFADPSDE1, the setting *Start value* should be above the setting *Voltage start value* of MFADPSDE1. In the example case, MFADPSDE1 *Voltage start value* is set at $0.07 \cdot U_n$, hence ROVPTOV1 *Start value* is set as $0.08 \cdot U_n$.
2) The default value of *Operate delay time* for MFADPSDE1 is 500 ms. Since ROVPTOV1 is a backup for this function, the setting *Operate delay time* should be higher than this, hence it is kept at 600 ms.
3) *Reset delay time* for ROVPTOV1 is the same as for MFADPSDE1, that is, 500 ms.

EFHPTOC1 - Non-directional earth-fault protection, high stage

EFHPTOC1 provides protection against double earth fault or cross-country fault situations in isolated or compensated networks. The resulting fault current is usually higher than the fault current of a single phase-to-earth fault, but is normally lower than the fault current associated with a short circuit with zero fault resistance at the fault location closest to the feeding substation.

The `START` signal of EFHPTOC1 is connected to the `RESET` input of the MFADPSDE1 and MFADPSDE2 function blocks in order to reset phasor accumulation during a double earth fault or cross-country fault. This helps in rapidly adapting to a possible fault direction change if a single-phase earth fault still persists in the system after the cross-country fault is tripped.

EFHPTOC1 uses the calculated residual current originating from the phase currents.

Table 19 shows recommended setting values; all other settings can be kept at default values.

Table 19: EFHPTOC1 settings for the relay in the example case

Setting	Suggested values	Description
Start value	$0.12 \times I_n$ 1)	Start value
Operate delay time	200 ms 2)	Operate delay time

1) *Start value* of EFHPTOC1 should be higher than that of MFADPSDE2, hence it is kept at $0.12 \cdot I_n$.
2) The default value of *Operate delay time* for MFADPSDE1 and MFADPSDE2 is 500 ms. Since EFHPTOC1 should act faster, the setting *Operate delay time* should be lower than this, hence it is kept at 200 ms.

It is important that all the different earth-fault functions in the relay are correctly coordinated.

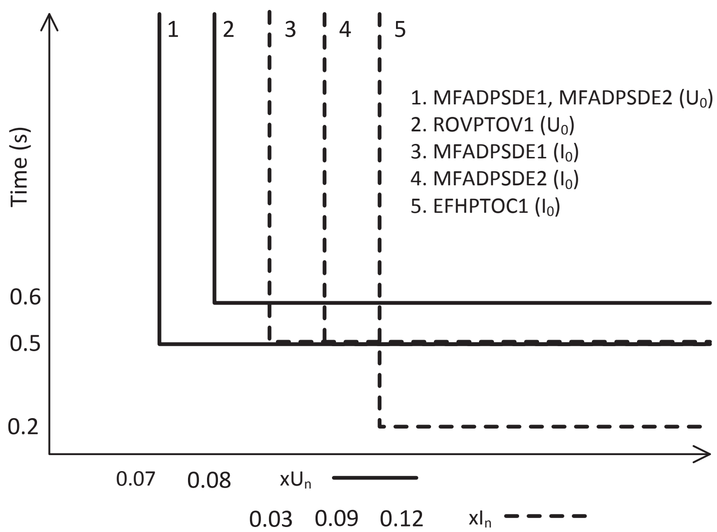

Figure 14: Recommended coordination between the earth-fault functions in the application example

MFADPSDE1 - Multifrequency admittance-based earth-fault protection

MFADPSDE1 is a secure, sensitive and selective earth-fault detection function which can work reliably in compensated networks as well as in mixed overhead line and underground cable networks.

Operation mode "General EF" (default), applicable to earth faults in unearthed and compensated networks, is used here. Since the example case depicts a compensated network, *Operating quantity* should be set to "Adaptive" (default).

The function starts the fault indication and direction determination when the fundamental frequency zero-sequence voltage U_0 exceeds *Voltage start value*. Hence, this setting defines the sensitivity of the function and has to be set higher than the maximum healthy-state zero-sequence voltage taking into account the possible network topology changes, coil and parallel resistor switching status and compensation degree variations. In the example, the healthy-state zero-sequence voltage is 5% of the nominal voltage, hence *Voltage start value* should be set above this value. If an external `RELEASE` input is activated, it overrides the setting *Voltage start value* and triggers direction determination and fault indication irrespective of the value of the zero-sequence voltage.

The setting *Tilt angle* is used to adjust the tilt of the operation sector and should compensate the measurement errors of residual current and voltage measurements. The default setting of "5 degrees" is kept for this example case, but it should always reflect the actual maximum expected measurement errors of CT and VT.

Min operate current is set to $p \cdot I_{RTot}$, where p is a security factor and I_{RTot} is the total resistive current in the network including network losses and the parallel resistor current. A typical value of *Min operate current* is between 3 and 5 A in primary. In the example case, the total resistive current in the network, including network losses and parallel resistor current, is 2.4 A and 8.6 A, respectively, at 20 kV.

The `INTR_EF` output indicates the detection of a restriking or intermittent earth fault in the network. This output is activated when the number of detected transients equals or exceeds the setting *Peak counter limit* even in "General EF" mode. For this example case, the default setting of *Peak counter limit* can be used. The `INTR_EF` output is non-directional, that is, it is activated both in the forward and reverse faults. Indication of a restriking or intermittent earth fault in the protected feeder is obtained by combining the `START` and `INTR_EF` outputs with a logical AND operator.

Table 20 shows recommended setting values; all other settings can be kept at default values.

Table 20: Function settings whose values differ from default values based on the example

Setting	Suggested values	Description
Voltage start value	$0.07 \times U_n$ 1)	Voltage start value
Min operate current	$0.03 \times I_n$ 2)	Minimum operate current

1) Healthy-state zero-sequence voltage of 5% + margin. 1 pu is 100 V in the open-delta winding and 20/√3 kV in the primary.
2) Assuming a security factor of 0.3, the minimum operating current setting can be calculated as 0.3 · (8.6 + 2.4) =~3 A, which equals 0.03 pu with 100/1 A CBCT. 1 pu is 100 A in primary, 1 A in secondary.

MFADPSDE2 - Multifrequency admittance-based earth-fault protection

MFADPSDE2 is used for cable terminal protection in the application example and works with the calculated I_0 instead of the measured residual current. When faults occur at cable termination, I_0 is more accurate if calculated from phase currents. The phase CT cores may not be identical and hence the *Min operate current* setting value should be kept slightly higher than for MFADPSDE1.

The setting guidelines for MFADPSDE1 can also be applied to MFADPSDE2. Table 21 shows recommended setting values; all other settings can be kept at default values.

Table 21: Function settings whose values differ from the default values based on the example

Setting	Suggested values	Description
Voltage start value	$0.07 \times U_n$ [1)]	Voltage start value
Min operate current	$0.09 \times I_n$ [2)]	Minimum operate current

1) Healthy-state zero-sequence voltage of 5% + margin. 1 pu is 100 V in the open-delta winding and 20/√3 kV in the primary.
2) To account for non-identical cores of phase CTs, the setting *Min operate current* has to be kept higher than for MFADPSDE1, that is, $0.03 \cdot 3 = 0.09 \cdot I_n$ resulting in lesser sensitivity than MFADPSDE1.

Section 4 Transformer protection

4.1 Introduction to application

The transformer protection and control functions in this relay are designed to protect power transformers of two and three windings, autotransformers as well as generator-transformer blocks. As the transformer is a vital power system component and, in most cases, the most expensive, it should be protected from, for example, short circuits, overloads and earth faults.

Transformers in operation can be subject to a variety of faults and abnormal conditions, all of which can have adverse effects on their performance and life. One of the main categories of transformer faults are the winding failures caused by dielectric, thermal and mechanical stress. These can occur as short circuits, local hot spots or breakage of windings. Other faults are, for example, the phase-to-phase faults, earth faults, core faults, bushing faults, overvoltage, overexcitation, and oil quality issues.

The faulty transformer must be disconnected as fast as possible. The protection functions must have high sensitivity to detect faults, but at the same time the protection should be stable against external faults and overexcitation. This can be typically achieved by differential protection functions which are in most cases the main protection used for transformers. Overcurrent protection functions can act as backup protection to differential protection functions, but can also be used as main protection. Earth-fault protection functions provide protection against various earth-fault conditions.

Equally important is the monitoring of insulation. The paper oil insulation, which is generally used in all the transformer windings, degrades over time. Temperature is the basic cause for the degradation of insulation life. The hot spot temperature of the winding should be calculated to estimate the insulation life consumption and it should be monitored continuously to see that the hot spot temperature does not exceed the flashover value of transformer oil. Typically, thermal protection, hot spot and ageing rate monitoring functions can be used for insulation monitoring.

The relay transformer protection functions are aimed at providing a comprehensive protection to the transformer against, for example, overcurrent, overvoltage, overexcitation, short circuit, inrush, thermal and earth faults. It can also monitor oil quality, hot spot and ageing.

Table 22: Typical transformer faults and conditions, protection functions and devices

Faults and conditions	Protection functions and devices
Short circuit faults and winding failures	Stabilized and instantaneous differential protection TRxPTDF, Three-phase non-directional overcurrent protection PHxPTOC
Winding inter-turn faults	Stabilized and instantaneous differential protection TRxPTDF, pressure relay, gas relay
Y connected winding earth faults	High-impedance based restricted earth-fault protection HREFPDIF, Numerical stabilized low-impedance restricted earth-fault protection LREFPNDF
D-winding earth faults, system earth faults, and earth-fault backup protection	Non-directional earth-fault protection EFxPTOC, Directional earth-fault protection DEFxPDEF, Residual overvoltage protection ROVPTOV
Insulation degradation, hot spots	Hot-spot and insulation ageing rate monitoring for transformers HSARSPTR, pressure relay, oil and winding temperature indicators
Overload	Three-phase thermal overload protection, two time constants T2PTTR
Overvoltage	Three-phase overvoltage protection PHPTOV
Overexcitation	Overexcitation protection OEPVPH
Overfrequency	Overfrequency protection FRPFRQ2
Undervoltage	Three-phase undervoltage protection PHPTUV
Underfrequency	Underfrequency protection FRPFRQ1
Transformer inrush	Three-phase inrush detector INRPHAR
Unbalance	Negative-sequence overcurrent protection NSPTOC
High-resistance joints, high eddy current between laminations, high-resistance faults, core bolt insulation failure, loss of oil due to leakage	Pressure relay
Incipient winding faults, core faults due to the impulse breakdown of the insulating oil, open circuits, which result in severe arcing, current flow through defective supporting and insulating structures, tap changer troubles caused by localized overheating or arcing	Gas relay
Defective joints at winding terminals	Pressure relay, gas relay
Short circuit due to an insulation failure	Main tank pressure relief device
Faults in the diverter switch oil compartment, overpressure in tank	OLTC tank pressure relay
Main tank oil level variations due to, for example, load changes, leakages or faults	Oil level indicator of main tank's expansion vessel

4.2 Description of the example case

To explain the application of different short-circuit, earth-fault and overload protection functions, a generic system is taken as an example. Figure 15 shows a representative configuration with a three-winding transformer for single bus/single breaker on primary, secondary and tertiary winding sides. CTs are connected to measure phase currents from each winding and the Y-winding (primary side) neutral current. The power transformer vector group in the example case is YNd1d1.

This example case focuses on the most typical current-based protection functions. Therefore, other protection functions are not discussed here. High-impedance based restricted earth-fault protection has been chosen for the power transformer's HV side, but the low-impedance based protection could also be used.

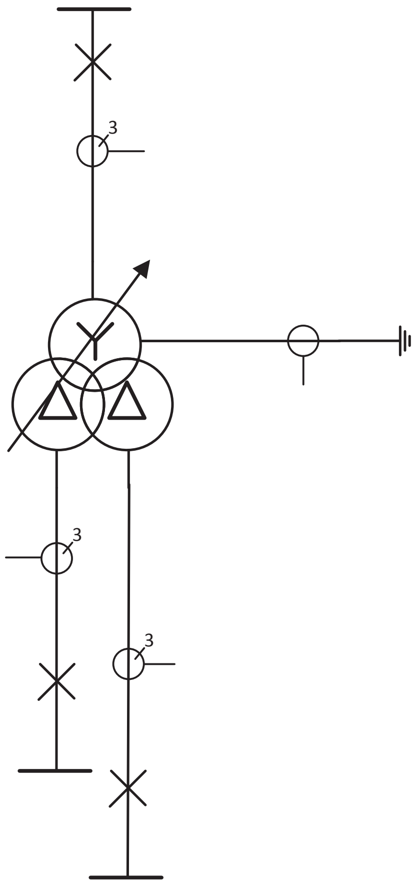

Figure 15: Single-line diagram of the example case for a three-winding transformer

4.3 Transformer protection relay

This chapter provides detailed information about the configuration of the relay used in this application example: the relay interfaces, the ACT diagram, the setting values and information on how the transformer protection can be achieved for the given example.

4.3.1 Relay interface, configuration and settings

Figure 16 shows the connection details of the relay's analog inputs (AI), binary inputs (BI) and binary outputs (BO). In this example, the power transformer has an on-load tap changer on the HV (winding 1) side. The CT connections according to Type 2 (see TRxPTDF in the technical manual) required for comprehensive transformer protection for the example case are also shown.

The figure also shows the neutral CT connection for the high-impedance based restricted earth-fault protection HREFPDIF used for the Y-winding (primary side) in the example case. This protection function measures the sum of the Y-side phase currents and neutral current. HREFPDIF requires a stabilizing resistor and a voltage-depended resistor (VDR) in the CT secondary circuit.

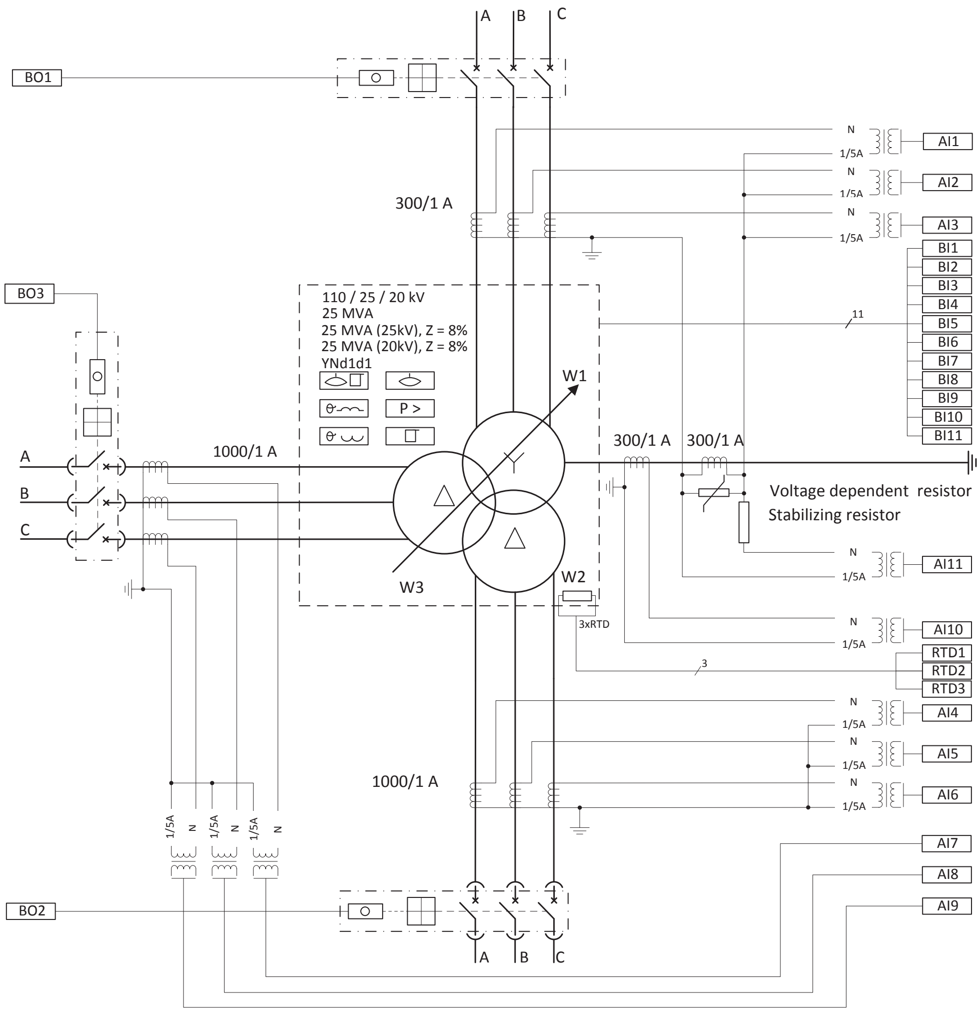

Figure 16: Relay interfaces and CT connections for the three-winding transformer of the example case

4.3.1.1 Analog input signals

Table 23: Physical analog input signals for implementing the application example

Analog input	Description
AI1	Transformer winding 1, current A
AI2	Transformer winding 1, current B
AI3	Transformer winding 1, current C
AI4	Transformer winding 2, current A
AI5	Transformer winding 2, current B
AI6	Transformer winding 2, current C
AI7	Transformer winding 3, current A
AI8	Transformer winding 3, current B
Table continues on next page	

Analog input	Description
AI9	Transformer winding 3, current C
AI10	Neutral current
AI11	Differential neutral current

4.3.1.2 RTD input signals

Table 24: Physical RTD input signals for implementing the application example

RTD input	Description
RTD1	Ambient temperature
RTD2	Top oil temperature

4.3.1.3 mA input signals

Table 25: Physical mA input signal for implementing the application example

mA input	Description
mA1	Tap position of the on-load tap changer

4.3.1.4 Binary input signals

Table 26: Binary input signals for implementing the application example

Binary input	Description
BI1	Gas relay's gas accumulation, alarm level information used for alarm purpose
BI2	Gas relay's gas accumulation, trip level information used for alarm and for tripping all breakers
BI3	Gas relay's oil surge information used for alarm and for tripping all breakers
BI4	OLTC tank pressure relay's information used for alarm and for tripping all breakers
BI5	Main tank pressure relief device information used for alarm and for tripping all breakers
BI6	Oil temperature indicator, alarm level information used for alarm
BI7	Oil temperature indicator, trip level information used for alarm and for tripping load off (secondary and tertiary side breakers)
BI8	Winding temperature indicator, alarm level information used for alarm
Table continues on next page	

Binary input	Description
BI9	Winding temperature indicator, trip level information used for alarm and for tripping load off (secondary and tertiary side breakers)
BI10	Oil level indicator of main tank's expansion vessel, low oil level information used for alarm
BI11	Oil level indicator of main tank's expansion vessel, high oil level information used for alarm

4.3.1.5 Binary output signals

Table 27: Physical binary output signals for implementing the application example

Binary output	Description
BO1	Open winding 1 circuit breaker
BO2	Open winding 2 circuit breaker
BO3	Open winding 3 circuit breaker

4.3.1.6 Recommended alarms

Table 28: Alarm list for implementing the application example

Event container	Event	Description
Gas Relay	BI1	Gas relay's gas accumulation alarm
Gas Relay	BI2	Gas relay's gas accumulation trip
Gas Relay	BI3	Gas relay's oil surge trip
Pressure relay	BI4	OLTC tank pressure relay trip
Pressure relief device	BI5	Main tank pressure relief device trip
Temperature indicator	BI6	Oil temperature alarm
Temperature indicator	BI7	Oil temperature trip
Temperature indicator	BI8	Winding temperature alarm
Temperature indicator	BI9	Winding temperature trip
Oil level	BI10	Oil level indicator of main tank's expansion vessel, low oil level alarm
Oil level	BI11	Oil level indicator of main tank's expansion vessel, high oil level alarm
TR3PTDF1	OPERATE	Operate signal from transformer differential protection
HREFPDIF1	OPERATE	Operate signal from high-impedance restricted earth-fault protection

Table continues on next page

Event container	Event	Description
EFLPTOC1	OPERATE	Operate signal from low stage non-directional earth-fault protection
PHIPTOC1	OPERATE	Operate signal from instantaneous non-directional overcurrent protection
PHLPTOC1	OPERATE	Operate signal from low stage non-directional overcurrent protection for winding 1
PHLPTOC2	OPERATE	Operate signal from low stage non-directional overcurrent protection for winding 2
PHLPTOC3	OPERATE	Operate signal from low stage non-directional overcurrent protection for winding 3
T2PTTR1	OPERATE	Operate signal from thermal protection
T2PTTR1	ALARM	Alarm signal from thermal protection
HSARSPTR1	ALARM	Alarm signal due to winding hot spot temperature detection
HSARSPTR1	WARNING	Warning signal due to winding hot spot temperature detection
HSARSPTR1	ALM_AGE_RATE	Alarm signal for average ageing rate over set time period

4.3.1.7 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 29: Function blocks used in the relay configuration

Function block	Description
ILTCTR1, ILTCTR2, ILTCTR3, RESTCTR1, RESTCTR2	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input into integer value.
TR3PTDF	Transformer differential protection of two- or three-winding transformers
PHIPTOC	Three-phase non-directional overcurrent protection, instantaneous stage
PHLPTOC1, PHLPTOC2, PHLPTOC3	Three-phase non-directional overcurrent protection, low stage
HREFPDIF1	High-impedance based restricted earth-fault protection
EFLPTOC1	Non-directional earth-fault protection, low stage
T2PTTR	Three-phase thermal overload protection, two time constants
Table continues on next page	

Function block	Description
HSARSPTR1	Hot-spot and insulation ageing rate monitoring for transformers
TPOSYLTC1	Tap changer position indication. The output of this function is used by TR3PTDF1.
INRPHAR1	Three-phase inrush detector. The 2nd harmonic block output of this function can be used for enabling the multiplier for PHIPTOC, PHLPTOC and EFLPTOC functions. For the example case, the 2nd harmonic block output from INRPHAR1 is connected to `ENA_MULT` input of PHIPTOC1 and EHLPTOC1.
TRPPTRC1, TRPPTRC2, TRPPTRC3	Trip command collector/handler with lockout/latching feature

Table 30: Physical analog channels of functions

Protection	Winding 1 currents AI1, AI2, AI3	Winding 2 currents AI4, AI5, AI6	Winding 3 currents AI7, AI8, AI9	I0 AI10	HV side restricted EF current AI11	Tap position mA1 (via TPOSYLTC)	Ambient Temp. RTD1	Top oil Temp. RTD2
TR3PTDF1	x	x	x			x		
PHIPTOC1	x							
PHLPTOC1	x							
PHLPTOC2		x						
PHLPTOC3			x					
HREFPDIF1					x			
EFLPTOC1				x				
T2PTTR1	x						x	
HSARSPTR1	x						x	x

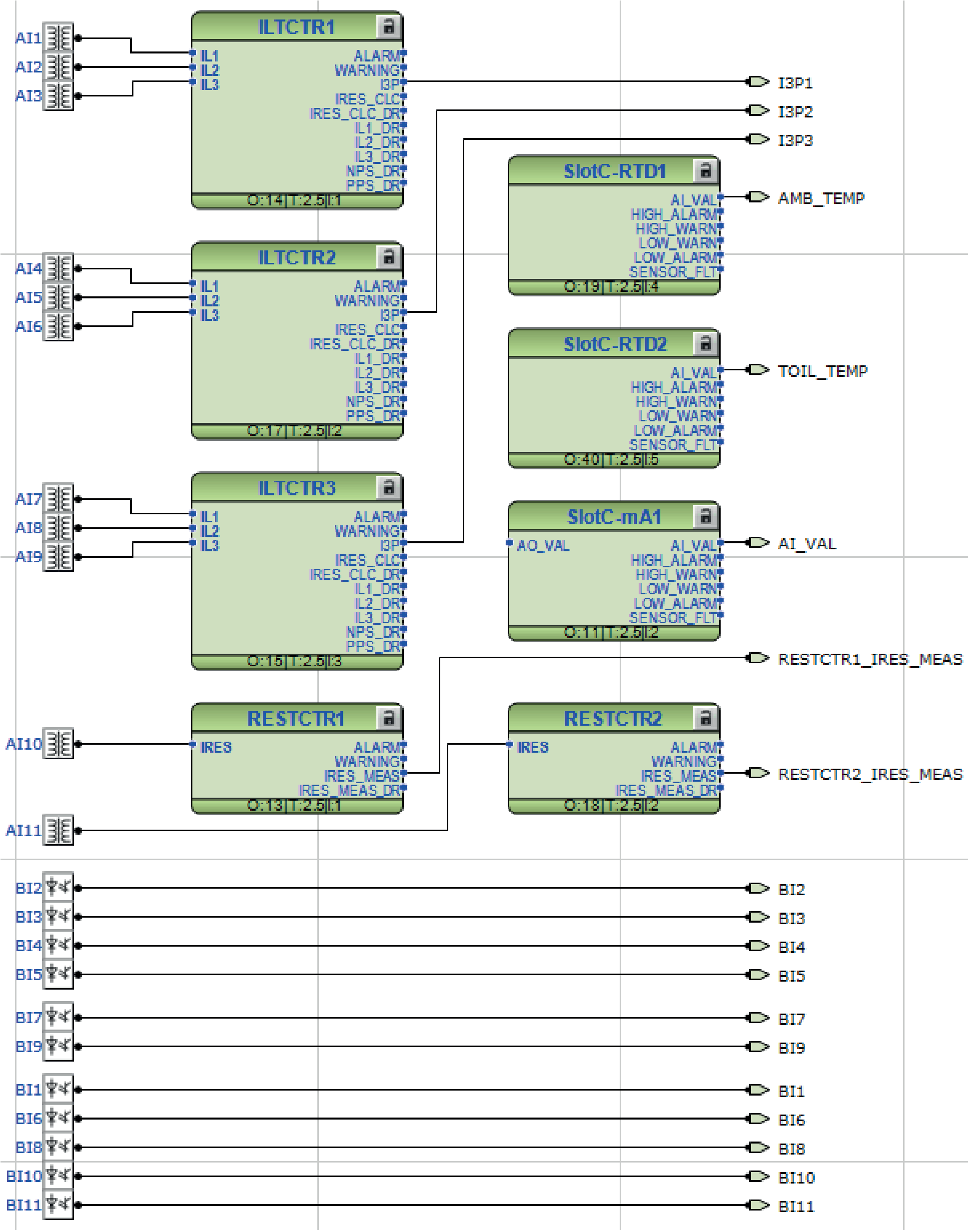

Figure 17: Relay inputs and preprocessing connections

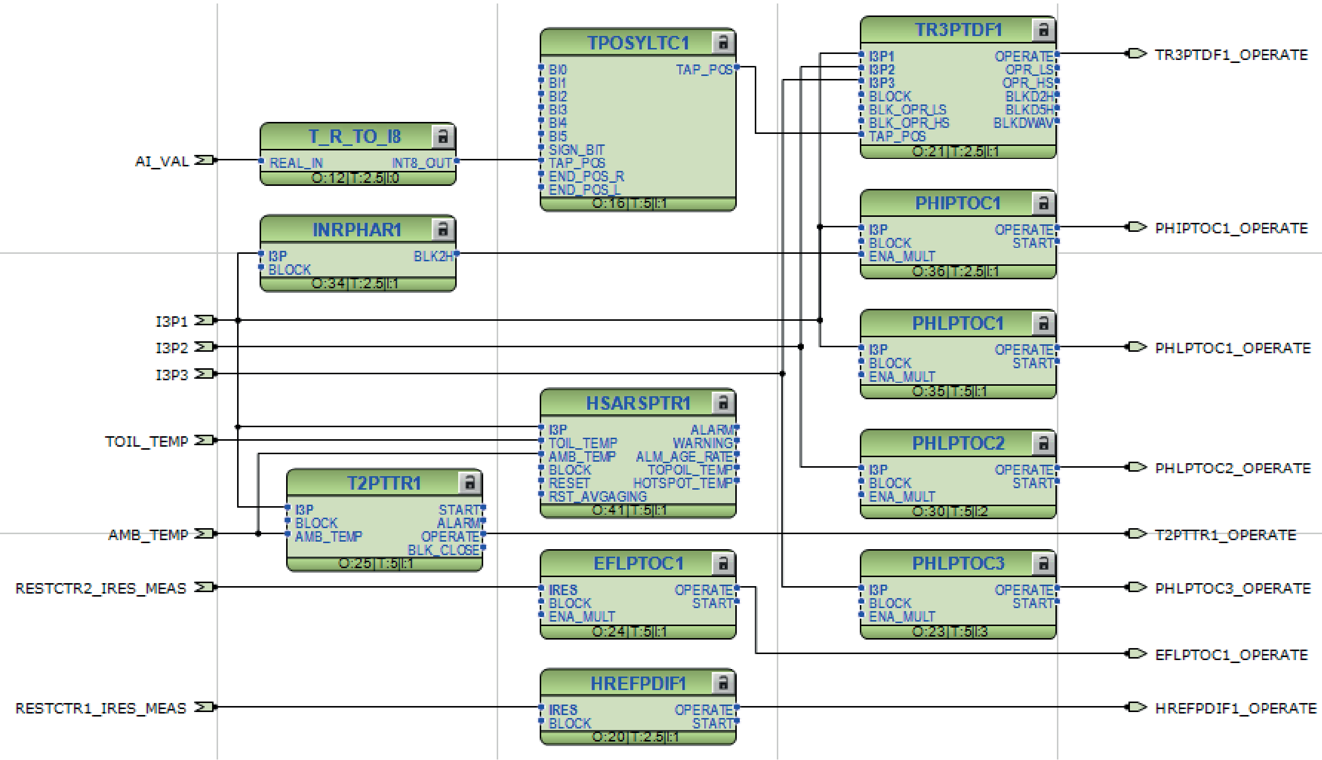

Figure 18: Application function block connections

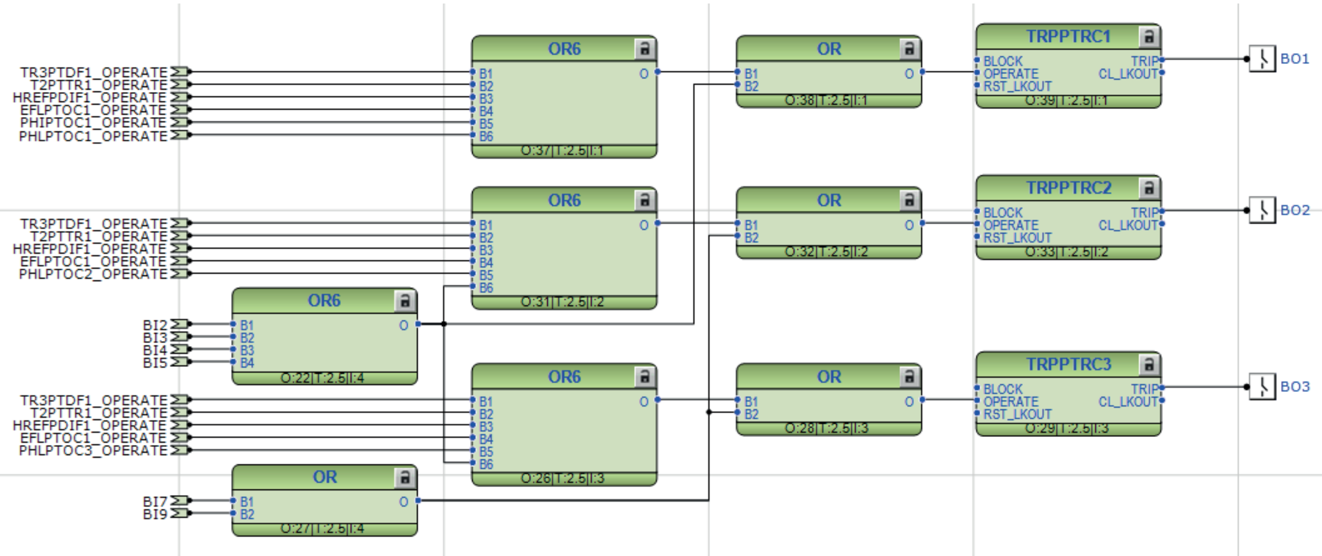

Figure 19: Relay output connections

4.3.1.8 Function blocks and setting values

ILTCTR1, ILTCTR2 and ILTCTR3 – Phase current preprocessing

ILTCTR1, ILTCTR2 and ILTCTR3 are the analog signal preprocessing functions for current signals. Table 31 shows recommended setting values; all other settings can be kept at default values.

Table 31: Settings for ILTCTR1, ILTCTR2 and ILTCTR3

Setting	Suggested values			Description
	ILTCTR1	ILTCTR2	ILTCTR3	
Primary current	300	1000	1000	Primary current value
Secondary current	1	1	1	Secondary current value

RESTCTR1 and RESTCTR2 – Residual current preprocessing

RESTCTR1 and RESTCTR2 are the analog signal preprocessing function for residual current signals. Table 32 shows recommended setting values; all other settings can be kept at default values.

Table 32: Settings for RESTCTR1 and RESTCTR2

Setting	Suggested values		Description
	RESTCTR1	RESTCTR2	
Primary current	300	300	Primary current value
Secondary current	1	1	Secondary current value

T_R_TO_I8 – Real to integer 8-bit conversion

The T_R_TO_I8 function is used to convert 32-bit floating type values to 8-bit integer type. This function does not have any settings.

TR3PTDF1 – Stabilized and instantaneous differential protection for two- or three-winding transformers

TR3PTDF1 is a unit protection function which is primarily used to protect three-winding transformers, but can also be used for the protection of two-winding transformers (see the technical manual) or generator-transformer blocks. In case of three-winding transformers, it is possible to measure three phase currents from all three windings and connect them at input group 1, 2 and 3, respectively. The basic principle of operation is to compare the currents flowing into the transformer with the currents leaving the transformer.

The stabilized, that is, low-set stage is set taking into account the CT errors, relay accuracy, power transformer no-load losses and light over-magnetization. The on-load tap changer position is connected to the function and the function is set for automatic compensation. The second harmonic restraint is used for blocking this stage at power transformer inrush. The instantaneous, that is, high-set stage is set above the power transformer inrush current (fundamental component).

Table 33 shows recommended setting values; all other settings can be kept at default values.

The setting *Zro A elimination* of TR3PTDF1 is used to select if the zero-sequence component is to be removed on one, two or all sides of the transformer. Since windings 2 and 3 in the example case are delta connected, there is no separate neutral earthing on those windings. Hence, zero-sequence component removal should not be selected. Zero-sequence elimination is applied to winding 1 in the example case.

Table 33: Settings whose values differ from default values based on the example

Setting	Suggested values	Description
Current group 3 type	Winding 3	Type of the third set / group of current inputs
CT connection 1-2	Type 2	CT connection type selection between windings 1 and 2
CT connection 1-3	Type 2	CT connection type selection between windings 1 and 3
CT ratio Cor Wnd 1	2.29 [1)]	CT ratio correction, winding 1
CT ratio Cor Wnd 2	1.73 [1)]	CT ratio correction, winding 2
CT ratio Cor 3	1.38 [1)]	CT ratio correction, current group 3 - winding 3 or restraint for winding 2 or 1
Zro A elimination	Winding 1	Elimination of the zero-sequence current
Phase shift Wnd 1-2	30 deg	Setting the phase shift between winding 1 and 2
Phase shift Wnd 1-3	30 deg	Setting the phase shift between winding 1 and 3

1) In the example case, winding 1 rated current is 25MVA/√3 · 110 kV = 131 A, CT ratio correction is 300/131 = 2.29, winding 2 rated current = 25MVA/√3 · 25 kV = 577 A, CT ratio correction = 1000/577 = 1.73, winding 3 rated current is 25MVA/√3 · 20 kV = 722 A, CT ratio correction is 1.38.

HREFPDIF1 – High-impedance based restricted earth-fault protection

HREFPDIF1 is mainly used as a unit protection for the transformer windings. The function uses a differential quantity, that is, the sum of three phase currents of the star-connected winding and the neutral current of the star-connected winding. The high-impedance principle requires external stabilizing and, typically, also voltage-dependent resistors. See the technical manual for further information.

Table 34 shows recommended setting values; all other settings can be kept at default values.

Table 34: Settings for HREFPDIF1

Setting	Suggested values	Description
Operate value	5%[1)]	Low operate value, percentage of the nominal current

1) Assume the excitation current of CT as I_e = 0.025 A (this value should be taken from the manufacturer's datasheet). Since the number of CTs per phase in the example is 4, the operate value can be set as 4 · 0.5 · 0.025 = 5% (See the technical manual for more details).

EFLPTOC1 – Non-directional earth-fault protection, low stage

EFLPTOC1 is used as non-directional earth-fault protection and measures the neutral current from the star-connected winding of the transformer (the HV winding in the example case given). When the neutral current exceeds the set limit, operate output is activated based on an operate time characteristic which can be definite time (DT) or inverse definite minimum time (IDMT).

Table 35 shows recommended setting values; all other settings can be kept at default values.

Table 35: Function settings for EFLPTOC1

Setting	Suggested values	Description
Start value	0.5 × I_n[1)]	Start value
Operate delay time	5000 ms[2)]	Operate delay time

1) A typical value is between 50...100% of the CT rated current.
2) Longer operating times are used as the function is used as standby for network earth-fault protection.

PHIPTOC1, PHLPTOC1, PHLPTOC2 and PHLPTOC3 – Three-phase non-directional overcurrent protection

The transformer overcurrent protection is intended to operate as main protection when differential protection is not used and can also be used as backup protection for differential protection for faults inside the zone of protection, that is, faults occurring in incoming or outgoing feeders, in the region of transformer terminals and tank cover.

Three-phase non-directional overcurrent protection, instantaneous stage PHIPTOC1 is a non-directional overcurrent and short-circuit protection function. The function starts when the current exceeds the set limit. The operate time characteristic is definite time (DT). Low-stage overcurrent protection function PHLPTOC1, PHLPTOC2 and PHLPTOC3 can have operate time characteristics of definite time (DT) or inverse definite minimum time (IDMT).

PHIPTOC1, PHLPTOC1, PHLPTOC2 and PHLPTOC3 measure the phase currents of the transformer. In the examples considered, PHIPTOC1 and PHLPTOC1 are connected to winding 1 of the transformer. PHLPTOC2 is connected to winding 2 of the transformer with proper coordination to get fast and reliable protection. Winding 3 of the transformer is protected with PHLPTOC3 in the example case.

The operation mode of PHIPTOC1 is DT. The *Start value* setting is typically set to 1.2 times the maximum through-fault current. The *Start value* setting of PHLPTOC1, PHLPTOC2 and PHLPTOC3 is typically set to 2 times the maximum load current. The mode of operation is set as IDMT. The operate time of PHLPTOC1, PHLPTOC2 and PHLPTOC3 can be coordinated with the downstream relays. Between PHLPTOC1 and PHLPTOC2, a time coordination of 150 ms can be set. The same time difference can be set between PHLPTOC1 and PHLPTOC3.

Table 36 and Table 37 show recommended setting values; all other settings can be kept at default values.

Table 36: Settings for PHIPTOC1

Setting	Suggested values	Description
Start value	$7 \times I_n$ 1)	Start value
Operate delay time	20 ms	Operate delay time

1) Assume the 110 kV side is rated for 20 kA short-circuit current, giving a short-circuit power of 3811 MVA. In the example case, assume transformer impedance as 8%. The winding 2 or 3 short circuit MVA = 25/0.08 = 312 MVA. System short circuit MVA = 3811 · 312/(3811 + 312) = 288 MVA. Maximum through-fault current = 1.1 · (288 + 25)MVA/(√3 · 110 kV) = 1807 A. Then, with a CT ratio of 300:1, the *Start value* setting should be 1.2 · 1807/300 ≈ 7.

Table 37: Settings for PHLPTOC1, PHLPTOC2 and PHLPTOC3

Setting	Suggested values			Description
	PHLPTOC1	PHLPTOC2	PHLPTOC3	
Start value	$0.9 \times I_n$ 1)	$1.2 \times I_n$ 1)	$1.5 \times I_n$ 1)	Start value
Minimum operate time	600 ms 2)	450 ms 2)	450 ms 2)	Minimum operate time

1) In the example case, winding 1 rated current is 25MVA/√3 · 110 kV = 13 1A. Then, with a CT ratio of 300:1, the *Start value* setting should be 2 · 131/300 ≈ 0.9. For winding 2, rated current = 25MVA/√3 · 25 kV = 577 A. Then with a CT ratio of 1000:1, the *Start value* setting should be 2 · 577/1000 ≈ 1.2. For winding 3, rated current is 25MVA/√3 · 20 kV = 722 A. Then with a CT ratio of 1000:1, the *Start value* setting should be 2 · 722/1000 ≈ 1.5.
2) PHLPTOC2 and PHLPTOC3 act as backup for feeder protection and hence have to be coordinated with the feeder relay setting. Assuming the feeder setting is 0.3 s definite time, PHLPTOC2 and PHLPTOC3 can be set as 0.3 + 0.15 = 0.45 s. PHLPTOC1 can then be set as 0.45 + 0.15 = 0.6 s.

T2PTTR1 – Three-phase thermal overload protection for power transformers, two time constants

Three-phase thermal protection T2PTTR1 protects the transformer mainly from short-time overloads. The alarm signal from T2PTTR1 gives an early warning to allow the operators to take action before the transformer trips. If the temperature continues to rise, the operate output is activated based on the thermal model of the transformer. Once tripped, the transformer is re-energized only after the transformer cooling time has elapsed.

T2PTTR1 takes the three-phase current measurement and the ambient temperature information (usually provided as an RTD input if used).

Table 38 shows recommended setting values; all other settings can be kept at default values.

Table 38: Settings whose values differ from the default values based on the example case

Setting	Suggested values	Description
Short time constant	306 s[1)]	Short time constant in seconds
Long time constant	4920 s[1)]	Long time constant in seconds
Current reference	0.44 xI_n[2)]	The load current leading to Temperature raise temperature

1) Available from the manufacturer's datasheet. If the manufacturer gives a single time constant, see the technical manual to get the corresponding short and long time constant values.
2) *Current reference* = 131 A/300 = 0.44 · I_n

HSARSPTR1 – Hot-spot and insulation ageing rate monitoring for transformers

HSARSPTR1 monitors the hot spot temperature of the transformer winding and the ageing rate of the insulation caused by thermal stress. HSARSPTR1 calculates the hot spot temperature and the loss of life of the transformer for one winding of the transformer. For the calculation, it uses the three phase currents and the RTD inputs for top oil temperature and ambient temperature. Table 39 shows recommended setting values; all other settings can be kept at default values.

Table 39: Settings whose values differ from the default values based on the example case

Setting	Suggested values	Description
Transformer Rating	25 MVA	Rating of the transformer
CT ratio correction	2.29[1)]	Current transformer ratio correction factor
Oil exponent	0.8[2)]	User-defined value for oil exponent
Winding Exponent	1.3[2)]	User-defined value for winding exponent
Constant K11	0.5[2)]	User-defined value of thermal model constant K11
Constant K21	2.00[2)]	User-defined value of thermal model constant K21
Oil time constant	12600 s[2)]	Oil time constant in seconds
Winding Tm constant	600 s[2)]	Winding time constant in seconds

1) In the example case, winding 1 rated current is 25MVA/√3 · 110 kV = 131 A, hence the CT ratio correction is 300/131 = 2.29.
2) The transformer settings are selected based on the settings *Parm select method*, *Cooling mode*, *Transformer type* and *Transformer rating*. In the example case, the setting *Parm select method* is set to "IEC", hence the transformer setting values are selected for "Medium size transformer" with "ONAN" cooling mode according to the IEC 60076-7 guidelines (see the technical manual).

TPOSYLTC1 – Tap changer position measurement

Tap changer position indication function TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using the T_R_TO_I8 function and connected to the TAP_POS input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this example case.

INRPHAR1 – Three-phase inrush detector

Three-phase inrush detector function INRPHAR1 is used to coordinate transformer inrush situations in distribution networks. All settings of INRPHAR1 are kept at default values for this example case.

TRPPTRC1, TRPPTRC2 and TRPPTRC3 - Master trip

Master trip TRPPTRC1, TRPPTRC2 and TRPPTRC3 are used as a trip command collector and handler after the protection functions. All settings of the TRPPTRC1, TRPPTRC2 and TRPPTRC3 function blocks are kept at default values for this example case.

Section 5 Transformer voltage control

5.1 Introduction to application

The load variation in a power network makes the system voltage vary accordingly. To maintain a constant voltage in the network, voltage-regulating power transformers are employed. These power transformers are equipped with on-load tap changers which change the ratio of a transformer by altering the number of turns in the primary or the secondary winding.

The voltage controller or OL5ATCC function is used to control the voltage on the load side of the power transformer. Based on the voltage and current measured, the function determines whether the voltage needs to be increased or decreased. The voltage is regulated by Raise or Lower commands sent to the tap changer. No regulation takes place as long as the voltage stays within the bandwidth setting. Once the measured voltage deviates from the bandwidth, control action starts.

Under certain circumstances, the automatic voltage regulator needs to be enhanced with additional functions such as Line Drop Compensation (LDC) and Reduce Set Voltage (RSV). See the technical manual for more details.

OL5ATCC can work in Manual, Auto single and Auto parallel modes. Also, various parallel operation modes are available to fit applications where two or more power transformers are connected to the same busbar at the same time. The parallel operation of OL5ATCC is based on three principles.

- Master/Follower (M/F) Principle
- Negative Reactance Principle (NRP)
- Minimizing Circulating Current (MCC) Principle

OL5ATCC has two settings, *Operation mode* and *Parallel mode*, for selecting the active operation mode. The setting *Operation mode* can have any of the following values: "Manual", "Auto single", "Parallel manual", "Auto parallel", "Input control" and "Command". More details about the operation modes can be found in the technical manual. Table 40 gives the typical applications of OL5ATCC.

The setting *Parallel mode* can have any of the following values: "Master", "Follower", "NRP", "MCC", "Input control" or "Command". If the *Parallel mode* setting is set to "Input control", the active operation mode is determined by the input `MSTR_TRIGG`. When the *Parallel mode* setting is set to "Command", the active operation mode is determined by the IEC 61850 command data point MstrOp.

Table 40: Typical applications and modes used

Application	OL5ATCC mode
Manual control of tap position for single transformers	Manual
Manual control of tap position for transformers connected in parallel	Parallel manual
Automatic control of transformer tap in single transformer application	Auto single
Parallel transformers with identical ratings and step voltages; communication between regulators is available	Auto parallel, M/F
Parallel transformers with different ratings and step voltages; communication between regulators is not available	Auto parallel, NRP
Parallel transformers of different ratings or step voltages in substations with varying reactive loads; communication between regulators is available enabling more accurate calculation of circulating currents	Auto parallel, MCC

5.2 Example case 1 – Single transformer control

5.2.1 Description of the example case

To explain the application of OL5ATCC, a single transformer control example case is illustrated here. Figure 20 shows the single-line diagram for an example case for a single transformer application along with the measurement requirements. An on-load tap changer is present in the HV winding.

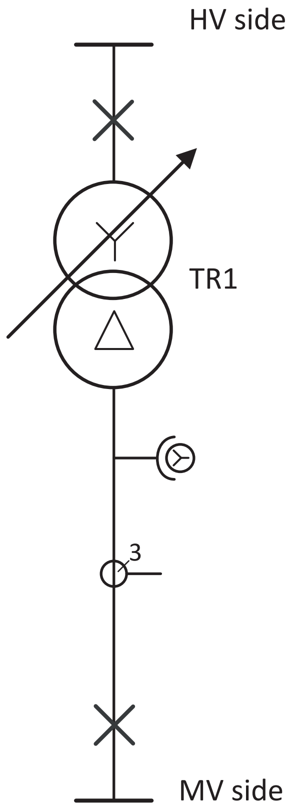

Figure 20: Single transformer application (example case 1)

Current and voltage information from the MV side (regulated side) is required for the OL5ATCC application. The tap position is also required. Example case 1 is used to illustrate manual and automatic control as well as LDC and RSV.

5.2.2 Transformer TR1 voltage control relay

5.2.2.1 Relay interface, configuration and settings

Figure 21 shows the connection details of the relay's analog inputs (AI), binary inputs (BI), milli-Ampere inputs (mA) and binary outputs (BO) for example case 1.

The CT connections for phase current measurements in all phases are also shown in the figure. The currents from the power transformer are used for various purposes.

- The highest phase current value is used for overcurrent blocking. For this, at least one phase current is required, but three phase currents are preferred. For this case, the measurements can be made from primary or secondary sides, but in the example case illustrated, current measurements are taken from the secondary side.

- Line drop compensation (average of the connected inputs): all three phase currents are required and measurements from the regulated side should be used.
- Calculating circulating current in the active operation modes: negative reactance principle (NRP) and minimizing circulating current (MCC). Current measurements are needed from the regulated side.

The VT connection for voltage measurement on the MV side is also shown in the figure. For the OL5ATCC application, at least one phase-to-phase voltage must be connected to the relay. If phase-to-earth voltages are used, at least two phase-to-earth voltages must be connected to the relay. Voltage measurement via process bus is supported for OL5ATCC1. As with physical voltage inputs on the relay, it is important that at least UL1 and UL2 are available.

The position value of the tap changer can be brought to OL5ATCC as a resistance value, an mA signal, a binary coded signal or via GOOSE. When the tap changer position is received via GOOSE, the position information is measured by another relay or from the RIO600 RTD4 module. The scaling of the tap changer position must be done in the sender. For more information on how these interfaces are implemented, see the function TPOSYLTC in the technical manual. In the example case 1 illustrated, the tap changer position value is input as an mA input.

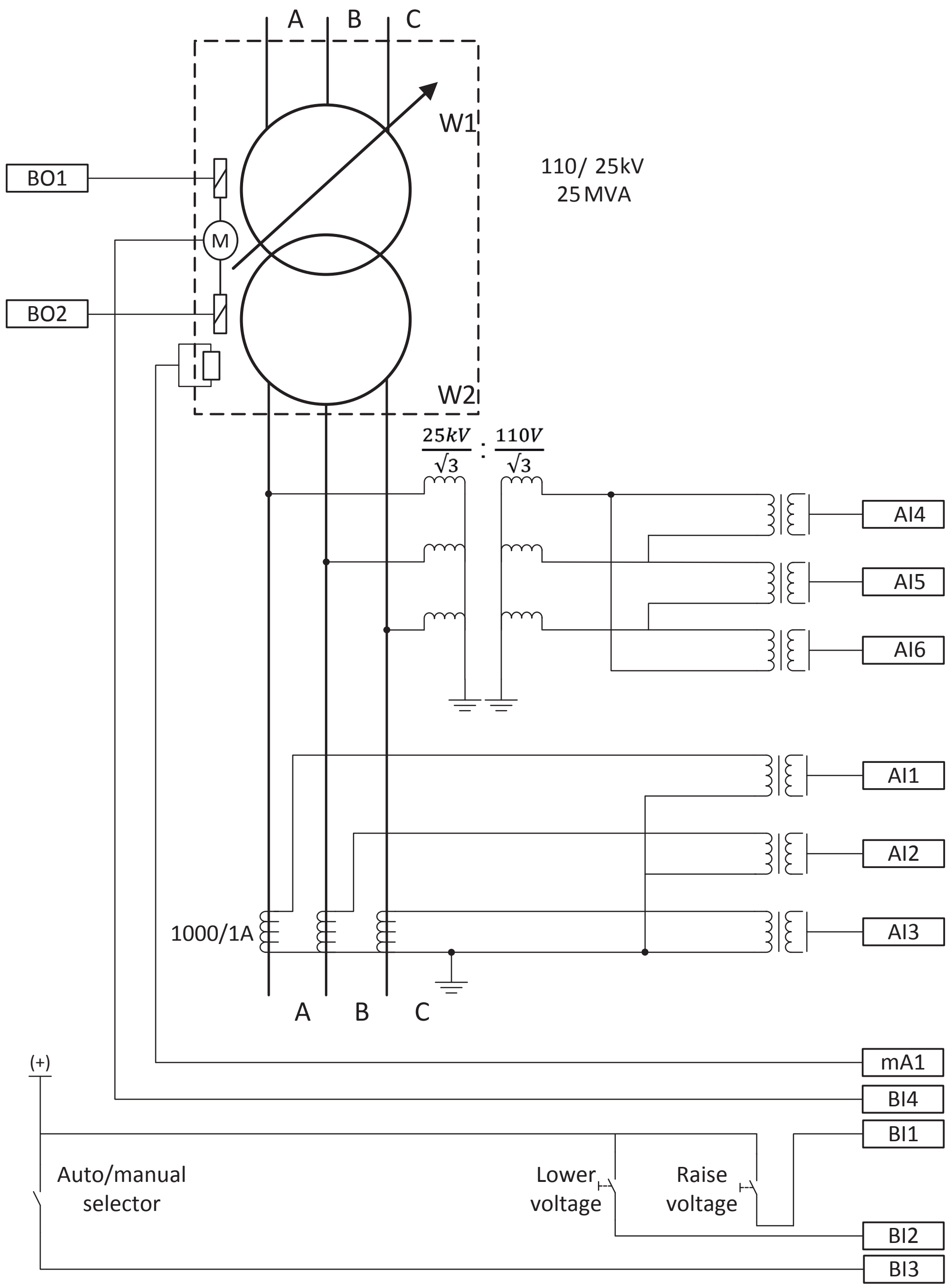

Figure 21: Relay 1 interfaces and CT/VT connections for TR1 in example case 1

Analog input signals

Table 41: Physical analog input signals necessary for implementing example case 1

Analog input	Description
AI1	Transformer winding 2, current A
AI2	Transformer winding 2, current B
AI3	Transformer winding 2, current C
AI4	Transformer winding 2, voltage AB
AI5	Transformer winding 2, voltage BC
AI6	Transformer winding 2, voltage CA

mA input signals

Table 42: Physical mA input signal for implementing example case 1

mA input	Description
mA1	Tap position of the on-load tap changer

Binary input signals

Table 43: Binary input signals necessary for implementing example case 1

Binary input	Description
BI1	Raise signal input. In manual mode, a TRUE on this input causes the tap to be raised.
BI2	Lower signal input. In manual mode, a TRUE on this input causes the tap to be lowered.
BI3[1)]	Auto input signal. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI4	Tap changer operating (TCO) input. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 44: Binary output signals necessary for implementing example case 1

Binary output	Description
BO1	Raise command for the tap changer (RAISE_OWN)
BO2	Lower command for the tap changer (LOWER_OWN)

Recommended alarms

Table 45: Alarm list for implementing example case 1

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error
OL5ATCC1	AUTO	Operation mode set as auto
OL5ATCC1	RAISE_OWN	Tap changer raise command
OL5ATCC1	LOWER_OWN	Tap changer lower command
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 46: Function blocks used in the relay configuration of example case 1

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control RAISE_LOCAL, LOWER_LOCAL and AUTO.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 47: Physical analog channels of the functions in example case 1

Function block	Secondary currents AI1, AI2, AI3	MV bus voltages AI4, AI5, AI6	Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 22, Figure 23 and Figure 24 show the relay ACT configuration for example case 1.

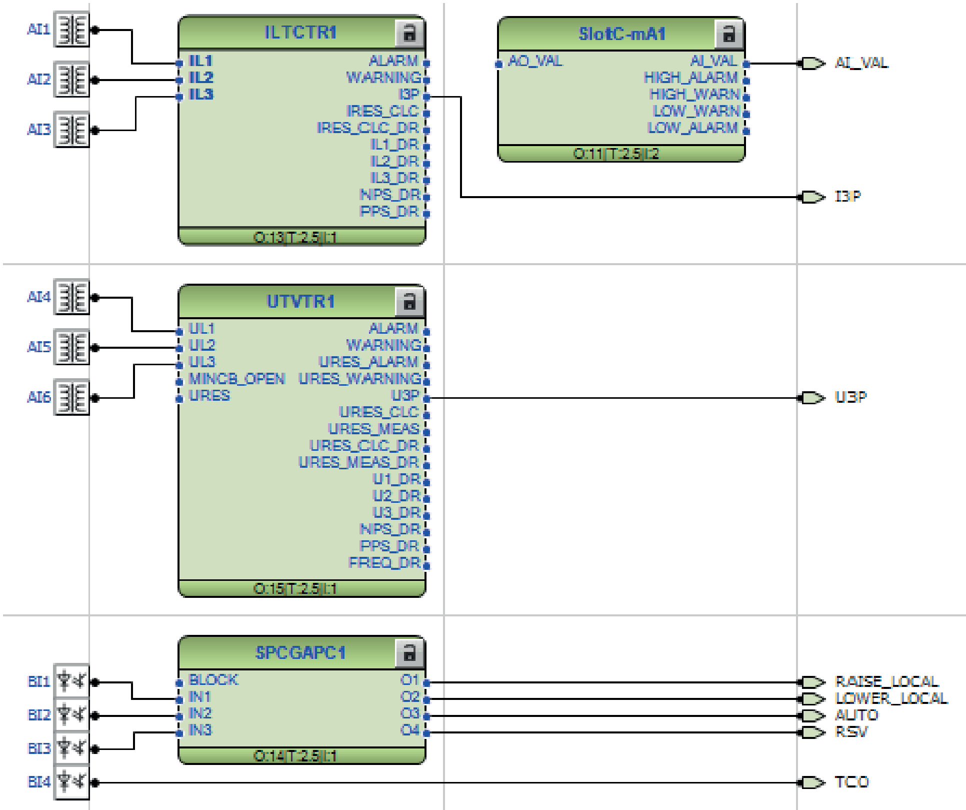

Figure 22: ACT configuration for example case 1 - Input section

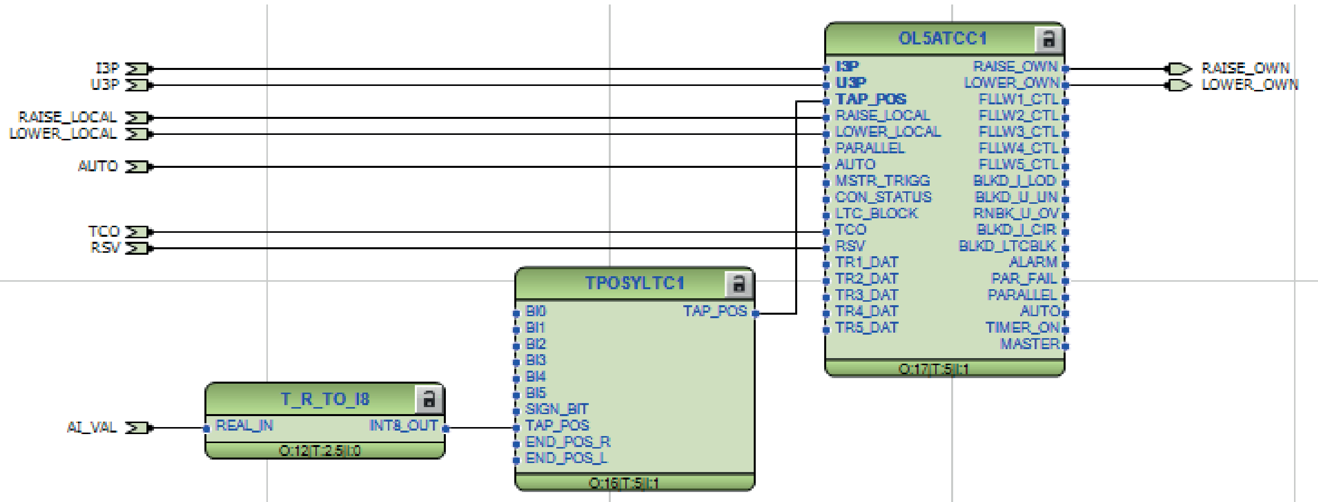

Figure 23: ACT configuration for example case 1 - Application section

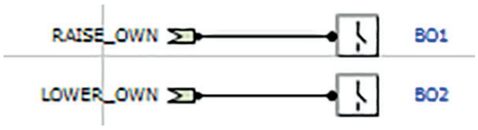

Figure 24: ACT configuration for example case 1 - Output section

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 48 shows recommended setting values; all other settings can be kept at default values.

Table 48: ILTCTR1 setting values for the transformer in example case 1

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 49 shows recommended setting values; all other settings can be kept at default values.

Table 49: UTVTR1 setting values for example case 1

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted to integer value using T_R_TO_I8 function and connected to `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `RAISE_LOCAL`, `LOWER_LOCAL` and `AUTO`. Table 50 shows recommended setting values; all other settings can be kept at default values.

Table 50: SPCGAPC1 setting values for example case 1

Setting	Suggested values	Description
Operation mode	Pulsed	Operation mode for generic control point 1
Description	Raise local	Description for output 1
Operation mode	Pulsed	Operation mode for generic control point 2
Description	Lower local	Description for output 2
Operation mode	Toggle	Operation mode for generic control point 3
Description	Auto	Description for output 3

OL5ATCC1 - Tap changer control with voltage regulator

The voltage regulator OL5ATCC1 (on-load tap changer controller) is used to regulate the voltage of power transformers with on-load tap changers in distribution substations. OL5ATCC1 provides manual or automatic voltage control of a power transformer using raise and lower signals to the on-load tap changer.

OL5ATCC1 can be used for voltage control of single transformers in manual or automatic mode of operation. It is possible to compensate for line drops and also to effect a reduced set voltage.

Manual voltage regulation

This operation mode is used to raise or lower the voltage level of the MV side of the transformer by giving manual commands. The binary input commands `RAISE_LOCAL` (BI1) or `LOWER_LOCAL` (BI2) activate the corresponding outputs `RAISE_OWN` (BO1) and `LOWER_OWN` (BO2) to control the voltage of the own transformer. The relay should be in “Local” mode; this can be verified from the LR state monitored data. The parameters for “Manual” mode in “Local (input or HMI)” and “Remote” are given in Table 51.

Table 51: OL5ATCC1 setting value for manual voltage regulation for example case 1

Setting	Suggested value	Description
Operation mode	Manual	Operation mode

Manual voltage control can also be done through remote commands if the relay is in remote mode. The relay is in remote mode if the LR state monitored data is “Remote”. All other settings are kept at default values.

Manual voltage control can also be achieved with *Operation mode* set to "Input control". The input `AUTO` (BI3) must be FALSE in this case.

Automatic voltage regulation

In automatic voltage regulation mode, the voltage is changed in steps automatically based on the setting *Band center voltage*. The control voltage is calculated from this setting by adding or subtracting different compensation factors.

Table 52: OL5ATCC1 setting value for Operation mode and Band center voltage for example case 1

Setting	Suggested values	Setting value calculation
Operation mode	Auto single	Operation mode
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.

A tolerance band is allowed on the calculated control voltage with a setting *Band width voltage*, as the tap changes happen in steps. A recommended setting for *Band width voltage* is at least twice the step voltage of the tap changer.

Table 53: OL5ATCC1 setting value for Band width voltage for example case 1

Setting	Suggested values	Setting value calculation
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.

Half of *Band width voltage* is the allowed deviation of the control voltage. Whenever the voltage goes above or below the band, OL5ATCC1 is activated and issues the commands `RAISE_OWN` (BO1) or `LOWER_OWN` (BO2) to bring the voltage within the band.

Load current limit setting is used to prevent the tap changer from operating in an overcurrent situation when the current is not high enough to activate the protective relay of the substation.

Table 54: OL5ATCC1 setting value for Load current limit for example case 1

Setting	Suggested values	Setting value calculation
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.

Block lower voltage setting allows blocking of both raise and lower voltage commands if the measured voltage is too low to be corrected by operating the tap changer, for example, when the VT secondary fuse is blown.

Table 55: OL5ATCC1 setting value for Block lower voltage for example case 1

Setting	Suggested values	Setting value calculation
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/VT primary rated value = 17.5 kV/25 kV.

In the automatic operation mode, the overvoltage situation triggers the fast lowering feature which can be adjusted with the setting parameter *Runback raise V*. This has to be set always to a value higher than the control voltage plus half of *Band width voltage*. Here control voltage is *Band center voltage* + compensation factors.

Table 56: OL5ATCC1 setting value for Runback raise V for example case 1

Setting	Suggested values	Setting value calculation
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.

Other important settings for automatic operation mode are listed below.

Table 57: Other OL5ATCC1 setting values for example case 1

Setting	Suggested values	Setting value calculation
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.
Raise block tap	17	Tap changer limit position which gives the highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

The operation mode can also be set on the HMI by selecting "Auto single" from the drop-down menu of Settings. Automatic voltage control can also be achieved with *Operation mode* set as "Input control"; `AUTO` (BI3) input must be TRUE in this case.

All other settings are kept at default values.

Line drop compensation (LDC)

The line drop compensation is used to compensate the voltage drop along a line or network fed by the transformer. As voltage drop depends on the load current, the LDC function calculates the correct increase of voltage for the specified line length. In example case 1, if the electrical circuit has a line length of 10 km with resistance and reactance per km of 0.1 Ω and 0.15 Ω per phase, respectively, the compensation parameters *Line drop V Ris* (U_r) and *Line drop V React* (U_x) have to be set as shown in Table 58.

Table 58: OL5ATCC1 setting values for LDC with no reverse power flow allowed

Setting	Suggested values	Description
Line drop V Ris	6.9%[1)]	Resistive line drop compensation factor
Line drop V React	10.4%[2)]	Reactive line drop compensation factor
LDC limit	0.2[3)]	Maximum limit for line drop compensation term

1)

$$Line\ drop\ V\ Ris = \frac{\sqrt{3} \cdot I_{CT\_n1} \cdot R}{U_{VT\_n1}} \cdot 100 = \frac{\sqrt{3} \cdot 1000 \cdot 0.1 \cdot 10}{25000} \cdot 100 = 6.9\%$$

(Equation 1)

2)

$$Line\ drop\ V\ React = \frac{\sqrt{3} \cdot I_{CT\_n1} \cdot X}{U_{VT\_n1}} \cdot 100 = \frac{\sqrt{3} \cdot 1000 \cdot 0.15 \cdot 10}{25000} \cdot 100 = 10.4\%$$

(Equation 2)

3) Maximum value of the LDC voltage term in the example case: $0.2 \cdot U_n$

If there are parallel lines between the transformer and load, the settings *Line drop V Ris* (U_r) and *Line drop V React* (U_x) should reflect the equivalent resistance and reactance. For example, if there are two identical lines with equal loads, the settings above are changed to 3.45% and 5.2%, respectively.

If topology changes are expected (which also affect the equivalent resistance and reactance), a different setting group can be used for each topology.

Table 59: Setting groups for topology changes

Setting	Suggested values			Description
	Setting group 1[1)]	Setting group 2[2)]	Setting group 3[3)]	
Line drop V Ris	6.9%	4.15%	8.3%	Resistive line drop compensation factor
Line drop V React	10.4%	5.54%	11.08%	Reactive line drop compensation factor
LDC limit	0.2	0.1	0.4	Maximum limit for line drop compensation term

1) Equivalent resistance = 1; Equivalent reactance = 1.5;
2) Equivalent resistance = 0.6; Equivalent reactance = 0.8;
3) Equivalent resistance = 1.2; Equivalent reactance = 1.6;

By default, the line drop compensation is effective only on the normal power flow direction. If the active power flow in the transformer turns opposite (that is, from the regulated side towards the system in the upper level), the LDC term is ignored. If LDC has to be allowed during reverse power flow, the setting *Rv Pwr flow allowed* can be used. This allows a negative LDC value to be received in reverse power flow situations.

All other settings related to LDC are kept at default values.

Table 60: Additional OL5ATCC1 setting for LDC to allow reverse power flow

Setting	Suggested value	Description
Rv Pwr flow allowed	TRUE	Reverse power flow allowed

Reduced Set Voltage (RSV)

During an underfrequency condition, either the power supply has to be increased or some load has to be shed to restore the power balance. Activation of Reduced Set Voltage (`RSV`) binary input helps in reducing the voltage level by giving a lower band center voltage value to the regulators. For this purpose, OL5ATCC1 has the setting group parameter *Band reduction*. If `RSV` input is true, the set target voltage value is decreased by *Band reduction*.

Table 61: OL5ATCC1 setting values for the RSV application

Setting	Suggested values			Description
	Setting group 1	Setting group 2	Setting group 3	
Band reduction	0.02	0.03	0.04	Step size for reduce set voltage (RSV)

5.2.3 Use of transformer voltage control application

5.2.3.1 Achieving transformer voltage control in manual mode

1. In the HMI application, tap the Tap_Changer_Control block in the single-line diagram.

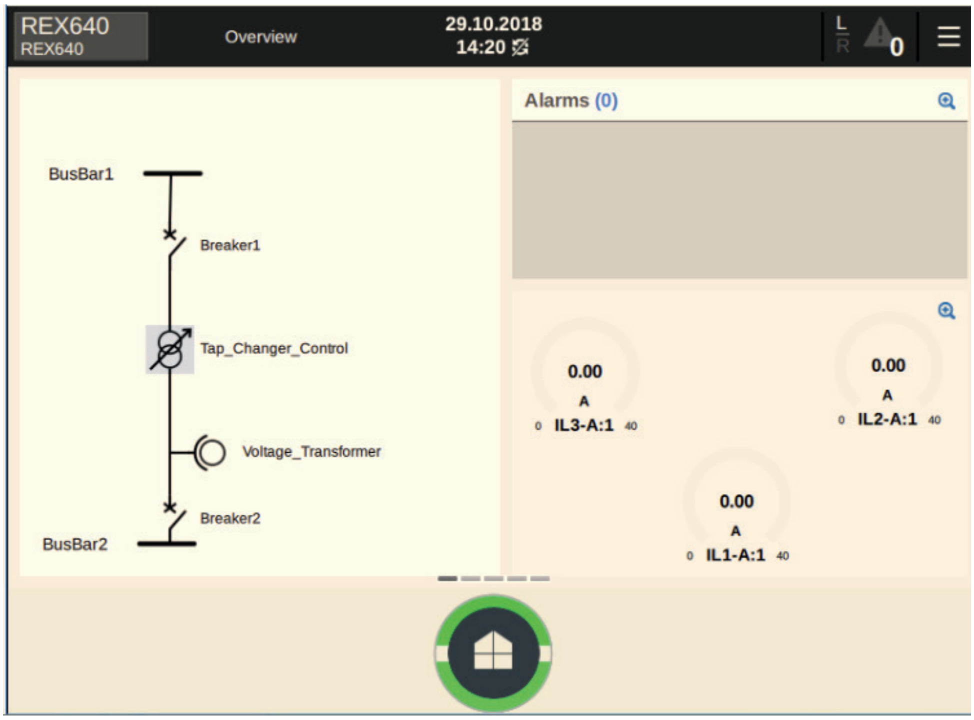

Figure 25: Opening the tap changer control

A dialog box opens where the voltage value and the tap position are displayed. In this example, the voltage is 0.98xUn and the tap position is 8.

2. Tap **Settings**.

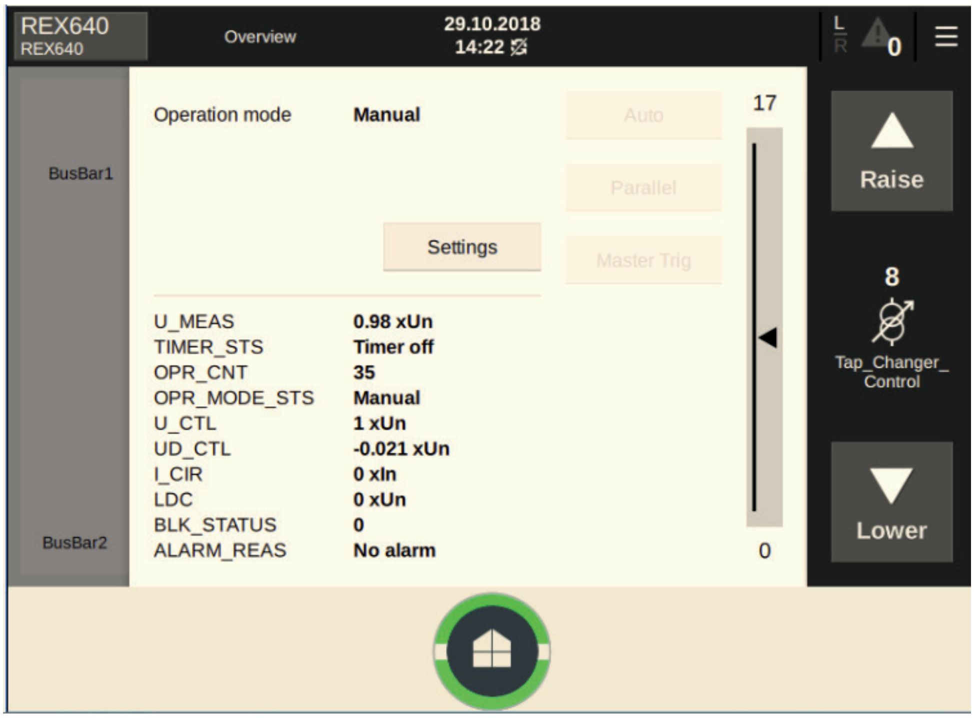

Figure 26: Opening the Settings menu

3. Tap **Raise** to raise the voltage.
   The voltage is now 1.0xUn at tap position 9.

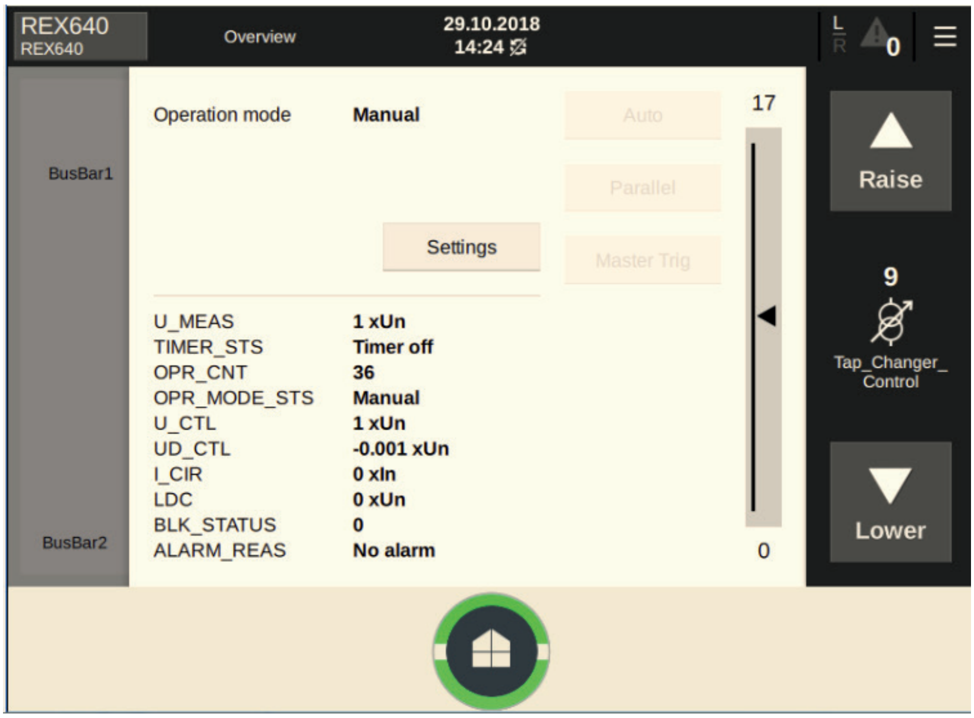

Figure 27: Operating the Raise/Lower buttons

5.3 Example case 2 – Parallel transformer control in M/F mode

This chapter provides detailed information about the configuration of the relays used in the application example: the relay interfaces, the ACT diagrams and parameter settings along with information on how the transformer voltage control can be achieved in Master/Follower mode for the given example.

5.3.1 Description of the example case

To explain the application of OL5ATCC for the parallel transformer application, a typical example case is illustrated with three transformers connected in parallel.

Figure 28 shows the single-line diagram for the example case along with the measurement requirements. An on-load tap changer is present in the HV winding of the transformers. Current and voltage information from the MV side (regulated side) is required for the OL5ATCC application. Additional information required is the tap position.

This example case is used to illustrate the Master/Follower (M/F) mode of operation. This mode can be used when the transformers connected in parallel have identical ratings. To implement the example case, three relays (Relay 1 for transformer TR1, Relay 2 for transformer TR2 and Relay 3 for transformer TR3) are required. Also, communication between the relays is needed.

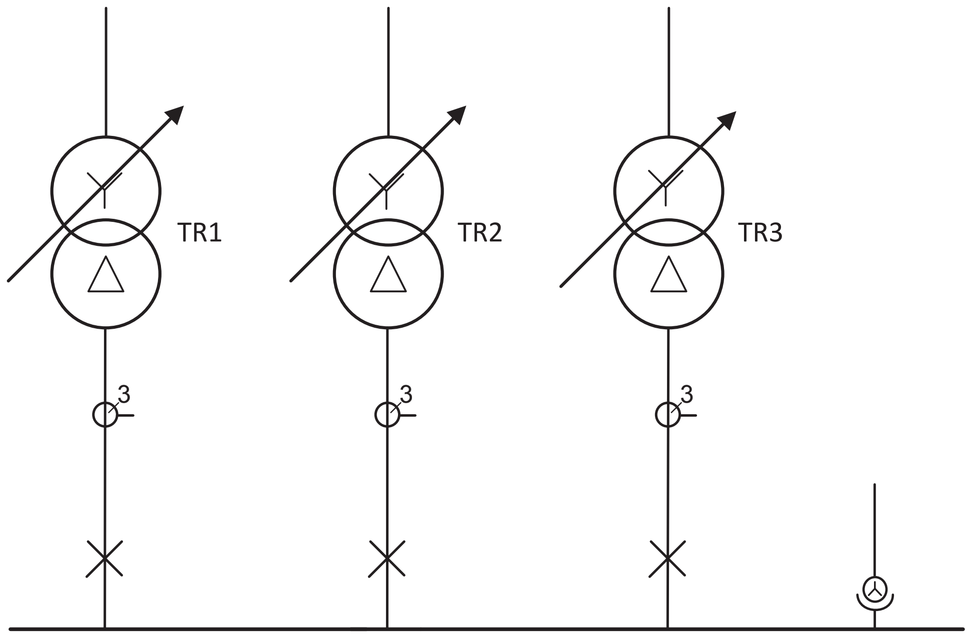

Figure 28: Parallel transformer application (example case 2)

5.3.2 Transformer TR1 voltage control relay (Master)

5.3.2.1 Relay interface, configuration and settings

Figure 29 shows the connection details of the relay's (Relay 1) analog inputs (AI), binary inputs (BI), milli-Ampere inputs (mA) and binary outputs (BO) for transformer TR1 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown. In the example case, the tap changer position value is input as an mA input for transformer TR1 and input to TPOSYLTC.

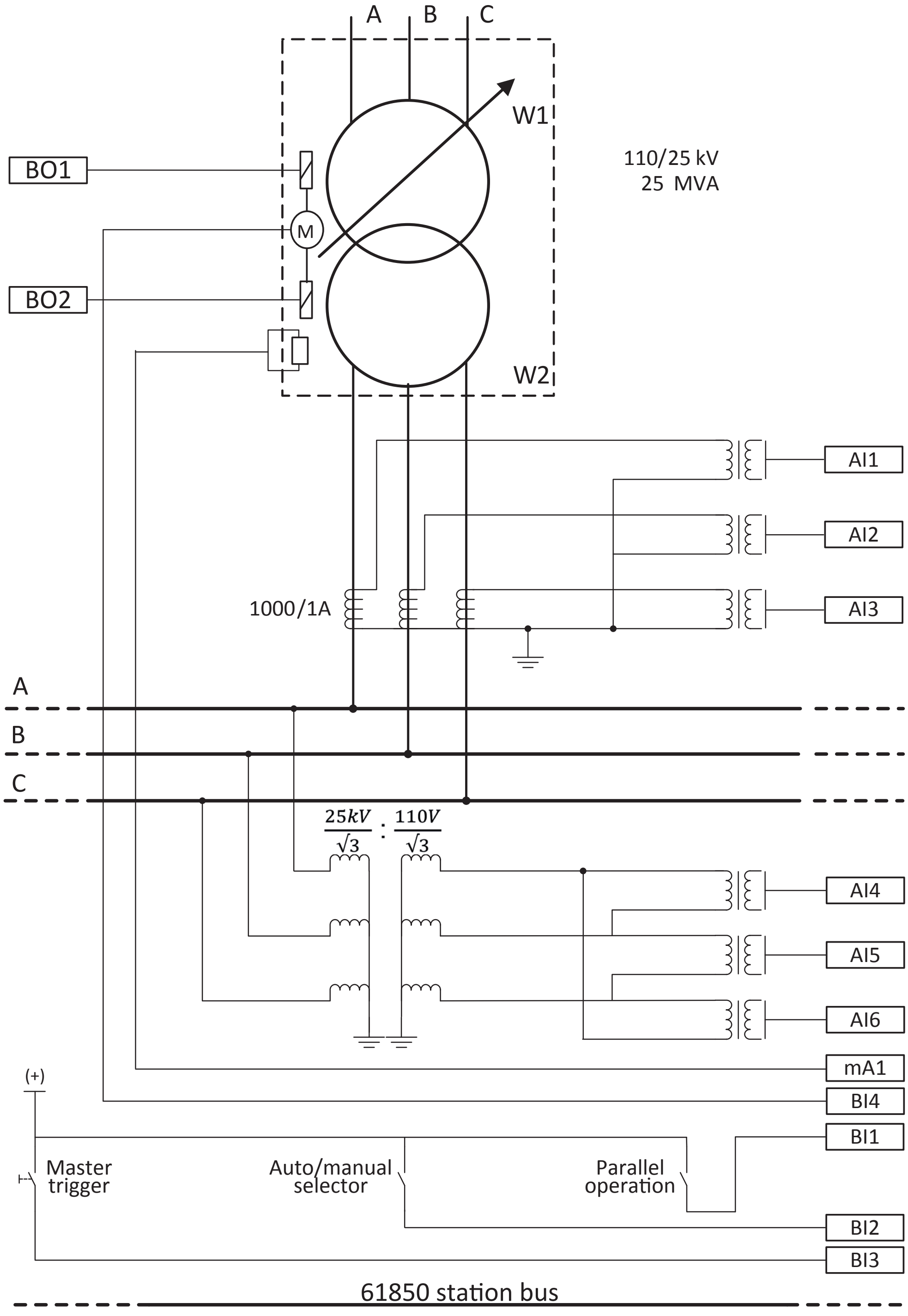

Figure 29: Relay 1 interfaces and CT/VT connections for TR1 in example case 2

Analog input signals

Table 62: Physical analog input signals for implementing Relay 1 in example case 2

Analog input	Description
AI1	Transformer TR1 winding 2, current A
AI2	Transformer TR1 winding 2, current B
AI3	Transformer TR1 winding 2, current C
AI4	Transformer TR1 winding 2, voltage AB
AI5	Transformer TR1 winding 2, voltage BC
AI6	Transformer TR1 winding 2, voltage CA

mA input signals

Table 63: Physical mA input signal for implementing Relay 1 in example case 2

mA input	Description
mA1	Tap position of the on-load tap changer for TR1

Binary input signals

Table 64: Binary input signals for implementing Relay 1 in example case 2

Binary input	Description
BI1[1)]	Parallel input signal for TR1. A TRUE on this input enables parallel operation of transformers.
BI2[1)]	Auto input signal for TR1. A TRUE on this input enables auto mode and a FALSE on this input enables manual mode.
BI3	Master Trigger input connected to MSTR_TRIGG for TR1. A rising edge input (FALSE to TRUE) causes the connected relay to assume the master role.
BI4	Tap changer operating (TCO) input for TR1. A TRUE on this input indicates that tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 65: Binary output signals for implementing Relay 1 in example case 2

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR1
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR1

Recommended alarms

Table 66: Alarm list for implementing Relay 1 in example case 2

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR1
OL5ATCC1	AUTO	Operation mode for TR1 set as auto
OL5ATCC1	PAR_FAIL	Parallel failure detected
OL5ATCC1	RAISE_OWN	Raise command for transformer TR1
OL5ATCC1	LOWER_OWN	Lower command for transformer TR1
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR1
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR1
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR1
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR1

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 67: Function blocks used in Relay 1 configuration of example case 2

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control PARALLEL and AUTO.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data from transformers connected in parallel, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`.
GOOSERCV_INT8	Received GOOSE 8-bit integer value information. The GOOSERCV_INT8 function is used to connect the GOOSE 8-bit integer inputs to the application. In the example case, it is used to receive tap position information from parallel transformers.

Table continues on next page

Function block	Description
GOOSERCV_INT32	Received GOOSE 32-bit integer value information. The GOOSERCV_INT32 function is used to connect GOOSE 32-bit integer inputs to the application. In the example case, it is used to receive tap follow command from the master relay.
GOOSERCV_ENUM	Received GOOSE enumerator value information. The GOOSERCV_ENUM function is used to connect GOOSE enumerator inputs to the application. In the example case, it is used to receive status information.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 68: Physical analog channels of Relay 1 functions in example case 2

Function block	TR1 secondary currents AI1, AI2, AI3	MV Bus voltages AI4, AI5, AI6	TR1 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 30, Figure 31, Figure 32 and Figure 33 show the ACT diagram for transformer TR1 in example case 2. All needed connections for parallel transformer voltage control in M/F mode are shown in the ACT.

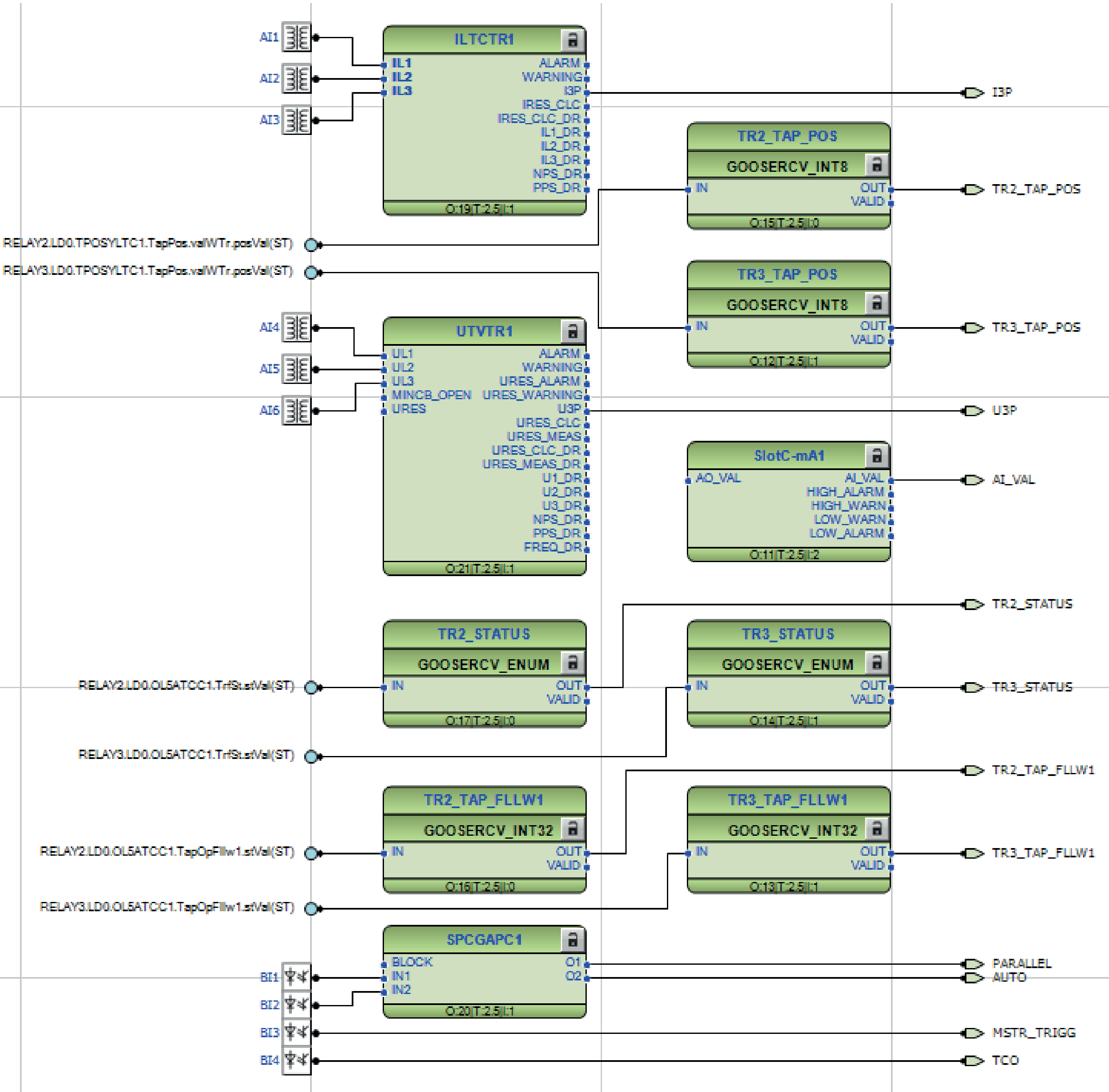

Figure 30: ACT diagram for transformer TR1 (Relay 1) in example case 2 – Input section

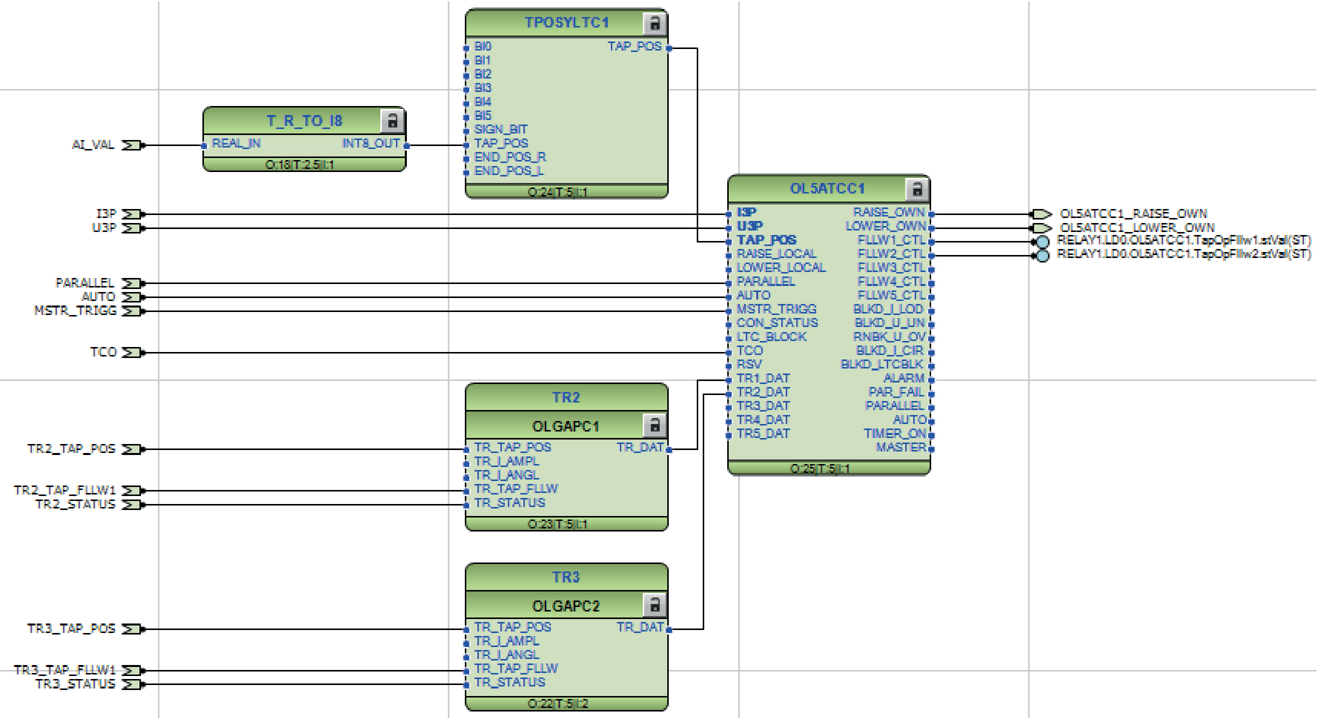

Figure 31: ACT diagram for transformer TR1 (Relay 1) in example case 2 – Application section

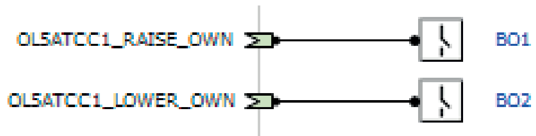

Figure 32: ACT diagram for transformer TR1 (Relay 1) in example case 2 – Output section

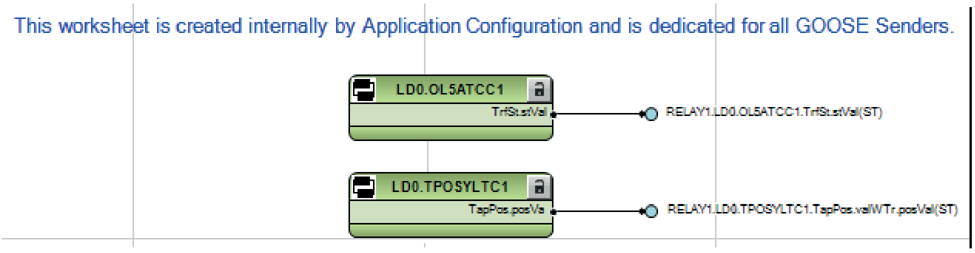

Figure 33: ACT diagram for transformer TR1 (Relay 1) in example case 2 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 69 shows recommended setting values; all other settings can be kept at default values.

Table 69: ILTCTR1 setting values for TR1 Relay in example case 2

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 70 shows recommended setting values; all other settings can be kept at default values.

Table 70: UTVTR1 setting values for TR1 Relay in example case 2

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 71 shows recommended setting values; all other settings can be kept at default values.

Table 71: SPCGAPC1 setting values for TR1 Relay in example case 2

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function can combine the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`. In Relay 1, OLGAPC1 connects inputs `TR2_TAP_POS`, `TR2_TAP_FLLW1` and `TR2_STATUS` to `TR1_DAT`. OLGAPC2 connects inputs `TR3_TAP_POS`, `TR3_TAP_FLLW1` and `TR3_STATUS` to `TR2_DAT`. `TRx_TAP_FLLWx` receives control commands (Raise/Lower) from the master when another relay is master. `TRx_STATUS` connection is mandatory for TR1 to know how many followers it has. In the absence of this input, TRx is considered as independent and is not controlled by Relay 1.

The function does not have any settings.

OL5ATCC1 – Tap changer control with voltage regulator in auto parallel M/F mode

The voltage regulator OL5ATCC1 (on-load tap changer controller) is designed to be used for regulating the voltage of power transformers with on-load tap changers in distribution substations. OL5ATCC1 provides manual or automatic voltage control of a power transformer using raise and lower signals to the on-load tap changer.

When automatic voltage control of multiple transformers connected in parallel has to be carried out, the auto parallel mode has to be used. Automatic voltage control for parallel identical transformers can be achieved using the Master/Follower mode, where the master measures and controls, and the others follow the master. In the example case, the regulator connected to transformer TR1 (Relay 1) is the master.

If tap positions from parallel transformers are unknown, `TR_TAP_POS` input to corresponding OLGAPC should be left unconnected. The master does a blind control of followers in this scenario.

Table 72: OL5ATCC1 setting values for automatic voltage control in M/F application

Setting	Suggested values	Setting value calculation
Operation mode	Input control	Operation mode
Parallel mode	Input control	Parallel mode selection
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Table continues on next page		

Setting	Suggested values	Setting value calculation
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/ VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives lowest voltage on the regulated side for the example is set to 0.
Raise block tap	17	Tap changer limit position which gives highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

See section Automatic voltage regulation of example case 1.

In the example case, automatic voltage control for parallel transformers in M/F mode is achieved with *Operation mode* and *Parallel Mode* set to "Input control". Inputs `PARALLEL` (BI1) and `AUTO` (BI2) must be TRUE and input `MSTR_TRIGG` (BI3) must have a rising edge change (FALSE to TRUE) in this case. The master role is kept until a participating parallel transformer starts acting as master or if the active operation mode is changed using *Operation mode* or *Parallel mode* selections.

The operation mode and the parallel mode can be set on the HMI by tapping Settings and selecting "Input control" for *Operation mode* and *Parallel mode*.

All other settings are kept at default values.

Line drop compensation (LDC)

The line drop compensation can be used to compensate the voltage drop along a line or network fed by the transformers in M/F mode. Table 73, Table 74 and Table 75 show recommended setting values; all other settings can be kept at default values.

Table 73: *OL5ATCC1 setting value for LDC with no reverse power flow allowed*

Setting	Suggested values	Description
Line drop V Ris	6.9%[1)]	Resistive line drop compensation factor
Line drop V React	10.4%[2)]	Reactive line drop compensation factor
LDC limit	0.2[3)]	Maximum limit for line drop compensation term
Parallel trafos	2[4)]	Number of parallel transformers in addition to own transformer

1)

$$Line\ drop\ V\ Ris = \frac{\sqrt{3} \cdot I_{CT\_n1} \cdot R}{U_{VT\_n1}} \cdot 100 = \frac{\sqrt{3} \cdot 1000 \cdot 0.1 \cdot 10}{25000} \cdot 100 = 6.9\%$$

(Equation 3)

2)

$$Line\ drop\ V\ React = \frac{\sqrt{3} \cdot I_{CT\_n1} \cdot X}{U_{VT\_n1}} \cdot 100 = \frac{\sqrt{3} \cdot 1000 \cdot 0.15 \cdot 10}{25000} \cdot 100 = 10.4\%$$

(Equation 4)

3) The maximum value of the LDC voltage term allowed in the example case is $0.2 \cdot U_n$.
4) To be used only if the number of transformers connected in parallel is not available (that is, all tap positions are not available)

Table 74: *Setting groups for topology changes*

Setting	Suggested values			Description
	Setting group 1[1)]	Setting group 2[2)]	Setting group 3[3)]	
Line drop V Ris	6.9%	4.15%	8.3%	Resistive line drop compensation factor
Line drop V React	10.4%	5.54%	11.08%	Reactive line drop compensation factor
LDC limit	0.2	0.1	0.4	Maximum limit for line drop compensation term

1) Equivalent resistance = 1; Equivalent reactance = 1.5;
2) Equivalent resistance = 0.6; Equivalent reactance = 0.8;
3) Equivalent resistance = 1.2; Equivalent reactance = 1.6;

Table 75: *Additional OL5ATCC1 setting value for LDC to allow reverse power flow*

Setting	Suggested values	Description
Rv Pwr flow allowed	TRUE	Reverse power flow allowed

Mode change

Change from one operation mode to another is possible with the help of inputs `PARALLEL`, `AUTO` and `MSTR_TRIGG`. For any participating parallel transformer to take over the master role, `MSTR_TRIGG` input should get a rising edge (FALSE to TRUE) input with `PARALLEL` and `AUTO` input TRUE. The existing master then changes its role to a follower.

Further, if the relay is in local mode, the manual raise and lower commands of OL5ATCC1 prevail over the remote commands (from SCADA). Similarly, when the relay is in remote mode, the remote raise and lower commands (from SCADA) prevail over the manual raise and lower commands of OL5ATCC1.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 76: GOOSE input signals for implementing Relay 1 in example case 2

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR2	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal1)	Tap position of TR2 from Relay 2	OLGAPC1	TR_TAP_POS
TR2	OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal2)	Lower/Raise command from Relay 2 when Relay 2 is master	OLGAPC1	TR_TAP_FLLW
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal3)	Status information of TR2 from Relay 2	OLGAPC1	TR_STATUS
TR3	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal1)	Tap position of TR3 from Relay 3	OLGAPC2	TR_TAP_POS
TR3	OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal2)	Lower/Raise command from Relay 3 when Relay 3 is master	OLGAPC2	TR_TAP_FLLW
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal3)	Status information of TR3 from Relay 3	OLGAPC2	TR_STATUS

1) Input signal received via GOOSERCV_INT8
2) Input signal received via GOOSERCV_INT32
3) Input signal received via GOOSERCV_ENUM

Table 77: GOOSE output signals for implementing Relay 1 in example case 2

Function block	Output	Data	Description
TPOSYLTC1	TAP_POS	LD0.TPOYLTC1.TapPos.valWTr.posVal	Tap position of TR1 from Relay 1 to Relay 2 and 3
OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal	Lower/Raise command from Relay 1 to Relay 2 and 3 when Relay 1 is master
OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal	Lower/Raise command from Relay 1 to Relay 2 and 3 when Relay 1 is master
OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal	Status information of TR1 from Relay 1 to Relay 2 and 3

5.3.3 Transformer TR2 voltage control relay (Follower 1)

5.3.3.1 Relay interface, configuration and settings

Figure 34 shows the connection details of the relay's (Relay 2) analog inputs (AI), binary inputs (BI), milli-Ampere inputs (mA) and binary outputs (BO) for transformer TR2 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown. In the example case, the tap changer position value is input as an mA input for transformer TR2 and input to TPOSYLTC.

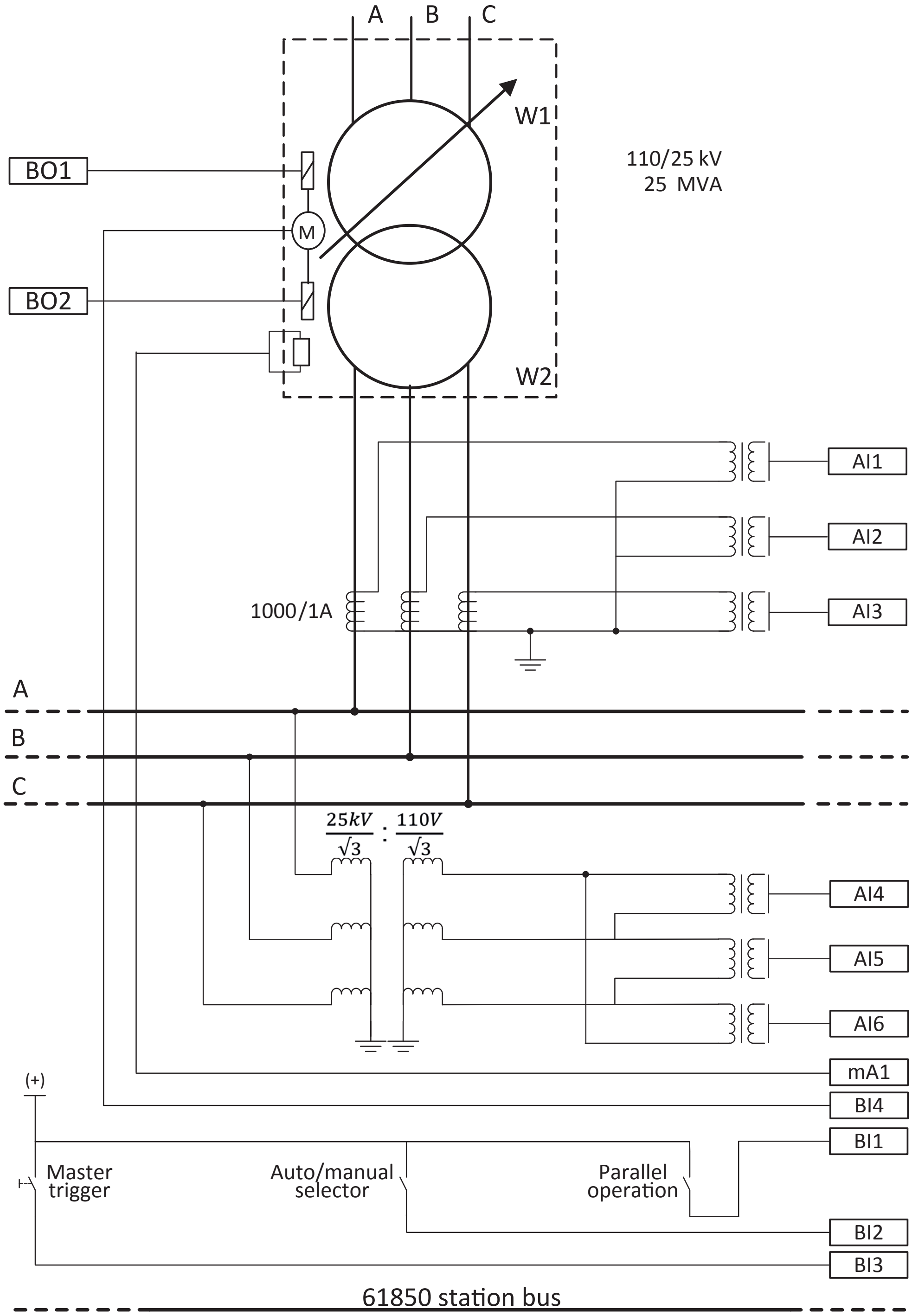

Figure 34: Relay 2 interfaces and CT/VT connections for TR2 in example case 2

Analog input signals

Table 78: Physical analog input signals for implementing Relay 2 in example case 2

Analog input	Description
AI1	Transformer TR2 winding 2, current A
AI2	Transformer TR2 winding 2, current B
AI3	Transformer TR2 winding 2, current C
AI4	Transformer TR2 winding 2, voltage AB
AI5	Transformer TR2 winding 2, voltage BC
AI6	Transformer TR2 winding 2, voltage CA

mA input signals

Table 79: Physical mA input signal for implementing Relay 2 in example case 2

mA input	Description
mA1	Tap position of the on-load tap changer for TR2

Binary input signals

Table 80: Binary input signals for implementing Relay 2 in example case 2

Binary input	Description
BI1[1)]	Parallel input signal for TR2. A TRUE on this input enables parallel operation of transformers.
BI2[1)]	Auto input signal for TR2. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI3	Master Trigger input connected to MSTR_TRIGG for TR2. A rising edge input (FALSE to TRUE) causes the connected relay to assume the master role.
BI4	Tap changer operating (TCO) input for TR2. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 81: Binary output signals for implementing Relay 2 in example case 2

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR2
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR2

Recommended alarms

Table 82: Alarm list for implementing Relay 2 in example case 2

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR2
OL5ATCC1	AUTO	Operation mode for TR2 set as auto
OL5ATCC1	PAR_FAIL	Parallel failure detected
OL5ATCC1	RAISE_OWN	Raise command for transformer TR2
OL5ATCC1	LOWER_OWN	Lower command for transformer TR2
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR2
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR2
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR2
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR2

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 83: Function blocks used in Relay 2 configuration of example case 2

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control `PARALLEL` and `AUTO`.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`.
GOOSERCV_INT8	Received GOOSE 8-bit integer value information. GOOSERCV_INT8 is used to connect the GOOSE 8-bit integer inputs to the application. In the example case, it is used to receive tap position information from parallel transformers.
Table continues on next page	

Function block	Description
GOOSERCV_INT32	Received GOOSE 32-bit integer value information. GOOSERCV_INT32 is used to connect GOOSE 32-bit integer inputs to the application. In the example case, it is used to receive tap follow command from the master relay.
GOOSERCV_ENUM	Received GOOSE enumerator value information. GOOSERCV_ENUM is used to connect GOOSE enumerator inputs to the application. In the example case, it is used to receive status information.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 84: Physical analog channels of Relay 2 functions in example case 2

Function block	TR2 secondary currents AI1, AI2, AI3	MV Bus voltages	TR2 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 35, Figure 36, Figure 37 and Figure 38 show the ACT diagram for transformer TR2 in example case 2. All needed connections for parallel transformer voltage control in M/F mode are shown in Application Configuration.

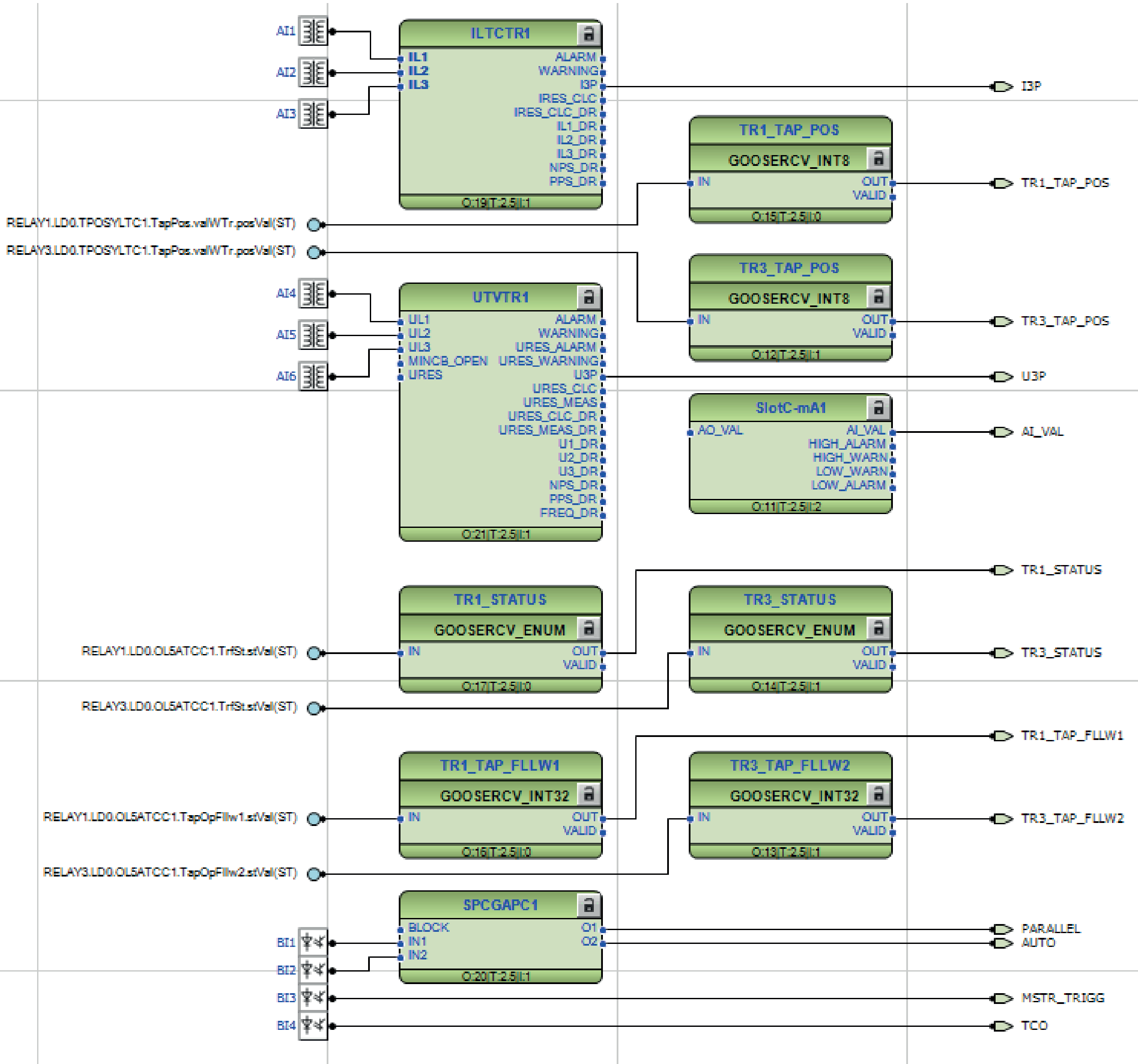

Figure 35: ACT diagram for transformer TR2 (Relay 2) in example case 2 – Input section

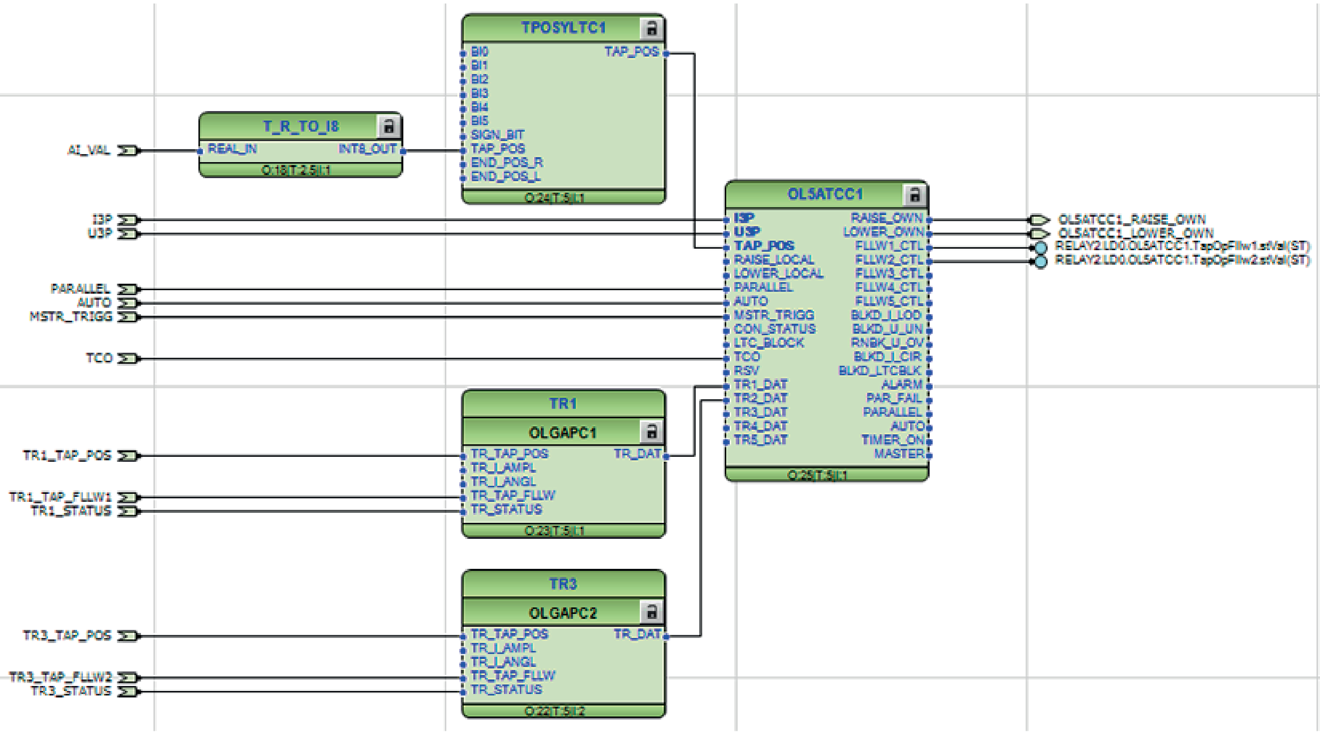

Figure 36: ACT diagram for transformer TR2 (Relay 2) in example case 2 – Application section

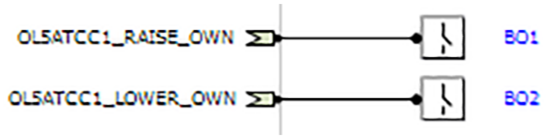

Figure 37: ACT diagram for transformer TR2 (Relay 2) in example case 2 – Output section

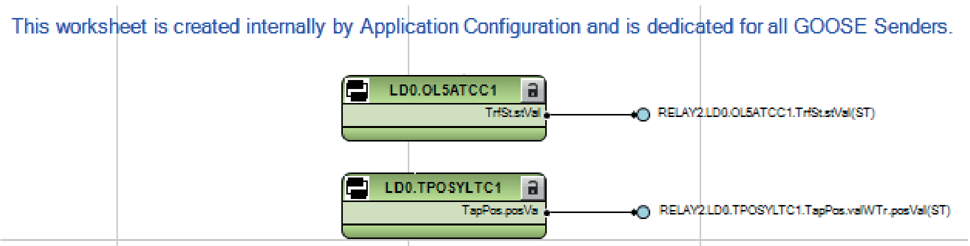

Figure 38: ACT diagram for transformer TR2 (Relay 2) in example case 2 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 85 shows recommended setting values; all other settings can be kept at default values.

Table 85: ILTCTR1 setting values for TR2 Relay in example case 2

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 86 shows recommended setting values; all other settings can be kept at default values.

Table 86: UTVTR1 setting values for TR2 Relay in example case 2

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 87 shows recommended setting values; all other settings can be kept at default values.

Table 87: SPCGAPC1 setting values for TR2 Relay in example case 2

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function combines the transformer data, that is, TR_TAP_POS, TR_I_AMPL, TR_I_ANGL, TR_TAP_FLLW and TR_STATUS as TR_DAT. In Relay 2, OLGAPC1 connects TR1_TAP_POS, TR1_TAP_FLLW1 and TR1_STATUS to TR1_DAT. OLGAPC2 connects inputs TR3_TAP_POS, TR3_TAP_FLLW2 and TR3_STATUS to TR2_DAT. TRx_TAP_FLLWx receives control commands (Raise/Lower) from the master when another relay is master. TRx_STATUS connection is mandatory for TR2 to know how many followers it has when it gets master role. In the absence of this input, TRx is considered as independent and is not controlled by Relay 2.

The function does not have any settings.

OL5ATCC1 - Tap changer control with voltage regulator

Relay 2 acts as a follower in this mode and the tap setting follows the master (Relay 1).

Table 88: OL5ATCC1 setting values for automatic voltage control in the follower application

Setting	Suggested values	Setting value calculation
Operation mode	Input control	Operation mode
Parallel mode	Input control	Parallel mode selection
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.

Table continues on next page

Setting	Suggested values	Setting value calculation
Raise block tap	17	Tap changer limit position which gives the highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

See section Automatic voltage regulation of example case 1.

In the example case, the follower mode can be achieved with *Operation mode* set to "Input control". Inputs PARALLEL (BI1) and AUTO (BI2) must be TRUE. There should be no rising edge transition on MSTR_TRIGG (BI3) input.

Operation mode and parallel mode settings can be done from the HMI application by tapping Settings and selecting "Input" from the drop-down for *Operation mode* and "Input control" from the drop-down for *Parallel mode*.

All other settings are kept at default values.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 89: GOOSE input signals for implementing Relay 2 in example case 2

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR1	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal1)	Tap position of TR1 from Relay 1	OLGAPC1	TR_TAP_POS
TR1	OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal2)	Lower/Raise command from Relay 1 when Relay 1 is master	OLGAPC1	TR_TAP_FLLW
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal3)	Status information of TR1 from Relay 1	OLGAPC1	TR_STATUS

Table continues on next page

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR3	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal[1)]	Tap position of TR3 from Relay 3	OLGAPC2	TR_TAP_POS
TR3	OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal[2)]	Lower/Raise command from Relay 3 when Relay 3 is master	OLGAPC2	TR_TAP_FLLW
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal[3)]	Status information of TR3 from Relay 3	OLGAPC2	TR_STATUS

1) Input signal received via GOOSERCV_INT8
2) Input signal received via GOOSERCV_INT32
3) Input signal received via GOOSERCV_ENUM

Table 90: GOOSE output signals for implementing Relay 2 in example case 2

Function block	Output	Data	Description
TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal	Tap position of TR2 from Relay 2 to Relay 1 and 3
OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal	Lower/Raise command from Relay 2 to Relay 1 and 3 when Relay 2 is master
OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal	Lower/Raise command from Relay 2 to Relay 1 and 3 when Relay 2 is master
OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal	Status information of TR2 from Relay 2 to Relay 1 and 3

5.3.4 Transformer TR3 voltage control relay (Follower 2)

5.3.4.1 Relay interface, configuration and settings

Figure 39 shows the connection details of the relay's (Relay 3) analog inputs (AI), binary inputs (BI), milli-Ampere inputs (mA) and binary outputs (BO) for transformer TR3 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown. In the example case, the tap changer position value is input as an mA input for transformer TR3 and input to TPOSYLTC.

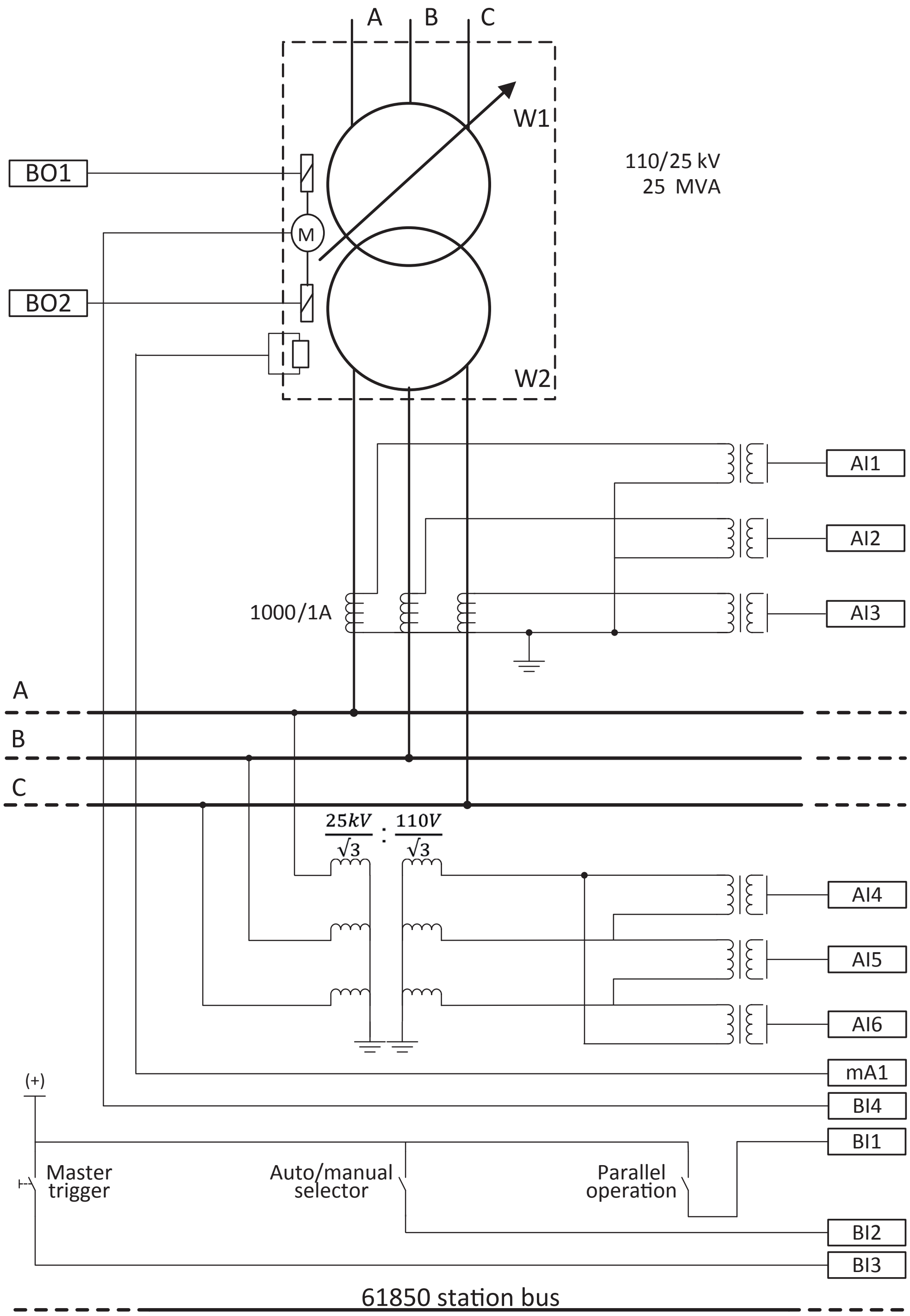

Figure 39: Relay 3 interfaces and CT/VT connections for TR3 in example case 2

Analog input signals

Table 91: Physical analog input signals for implementing Relay 3 in example case 2

Analog input	Description
AI1	Transformer TR3 winding 2, current A
AI2	Transformer TR3 winding 2, current B
AI3	Transformer TR3 winding 2, current C
AI4	Transformer TR3 winding 2, voltage AB
AI5	Transformer TR3 winding 2, voltage BC
AI6	Transformer TR3 winding 2, voltage CA

mA input signals

Table 92: Physical mA input signal for implementing Relay 3 in example case 2

mA input	Description
mA1	Tap position of the on-load tap changer for TR3

Binary input signals

Table 93: Binary input signals for implementing Relay 3 in example case 2

Binary input	Description
BI1 1)	Parallel input signal for TR3. A TRUE on this input enables parallel operation of transformers.
BI2 1)	Auto input signal for TR3. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI3	Master Trigger input connected to MSTR_TRIGG for TR3. A rising edge input (FALSE to TRUE) causes the connected relay to assume the master role.
BI4	Tap changer operating (TCO) input for TR3. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 94: Binary output signals for implementing Relay 3 in example case 2

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR3
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR3

Recommended alarms

Table 95: Alarm list for implementing Relay 3 in example case 2

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR3
OL5ATCC1	AUTO	Operation mode for TR3 set as auto
OL5ATCC1	PAR_FAIL	Parallel failure detected
OL5ATCC1	RAISE_OWN	Raise command for transformer TR3
OL5ATCC1	LOWER_OWN	Lower command for transformer TR3
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR3
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR3
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR3
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR3

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 96: Function blocks used in Relay 3 configuration of example case 2

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control `PARALLEL` and `AUTO`.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`.
GOOSERCV_INT8	Received GOOSE 8-bit integer value information. The GOOSERCV_INT8 function is used to connect the GOOSE 8-bit integer inputs to the application. In the example case, it is used to receive tap position information from parallel transformers.
Table continues on next page	

Function block	Description
GOOSERCV_INT32	Received GOOSE 32-bit integer value information. The GOOSERCV_INT32 function is used to connect GOOSE 32-bit integer inputs to the application. In the example case, it is used to receive tap follow command from the master relay.
GOOSERCV_ENUM	Received GOOSE enumerator value information. The GOOSERCV_ENUM function is used to connect GOOSE enumerator inputs to the application. In the example case, it is used to receive status information.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 97: Physical analog channels of Relay 3 functions in example case 2

Function block	TR3 secondary currents AI1, AI2, AI3	MV Bus voltages AI4, AI5, AI6	TR3 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 40, Figure 41, Figure 42 and Figure 43 show the ACT diagram for transformer TR3 in example case 2. All needed connections for parallel transformer voltage control in M/F mode are shown in Application Configuration.

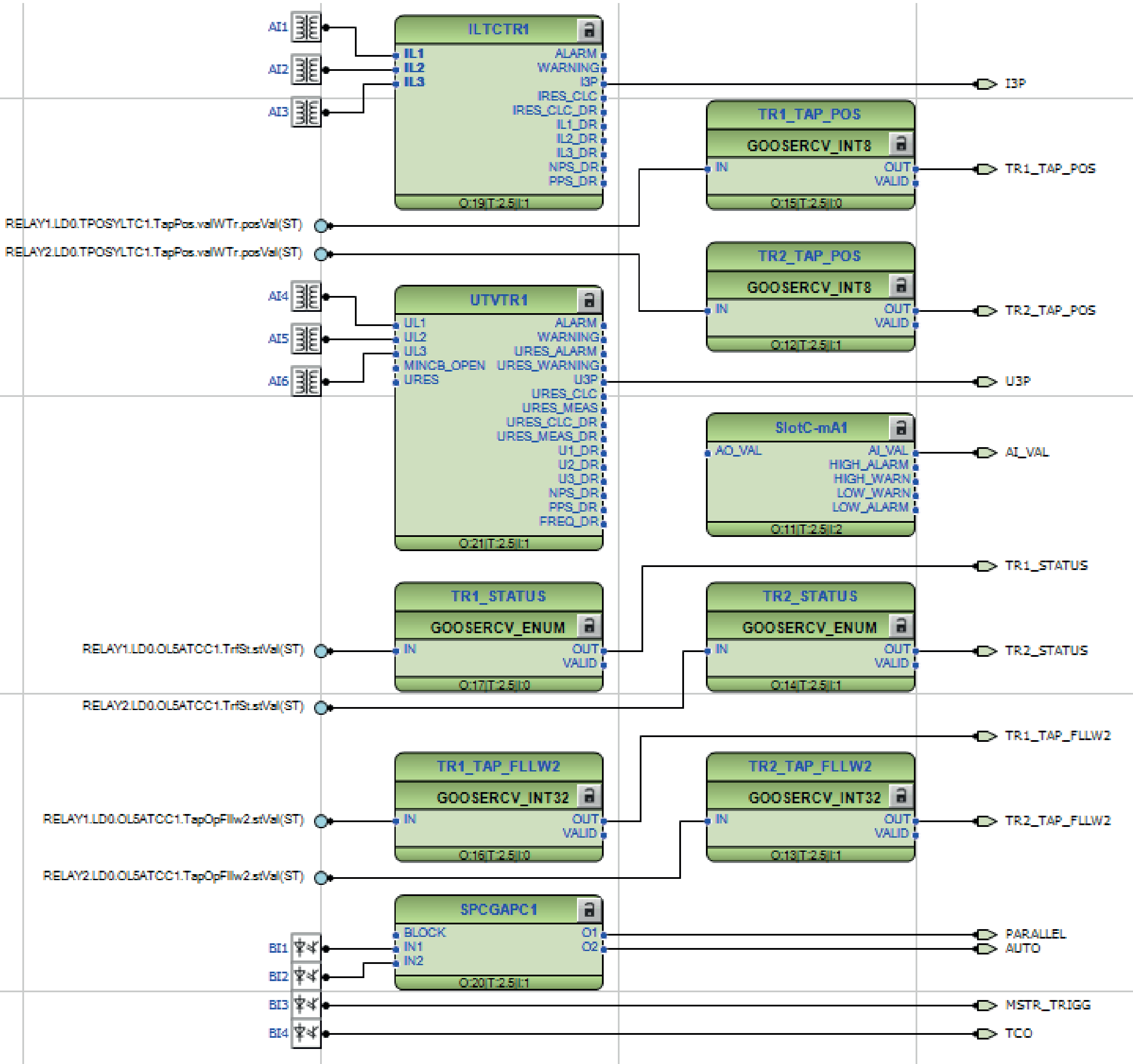

Figure 40: ACT diagram for transformer TR3 (Relay 3) in example case 2 – Input section

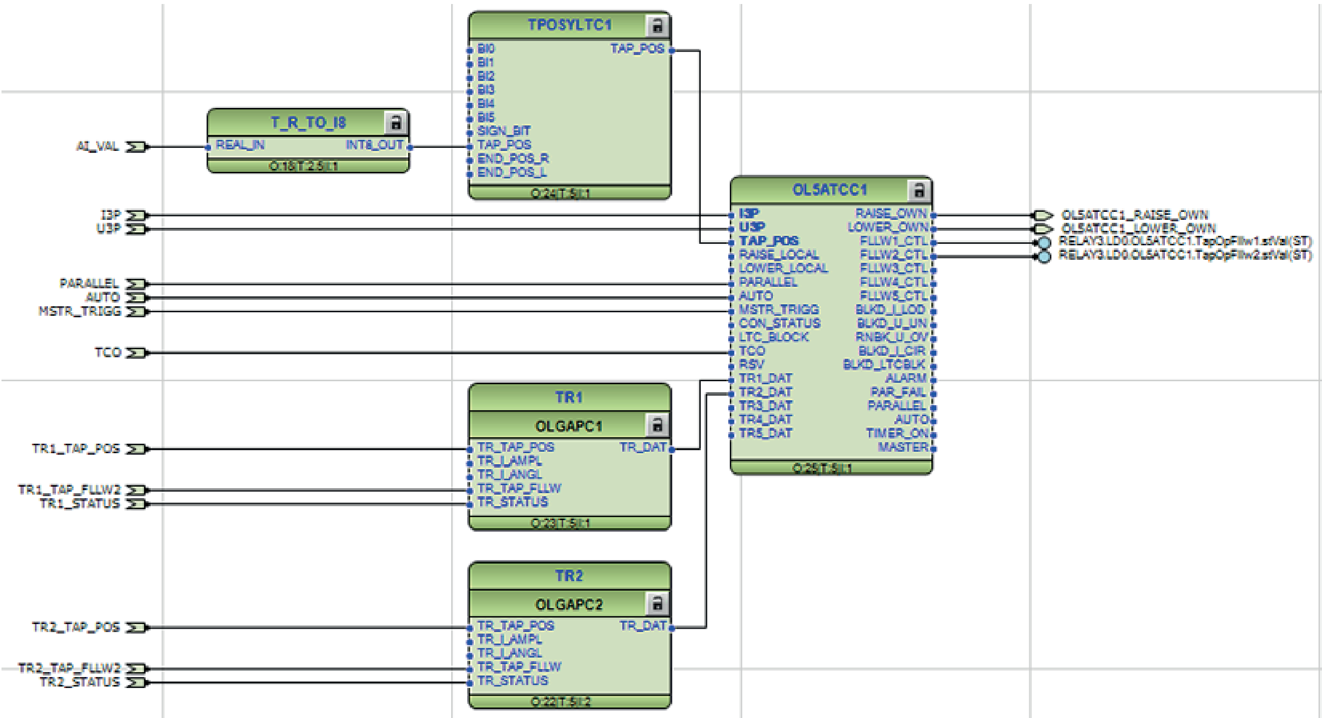

Figure 41: ACT diagram for transformer TR3 (Relay 3) in example case 2 – Application section

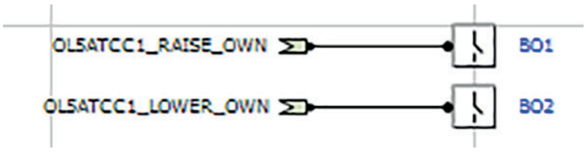

Figure 42: ACT diagram for transformer TR3 (Relay 3) in example case 2 – Output section

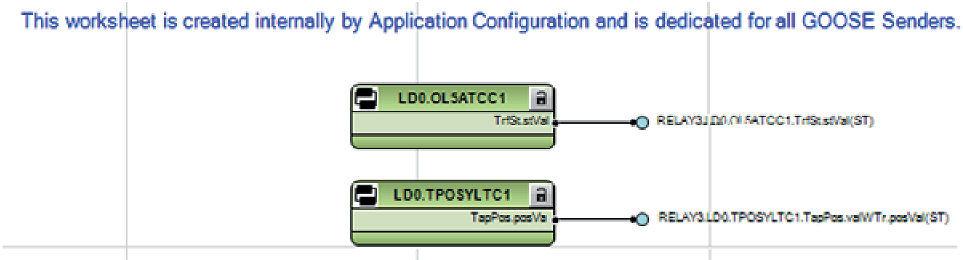

Figure 43: ACT diagram for transformer TR3 (Relay 3) in example case 2 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 98 shows recommended setting values; all other settings can be kept at default values.

Table 98: ILTCTR1 setting values for TR3 Relay in example case 2

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 99 shows recommended setting values; all other settings can be kept at default values.

Table 99: UTVTR1 setting values for TR3 Relay in example case 2

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 100 shows recommended setting values; all other settings can be kept at default values.

Table 100: SPCGAPC1 setting values for TR3 Relay in example case 2

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`. In Relay 3, OLGAPC1 connects `TR1_TAP_POS`, `TR1_TAP_FLLW2` and `TR1_STATUS` to `TR1_DAT`. OLGAPC2 connects inputs `TR2_TAP_POS`, `TR2_TAP_FLLW2` and `TR2_STATUS` to `TR2_DAT`. `TRx_TAP_FLLWx` receives control commands (Raise/Lower) from the master when another relay is master. TRx_STATUS connection is mandatory for TR3 to know how many followers it has when it gets the master role. In the absence of this input, TRx is considered as independent and is not controlled by Relay 3.

The function does not have any settings.

OL5ATCC1 - Tap changer control with voltage regulator

In the example case, Relay 3 acts as a follower in this mode and the tap setting follows the master (Relay 1).

Table 101: OL5ATCC function settings for automatic voltage control in M/F application

Setting	Suggested values	Description
Operation mode	Input control	Operation mode
Parallel mode	Input control	Parallel mode selection
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/ 17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/ VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.

Table continues on next page

Setting	Suggested values	Description
Raise block tap	17	Tap changer limit position which gives the highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 102: GOOSE input signals for implementing Relay 3 in example case 2

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR1	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal[1)]	Tap position of TR1 from Relay 1	OLGAPC1	TR_TAP_POS
TR1	OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal[2)]	Lower/Raise command from Relay 1 when Relay 1 is master	OLGAPC1	TR_TAP_FLLW
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal[3)]	Status information of TR1 from Relay 1	OLGAPC1	TR_STATUS
TR2	TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal[1)]	Tap position of TR2 from Relay 2	OLGAPC2	TR_TAP_POS
TR2	OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal[2)]	Lower/Raise command from Relay 2 when Relay 2 is master	OLGAPC2	TR_TAP_FLLW
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal[3)]	Status information of TR2 from Relay 2	OLGAPC2	TR_STATUS

1) Input signal received via GOOSERCV_INT8
2) Input signal received via GOOSERCV_INT32
3) Input signal received via GOOSERCV_ENUM

Table 103: GOOSE output signals for implementing Relay 3 in example case 2

Function block	Output	Data	Description
TPOSYLTC1	TAP_POS	LD0.TPOSYLTC1.TapPos.valWTr.posVal	Tap position of TR3 from Relay 3 to Relay 1 and 2
OL5ATCC1	FLLW1_CTL	LD0.OL5ATCC1.TapOpFllw1.stVal	Lower/Raise command from Relay 3 to Relay 1 and 2 when Relay 3 is master
OL5ATCC1	FLLW2_CTL	LD0.OL5ATCC1.TapOpFllw2.stVal	Lower/Raise command from Relay 3 to Relay 1 and 2 when Relay 3 is master
OL5ATCC1	N/A	LD0.OL5ATCC1.TrfSt.stVal	Status information of TR3 from Relay 3 to Relay 1 and 2

5.4 Example case 3 – Parallel transformer control in MCC mode

This chapter provides detailed information about the configuration of the relays used in the application example: the relay interfaces, the ACT diagrams and parameter settings along with information on how the transformer voltage control can be achieved in MCC mode for the given example.

5.4.1 Description of the example case

To explain the application of OL5ATCC for the parallel transformer application, a typical example case is illustrated with three transformers connected in parallel. Figure 44 shows the single-line diagram for the example case along with the measurement requirements. An on-load tap changer is present in the HV winding of the transformers. Current information from the MV side (regulated side) as well as voltage information from the MV side are required for OL5ATCC application. Additional information required is the tap position.

This example case is used to illustrate the minimizing circulating current (MCC) mode of operation. This mode can be used when the transformers connected in parallel have identical or different ratings. The MCC principle is an optimal solution for controlling parallel transformers of different ratings or step voltages in substations with varying reactive loads. To implement the example case, three relays (Relay 1 for transformer TR1, Relay 2 for transformer TR2 and Relay 3 for transformer TR3) are required. Communication between the regulators is needed for operating in MCC mode.

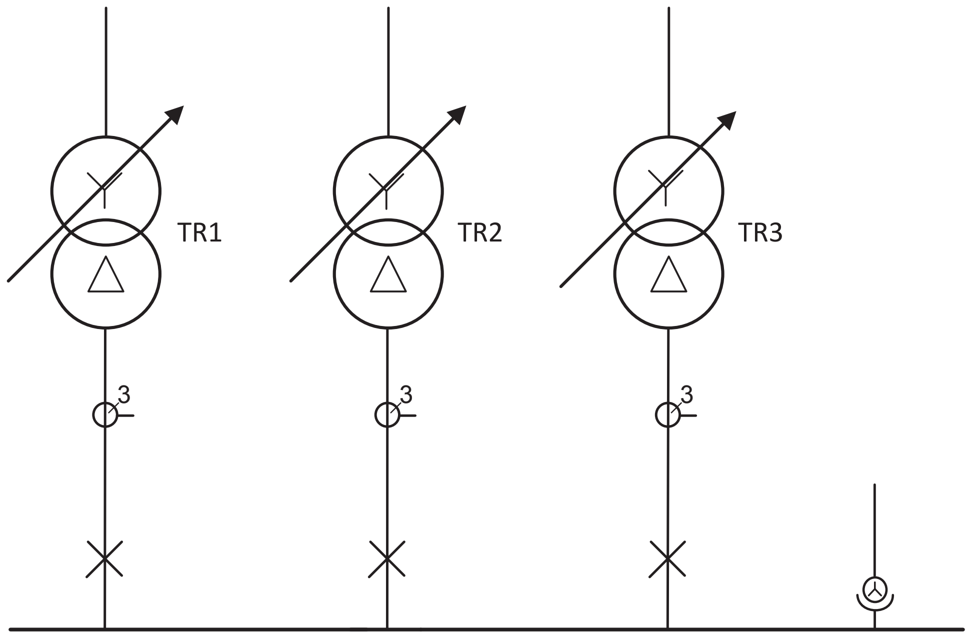

Figure 44: Parallel transformer application (example case 3)

5.4.2 Transformer TR1 voltage control relay

5.4.2.1 Relay interface, configuration and settings

Figure 45 shows the connection details of the relay's (Relay 1) analog inputs (AI), binary inputs (BI), milli-Ampere (mA) inputs and binary outputs (BO) for transformer TR1 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown in the figure. In the example case illustrated, the tap changer position value is input as an mA input for transformer TR1 and input to TPOSYLTC.

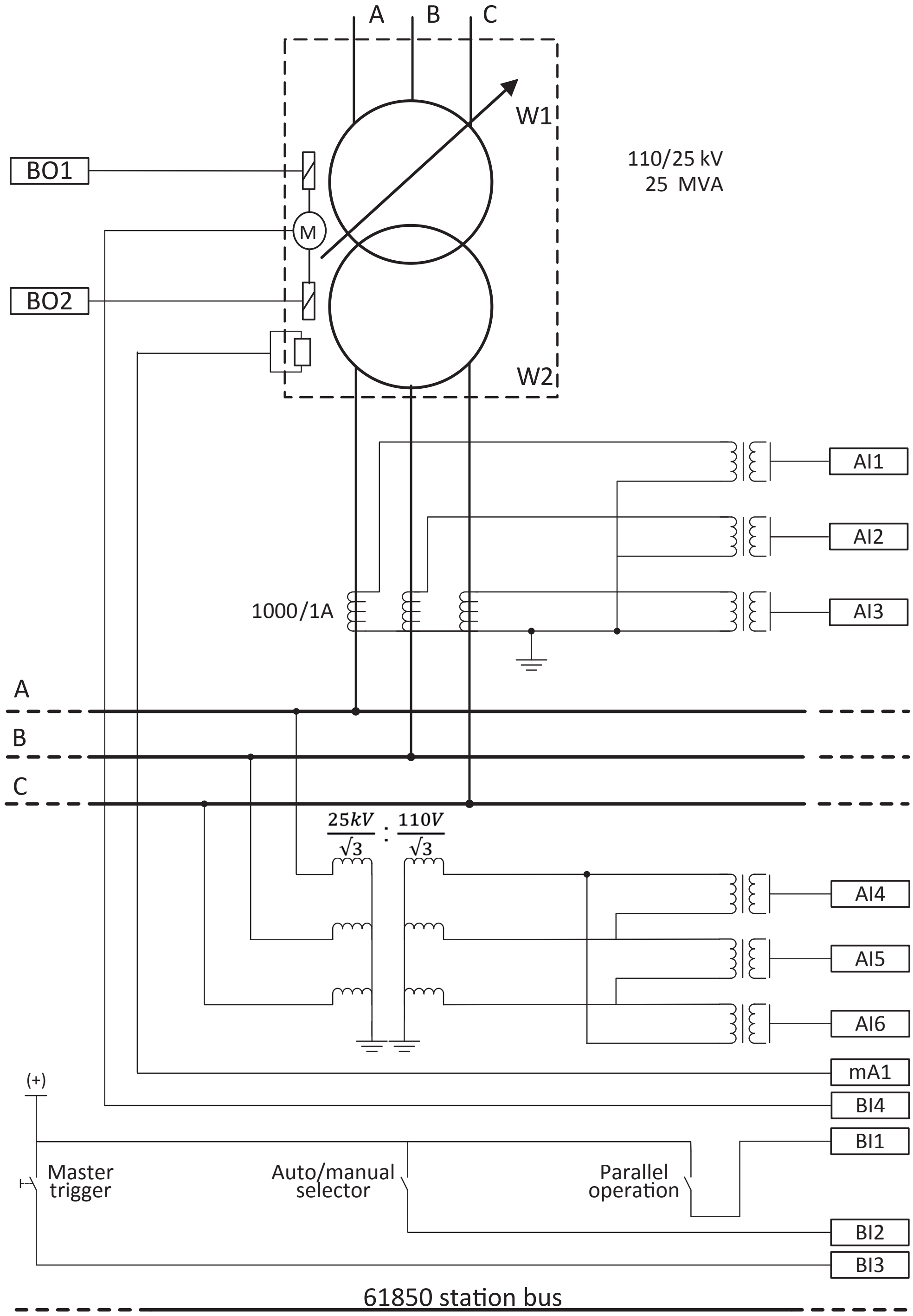

Figure 45: Relay 1 interfaces and CT/VT connections for TR1 in example case 3

Analog input signals

Table 104: Physical analog input signals for implementing Relay 1 in example case 3

Analog input	Description
AI1	Transformer TR1 winding 2, current A
AI2	Transformer TR1 winding 2, current B
AI3	Transformer TR1 winding 2, current C
AI4	Transformer TR1 winding 2, voltage AB
AI5	Transformer TR1 winding 2, voltage BC
AI6	Transformer TR1 winding 2, voltage CA

mA input signals

Table 105: Physical mA input signal for implementing Relay 1 in example case 3

mA input	Description
mA1	Tap position of the on-load tap changer for TR1

Binary input signals

Table 106: Binary input signals for implementing Relay 1 in example case 3

Binary input	Description
BI1[1)]	Parallel input signal for TR1. A TRUE on this input enables parallel operation of transformers.
BI2[1)]	Auto input signal for TR1. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI3	Network connection status of the transformer (CON_STATUS) input for TR1. A TRUE on this input indicates that the transformer is connected to the network.
BI4	Tap changer operating (TCO) input for TR1. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 107: Binary output signals for implementing Relay 1 in example case 3

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR1
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR1

Recommended alarms

Table 108: Alarm list for implementing Relay 1 in example case 3

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR1
OL5ATCC1	AUTO	Operation mode for TR1 set as auto
OL5ATCC1	RAISE_OWN	Raise command for transformer TR1
OL5ATCC1	LOWER_OWN	Lower command for transformer TR1
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR1
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR1
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR1
OL5ATCC1	BLKD_I_CIR	Indication of high circulating current blocking for TR1
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR1

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 109: Function blocks used in Relay 1 configuration of example case 3

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control `PARALLEL` and `AUTO`.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data from parallel transformers, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`.
GOOSERCV_CMV	Received GOOSE measured value (phasor) information. The GOOSERCV_CMV function is used to connect the GOOSE measured value inputs `TR_I_AMPL` and `TR_I_ANGL` to the application.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 110: Physical analog channels of Relay 1 functions in example case 3

Function block	TR1 secondary currents AI1, AI2, AI3	MV Bus voltages AI4, AI5, AI6	TR1 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 46, Figure 47, Figure 48 and Figure 49 show the ACT diagram for transformer TR1 in example case 3. All needed connections for parallel transformer voltage control in MCC mode are shown in Application Configuration.

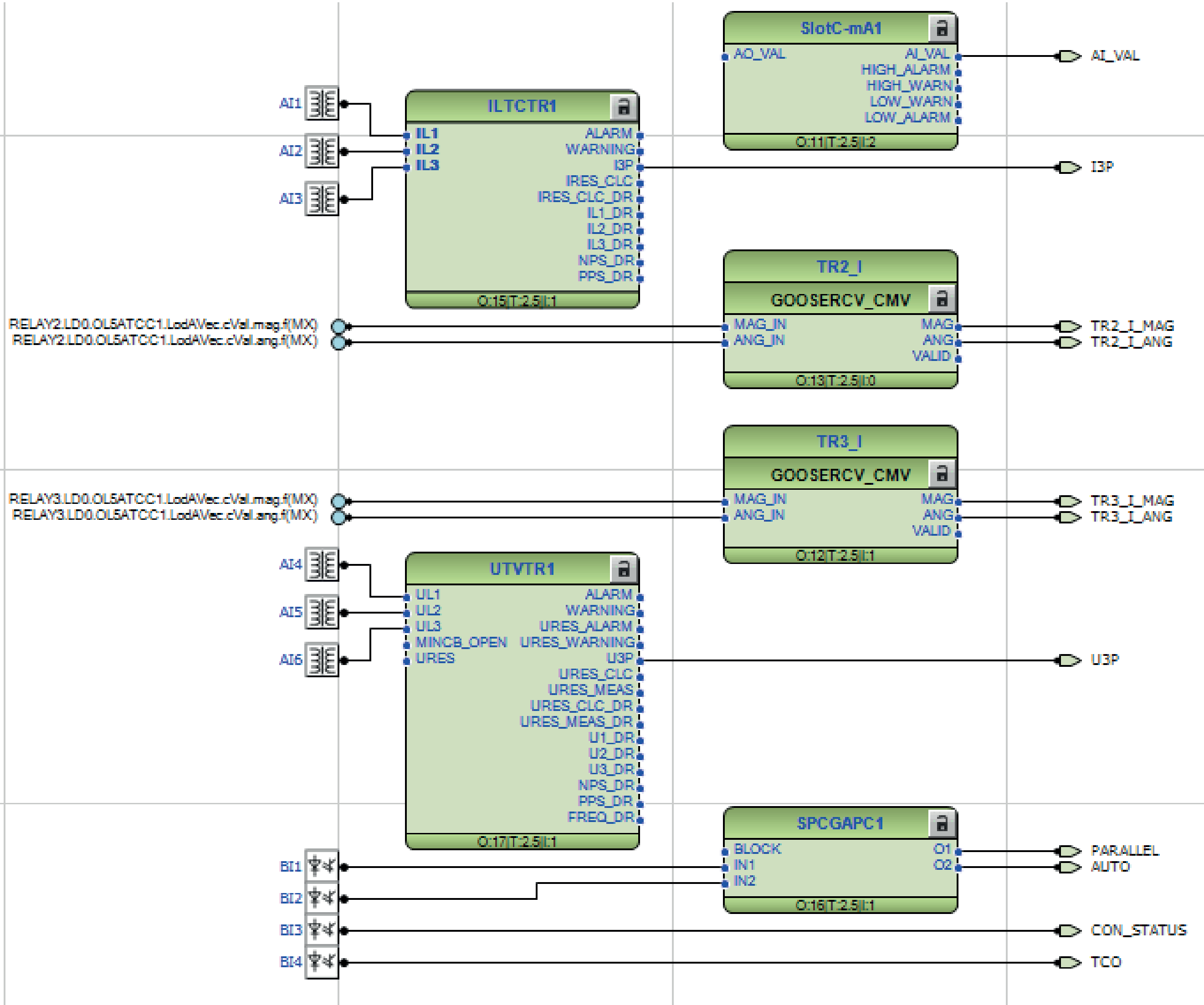

Figure 46: ACT diagram for transformer TR1 (Relay 1) in example case 3 - Input section

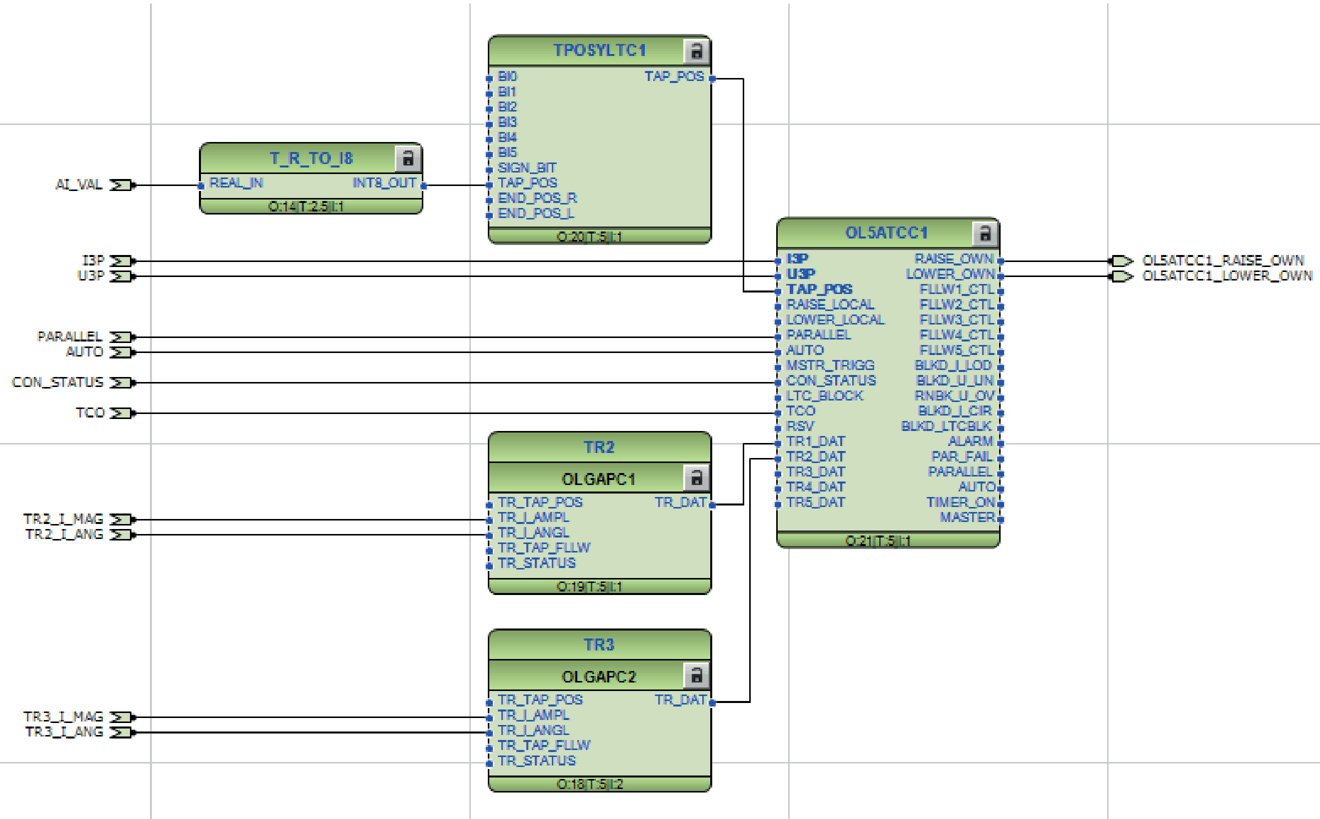

Figure 47: ACT diagram for transformer TR1 (Relay 1) in example case 3 - Application section

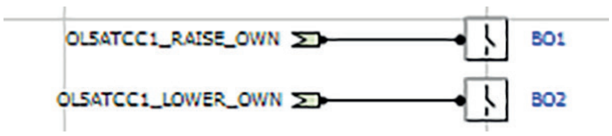

Figure 48: ACT diagram for transformer TR1 (Relay 1) in example case 3 - Output section

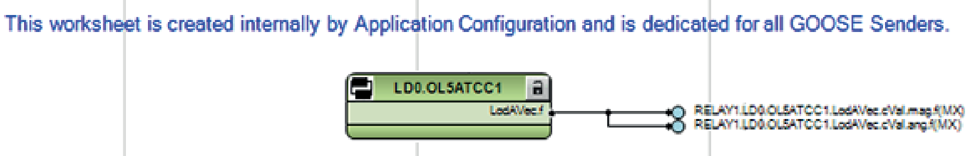

Figure 49: ACT diagram for transformer TR1 (Relay 1) in example case 3 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 function is the analog signal preprocessing function for current signals. Table 111 shows recommended setting values; all other settings can be kept at default values.

Table 111: ILTCTR1 setting values for Relay 1 in example case 3

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 112 shows recommended setting values; all other settings can be kept at default values.

Table 112: UTVTR1 setting values for Relay 1 in example case 3

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT primary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 113 shows recommended setting values; all other settings can be kept at default values.

Table 113: SPCGAPC1 setting values for Relay 1 in example case 3

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`. In Relay 1, OLGAPC1 connects `TR2_I_AMPL` and `TR2_I_ANGL` to `TR1_DAT`. OLGAPC2 connects inputs `TR3_I_AMPL` and `TR3_I_ANGL` to `TR2_DAT`. This function does not have any settings.

OL5ATCC1 - Tap changer control with voltage regulator in auto parallel MCC mode

The MCC is a parallel mode of operation of voltage regulator OL5ATCC1 (on-load tap changer controller) which can be used with parallel transformers of non-identical ratings. Since this control scheme allows the exchange of data between regulators, the circulating current can be calculated more exactly than with other schemes.

To start the parallel operation, the *Operation mode* parameter has to be set to MCC for all the regulators of the connection. The signal `CON_STATUS` (BI3) must indicate that the transformers are connected to the network and is used to identify if a transformer controller can send the current information to other transformer controllers for circulating current minimization purposes. If `CON_STATUS` (BI3) is TRUE, the information transmission is started and the circulating current information receiving is allowed.

The phasor information from the other parallel relays needed for the circular current calculation is sent over horizontal GOOSE communication. The received current phasor information can be read from the OLGAPC1 and OLGAPC2 function input data `TR_I_AMPL` and `TR_I_ANGL` for the magnitude and angle, respectively. The status FALSE needs to be connected to the `CON_STATUS` (BI3) input to ensure a proper operation of the MCC calculation if the parallel transformer is disconnected but OL5ATCC1 remains in the MCC mode. This way the disconnected transformer is excluded from the circulating current calculations.

In the example case, since all the transformers are identical, the *Stability factor* setting of the regulators is equal.

Table 114: OL5ATCC1 settings for automatic voltage control in MCC application

Setting	Suggested values	Setting value calculation
Operation mode	Auto parallel	Operation mode
Parallel mode	MCC	Parallel mode selection
Runback raise V	1.12 xU_n[1)]	Voltage limit where fast lower commands take place
Stability factor	5%[2)]	Stability factor in parallel operation
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/ 17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.
Raise block tap	17	Tap changer limit position which gives highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

1) See section Automatic voltage regulation of example case 1.
2) Assuming a factor of 5% (depending on loop impedance) for illustration purpose

Operation mode and parallel mode settings can be done from the HMI application by tapping Settings and selecting "Auto parallel" from the drop-down for *Operation mode* and "MCC" from the drop-down for *Parallel mode*. The MCC mode can also be achieved with *Operation mode* set to "Input control". Inputs PARALLEL (BI1) and AUTO (BI2) must be TRUE in this case.

All other settings are kept at default values.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 115: GOOSE input signals for implementing Relay 1 in example case 3

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f[1)]	TR2 current magnitude from Relay 2	OLGAPC1	TR_I_AMPL
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f[1)]	TR2 current angle from Relay 2	OLGAPC1	TR_I_ANGL
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f[1)]	TR3 current magnitude from Relay 3	OLGAPC2	TR_I_AMPL
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f[1)]	TR3 current angle from Relay 3	OLGAPC2	TR_I_ANGL

1) Input signal received via GOOSERCV_CMV

Table 116: GOOSE output signals for implementing Relay 1 in example case 3

Function block	Output	Data	Description
OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f	TR1 current magnitude from Relay 1 to Relay 2 and 3
OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f	TR1 current angle from Relay 1 to Relay 2 and 3

5.4.3 Transformer TR2 voltage control relay

5.4.3.1 Relay interface, configuration and settings

Figure 50 shows the connection details of the relay's (Relay 2) analog inputs (AI), binary inputs (BI), milli-Ampere (mA) inputs and binary outputs (BO) for transformer TR2 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown in the figure. In the example case illustrated, the tap changer position value is input as an mA input for transformer TR2 and input to TPOSYLTC.

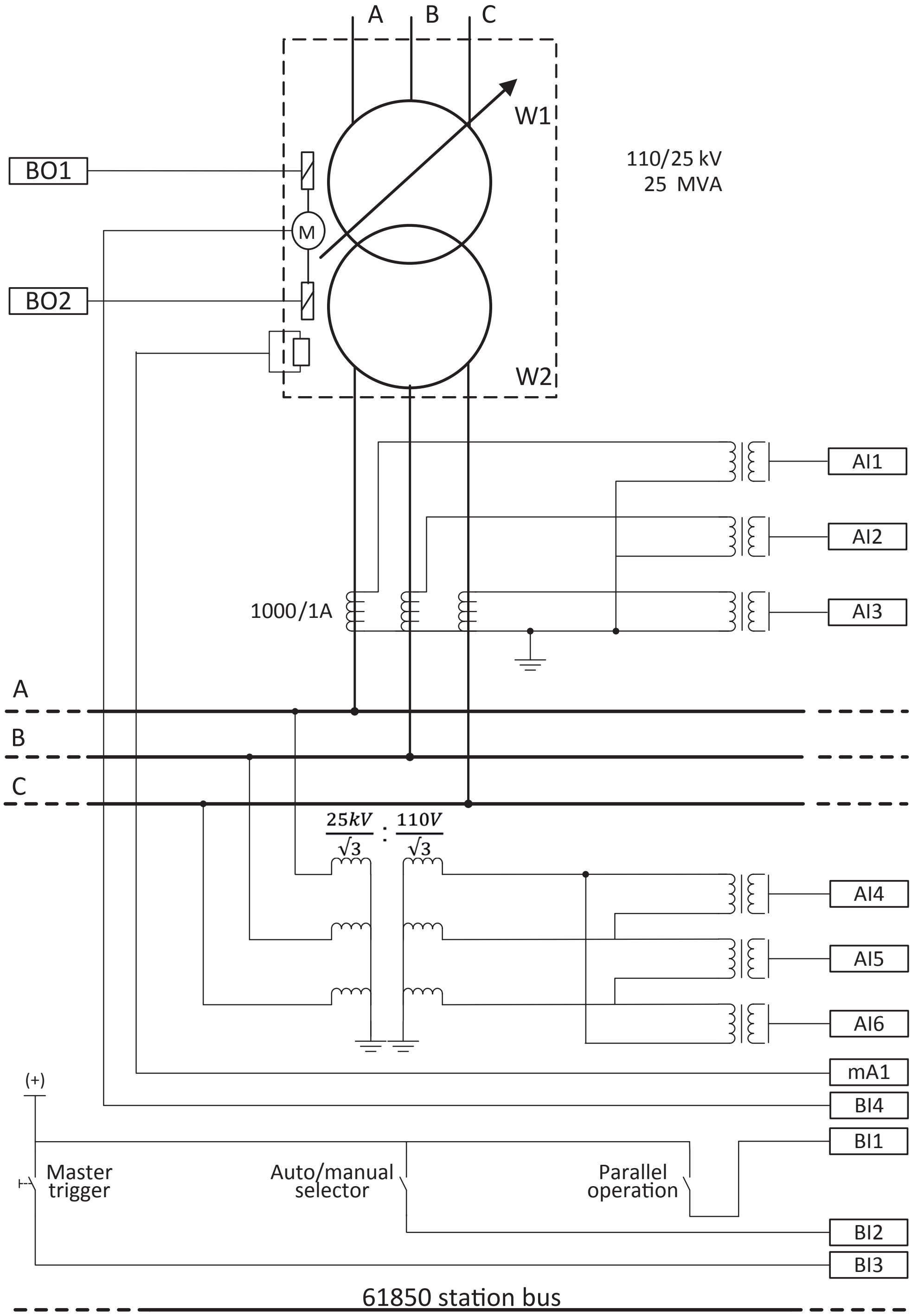

Figure 50: Relay 2 interfaces and CT/VT connections for TR2 in example case 3

Analog input signals

Table 117: Physical analog input signals for implementing Relay 2 in example case 3

Analog input	Description
AI1	Transformer TR2 winding 2, current A
AI2	Transformer TR2 winding 2, current B
AI3	Transformer TR2 winding 2, current C
AI4	Transformer TR2 winding 2, voltage AB
AI5	Transformer TR2 winding 2, voltage BC
AI6	Transformer TR2 winding 2, voltage CA

mA input signals

Table 118: Physical mA input signal for implementing Relay 2 in example case 3

mA input	Description
mA1	Tap position of the on-load tap changer for TR2

Binary input signals

Table 119: Binary input signals for implementing Relay 2 in example case 3

Binary input	Description
BI1[1)]	Parallel input signal for TR2. A TRUE on this input enables parallel operation of transformers.
BI2[1)]	Auto input signal for TR2. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI3	Network connection status of the transformer (CON_STATUS) input for TR2. A TRUE on this input indicates that the transformer is connected to the network.
BI4	Tap changer operating (TCO) input for TR2. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 120: Binary output signals for implementing Relay 2 in example case 3

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR2
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR2

Recommended alarms

Table 121: Alarm list for implementing Relay 2 in example case 3

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR2
OL5ATCC1	AUTO	Operation mode for TR2 set as auto
OL5ATCC1	RAISE_OWN	Raise command for transformer TR2
OL5ATCC1	LOWER_OWN	Lower command for transformer TR2
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR2
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR2
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR2
OL5ATCC1	BLKD_I_CIR	Indication of high circulating current blocking for TR2
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR2

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 122: Function blocks used in Relay 2 configuration of example case 3

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control `PARALLEL` and `AUTO`.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and TR_STATUS as `TR_DAT`.
GOOSERCV_CMV	Received GOOSE measured value (phasor) information. The GOOSERCV_CMV function is used to connect the GOOSE measured value inputs `TR_I_AMPL` and `TR_I_ANGL` to the application.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 123: Physical analog channels of Relay 2 functions in example case 3

Function block	TR2 secondary currents AI1, AI2, AI3	MV Bus voltages	TR2 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 51, Figure 52, Figure 53 and Figure 54 show the ACT diagram for transformer TR2 in example case 3. All needed connections for parallel transformer voltage control in MCC mode are shown in Application Configuration.

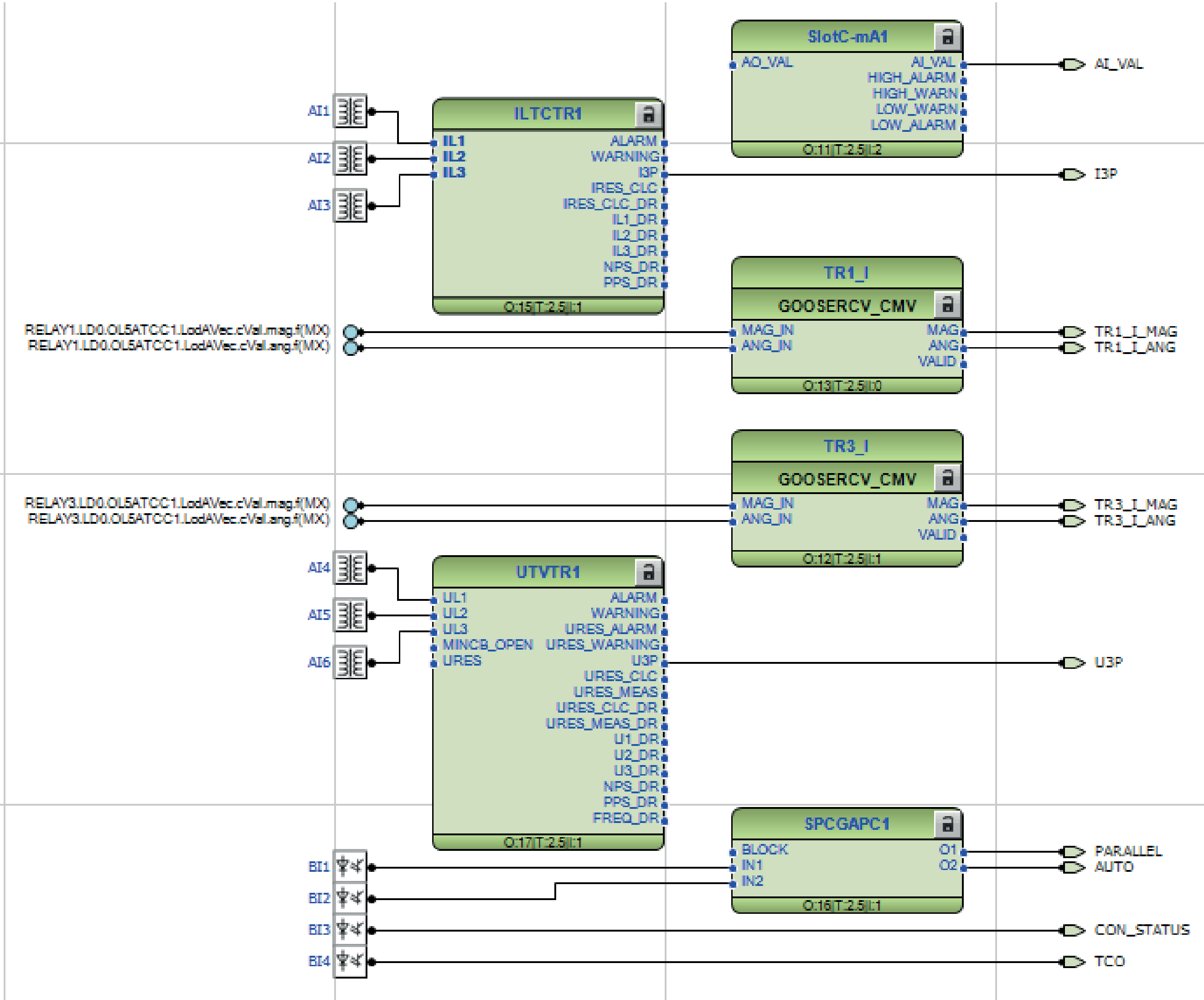

Figure 51: ACT diagram for transformer TR2 (Relay 2) in example case 3 - Input section

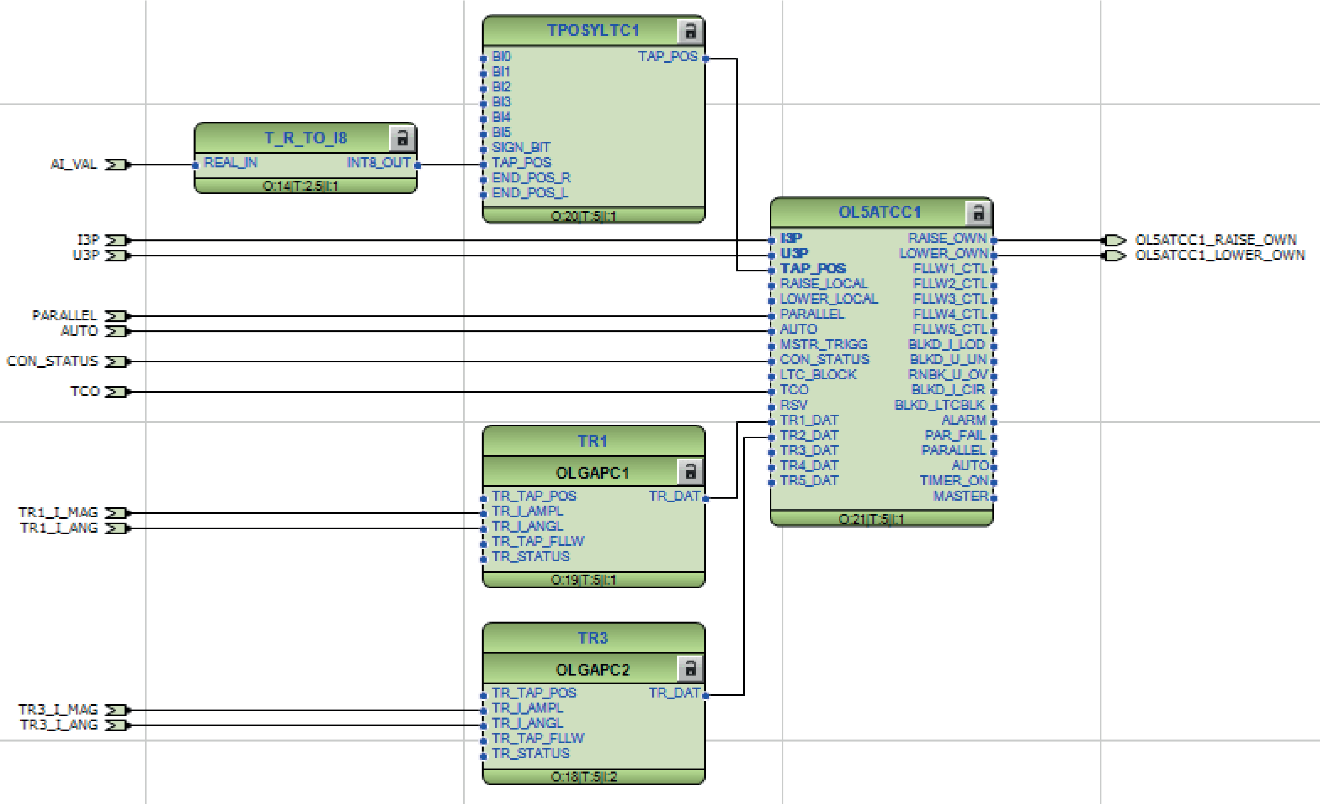

Figure 52: ACT diagram for transformer TR2 (Relay 2) in example case 3 - Application section

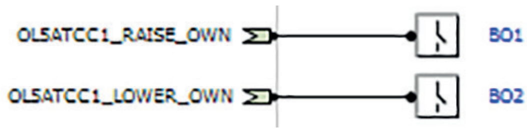

Figure 53: ACT diagram for transformer TR2 (Relay 2) in example case 3 - Output section

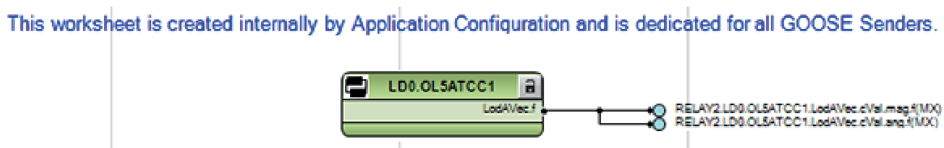

Figure 54: ACT diagram for transformer TR2 (Relay 2) in example case 3 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 124 shows recommended setting values; all other settings can be kept at default values.

Table 124: ILTCTR1 setting values for Relay 2 in example case 3

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 125 shows recommended setting values; all other settings can be kept at default values.

Table 125: UTVTR1 setting values for Relay 2 in example case 3

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 126 shows recommended setting values; all other settings can be kept at default values.

Table 126: SPCGAPC1 setting values for Relay 2 in example case 3

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`. In Relay 2, OLGAPC1 connects `TR1_I_AMPL` and `TR1_I_ANGL` to `TR1_DAT`. OLGAPC2 connects inputs `TR3_I_AMPL` and `TR3_I_ANGL` to `TR2_DAT`. This function does not have any settings.

OL5ATCC1 - Tap changer control with voltage regulator

Inputs `TR1_I_AMPL` and `TR1_I_ANGL` over GOOSERCV_CMV function need to be connected to OLGAPC1 and inputs `TR3_I_AMPL` and `TR3_I_ANGL` over GOOSERCV_CMV function need to be connected to OLGAPC2.

Table 127: OL5ATCC1 setting values for MCC application

Setting	Suggested values	Setting value calculation
Operation mode	Auto parallel	Operation mode
Parallel mode	MCC	Parallel mode selection
Runback raise V	1.12 xU_n[1)]	Voltage limit where fast lower commands takes place
Stability factor	5%[2)]	Stability factor in parallel operation
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.
Table continues on next page		

Setting	Suggested values	Setting value calculation
Raise block tap	17	Tap changer limit position which gives highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

1) See section Automatic voltage regulation of example case 1.
2) Assuming a factor of 5% (depending on loop impedance) for illustration purpose

The MCC mode can also be achieved with *Operation mode* set as "Input control". Inputs `PARALLEL` (BI1) and `AUTO` (BI2) must be TRUE in this case. All other settings are kept at default values.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 128: GOOSE input signals for implementing Relay 2 in example case 3

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f 1) 1)	TR1 current magnitude from Relay 1	OLGAPC1	TR_I_AMPL
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f 1)	TR1 current angle from Relay 1	OLGAPC1	TR_I_ANGL
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f 1)	TR3 current magnitude from Relay 3	OLGAPC2	TR_I_AMPL
TR3	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f 1)	TR3 current angle from Relay 3	OLGAPC2	TR_I_ANGL

1) Input signal received via GOOSERCV_CMV

Table 129: GOOSE output signals for implementing Relay 2 in example case 3

Function block	Output	Data	Description
OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f	TR2 current magnitude from Relay 2 to Relay 1 and 3
OL5ATCC1	N/A	LD0.Ol5ATCC1.LodAVec.cVal.ang.f	TR2 current angle from Relay 2 to Relay 1 and 3

5.4.4 Transformer TR3 voltage control relay

5.4.4.1 Relay interface, configuration and settings

Figure 55 shows the connection details of the relay's (Relay 3) analog inputs (AI), binary inputs (BI), milli-Ampere (mA) inputs and binary outputs (BO) for transformer TR3 of the example case. The CT connections for phase current measurements in all phases and the VT connection for voltage measurement on the MV side are also shown. In the example case illustrated, the tap changer position value is input as an mA input for transformer TR3 and input to TPOSYLTC.

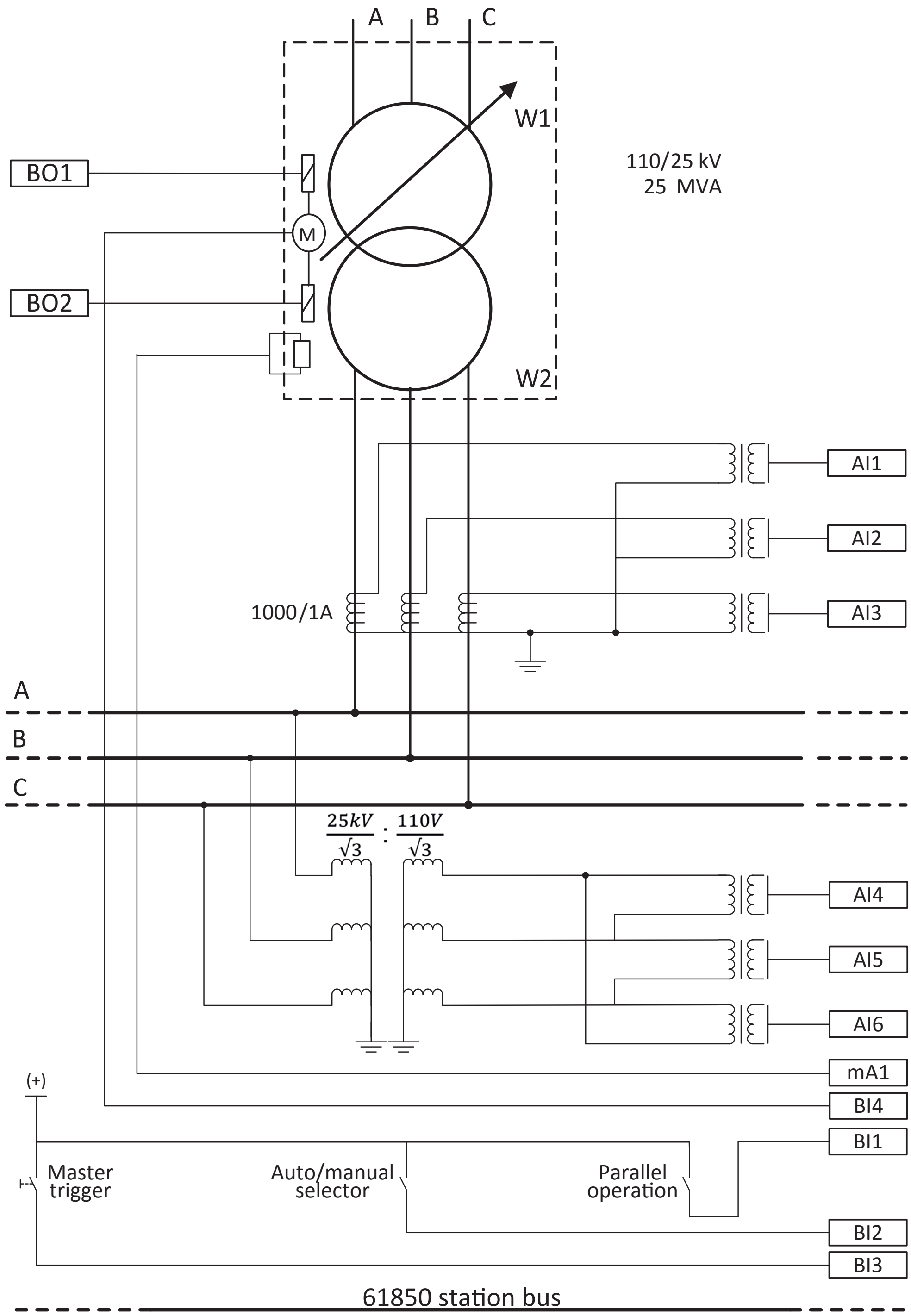

Figure 55: Relay 3 interfaces and CT/VT connections for TR3 in example case 3

Analog input signals

Table 130: Physical analog input signals for implementing Relay 3 in example case 3

Analog input	Description
AI1	Transformer TR3 winding 2, current A
AI2	Transformer TR3 winding 2, current B
AI3	Transformer TR3 winding 2, current C
AI4	Transformer TR3 winding 2, voltage AB
AI5	Transformer TR3 winding 2, voltage BC
AI6	Transformer TR3 winding 2, voltage CA

mA input signals

Table 131: Physical mA input signal for implementing Relay 3 in example case 3

mA input	Description
mA1	Tap position of the on-load tap changer for TR3

Binary input signals

Table 132: Binary input signals for implementing Relay 3 in example case 3

Binary input	Description
BI1[1)]	Parallel input signal for TR3. A TRUE on this input enables parallel operation of transformers.
BI2[1)]	Auto input signal for TR3. A TRUE on this input enables the auto mode and a FALSE on this input enables the manual mode.
BI3	Network connection status of the transformer (CON_STATUS) input for TR3. A TRUE on this input indicates that the transformer is connected to the network.
BI4	Tap changer operating (TCO) input for TR3. A TRUE on this input indicates that the tap changer is currently operating.

1) Needed only when *Operation mode* is set as "Input control"

Binary output signals

Table 133: Binary output signals for implementing Relay 3 in example case 3

Binary output	Description
BO1	Raise command for own transformer (RAISE_OWN), that is, for TR3
BO2	Lower command for own transformer (LOWER_OWN), that is, for TR3

Recommended alarms

Table 134: Alarm list for implementing Relay 3 in example case 3

Event container	Event	Description
OL5ATCC1	ALARM	Alarm due to command error, pump error or TCO error for TR3
OL5ATCC1	AUTO	Operation mode for TR3 set as auto
OL5ATCC1	RAISE_OWN	Raise command for transformer TR3
OL5ATCC1	LOWER_OWN	Lower command for transformer TR3
OL5ATCC1	BLKD_I_LOD	Indication of overcurrent blocking for TR3
OL5ATCC1	BLKD_V_UN	Indication of undervoltage blocking for TR3
OL5ATCC1	RNBK_V_OV	Indication of raise voltage runback for TR3
OL5ATCC1	BLKD_I_CIR	Indication of high circulating current blocking for TR3
OL5ATCC1	BLKD_LTCBLK	Indication of external blocking for TR3

Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 135: Function blocks used in Relay 3 configuration of example case 3

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing block
T_R_TO_I8	Real to integer 8-bit conversion. This function is used to convert the mA input to integer value.
TPOSYLTC1	Tap changer position indication. The output of this function is used by OL5ATCC1.
SPCGAPC1	Generic control points. SPCGAPC1 offers the capability to activate its outputs through a local or remote control and is used in this application to control `PARALLEL` and `AUTO`.
OLGAPC1, OLGAPC2	Transformer data combiner. This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`.
GOOSERCV_CMV	Received GOOSE measured value (phasor) information. The GOOSERCV_CMV function is used to connect the GOOSE measured value inputs `TR_I_AMPL` and `TR_I_ANGL` to the application.
OL5ATCC1	On-load tap changer controller. The output of this function causes the tap position to be raised or lowered.

Table 136: Physical analog channels of Relay 3 functions in example case 3

Function block	TR3 secondary currents AI1, AI2, AI3	MV Bus voltages AI4, AI5, AI6	TR3 Tap position, mA1
OL5ATCC1	x	x	
TPOSYLTC1			x

Figure 56, Figure 57, Figure 58 and Figure 59 show the ACT diagram for transformer TR3 in example case 3. All needed connections for parallel transformer voltage control in MCC mode are shown in Application Configuration.

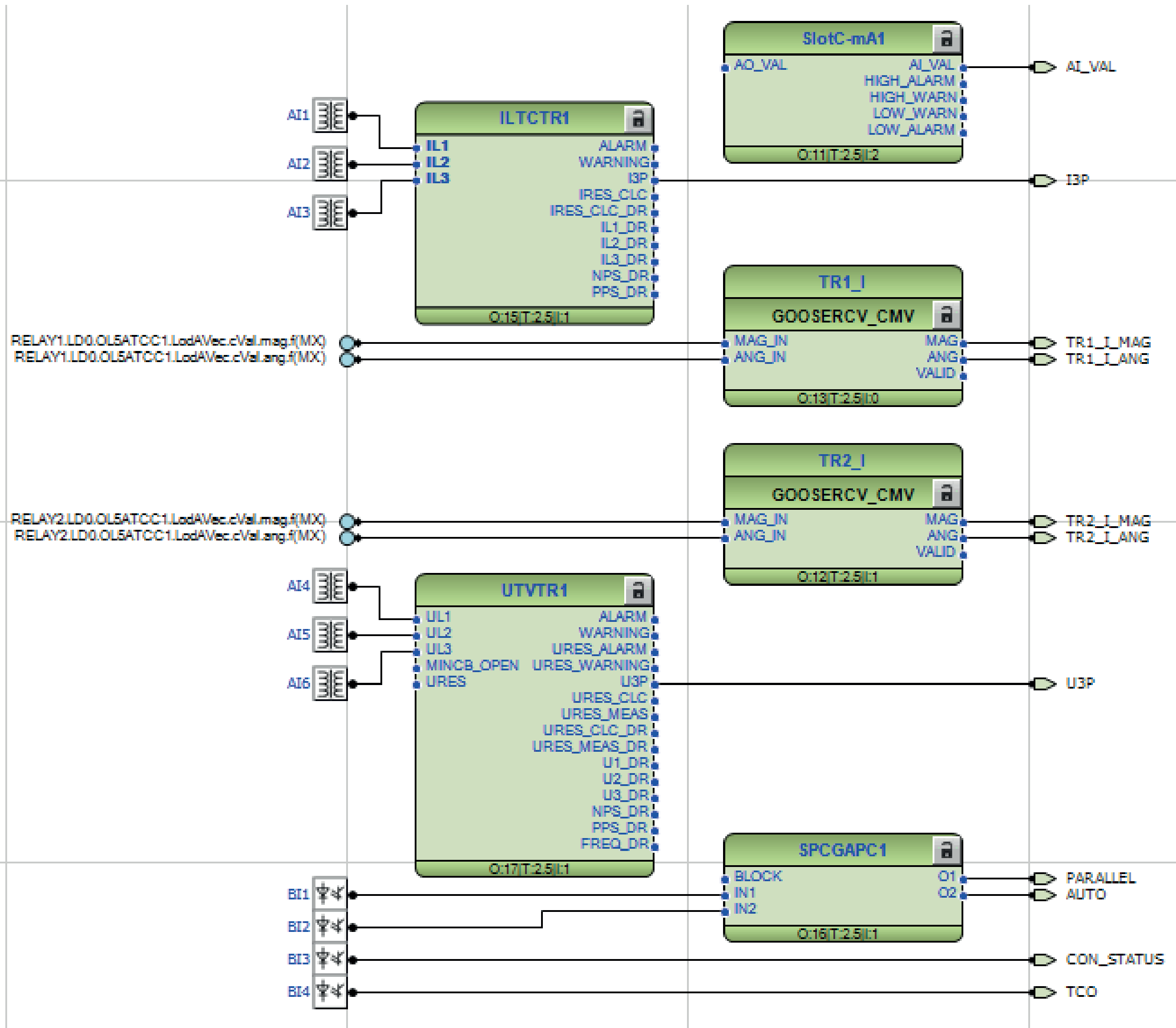

Figure 56: ACT diagram for transformer TR3 (Relay 3) in example case 3 – Input section

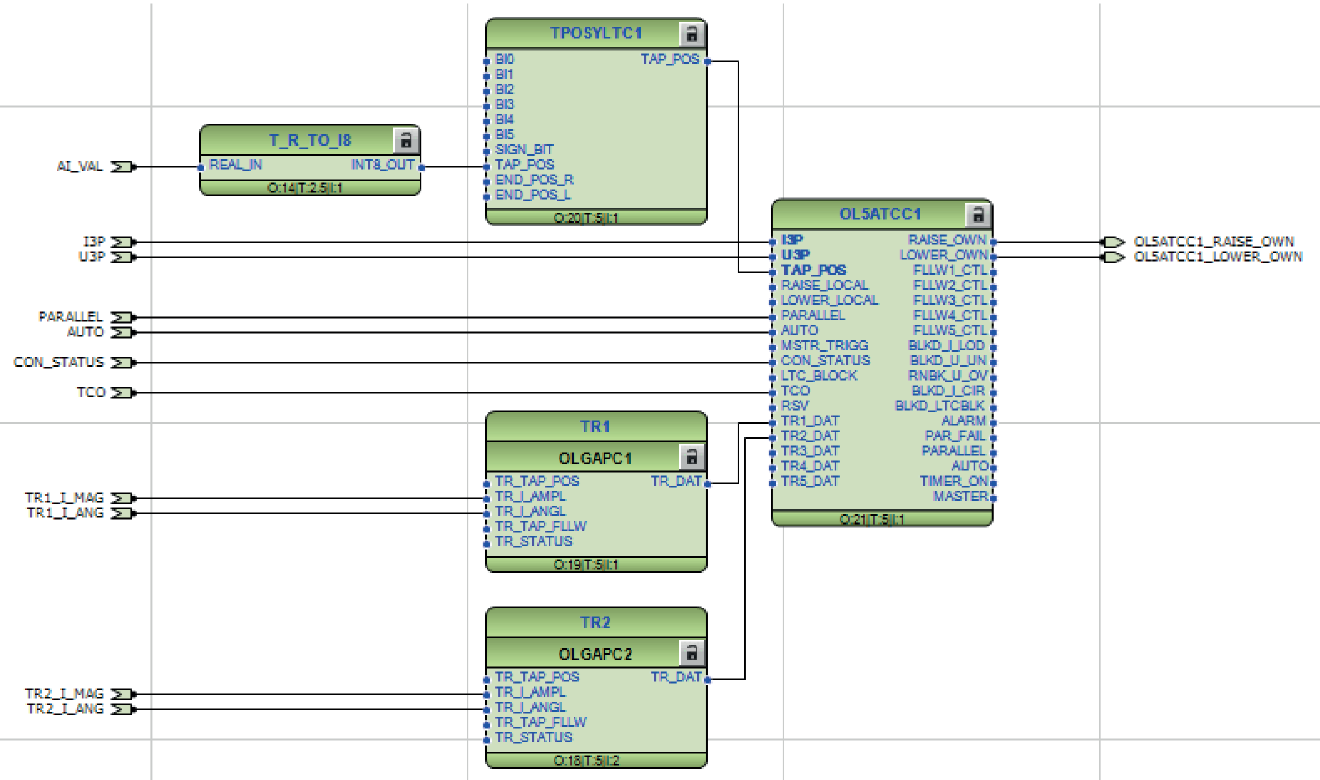

Figure 57: ACT diagram for transformer TR3 (Relay 3) in example case 3 – Application section

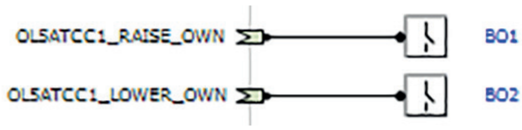

Figure 58: ACT diagram for transformer TR3 (Relay 3) in example case 3 – Output section

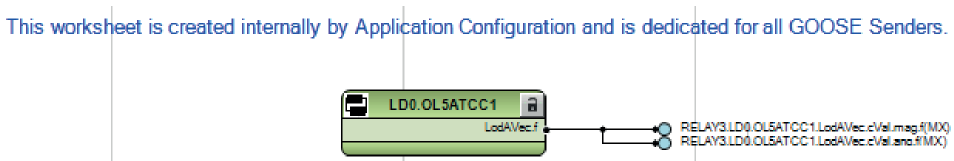

Figure 59: ACT diagram for transformer TR3 (Relay 3) in example case 3 – GOOSE sender

Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for current signals. Table 137 shows recommended setting values; all other settings can be kept at default values.

Table 137: ILTCTR1 setting values for Relay 3 in example case 3

Setting	Suggested values	Description
Primary Current	1000	CT primary rated value
Secondary Current	1	CT secondary rated value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 138 shows recommended setting values; all other settings can be kept at default values.

Table 138: UTVTR1 setting values for Relay 3 in example case 3

Setting	Suggested values	Description
Primary voltage	25 kV	VT primary rated value
Secondary voltage	110 V	VT secondary rated value

T_R_TO_I8 - Real to integer 8-bit conversion

T_R_TO_I8 is used to convert 32-bit floating type values to 8-bit integer type. In the example case, this function is used to convert the tap position from mA input into integer before connecting it to TPOSYLTC1. This function does not have any settings.

TPOSYLTC1 – Tap changer position indication

TPOSYLTC1 is used for transformer tap position supervision. In the example case, the tap position is available as an mA input. This can be converted into an integer value using T_R_TO_I8 before it is connected to the `TAP_POS` input of TPOSYLTC1. All settings of TPOSYLTC1 are kept at default values for this case.

SPCGAPC1 – Generic control points

SPCGAPC1 outputs can be activated through local or remote control. The function is used in this application to control `PARALLEL` and `AUTO`. Table 139 shows recommended setting values; all other settings can be kept at default values.

Table 139: SPCGAPC1 setting values for Relay 3 in example case 3

Setting	Suggested values	Description
Operation mode	Toggle	Operation mode for generic control point 1
Description	Parallel	Description for output 1
Operation mode	Toggle	Operation mode for generic control point 2
Description	Auto	Description for output 2

OLGAPC1 and OLGAPC2 - Transformer data combiner

This function combines the transformer data, that is, `TR_TAP_POS`, `TR_I_AMPL`, `TR_I_ANGL`, `TR_TAP_FLLW` and `TR_STATUS` as `TR_DAT`. In Relay 3, OLGAPC1 connects `TR1_I_AMPL` and `TR1_I_ANGL` to `TR1_DAT`. OLGAPC2 connects inputs `TR2_I_AMPL` and `TR2_I_ANGL` to `TR2_DAT`. This function does not have any settings.

OL5ATCC1 - Tap changer control with voltage regulator

Inputs `TR1_I_AMPL`, `TR1_I_ANGL`, `TR2_I_AMPL` and `TR2_I_ANGL` over GOOSERCV_CMV function need to be connected to OLGAPC1 and OLGAPC2 function blocks.

Table 140: OL5ATCC1 setting values for MCC application

Setting	Suggested values	Setting value calculation
Operation mode	Auto parallel	Operation mode
Parallel mode	MCC	Parallel mode selection
Runback raise V	1.12 xU_n[1)]	Voltage limit where fast lower commands takes place
Stability factor	5%[2)]	Stability factor in parallel operation
Band center voltage	1.0 xUn	To regulate voltage at 25 kV, the setting required is 25 kV/VT primary rated value = 25 kV/25 kV.
Band width voltage	3%	With a control voltage range of 21...27 kV having 17 taps, the step voltage = (27 - 21)/17=0.353 kV. The setting required is (2 · 0.353 kV/VT primary rated value) · 100 = (2 · 0.353 kV/25 kV) · 100.
Load current limit	2.0 xIn	To block the tap changer operations above 2000 A, the setting required is 2000/CT primary rated value = 2000/1000.
Block lower voltage	0.7 xUn	To block voltage correction commands below 17.5 kV, the setting required is 17.5 kV/VT primary rated value = 17.5 kV/25 kV.
Runback raise V	1.12 xUn	Assuming a control voltage of 1.1 xUn and *Band width voltage* of 3%, the setting required is 1.1 + 0.03/2.
Lower block tap	0	Tap changer limit position which gives the lowest voltage on the regulated side for the example is set to 0.
Table continues on next page		

Setting	Suggested values	Setting value calculation
Raise block tap	17	Tap changer limit position which gives highest voltage on the regulated side for the example is set to 17.
Control delay time 1	60 s	Control delay time for the first control pulse is set to 60 s for the example case.
Control delay time 2	30 s	Control delay time for the following control pulses is set to 30 s for the example case.

1) See section Automatic voltage regulation of example case 1.
2) Assuming a factor of 5% (depending on loop impedance) for illustration purpose

The MCC mode can also be achieved with *Operation mode* set as "Input control". Inputs PARALLEL (BI1) and AUTO (BI2) must be TRUE in this case. All other settings are kept at default values.

IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 141: GOOSE input signals for implementing Relay 3 in example case 3

Source data in the other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f[1)]	TR1 current magnitude from Relay 1	OLGAPC1	TR_I_AMPL
TR1	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f[1)]	TR1 current angle from Relay 1	OLGAPC1	TR_I_ANGL
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f[1)]	TR2 current magnitude from Relay 2	OLGAPC2	TR_I_AMPL
TR2	OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f[1)]	TR2 current angle from Relay 2	OLGAPC2	TR_I_ANGL

1) Input signal received via GOOSERCV_CMV

Table 142: GOOSE output signals for implementing Relay 3 in example case 3

Function block	Output	Data	Description
OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.mag.f	TR3 current magnitude from Relay 3 to Relay 1 and 2
OL5ATCC1	N/A	LD0.OL5ATCC1.LodAVec.cVal.ang.f	TR3 current angle from Relay 3 to Relay 1 and 2

Section 6 Arc flash protection

6.1 Introduction to application

The consequences of an arcing short circuit or earth fault inside a low-voltage or medium-voltage switchgear panel can be disastrous. An arc fault poses a serious threat to the switchgear operating and maintenance staff. Moreover, the extremely hot electric arc can destroy valuable equipment causing prolonged and costly distribution downtimes. An arc fault can arise from, for example, insulation faults and weaknesses, malfunction of a switchgear device, improper (loose) busbar or cable joints, overvoltage, corrosion, pollution, moisture, ferro-resonance (instrument transformers) and even ageing under electrical stress. Most of these fault reasons can be prevented by appropriate maintenance. Despite all precautions, arc faults may be caused by human error or by animals entering the switchgear panel.

Time is a critical parameter for the detection and minimization of the effects of arc faults as the arc incident energy rapidly increases with time. An arc fault lasting 500 ms may cause severe damage to the installation. If the arc lasts less than 100 ms, the damage is limited. Figure 60 illustrates the relationship between the arc fault energy and the fault clearing time in milliseconds at a certain arc fault current level.

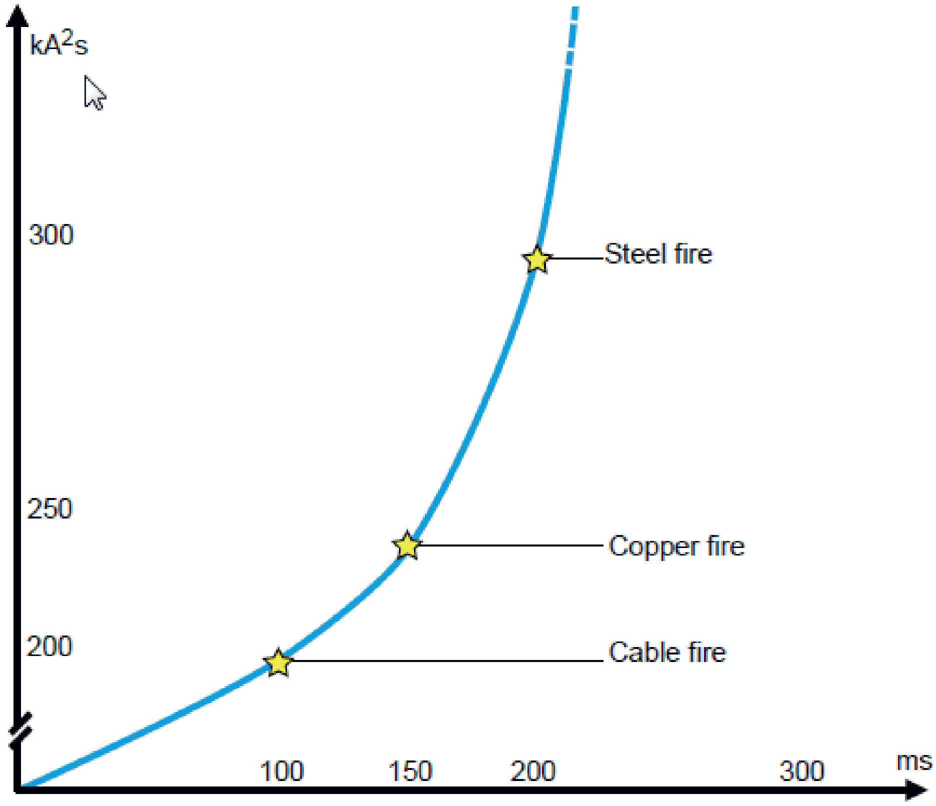

Figure 60: Arc fault impact as a function of the fault energy and the fault arcing time

6.2 Description of the example case

The case under discussion is a double busbar system with a single breaker. The air-insulated and metal-enclosed switchgear is located indoors. The single-line diagram describing the case is shown in Figure 61. The target is to implement an arc flash protection system for the whole switchgear. The implemented protection system must offer the best security, selectivity and fast operation performance.

The figure also shows the different compartments of the switchgear. When considering the location and type of the used arc flash sensors, the actual construction of the switchgear has been taken into account. There are generally four different compartments within a panel: busbar 1, busbar 2, circuit breaker and MV cable end termination. The bus coupler panel is different as it consists of four different compartments: one circuit breaker compartment and three bus riser compartments.

Each feeder and bus coupler in the figure is equipped with a relay. In this example case, the focus is on the arc protection, therefore other relay functionality is ignored. Four independent light detection sensor channels are provided for connecting lens or fiber loop sensors.

The arc protection function blocks ARCSARC1…4 also contain continuous arc light sensor supervision. Both sensor types are supervised targeting for high dependability. In case of a sensor fault, an `ALARM` output is activated. It is recommended to report this ALARM or corresponding events to the control system. See tech.note for details.

In this example, arc detection is secured by using both light detection and simultaneous overcurrent criteria.

If an outgoing feeder back-feeds current towards the bus at arc faults occurring in busbar or CB compartment, such an outgoing feeder is tripped selectively. If it is desired to trip also other outgoing feeders that do not feed the fault current but are connected to the same bus, add bus-specific intertrip signals to the logic.

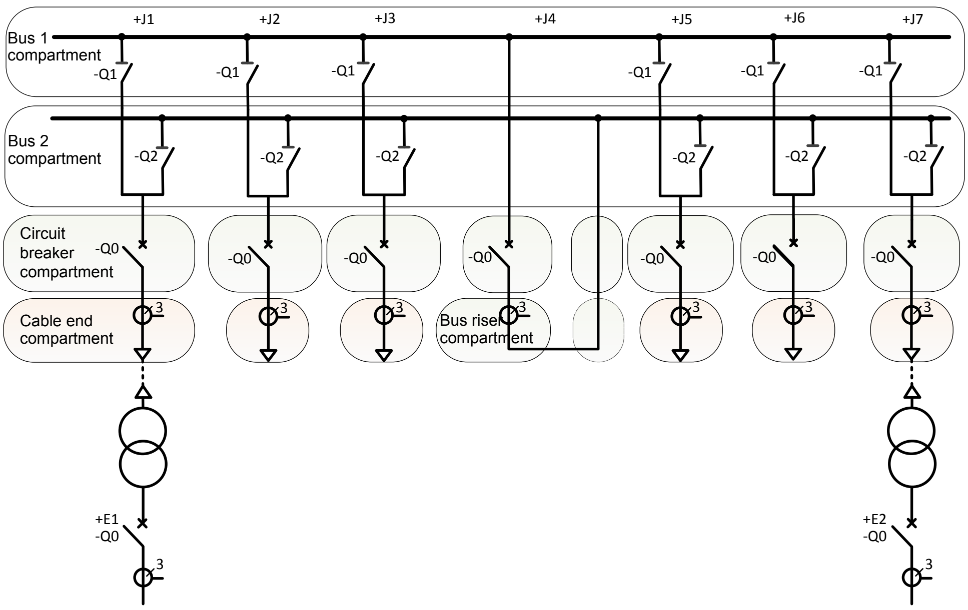

Figure 61: Single-line diagram with physical compartments highlighted describing this example case

In this example case, the arc flash protection system operates as the main protection against arc faults. Normal overcurrent protection functionality should be used as a backup for the arc flash protection. The arc flash protection system always trips (de-energizes) a minimum part of the installation necessary to isolate the faulty section.

To achieve this selectivity goal, and considering several possible arc fault locations, signaling between relays in different panels is required to inform about the detected arc flash and its location, that is, the actual compartment.

In this example case, for simplicity and presentational reasons, this signaling is implemented with binary I/O and physical copper wires. However, it is preferable to make the signaling using IEC 61850 GOOSE messaging. The main benefit of using GOOSE messaging is to get the fastest possible protection operation times and continuously supervised communication.

Figure 62 and Table 143 introduce the connection signals used, that is what information is communicated between the relays. The table also tells which additional feeders have to be tripped to isolate the faulty section depending on the location of the arc flash.

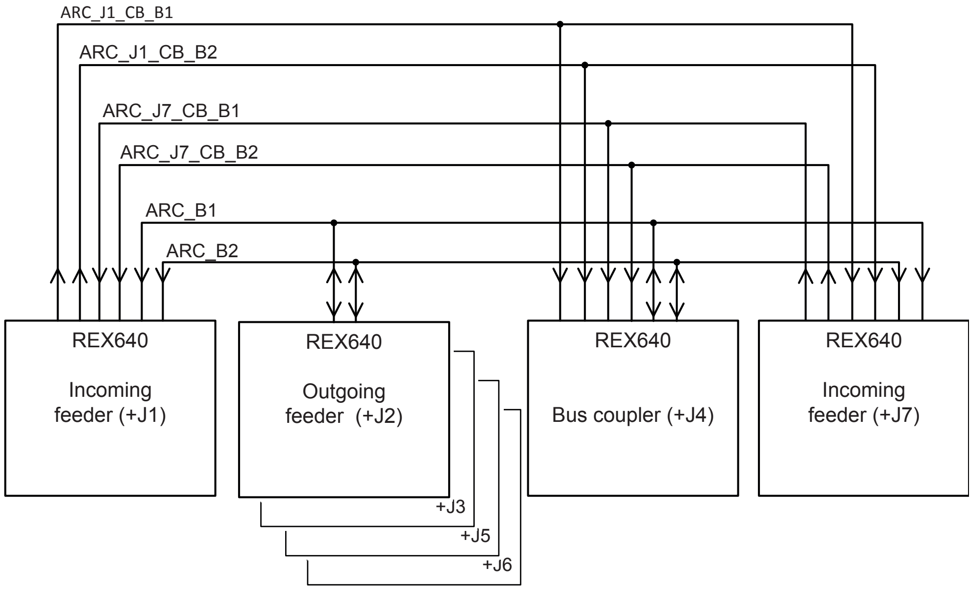

Figure 62: Arc flash detection signaling between the relays

Table 143: Arc flash signaling between the switchgear panels

Arc flash location	Signal name	Feeders to trip
Incoming feeder +J1 CB compartment; incomer +J1 is connected to Bus1	ARC_J1_CB_B1	Bus coupler +J4 and incoming feeder +J7 if it is connected to Bus1
Incoming feeder +J1 CB compartment; incomer +J1 is connected to Bus2	ARC_J1_CB_B2	Bus coupler +J4 and incoming feeder +J7 if it is connected to Bus2
Incoming feeder +J7 CB compartment; incomer +J7 is connected to Bus1	ARC_J7_CB_B1	Bus coupler +J4 and incoming feeder +J1 if it is connected to Bus1
Incoming feeder +J7 CB compartment; incomer +J7 is connected to Bus2	ARC_J7_CB_B2	Bus coupler +J4 and incoming feeder +J1 if it is connected to Bus2

Table continues on next page

Arc flash location	Signal name	Feeders to trip
Bus1 compartment	ARC_B1	Bus coupler +J4 and those outgoing feeders which are connected to Bus1 and feed fault current
Any outgoing feeder CB compartment; that feeder is connected to Bus1		
Buscoupler +J4 CB compartment		
Bus2 compartment	ARC_B2	Bus coupler +J4 and those outgoing feeders which are connected to Bus2 and feed fault current
+J4 bus riser compartments		
Any outgoing feeder CB compartment; that feeder is connected to Bus2		
Buscoupler +J4 CB compartment		

For example: An arc flash is detected in the incoming feeder +J1 CB compartment, and incoming feeder +J1 is connected to Bus1. Then signal ARC_J1_CB_B1 is used to tell the relay at bus coupler +J4 and the relay at incoming feeder +J7 to trip their breaker if they are also connected to Bus1 (and the overcurrent condition is simultaneously fulfilled).

6.3 ARC protection at incoming feeder +J1

This chapter describes the incoming feeder +J1 protection relay interface, configuration and settings. The same principles apply to the incoming feeder +J7.

6.3.1 Conceptual arc flash protection logic

Figure 63 explains the conceptual arc flash protection logic and arc flash signaling with other relays.

When an arc flash is detected in the incoming feeder +J1 CB compartment and simultaneous overcurrent is detected on the HV side of the feeding power transformer, the circuit breakers +J1-Q0 and +E1-Q0 need to be tripped. Depending on the status of the busbar disconnectors +J1-Q1 and +J1-Q2, the signals ARC_J1_CB_B1 and ARC_J1_CB_B2 are activated for the tripping bus coupler +J4 and/or incoming feeder +J7 if those relays see simultaneous overcurrent.

When an arc flash is detected in the cable end compartment and overcurrent is detected on the HV side of the feeding power transformer, the circuit breakers +J1-Q0 and +E1-Q0 need to be tripped.

The arc flash can also be detected elsewhere by other relays and ARC_J7_CB_B1, ARC_J7_CB_B2, ARC_B1 or ARC_B2 can be activated. Depending on the status of the busbar disconnectors +J1-Q1 and +J1-Q2 and if overcurrent is simultaneously detected on the MV side of the feeding power transformer, the circuit breaker +J1-Q0 needs to be tripped.

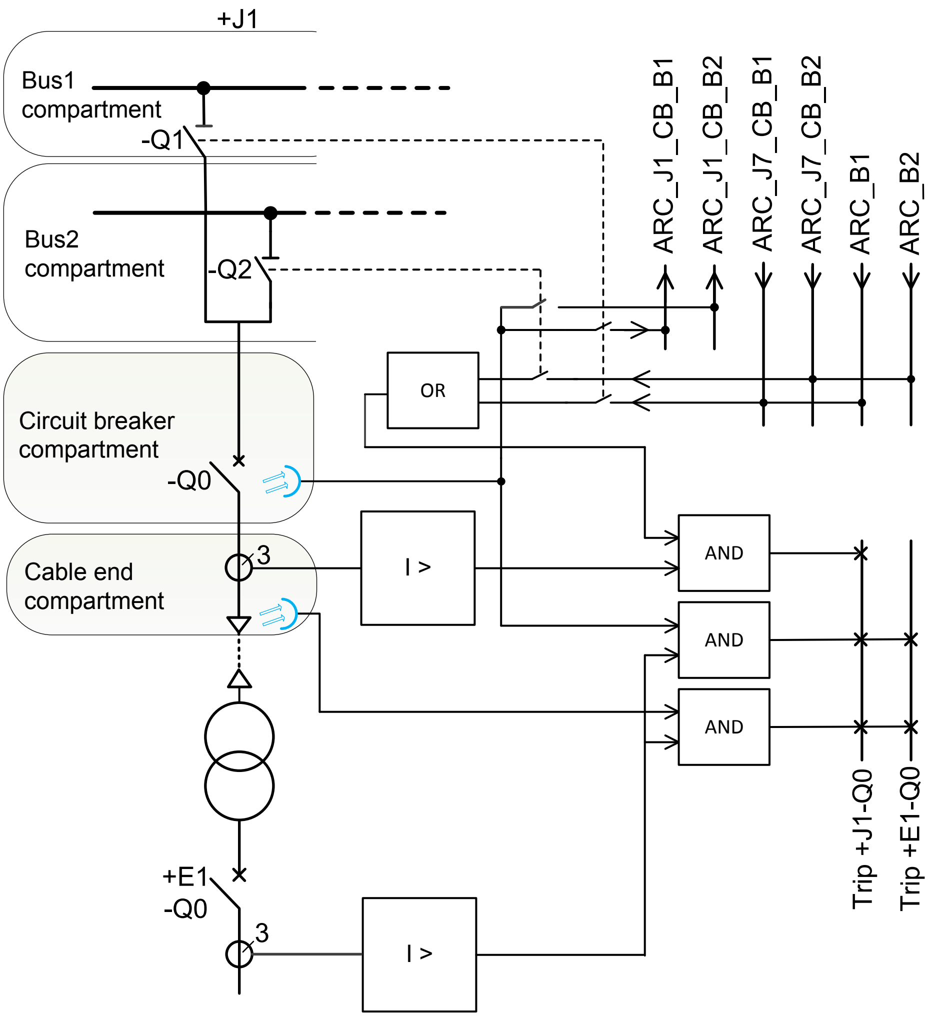

Figure 63: Conceptual logic for the incoming feeder +J1 and arc flash signaling with other relays

6.3.2 Relay interface, configuration and settings

Figure 64 shows the binary inputs (BI), binary outputs (BO), analog input (AI) signals and ARC inputs.

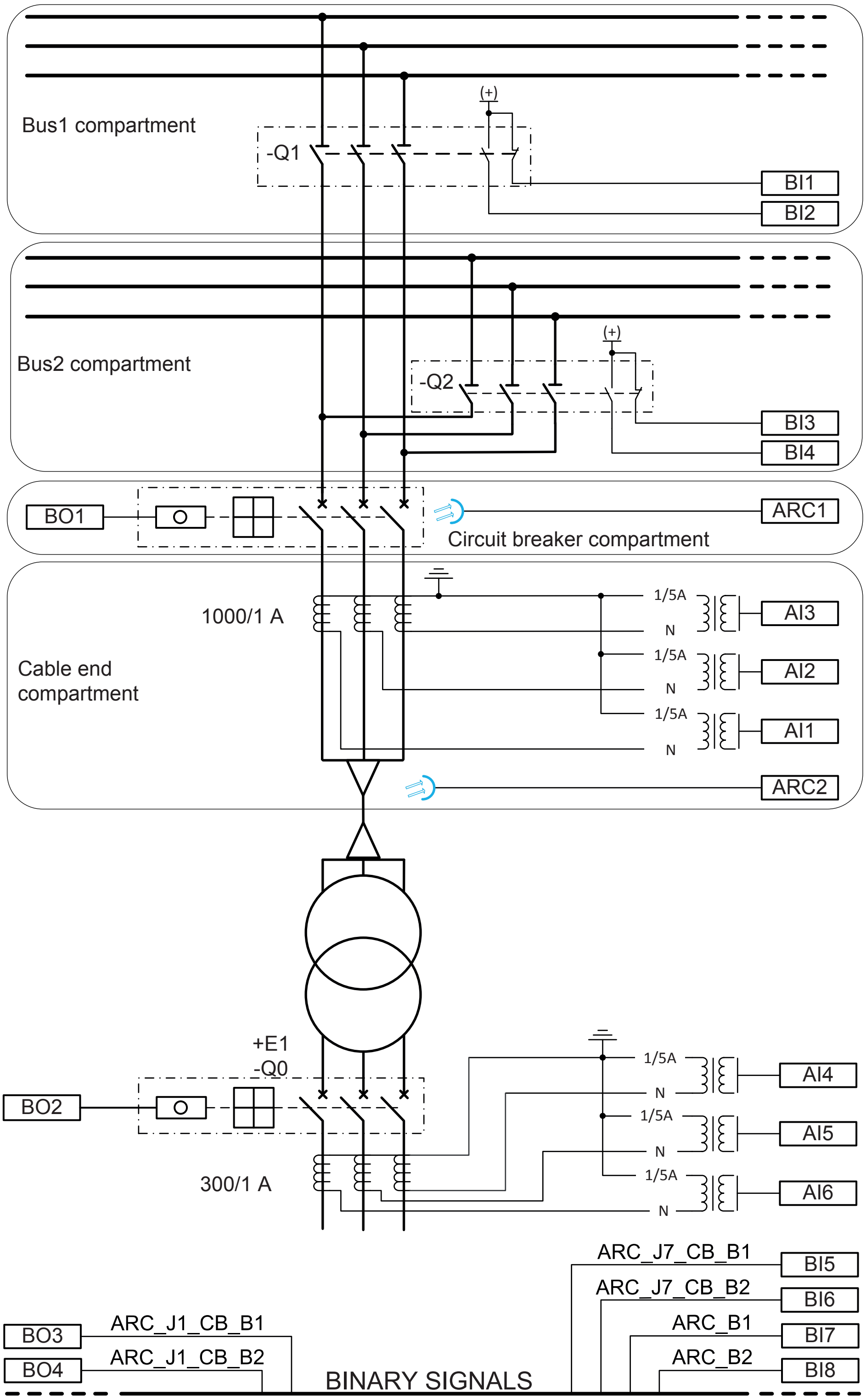

Figure 64: Connection diagram for the incoming feeder +J1

6.3.2.1 Analog input signals

Table 144: Physical analog inputs

Analog input	Description
AI1	Feeding transformer MV side current measurement, phase L1
AI2	Feeding transformer MV side current measurement, phase L2
AI3	Feeding transformer MV side current measurement, phase L3
AI4	Feeding transformer HV side current measurement, phase L1
AI5	Feeding transformer HV side current measurement, phase L2
AI6	Feeding transformer HV side current measurement, phase L3

6.3.2.2 Arc flash sensor inputs

Table 145: Physical arc flash sensors

ARC inputs	Description
ARC1	Arc flash detection in CB compartment +J1. Lens sensor is used.
ARC2	Arc flash detection in cable end compartment +J1. Lens sensor is used.

6.3.2.3 Binary input signals

Table 146: Physical binary inputs

Binary input	Description
BI1	Open status of the Busbar 1 disconnector +J1-Q1
BI2	Close status of the Busbar 1 disconnector +J1-Q1
BI3	Open status of the Busbar 2 disconnector +J1-Q2
BI4	Close status of the Busbar 2 disconnector +J1-Q2
BI5	ARC_J7_CB_B1 signal. Activated if the arc flash is detected in +J7 CB compartment, and +J7 is connected to Bus1
BI6	ARC_J7_CB_B2 signal. Activated if the arc flash is detected in +J7 CB compartment, and +J7 is connected to Bus2
BI7	ARC_B1 signal. Activated if the arc flash is detected in Bus1 area
BI8	ARC_B2 signal. Activated if the arc flash is detected in Bus2 area

6.3.2.4 Binary output signals

Table 147: Physical binary outputs

Binary output	Description
BO1	Trip signal for opening the circuit breaker +J1-Q0
BO2	Trip signal for opening the circuit breaker +E1-Q0
BO3	ARC_J1_CB_B1 signal. Arc flash detected in +J1 CB compartment and incoming feeder +J1 is connected to Bus1
BO4	ARC_J1_CB_B2 signal. Arc flash detected in +J1 CB compartment and incoming feeder +J1 is connected to Bus2

6.3.2.5 Recommended alarms

Table 148: Alarm list for implementing the incoming feeder +J1 relay arc protection example

Event container	Event	Description
ARCSARC1	ARC_FLT_DET	Arc light detected in the incoming feeder +J1 CB compartment
ARCSARC1	ALARM	Disconnected or faulty light sensor in +J1 CB compartment
ARCSARC1	OPERATE	Operate from Arc light in the incoming feeder +J1 CB compartment and OC on the HV side of the power transformer
ARCSARC2	ARC_FLT_DET	Arc light detected in the incoming feeder +J1 cable end compartment
ARCSARC2	ALARM	Disconnected or faulty light sensor in +J1 cable end compartment
ARCSARC2	OPERATE	Operate from Arc light in the incoming feeder +J1 cable end compartment and OC on the HV side of the power transformer
ARCSARC3	OPERATE	Operate from Arc light detected elsewhere by other relays and OC on the MV side of the power transformer

6.3.2.6 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600 and it is shown in Figure 65, Figure 66 and Figure 67.

The functionality implements the conceptual logic, but it is designed taking into account the relay's function blocks and their features.

In the implemented relay configuration, a dedicated arc protection function ARCSARC is used. The function detects arc flash light and simultaneous overcurrent and provides an internal logic for combining different conditions. In this application, three ARCSARC instances are necessary.

Table 149: ARCSARC1, 2, 3 inputs and sources

Input	Source/Function	
	ARCSARC1 and ARCSARC2[1)]	ARCSARC3[2)]
I3P	HV side currents from the analog inputs `AI4`, `AI5` and `AI6` via ILTCTR1 function	MV side currents from analog inputs `AI1`, `AI2` and `AI3` via ILTCTR2 function
IRES	From ILTCTR1, not used[3)]	From ILTCTR2, not used[3)]
REM_FLT_ARC	Not used	Compartment and busbar specific arc flash location detection by other relays is received via BI5…BI8. These activate the input `REM_FLT_ARC`.

1) Arc light sensor inputs ARC1…4 are always internally routed to ARCSARC1…4 function blocks. These inputs are not visible in Figure 65.
2) No arc light sensor is connected to ARCSARC3
3) Input `IRES` must be connected to ILTCTR function, although residual current is not used in this example case.

Table 150: ARCSARC1, 2, 3 outputs and target connections

Output	Target connection/Function		
	ARCSARC1	ARCSARC2	ARCSARC3
OPERATE	To be connected to circuit breaker trip circuit BO1 and BO2	To be connected to circuit breaker trip circuit BO1 and BO2	To be connected to circuit breaker trip circuit BO1
ARC_FLT_DET	Detection of arc flash in circuit breaker compartment +J1-Q0. This signal is routed to BO3 and BO4 depending on the busbar this feeder is connected to.	Not used	Not used

The configuration also requires other dedicated functions which are listed in Table 151. Additionally, some logic gates are needed for implementing the necessary logic. These are visible in Figure 66 and Figure 67.

Table 151: Other functions used in the relay configuration

Function block	Description
ILTCTR	Analog signal preprocessing for other function blocks
DCSXSWI	Disconnector position indication indicates the bus disconnector's position. The information is needed in order to determine to which bus the feeder is connected.
TRPPTRC	Master trip function for trip command collector/ handler with lockout/latching feature

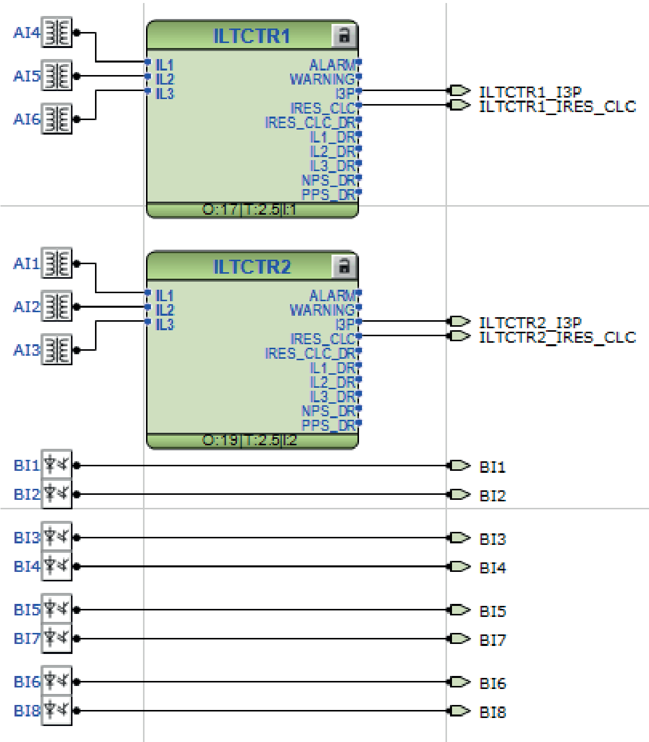

Figure 65: Relay inputs and preprocessing connections

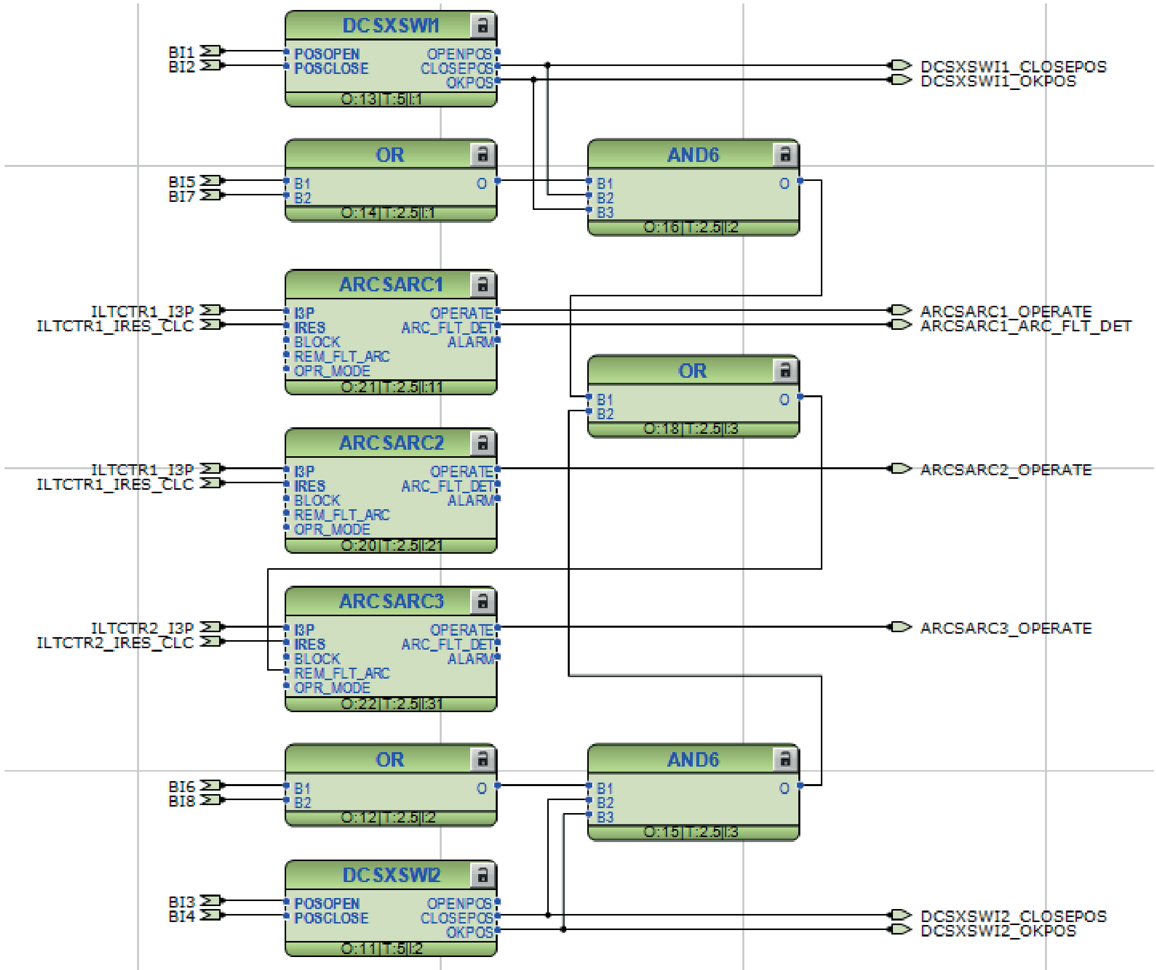

Figure 66: Application function block connections

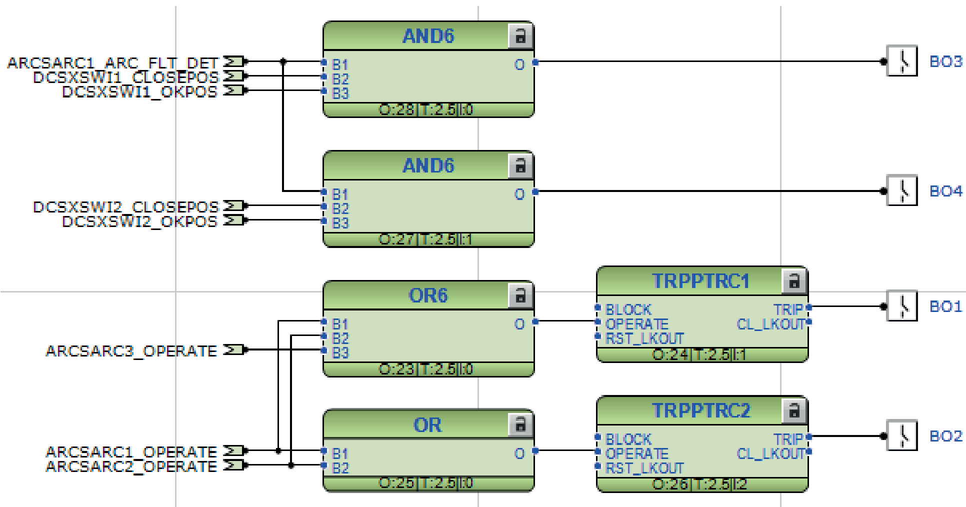

Figure 67: Relay output connections

6.3.2.7 Function blocks and setting values

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function for current signals. In this example, the CT ratios are 300/1A and 1000/1A at the HV and MV sides, respectively.

Table 152: Function settings for ILTCTR

Setting	ILTCTR1	ILTCTR2	Description
Primary current	300	1000	Primary current value
Secondary current	1	1	Secondary current value

ARCSARC arc protection

The arc protection functions ARCSARC1…4 are internally connected to physical arc light sensor inputs ARC1…4.

ARCSARC1 is used to detect light in the CB compartment with lens sensor 1. In addition to light, the ARCSARC1 function also monitors phase currents from the HV side of the feeding transformer to be able to make secure tripping, that is, to trip only if overcurrent is simultaneously fed through the power transformer.

ARCSARC2 is used to detect light in the cable end compartment with lens sensor 2. This ARCSARC2 function also monitors phase currents from the HV side of the feeding transformer to be able to make secure tripping, that is, to trip only if overcurrent is simultaneously fed through the power transformer.

ARCSARC3 is used for external arc faults. Binary inputs `BI5` and `BI6` provide the information about the external fault. Depending on the status of the busbar disconnectors +J1-Q1 and +J1-Q2, external light information routed to input `REM_FLT_ARC` activates and allows ARCSARC3 tripping only if the overcurrent condition is simultaneously met on the MV side of the feeding transformer.

Table 153 shows recommended setting values; all other settings can be kept at default values.

Table 153: ARCSARC1, 2, 3 settings

Setting	Recommended value for ARCSARC1	Recommended value for ARCSARC2	Recommended value for ARCSARC3	Description
Phase start value	2.5 x In	2.5 x In	2.5 x In	Operating phase current[1)]
Operation mode	Light + current	Light + current	Light + current	Operation mode of the function
Sensor supervision	ON	ON	OFF[2)]	Sensor supervision enabled/disabled

1) The value has to be clearly over the stationary load current, but clearly below the fault current level caused by the arc flash to enable the ARCSARC function to trip.
2) No arc sensor connected. “OFF” means that arc sensor supervision is switched off for this arc sensor.

6.4 ARC protection at bus coupler +J4

This chapter describes the bus coupler +J4 protection relay interface, configuration and settings.

6.4.1 Conceptual arc flash protection logic

When an arc flash is detected in the compartments Bus1, Bus2, CB or bus riser and overcurrent is detected in bus riser, the bus coupler circuit breaker +J4-Q0 needs to be tripped.

When an arc flash is detected in Bus1 or bus coupler CB compartment, ARC_B1 is signaled to the other relays. When an arc flash is detected in bus riser, Bus2 or CB compartment, ARC_B2 is signaled to the other relays.

The arc flash can also be detected elsewhere by other relays and ARC_J7_CB_B1, ARC_J7_CB_B2, ARC_B1 or ARC_B2 can be activated. If overcurrent is simultaneously detected in the bus riser, the bus coupler circuit breaker +J4-Q0 needs to be tripped.

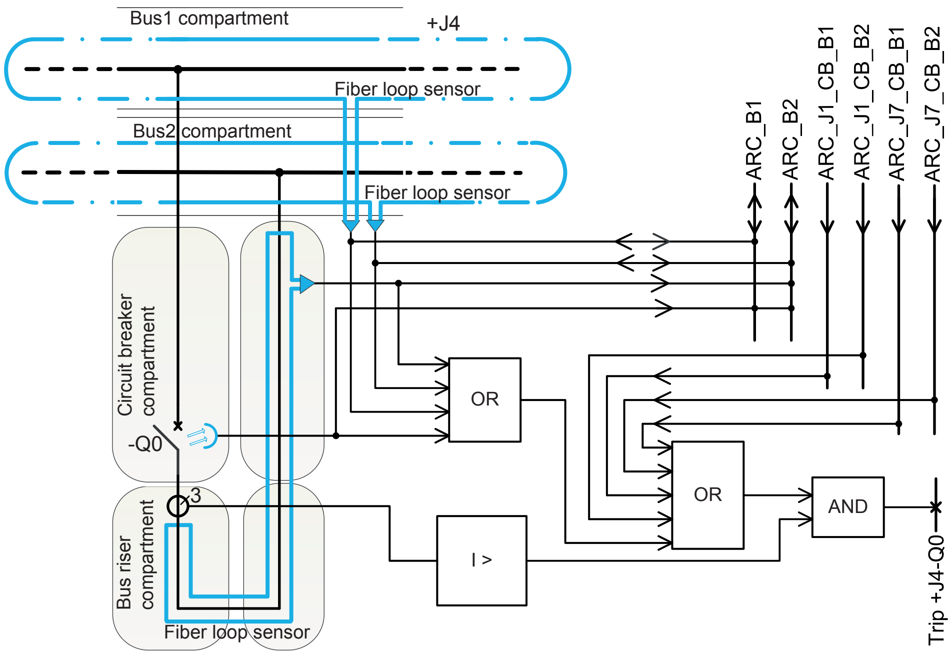

Figure 68: Conceptual logic for the bus coupler +J4 and arc flash signaling with other relays

6.4.2 Relay interface, configuration and settings

Figure 69 shows the binary inputs (BI), binary outputs (BO), analog input (AI) signals and ARC inputs.

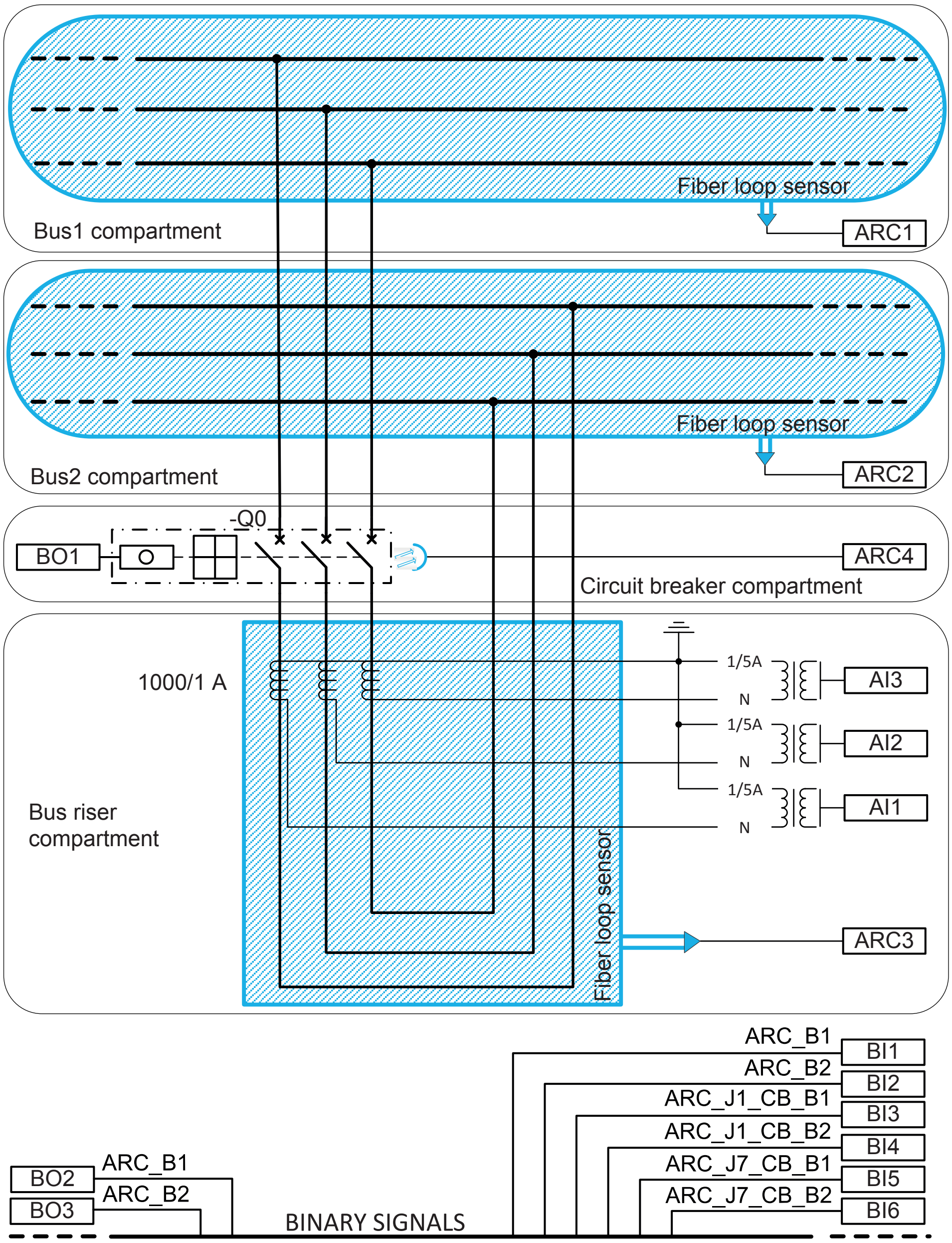

Figure 69: Connection diagram for the bus coupler +J4

6.4.2.1 Analog input signals

Table 154: Physical analog inputs

Analog input	Description
AI1	Bus coupler current measurement, phase L1
AI2	Bus coupler current measurement, phase L2
AI3	Bus coupler current measurement, phase L3

6.4.2.2 Arc flash sensors

Table 155: Physical arc flash sensors

Sensor	Description
ARC1	Arc flash detection in Bus1. Fiber loop sensor is used.
ARC2	Arc flash detection in Bus2. Fiber loop sensor is used.
ARC3	Arc flash detection in bus riser. Fiber loop sensor is used.
ARC4	Arc flash detection in bus coupler CB compartment +J4. Lens sensor is used.

6.4.2.3 Binary input signals

Table 156: Physical binary inputs

Binary input	Description
BI1	ARC_B1 signal. Arc flash detected in outgoing feeder CB compartment, and feeder is connected to Bus1
BI2	ARC_B2 signal. Arc flash detected in outgoing feeder CB compartment, and feeder is connected to Bus2
BI3	ARC_J1_CB_B1 signal. Arc flash detected in +J1 CB compartment, and +J1 is connected to Bus1
BI4	ARC_J1_CB_B2 signal. Arc flash detected in +J1 CB compartment, and +J1 is connected to Bus2
BI5	ARC_J7_CB_B1 signal. Arc flash detected in +J7 CB compartment, and +J7 is connected to Bus1
BI6	ARC_J7_CB_B2 signal. Arc flash detected in +J7 CB compartment, and +J7 is connected to Bus2

6.4.2.4 Binary output signals

Table 157: Physical binary outputs

Binary output	Description
BO1	Trip signal for opening the circuit breaker +J4-Q0
BO2	ARC_B1 signal. Arc flash detected in Bus1 compartment or in CB compartment +J4-Q0
BO3	ARC_B2 signal. Arc flash detected in Bus2 compartment, in CB compartment +J4-Q0 or in bus riser +J4

6.4.2.5 Recommended alarms

Table 158: Alarm list for implementing the bus coupler +J4 relay arc protection example

Event container	Event	Description
ARCSARC1	ARC_FLT_DET	Arc light detected in Bus1 compartment
ARCSARC1	ALARM	Disconnected or faulty light sensor in Bus1 compartment
ARCSARC1	OPERATE	Operate from Arc light detected in Bus1 compartment or externally by other relays and OC is fed through the bus coupler
ARCSARC2	ARC_FLT_DET	Arc light detected in Bus2 compartment
ARCSARC2	ALARM	Disconnected or faulty light sensor in Bus2 compartment
ARCSARC2	OPERATE	Operate from Arc light detected in Bus2 compartment and OC is fed through the bus coupler
ARCSARC3	ARC_FLT_DET	Arc light detected in bus riser compartment
ARCSARC3	ALARM	Disconnected or faulty light sensor in Bus riser compartment
ARCSARC3	OPERATE	Operate from Arc light detected in bus riser compartment and OC is fed through the bus coupler
ARCSARC4	ARC_FLT_DET	Arc light detected in bus coupler +J4 CB compartment
ARCSARC4	ALARM	Disconnected or faulty light sensor in bus coupler CB compartment
ARCSARC4	OPERATE	Operate from Arc light detected in bus coupler CB compartment and OC is fed through the bus coupler

6.4.2.6 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600 and it is shown in Figure 70, Figure 71 and Figure 72. The functionality implements the conceptual logic, but it is designed taking into account the relay's function blocks and their features.

In the implemented relay configuration, a dedicated arc protection function ARCSARC is used. The function detects arc flash light and simultaneous overcurrent and provides an internal logic for combining different conditions. In this application, four ARCSARC instances are necessary.

Table 159: ARCSARC1, 2, 3, 4 inputs and sources

Input	Source/Function	
	ARCSARC1[1)]	ARCSARC2, ARCSARC3 and ARCSARC4[1)]
I3P	Bus coupler currents from analog inputs `AI1`, `AI2` and `AI3` via ILTCTR1 function	Bus coupler currents from analog inputs `AI1`, `AI2` and `AI3` via ILTCTR1 function
IRES	From ILTCTR1, not used[2)]	From ILTCTR1, not used[2)]
REM_FLT_ARC	Detection of arc flash by other relays is received via BI1...BI6. These activate the input `REM_FLT_ARC`.	Not used

1) Arc light sensor inputs ARC1…4 are always internally routed to ARCSARC1…4 function blocks. These inputs are not visible in Figure 70.
2) Input `IRES` must be connected to ILTCTR function, although residual current is not used here.

Table 160: ARCSARC1, 2, 3, 4 outputs and target connections

Output	Target connection/Function			
	ARCSARC1	ARCSARC2	ARCSARC3	ARCSARC4
OPERATE	To be connected to circuit breaker trip circuit BO1	To be connected to circuit breaker trip circuit BO1	To be connected to circuit breaker trip circuit BO1	To be connected to circuit breaker trip circuit BO1
ARC_FLT_DET	Detection of arc in Bus1 compartment routed to BO2	Detection of arc in Bus2 compartment routed to BO3	Detection of arc in bus riser routed to BO3	Detection of arc in CB compartment routed to BO2 and BO3

The configuration also requires other dedicated functions which are listed in Table 161. Additionally, some logic gates are needed for implementing the necessary logic. These are visible in Figure 71 and Figure 72.

Table 161: Other functions used in the relay configuration

Function block	Description
ILTCTR	Analog signal preprocessing for other function blocks
TRPPTRC	Master trip function for trip command collector/ handler with lockout/latching feature

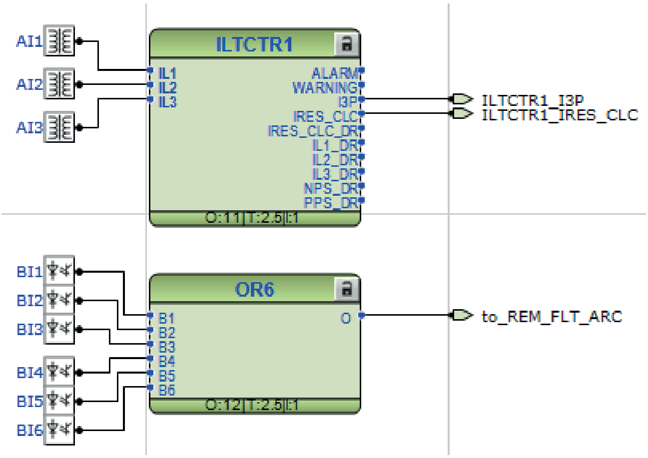

Figure 70: Relay inputs and preprocessing connections

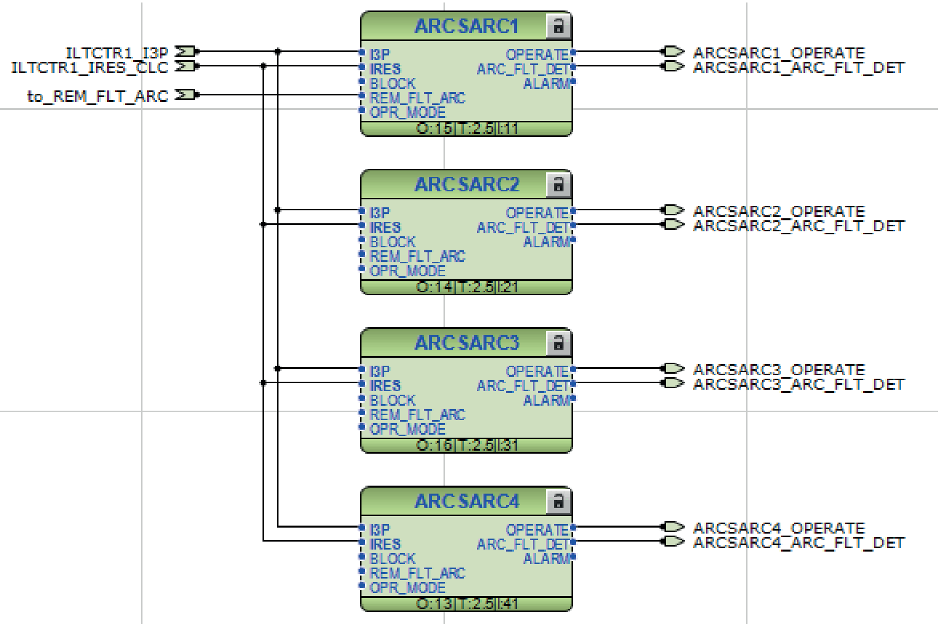

Figure 71: Application function block connections

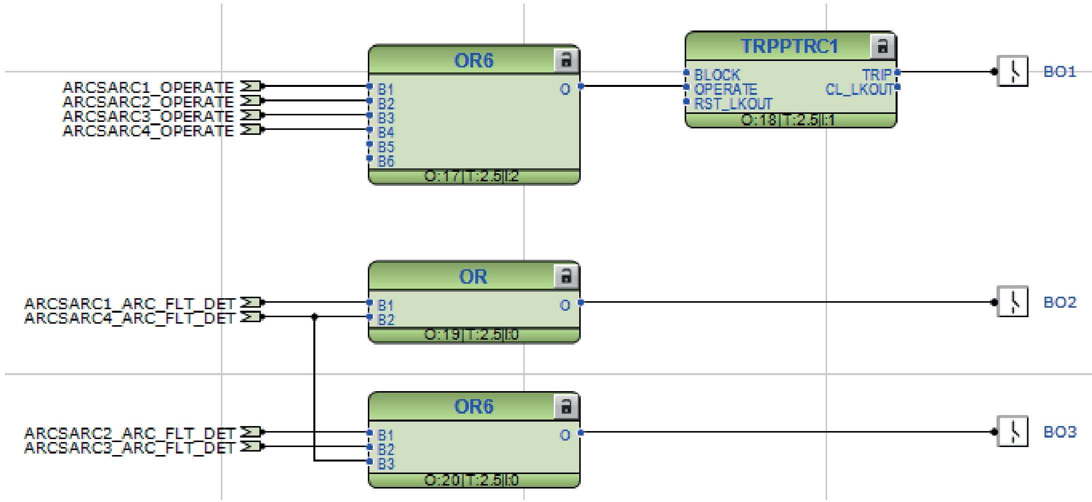

Figure 72: Relay output connections

6.4.2.7 Function blocks and setting values

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function for current signals. In this example, the CT ratio is 300/1A at the HV side.

Table 162: Function settings for ILTCTR

Setting	ILTCTR1	Description
Primary current	300	Primary current value
Secondary current	1	Secondary current value

ARCSARC arc protection

The arc protection functions ARCSARC1…4 are internally connected to physical ARC inputs 1…4. This example case uses four ARCSARC instances, three instances for the fiber loop sensors and one instance for a lens sensor.

ARCSARC1 is used to detect light in the Bus1 busbar compartment using fiber loop sensor 1 and for external arc faults. Binary inputs `BI1…BI6` provide the information about the external fault. External light information routed to input `REM_FLT_ARC` activates and allows ARCSARC1 tripping if simultaneous overcurrent condition is met.

ARCSARC2 is used to detect light in the Bus2 compartment with fiber loop sensor 2. ARCSARC3 is used to detect light in the bus riser with fiber loop sensor 3. ARCSARC4 is used to detect light in the bus coupler circuit breaker compartment +J4-Q0 with lens sensor 4.

ARCSARC1…4 functions also monitor phase currents from the bus riser compartment to be able to make selective tripping, that is, to trip only if overcurrent is fed through the bus coupler.

Table 163 shows recommended setting values; all other settings can be kept at default values.

Table 163: ARCSARC1, 2, 3, 4 settings

Setting	Recommended value for ARCSARC1	Recommended value for ARCSARC2	Recommended value for ARCSARC3	Recommended value for ARCSARC4	Description
Phase start value	2.5 x In	2.5 x In	2.5 x In	2.5 x In	Operating phase current1)
Operation mode	Light + current	Light + current	Light + current	Light + current	Operation mode of the function
Sensor supervision	ON	ON	ON	ON	Sensor supervision enabled/ disabled

1) The value has to be clearly over the stationary load current, but clearly below the fault current level caused by the arc flash to enable the ARCSARC function to trip.

6.5 ARC protection at outgoing feeder +J2

This chapter describes on outgoing feeder +J2 protection relay interface, configuration and settings. The same principles apply to outgoing feeders +J3, +J5 and +J6.

6.5.1 Conceptual arc flash protection logic

Figure 73 explains the conceptual arc flash protection logic and arc flash signaling with other relays.

When an arc flash is detected inside the CB compartment of the outgoing feeder +J2, depending on the status of the busbar disconnectors +J2-Q1 and +J2-Q2, either signal `ARC_B1` or `ARC_B2` is activated to inform both incomer and bus coupler relays about that. If they detect simultaneous overcurrent, they trip the relevant incoming feeder circuit breaker and the bus coupler circuit breaker to isolate the faulty section. Also, if an arc flash is detected remotely in the Bus1 or Bus2 compartments monitored by the bus coupler relay, or in the CB compartment of another outgoing feeder, either signal `ARC_B1` or `ARC_B2` is activated.

Should an arc fault, which is detected locally in the CB compartment or remotely, be back-fed so that overcurrent is simultaneously detected by the outgoing feeder relay, circuit breaker +J2-Q0 is tripped.

If an arc flash is detected inside the cable end compartment and overcurrent is detected in the outgoing feeder, then only circuit breaker +J2-Q0 is tripped selectively.

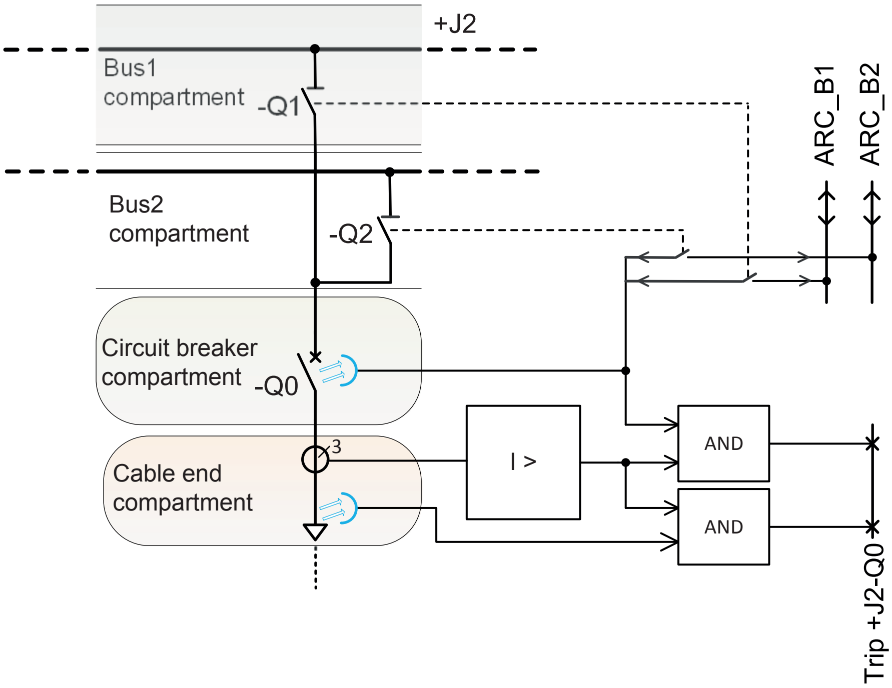

Figure 73: Conceptual logic for the outgoing feeder +J2 and arc flash signaling with other relays

6.5.2 Relay interface, configuration and settings

Figure 74 shows the binary inputs (BI), binary outputs (BO), analog input (AI) signals and ARC inputs.

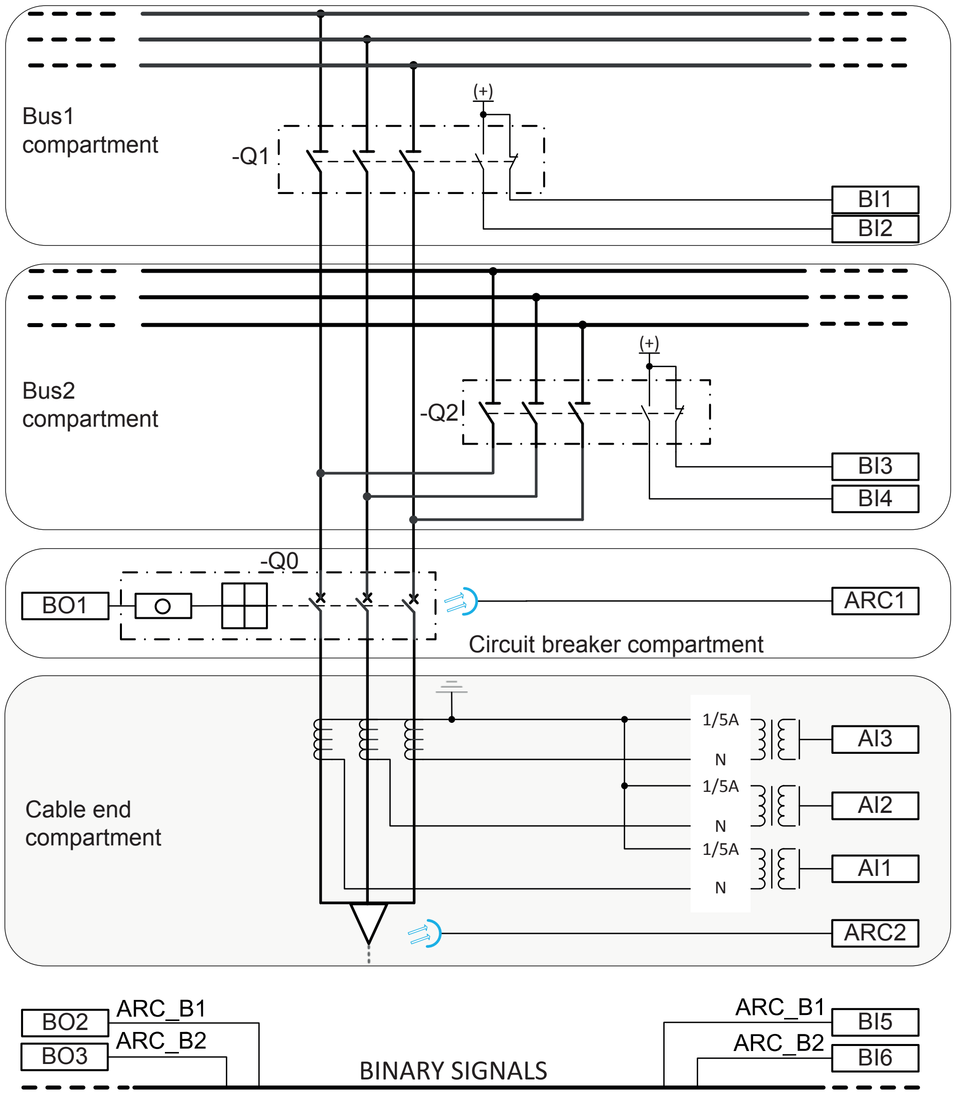

Figure 74: Connection diagram for the outgoing feeder +J2

6.5.2.1 Analog input signals

Table 164: Physical analog inputs

Analog input	Description
AI1	Outgoing feeder current measurement, phase L1
AI2	Outgoing feeder current measurement, phase L2
AI3	Outgoing feeder current measurement, phase L3

6.5.2.2 Arc flash sensors

Table 165: Physical arc flash sensors

ARC-inputs	Description
ARC1	Arc flash detection in CB compartment +J2. Lens sensor is used.
ARC2	Arc flash detection in cable end compartment +J2. Lens sensor is used.

6.5.2.3 Binary input signals

Table 166: Physical binary inputs

Binary input	Description
BI1	Open status of the Busbar 1 disconnector +J2-Q1
BI2	Close status of the Busbar 1 disconnector +J2-Q1
BI3	Open status of the Busbar 2 disconnector +J2-Q2
BI4	Close status of the Busbar 2 disconnector +J2-Q2
BI5	ARC_B1 signal. Activated if arc flash detected in Bus1 area
BI6	ARC_B2 signal. Activated if arc flash detected in Bus2 area

6.5.2.4 Binary output signals

Table 167: Physical binary outputs

Binary output	Description
BO1	Trip signal for opening the circuit breaker +J2-Q0
BO2	ARC_B1 signal. Arc flash detected with lens sensor in outgoing feeder +J2-Q0, and +J2 is connected to Bus1
BO3	ARC_B1 signal. Arc flash detected with lens sensor in outgoing feeder +J2-Q0, and +J2 is connected to Bus2

6.5.2.5 Recommended alarms

Table 168: Alarm list for implementing the outgoing feeder +J2 relay arc protection example

Event container	Event	Description
ARCSARC1	ARC_FLT_DET	Arc light detected in the outgoing feeder +J2 CB compartment
ARCSARC1	ALARM	Disconnected or faulty light sensor in +J2 CB compartment
ARCSARC1	OPERATE	Operate from Arc light detected in the outgoing feeder +J2 CB compartment and OC backfed to the feeder
ARCSARC2	ARC_FLT_DET	Arc light detected in the outgoing feeder +J2 cable end compartment
ARCSARC2	ALARM	Disconnected or faulty light sensor in +J2 cable end compartment
ARCSARC2	OPERATE	Operate from Arc light detected in the outgoing feeder +J2 cable end compartment and OC fed through the feeder
ARCSARC3	OPERATE	Operate from Arc light detected remotely by buscoupler relay and OC backfed to the feeder

6.5.2.6 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600 and it is shown Figure 75, Figure 76 and Figure 77. The functionality implements the conceptual logic, but it is designed taking into account the relay's function blocks and their features.

In the implemented relay configuration, a dedicated arc protection function ARCSARC is used. The function detects arc flash light and simultaneous overcurrent and provides an internal logic for combining different conditions. In this application, three ARCSARC instances are necessary.

Table 169: ARCSARC1, 2, 3 inputs and sources

Input	Source/Function	
	ARCSARC1 and ARCSARC2[1)]	ARCSARC3[2)]
I3P	Feeder currents from analog inputs `AI1`, `AI2` and `AI3` via ILTCTR1 function	Feeder currents from analog inputs `AI1`, `AI2` and `AI3` via ILTCTR1 function
IRES	From ILTCTR1, not used[3)]	From ILTCTR1, not used[3)]
REM_FLT_ARC	Not used	Detection of arc flash by bus coupler relay is received via BI5...BI6 depending on the busbar this feeder is connected to. This activates the input `REM_FLT_ARC`.

1) Arc light sensor inputs ARC1…4 are always internally routed to ARCSARC1…4 function blocks, respectively. These inputs are not visible in Figure 75.
2) No light sensor is connected to ARCSARC3.
3) Input `IRES` must be connected to ILTCTR1 function, although residual current is not used here.

Table 170: ARCSARC1, 2, 3 outputs and target connections

Output	Target connection/Function	
	ARCSARC1	ARCSARC2 and ARCSARC3
OPERATE	To be connected to circuit breaker trip circuit BO1	To be connected to circuit breaker trip circuit BO1
ARC_FLT_DET	Detection of arc flash in circuit breaker compartment +J2-Q0. This is routed to BO2 and BO3 depending on the busbar this feeder is connected to.	Not used

The configuration also requires other dedicated functions which are listed in Table 171. Additionally, some logic gates are needed for implementing the necessary logic. These are visible in Figure 76 and Figure 77.

Table 171: Other functions used in the relay configuration

Function block	Description
ILTCTR	Analog signal preprocessing for other function blocks
DCSXSWI	Disconnector position indication indicates the bus disconnector's position. The information is needed in order to determine to which bus the outgoing feeder is connected.
TRPPTRC	Master trip function for trip command collector/ handler with lockout/latching feature

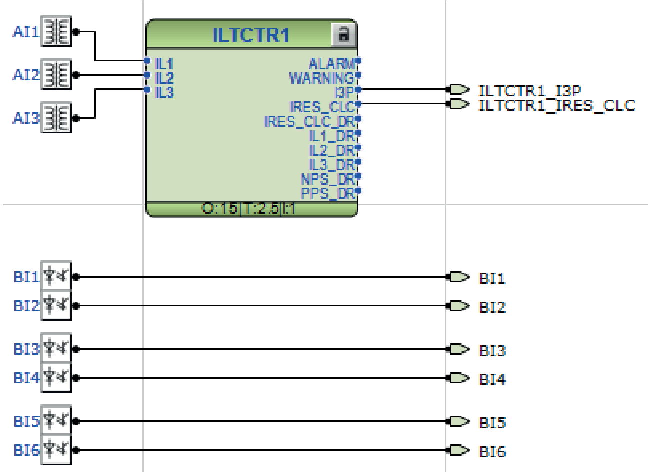

Figure 75: Relay inputs and preprocessing connections

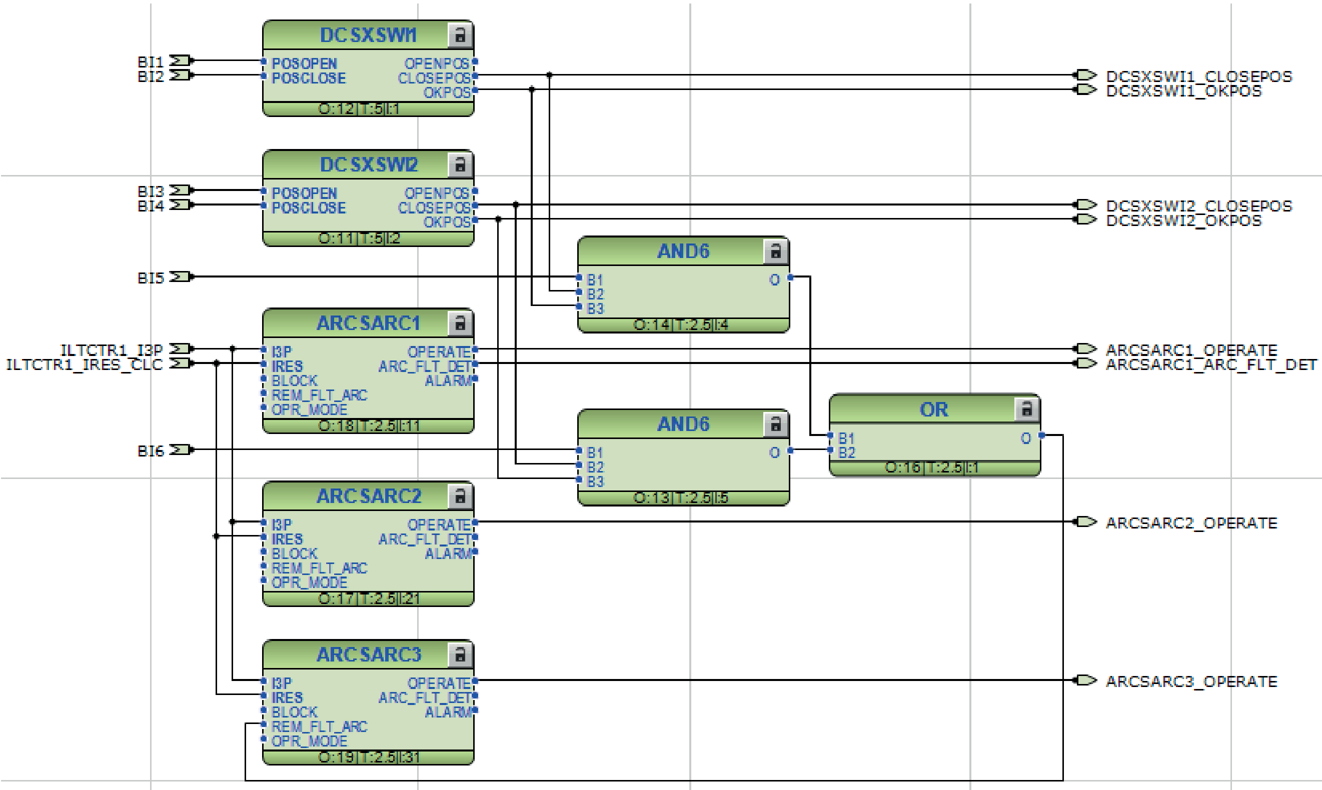

Figure 76: Application function block connections

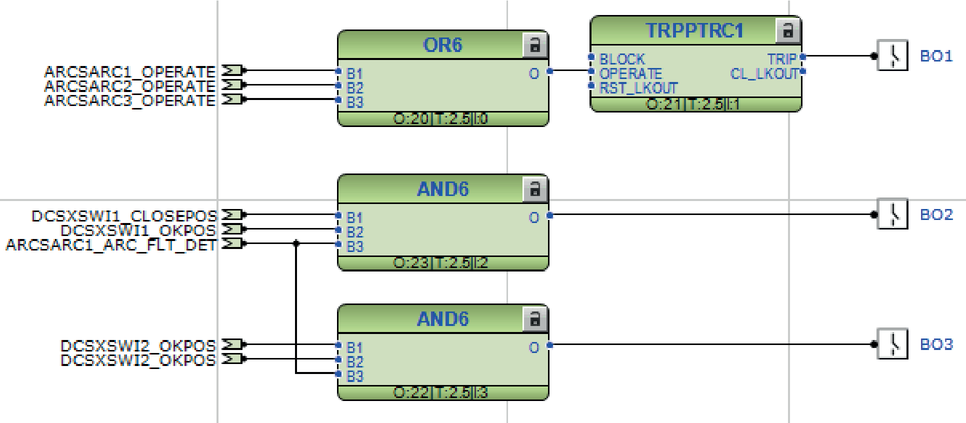

Figure 77: Relay output connections

6.5.2.7 Function blocks and setting values

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function for current signals. In this example, the CT ratio is 300/1 A at the HV side.

Table 172: Function settings for ILTCTR

Setting	ILTCTR1	Description
Primary current	300	Primary current value
Secondary current	1	Secondary current value

ARCSARC arc protection

The arc protection functions ARCSARC1…4 are connected to physical ARC inputs 1…4. This example case uses three ARCSARC instances, two instances for the lens sensors and one instance for the arc flash from another part of the switchgear.

ARCSARC1 is used to detect light in the CB compartment using lens sensor 1.

ARCSARC2 is used to detect light in the cable end compartment using lens sensor 2.

The ARCSARC1 and ARCSARC2 functions monitor also the feeder +J2 phase currents to be able to make secure tripping, that is, to trip only in case of simultaneous overcurrent.

ARCSARC3 is only used for external arc faults. Binary inputs `BI5` and `BI6` provide the information about the external fault. Depending on the status of the busbar disconnectors +J2-Q1 and +J2-Q2, external light information input `REM_FLT_ARC` activates and allows ARCSARC3 tripping if the overcurrent condition is met.

Table 173 shows recommended setting values; all other settings can be kept at default values.

Table 173: ARCSARC1, 2, 3 settings

Setting	Recommended value for ARCSARC1	Recommended value for ARCSARC2	Recommended value for ARCSARC3	Description
Phase start value	2.5 x In	2.5 x In	2.5 x In	Operating phase current[1)]
Operation mode	Light + current	Light + current	Light + current	Operation mode of the function
Sensor supervision	ON	ON	OFF[2)]	Sensor supervision enabled / disabled

1) The value has to be clearly over the stationary load current, but clearly below the fault current level caused by the arc flash to enable the ARCSARC function to trip.
2) No arc sensor connected. “OFF” means that arc sensor supervision is switched off for this arc sensor.

Section 7 Distance and directional earth-fault protection with scheme communication

7.1 Introduction to application

Power transmission and distribution lines and cables are critical components of a power system. The faults occurring on lines or cables have to be detected and isolated as fast as possible to prevent cascading which might eventually result in a system blackout. Hence line and cable protection occupies an important place among the various protection methods and employs a number of different protection strategies to ensure fast, selective and secure fault clearing.

This application example explains the distance-based protection and the use of scheme communication to further improve its speed. Distance-based protection is used for longer lines and uses voltage and current measurements to estimate an equivalent impedance. If the measured impedance is less than the set zone value, a trip command is issued. To make the protection more selective, different protection zones are introduced as, for example, zone 1 and zone 2. Zone 1 typically provides immediate trip without any intentional time delay. For other zones, backup protection with a graded time delay is used to ensure selectivity. Usually, 75...80 percent of the protected line comes under zone 1.

If fast fault clearing is required for the part of the line not covered by zone 1, the distance protection function can be combined with a logic which uses communication channels and is referred to as scheme communication logic for distance protection. The protection relays support one communication channel in each direction which can transmit binary signals. The performance of the scheme communication logic depends on the communication channel speed, security against false or lost signals and its dependability to ensure that the signals are reliably transmitted during power system faults. Since the aim of this scheme is to achieve faster tripping, the communication speed, or minimum time delay, is always of the utmost importance.

Selectivity for earth-fault protection may be difficult to achieve in meshed networks with isolated or compensated neutral. This is due to the fact that the fault current magnitude and the apparent fault loop impedance do not significantly depend on the fault location. In such networks, directional earth-fault protection functions can determine the fault direction (forward or reverse), but they cannot determine whether the fault is on the protected line or beyond the adjacent substation. Scheme communication can be combined with the earth-fault protection to achieve selective unit protection.

There are several available communication scheme types.

- Direct underreaching transfer trip DUTT
- Permissive underreaching transfer trip PUTT
- Permissive overreaching transfer trip POTT
- Directional comparison blocking DCB

In the DUTT scheme, the trip signal from the remote end is directly used for instantaneously tripping the circuit breaker. In permissive schemes, trip signals are interchanged between the terminals to receive permission to trip during an internal fault. The DCB scheme is used for sending a blocking signal to the remote terminal via the communication channel if the fault is locally seen in the reverse direction. In all the schemes, tripping is always blocked in case of external faults. The permissive schemes are faster and more secure against false tripping, but since they depend on a received signal for faster trip, their dependability (ability to trip) is lower than that of a blocking scheme.

Table 174: Typical line faults and conditions, protection and protection-related functions

Faults and conditions	Protection and protection-related functions
Phase-to-earth, phase-to-phase-to-earth, three-phase faults	DSTPDIS
Earth fault	DEFLPDEF, DEFHPDEF
Cross-country fault	DSTPDIS

7.2 Description of the example case

To explain the application of distance and directional earth-fault protection with scheme communication, a generic underground cable system is taken as an example. Figure 78 shows a representative configuration of a 10 MVA, 11 kV isolated neutral system with a cable having relays at both ends on bus A and bus B, respectively. The protected unit is a 3x240 mm^2 Al + 70 Cu underground cable and the maximum load current is 385 A. The length of the protected cable is 10 km, the shortest adjacent cable is 12 km and the longest cable is 20 km.

CTs are connected to measure phase currents. As this is an isolated neutral system, a core balance CT (CBCT) is used to measure residual current I_0 at both ends. These measurements are used to provide directional earth-fault protection. VTs are connected at both ends to measure phase voltages and residual voltage U_0 in open-delta connection.

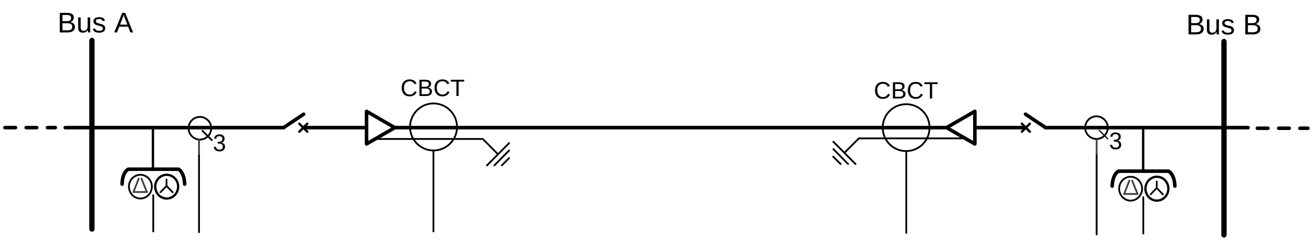

Figure 78: Single-line diagram of the example case for the scheme communication application

7.3 Local end protection relay

This chapter provides detailed information about the configuration of the relay at bus A used in this application example: the relay interfaces, the ACT diagram and parameter settings and information on how the distance and directional earth-fault protection with scheme communication can be achieved for the given example.

This chapter is also applicable for the relay at bus B by replacing the current and voltage inputs as well as the binary and trip signals for the other end of the line.

7.3.1 Relay interface, configuration and settings

Figure 79 shows the connection details of the relay's analog inputs and binary outputs. The CT and CBCT connections for phase currents and the residual current measurement required for line protection with scheme communication in the example case are also shown in the figure. The VT connections for phase voltage measurements and the open-delta connection for residual voltage measurement are also shown. A fiber-optic channel is used for protection communication.

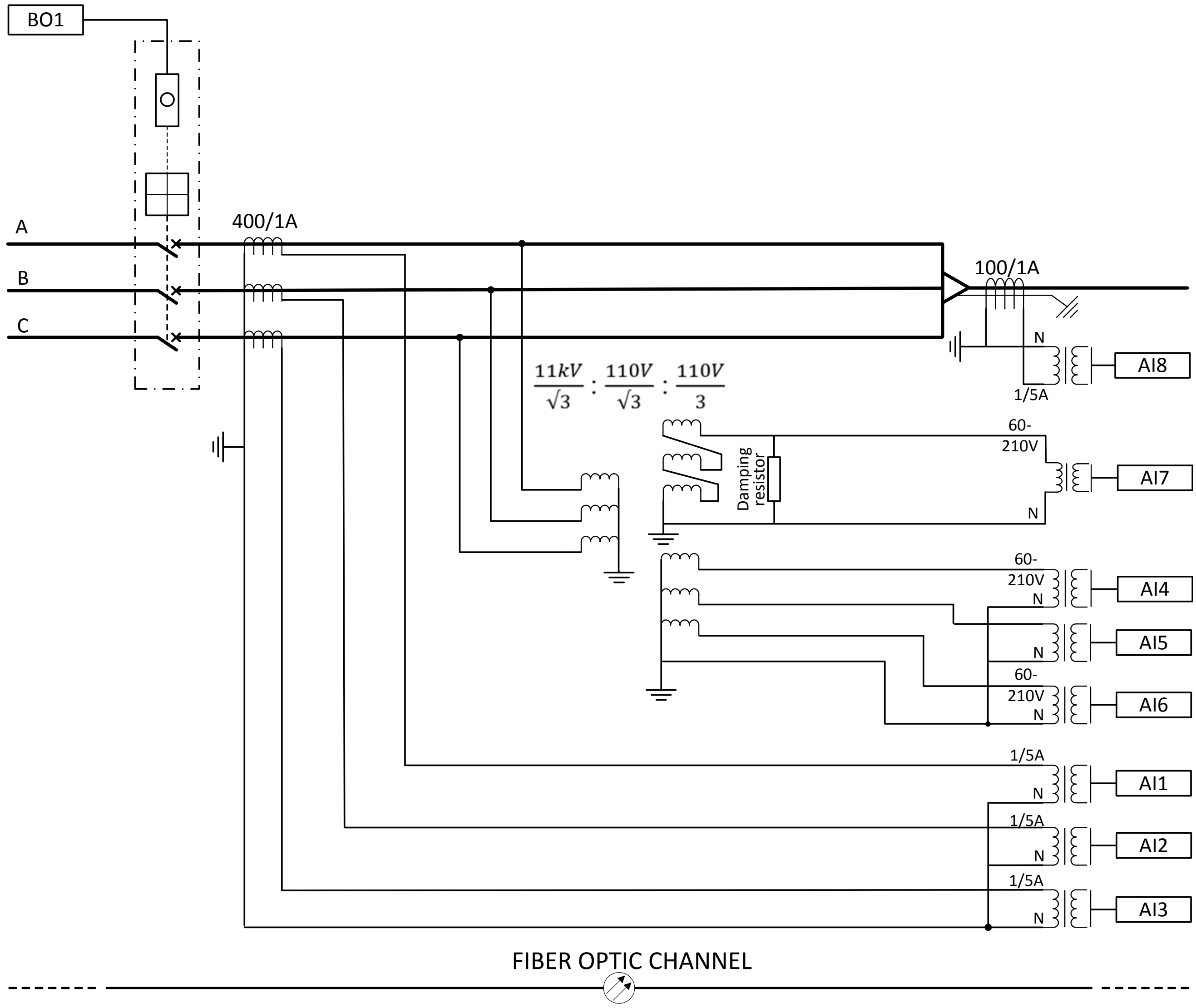

Figure 79: Relay interfaces and CT/VT connections for the scheme communication example case

7.3.1.1 Analog input signals

Table 175: Physical analog input signals for implementing the application example

Analog input	Description
AI1	Phase A current I_A
AI2	Phase B current I_B
AI3	Phase C current I_C
AI4	Phase A voltage U_A
AI5	Phase B voltage U_B
Table continues on next page	

Analog input	Description
AI6	Phase C voltage U_C
AI7	Residual voltage
AI8	Residual current

7.3.1.2 Binary output signals

Table 176: Physical binary output signal for implementing the application example

Binary output	Description
BO1	Trip signal to breaker

7.3.1.3 Recommended alarms

Table 177: Alarm list for implementing the application example

Event container	Event	Description
DSTPDIS1	OPERATE_Z1	Operate from distance protection Zone 1
DSTPDIS1	OPERATE_Z2	Operate from distance protection Zone 2
DSTPDIS1	OPERATE_Z3	Operate from distance protection Zone 3
DSTPDIS1	XC_FLT	Cross-country fault
DSOCPSCH1	OPERATE	Trip by the communication scheme logic for distance protection
DSOCPSCH1	CS	Carrier send signal sent by the communication scheme logic for distance protection
DSOCPSCH1	CRL	Carrier signal received signal from the communication scheme logic for distance protection
DEFLPDEF1	OPERATE	Operate from directional earth-fault low stage
DEFHPDEF1	OPERATE	Operate from directional earth-fault high stage
RESCPSCH1	OPERATE	Trip by the communication scheme logic for earth-fault protection
RESCPSCH1	CS	Carrier send signal sent by the communication scheme logic for earth-fault protection
RESCPSCH1	CRL	Carrier receive signal from the communication scheme logic for earth-fault protection
PCSITPC1	ALARM	Communication channel failure alarm

7.3.1.4 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 178: Functions used in the relay configuration

Function block	Description
ILTCTR1, RESTCTR1, UTVTR1	Analog signal preprocessing block
DSTPDIS1	Distance protection
DSOCPSCH1	Scheme communication logic
DEFLPDEF1	Directional earth-fault protection, low stage
DEFHPDEF1	Directional earth-fault protection, high stage
RESCPSCH1	Communication logic for residual overcurrent
BSTGAPC1	Binary signal transfer
PCSITPC1	Protection communication supervision
TRPPTRC1	Master trip
OR OR20	OR gate with two inputs OR gate with twenty inputs

Table 179: Physical analog channels of functions

Protection	Phase currents AI1, AI2, AI3	Phase voltages AI4, AI5, AI6	Open delta voltage AI7	Residual current AI8
DSTPDIS1	x	x	x	
DEFLPDEF1			x	x
DEFHPDEF1			x	x

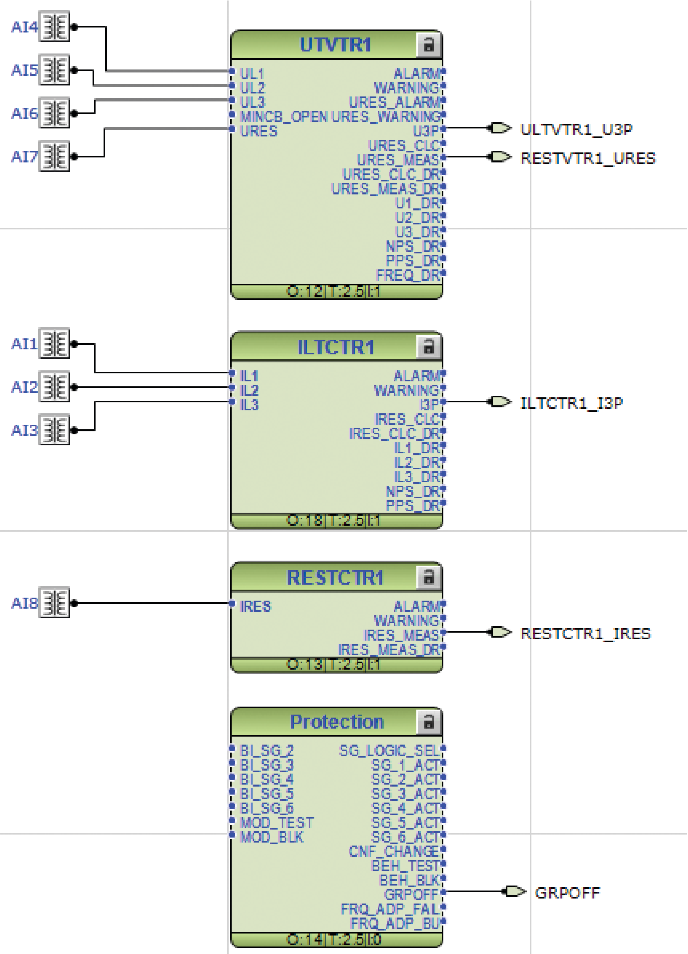

Figure 80: Relay inputs and preprocessing connections

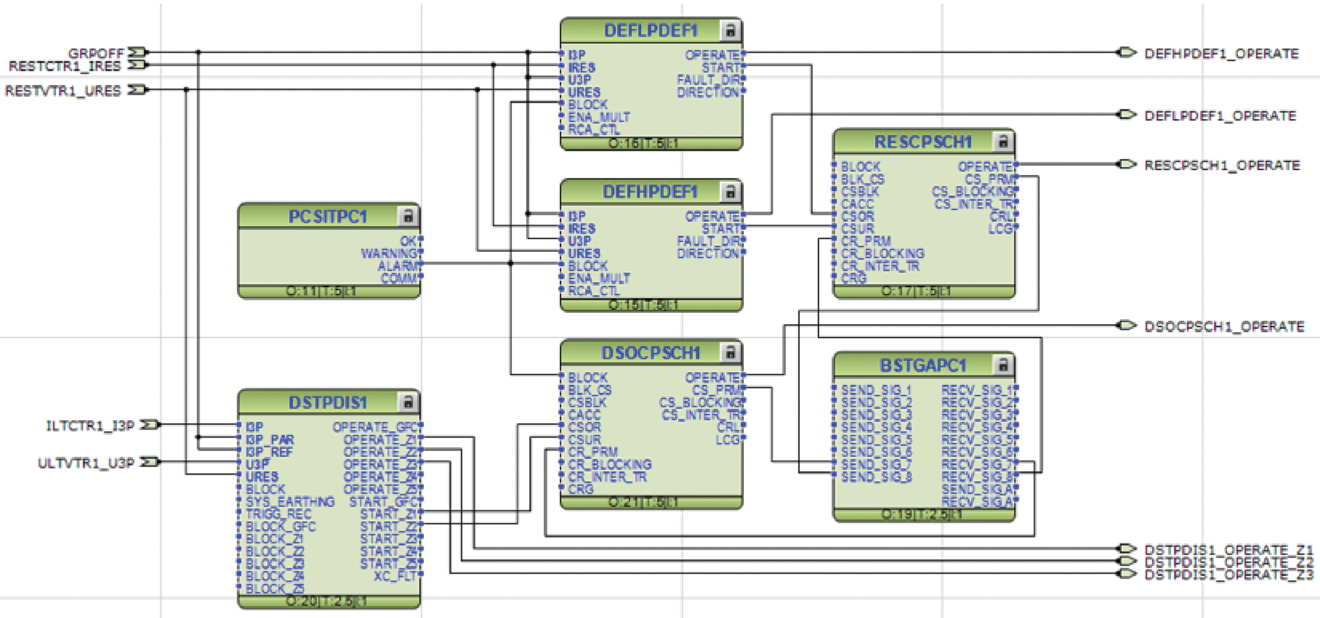

Figure 81: Application function block connections

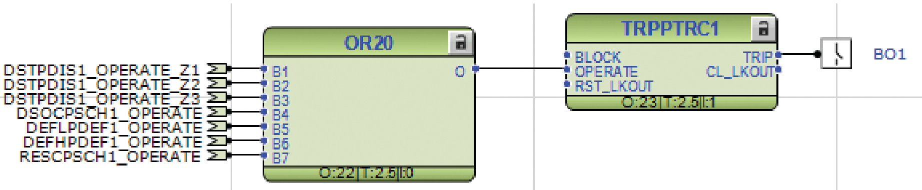

Figure 82: Relay output connections

7.3.1.5 Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for phase currents. Table 180 shows recommended setting values; all other settings can be kept at default values.

Table 180: ILTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	400 A	Primary current value
Secondary current	1 A	Secondary current value

RESTCTR1 – Residual current preprocessing

RESTCTR1 is the analog signal preprocessing function for the residual current signal. Table 181 shows recommended setting values; all other settings can be kept at default values.

Table 181: RESTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	100 A	Primary current
Secondary current	1 A	Secondary current

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 182 and Table 183 show recommended setting values; all other settings can be kept at default values.

Table 182: UTVTR1: Phase voltage transformer settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	6.35 kV	Primary rated voltage
Secondary voltage	63.5 V	Secondary rated voltage

Table 183: UTVTR1: Residual voltage transformer settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	6.35 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

DSTPDIS1 – Distance protection

DSTPDIS provides a full-scheme distance protection function for distribution and sub-transmission networks where three-phase tripping is allowed for all kinds of faults. DSTPDIS has five flexible, configurable impedance zones for protection (Z1, Z2, Z3, Z4 and Z5). Zones Z1, Z2 and Z3 , enabled in the forward direction, are used in the example application. Zone Z1 is set at 80 percent of the protected line, zone Z2 is set at 100 percent of the protected line + 20 percent of the adjacent shortest line and zone Z3 is set at 100 percent of the protected line + 50 percent of the adjacent longest line.

Zones Z1A, Z2A and Z3A in Figure 83 are defined for the relay at bus A and zones Z1B, Z2B and Z3B are defined for the relay at bus B. The figure also shows a fault in zone 2 of the relay at bus A (Z2A) and zone 1 of the relay at bus B (Z1B). The parameters for the protected cable and the adjacent shortest and longest cables are given in Table 184.

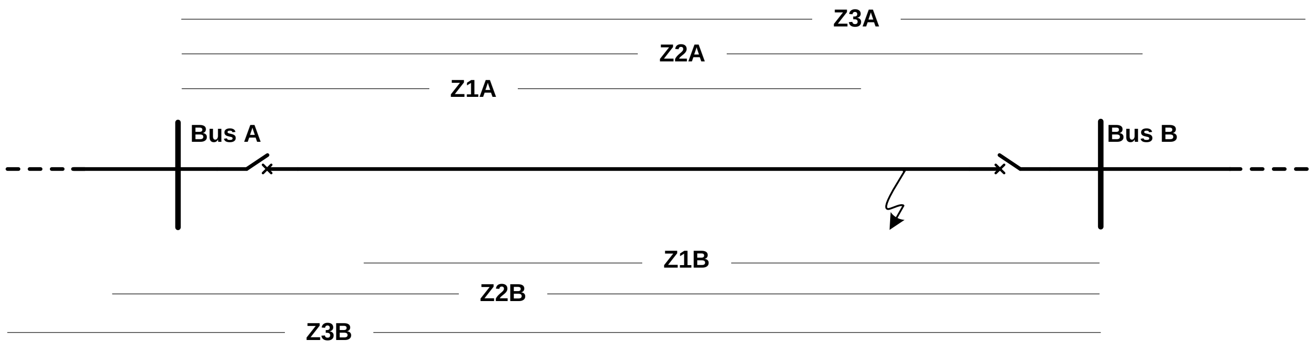

Figure 83: Zone definitions and fault location for the example case

Table 184: Line parameters

Parameter	Cable data	Parameter	Protected line	Adjacent shortest line	Adjacent longest line
Positive-sequence resistance (R1) in ohms/km	0.15	R1 in ohms	1.5	1.8	3.0
Positive-sequence reactance (X1) in ohms/km	0.11	X1 in ohms	1.1	1.32	2.2
Zero-sequence resistance (R0) in ohms/km	1.09	R0 in ohms	10.9	13.08	21.8
Zero-sequence reactance (X0) in ohms/km	0.25	X0 in ohms	2.5	3.0	5.0

Table 185 shows recommended setting values; all other settings can be kept at default values.

Table 185: DSTPDIS1 settings for the relay in the example case

Setting	Suggested values	Description	Comments
Str A Ph Sel GFC	1.93 xIn	Phase current start value, PSL	2 · 485/400 (xIn)
X Gnd Fwd reach GFC	7.5 ohm	Reactive forward reach for PE-loops, underimpedance, PSL	2.5 + 5.0 (ohm)
X Gnd Rv reach GFC	5.0 ohm	Reactive reverse reach for PE-loops, underimpedance, PSL	2 · 2.5 (ohm)
Ris Gnd Fwd Rch GFC	32.7 ohm	Resistive forward reach for PE-loops, underimpedance, PSL	10.9 + 21.8 (ohm)
Ris Gnd Rv Rch GFC	21.8 ohm	Resistive reverse reach for PE-loops, underimpedance, PSL	2 · 10.9 (ohm)
X PP Fwd reach GFC	3.3 ohm	Reactive forward reach for PP-loops, underimpedance, PSL	1.1 + 2.2 (ohm)
X PP Rv reach GFC	2.2 ohm	Reactive reverse reach for PP-loops, underimpedance, PSL	2 · 1.1 (ohm)

Table continues on next page

Setting	Suggested values	Description	Comments
Ris PP Fwd Rch GFC	4.5 ohm	Resistive forward reach for PP-loops, underimpedance, PSL	1.5 + 3.0 (ohm)
Ris PP Rv Rch GFC	3.0 ohm	Resistive reverse reach for PP-loops, underimpedance, PSL	2 · 1.5 (ohm)
Gnd Op current GFC	0.19 xIn	Basic start value for residual curr., EF-detection function	0.2 · 385/400 (xIn)
Max phase angle GFC	15 deg	Right-hand side angle, earth-fault directional function	Recommended value
Min phase angle GFC	115 deg	Left-hand side angle, earth-fault directional function	Recommended value
Op Mod PP loops Zn1	TRUE	Enable PP/3P-loop measurement, zone 1	
R1 zone 1	1.2 ohm	Positive-sequence resistive reach, zone 1	1.5 · 80/100 (ohm)
X1 zone 1	0.88 ohm	Positive-sequence line (reach) reactive, zone 1	1.1 · 80/100 (ohm)
Op Mod Gnd loops Zn1	TRUE	Enable PE-loop measurement, zone 1	
R0 zone 1	8.72 ohm	Zero-sequence resistive reach, zone 1	10.9 · 80/100 (ohm)
X0 zone 1	2.0 ohm	Zero-sequence reactive reach, zone 1	2.5 · 80/100 (ohm)
Op Mod PP loops Zn2	TRUE	Enable PP/3P-loop measurement, zone 2	
R1 zone 2	1.86 ohm	Positive-sequence resistive reach, zone 2	1.5 + 1.8 · 0.2 (ohm)
X1 zone 2	1.36 ohm	Positive-sequence line (reach) reactive, zone 2	1.1 + 1.32 · 0.2 (ohm)
Op Mod Gnd loops Zn2	TRUE	Enable PE-loop measurement, zone 2	
R0 zone 2	13.52 ohm	Zero-sequence resistive reach, zone 2	10.9 + 13.08 · 0.2 (ohm)
X0 zone 2	3.1 ohm	Zero-sequence reactive reach, zone 2	2.5 + 3.0 · 0.2 (ohm)
Op Mod PP loops Zn3	TRUE	Enable PP/3P-loop measurement, zone 3	
R1 zone 3	3.0 ohm	Positive-sequence resistive reach, zone 3	1.5 + 3.0 · 0.5 (ohm)
X1 zone 3	2.2 ohm	Positive-sequence line (reach) reactive, zone 3	1.1 + 2.2 · 0.5 (ohm)
Op Mod Gnd loops Zn3	TRUE	Enable PE-loop measurement, zone 3	
R0 zone 3	21.8 ohm	Zero-sequence resistive reach, zone 3	10.9 + 21.8 · 0.5 (ohm)
X0 zone 3	5.0 ohm	Zero-sequence reactive reach, zone 3	2.5 + 5.0 · 0.5 (ohm)

DSOCPSCH1 – Scheme communication logic

DSOCPSCH1 provides instantaneous fault clearing independent of the fault location on the protected line or feeder and requires a communication channel capable of transmitting binary signals in both directions. The communication channel should be fast, secure and dependable and hence, dedicated communication channels are recommended. For short distances of up to a few kilometers, a simple pilot wire based on auxiliary power can be used. For distances of up to 50 km, the fiber-optic cables with the integrated communication interface can be used, whereas for distances of up to 150 km fiber-optic cables with external equipment can be used.

The available communication scheme types supported by DSOCPSCH1 are DUTT, PUTT, POTT and DCB. In the application example, the POTT scheme is used and therefore *Scheme type* is set as "Permissive Overreach". The logical representation of the POTT scheme is shown in Figure 84.

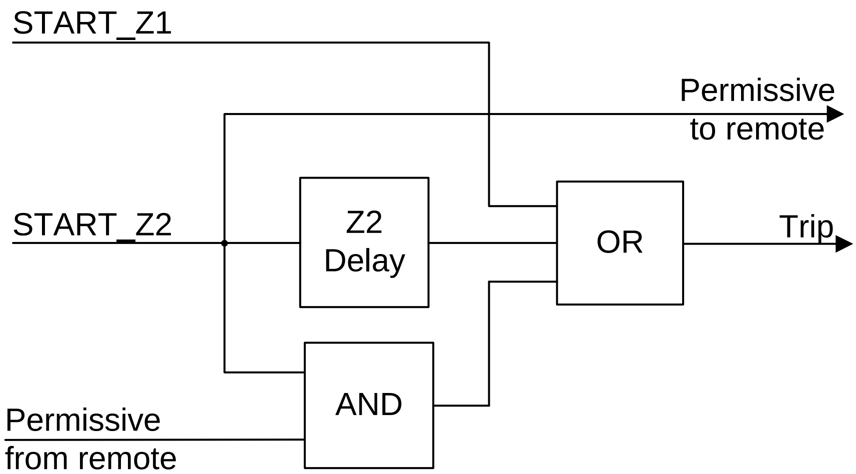

Figure 84: Logical representation for the POTT scheme

Figure 85 shows the simplified functional diagram for the POTT scheme. A fault occurs in zone 2 of the relay at bus A and zone 1 of the relay at bus B. The distance element of the relay at bus A picks up the fault and activates START_Z2. The distance element of relay at bus B also picks up and activates both START_Z1 and START_Z2. Since the relay at bus B picks up in Zone 1, an instantaneous trip is issued to breaker B. The relay at bus B issues permission to the relay at bus A which causes the relay at bus A to activate breaker A trip after a settable pick-up delay *Coordination Time* thus avoiding Zone 2 delay. In the POTT scheme, *Coordination Time* can be set as 0 s as there is no need to delay the tripping.

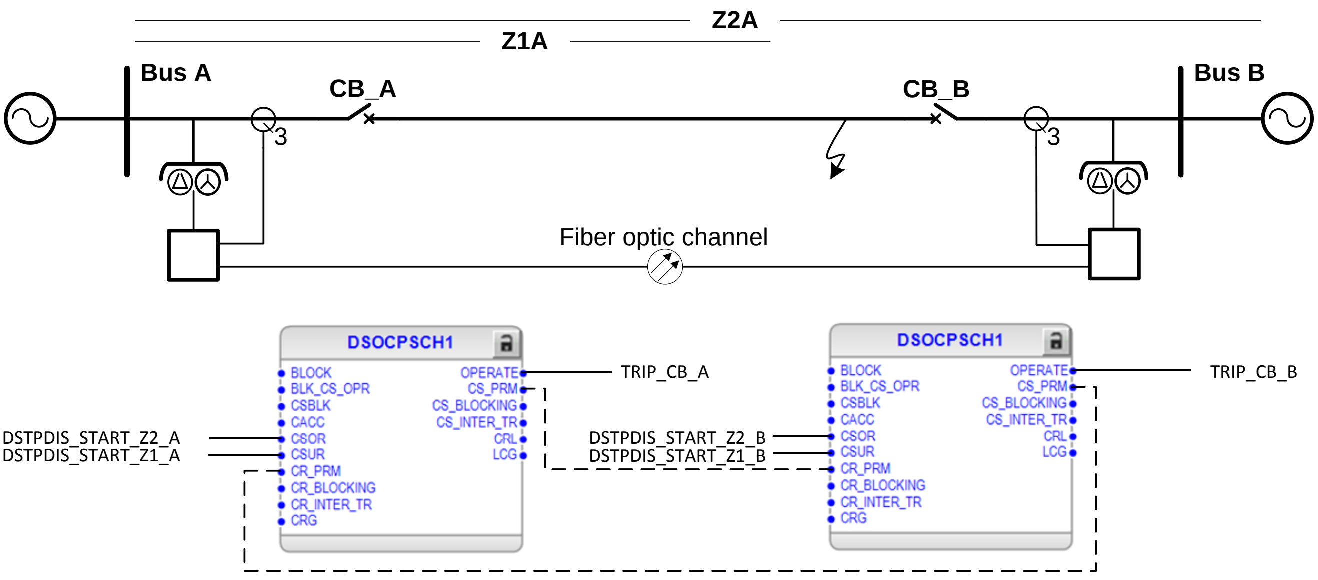

Figure 85: Simplified functional diagram of the POTT scheme for distance protection

Table 186 shows recommended setting values; all other settings can be kept at default values.

Table 186: DSOCPSCH1 settings whose values differ from the default values based on the example case

Setting	Suggested values	Description
Scheme type	Permissive Overreach	Scheme type
Coordination time	0 s	Communication scheme coordination time

DEFHPDEF1 and DEFLPDEF1 – Directional earth-fault protection

DEFHPDEF1 and DEFLPDEF1 are used for directional earth-fault protection for feeders and lines. Communication logic for residual overcurrent (RESCPSCH1) is used along with the directional earth-fault protection blocks to provide a permissive overreach protection scheme. The non-default settings for these functions are shown in Table 187; all other settings of DEFHPDEF1 and DEFLPDEF1 are kept at default values for this example case. For the measured residual current, the used nominal value is the CBCT rated primary current (that is, 100 A).

Table 187: *DEFHPDEF1 and DEFLPDEF1 settings for the relay in the example case*

Setting	Suggested values		Description
	DEFHPDEF1	DEFLPDEF1	
Start value	1.92 xIn[1)]	0.77 xIn[2)]	Start value
Operate delay time	50 ms[3)]	100 ms[4)]	Operate delay time

1) *Start value* for DEFHPDEF1 can be set at 50% of the rated current, that is, 0.5 · 385 A/100 A ≈ 1.92.
2) *Start value* for DEFLPDEF1 can be set at 20% of the rated current, that is, 0.2 · 385 A/100 A ≈ 0.77.
3) *Operate delay time* for DEFHPDEF1 can be set as 50 ms.
4) *Operate delay time* for DEFLPDEF1 can be set as 100 ms, a little slower than DEFHPDEF1.

RESCPSCH1 - Communication logic for residual overcurrent

RESCPSCH1 is the scheme communication logic for the residual overcurrent protection and is used in the application function with directional earth-fault protection blocks DEFLPDEF1 and DEFHPDEF1. Like DSOCPSCH1, this function supports scheme types DUTT, PUTT, POTT and DCB. Figure 86 shows the simplified functional diagram for the POTT scheme; the `START` signals from DEFLPDEF1 and DEFHPDEF1 are connected to RESCPSCH1 `CSOR` and `CSUR`, respectively.

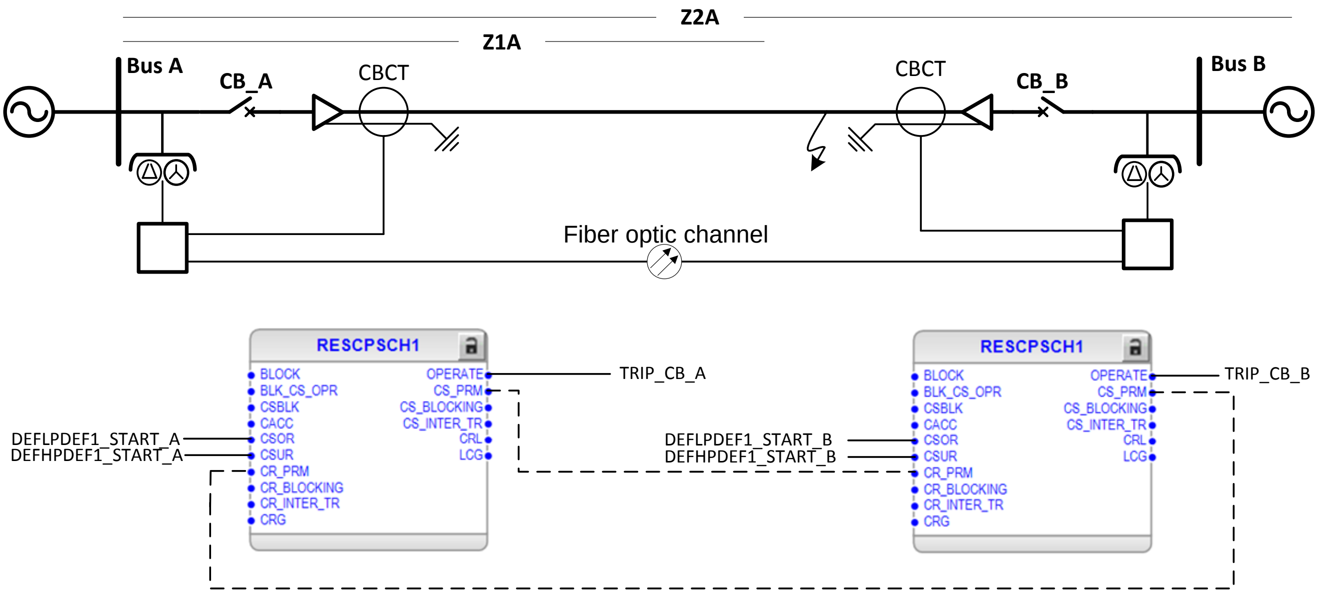

Figure 86: *Simplified functional diagram of the POTT scheme for directional earth-fault protection*

POTT is enabled with *Scheme type* set to "Permissive Overreach". In the POTT scheme, *Coordination time* can be set as 0 s as there is no need to delay the tripping. Table 188 shows recommended setting values; all other settings can be kept at default values.

Table 188: RESCPSCH1 settings for the relay in the example case

Setting	Suggested values	Description
Scheme type	Permissive Overreach	Scheme type
Coordination time	0 s	Communication scheme coordination time

BSTGAPC1 – Binary signal transfer

BSTGAPC1 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 using a fiber optic cable and can be freely configured and used for any purpose in the line differential application. In this application example, the binary signals transferred to the remote relay are DSOCPSCH1_CS_PRM (permissive from DSOCPSCH1) connected at `SEND_SIG_7` and RESCPSCH1_CS_PRM (permissive from RESCPSCH1) connected at `SEND_SIG_8`. The corresponding information from the remote end is available at `RECV_SIG_7` and `RECV_SIG_8`.

All settings of BSTGAPC1 are kept at default values for this example case.

PCSITPC1 – Protection communication supervision

PCSITPC1 monitors the protection communication channel. It blocks the protection functions when interference in the protection communication channel is detected. The blocking happens automatically for BSTGAPC1 which is dependent on the continuous availability of the protection communication.

All settings of PCSITPC1 are kept at default values for this example case.

TRPPTRC1 – Master trip

TRPPTRC1 is used as a trip command collector and handler after the protection functions. All settings of TRPPTRC1 are kept at default values for this example case.

Section 8 Line differential and directional earth-fault protection

8.1 Introduction to the application

Line differential protection is an absolute selective unit protection with a number of advantages. It can be easily coordinated with other protections. All faults on the line, between the line bay CTs, can be cleared instantaneously. The sensitivity can be made high and it is also not influenced by fault current reversal at earth faults on parallel lines.

Selectivity for earth-fault protection may be difficult to achieve in meshed networks with isolated or compensated neutral because fault current magnitude and apparent fault loop impedance do not significantly depend on the fault location. In such networks, directional earth-fault protection functions can determine the fault direction (forward or reverse), but they cannot determine whether the fault is on the protected line or beyond the adjacent substation. Protection communication can be combined with the earth-fault protection into a selective unit protection.

The line differential and directional earth-fault protection can be applied to radial, looped and meshed network topologies and can be used in isolated neutral networks, resistance earthed networks, compensated (impedance earthed) networks and solidly earthed networks. It can be used for interconnected feeders between a primary substation with reserve connections, distributed generation having power generation at the remote end of the feeder and weak grid supplying relatively long distribution lines. The line differential protection provides absolute selectivity and fast operating times as a unit protection in short lines where distance protection cannot be applied, whereas the earth-fault protection functions provide protection against various earth faults occurring on a feeder or line.

Table 189: Typical line faults and conditions and recommended protection and protection-related functions

Faults and conditions	Protection and protection-related functions
Phase-to-earth, phase-to-phase-to-earth, three-phase faults	Line differential protection with inzone power transformer LNPLDF
Earth fault	Directional earth-fault protection, low stage DEFLPDEF
Overcurrent	Three-phase non-directional overcurrent protection PHxPTOC
Inrush detection	Line differential protection with inzone power transformer LNPLDF, Three-phase inrush detector INRPHAR

8.2 Description of the example case

To explain the application of line differential with directional earth-fault protection, a generic line in a system is taken as an example (example case 1). Figure 87 shows a representative configuration of a 10 MVA, 11 kV isolated neutral system with an overhead line having relays at both ends A and B. The rated line current is 500 A and the length of the protected line is 10 km.

CTs are connected to measure phase currents and a CBCT measures residual current I_0 at both ends. VTs are connected at both ends to measure residual voltage U_0 in open-delta connection.

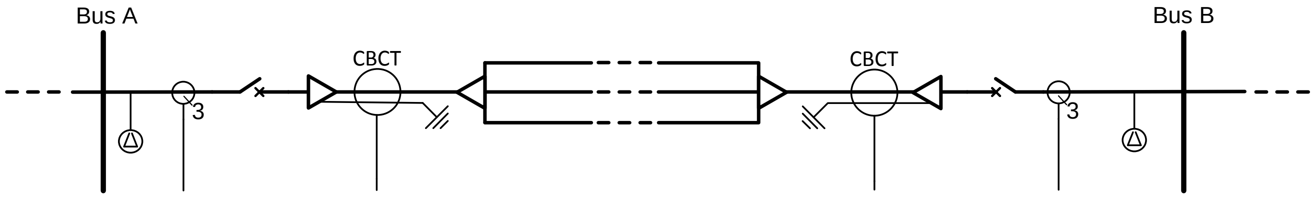

Figure 87: Single-line diagram of the example case for line differential and directional earth-fault protection

The CT connection type (see the technical manual, LNPLDF function settings for more details) in this example case is Type 1 and the CT ratings on both sides are the same.

8.3 Local end protection relay (A)

This chapter provides detailed information about the configuration of the relay at line end A (local end protection relay) used in this application example: the relay interfaces, the ACT diagram and parameter settings and information on how the line differential and directional earth-fault protection can be achieved for the given example.

This chapter is also applicable for the relay at line end B (remote end protection relay in this example) by replacing the current and voltage inputs as well as binary and trip signals for the other end of the line.

8.3.1 Relay interface, configuration and settings

Figure 88 shows the connection details of the relay's analog inputs (AI), binary inputs (BI) and binary outputs (BO). CT and CBCT connections for phase currents and the residual current measurement required for line differential and directional earth-fault protection are also shown in Figure 88. VT connections for phase voltage measurements and an open-delta connection for residual voltage measurement are also shown.

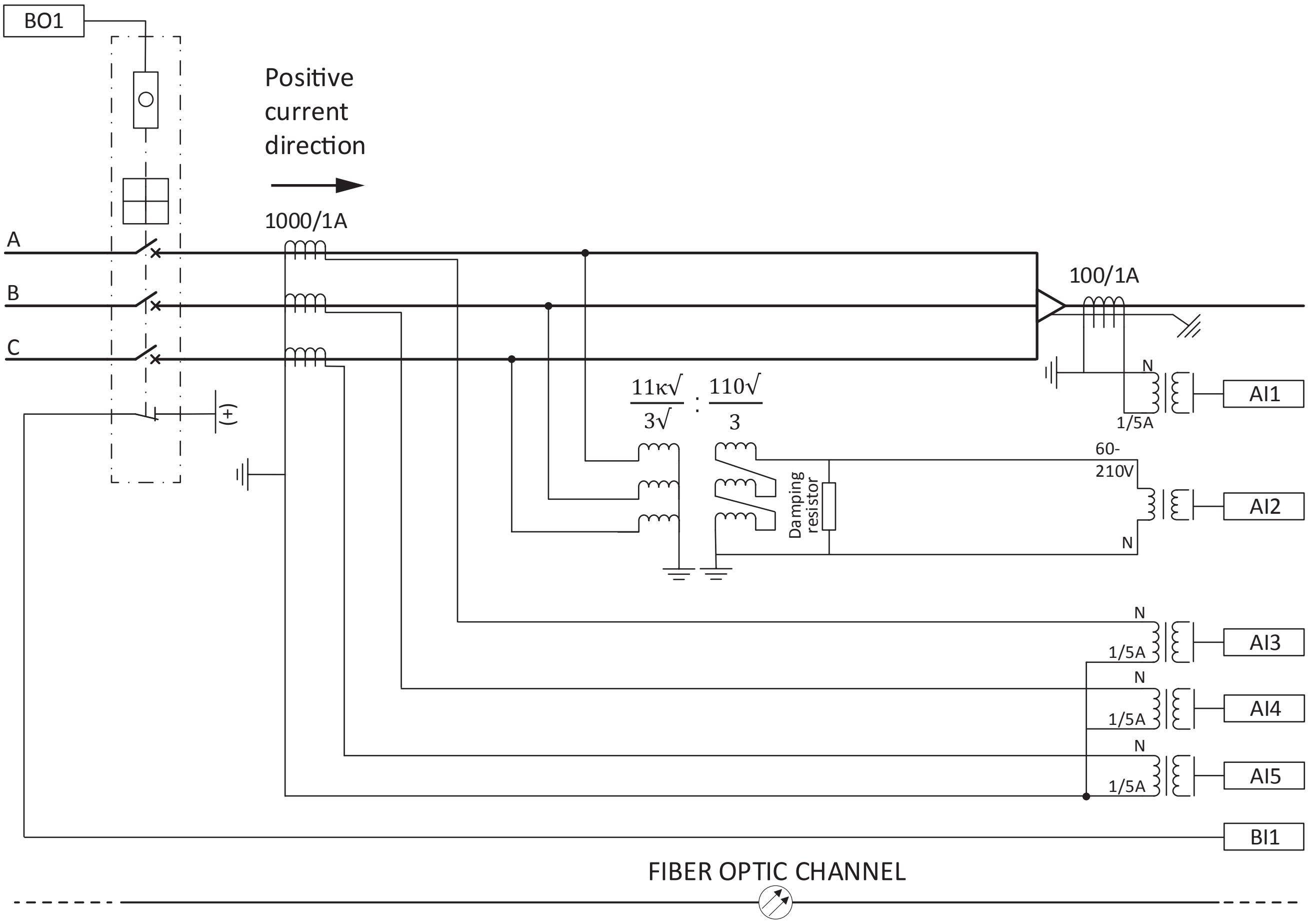

Figure 88: Relay interfaces and CT/VT connections for example case 1 relay at line end A

8.3.1.1 Analog input signals

Table 190: Physical analog input signals for implementing the application example

Analog input	Description
AI1	Residual current
AI2	Residual voltage
AI3	Phase A current I_A
AI4	Phase B current I_B
AI5	Phase C current I_C

8.3.1.2 Binary input signals

Table 191: Physical binary input signal for implementing the application example

Binary input	Description
BI1	Circuit breaker open status (CB_OPEN)

8.3.1.3 Binary output signals

Table 192: Physical binary output signal for implementing the application example

Binary output	Description
BO1	Open CB

8.3.1.4 Recommended alarms

Table 193: Alarm list for implementing the application example

Event container	Event	Description
LNPLDF1	OPERATE	Operate from line differential protection
LNPLDF1	OPR_LS_LOC	Operate from low stage of line differential protection at local end
LNPLDF1	OPR_LS_REM	Operate from low stage of line differential protection at remote end
LNPLDF1	OPR_HS_LOC	Operate from high stage of line differential protection at local end
LNPLDF1	OPR_HS_REM	Operate from high stage of line differential protection at remote end
DEFLPDEF1	OPERATE	Operate from directional earth fault low stage
PHIPTOC1	OPERATE	Operate from instantaneous overcurrent protection
PHHPTOC1	OPERATE	Operate from high-stage overcurrent protection
PHLPTOC1	OPERATE	Operate from low-stage overcurrent protection
PCSITPC1	WARNING	Differential protection internally blocked due to detected interference
PCSITPC1	ALARM	Differential protection internally blocked due to detected long interference

8.3.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

The functions used in the ACT diagram and their purposes are listed in Table 194.

Table 194: Function blocks used in the application example

Function block	Description
ILTCTR1, RESTCTR1, UTVTR1	Analog signal preprocessing block
LNPLDF1	Line differential protection with inzone power transformer
DEFLPDEF1	Directional earth-fault protection – forward direction
DEFLPDEF2	Directional earth-fault protection – reverse direction
PHIPTOC1	Three-phase non-directional overcurrent protection, instantaneous stage
PHHPTOC1	Three-phase non-directional overcurrent protection, high stage
PHLPTOC1	Three-phase non-directional overcurrent protection, low stage
BSTGAPC1	Binary signal transfer
PCSITPC1	Protection communication supervision
TRPPTRC1	Master trip
OR20	OR gate with twenty inputs
AND, AND6	Logic function AND
NOT	NOT gate

Table 195: Physical analog channels of functions

Protection	Phase currents AI3, AI4, AI5	Open delta voltage AI2	Residual current AI1	Remote end phase currents (via fiber optic)
LNPLDF1	x			x
DEFLPDEF1		x	x	
DEFLPDEF2		x	x	
PHIPTOC1	x			
PHHPTOC1	x			
PHLPTOC1	x			

Figure 89, Figure 90 and Figure 91 give the input, application and output section, respectively, for the relay's ACT configuration for the line differential and directional earth fault.

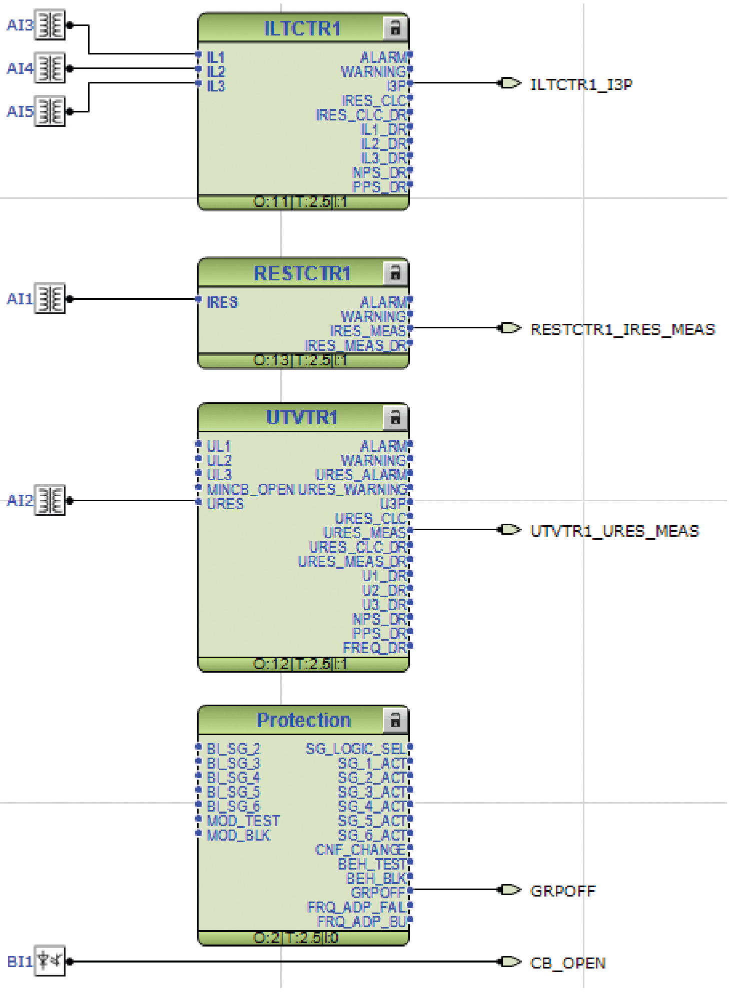

Figure 89: Input section

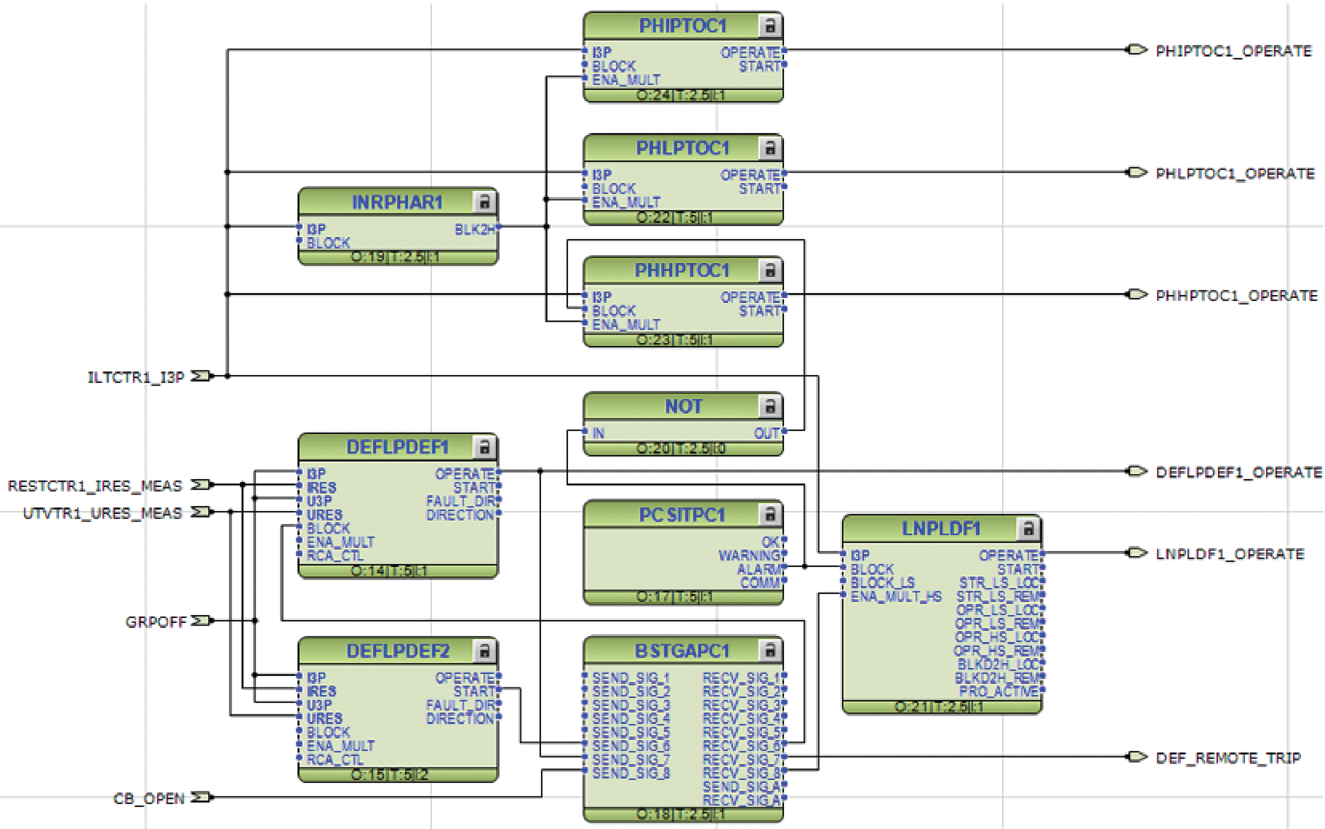

Figure 90: Application section

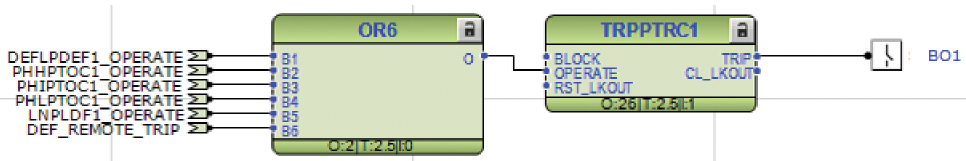

Figure 91: Output section

8.3.1.6 Function blocks and setting values

ILTCTR1 – Phase current preprocessing

ILTCTR1 is the analog signal preprocessing function for phase currents. Table 196 shows recommended setting values; all other settings can be kept at default values.

Table 196: ILTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	1000 A	Primary current value
Secondary current	1 A	Secondary current value

RESTCTR1 – Residual current preprocessing

RESTCTR1 is the analog signal preprocessing function for the residual current signal. Table 197 shows recommended setting values; all other settings can be kept at default values.

Table 197: RESTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	100 A	Primary current
Secondary current	1 A	Secondary current

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received residual voltage inputs to the application. Table 198 shows recommended setting values; all other settings can be kept at default values.

Table 198: UTVTR1: Residual voltage transformer settings for the relay in example case 1

Setting	Suggested values	Description
Primary voltage	6.35 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

LNPLDF1 – Line differential protection with inzone power transformer

LNPLDF1 is used for differential protection of distribution network lines and cables. It includes low, stabilized and high, non-stabilized stages. The differential current is calculated at both ends from the currents entering and leaving the protection zone; digital communication channels are used for data exchange. The remote end currents are received via the fiber optic cable between the relays and does not need any special configuration. LNPLDF1 is blocked via PCSITPC1 in case of loss of protection communication.

Harmonic restraint is not activated as there is no in-zone transformer in the protected line. *Low operate value* is set based on the no-load current of the line, the load current of the possible tapped loads and inaccuracies of the CTs. The *High operate value* setting is used by the instantaneous high stage, which operates immediately, and is recommended to be set greater than 0.7 times the three-phase maximum through-fault current and less than 0.7 times the three-phase maximum inside fault current. Table 199 shows recommended setting values; all other settings can be kept at default values.

Table 199: LNPLDF1 settings for the relay in example case 1

Setting	Suggested values	Description
CT ratio correction	2.000[1)]	CT ratio correction
Low operate value	15%[2)]	Basic setting for the stabilized stage start
High operate value	1000%[3)]	Instantaneous stage operate value
High Op value Mult	0.7[4)]	Multiplier for scaling the high-stage operate value

1) Rated current / nominal current = 1000/500 = 2
2) Recommended 15% of the rated current
3) In example case 1, assume maximum through-fault current as 12 kA and maximum inside fault current as 15 kA. Then, *High operate value* can be set > 0.7 · (12000/1000) · 100 and < 0.7 · (15000/1000) · 100, that is, between 840% and 1050%, hence set as 1000%.
4) *High operate value* is reduced to make the function more sensitive in case the other end breaker is open.

DEFLPDEF1 and DEFLPDEF2 – Directional earth-fault protection

DEFLPDEF1 and DEFLPDEF2 are used as directional earth-fault protection for feeders and lines. For the isolated network in the application example, the measured open-delta voltage is used as the polarizing quantity. Earth-fault currents are low in an isolated neutral system and hence CBCT is used for residual current measurement.

A selective unit protection for the earth-fault protection is achieved by using DEFLPDEF2 (set to reverse direction) to detect an earth fault outside the protected zone and DEFLPDEF1 (set to forward direction) to detect a fault on the line. Trip is issued to both side breakers when DEFLPDEF1 detects a fault and no blocking is received from the other end's DEFLPDEF2. The scheme used in the application example is shown in Figure 92.

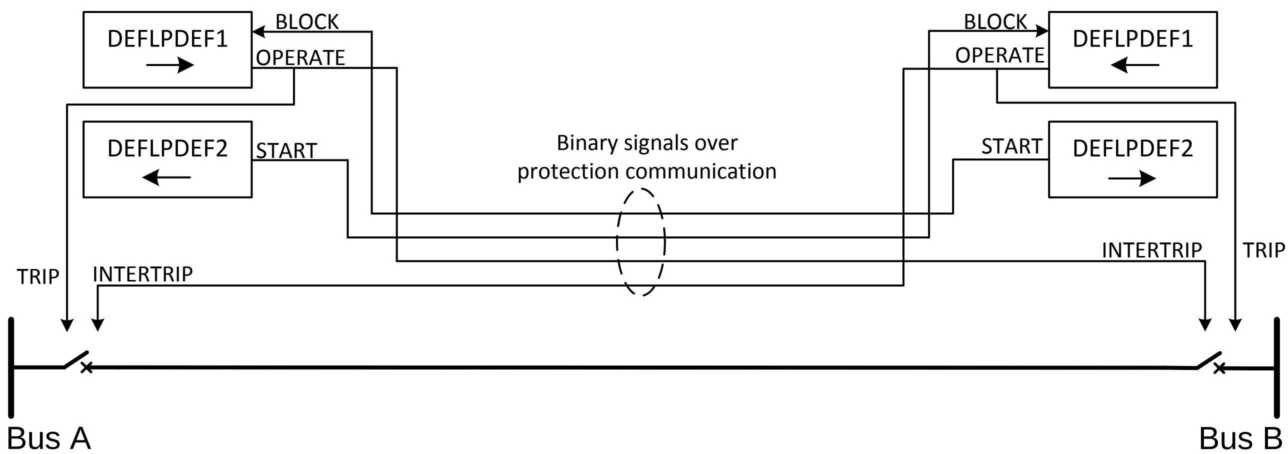

Figure 92: Directional earth-fault protection scheme

The non-default settings for these function blocks in the example application are shown in Table 200. All other settings of DEFLPDEF1 and DEFLPDEF2 are kept at default values for this example case.

Table 200: DEFLPDEF1 and DEFLPDEF2 settings for the relay in example case 1

Setting	Suggested values		Description
	DEFLPDEF1	DEFLPDEF2	
Start value	0.015 xIn[1)]	0.01 xIn[2)]	Start value
Directional mode	Forward	Reverse	Directional mode
Operate delay time	200 ms[3)]	300000 ms[4)]	Operate delay time

1) *Start value* for DEFLPDEF1 can be set at 0.015 for the isolated neutral system given in the example.
2) *Start value* for DEFLPDEF2 can be set lower than DEFLPDEF1, that is, 0.01.
3) *Operate delay time* for DEFLPDEF1 in this example is set to 200 ms to avoid too sensitive tripping in case of transient or self-recovering faults.
4) *Operate delay time* for DEFLPDEF2 can be set very high, that is, 300 s, as only the `START` signal is used and the `OPERATE` output is not used.

INRPHAR1 – Three-phase inrush detector

INRPHAR1 is used to detect transformer inrush in distribution networks. In example case 1, even though an in-zone transformer is not present, INARPHAR1 is used because inrush current may be flowing through the line. The `BLK2H` output of INRPHAR1 enables multiplying the active settings for overcurrent protection PHxPTOC1. All settings of INRPHAR1 are kept at default values for this example case.

PHIPTOC1, PHHPTOC1, PHLPTOC1 – Three-phase non-directional overcurrent protection

PHIPTOC1 provides short circuit protection against severe faults where heavy CT saturation is expected. This protection function is always active and is used to ensure fast tripping despite heavy CT saturation. During such a situation, PHIPTOC1 sees the fault current higher than LNPLDF1 as it uses the peak-to-peak measuring principle. PHHPTOC1 is normally kept blocked. It is activated and used as a backup overcurrent protection in case of failure of the protection communication. PHLPTOC1 provides overload protection and is always active. Its settings must be coordinated with other overcurrent relays in the network.

If transformer inrush is detected by INRPHAR1, then the *Start value* of the PHxPTOC1 functions are multiplied by the *Start value Mult* setting (in this example case, kept at default value of 1.0). Table 201 gives the settings for PHIPTOC, PHHPTOC1 and PHLPTOC1. All other settings of these functions are kept at default values for this example case.

Table 201: PHIPTOC1, PHHPTOC1 and PHLPTOC1 settings for the relay in example case 1

Setting	Suggested values			Description
	PHIPTOC1	PHHPTOC1	PHLPTOC1	
Start value	10.5 xIn[1)]	2.5 xIn[2)]	0.75 xIn[3)]	Start value
Operate delay time	200 ms[4)]	200 ms[5)]	500 ms[6)]	Operate delay time

1) *Start value* for PHIPTOC1 is recommended to be set at 0.7 times the maximum inside fault current or below and for this example case can be set at 0.7 · 15 kA/1000 = 10.5.
2) *Start value* for PHHPTOC1 can be set at 5 times the rated current. Hence, the setting is 5 · 500/1000 = 2.5.
3) To allow 50% continuous overloading, *Start value* for PHLPTOC1 can be set at 1.5 times the rated current. Hence, the setting is 1.5 · 500/1000 = 0.75.
4) *Operate delay time* for PHIPTOC1 can be set as 200 ms in this example case. As the *Start value* setting corresponds to less than the maximum through-fault current, PHIPTOC must be time-coordinated with other protections in the network.
5) *Operate delay time* for PHHPTOC1 can be set as 200 ms.
6) *Operate delay time* for PHLPTOC1 can be set as 500 ms.

BSTGAPC1 – Binary signal transfer

BSTGAPC1 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 using a fiber optic cable and can be freely configured and used for any purpose in the line differential application.

In this application example, the binary signals transferred to the remote relay are `START` from DEFLPDEF2 connected at `SEND_SIG_6` (to block the remote end relay's DEFLPDEF1), `OPERATE` from DEFLPDEF1 connected at `SEND_SIG_7` (to open the remote CB) and `CB_OPEN` (local circuit breaker open status) connected at `SEND_SIG_8`. The corresponding information from the remote end is available at `RECV_SIG_6` (DEFLPDEF2 `START`), `RECV_SIG_7` (DEFLPDEF1 `OPERATE`) and `RECV_SIG_8` (remote CB open status).

All settings of BSTGAPC1 are kept at default values for this example case.

PCSITPC1 – Protection communication supervision

PCSITPC1 monitors the protection communication channel. It blocks the line differential protection functions when interference in the protection communication channel is detected. The blocking takes place automatically for LNPLDF1 and BSTGAPC1 which are dependent on the continuous availability of the protection communication.

All settings of PCSITPC1 are kept at default values for this example case.

TRPPTRC1 – Master trip

TRPPTRC1 is used as trip command collector and handler after the protection functions. All settings of TRPPTRC1 are kept at default values for this example case.

8.4 Line differential protection with power transformer in zone

The basic protection principle given in chapter Local end protection relay (A) for line differential protection is also valid when there is a power transformer in zone (example case 2). Figure 93 shows the single-line diagram of the line differential protection application example with a power transformer in zone. An 11 / 20 kV, 10 MVA transformer with impedance 6% is present in the protected zone of the isolated neutral system. The 20 kV side winding is earthed star (YN) and the 11 kV side winding is delta connected (d). The 20 kV side leads the 11 kV side by 30 degrees (clock number 11).

The parameter settings for the relays at line end A (local end) and line end B side (remote end) which vary from example case 1 are explained in the following chapters.

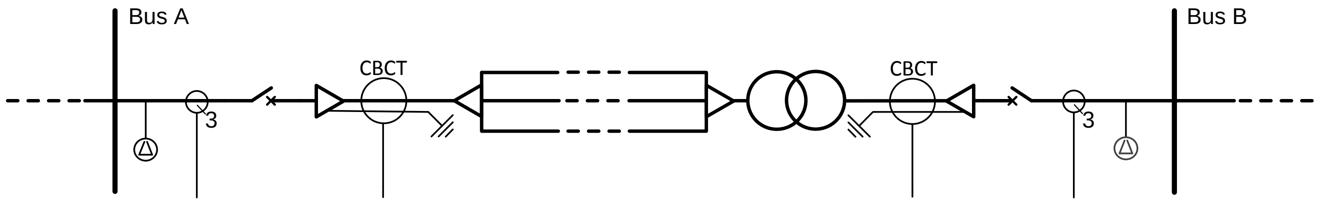

Figure 93: Simplified single-line diagram with power transformer in zone

8.4.1 Relay interface, configuration and settings

The CT, CBCT, VT and open-delta VT connections are similar to those shown in Figure 88. The analog inputs (AI), binary inputs (BI), binary outputs (BO) and recommended alarm information given in chapters Analog input signals, Binary input signals, Binary output signals and Recommended alarms are also valid for this example case.

8.4.1.1 Relay configuration

The ACT configuration of example case 1 shown in Figure 89 (input section), Figure 90 (application section) and Figure 91 (output section) remains the same for example case 2.

8.4.1.2 Function blocks and setting values

ILTCTR1 – Phase current preprocessing

Table 202 shows recommended setting values for the relay at line end B. The settings for the relay at A are the same as in Table 196. All other settings can be kept at default values.

Table 202: ILTCTR1 settings for the relay at B in example case 2

Setting	Suggested values	Description
Primary current	400 A	Primary current value
Secondary current	1 A	Secondary current value

RESTCTR1 – Residual current preprocessing

The settings for RESTCTR1 are the same as those given in Table 197.

UTVTR1 – Phase and residual voltage preprocessing

Table 203 shows recommended setting values for the relay at line end B in this example case. The settings for the relay at A are the same as in Table 198. All other settings can be kept at default values.

Table 203: UTVTR1: Residual voltage transformer settings for the relay at B in example case 2

Setting	Suggested values	Description
Primary voltage	11.55 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

LNPLDF1 – Line differential protection with inzone power transformer

Table 204 shows recommended setting values; all other settings can be kept at default values.

Table 204: LNPLDF1 settings for the relays at A and B in example case 2

Setting	Suggested values	Description
Winding selection	Winding 1	Relay location: on the HV (Winding 1) side or the LV (Winding 2) side
Winding 1 type	YN	Connection of the HV side windings
Winding 2 type	D	Connection of the LV side windings
Clock number	Clk Num 11	Setting the phase shift between HV and LV with clock number for connection group compensation (for example, Dyn11 -> 11)
CT ratio correction	1.455[1)]	CT ratio correction
Restraint mode	Harmonic2	Selects what restraint modes are in use
Table continues on next page		

Setting	Suggested values	Description
Low operate value	15%[2)]	Basic setting for the stabilized stage start
High operate value	1000%[3)]	Instantaneous stage operate value
High Op value Mult	0.7[4)]	Multiplier for scaling the high-stage operate value

1) The rated current on the 20 kV side is 500 · 11/20 = 275 A. Hence, *CT ratio correction* = rated current / nominal current = 400/275 = 1.4545.
2) 15% of rated current can be set as *Low operate value*.
3) In the example case, the maximum through-fault power is 10 MVA/0.06 = 167 MVA and using short circuit power of 286 MVA, the combined through-fault power is (286 · 167)/(286 + 167) = 105 MVA. Hence, the maximum outside fault current is 105 MVA/√3 · 11kV = 5.5 kA at 11 kV side and 105MVA/√3 · 11 kV = 3 kA at 20 kV side. The maximum inside fault current is taken as 15 kA. Then, for the 11 kV side, *High operate value* can be set > 0.7 · (5500/400) · 100 and < 0.7 · (15000/1000) · 100, that is, between 385% and 1050%, hence set as 1000%. For the 20 kV side, *High operate value* can be set > 0.7 · (3000/400) · 100 and < 0.7 · (15000/1000) · 100, that is, between 525% and 1050%, hence set as 1000%.
4) *High operate value* is reduced to make the function more sensitive during line energization.

DEFLPDEF1 – Directional earth-fault protection

As the star-delta (Y/D) connected in-zone transformer cuts the zero-sequence path, the blocking from the other end is not required. Hence DEFLPDEF2 can be disabled in the configuration. The non-default settings for DEFLPDEF1 with in-zone power can be the same as in Table 200. All other settings of DEFLPDEF1 are kept at default value for this example case.

INRPHAR1 – Three-phase inrush detector

INRPHAR1 is used to detect transformer inrush in distribution networks. The `BLK2H` output of INRPHAR1 enables multiplying the active settings for the instantaneous stage of overcurrent protection PHIPTOC1. All settings of INRPHAR1 are kept at default values for this example case.

PHIPTOC1, PHHPTOC1, PHLPTOC1 – Three-phase non-directional overcurrent protection

PHIPTOC1, PHHPTOC1 and PHLPTOC1 function as in the example case without an in-zone transformer. If transformer inrush is detected by INRPHAR1, then the *Start value* of PHxPTOC1 is multiplied by the *Start value Mult* setting. The settings for PHHPTOC1 and PHLPTOC1 in the relay at A are the same as in Table 201. The settings for PHIPTOC1 are given in Table 205.

The settings for the relay at B in example case 2 are shown in Table 206.

All other settings are kept at default value for this example case.

Table 205: PHIPTOC1 settings for the relay at A in example case 2

Setting	Suggested values	Description
Start value	6.6 xIn1)	Start value
Operate delay time	50 ms2)	Operate delay time
Start value Mult	3.03)	Multiplier for scaling the start value

1) *Start value* for PHIPTOC1 can be set at 1.2 times maximum through fault current, that is, 1.2 · 5.5 kA/1000 ≈ 6.6.
2) *Operate delay time* for PHIPTOC1 can be set to minimum, that is, 20 ms for fast operation.
3) *Start value Mult* is kept as 3 to account for the inrush current.

Table 206: PHIPTOC1, PHHPTOC1 and PHLPTOC1 settings for the relay at B in example case 2

Setting	Suggested values			Description
	PHIPTOC1	PHHPTOC1	PHLPTOC1	
Start value	9.0 xIn1)	1.03 xIn2)	0.75 xIn3)	Start value
Operate delay time	50 ms4)	100 ms5)	150 ms6)	Operate delay time
Start value Mult	3.07)	(default)	(default)	Multiplier for scaling the start value

1) *Start value* for PHIPTOC1 can be set at 1.2 times maximum through fault current, that is, 1.2 · 3 kA/400 ≈ 9.0.
2) *Start value* for PHHPTOC1 can be set at 1.5 times the rated current. Hence, the setting is 1.5 · 275/400 ≈ 1.03
3) *Start value* for PHLPTOC1 can be set at 1.1 times the rated current. Hence, the setting is 1.1 · 275/400 ≈ 0.75.
4) *Operate delay time* for PHIPTOC1 can be set to minimum, that is, 20 ms for fast operation.
5) *Operate delay time* for PHHPTOC1 can be set as 200 ms in this example case.
6) *Operate delay time* for PHLPTOC1 can be set as 500 ms in this example case.
7) *Start value Mult* is kept as 3 to account for the inrush current.

Section 9 Generator protection

9.1 Introduction to application

The generator protection and control functions in this relay are designed to protect a power generator directly connected to the network as well as a generator connected through a step-up transformer. As the generator is a vital power system component and, in most cases, the most expensive, it should be protected from, for example, short circuits, overloads and earth faults.

Generators in operation can be subject to a variety of faults and abnormal conditions, all of which can have adverse effects on their performance and life. One of the main categories of generator faults are the winding failures caused by dielectric, thermal and mechanical stress. These can manifest themselves as short circuits, local hot spots or breakage of windings. Other faults are, for example, phase-to-phase faults, earth faults, core faults, bushing faults, overvoltage and overexcitation.

The faulty generator must be disconnected as fast as possible. The protection functions must have high sensitivity to detect faults, but at the same time, the protection should be stable against external faults. This can be typically achieved by differential protection functions which are in most cases the main protection used for the generator.

The generator's neutral earthing method determines the earth-fault protection schemes for the generator stator. Earth-fault protection functions provide protection against various earth-fault conditions. The relay's generator protection functions aim at providing a comprehensive protection to the generator against, for example, overcurrent, overvoltage, overexcitation, short circuit and earth faults.

Table 207: Typical generator fault conditions and protection functions

Type of fault	Protection function
Short circuit faults and winding failures	Stabilized and instantaneous differential protection for machines MPDIF, Three-phase voltage-dependent overcurrent protection PHPVOC, Three-phase underimpedance protection UZPDIS
90% stator earth fault	Residual overvoltage protection ROVPTOV, Non-directional earth-fault protection, low stage EFLPTOC
Winding inter-turn faults	Stabilized and instantaneous differential protection for machines MPDIF
Underexcitation or loss of field	Three-phase underexcitation protection UEXPDIS
Table continues on next page	

Type of fault	Protection function
100% stator earth fault protection	Third harmonic-based stator earth-fault protection H3EFPSEF and Residual overvoltage protection ROVPTOV
Rotor earth fault	Rotor earth-fault protection (injection method) MREFPTOC
Circuit breaker failure detection	Circuit breaker failure protection CCBRBRF

Abnormal power system conditions can have an adverse impact on the turbine-generator if not corrected in due time. These abnormal conditions can arise due to, for example, an external fault, a problem in the excitation system or prime mover or the connected load. It is important that the turbine - generator be isolated from the power system if the abnormal condition persists.

Table 208: Typical generator abnormal operation conditions and protection functions

Abnormal operation	Protection function
Thermal overload	Stator temperature measurement based thermal overload protection, Three-phase non-directional overcurrent protection, low stage PHLPTOC, Three-phase thermal overload protection, two time constants T2PTTR
Directional under power	Underpower protection DUPPDPR
Reverse power	Reverse power/directional overpower protection DOPPDPR
Overexcitation	Overexcitation protection OEPVPH
Out of step condition	Out-of-step protection with double blinders OOSRPSB
Unbalance loading	Negative-sequence overcurrent protection for machines MNSPTOC
Dead machine CB energization	Three-phase non-directional overcurrent protection, instantaneous stage PHIPTOC and Three-phase undervoltage protection PHPTUV2
Undervoltage	Three-phase undervoltage protection PHPTUV
Underfrequency	Frequency protection FRPFRQ1
Overvoltage	Three-phase overvoltage protection PHPTOV
Overfrequency	Frequency protection FRPFRQ2
Rate of change of frequency	Frequency protection FRPFRQ

The inclusion of different types of protection functionality in the overall generator protective scheme depends on the type (hydro, turbo), size and criticality of the generator.

The tripping of the equipment associated with the turbine-generator is associated with a different action, depending on the cause and potential of damage to the turbine-generator.

9.1.1 Protective scheme for generators

Table 209: Protective scheme for turbogenerators

Protection function	Type and size of machine					
	Air cooled				Hydrogen cooled	Hydrogen water cooled
	<5 MVA	5...20 MVA	20...80 MVA	80...150 MVA	100...300 MVA	300...1500 MVA
95% stator earth fault	x	x	x	x	x	x
100% stator earth fault					x	x
Rotor earth fault	x	x	x	x	x	x
Differential protection		x	x	x	x	x
Unit differential protection	x	x	x	x	x	x
Impedance short circuit protection	x	x	x	x	x	x
Stator thermal overload protection						x
Rotor thermal overload protection						x
Negative phase sequence current protection		x	x	x	x	x
Loss of excitation protection		x	x	x	x	x
Overexcitation protection				x	x	x
Overvoltage protection	x	x	x	x	x	x
Shaft current protection				x	x	x
Underfrequency protection						
Reverse power protection	x	x	x	x	x	x
Dead machine protection				x	x	x
Speed monitoring system	x	x	x	x	x	x
Temperature system	x	x	x	x	x	x
Arc monitoring system			x	x	x	x

Table 210: Protective scheme for hydro generators

Protection function	Type and size of machine				
	Air cooled				Hydrogen water cooled
	<5 MVA	5...20 MVA	20...80 MVA	80...600 MVA	300...600 MVA
95% stator earth fault	x	x	x	x	x
100% stator earth fault				x	x
Rotor earth fault	x	x	x	x	x
Differential protection		x	x	x	x
Unit differential protection	x	x	x	x	x
Impedance short circuit protection	x	x	x	x	x
Stator thermal overload protection				x	x
Rotor thermal overload protection				x	x
Negative phase sequence current protection		x	x	x	x
Loss of excitation protection		x	x	x	x
Overexcitation protection				x	x
Overvoltage protection	x	x	x	x	x
Shaft current protection		x	x	x	x
Underfrequency protection					
Reverse power protection	x	x	x	x	x
Dead machine protection				x	x
Speed monitoring system	x	x	x	x	x
Temperature system	x	x	x	x	x
Arc monitoring system			x	x	x

9.1.2 Turbine - generator: Tripping scheme

Table 211: Tripping scheme for the turbine - generator unit

Cause	Grid disconnection	Generator CB trip	Turbine trip	Excitation off
Generator electrical protection, generator transformer electrical protection, earth fault	x	x	x	x
Grid disturbance	x			
Generator overexcitation protection[1)]		x		x
Turbine mechanical problem[2)]		x	x	

1) If the generator is not connected to grid
2) First the turbine trips and then the generator trips with low forward protection or reverse power protection

9.2 Description of the example case

To explain the application of short circuit, earth fault, stator fault, overload and rotor fault protection functions, a generic system is considered as an example. Figure 94 shows a synchronous generator and a condensate steam turbine connected to an 11 kV single bus. The generator's neutral is earthed with high impedance. A circuit breaker (CB) can connect the generator to an 11 kV single bus. Six nos. pt 100 type resistance – temperature detectors (RTD) are embedded in the generator's stator slots.

The figure shows a representative configuration with a generator for single bus/ single breaker on the terminal side and high impedance earthing through a neutral earthing transformer on the neutral side of the generator.

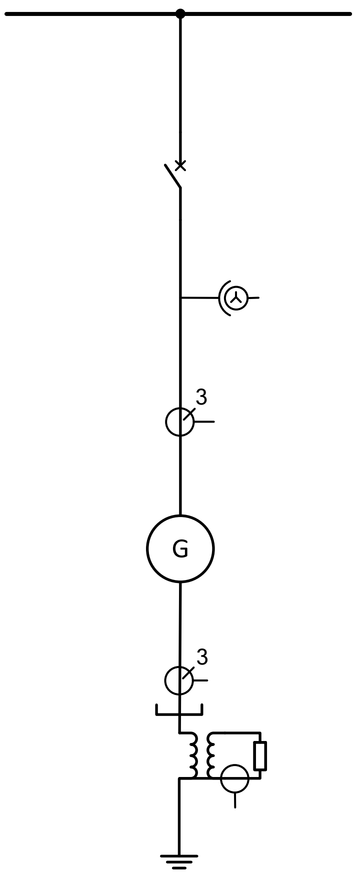

Figure 94: Single-line diagram of the example case for generator CB bay

To explain the settings of various protection functions, the turbine-generator design data for the example case is shown in Table 212 and the generator's capability curve is illustrated in Figure 95.

Table 212: Technical data for the three-phase synchronous generator

Setting	Value
Prime mover	Steam turbine
Stator neutral earthing type	High impedance
Rated active power	10 MW
Rated voltage Ph-Ph	11 kV
Rated current	656
Rated power factor	0.8
Synchronous reactance X_d (pu at 12.5 MVA)	1.2
Transient reactance X'_d (pu at 12.5 MVA)	0.23
Subtransient reactance X''_d (pu at 12.5 MVA)	0.15
Resistance (pu at 12.5 MVA)	0.003
Leakage reactance (pu at 12.5 MVA)	0.16
Table continues on next page	

Setting	Value
Negative phase sequence reactance (pu at 12.5 MVA) X_2	0.15
Zero phase sequence reactance (pu at 12.5 MVA) X_0	0.1
Insulation class	B
Generator time constant	10 min

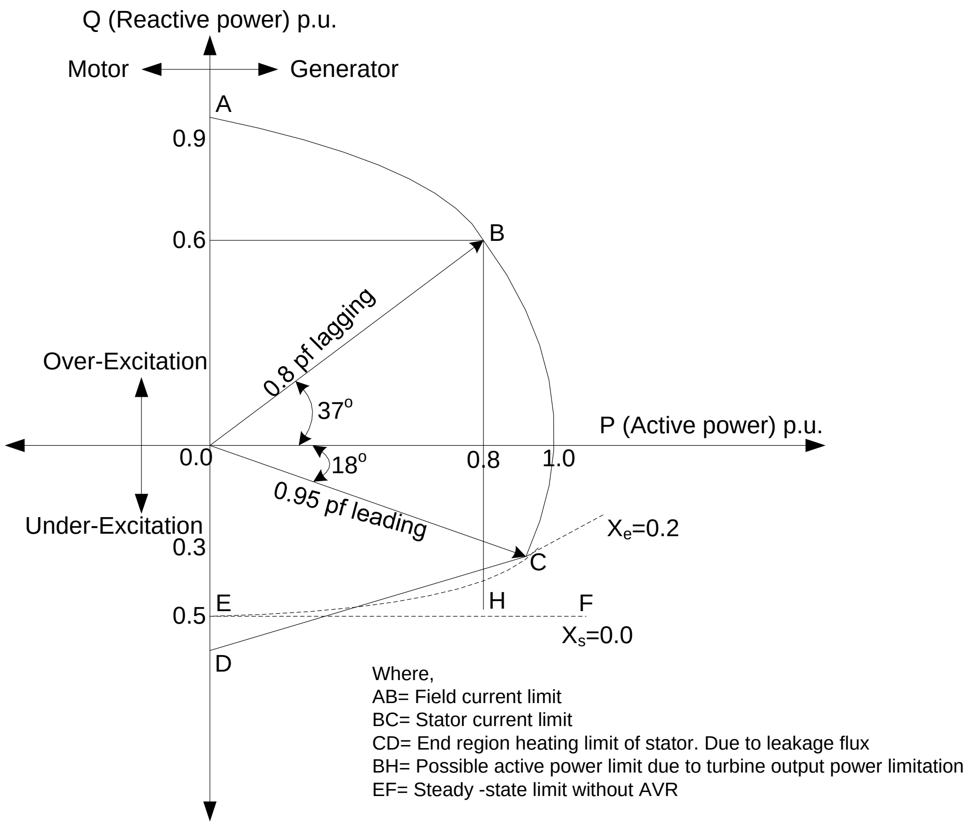

Figure 95: Generator capability curve

The generator in the example case is connected to the rest of the power system as shown in Figure 96. An 11 kV generator bus is connected to a 110 kV transmission line by a step-up transformer.

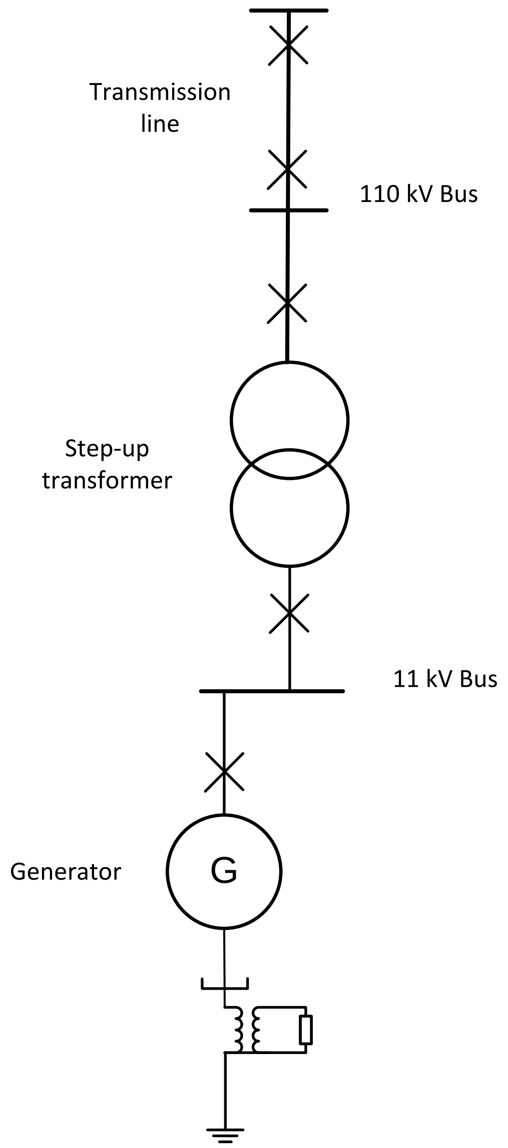

Figure 96: Generator connection to the power system

The setting calculation of the OOSRPSB1 function uses the settings shown in Table 213.

Table 213: Technical data for the step-up transformer, transmission line and grid

Setting	Value
Step-up transformer	
Rated power	12.5 MVA
Ration (Low voltage Ph-Ph / High voltage Ph-Ph)	11 /110 kV
Short circuit impedance $Z_{sc}Tx$	10%
Short circuit resistance $R_{sc}Tx$	0.5%
Transmission line	
Table continues on next page	

Setting	Value
Length	30 km
Positive sequence reactance per kilometer (X1Line)	0.5
Positive sequence resistance per kilometer (R1Line)	0.05
Grid	
Short circuit power of grid Sn	800 MVA

9.3 Generator protection relay

9.3.1 Relay interface, configuration and settings

Figure 97 shows the connection details of the relay's analog inputs (AI), binary inputs (BI), binary outputs (BO) and RTD input. The CT and VT connections required for a comprehensive generator protection for the example case are also shown.

CTs are connected to measure phase currents from both sides of the generator windings (that is, phase and neutral) terminal. One CT is connected to the secondary of the neutral earthing transformer to measure the earth-fault current.

An external current injection device, REK 510, is used for rotor earth-fault protection.

VTs are connected to measure the phase voltages from the terminal side and the residual voltage from secondary of neutral earth transformer.

Two binary inputs are connected to identify the CB open and close positions. Three binary outputs are used to trip the CB, AVR and prime mover.

Six RTDs are connected to the generator; one RTD is for ambient temperature measurement.

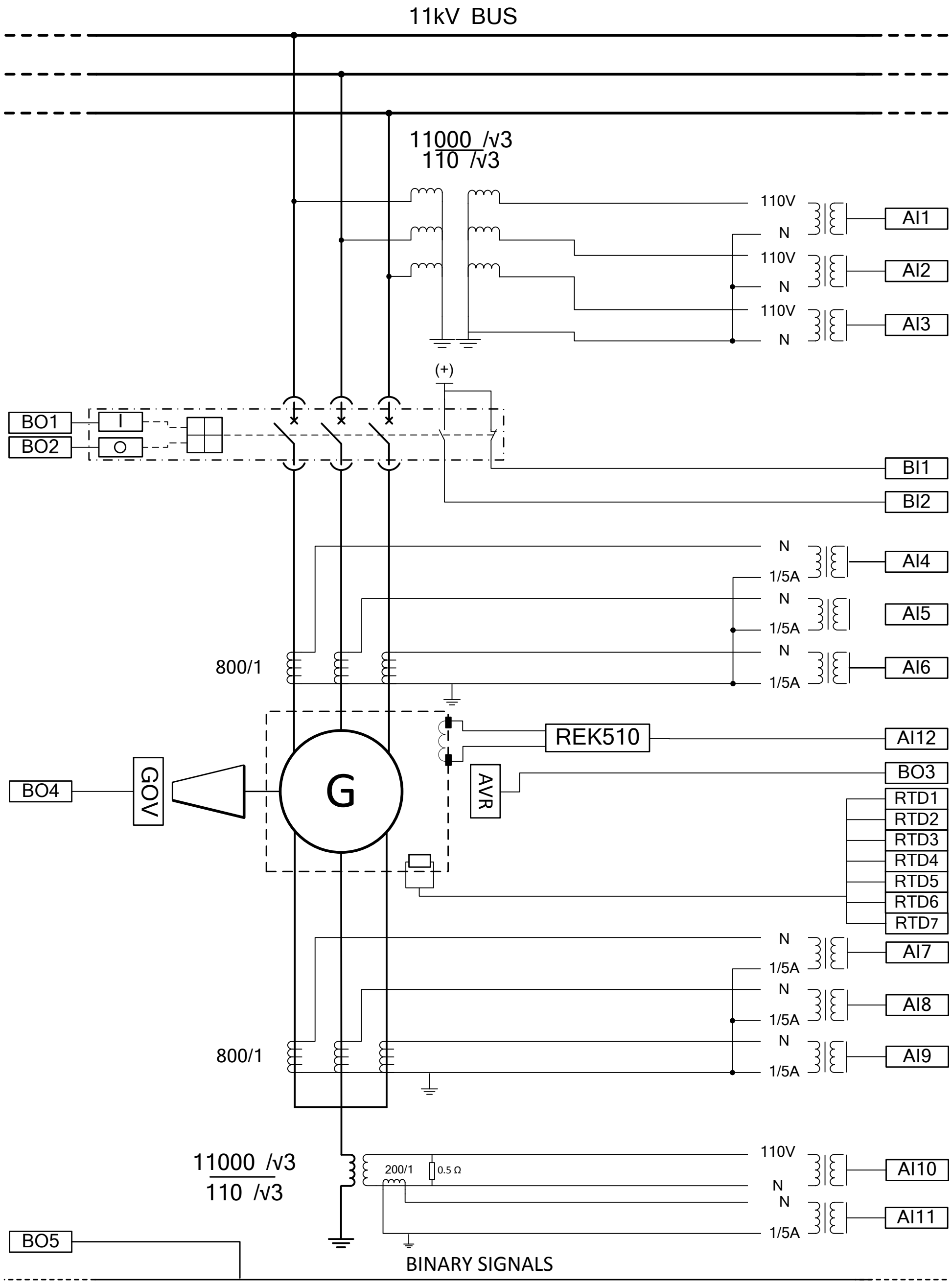

Figure 97: Relay interfaces, CT-VT, BI, BO and RTD connections for the generator of the example case

9.3.1.1 Analog input signals

Table 214: Physical analog input signals for implementing the application example

Analog input	Description
AI1	Generator terminal U_A voltage
AI2	Generator terminal U_B voltage
AI3	Generator terminal U_C voltage
AI4	Generator terminal I_A current
AI5	Generator terminal I_B current
AI6	Generator terminal I_C current
AI7	Generator neutral side I_A current
AI8	Generator neutral side I_B current
AI9	Generator neutral side I_C current
AI10	Generator neutral voltage
AI11	Neutral earthing transformer secondary current
AI12	Rotor earth-fault detector current (from REK 510)

9.3.1.2 RTD input signals

Table 215: Physical RTD input signals for implementing the application example

RTD input	Description
RTD1	Winding temperature for phase 1 (measurement 1)
RTD2	Winding temperature for phase 1 (measurement 2)
RTD3	Winding temperature for phase 2 (measurement 1)
RTD4	Winding temperature for phase 2 (measurement 2)
RTD5	Winding temperature for phase 3 (measurement 1)
RTD6	Winding temperature for phase 3 (measurement 2)
RTD7	Ambient temperature

9.3.1.3 Binary input signals

Table 216: Physical binary input signals for implementing the application example

Binary input	Description
BI1	Circuit breaker close position
BI2	Circuit breaker open position

9.3.1.4 Binary output signals

Table 217: Physical binary output signals for implementing the application example

Binary output	Description
BO1	This output is used for closing the generator circuit breaker.
BO2	This output is used for tripping or opening the generator circuit breaker.
BO3	This output is used for closing the excitation system.
BO4	This output is used for tripping the turbine.
BO5	CBFP trip to all sources that are connected with a breaker to the same power system

9.3.1.5 Recommended alarms

Table 218 presents a proposal for LHMI and WHMI alarm handling. The table lists the event container, event and alarm configuration text for the functions which should be tagged as alarms using Event Filtering in PCM600.

Table 218: Alarm list for implementing the application example

Event container	Event	Description
ILTCTR1	ALARM	Phase current preprocessing
ILTCTR1	WARNING	Phase current preprocessing
ILTCTR2	ALARM	Phase current preprocessing
ILTCTR2	WARNING	Phase current preprocessing
RESTCTR1	ALARM	Residual current preprocessing
RESTCTR1	WARNING	Residual current preprocessing
RESTCTR2	ALARM	Residual current preprocessing
RESTCTR2	WARNING	Residual current preprocessing
UTVTR1	ALARM	Phase and residual voltage preprocessing
UTVTR1	WARNING	Phase and residual voltage preprocessing
UTVTR2	ALARM	Phase and residual voltage preprocessing
UTVTR2	WARNING	Phase and residual voltage preprocessing
MPDIF1	OPERATE	Stabilized and instantaneous differential protection for machines
PHPVOC1	OPERATE	Three-phase voltage-dependent overcurrent protection
ROVPTOV1	OPERATE	Residual overvoltage protection

Table continues on next page

Event container	Event	Description
H3EFPSEF1	OPERATE	Third harmonic-based stator earth-fault protection
EFLPTOC1	OPERATE	Non-directional earth-fault protection, low stage
OOSRPSB1	OPERATE	Out-of-step protection with double blinders
DOPPDPR1	OPERATE	Reverse power/directional overpower protection
DUPPDPR1	OPERATE	Underpower protection
UEXPDIS1	OPERATE	Three-phase underexcitation protection
OEPVPH/1	OPERATE	Overexcitation protection
MNSPTOC1	OPERATE	Negative-sequence overcurrent protection for machines
MREFPTOC1	OPERATE	Rotor earth-fault protection (injection method)
MREFPTOC1	ALARM	Rotor earth-fault protection (injection method)
PHPTOV1	OPERATE	Three-phase overvoltage protection
PHPTUV1	OPERATE	Three-phase undervoltage protection
FRPFRQ1	OPR_UFRQ	Frequency protection
FRPFRQ2	OPR_OFRQ	Frequency protection
MAPGAPC1	OPERATE	Multipurpose protection
MAPGAPC2	OPERATE	Multipurpose protection
MAPGAPC3	OPERATE	Multipurpose protection
MAPGAPC4	OPERATE	Multipurpose protection
MAPGAPC5	OPERATE	Multipurpose protection
MAPGAPC6	OPERATE	Multipurpose protection
PHLPTOC1	OPERATE	Three-phase non-directional overcurrent protection, low stage
UZPDIS1	OPERATE	Three-phase underimpedance protection
PHIPTOC1	OPERATE	Three-phase non-directional overcurrent protection, instantaneous stage
PHPTUV2	OPERATE	Three-phase undervoltage protection
PHHPTOC1	OPERATE	Three-phase non-directional overcurrent protection, high stage
CCBRBRF1	CB_FAULT_AL	Circuit breaker failure protection
Table continues on next page		

Event container	Event	Description
SEQSPVC1	FUSEF_U	Fuse failure supervision
TRPPTRC1	TRIP	Master trip
T2PTTR1	OPERATE	Three-phase thermal overload protection, two time constants

9.3.1.6 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 219: Function blocks used in the relay configuration

Function block	Description
ILTCTR, UTVTR, RESTVTR, RESTCTR	Analog signal preprocessing block
MPDIF1	Stabilized and instantaneous differential protection for machines
PHPVOC1	Three-phase voltage-dependent overcurrent protection
ROVPTOV1	Residual overvoltage protection
H3EFPSEF1	Third harmonic-based stator earth-fault protection
EFLPTOC1	Non-directional earth-fault protection, low stage
OOSRPSB1	Out-of-step protection with double blinders
DUPPDPR1	Underpower protection
DOPPDPR1	Reverse power/directional overpower protection
UEXPDIS1	Three-phase underexcitation protection
OEPVPH1	Overexcitation protection
MNSPTOC1	Negative-sequence overcurrent protection for machines
MREFPTOC1	Rotor earth-fault protection (injection method)
PHPTOV1	Three-phase overvoltage protection
PHPTUV1, PHPTUV2	Three-phase undervoltage protection
FRPFRQ1, FRPFRQ2	Frequency protection
PHLPTOC1	Three-phase non-directional overcurrent protection, low stage
UZPDIS1	Three-phase underimpedance protection
PHIPTOC1	Three-phase non-directional overcurrent protection, instantaneous stage
PHHPTOC1	Three-phase non-directional overcurrent protection, high stage
CCBRBRF1	Circuit breaker failure protection
INRPHAR1	Three-phase inrush detector

Table continues on next page

Function block	Description
T2PTTR1	Three-phase thermal overload protection, two time constants
TRPPTRC	Trip command collector/handler with lockout/ latching feature
SEQSPVC	Fuse failure supervision is used to block the voltage-dependent protection to avoid the malfunction.

Table 220: Physical analog channels of the functions

Protection	Terminal side Voltage, AI1, AI2, AI3	Terminal side currents, AI4, AI5, AI6	Neutral side currents, AI7, AI8, AI9	Neutral voltage, AI10	Neutral earthing transformer secondary current A11	Rotor earth-fault detector current AI12
MPDIF1		x	x			
PHPVOC1	x		x			
ROVPTOV1				x		
H3EFPSEF1	x			x		
EFLPTOC1					x	
OOSRPSB1	x		x			
DUPPDPR1	x	x				
DOPPDPR1	x	x				
UEXPDIS1	x	x				
OEPVPH1	x	x				
MNSPTOC1		x				
MREFPTOC1						x
PHPTOV1	x					
PHPTUV1	x					
FRPFRQ1	x					
FRPFRQ2	x					
PHLPTOC1		x				
UZPDIS1	x		x			
PHIPTOC1		x				
PHPTUV2	x					
PHHPTOC1			x			
CCBRBRF1		x			x	
INRPHAR1		x				
T2PTTR1		x				

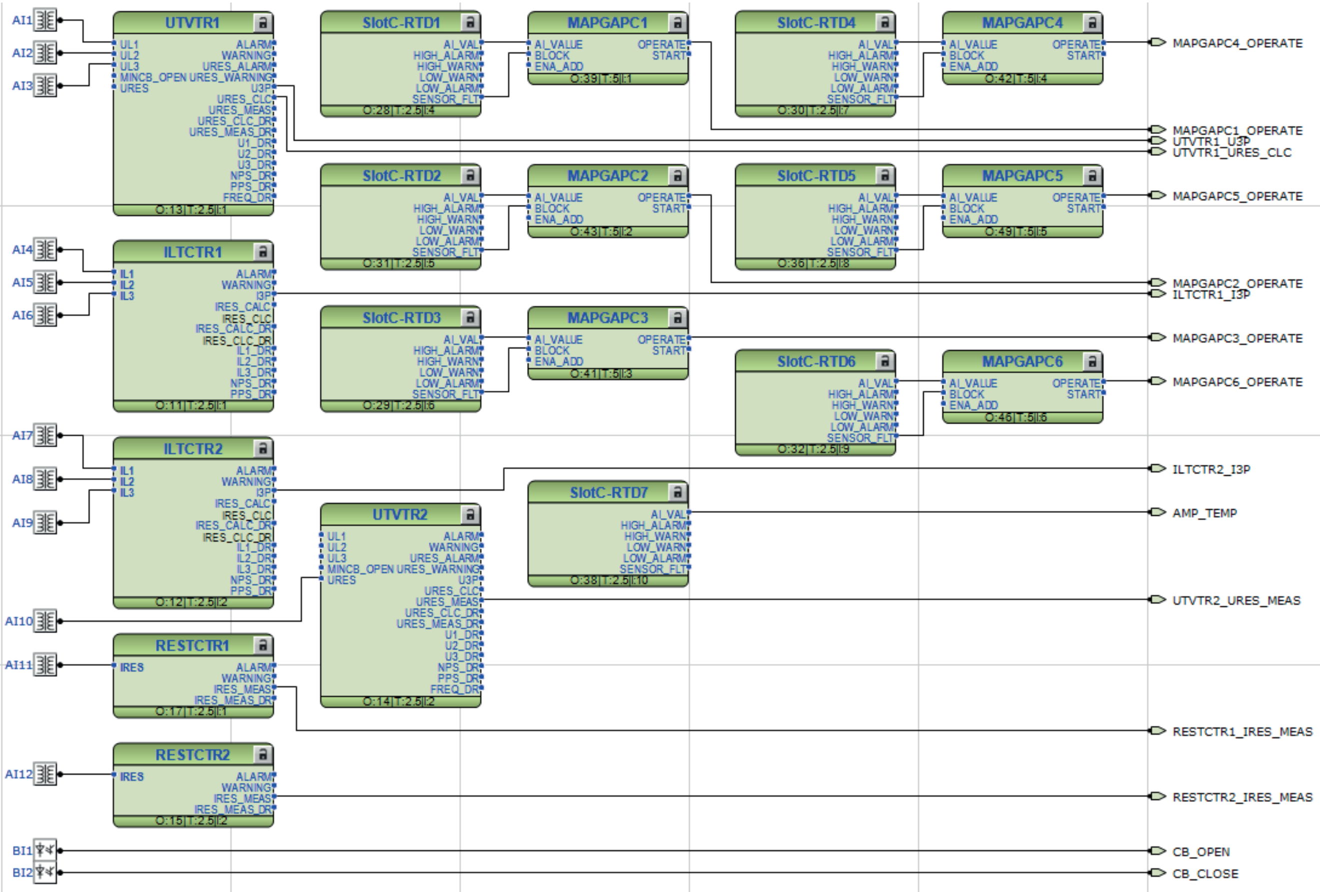

Figure 98: Analog input, RTD and binary input connection as an example case

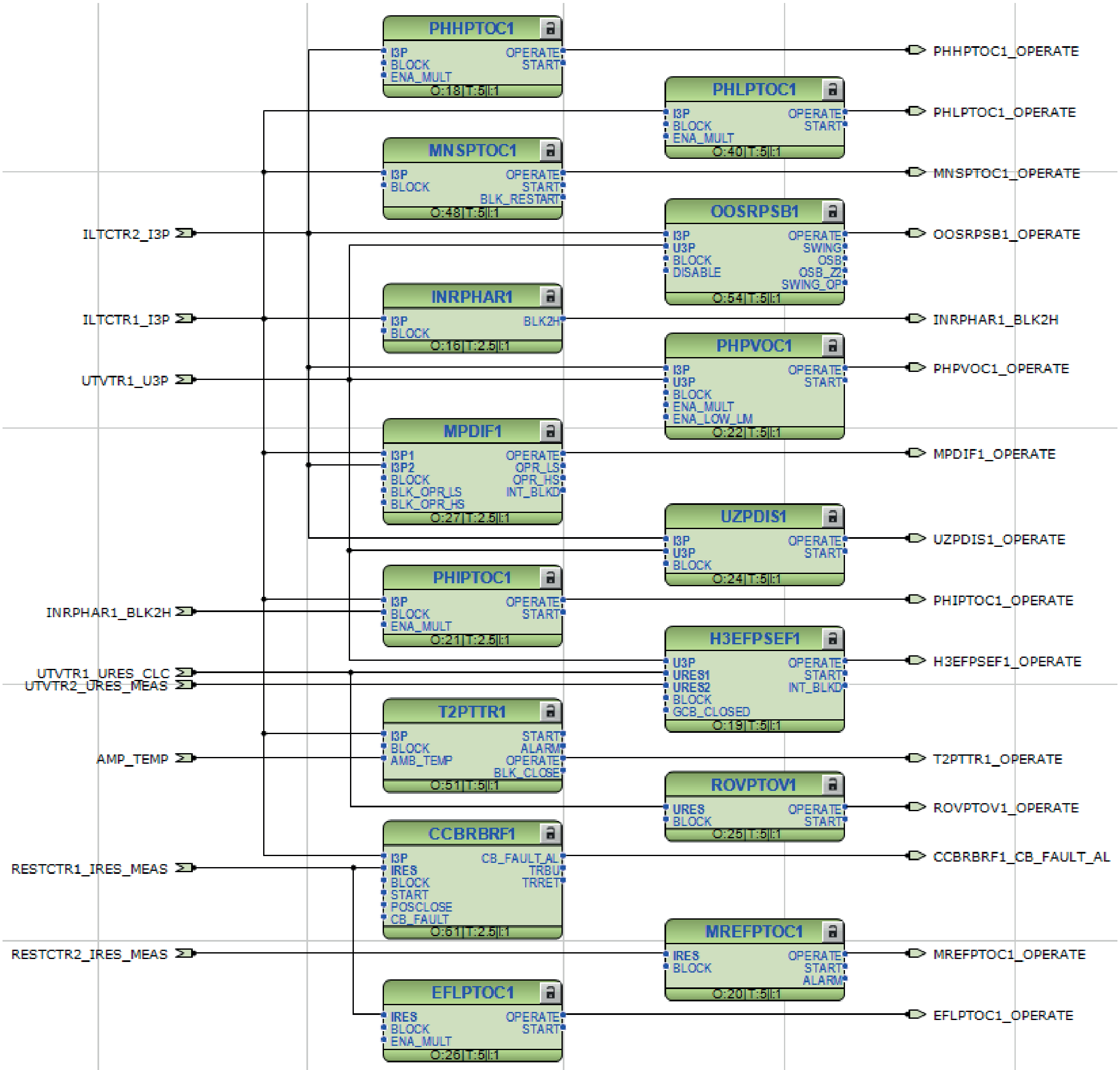

Figure 99: Protection function connection as an example case (part 1)

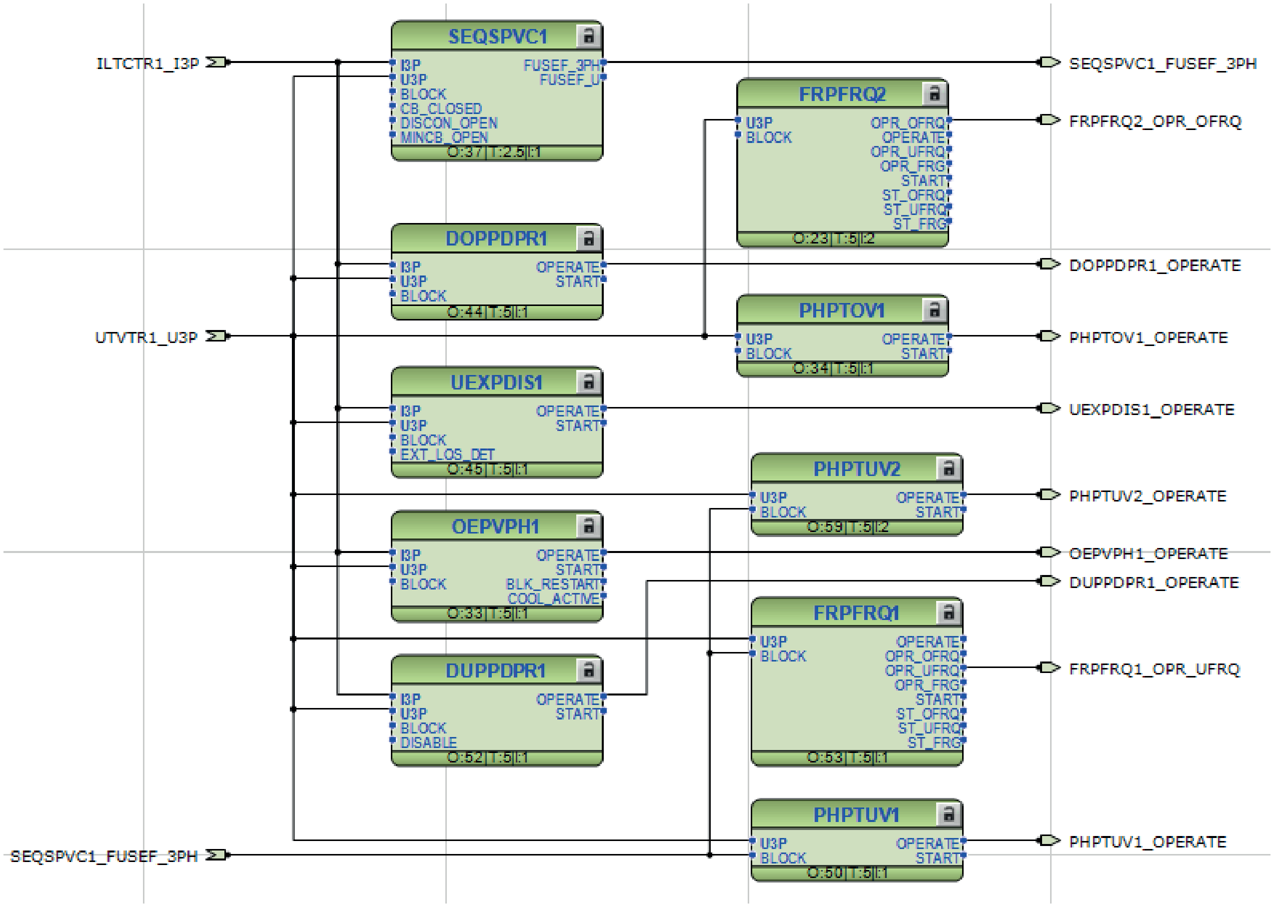

Figure 100: Protection function connection as an example case (part 2)

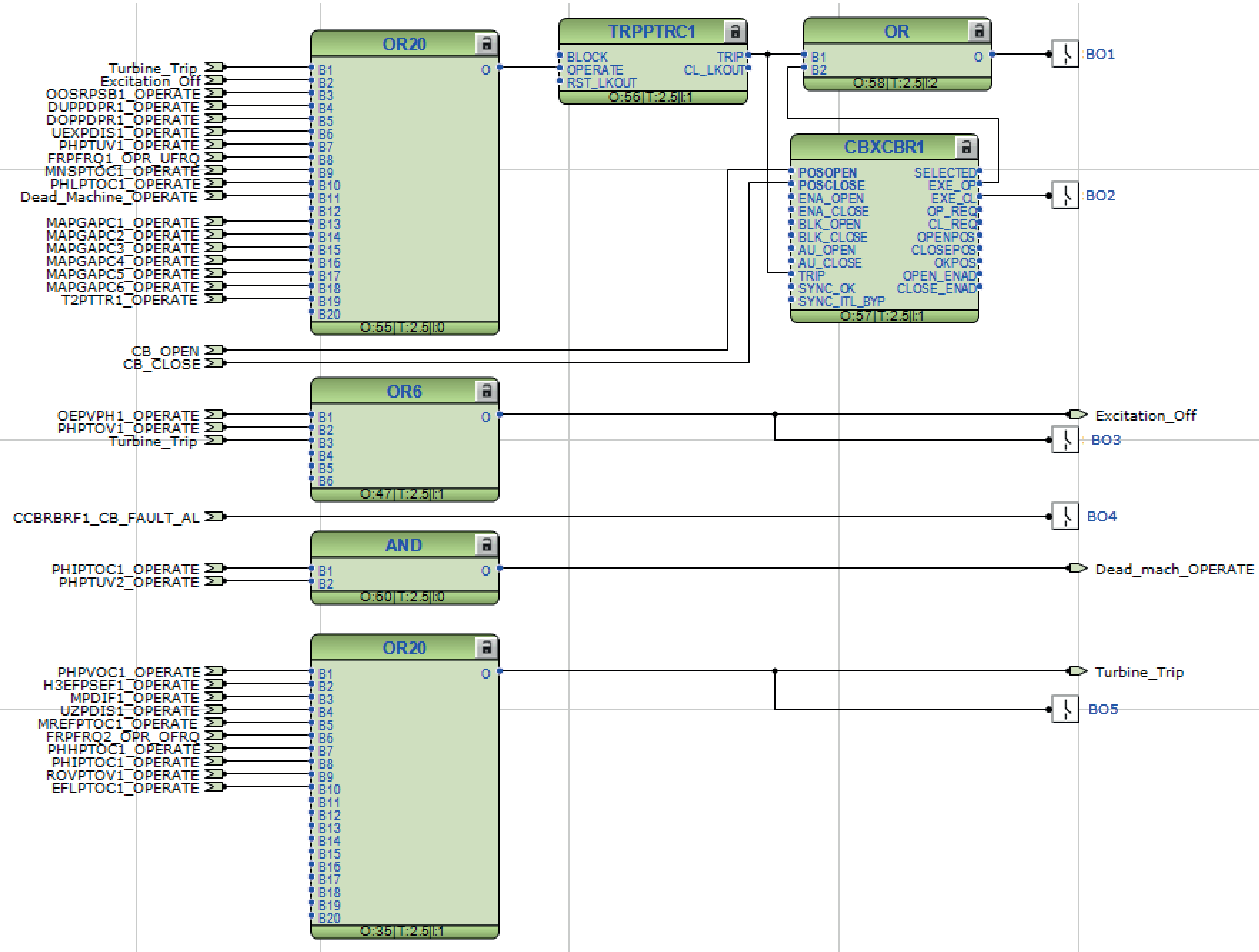

Figure 101: Binary output connection as an example case

9.3.1.7 Function blocks and setting value

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function for current signals. The generator terminal side current CT connection is provided on ILTCTR1. The generator neutral side current CT connection is provided on ILTCTR2.

Table 221: Function settings for ILTCTR

Setting	Recommended values		Description
	ILTCTR1	ILTCTR2	
Primary current	800 A	800 A	Primary current value
Secondary current	1 A	1 A	Secondary current value
Frequency adaptivity	Backup frequency source	Enable	

RESTCTR – Residual current preprocessing

RESTECTR1 is the analog signal processing block for the neutral earthing transformer's secondary current signal.

Table 222: Function settings for RESTCTR1

Setting	Recommended values	Description
Primary current	200 A	Primary CT current
Secondary current	1 A	Secondary current value
Frequency adaptivity	Enable	

RESTECTR2 is the analog signal processing block for the rotor earth-fault detector's analog signal.

Table 223: Function settings for RESTCTR2

Setting	Recommended values	Description
Primary current	1 A	Primary CT current
Rated current	1 A	Secondary current value
Frequency adaptivity	Disable	

UTVTR – Phase and residual voltage preprocessing

UTVTR1 is the analog signal processing block for generator terminal side voltage signals.

Table 224: Function settings for UTVTR1

Setting	Recommended values	Description
Primary voltage	11.00 kV	Primary VT voltage
Secondary voltage	100 V	Secondary VT voltage
Rated voltage	11.00 kV	Generator rated voltage
VT connection	Wye	VT connection type
Frequency adaptivity	Main frequency source	

UTVTR2 is the analog signal processing block for generator neutral earthing transformer secondary voltage signal.

Table 225: Function settings for UTVTR2

Setting	Recommended values	Description
Primary voltage	11.00 kV	Primary VT voltage
Secondary voltage	100 V	Secondary VT voltage
Frequency adaptivity	Enable	

MPDIF1 – Stabilized and instantaneous differential protection for machines

A short circuit between the phases of the stator windings causes large fault currents, creating, thus, a risk of damage to the insulation, windings and stator core. The large short circuit currents cause large 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 damage and the economic loss.

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. This results in a differential current, which is then used as a basis for generating the operating signal. Due to this principle, the differential protection does not trip during external faults. However, inter-turn faults in the same phase are usually not detected unless these faults develop into another type of fault.

Table 226 shows recommended setting values; all other settings of MPDIF1 are kept at default values for this example case.

Table 226: Function settings whose values differ from the default values based on the examples

Setting	Recommended values	Description
DC restrain enable	TRUE	This setting should be set "TRUE" if the network (generator) has long DC-time-constant.
CT connection type	Type2	As an example case Type 2
CT ratio Cor Line	1.22 1)	CT ratio correction, ratio between the line side and the rated current
CT ratio Cor Neut	1.22 2)	CT ratio correction, ratio between the neutral side and the rated current

1) Setting *CT ratio Cor Line* = 800/656 = 1.22
2) Setting *CT ratio Cor Neut* = 800/656 = 1.22

PHPVOC1 – Three-phase voltage-dependent overcurrent protection

In case of a short circuit, the generator sustained fault current, determined by the generator synchronous reactance, could be well below the full-load current. Also, if the generator excitation power is fed from the generator terminals, a voltage drop due to the short circuit also leads to a low fault current. The primary protection, such as a normal overcurrent protection, might not detect this kind of a fault situation therefore a voltage-depended overcurrent protection should be used as backup.

The voltage slope characteristic is used to provide backup to the differential relay. The current start value varies according to the generator terminal voltages between the set voltage high limit and voltage low limit as shown in Figure 102, thus ensuring the operation of the function in spite of the drop in fault current value.

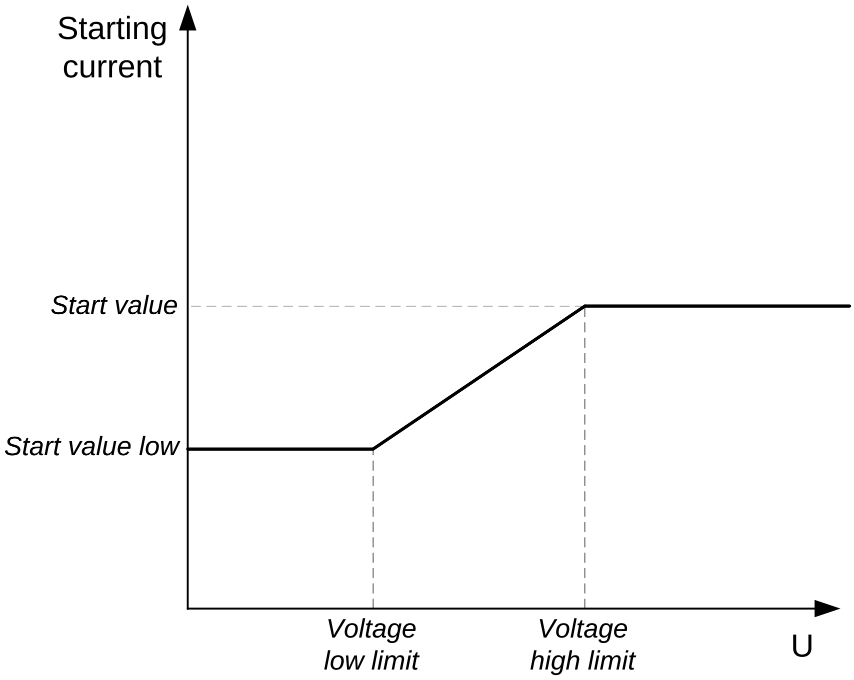

Figure 102: Voltage slope characteristic

The operation of the function should be time graded in the main protection scheme to ensure that the function does not operate before the main protection. Table 227 shows recommended setting values; all other settings of PHPVOC1 are kept at default values for this example case.

Table 227: Function settings for PHPVOC1 as voltage slope characteristics

Setting	Recommended values	Description
Start value	0.92 xIn[1)]	It should be equal to or higher than 150% of the generator rated current at voltage high limit. In this example, 150% is used.
Start value low	0.31 xIn[2)]	It should be equal to or higher than 150% of the generator rated current at voltage low limit. In this example, 150% is used.
Voltage high limit	0.75 xUn	A typical setting value is between 0.75...1.00 · Un
Voltage low limit	0.25 xUn	A typical setting value is between 0.25...0.50 · Un
Control mode	Voltage control	

1) *Start value*
   = *Voltage high limit* · 1.5 · generator rated current / CT primary
   =0.75 · 1.5 · 656/800
   = 0.92
2) *Start value low*
   = *Voltage low limit* · 1.5 · generator rated current / CT primary
   = 0.31

ROVPTOV1 – Residual overvoltage protection

A higher earth-fault current leads to higher generator core damage. One of the ways to minimize the core damage is to use high impedance earthing of the generator neutral. When an earth fault occurs, the high impedance increases the overvoltage on the healthy phase. This increase of voltage can lead to another failure. To prevent residual voltage from reaching an unacceptable level, ROVPTOV is used. Table 228 shows recommended setting values; all other settings are kept at default values for this example case.

Table 228: Function settings whose values differ from the default values based on the example

Setting	Recommended values	Description
Start value	0.029 xUn[1)]	Start value
Operate delay time	60 ms	This setting should be coordinated with the operating time of VT primary and secondary fuses.

1) Current in neutral of generator at line-to-earth fault
   = Rated Voltage ph-ph /(√3 · Secondary resistance · (VT Voltage ph-ph primary/Voltage secondary)^2
   = 11000 /(√3 · 0.5 · (11000/110)^2
   = 1.27 amp
   Secondary current in neutral earthing transformer at line-to-earth fault
   = 1.27 · 11000/110
   = 127
   Voltage across resistance
   = 127 · 0.5
   = 63.5
   Start value
   = 5% of Voltage across resistance /VT secondary voltage
   = 0.05 · 63.5/110

= 0.029

In the example case, 5% stator (from neutral) is still unprotected against the stator earth fault.

EFLPTOC1 – Non-directional earth-fault protection – low stage

In the example application, the earth-fault current is limited by a high-impedance neutral earthing scheme of the generator. EFLPTOC1 can provide earth protection in addition to residual overvoltage protection. This function also provides the protection coverage during the CB open condition after the excitation turns on. Table 229 shows recommended setting values; all other settings are kept at default values for this example case.

Table 229: Function settings whose values differ from the default values based on the example

Setting	Recommended values	Description
Start value	0.06 xIn[1)]	10% of the secondary current in neutral of generator at line-to-earth fault. The setting must be above the normal unbalance currents that appear in neutral.
Operating curve type	12 = IEC Ext. inv.	Extremely inverse time curve

1) *Start value* = 10% of Secondary current (at NGT) /CT primary
= 0.1 · 127/200
= 0.06

H3EFPSEF1 – Third harmonic-based stator earth-fault protection

In case of a stator earth fault, residual overvoltage protection or non-directional earth fault protection can detect the fault up to 90...95 percent from the generator terminal. H3EFPSEF1 is used to detect stator earth fault at the neutral point, and at least up to 15...20 percent from the neutral point along the stator winding. To detect the earth fault, the function compares the third harmonic voltages produced by the generator at the neutral and terminal sides of the generator.

To ensure reliable operation of the protection, the generator needs to produce third harmonic voltage which is at least 1% of the generator's rated voltage. When H3EFPSEF1 works only as third harmonic neutral point undervoltage protection, it is necessary to block the function during the start-up and shutdown of the generator.

The level of third harmonic voltage at the generator terminal and at neutral point depends on the loading of the generator as well as the generator design, hence a field test should be performed for setting different parameters. See the technical manual for more details.

Table 230: Calculation steps for the H3EFPSEF1 settings

Sl no	% Generator load	UD_3H	UB_3H	Ratio UB_3H / UD_3H	Min ratio	Beta value for K =1.5	Beta value for K =1.5
1	10	1.2	1.5	1.25	1.25	1.5/1.25 = 1.2	2/1.25 = 1.6
2	20	1.5	2.5	1.67			
3	25	1.9	3	1.58			
4	50	2.9	4.2	1.49			
5	75	3.6	6	1.67			
6	100	4.2	7.5	1.79			

Step 1 : Calculate the ratio UB_3H : UD_3H (column 5)

Step 2 : Calculate the Min of UB_3H : UD_3H (column 6)

Step 3 : Calculate Beta value for different safety factor K (column 7, 8)

Table 231 shows recommended setting values; all other settings are kept at default values for this example case.

Table 231: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Voltage selection	U_0	This setting depends on the availability of terminal side voltage. In this example, terminal side voltage is fed from three Ph-N VTs. If the Ph-N connection is not available, see the technical manual for the different options.
Beta	1.2	Portion of neutral side; third harmonic used as bias
Generator CB used	Yes	As an example case

DOPPDPR1 – Reverse power protection

Sometimes the mechanical power from a generator prime mover may decrease so much that it does not cover the internal losses. The synchronous generator becomes a synchronous motor and starts importing power from the system. A generator acting as a motor implies no risk to the generator but can cause damage to the prime mover. The extent of the damage depends on the type of the prime mover.

The task of reverse power protection DOPPDPR1 is to protect the prime mover.

Whenever a low value of the reverse power setting is required, underpower protection should be used in conjunction with directional overpower protection. The limit depends on the CT and VT accuracy.

Table 232 shows recommended setting values; all other settings are kept at default values for this example case.

Table 232: Function settings whose values differ from the default values based on the example

Setting	Recommended values	Description
Start value	0.07 xSn[1)]	The no-load power imported from the power system varies depending on the type of prime mover: from 0.2% of rated power (Hydro turbine) to 50% (Gas turbine). In this example, 10% is used.
Directional mode	Reverse	Reverse power direction
Operate delay time	2000 ms	Depends on the prime mover's capability. In this example, 2 s is used.

1) *Start value* = No-load power / √3 · VT primary · CT primary
= 0.10 · 10 · 1000/ (√3 · 11 · 800)
= 0.07

DUPPDPR1 – Underpower protection

Sometimes the mechanical power from a generator prime mover may decrease so much that it does not cover the internal losses. Steam turbines easily become overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. The task of an underpower protection is to protect the prime mover from very low power output conditions.

Table 233 shows recommended setting values; all other settings are kept at default values for this example case.

Table 233: Function settings for DUPPDPR1

Setting	Recommended values	Description
Start value	0.03 xSn[1)]	Depends on the continuous low power capability of the prime mover. In this example, 5% is used.
Operate delay time	5000 ms	Depends on the loading rate of the generator after CB closing (here 5 s is used for 50 % loading)

1) *Start value* = 0.05 · rated active power(MW) · 1000 /√3 · VT primary(kV) · CT primary
= 0.05 · 10 · 1000/ √3 · 11 · 800
= 0.033
= 0.03

UEXPDIS1 – Three-phase underexcitation protection

A reduction of the excitation current weakens the coupling between the rotor and the external power system. The machine may lose the synchronism and starts to operate like an induction machine, which increases the consumption of reactive power. Even if the machine does not lose synchronism it may not be acceptable to operate in this state for a long time. The underexcitation causes excessive heat in the end region of the stator winding. This can damage the insulation of the stator winding and even the iron core.

Underexcitation also causes the generator to operate in asynchronous mode. This increases rotor speed which causes heat in the rotor iron and damping windings. A high intake of reactive power from the network during underexcitation causes problems in the network such as voltage dip and stability and power swings. The power swings stress the prime mover causing turbine blade cavitation and mechanical stress in the gearbox.

The capability curve describes the underexcitation capability of the machine. Excessive capacitive load on the synchronous generator causes it to drop out of step. The reason is the steady-state stability limit as defined by the load angle = 90°, which can only be reached when the unit is underexcited. UEXPDIS1 protects the synchronous machines against an unstable operation due to loss of excitation. Partial or total loss of excitation causes a reactive power intake from the network to generator and the reactance of the system viewed from the generator terminals turns negative. This kind of "drop of reactance" condition can be detected by measuring the impedance of the system.

Table 234 shows recommended setting values; all other settings are kept at default values for this example case.

Table 234: Function settings for UEXPDIS1

Setting	Recommended values	Description
Diameter[1)]	146 %Zn	Diameter of the Mho diagram (Normally set equal to the machine synchronous reactance Xd,)
Offset[2)]	-14 %Zn	Offset of top of the impedance circle from the R-axis. This is usually set equal to –Xd'/2,
Operate delay time	5000 ms	This setting depends on the generator's short-time underexcitation capability as well as on the AVR response. In this example, 5 s is used.

1) Generator synchronous impedance at 11 kV:
$X_{Gen\_d} = X_d \cdot$ Rated voltage · Rated voltage/ (Rated active power/power factor)
= 1.2 · 11 · 11/ 12.5
= 11.616
Diameter of circle = X_{Gen_d} · (CT primary · √3 · 100)/(VT primary · 1000)
=11.616 · 800 · √3 · 100/11 · 1000
=146

2) Generator transient impedance at 11 kV:
$X'_{Gen\_d} = X'_d \cdot$ Rated voltage · Rated voltage/(Rated active power/power factor)
= 0.23 · 11 · 11/ 12.5
=2.2264
Offset = -0.5 · X'_{Gen_d} · CT primary · √3 · 100/ VT primary · 1000
= -0.5 · 2.2264 · 800 · √3 · 100/ 11 · 1000
= -14

OOSRPSB1 – Out-of-step protection with double blinders

Out-of-step protection functions detect stable power swings and out-of-step conditions by using 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. 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 a fault condition or 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.

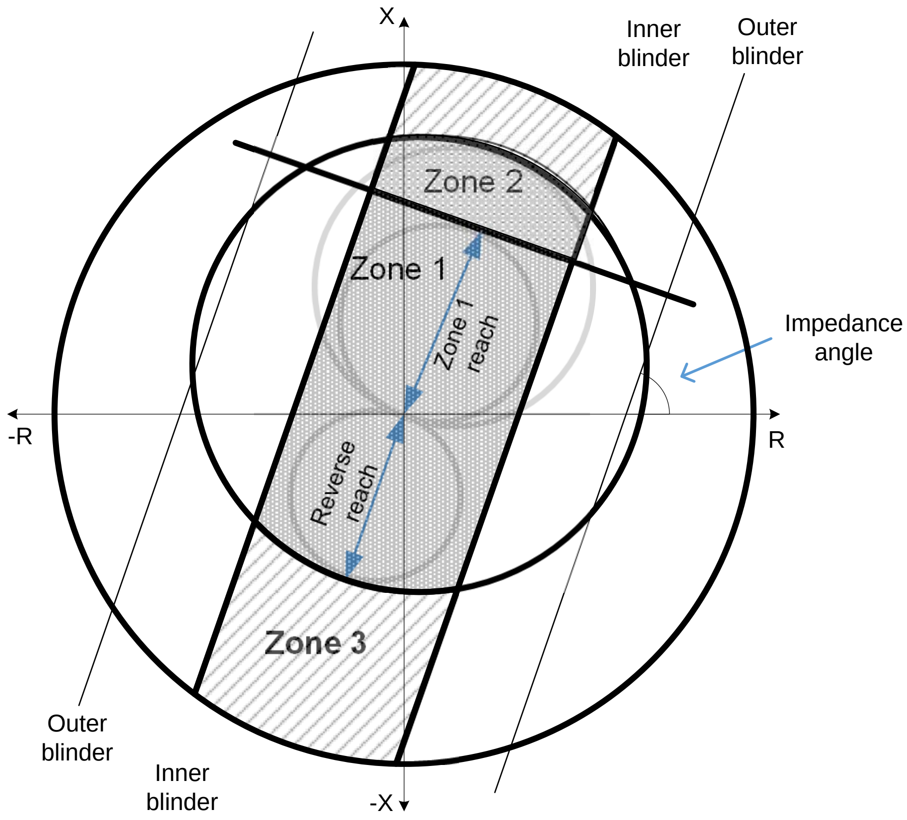

Figure 103: Operating zone for out-of-step protection with double blinder

Table 235: Calculation steps for out-of-step function settings

	Generator	Step-up transformer	Transmission line	Grid
Z base at generator terminal voltage 11 kV	Z_{b_Gen} = 11 · 11/ 12.5 = 9.68 ohm	Z_{b_Tx} = 11 · 11/ 12.5 = 9.68 ohm	Base change factor B_f = 11 · 11/110/110 = 0.01	Base change factor B_f = 11 · 11/110/110 = 0.01
Total impedance calculation	$X'_{d\_Gen} = X'_d \cdot Z_{b\_Gen}$ = 0.23 · 9.68 = 2.2264 ohm	$Z_{Tx} = Z_{Tx} \cdot Z_{b\_Tx}$ =0.1 · 9.68 = 0.968	X_L = X1Line · Length · B_f = 0.5 · 30 · 0.01 = 0.15	Zs =110 · 110 · B_f /(Sn) = 110 · 110 · 0.01/800 = 0.1513
Impedance angle (deg)	= $\cos^{-1}$ ((R_{sc}Tx) /(Z_{sc}Tx)) · 180/pi = $\cos^{-1}$(0.5/10) · 180/pi = 87.13 deg			
Forward reach (primary - ohm)	= $Z_{Tx} + X_L + Z_S$ = 0.968 + 0.15 + 0.1513 = 1.2693			
Reverse reach (primary - ohm)	= X'_{d_Gen} = 2.2264			
Zone1 reach (%)	= 80% of Z_{Tx} · 100/ Forward reach= 0.8 · 0.968 · 100/1.2693 = 61.01			
Inner blinder R (primary - ohm)	= (Forward reach + reverse reach) /(2 · tan60) = (1.2693 + 2.2264)/2 · 1.7320 =1.01			
Outer blinder R (primary - ohm)	= (Forward reach + reverse reach) /(2 · tan(45)) = (1.2693 + 2.2264) /2 · 1 = 1.74			

Table 236 shows recommended setting values; all other settings of OOSRPSB1 are kept at default values for this example case.

Table 236: Function settings for OOSRPSB1

Setting	Recommended values	Description
Forward reach	1.27 ohm	Forward reach of mho circle
Reverse reach	2.23 ohm	Reverse reach of mho circle
Inner blinder R	1.01 ohm	Resistance value if inner blinder at R axis
Outer blinder R	1.74 ohm	Resistance value of outer blinder at R axis
Impedance angle	87.13 deg	Angle between mho circle and blinders and R axis
Zone 1 reach	61.01 %	Percentage of Mho forward reach indicating the end of zone 1 and the beginning of zone 2
Swing time	30 ms	Time between blinders for swing to be detected (according to blinder setting, this corresponds to 2.77 Hz)

Table continues on next page

Setting	Recommended values	Description
Max number slips	1	Number of pole slips before operating zone 1
Zone 2 enable	Yes	Enable zone 2 feature
Max Num slips Zn2	4	Number of pole slips before operating zone 2
Breaker open time	50 ms	Opening time of the breaker

OEPVPH1 – Overexcitation protection

Overvoltage, under frequency or a combination of the two, results in an excessive flux density level. If the laminated core of the 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. Since the flux density is directly proportional to the voltage and inversely proportional to the frequency, OEPVPH1 calculates the relative V/Hz ratio instead of measuring the flux density directly.

Table 237 shows recommended setting values; all other settings are kept at default values for this example case.

Table 237: Function settings whose values differ from the default values based on the example

Setting	Recommended values	Description
Start value	105 %	The nominal level (nominal voltage at nominal frequency) is usually considered as the 100% level, which can be slightly exceeded based on the design. In this example, 105% is used.
Operating curve type	IEC Def. Time	Selection of time delay curve type. If the V/Hz capability of the generator is available, see the technical manual for other curve settings.
Operate delay time	5000 ms	Excitation system response (field forcing); typically varies between 1...10 s. In this example, 5 s is used.
Leakage React	16 %	Leakage reactance (% at 12.5 MVA)
Voltage Max Cont	100 %	Usually the U/f characteristics are specified so that the ratio is 1.00 at the nominal voltage and the nominal frequency, therefore the value 100% for setting Volt Max continuous is recommended.

MNSPTOC1 – Negative-sequence overcurrent protection

If the generator is connected to unbalance load or delivers unbalance load, negative phase sequence currents flow through the stator windings, which induces negative sequence voltage in the rotor windings. The frequency of the induced current is approximately twice the supply frequency. Due to the 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 a value less than the rated current of the generator. This excessive heating can damage the rotor winding insulation.

MNSPTOC1 protects synchronous generators from phase unbalance. Table 238 shows recommended setting values; all other settings are kept at default values for this example case.

Table 238: Function settings whose values differ from the default values based on the example

Setting	Recommended values	Description
Start value	0.08 xIn[1)]	The continuous unbalance load carrying capacity of generator should be considered. Here it is considered 10% of the rated generator current.
Operating curve type	IEC Def. Time	Selection of time delay curve type. If unbalance capability, that is, $I^2_2 \cdot t$ capability of generator is available, see the technical manual for other curve settings.
Operate delay time	1000 ms	Operate delay time

1) *Start value* = 10% · rated current /CT primary
= 0.1 · 656/800
= 0.082

MREFPTOC1 – Rotor earth-fault protection (injection method)

The rotor circuit of a synchronous generator is normally isolated from the earth. The rotor circuit can be exposed to an abnormal mechanical or thermal stress due to, for example, vibrations, overcurrent and choked cooling medium flow. This can result in the breakdown of the insulation between the field winding and the rotor iron at the point exposed to excessive stress.

In generators with slip rings, the rotor insulation resistance is sometimes reduced due to the accumulated carbon dust layer produced by the carbon brushes.

As the circuit has a high impedance to earth, a single earth fault does not lead to any immediate damage because the fault current is small due to a low voltage. However, there is a risk that a second earth fault appears, creating a rotor winding inter-turn fault and causing severe magnetic imbalance and heavy rotor vibrations that soon lead to a severe damage.

Therefore, when an insulation failure is detected, the machine must be disconnected as soon as possible. It is recommended that the alarm and operate stages of MREFPTOC1 are both used: the alarm stage for giving an indication for weakly developed earth faults and operate stage for a protection against fully developed earth faults. Normally, the equipment is tripped after a short time delay.

The injection device REK 510 sets up a 100 VAC secondary voltage via its coupling capacitors (C1, C2) to the rotor circuit towards earth as shown in Figure 104. C_E and R_E correspond to rotor earthing capacitance and rotor fault resistance.

In the example synchronous generator, the excitation field winding is connected with brushes.

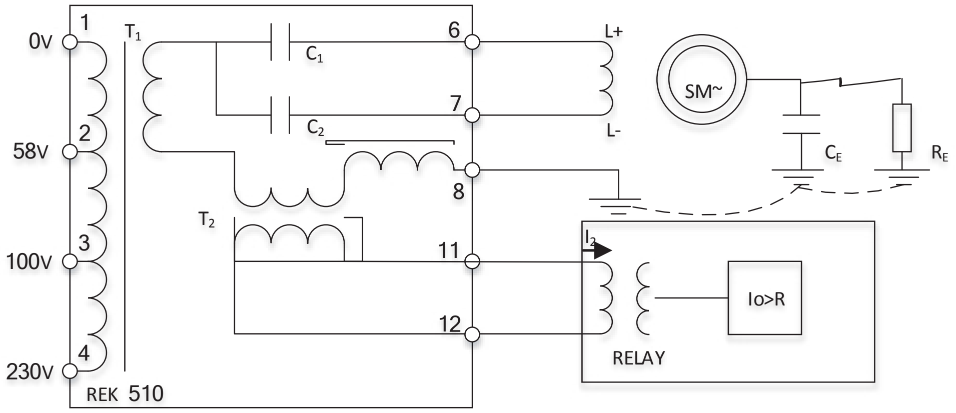

Figure 104: Principle of rotor earth-fault protection with current injection device

Setting values cannot be calculated beforehand. Instead, values are defined during the commissioning test phase. See the technical manual for more information. Table 239 is prepared for calculating the setting values. Alarm start value should correspond to 10 kohm and operate start value should correspond to 2 kohm.

Table 239: Simulating resistor (R_E) vs monitor injected current I_2

R_E (kohm)	I_2
2	0.4
10	0.19

Table 240 shows recommended setting values; all other settings are kept at default values for this example case.

Table 240: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Alarm start value	0.40 pu	Alarm start value
Operate start value	0.19 pu	Operate start value

PHPTOV1 – Three-phase overvoltage protection

Load reduction on the connected generator or disconnection of the generator from the power grid can lead to excessive voltage rise on the generator terminal. Under normal conditions, automatic voltage regulator (AVR) controls the generator terminal voltage and brings back the generator terminal voltage to normal operating conditions but in case of faulty (fully or sluggish response) AVR, this excessive voltage can have a negative impact on the generator or the connected equipment insulation.

PHPTOV1 protects synchronous generators from overvoltage. Table 241 shows recommended setting values; all other settings are kept at default values for this example case.

Table 241: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Start value	1.20xUn	The continuous overvoltage capacity of the generator should be considered. Here it is considered 120% of the rated generator terminal voltage.
Operate delay time	1000 ms	The setting should consider the AVR response time and should be set so that in normal operation no unwanted tripping of the generator circuit breaker occurs. For the example case, 1000 ms is used.

PHPTUV1 – Three-phase undervoltage protection

Excessive reactive power consumption (in case of excessive running inductive load, starting of large induction motors or under fault condition) can lead to a reduction of the generator terminal voltage. Undervoltage can also occur due to faulty AVR operation. This undervoltage does not have a negative impact on the generator, but the connected equipment (motor) draws more current for the same connected load which can lead to thermal heating of respective loads. In general, motor protection is equipped with undervoltage tripping. Hence undervoltage protection is considered here as backup protection.

PHPTUV1 protects synchronous generators from undervoltage. Table 242 shows recommended setting values; all other settings are kept at default values for this example case

Table 242: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Start value	0.80xUn	Start value
Operate delay time	1000 ms	The setting should consider the AVR response time and the largest motor starting time. Tripping of generator should also consider the availability of shunt capacitor and its automatic operations. For the example case, 1.0 s is used.

FRPFRQ – Frequency protection

The system frequency stability is one of the main principles in the distribution and transmission network. To protect all frequency-sensitive electrical apparatus in the network, the deviation from the allowed band for safe operation should be inhibited.

Underfrequency may occur from system overload, either loss of generation in island network or loss of tie lines importing power. Underfrequency may also occur if there is no sufficient thermal power (steam) for the connected load in island condition. As frequency reduces, the ventilation capability of the generator also reduces, which makes the generator's stator or rotor winding and core temperature increase for the same load. Due to the reduced frequency, flux density (V/Hz) increases which accelerates core losses.

Overfrequency may occur from system load rejection, either loss of load in island network or loss of tie lines' exporting power. Overfrequency (that is, speed) beyond the rated value can lead to mechanical stress on the turbine.

FRPFRQ1 is configured for underfrequency and FRPFRQ2 is configured for overfrequency to isolate the generator from the rest of the power system. Table 243 and Table 244 show recommended setting values; all other settings of are kept at default values for this example case.

Table 243: Function parameters for FRPFRQ1 as underfrequency protection

Setting	Recommended values	Description
Operation mode	Freq<	Enables underfrequency protection
Start value Freq<	0.9500 xFn	95...105% allowable band for frequency operation is used in the example case.

Table 244: Function parameters for FRPFRQ2 as overfrequency protection

Setting	Recommended values	Description
Operation mode	Freq>	Enables overfrequency protection
Start value Freq>	1.0500 xFn	95...105% allowable band for frequency operation is used in the example case.

T2PTTR1 - Three-phase thermal overload protection, two time constants

The synchronous generator is designed for a specific rated maximum capacity. If the load increases beyond this level, losses in generator stator also increase beyond the design value. This in turn increases the generator stator core / winding temperature beyond the safe design limit. This excessive temperature rise can adversely affect the insulation's withstand capability. The weak spots that can appear increase the risk of phase-to-phase or phase-to-earth faults. T2PTTR protects the generator mainly from short-time overloads. The alarm signal from T2PTTR gives an early warning to allow the operators to take action before the generator trips. If the temperature rise continues, the `OPERATE` output is activated depending on the thermal model of the generator. Once tripped, the generator can be re-energized only after the generator cooling time has elapsed.

T2PTTR takes three phase current measurements and the ambient temperature information (provided as an RTD input). Table 245 shows recommended setting values; all other settings are kept at default values for this example case.

Table 245: Function settings whose values differ from default values based on the example case

Setting	Suggested values	Description
Short time constant	168 s[1)]	Short time constant in seconds
Long time constant	2700 s[1)]	Long time constant in seconds
Current reference	0.82 xI_n[2)]	The load current leading to Temperature raise temperature

1) Available from the manufacturer’s datasheet. If the manufacturer gives a single time constant, see the technical manual to get the corresponding short and long time constant values.
2) *Current reference* = Generator rated current / CT primary
= 656 /800
= $0.82 \cdot I_n$

Thermal overload protection

Stator temperature measurement based thermal overload protection is the main protection against generator thermal overload. Direct sensing of the stator temperature provides the protection against the conditions not sensed by overcurrent protection such as reduced ventilation. Six RTDs (two per phase) are used in the example case.

Table 246 shows recommended setting values; all other settings are kept at default values for this example case.

Table 246: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Input mode	Pt100	Pt 100 type RTD considered for the example case
Value unit	Degrees celsius	Selected unit for output value format
Value minimum	15°C	Minimum output value for scaling and supervision
Value maximum	180°C	Maximum output value for scaling and supervision
Val high high limit	115°C[1)]	Recorded maximum temperature at heat run test of the generator (at ambient 40°C); 110°C in the example case.
Value high limit	110°C	

1) *Value high limit* = Highest recorded temperature at generator heat run test
= 110
= 110°C
Val high high limit = *Value high limit* + 5°C
= 115°C

Multipurpose protection MAPGAPC1 is configured for tripping the generator circuit breaker. Table 247 shows recommended setting values; all other settings are kept at default values for this example case.

Table 247: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Start value	120	Recorded maximum temperature at heat run test of the generator + 10°C consider tripping
Operate delay time	1000 ms	Operate delay for alarm and operate

PHLPTOC1 – Three-phase non-directional overcurrent protection, low stage

Primary thermal overload protection is provided by monitoring RTD directly or by T2PTTR1. If the primary protection fails, backup protection is provided to protect the generator from thermal overload. PHLPTOC1 provides the backup protection in the example case.

Table 248 shows recommended setting values; all other settings are kept at default values for this example case.

Table 248: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Start value	0.90 x In[1)]	110% of full load current
Operating curve type	IEC Ext. inv.	See the generator stator thermal withstand capability. Here it is considered 7 s at 225% of full load current or more.

1) *Start value* = 1.1 · Rated current /CT primary
= 1.1 · 656/800
= 0.90

UZPDIS1 – Three-phase underimpedance protection

UZPDIS1 is used as backup protection against short circuit faults at generator terminals. The function protects the zone between the generator windings and the generator side windings of the step-up transformer, mainly the generator bus, the low-voltage part of the step-up transformer and a part of the stator winding.

Table 249 shows recommended setting values; all other settings are kept at default values for this example case.

Table 249: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Polar reach	10%Zn[1)]	Approximately 80% of transformer short circuit impedance
Operate delay time	1000 ms	Sufficient time delay should be provided to operate the main function. Here 1 s is used.

1) Transformer short circuit impedance at 11 kV
Z_{Tx} = $X_{\_TX}$ · Rated voltage · Rated voltage/ Rated power of transformer
= 0.1 · 11 · 11/ 12.5
= 0.968

Reach = 80% of Z_{Tx} · CT primary · √3 · 100/ VT primary
= 0.8 · 0.968 · 800 · √3 · 100/11 · 1000
= 9.76

In directly connected machines where the impedance towards the network is limited, it is recommended to use the three-phase voltage-dependent overcurrent protection PHPVOC instead of the three-phase underimpedance protection UZPDIS1.

Dead machine protection

If the generator circuit breaker closes and the field excitation is off, the generator starts to behave as an induction motor. The long acceleration time maximizes the thermal stress on the generator.

Hence closing of generator circuit breaker at standstill or low speed can lead to fatal failures of generator or other equipment (for example, oil lubricated bearings or the turbine).

A dead machine protection scheme can be configured using PHIPTOC1 and PHPTUV2.

Table 251 and Table 252 show recommended setting values; all other settings are kept at default values for this example case.

Table 250: Steps for calculating the accidental energization current for the example case

	Generator	Step-up transformer	System
Reactance calculation (pu)	Negative phase sequence reactance X_2 = 0.15	$X_{\_Tx}$ = 0.10	X_{sys} = =0.10 (considered in the example case)
Total reactance calculation	$X_{total} = X_2 + X_{\_Tx} + X_{sys}$ = 0.15 + 0.1 + 0.1 = 0.35		
Accidental energization current (pu)	= 1/ X_{total} = 1/0.35 = 2.86		
Accidental energization current (amp)	I_{AEC}= Rated current · Accidental energization current (pu) = 656 · 2.86 = 1876.16 amp		

Table 251: Function settings for PHIPTOC1 for dead machine protection

Setting	Recommended values	Description
Start value[1)]	1.03 x In	It should be set as 50 % of I_{AEC} and should be less than 1.25 of the rated current.
Operate delay time	1000 ms	The setting should consider the AVR response time and should be set so that in normal operation no unwanted tripping happens. For the example case, 1000 ms is used.

1) *Start value* = Minimum (1.25 · Rated current, 0.5 · I_{AEC})/CT Primary
= Minimum (1.25 · 656, 0.5 · 1876.16)/800
=1.25 · 656/800
= 1.025

Table 252: Function settings for PHPTUV2 for dead machine protection

Setting	Recommended values	Description
Start value	0.50xUn	50 % of nominal voltage
Operate delay time	5000 ms	It should be more than the system's fault clearing time. For the example case, 5 s is used.
Type of reset curve	Def time reset	
Reset delay time	500 ms	It should be more than the response time of PHIPTOC1, `START` output.

Turbine-generator protection during start-up

Starting of the turbine-generator set consists of three steps for steam turbine as a prime mover.

1. The turbine starts to roll while the excitation and generator circuit breaker are off. As the speed of prime mover increases, terminal voltage also increases due to remanence magnetization. At 90...95% of rated speed this value can be 10...15% of rated voltage (depends on the generator design).
2. Once the turbine speed reaches 90...95%, field excitation turns on while the generator circuit breaker remains off.
3. The voltage builds up and the generator circuit breaker turns on (that is, the turbine-generator is synchronized with the rest of the power system in case of parallel operation).

While the excitation and generator circuit breaker are off, the prime mover (in the example case, steam turbine) is protected primarily by mechanical protection which includes, for example, shaft vibration, axial vibration and bearing temperature.

As soon as the excitation circuit breaker is on (in the example case, 90% of speed) in step 2 generator is subjected to fault, hence it is very important that:

- The generator protection must be available in step 2 and
- Protection functions must not malfunction at reduced frequency

Protection functions are designed for maximum sensitivity at nominal frequency, hence to overcome the reduced sensitivity at reduced frequency (90% in the example case at step 2), the setting configuration /Configuration/System/Control/ Frequency adaptivity should be "Enable".

PHHPTOC1 – Three-phase non-directional overcurrent protection, high stage

As in step 2, the generator circuit breaker is off and the voltage is 10...100% of the rated voltage hence the fault current can be as low as 10%. PHHPTOC1 can be configured only for step 2. Table 253 shows recommended setting values; all other settings are kept at default values for this example case.

Table 253: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Start value	0.71xIn[1)]	20% of short circuit current at rated voltage
Start value Mult	2.2[2)]	50% of short circuit current at rated voltage in pu

1) *Start value* = 0.2 · (1/ X'_d) · Rated current /CT primary
= 0.2 · (1/0.23) · 656/800
= 0.71

2) *Start value Mult* = 0.5 · (1/ X'_d)
= 0.5 · 1/0.23
= 2.2

Once the CB is closed, the start value should change to short circuit current at rated voltage or should be blocked. In the example case, the start value is changed.

INRPHAR1 – Three-phase inrush detector

The magnetizing inrush occurs during energizing of the transformer (connected to the generator or in the same network) or when the transformer voltage is normalized after a reduction in voltage due to a short circuit in the system. The inrush current can be many times the rated current and can last for several seconds. This increase in inrush current can lead to the malfunction of the connected generator's protection scheme operating on current signal. INRPHAR1 can be used to block this protection scheme.

All settings of INRPHAR are kept at default values for this example case.

CCBRBRF1 - Circuit breaker failure protection

The n-1 criterion is often used in the design of a fault clearance system. This means that the fault is cleared even if a component in the fault clearance system is faulty.

A circuit breaker is a necessary and critical component in the fault clearance system. For practical and economic reasons, it is not feasible to duplicate the circuit breaker for the protected component, but breaker failure protection is used instead.

CCBRBRF issues a backup trip command to the upstream circuit breakers (in a grid-connected system) and to the circuit breakers of all the sources (generator operating in parallel) if the original circuit breaker fails to trip for the protected component.

Table 254 shows recommended setting values; all other settings of are kept at default values for this example case.

Table 254: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Current value	0.25xIn[1)]	30% of rated current
Current value Res	0.06xIn[2)]	10% of secondary current in neutral of generator at line-to-earth fault
CB failure delay	100 ms[3)]	In the example case, the maximum CB open time is 60 ms. 20 ms is needed for the function to detect the correct breaker function and 20 ms is considered as safety margin.

1) *Current value* = 0.3 · Rated current/CT Primary
= 0.3 · 656/800
= 0.25
2) *Current value Res* = 10% of Secondary current (at NGT) /CT primary
= 0.1 · 127 /200
=0.06
3) *CB failure delay* = maximum circuit breaker open time + safety margin + 20
= 60 + 20 + 20

= 100

TRPPTRC1 - Master trip

TRPPTRC is used as a trip command collector and handler after the protection functions. All settings of TRPPTRC are kept at default values for this example case.

SEQSPVC1 – Fuse failure supervision

Few protection functions operate on the basis of the measured voltage value in the relay measuring point. These functions can malfunction if there is a fault in the measuring circuits between the voltage transformer and the protection relay.

A fault in the voltage-measuring circuit is supervised by SEQSPVC1. A fast fuse failure detection is one of the means to block voltage-based functions before they operate.

Table 255 shows recommended setting values; all other settings can be kept at default values.

Table 255: Function settings whose values differ from default values based on the example

Setting	Recommended values	Description
Neg Seq current Lev	0.09xIn 1)	Maximum negative sequence current during normal operation is 10% and a safety factor of 10% is used here.
Neg Seq voltage Lev	0.06xUn 2)	Maximum negative sequence voltage during normal operation is 5% and a safety factor of 20% is used here.
Change rate enable	TRUE	
Enable seal in	TRUE	

1) *Neg Seq current Lev* = 10% · safety factor · rated current /CT primary
= 0.10 · 1.1 · 656/800
= 0.09

2) *Neg Seq voltage Lev* = 5% · safety factor · rated voltage (ph-ph) /VT primary (ph-ph)
= 0.05 · 1.2 · 11000/11000
= 0.06

Section 10 Asynchronous motor protection

10.1 Introduction to application

Electric motors are exposed to many kinds of disturbances and stress. Part of the disturbances are due to imposed external conditions such as over- and undervoltage, over- and underfrequency, harmonics, unbalanced system voltages and supply interruptions such as auto-reclosing that occurs in the supplying network. Other causes of external disturbances are dirt in the motor, cooling system and bearing failures or an increase of ambient temperature and humidity. Stress factors due to abnormal use of the motor drive are frequent successive start-ups, stall and overload situations including mechanical stress. The stress and disturbances mechanically deteriorate the winding insulation of the motor and increase the thermal ageing rate, which may lead to an insulation failure.

The purpose of the motor protection is to limit the effects of the disturbances and stress factors to a safe level, for example, by limiting overloading or by preventing too frequent start-up attempts. If, however, a motor failure takes place, the purpose of the protection is to disconnect the motor from the supplying network in due time.

Table 256: Typical faults and conditions, protection functions and devices

Faults and conditions	Protection functions and devices
Stator short circuit and earth fault	Three-phase non-directional overcurrent protection PHxPTOC, Non-directional earth-fault protection EFxPTOC, Directional earth-fault protection DEFxPDEF, High-impedance based restricted earth-fault protection HREFPDIF, Stabilized and instantaneous differential protection for machines MPDIF, High-impedance or flux-balance based differential protection MHZPDIF, fuses
Inter-winding short circuits	Stabilized and instantaneous differential protection for machines MPDIF, High-impedance or flux-balance based differential protection MHZPDIF
Overloading	Thermal overload protection for motors MPTTR, RTD sensors
Inadequate ventilation, reduced cooling, unusual ambient conditions	RTD sensors
Locked rotor, failure to accelerate	Motor start-up supervision STTPMSU
Stalling (jamming) of a running motor	Motor load jam protection JAMPTOC
Prolonged starting	Motor start-up supervision STTPMSU
Too frequent starting	Motor start counter MSCPMRI, Motor start-up supervision STTPMSU

Table continues on next page

Faults and conditions	Protection functions and devices
Network unbalance, single phasing	Negative-sequence overcurrent protection for machines MNSPTOC, Negative-sequence overvoltage protection NSPTOV
Phase reversal, incorrect rotation direction	Phase reversal protection PREVPTOC
Under/overvoltage	Three-phase undervoltage protection PHPTUV, Positive-sequence undervoltage protection PSPTUV, Three-phase overvoltage protection PHPTOV
Frequency	Frequency protection FRPFRQ
Loss of load	Loss of load supervision LOFLPTUC
Emergency starting	Emergency start-up ESMGAPC

10.2 Description of the example case

In this example case, a 3900 kW, 10.7 kV asynchronous motor driving a compressor is protected. Motor parameters are shown in Table 257, and the single-line diagram in Figure 105.

Table 257: Motor data

Motor parameter	Value
Rated output	3900 kW
Voltage	11 kV ±5%
Current	246 A
Duty type	S1 (Continuous running duty)
Method of cooling	IC 81W, cooling water temp 22°C
Ambient temperature, max	40°C
Insulation or temperature rise	Class F / B
Starting current	5.6 · rated current
Starting time	3.9 s (U = 100%), 9.1 s (U = 80%)
Maximum stalling time	5 s (warm)
Number of consecutive starts	3 / 2 (cold/warm)
Warm-up and cool-down time constants	25 min and 150 min
Altitude, max.	1000 meters above sea level

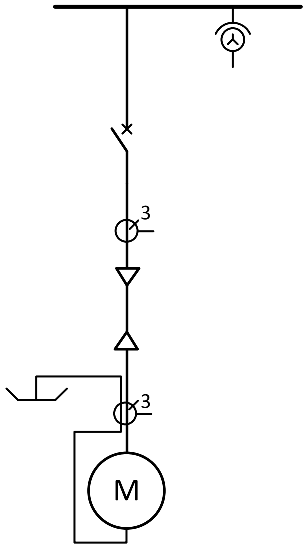

Figure 105: Single-line diagram

The motor is equipped with phase CTs 300/5 A and self-balanced CTs 50/1 A. In addition, the protection receives voltage measurement from the bus.

10.3 Motor protection relay

This chapter provides detailed information about the configuration of the relay used in this application example: the relay interfaces, the recommended alarms, the ACT diagram and the parameter settings.

10.3.1 Relay interface, configuration and settings

Figure 106 presents the connection details of the relay's analog inputs (AI), binary inputs (BI) and binary outputs (BO).

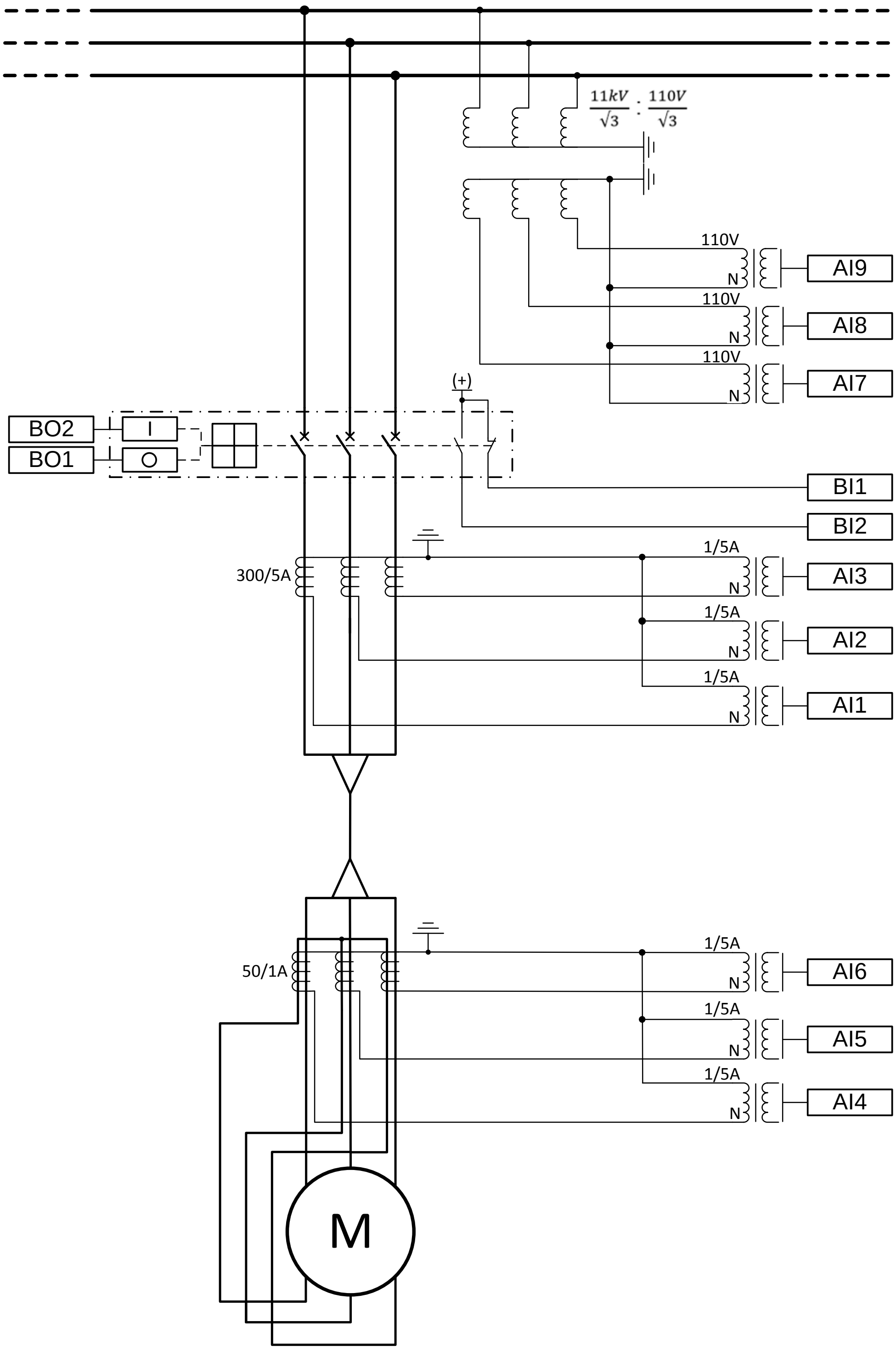

Figure 106: Relay interfaces and CT/VT connections for the example case

10.3.1.1 Analog input signals

Table 258: Physical analog input signals

Analog input	Description
AI1	Phase current measurement, phase I_A
AI2	Phase current measurement, phase I_B
AI3	Phase current measurement, phase I_C
AI4	Differential current measurement, phase I_A
AI5	Differential current measurement, phase I_B
AI6	Differential current measurement, phase I_C
AI7	Phase-to-earth voltage U_A
AI8	Phase-to-earth voltage U_B
AI9	Phase-to-earth voltage U_C

10.3.1.2 Binary input signals

Table 259: Physical binary input signals

Binary input	Description
BI1	Breaker position open signal
BI2	Breaker position close signal

10.3.1.3 Binary output signals

Table 260: Physical output signals

Binary output	Description
BO1	Trip signal for opening the breaker
BO2	Breaker closing signal, that is, motor starting

10.3.1.4 Recommended alarms

Table 261 presents a proposal for LHMI and WHMI alarm handling. The table lists the functions, and events under the functions, which should be tagged as alarms using Event Filtering in PCM600.

Table 261: Alarm list for implementing the application example

Event container	Event	Description
PHIPTOC1	OPERATE	Trip from short circuit protection
STTPMSU1	OPR_IIT	Trip from start-up protection
JAMPTOC1	OPERATE	Trip from jam protection
MPTTR1	OPERATE	Trip from thermal overload protection

Table continues on next page

Event container	Event	Description
MSCPMRI1	OPERATE	Trip from start counter
MNSPTOC1	OPERATE	Trip from unbalance protection
PREVPTOC1	OPERATE	Trip from phase sequence protection
DEFLPDEF1	OPERATE	Trip from earth-fault protection
PHPTUV1	OPERATE	Trip from undervoltage protection
PHPTOV1	OPERATE	Trip from overvoltage protection
MPDIF1	OPERATE	Trip from differential protection
OR6	Q	Restart inhibited

10.3.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600. The relay configuration for the example case is presented in Figure 107, Figure 108 and Figure 109.

All protection function operate signals are used for tripping. In STTPMSU1, the operate outputs `OPR_IIT` and `OPR_STALL` are recommended to be connected for tripping although in this example case `OPR_STALL` is not used.

Motor starting, that is, closing of the breaker via CBXCBR1, is allowed only if there is no protection function inhibiting starting.

- MPTTR1: motor thermal capacity is too high for start
- MSCPMRI1: motor started too frequently
- STTPMSU1: too short time from the latest start
- MNSPTOC1: insufficient cooling after unbalance trip

In such a case, some time is needed for the motor to cool down before starting is allowed.

Table 262: Function blocks used in the relay configuration

Function block	Description
ILTCTR1, ILTCTR2, UTVTR1	Analog signal preprocessing for protection functions
Protection	Provides GRPOFF signal
CBXCBR1	Circuit breaker control
TRPPTRC1	Master trip
PHIPTOC1	Three-phase non-directional overcurrent protection
MPTTR1	Thermal overload protection
JAMPTOC1	Motor load jam protection
STTPMSU1	Motor start-up supervision
Table continues on next page	

Function block	Description
MSCPMRI1	Motor start counter
MNSPTOC1	Negative-sequence overcurrent protection
PREVPTOC1	Phase reversal protection
MHZPDIF1	High-impedance or flux-balance based differential protection
PHPTUV1	Three-phase undervoltage protection
PHPTOV1	Three-phase overvoltage protection
DEFLPDEF1	Directional earth-fault protection, low stage
OR OR6 OR20	OR gate with two inputs OR gate with six inputs OR gate with twenty inputs
SR	SR flip-flop, volatile

Table 263: Physical analog channels of functions

Protection	Phase currents AI1, AI2, AI3	Differential currents AI4, AI5, AI6	Phase-to-earth voltages AI7, AI8, AI9
MPTTR1	x		
PHIPTOC1	x		
MSCPMRI1			
STTPMSU1	x		
MNSPTOC1	x		
PREVPTOC1	x		
MHZPDIF1		x	
JAMPTOC1	x		
PHPTOV1			x
PHPTUV1			x
DEFLPDEF1	x (calculated Io)		x (calculated Uo)

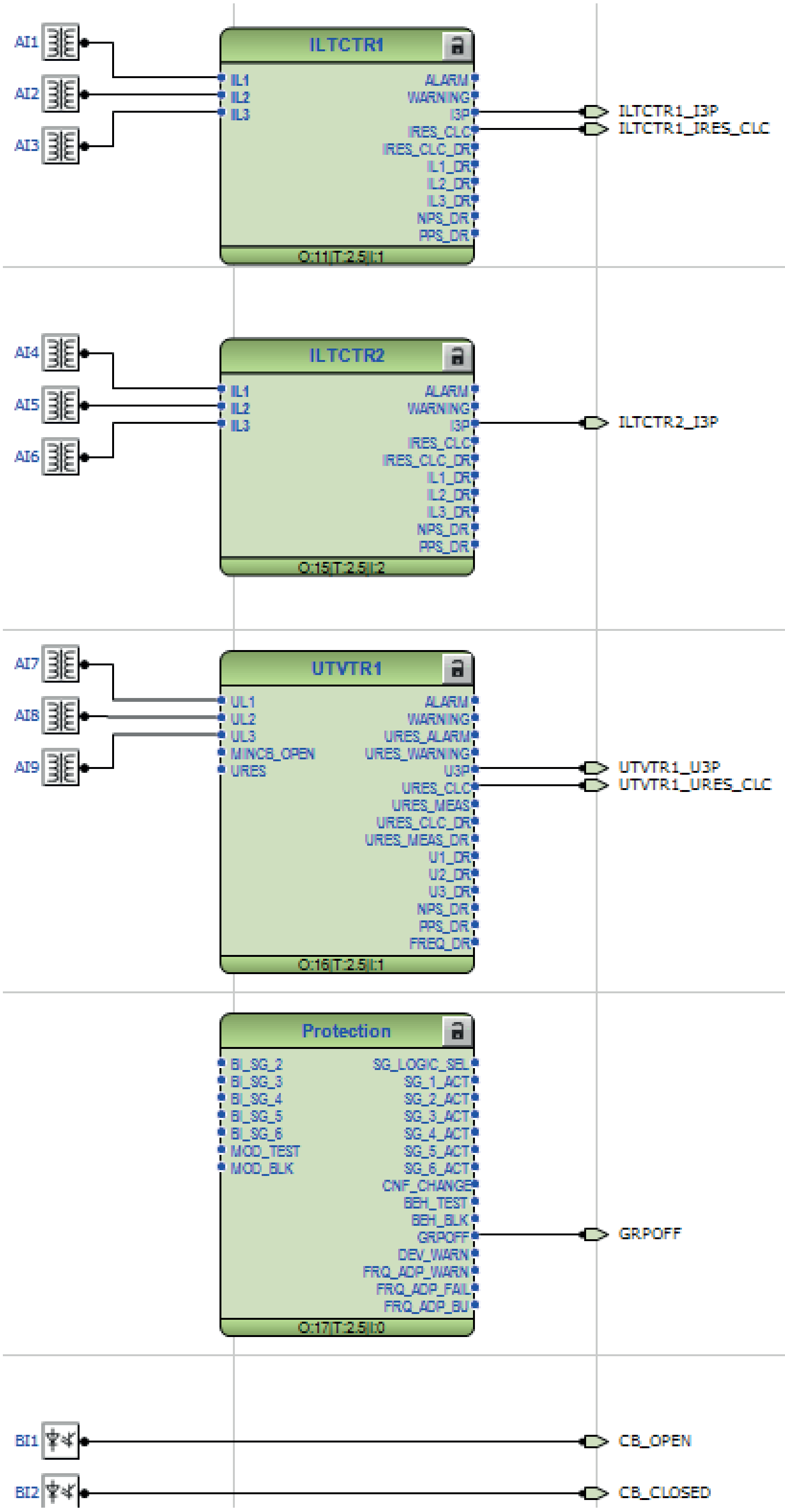

Figure 107: Input section

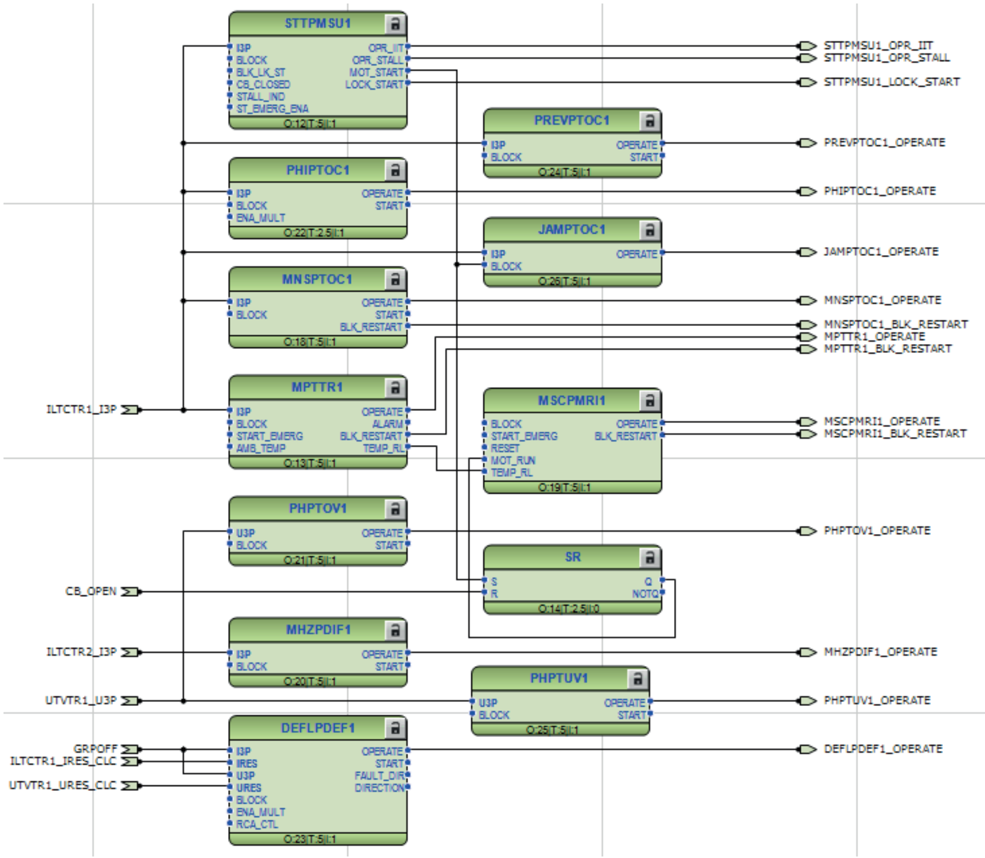

Figure 108: Application section

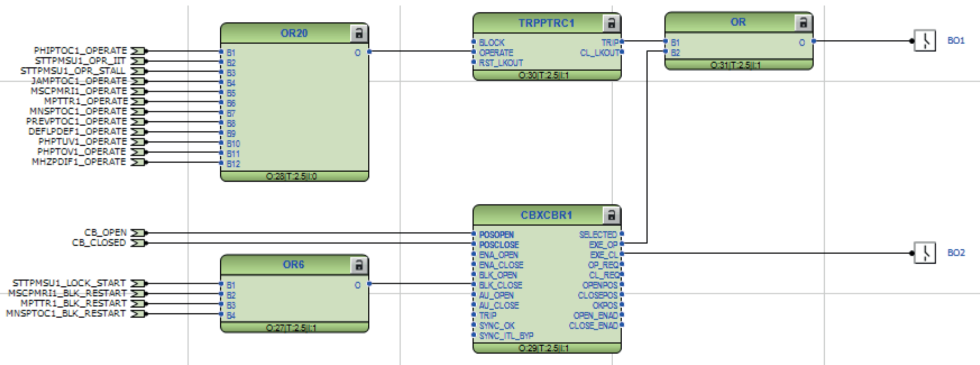

Figure 109: Output section

10.3.1.6 Function blocks and setting values

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function block; ILTCTR1 is used for phase currents while ILTCTR2 is used for the differential current signal. Table 264 shows recommended setting values; all other settings can be kept at default values.

Table 264: ILTCTR settings for the relay in the example case

Setting	Suggested values		Description
	ILTCTR1	ILTCTR2	
Primary current	300 A	50 A	Primary current value
Secondary current	5 A	1 A	Secondary current value

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application. Table 265 and Table 266 show the function settings for the example case.

Table 265: UTVTR1: Phase voltage transformer function settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	11 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

Table 266: UTVTR1: Residual voltage transformer function settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	6.35 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

MPTTR1 – Thermal overload protection for motors

Motor overload is mainly a result of abnormal use of the motor, unbalanced supply voltages or harmonics. All these increase motor losses thus causing additional heating. Should the motor temperature exceed the rated limits specified for the insulation class, the winding insulation deterioration accelerates, that is, the motor lifetime shortens. As a rule of thumb, each 8...12°C temperature increase halves the life-time. Too high or frequent overloading may also lead to an electrical fault in the winding or damage in the rotor.

Therefore, the thermal overload protection is the most important protection in addition to the short circuit protection of the motor. Usually also authorities require the motors to be equipped with thermal overload protection.

MPTTR1 calculates the motor thermal capacity based on the phase current measurement. The true RMS value of the current is measured in order to take into account also the harmonics. MPTTR1 protects against any kind of thermal overload except reduced cooling, which requires RTD sensors to monitor the winding temperature.

Finding suitable settings for MPTTR1 can be done in three steps: first, *Overload factor* is decided, then *Weighting factor* and time constants, and finally the rest of the settings.

Step 1:

The *Overload factor* setting defines the maximum continuously allowed load. The motor in this example case has class B (80°C) thermal rise and class F insulation (max. temperature 155°C). When used in the designed 40°C ambient temperature, this motor reaches the maximum value of 155°C if the load current is √[(155 - 40)/80] = 1.198 times the motor rated load or higher. This is the maximum value for the *Overload factor* setting. However, typically a smaller value like 1.05 is used in MPTTR.

Step 2:

The thermal behavior of the stator and the rotor during start-ups and longtime overload situations differs significantly from each other. In MPTTR1, if *Weighting factor* = "50%", both the motor “hot spot” behavior and the thermal background are modelled. In case of an overload or start-up, MPTTR1 follows the thermal behavior of the hottest spots (typically rotor), while taking 50% of that thermal rise to the background (motor body). After overloading, it is assumed that the heat of the hot spots is quickly transferred to the surrounding material (motor body), hence MPTTR1 quickly drops the hot spot thermal level to the background thermal level.

A general recommendation is that, by default, *Weighting factor* = "50%", and *Overload factor* = "1.05". This also means that approximately half of the thermal capacity of the motor is used when the motor runs with full load, that is, the motor has capacity for warm re-start without any cooling time.

There are various methods to find settings for the time constants. In this example case, the motor thermal limit curves are available and the MPTTR1 *Time constant normal* is set accordingly, that is, protection curves are equal or below the running motor thermal limit curves. Thermal overload protection curves do not need to be equal or below the locked rotor thermal limit curves as the relay has a dedicated protection function for this.

Using the warm-up time constant, given by the motor manufacturer, for the protection is not recommended as it typically results in insufficient thermal protection. This is because the warm-up time constant mainly represents the stator at motor normal operation, and thus fails to take into account material safety limits, for example, in other parts of the motor during overloading. The motor cooldown time constant, however, can be used as a good starting point for the MPTTR1 *Time constant stop* setting.

Time constant start is most typically set to be equal to *Time constant normal*.

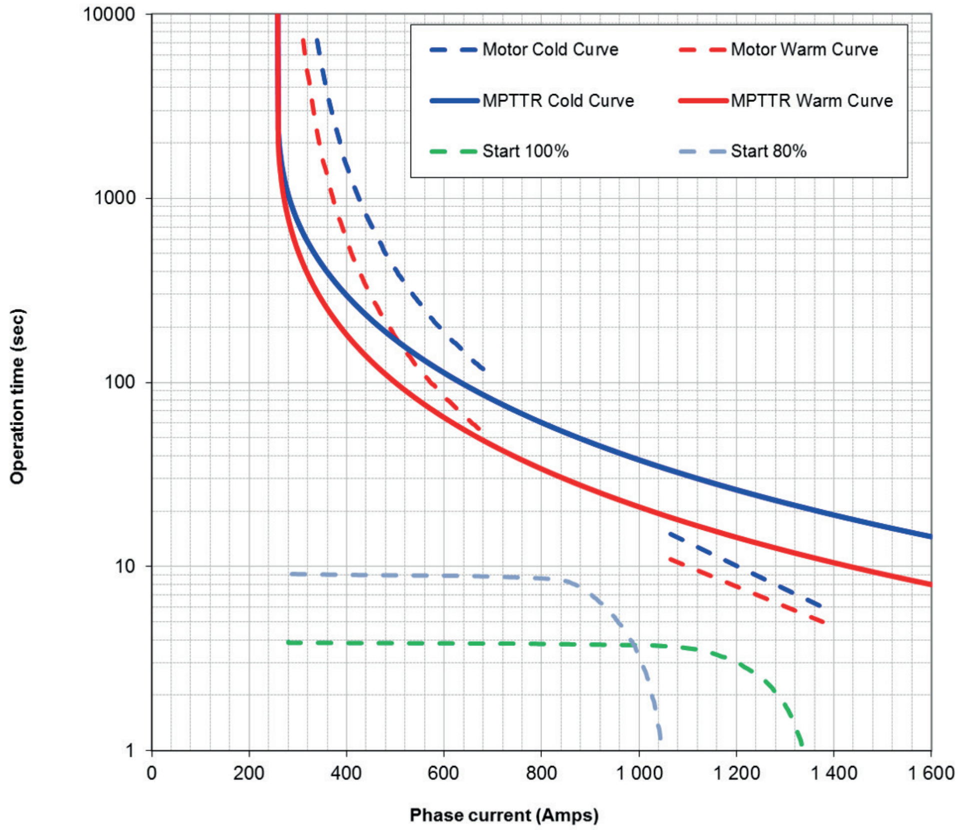

Figure 110: Motor thermal limit, time-current and thermal overload protection curves

Step 3:

To take into account the excess heating caused by unbalance, the MPTTR1 setting *Negative Seq factor* can be used.

The *Restart thermal Val* setting is used to prevent motor restarting until the motor has enough thermal capacity for starting. The setting value can be calculated as

$$Restart\ thermal\ Val = 95\% - \frac{start\text{-}up\ time}{Cold\ motor\ trip\ time\ at\ start\text{-}up\ current} \cdot 100\%$$

(Equation 5)

In this example case, the start-up time at the rated voltage is 3.9 sec, and the MPTTR1 trip time at the start-up current is about 20 sec (Figure 110). This gives 95% - (3.9/20) · 100% = 75%. Start-up at 80% of the rated voltage takes 9.1 sec and the trip time is 33.3 sec, giving 95% - (9.1/33.3) · 100% = 66.7%.

It is recommended to check that MPTTR1 allows the required number of warm starts. *Restart thermal Val* together with *Time constant stop* can be chosen accordingly to limit how fast the next starting can be allowed. In this example case, *Restart thermal Val* is set to 56%.

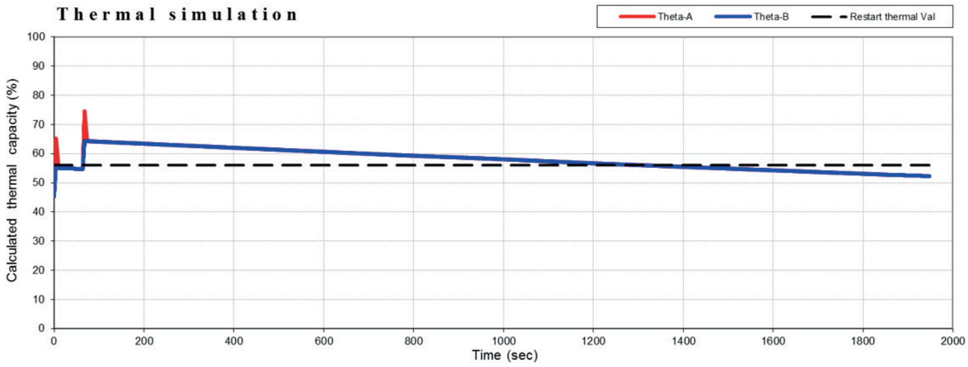

Figure 111: Simulation of two warm starts at rated voltage with recommended settings

Table 267: MPTTR1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Overload factor	1.05	Allowed continuous overload
Restart thermal Val	56 %	Thermal level for inhibiting motor restarting
Negative Seq factor	5.6[1)]	Heating effect factor for unbalance
Weighting factor p	50 %	Weighting factor for thermal modelling
Time constant normal	550 sec	Time constant during motor normal operation and light overloading
Time constant start	550 sec	Time constant during the motor start
Time constant stop	9000 sec[2)]	Time constant during the motor standstill
Current reference	0.82 xIn[3)]	Motor full load current

1) $175 / (I_{start-up} / I_{rated})^2 = 175 / 5.6^2 = 5.58$
2) Same as motor cooldown time constant (150 min)
3) Motor rated / CT rated = 246 A / 300 A = 0.82 xIn

PHIPTOC1 – Three-phase non-directional overcurrent protection, instantaneous stage

PHIPTOC1 is used to give protection against short circuits in the motor or feeder cable. For PHIPTOC1, which uses a peak-to-peak measuring function, setting 1.5 · motor start-up current with minimum operation time is recommended. Table 268 shows recommended setting values; all other settings can be kept at factory default values.

Table 268: PHIPTOC1 settings

Setting	Recommended value	Description
Start value	6.9 xIn 1)	Start value
Operate delay time	20 ms	Operate delay time

1) 1.5 · 5.6 · 246 A / 300 A = 6.9 xIn

MSCPMRI1 – Motor start counter

The motor manufacturer states that the motor can be successively started three times from the cold condition, or twice from the warm condition. MSCPMRI1 is used to limit the starting to these numbers.

A typical time to cool down the heating effect caused by a single start is 60 min unless the motor manufacturer states otherwise.

To distinguish between cold and warm starts, the *Warm start level* must be set correctly. This depends on the MPTTR1 settings as information of the motor thermal level is received from MPTTR1. A good setting is about 0.5...0.7 times the MPTTR1 *Weighting factor*, which corresponds to a motor thermal rise of about 50...75% of the rated operation temperature.

Table 269: MSCPMRI1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Warm start level	35% 1)	Thermal threshold to define a warm start
Max Num of cold start	3	Max number of cold starts allowed
Max Num or warm start	2	Max number of warm starts allowed
Cnt decrease time	60 min	Cooldown time after a start
Cnt Dec time Mult	1	Multiplier for *Cnt decrease time* when the motor is stopped

1) 0.7 · MPTTR1 weighting factor

STTPMSU1 – Motor start-up supervision

This function consists of motor start-up detection (`MOT_START` output), thermal stress based start-up protection (`OPER_IIT` output), definite time based locked rotor protection (`OPR_STALL` output) and cumulative start-up time counter (`LOCK_START` output).

To detect the motor start-up correctly, first the *Motor standstill A* setting is set below the motor no-load current, typically 12% of the motor rated current. Next, the *Start detection A* setting is set typically at least 150% of the motor rated current and below 75% of the motor starting current. Finally, setting *Str over delay time* is used to define how long stator currents must remain below 0.9 · *Start detection A* before motor starting is considered ended. The 100 ms time is used unless there is

Y/D starting or very low motor starting current (for example, round wound motors and soft starts).

The thermal stress based start-up protection is based on the integral of start current over the start time, simplified as $I^2 \cdot t$ (or IIT). *Motor start-up A* is set equal to the motor starting current. *Motor start-up time* is preferably set below the motor locked rotor time, but at least 10% over the motor actual starting time. In this way the motor is protected against locked rotor and prolonged start. *Operation mode* is set to "IIT", which means that the *Lock rotor time* setting is ineffective.

Operation mode “Stall” can be used only if the motor is provided with a speed-switch indicating that the rotor is stationary or rotating.

The cumulative start-up counter can be used to limit the motor cumulative starting time. This feature and MSCPMRI1 are overlapping: MSCPMRI1 counts the number of cold and warm starts ignoring the starting time, whereas STTMPSU1 counts the cumulative starting time. Thus, this protection in STTPMSU1 can be used as additional limitation of the number of starts when the start-up time is within allowed limits, but longer than normal, for example, at too heavy load starts. When the cumulative starting time exceeds setting *Cumulative time Lim*, further restarts are inhibited until the counter falls below the setting. The fall rate is set with *Counter Red rate* setting.

STTPMSU1 also has the setting *Restart inhibit time* for preventing motor restarting until the time since the latest start has elapsed. Typically, 5..10 min time between consecutive starts is often enough to considerably reduce cumulative thermal stress caused by too fast re-starting, especially in the rotor.

Table 270: STTPMSU1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Operation mode	IIT	Operation mode
Motor start-up A	4.6 xIn 1)	IIT protection current setting
Motor start-up time	4.5 s	IIT protection trip time when the motor current equals current setting
Lock rotor time	N/A 2)	Permitted locked rotor time
Counter Red rate	3.9 s/h 3)	Cumulative start-up counter reduction rate
Cumulative time Lim	8.5 s 4)	Cumulative start-up counter threshold for inhibiting restarting
Restart inhibit time	10 min	Inhibition time after each start

1) Motor starting current 5.6 · 246 A / 300 A = 4.6 xIn
2) Not effective in IIT mode
3) Equals motor starting time
4) 1.1 · 2 · start-up time (for allowing 2 + 1 cold starts)

MNSPTOC1 – Negative-sequence overcurrent protection for machines

MNSPTOC1 is used to give protection against phase unbalance and broken phase condition. These cause additional heat losses and local overheating of the rotor as well as mechanical vibrations. A typical setting is 8...15%. Both definite operation time (typically 5...10 s) and the IDMT curve are used.

Any unbalance in the network causes unbalance in the system voltages especially if the supply is weak. The voltage unbalance then causes phase current unbalance in the healthy motor, which starts the unbalance protection. Therefore, to ensure that only the faulty motor feeder is tripped, the IDMT characteristic is recommended. When using IDMT, the *Machine time Mult* setting corresponds to the motor constant $I_2^2 \cdot t$, that is, it determines the rotor's ability to withstand heating caused by the negative-sequence current. The setting can be estimated as $175 / I_{start}^2$.

In case of a broken phase, the negative-sequence current is 58% of the stator current. The motor speed decreases due to the drop in electrical power, causing the stator current to increase until a new power/torque-equilibrium is found, or the motor stops. If the motor stops, the stator current equals the start-up current and the negative-sequence current in the example motor is 58% · 5.6 = 325% of the motor rated current.

The additional heat production due to unbalance can also be taken into account in MPTTR1.

Table 271: MNSPTOC1 settings whose values differ from default values based on the example case

Setting	Recommended values	Description
Start value	0.12 xIn[1)]	Start value
Operating curve type	Inv. Curve B	Operating curve type
Machine time Mult	5.6[2)]	Machine-related time constant for the IDMT curve
Current reference	0.82 xIn[3)]	Motor full-load current

1) 15% of motor rated (0.15 · 246 A / 300 A) = 0.12 xIn
2) $175 / I_{start}^2 = 5.6$
3) Motor rated / CT rated = 246 A / 300 A = 0.82 xIn

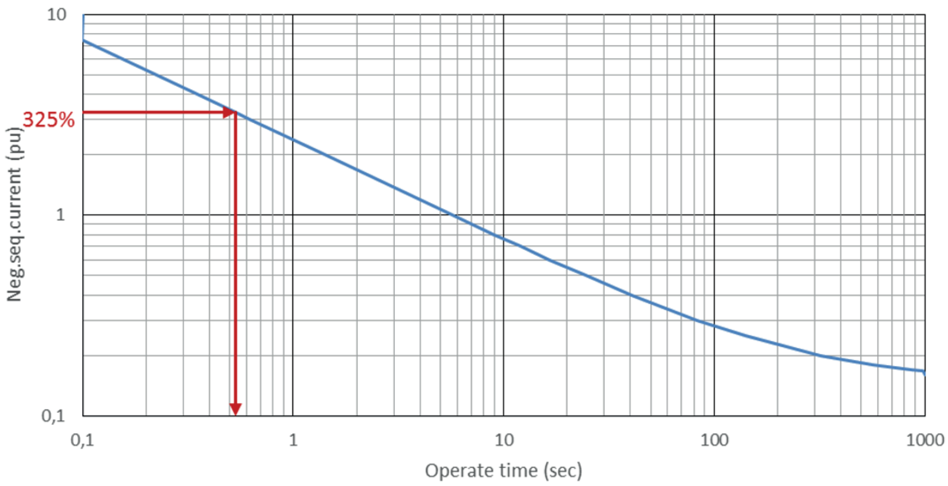

Figure 112: MNSPTOC1 operation time with recommended settings

PREVPTOC1 – Phase reversal protection

PREVPTOC1 can be used for preventing motor operation in incorrect direction. The protection is based on the ratio of the negative- and positive-sequence current. In normal phase order, assuming there is no unbalance, the positive-sequence current equals the stator current and the negative-sequence current is zero. In case of incorrect, that is, reversed phase order, the positive-sequence current is zero, and the negative-sequence current equals the stator current.

Table 272: PREVPTOC1 settings whose values differ from default values based on the example case

Settings	Recommended value	Description
Start value	0.62 xIn[1)]	Start value
Operate delay time	100 ms	Operate delay time

1) 0.75 · 236 A / 300 A = 0.62 xIn

MHZPDIF1 – High-impedance or flux-balance based differential protection

The relay offers various methods for realizing a differential protection. In this example case, the motor is connected in star and equipped with separate CTs for measuring the flux-balanced differential currents in each phase. Hence, MHZPDIF1 is used.

The advantage of the flux-balance differential protection with three CTs over the stabilized differential protection using phase measurement from six CTs is that the flux-balance CTs can be selected regardless of the phase current amplitude.

The setting is typically very low, in this example case 4% of CT rated, that is, 12 A in primary.

Table 273: MHZPDIF1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Operate value	4 %In	Operate value
Minimum operate time	20 ms	Operate delay time

JAMPTOC1 – Motor load jam protection

JAMPTOC1 is used to give protection against running motor jamming, for example, because of too high mechanical load. Should this happen, the stator current rises up to the locked rotor current. The protection trips if the stator current exceeds the setting during the set time. This function is blocked during motor starting.

Start value is typically set to 50...75% of the locked rotor current and for *Operate delay time* about 1...2 s is used.

Table 274: JAMPTOC1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Start value	2.3 xIn[1)]	Start value
Operate delay time	2000 ms	Operate delay time

1) 0.5 · 5.6 · 246 A / 300 A = 2.3 xIn

PHPTUV1 – Three-phase undervoltage protection

Undervoltage causes an increase of the stator current, and overloading of the motor. This, however, is detected by thermal overload protection.

When using only one stage of undervoltage protection, the protection is typically set 70% of the rated voltage and short-operation time. If supply voltage is lost, the undervoltage protection, for example, typically requires the motor to be tripped to prevent a simultaneous restart of all motors when the voltages return.

When using two-stage protection, the second stage is typically set to 90%, but the operation time must be longer than the motor undervoltage starting time.

Table 275: PHPTUV1 settings whose values differ from default values based on the example case

Settings	Recommended value	Description
Start value	0.68 xUn[1)]	Start value
Operate delay time	1000 ms[2)]	Operate delay time

1) 0.7 · 10.7 kV/11 kV = 0.68 xUn
2) Allows short-time interruptions and transitions

PHPTOV1 – Three-phase overvoltage protection

In most cases, motors can be approximated as volt-independent loads with constant U/f ratio. An increase in this ratio due to overvoltage or underfrequency increases the flux density in the motor, which can result in excess heating.

Typically, the overvoltage protection is set to about 110...120% of the rated voltage, and the operate time to a few seconds. The protection must be coordinated with the incoming/bus overvoltage protection.

Table 276: PHPTOV1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Start value	1.07 xUn[1)]	Start value
Operate delay time	5000 ms[2)]	Operate delay time

1) 1.1 · 10.7 kV/11 kV = 1.07 xUn
2) Allows short-time transitions

DEFLPDEF1 – Directional earth-fault protection, low stage

From the protection point of view, measuring the earth-fault current with a core-balanced CT (CBCT) is the best choice. There are two advantages: the CBCT ratio can be selected smaller than the phase CT ratio, and there is no risk of CT saturation at motor inrush.

However, in motor applications, the earth-fault current is typically measured or calculated as a sum of phase currents. As a drawback, should any of the phase CTs saturate at the beginning of the motor inrush, the relay sees untrue earth-fault current. In this example case, DEFLPDEF1 is used to allow the protection to operate only if at the same time there is residual voltage (Uo) present.

In this example case, the maximum earth-fault current in the network is 30 A. Using 1% setting (1% · 300 A = 3 A in primary) for earth-fault protection thus protects 90% of the motor winding, excluding the effect of the possible fault resistance. The operation time must be coordinated with other earth-fault protection in the network. In this example, 100 ms time is used.

The *Start value* setting must be equal to or below the residual voltage in the network at the relay's 3 A setting. However, the *Start value* setting must be higher than the normal healthy-state residual voltage in the network. In this example case, 0.10 · Un is used. The calculated residual voltage can be used only when VTs are star-connected to the relay as in this example case.

Table 277: DEFLPDEF1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Start value	0.01 xIn	Start value for the residual current
Directional mode	Non-directional[1)]	Directional mode
Operate delay time	100 ms	Operate delay time
Voltage start value	0.10 xUn	Start value for the residual voltage
Enable voltage limit	True	*Voltage start value* in use; that is, the protection does not start/ operate unless the residual voltage exceeds *Voltage start value*.

1) Can also be used as directional

Section 11 Synchronous motor protection

11.1 Introduction to application

Electric motors are exposed to many kinds of disturbances and stress. Part of the disturbances are due to imposed external conditions such as over- and undervoltage, over- and underfrequency, harmonics, unbalanced system voltages and supply interruptions such as auto-reclosing that occurs in the supplying network. Other causes of external disturbances are dirt in the motor, cooling system and bearing failures or an increase of ambient temperature and humidity. Stress factors due to abnormal use of the motor drive are frequent successive start-ups, stall and overload situations including mechanical stress. The stress and disturbances mechanically deteriorate the winding insulation of the motor and increase the thermal ageing rate, which may lead to an insulation failure.

The purpose of the motor protection is to limit the effects of the disturbances and stress factors to a safe level, for example, by limiting overloading or by preventing too frequent start-up attempts. If, however, a motor failure takes place, the purpose of the protection is to disconnect the motor from the supplying network in due time.

Table 278: Typical faults and conditions, protection functions and devices

Faults and conditions	Protection functions and devices
Stator short circuit and earth fault	Three-phase non-directional overcurrent protection PHxPTOC, Non-directional earth-fault protection EFxPTOC, Directional earth-fault protection DEFxPDEF, High-impedance based restricted earth-fault protection HREFPDIF, Stabilized and instantaneous differential protection for machines MPDIF, High-impedance or flux-balance based differential protection MHZPDIF, fuses
Inter-winding short circuits	Stabilized and instantaneous differential protection for machines MPDIF, High-impedance or flux-balance based differential protection MHZPDIF
Overloading	Thermal overload protection for motors MPTTR, RTD sensors
Inadequate ventilation, reduced cooling, unusual ambient conditions	RTD sensors
Locked rotor, failure to accelerate	Motor start-up supervision STTPMSU
Stalling (jamming) of a running motor	Motor load jam protection JAMPTOC
Prolonged starting	Motor start-up supervision STTPMSU
Too frequent starting	Motor start counter MSCPMRI, Motor start-up supervision STTPMSU

Table continues on next page

Faults and conditions	Protection functions and devices
Network unbalance, single phasing	Negative-sequence overcurrent protection for machines MNSPTOC, Negative-sequence overvoltage protection NSPTOV
Phase reversal, incorrect rotation direction	Phase reversal protection PREVPTOC
Under/overvoltage	Three-phase undervoltage protection PHPTUV, Positive-sequence undervoltage protection PSPTUV, Three-phase overvoltage protection PHPTOV
Frequency	Frequency protection FRPFRQ
Loss of load	Loss of load supervision LOFLPTUC
Emergency starting	Emergency start-up ESMGAPC
Rotor earth-fault in motors with slip-rings	Rotor earth-fault protection (MREFPTOC) with current injection device REK 510
Underexcitation, loss of field	Three-phase underexcitation protection UEXPDIS
Active power limitation	Reverse power/directional overpower protection DOPPDPR
Out of step	Out-of-step protection with double blinders OOSRPSB

11.2 Description of the example case

In this example case, a 5800 kW, 11 kV brushless synchronous motor driving a compressor is protected. Motor settings are shown in Table 279, the motor capability diagram in Figure 113 and the single-line diagram in Figure 114.

Table 279: Motor data

Motor setting	Value
Rated output	5800 kW (6600 kVA)
Voltage	11 000 V ±10%
Frequency	50 Hz ±5%
Speed	1500 rpm, critical speed >1725 rpm
Current	346 A (6600 kVA)
Method of cooling	IC 6A1A6, air-to-air heat exchanger
Ambient temperature, max	40°C
Insulation / temperature rise	Class F / B
Starting current, DOL starting method	3.99 · rated current at infinite net 3.47 · rated current at 86% voltage 3.07 · rated current at 76% voltage
Starting time	4 s (U = 100%), 6 s (U = 86%), 8 s (U = 76%)
Number of consecutive starts	3 / 2 (cold/warm), >30 min between each start
Reactances	X_d = 124.2%, $X_{d'}$ = 33.2%

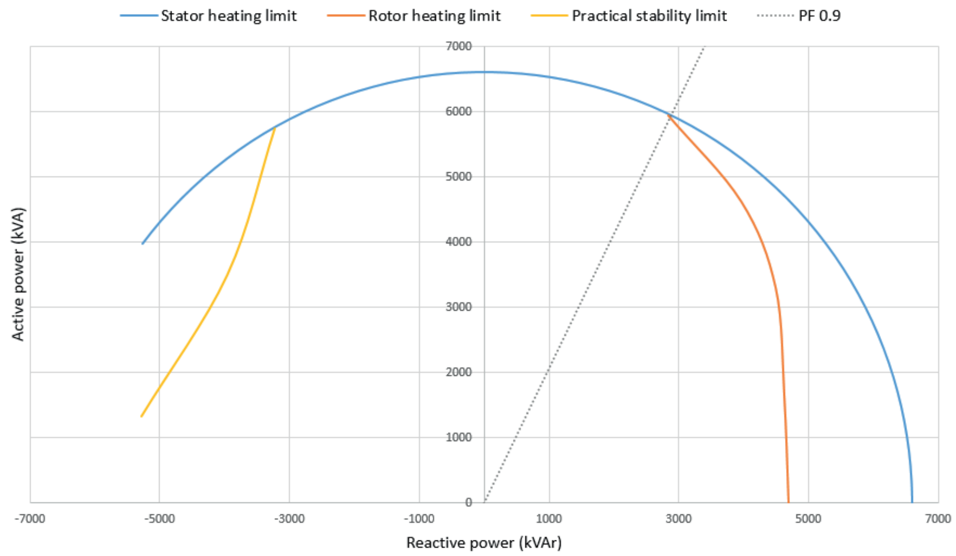

Figure 113: Motor capability diagram

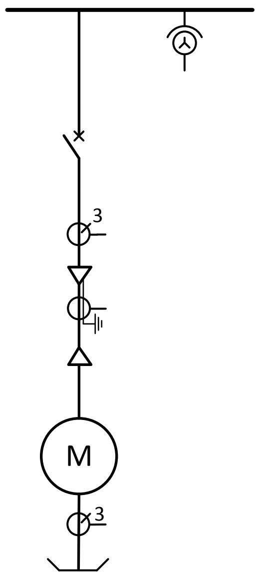

Figure 114: Single-line diagram

The motor is equipped with phase CTs 600/1 A and CBCT 100/1 A. In addition, the protection receives voltage measurement from the bus.

11.3 Motor protection relay

This chapter provides detailed information about the configuration of the relay used in this application example: the relay interfaces, the recommended alarms, the ACT diagram and the parameter settings.

11.3.1 Relay interface, configuration and settings

Figure 115 shows the connection details of the relay's analog inputs (AI), binary inputs (BI) and binary outputs (BO).

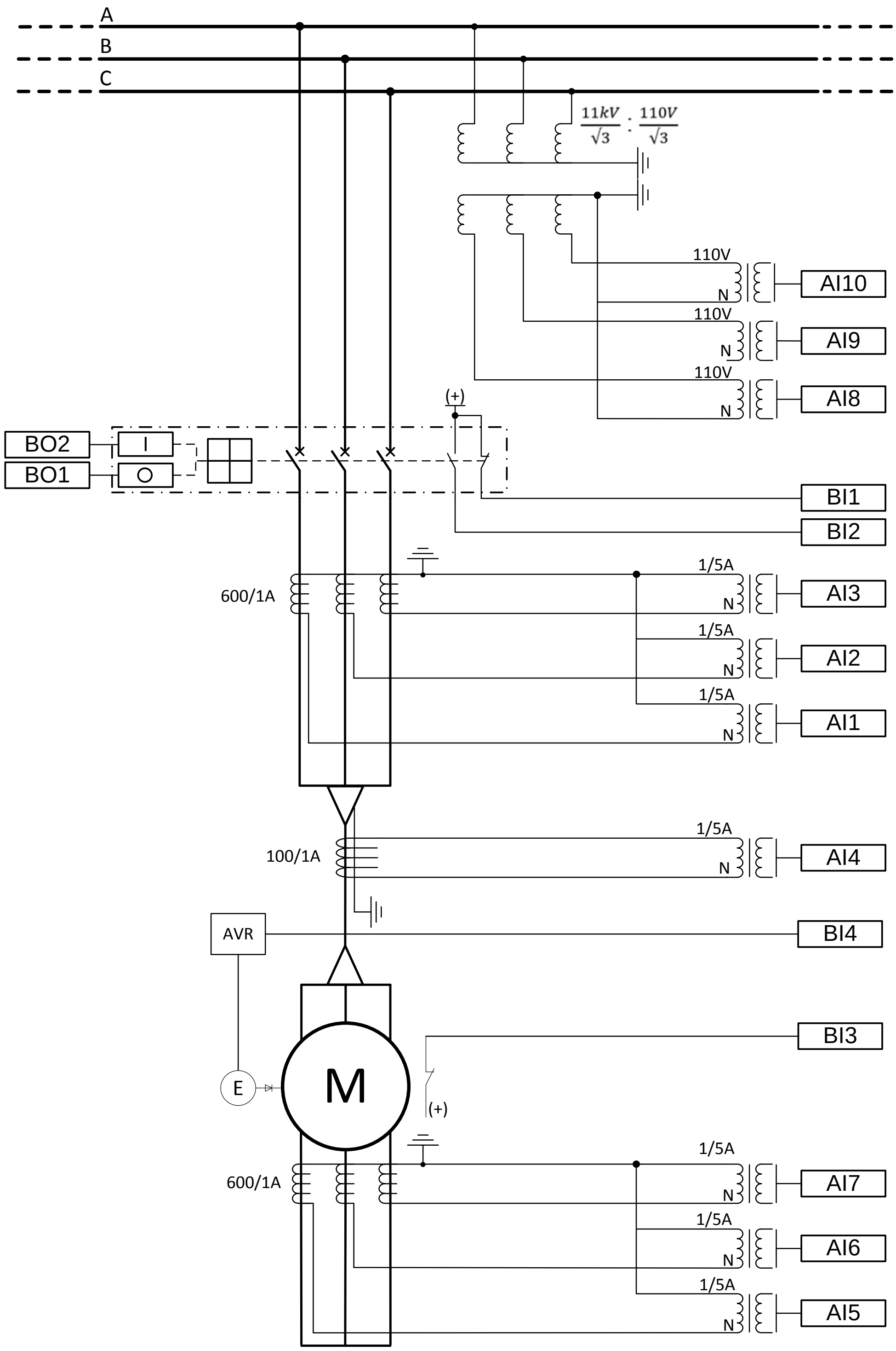

Figure 115: Relay interfaces and CT/VT connections for the example case

11.3.1.1 Analog input signals

Table 280: Physical analog input signals

Analog input	Description
AI1	Line-side phase current measurement, phase I_A
AI2	Line-side phase current measurement, phase I_B
AI3	Line-side phase current measurement, phase I_C
AI4	Residual current measurement
AI5	Neutral-side phase current measurement, phase I_A
AI6	Neutral-side phase current measurement, phase I_B
AI7	Neutral-side phase current measurement, phase IL3
AI8	Phase-to-earth voltage U_A
AI9	Phase-to-earth voltage U_B
AI10	Phase-to-earth voltage U_C

11.3.1.2 Binary input signals

Table 281: Physical binary input signals

Binary input	Description
BI1	Breaker position open signal
BI2	Breaker position close signal
BI3	Speed switch
BI4	Status information of the excitation system (loss of excitation)

11.3.1.3 Binary output signals

Table 282: Physical binary output signals

Binary output	Description
BO1	Trip signal for opening the breaker
BO2	Breaker closing signal, that is, motor starting

11.3.1.4 Recommended alarms

Table 283 presents a proposal for LHMI and WHMI alarm handling. The table lists the functions, and events under the functions, which should be tagged as alarms using Event Filtering in PCM600.

Table 283: Alarm list for implementing the application example

Event container	Event	Description
PHIPTOC1	OPERATE	Trip from short circuit protection
STTPMSU1	OPR_IIT	Trip from start-up protection
JAMPTOC1	OPERATE	Trip from jam protection
MPTTR1	OPERATE	Trip from thermal overload protection
MSCPMRI1	OPERATE	Trip from start counter
MNSPTOC1	OPERATE	Trip from unbalance protection
PREVPTOC1	OPERATE	Trip from phase sequence protection
EFLPTOC1	OPERATE	Trip from earth-fault protection
PHPTUV1	OPERATE	Trip from undervoltage protection
PHPTOV1	OPERATE	Trip from overvoltage protection
MPDIF1	OPERATE	Trip from differential protection
UEXPDIS1	OPERATE	Trip from underexcitation protection
OOSRPSB1	OPERATE	Trip from out-of-step protection
DOPPDPR1	OPERATE	Trip from overpower protection
OR6	Q	Restart inhibited

11.3.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600. The relay configuration for the example case is presented in Figure 116, Figure 117 and Figure 118.

All protection function operate signals are used for tripping. In STTPMSU1, the operate outputs `OPR_IIT` and `OPR_STALL` are recommended to be connected for tripping.

Motor starting, that is, closing of the breaker via CBXCBR, is allowed only if there is no protection function inhibiting starting.

- MPTTR1: motor thermal capacity is too high for start
- MSCPMRI1: motor started too frequently
- STTPMSU1: too short time from the latest start
- MNSPTOC1: insufficient cooling after unbalance trip

In such a case, some time is needed for the motor to cool down before starting is allowed.

Table 284: Function blocks used in the relay configuration

Function block	Description
ILTCTR1, ILTCTR2, RESTCR1, UTVTR1	Analog signal preprocessing for protection functions
CBXCBR1	Circuit-breaker control
TRPPTRC1	Master trip
PHIPTOC1	Three-phase non-directional overcurrent protection, instantaneous stage
MPTTR1	Thermal overload protection for motors
JAMPTOC1	Motor load jam protection
STTPMSU1	Motor start-up supervision
MSCPMRI1	Motor start counter
MNSPTOC1	Negative-sequence overcurrent protection for machines
PREVPTOC1	Phase reversal protection
MPDIF1	Stabilized and instantaneous differential protection for machines
PHPTUV1	Three-phase undervoltage protection
PHPTOV1	Three-phase overvoltage protection
EFLPTOC1	Non-directional earth-fault protection, low stage
UEXPDIS1	Three-phase underexcitation protection
DOPPDPR1	Reverse power/directional overpower protection
OOSRPSB1	Out-of-step protection with double blinders
OR OR6 OR20	OR gate with two inputs OR gate with six inputs OR gate with twenty inputs
SR	SR flip-flop, volatile

Table 285: Physical analog channels of functions

Protection	Terminal side phase currents AI1, AI2, AI3	Residual current AI4	Neutral point phase currents AI5, AI6, AI7	Phase-to-earth voltages AI8, AI9, AI10
MPTTR1	x			
PHIPTOC1	x			
STTPMSU1	x			
MNSPTOC1	x			
PREVPTOC1	x			
MPDIF1	x		x	
JAMPTOC1	x			
PHPTOV1				x
PHPTUV1				x
EFLPTOC1		x		
Table continues on next page				

Protection	Terminal side phase currents AI1, AI2, AI3	Residual current AI4	Neutral point phase currents AI5, AI6, AI7	Phase-to-earth voltages AI8, AI9, AI10
UEXPDIS1	x			x
DOPPDPR1	x			x
OOSRPSB1	x			x

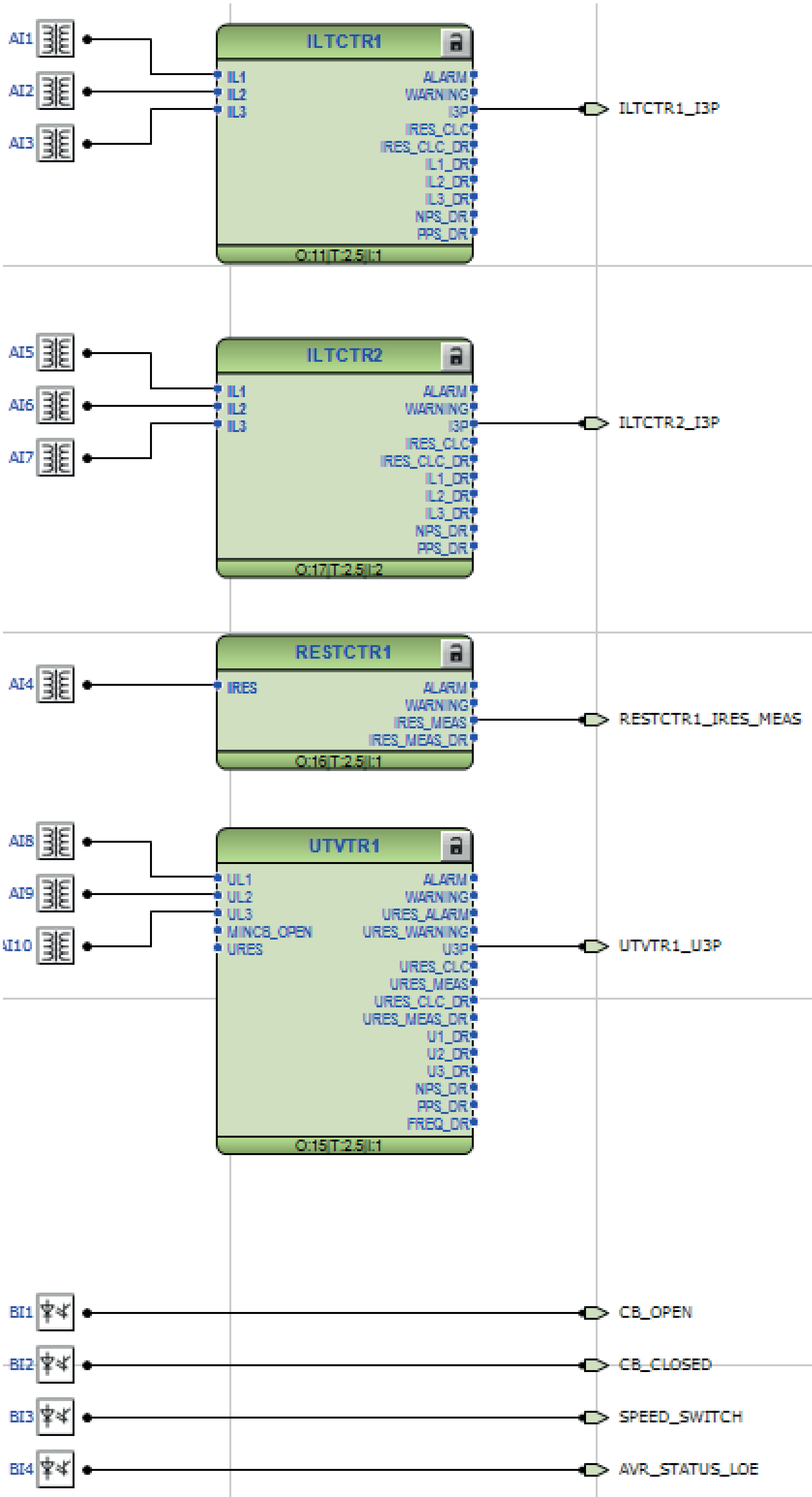

Figure 116: Input section

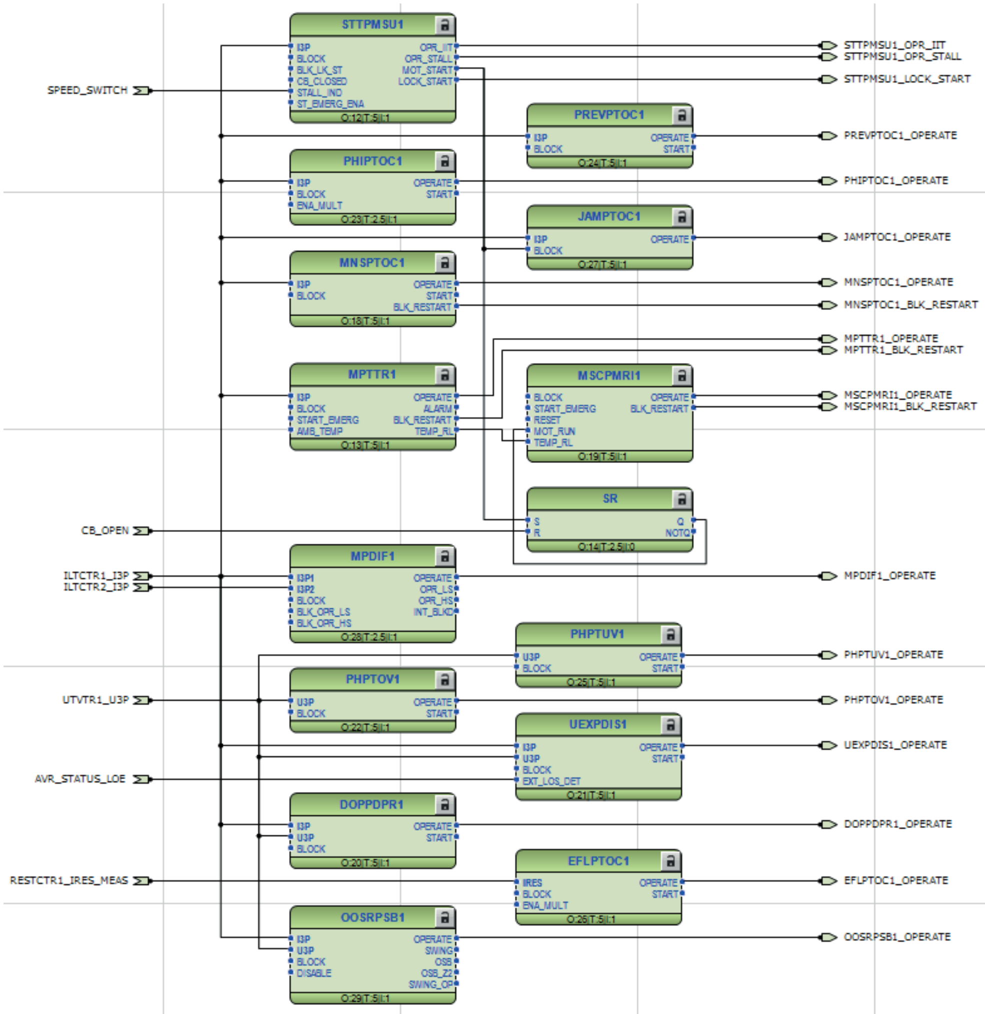

Figure 117: Application section

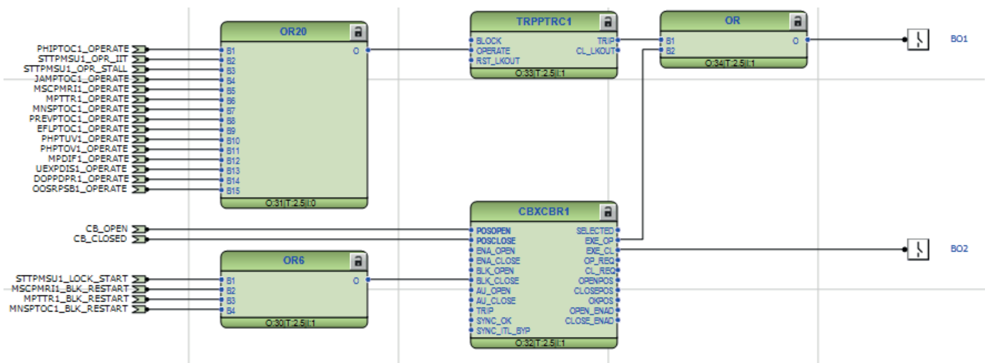

Figure 118: Output section

11.3.1.6 Function blocks and setting values

ILTCTR – Phase current preprocessing

ILTCTR is the analog signal preprocessing function block; ILTCTR1 is used for line-side phase currents while ILTCTR2 is used for the motor neutral-side phase currents. Table 286 shows recommended setting values; all other settings can be kept at default values.

Table 286: ILTCTR settings for the relay in the example case

Setting	Suggested values	Description
Primary current	600 A	Primary current value
Secondary current	1 A	Secondary current value

RESTCTR1 – Residual current preprocessing

RESTCTR1 is the analog signal preprocessing function for the residual current signal.

Table 287: RESTCTR1 settings for the relay in the example case

Setting	Suggested values	Description
Primary current	100 A	Primary current
Secondary current	1 A	Secondary current

UTVTR1 – Phase and residual voltage preprocessing

UTVTR1 is used to connect the received analog phase voltage inputs to the application.

Table 288: UTVTR1: Phase voltage transformer function settings for the relay in the example case

Setting	Suggested values	Description
Primary voltage	11 kV	Primary rated voltage
Secondary voltage	110 V	Secondary rated voltage

MPTTR1 – Thermal overload protection for motors

Motor overload is mainly a result of abnormal use of the motor, unbalanced supply voltages or harmonics. All these increase motor losses thus causing additional heating. Should the motor temperature exceed the rated limits specified for the insulation class, the winding insulation deterioration accelerates, that is, the motor lifetime shortens. As a rule of thumb, each 8...12°C temperature increase halves the life time. Too high or frequent overloading may also lead to an electrical fault in the winding or damage in the rotor.

Therefore, the thermal overload protection is the most important protection in addition to the short circuit protection of the motor. Usually also authorities require the motors to be equipped with thermal overload protection.

MPTTR1 calculates the motor thermal capacity based on the phase current measurement. The true RMS value of the current is measured in order to take into account also the harmonics. MPTTR1 protects against any kind of thermal overload except reduced cooling, which requires RTD sensors to monitor the winding temperature.

Finding suitable settings for MPTTR1 can be done in three steps: first, *Overload factor* is decided, then *Weighting factor* and time constants, and finally the rest of the settings.

Step 1:

The *Overload factor* setting defines the maximum continuously allowed load. The motor in this example case has class B (80°C) thermal rise and class F insulation (max. temperature 155°C). When used in the designed 40°C ambient temperature, this motor reaches the maximum value of 155°C if the load current is √[(155 - 40)/80] = 1.198 times the motor rated load or higher. This is the maximum value for the *Overload factor* setting. However, typically a smaller value such as 1.05 is used in MPTTR1.

Step 2:

The thermal behavior of the stator and the rotor during start-ups and longtime overload situations differs significantly from each other. In MPTTR1, if *Weighting factor* = "50%", both the motor “hot spot” behavior and the thermal background are modelled. In case of an overload or start-up, MPTTR1 follows the thermal behavior of the hottest spots (typically rotor), while taking 50% of that thermal rise to the background (motor body). After overloading, it is assumed that the heat of the hot spots is quickly transferred to the surrounding material (motor body), hence MPTTR1 quickly drops the hot spot thermal level to the background thermal level.

A general recommendation is that, by default, *Weighting factor* = "50%", and *Overload factor* = "1.05". This also means that approximately half of the thermal capacity of the motor is used when the motor runs with full load, that is, the motor has capacity for warm re-start without any cooling time.

There are various methods to find settings for the time constants. In this example case, the motor thermal limit curves are available and the MPTTR1 *Time constant normal* is set accordingly, that is, protection curves are equal to or below the running motor thermal limit curves. Thermal overload protection curves do not need to be equal to or below the locked rotor thermal limit curves as the relay has dedicated protection function for this.

Using the warm-up time constant, given by the motor manufacturer, for the protection is not recommended as it typically results in insufficient thermal protection. This is because the warm-up time constant mainly represents the stator at motor normal operation, and thus fails to take into account material safety limits, for example, in other parts of the motor during overloading. The motor cooldown time constant, however, can be used as a good starting point for the MPTTR1 *Time constant stop* setting.

Time constant start is most typically set to be equal to *Time constant normal*.

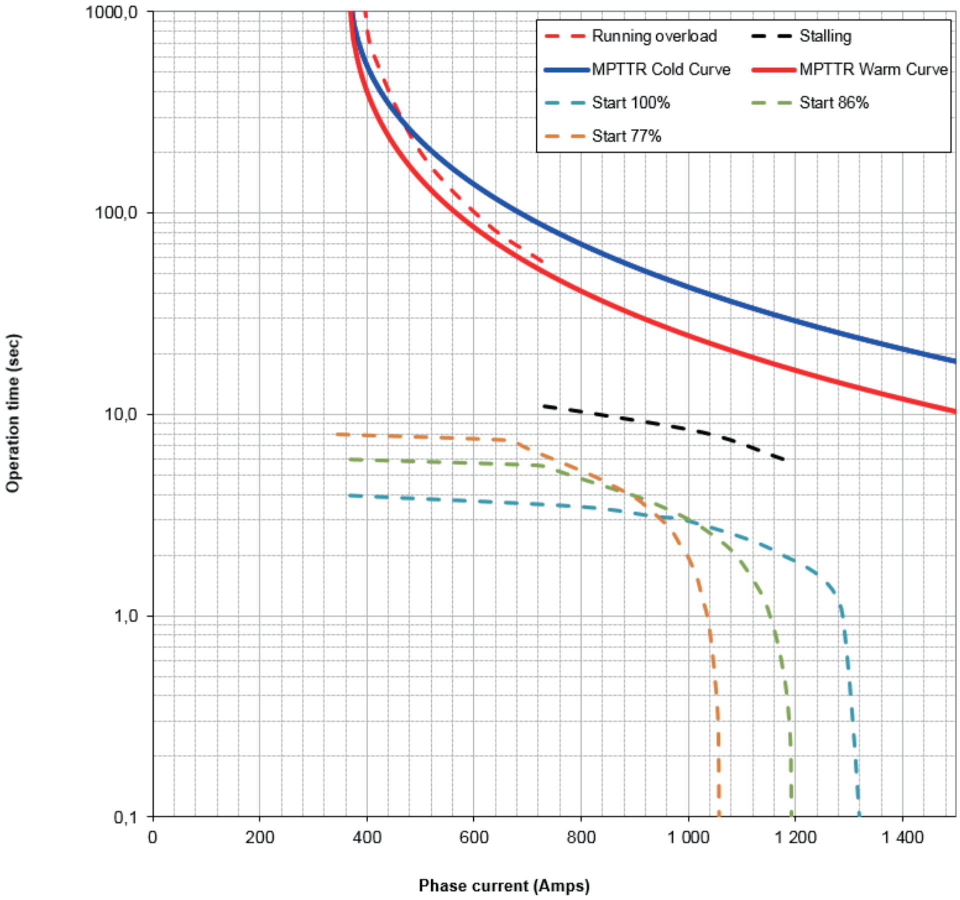

Figure 119: Motor thermal limit, motor time-current and thermal overload protection curves

Step 3:

To take into account the excess heating caused by unbalance, the MPTTR1 setting *Negative Seq factor* can be used.

The *Restart thermal Val* setting is used to prevent motor restarting until the motor has enough thermal capacity for starting. The setting value can be calculated as

$$Restart\ thermal\ Val = 95\% - \frac{start\text{-}up\ time}{Cold\ motor\ trip\ time\ at\ start\text{-}up\ current} \cdot 100\%$$

(Equation 6)

In this example case, the start-up time at the rated voltage is 4 sec, and the MPTTR1 trip time at the start-up current is about 21 sec (Figure 119). This gives 95% - (4/21) · 100% = 76%. Start-up at 76% of the rated voltage takes 8 sec and the trip time is 37 sec, giving 95% - (8/37) · 100% = 73%. In this example case, *Restart thermal Val* is set to 70%.

It is recommended to check that MPTTR1 allows the required number of warm starts. *Restart thermal Val*together with *Time constant stop* can be chosen accordingly to limit how fast the next starting can be allowed.

In this example case, two warm starts per hour are allowed when having at least 30 min between the starts. Compared to the motor thermal capability curve (running overload), this indicates that thermally the motor is rotor critical. The *Time constant stop* setting is chosen so that the thermal level after 30 min standstill is about the same as before the warm start.

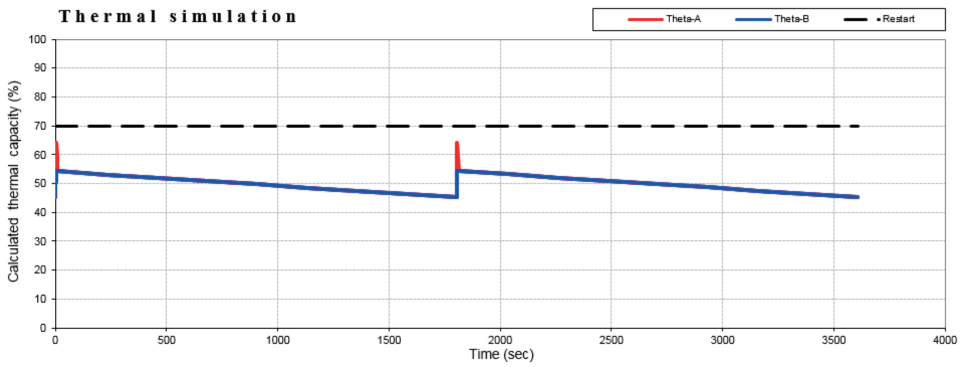

Figure 120: Simulation of two warm starts at rated voltage with recommended settings

Table 289: MPTTR1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Overload factor	1.05	Allowed continuous overload
Restart thermal Val	70%	Thermal level for inhibiting motor restarting
Negative Seq factor	11.0[1)]	Heating effect factor for unbalance
Weighting factor p	50%	Weighting factor for thermal modelling
Time constant normal	300 s	Time constant during motor normal operation and light overloading
Time constant start	300 s	Time constant during the motor start
Time constant stop	10000 s	Time constant during the motor standstill
Current reference	0.58 xIn[2)]	Motor full-load current

1) $175 / (I_{start\text{-}up} / I_{rated})^2 = 175 / 3.99^2 = 10.99$
2) Motor rated / CT rated = 346 A / 600 A = 0.577 xIn

PHIPTOC1 – Three-phase non-directional overcurrent protection, instantaneous stage

PHIPTOC1 is used to give protection against short circuits in the motor or feeder cable. For PHIPTOC1, which uses a peak-to-peak measuring function, setting 1.5 · motor start-up current with minimum operation time is recommended. Table 290 shows recommended setting values; all other settings can be kept at factory default values.

Table 290: PHIPTOC1 settings

Setting	Recommended value	Description
Start value	3.5 xIn 1)	Start value
Operate delay time	20 ms	Operate delay time

1) 1.5 · 3.99 · 346 A / 600 A = 3.5 xIn

MSCPMRI1 – Motor start counter

The motor manufacturer states that the motor can be successively started three times from the cold condition, or twice from the warm condition. To limit the starting to these numbers, MSCPMRI1 is used.

The typical time to cool down the heating effect caused by a single start is 60 min unless the motor manufacturer states otherwise.

To distinguish between cold and warm starts, *Warm start level* must be set correctly. This depends on the MPTTR1 settings, as information of the motor thermal level is received from MPTTR1. A good setting is about 0.5...0.7 times the MPTTR1 *Weighting factor*, which corresponds to a motor thermal rise of about 50...75% of the rated operation temperature.

Table 291: MSCPMRI1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Warm start level	35% 1)	Thermal threshold to define a warm start
Max Num of cold stars	3	Max number of cold starts allowed
Max Num or warm start	2	Max number of warm starts allowed
Cnt decrease time	60 min	Cooldown time after a start
Cnt Dec time Mult	1	Multiplier for *Cnt decrease time* when the motor is stopped

1) 0.7 · MPTTR1 weighting factor

The required 30 min time between each start is handled with STTPMSU1.

STTPMSU1 – Motor start-up supervision

This function consists of motor start-up detection (MOT_START output), thermal stress based start-up protection (OPER_IIT output), definite time based locked rotor protection (OPR_STALL output) and cumulative start-up time counter (LOCK_START output).

To detect the motor start-up correctly, first the *Motor standstill A* setting is set below the motor no-load current. For the synchronous motor, this can be about 1% whereas for the mechanical load (in this example, the compressor), the no-load losses are determinant.

Next, the *Start detection A* setting is typically set at least 150% of the motor rated current and below 75% of the motor starting current. Finally, setting *Str over delay time* is used to define how long stator currents must remain below 0.9 · *Start detection A* before motor starting is considered ended. The 100 ms time is used.

The thermal stress based start-up protection is based on the integral of start current over the start time, simplified as $I^2 \cdot t$ (or IIT). *Motor start-up A* is set equal to the motor starting current. *Motor start-up time* is preferably set below the motor locked rotor time, but at least 10% over the motor actual starting time. In this way, the motor is protected against locked rotor and prolonged start. *Operation mode* is set to "IIT", which means that the *Lock rotor time* setting is ineffective.

Operation mode “Stall” is used when the motor is provided with a speed switch indicating that the rotor is stationary or rotating. *Lock rotor time* is set equal to or below the allowed locked rotor (stalling) time.

The cumulative start-up counter can be used to limit the motor cumulative starting time. This feature and MSCPMRI1 are overlapping: MSCPMRI1 counts the number of cold and warm starts ignoring the starting time, whereas STTMPSU1 counts the cumulative starting time. Thus, this protection in STTPMSU1 can be used as additional limitation of the number of starts when the start-up time is within allowed limits, but longer than normal, for example, at too heavy load starts. When the cumulative starting time exceeds setting *Cumulative time Lim*, further restarts are inhibited until the counter falls below the setting. The fall rate is set with *Counter Red rate* setting.

STTPMSU1 also has a *Restart inhibit time* setting for preventing motor restarting until the time since the latest start has elapsed. In this example case, the motor is allowed to be started only after 30 min from the previous starting.

Table 292: STTPMSU1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Operation mode	IIT & Stall	Operation mode
Motor start-up A	2.3 xIn[1)]	IIT protection current setting
Motor start-up time	3.0 s	IIT protection trip time when motor current equals current setting
Lock rotor time	2 s	Permitted locked rotor time
Counter Red rate	4.0 s/h[2)]	Cumulative start-up counter reduction rate
Cumulative time Lim	8.8 s[3)]	Cumulative start-up counter threshold for inhibiting restarting
Restart inhibit time	30 min	Inhibition time after each start
Motor standstill A	0.05 x In	Current threshold for stopped motor

1) Motor starting current 3.99 · 346 A / 600 A = 2.3 xIn
2) Equals motor starting time
3) 1.1 · 2 · start-up time (for allowing 2+1 cold starts)

MNSPTOC1 – Negative-sequence overcurrent protection for machines

MNSPTOC1 is used to give protection against phase unbalance and broken phase condition. These cause additional heat losses and local overheating of the rotor as well as mechanical vibrations. A typical setting is 8...15%. Both definite operation time (typically 5...10 s) and the IDMT curve are used.

Any unbalance in the network causes unbalance in the system voltages especially if the supply is weak. The voltage unbalance then causes phase current unbalance in the healthy motor, which starts the unbalance protection. Therefore, to ensure that only the faulty motor feeder is tripped, the IDMT characteristic is recommended. When using IDMT, the *Machine time Mult* setting corresponds to the motor constant $I_2^2 \cdot t$, that is, it determines the rotor's ability to withstand heating caused by the negative-sequence current. The setting can be estimated as 175 / I_{start}^2.

In case of a broken phase causing the motor to stop, the stator current equals the start-up current and the negative-sequence current in the example motor is 58% · 3.99 = 232% of the motor rated current.

The additional heat production due to unbalance can also be taken into account in MPTTR1.

Table 293: MNSPTOC1 settings whose values differ from default values based on the example case

Setting	Recommended values	Description
Start value	0.08 xIn[1)]	Start value
Operating curve type	Inv. Curve B	Operating curve type
Machine time Mult	11[2)]	Machine-related time constant for the IDMT curve
Current reference	0.57 xIn[3)]	Motor full-load current

1) 15% of motor rated (0.15 · 346 A / 600 A) = 0.08 xIn
2) 175 / I_{start}^2 = 11
3) Motor rated / CT rated = 346 A / 600 A = 0.57 xIn

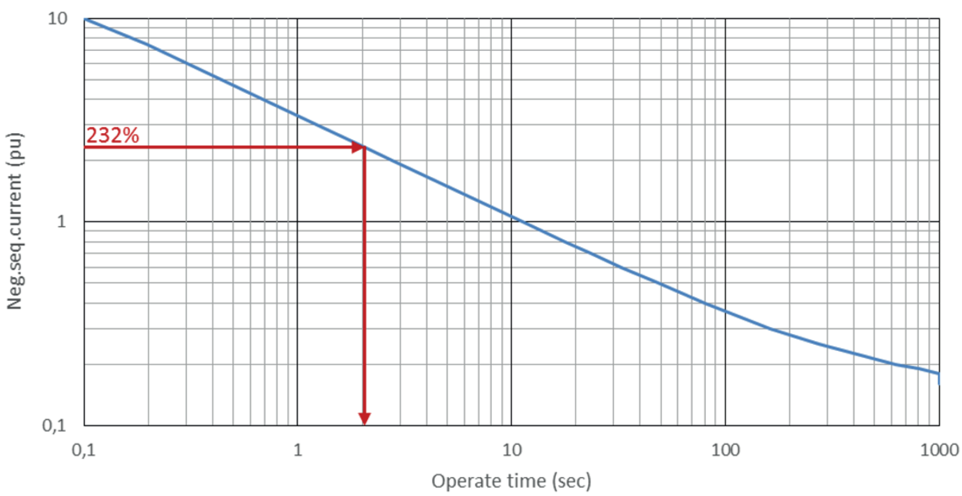

Figure 121: MNSPTOC1 operation time with recommended settings

PREVPTOC1 – Phase reversal protection

PREVPTOC1 can be used for preventing motor operation in incorrect direction. The protection is based on the ratio of the negative- and positive-sequence current. In normal phase order, assuming there is no unbalance, the positive-sequence current equals the stator current and the negative-sequence current is zero. In case of incorrect, that is, reversed phase order, the positive-sequence current is zero, and the negative-sequence current equals the stator current.

Table 294: PREVPTOC1 settings whose values differ from default values based on the example case

Settings	Recommended value	Description
Start value	0.43 xIn[1)]	Start value
Operate delay time	100 ms	Operate delay time

1) 0.75 · 346 A / 600 A = 0.43 xIn

MPDIF1 – Stabilized and instantaneous differential protection for machines

The relay offers various methods for realizing a differential protection. In this example case, the motor is equipped with CTs for measuring currents of both sides of the motor windings. Hence, MPDIF1 is used.

First, the *Slope section 2* setting is calculated as sum of both side CT and relay errors + some safety margin. Using *End section 1* = "50%", *Low operate value* is then calculated as 50% of *Slope section 2* + a small safety margin. *High operate value* is set slightly over the motor start-up current.

Table 295: MPDIF1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Low operate value	10%[1)]	Basic setting for the stabilized stage start
High operate value	450%[2)]	Instantaneous stage operate value
Slope section 2	16%[3)]	Slope of the second line of the operating characteristics
End section 1	50%	Turn point between the first and the second line of the operating characteristics
End section 2	120%	Turn point between the second and the third line of the operating characteristics
Slope section 3	100%	Slope of the third line of the operating characteristics
CT connection type	Type 2	CT connection type
CT ratio Cor Line	1.73[4)]	CT ratio correction, line side
CT ratio Cor Neut	1.73[4)]	CT ratio correction, motor star-point side

1) 0.5 · *Slope section 2* + margin 2%
2) Slightly over start-up current
3) Line CT class 5% + Neutral CT class 5% + relay accuracy 3% + safety margin 3%
4) 600 A/346 A = 1.73

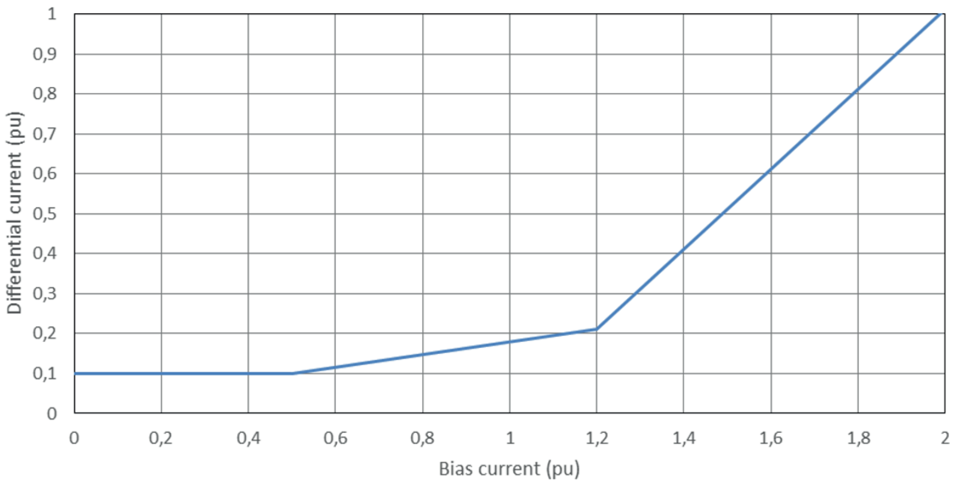

Figure 122: MPDIF1 lows-set stage operation characteristics

JAMPTOC – Motor load jam protection

JAMPTOC is used to give protection against running motor jamming, for example, because of too high mechanical load. Should this happen, the stator current rises up to the locked rotor current. The protection trips if the stator current exceeds the setting during the set time. This function is blocked during motor starting.

Start value is typically set 50...75% of the locked rotor current and for *Operate delay time* about 1...2 s is used.

Table 296: JAMPTOC settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Start value	1.15 xIn[1)]	Start value
Operate delay time	2000 ms	Operate delay time

1) 0.5 · 3.99 · 346 A / 600 A = 1.15 xIn

PHPTUV1 – Three-phase undervoltage protection

Undervoltage causes an increase of stator current, and overloading of the motor. This, however, is detected by thermal overload protection.

When using only one stage of undervoltage protection, the protection is typically set 70% of the rated voltage and short-operation time. If supply voltage is lost, the undervoltage protection, for example, typically requires the motor to be tripped to prevent a simultaneous restart of all motors when the voltages return.

When using two-stage protection, the second stage is typically set to 90%, but the operation time must be longer than the motor undervoltage starting time. Table 297 shows recommended setting values; all other settings are kept at factory default values for this example case.

Table 297: PHPTUV1 settings

Settings	Recommended value	Description
Start value	0.65 xUn	Start value
Operate delay time	1000 ms	Operate delay time

PHPTOV1 – Three-phase overvoltage protection

Typically, the overvoltage protection is set to about 110...120% of the rated voltage, and the operate time to a few seconds. The protection must be coordinated with the incoming/bus overvoltage protection.

Table 298: PHPTOV1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Start value	1.10 xUn	Start value
Operate delay time	5000 ms[1)]	Operate delay time

1) Allows short-time transitions

EFLPTOC1 – Non-directional earth-fault protection, low stage

In this example case, the maximum earth-fault current in the network is 30 A. Using, for example, 3% setting (3% · 100 A = 3 A in primary) for earth-fault protection thus protects 90% of the motor winding, excluding the effect of the possible fault resistance. The operation time must be coordinated with other earth-fault protection in the network. In this example, 100 ms time is used.

Table 299: EFLPTOC1 settings

Setting	Recommended value	Description
Start value	0.03 xIn	Start value for residual current
Operate delay time	100 ms	Operate delay time

UEXPDIS1 – Three-phase underexcitation protection

Partial or total loss of excitation causes a reactive power intake from the network to a motor, which has adverse effects. The underexcitation protection calculates the apparent impedance based on the motor voltages and currents. The operation characteristic is a circular offset mho on the impedance plane. In addition, the protection is activated by binary input from AVR indicating loss of excitation.

The protection settings are based on the motor synchronous (x_d = 124.2%) and transient ($x_{d'}$ = 33.2%) reactance. The motor rated current and voltage are 346 A and 11 kV giving motor base impedance Z_{motor} = 11 kV / (√3 · 346 A) = 18.355 ohm. CT and VT rated values are 600 A and 11 kV giving Z_{relay} = 11 kV / (√3 · 600 A) = 10.585 ohm.

Table 300: UEXPDIS1 settings whose values differ from default values based on the example case

Setting	Recommended value	Description
Diameter	215%[1)]	Diameter of the mho diagram
Offset	-29%[2)]	Offset of top of the impedance circle from the R axis
Displacement	0%	Displacement of impedance circle center from the X axis
Operate delay time	5000 ms	Operate delay time

1) 124.2% · 18.355 ohm / 10.585 ohm = 215.4%
2) 33.2%/2 · 18.355 ohm / 10.585 ohm = 28.8%

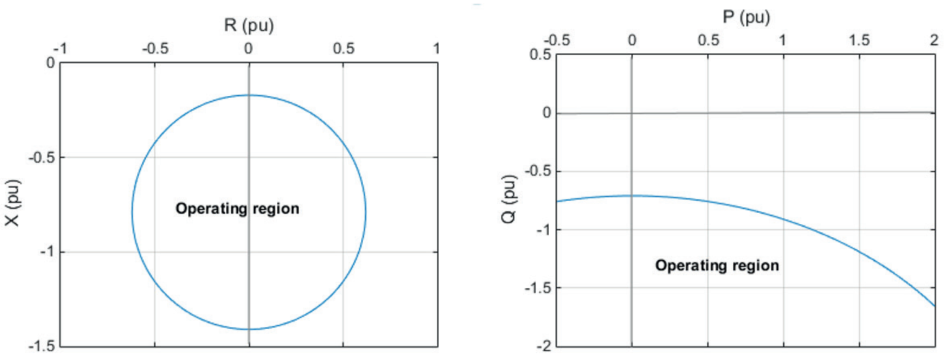

Figure 123: UEXPDIS1 operation characteristics presented in impedance and power planes. Values in motor pu

OOSRPSB1 – Out-of-step protection with double blinders

OOSRPSB1 is used for detecting an out-of-step condition of the synchronous motor. The protection settings are based both on the motor and the network side parameters. In this example case, the 11 kV bus is powered from a 110 kV network having short circuit power 2000 MVA. The power line for connection to the 110 kV grid is 20 km, positive-sequence reactance $X1_{line}$ = 0.4 Ω/km. The power transformer is 110/11 kV, 40 MVA, Zk 10%, Rk=1% and the rated current at the 11 kV side is 2099 A.

Table 301: Calculation steps for out-of-step function settings

	Motor	Transformer	Transmission line	Grid
Nominal impedance	Z_{motor} = 11 kV/(√3 · 346 A) = 18.36 Ω	Z_{tr} = 11 kV/(√3 · 2099 A) = 3.03 Ω		
Short circuit impedance		Zk_{tr} = 3.03 Ω · 0.10 = 0.303 Ω		Zk_{grid} = [(110 kV)^2 / 2000 MVA] / (110 kV/11 kV)^2 = 0.06 Ω
Reactances reduced to 11 kV			X1=0.4 Ω/km · 20 km · (110 kV/11 kV)^2 = 0.08 Ω	
Forward reach (primary ohms)	= Zk_{tr} + X1 + Zk_{grid} = 0.303 + 0.08 + 0.06 Ω = 0.44 Ω			
Zone1 reach (%)	= 0.8 · Zk_{tx} in % of forward reach = 0.8 · 0.303 / 0.44 Ω · 100% = 55%			
Reverse reach (primary ohm)	= X'_{d_motor} = 0.33 · 18.36 Ω = 6.06 Ω			
Inner blinder R (primary ohm)	= (Forward reach + reverse reach) /[2 · tan(120deg/2)] =(0.44 + 6.06 Ω)/[2 · 1.732] = 1.88 Ω			
Outer blinder R (primary ohm)	= (Forward reach + reverse reach) /[2 · tan(90deg/2)] =(0.44 + 6.06 Ω)/[2 · 1.00] = 3.25 Ω			
Impedance angle (deg)	= $\cos^{-1}$ (Rk / Zk) = $\cos^{-1}$(1%/10%) = 84 deg			

Table 302 shows recommended setting values; all other settings of OOSRPSB1 are kept at factory default values for this example case.

Table 302: Function settings for OOSRPSB1

Setting	Recommended value	Description
Forward reach	0.44 Ω	Forward reach of mho circle
Reverse reach	6.06 Ω	Reverse reach of mho circle
Inner blinder R	1.88 Ω	Resistance value of inner blinder at R axis
Outer blinder R	3.25 Ω	Resistance value of outer blinder at R axis
Impedance angle	84°	Angle between R axis and mho circle and blinders
Zone 1 reach	55%	Percentage of mho forward reach indicating the end of zone 1 and the beginning of zone 2
Swing time	30 ms	Time between blinders for swing to be detected (30 ms gives max detachable slip 2.77 Hz)
Max number slips	1	Number of pole slips before operating zone 1
Table continues on next page		

Setting	Recommended value	Description
Zone 2 enable	Yes	Enable zone 2 feature
Max Num slips Zn2	4	Number of pole slips before operating zone 2
Breaker open time	50 ms	Opening time of the breaker
Voltage reversal	Yes	

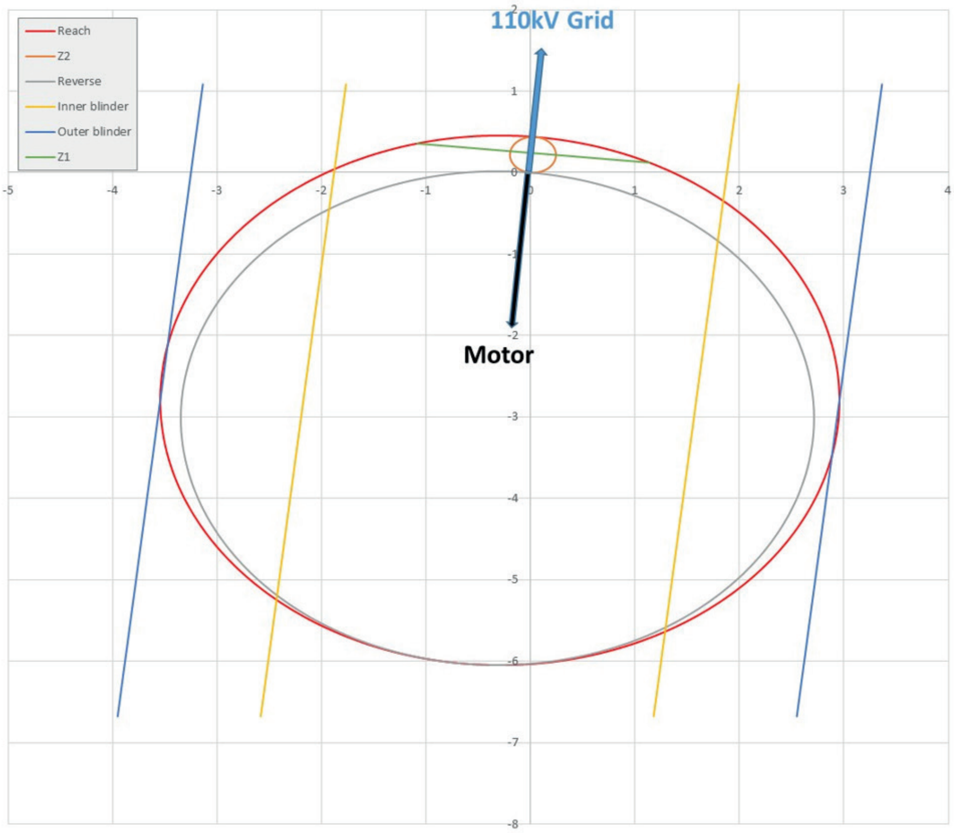

Figure 124: OOSRPSB1 operation characteristics in impedance plane. Values in primary ohm

DOPPDPR1 – Reverse power/directional overpower protection

The overpower protection is used to limit the motor active power. Table 303 shows recommended setting values; all other settings can be kept at factory default values.

Table 303: DOPPDPR1 settings

Setting	Recommended value	Description
Start value	0.53 xSn[1)]	Start value
Operate delay time	5000 ms	Operate delay time

1) 1.05 · 5800 kW / (√3 · 11 kV · 600 A) = 0.532 xSn

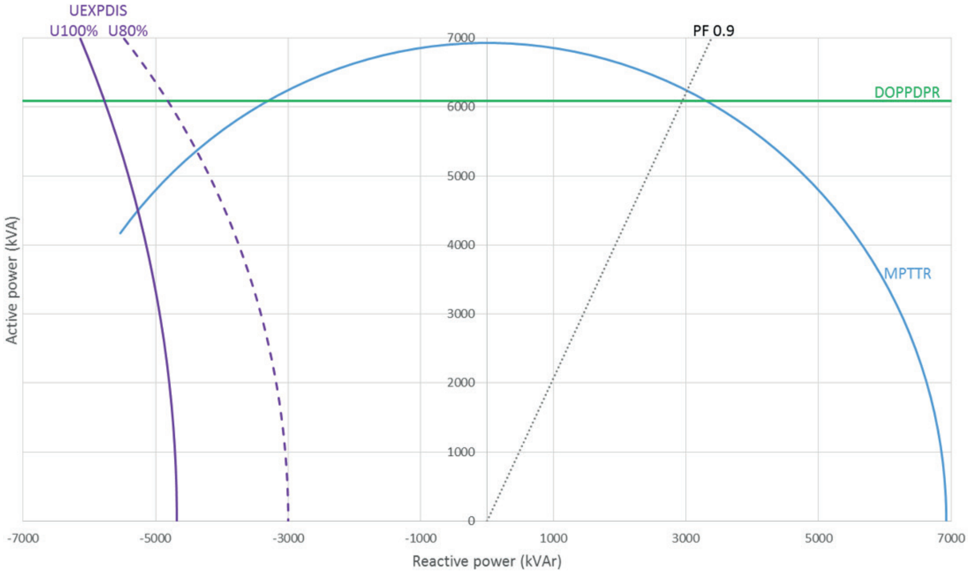

Figure 125: MPTTR1, UEXPDIS1 and DOPPDPR1 operation characteristics in PQ plane

Section 12 Generator breaker synchronization

12.1 Introduction to application

The protection relay offers autosynchronization functionality for synchronizing the generator breaker closing according to given conditions and with minimal additional stress for mechanics and cables. A dedicated function, ASGCSYN, is provided for automatic generator breaker synchronization.

This application example presents how to configure the relay for synchronizing the generator with the network and then closing the generator breaker. First necessary external measurements and control signals are presented, then the relay configuration is presented and the necessary setting values are explained.

This application example handles the use cases where control operations are performed on the local relay display (the relay's L/R state = L). Remote control can be implemented by connecting the relays to a distributed control system.

12.2 Description of the example case

Figure 126 presents a simple 50 Hz network where a generator is connected to the busbar via a generator circuit breaker (GCB). The generator prime mover governor (GOV) and the voltage regulator (AVR) are also shown in the figure since the relay directly interacts with them. Voltage measurements are needed both from the generator's terminals and the busbar.

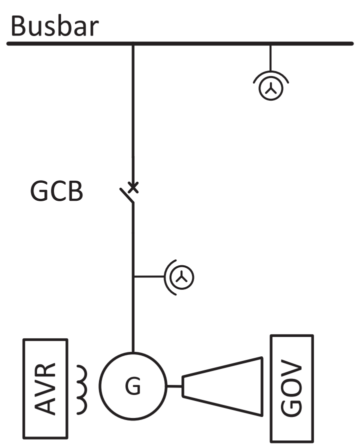

Figure 126: Single-line diagram of the application

12.3 Relay as an autosynchronizer

This chapter provides detailed information about the configuration of the relay used in this application example: the relay interfaces, the ACT diagram, the setting values and information on how the generator synchronization can be achieved for the given example. Instructions for using the application from the local relay display are also provided.

12.3.1 Relay interface, configuration and settings

Autosynchronization requires voltage measurements from the generator's terminals and the busbar using the respective voltage transformers. In Figure 127 all three phase-to-earth voltages (AI1, AI2 and AI3) from the generator are wired to the relay. Autosynchronizer for generator breaker ASGCSYN requires only one voltage from the generator, but three voltages are shown here since three-phase voltage measurements are typically needed for a protection application. See the generator protection application example. From the busbar side, one phase-to-earth voltage (AI4) is wired to the relay.

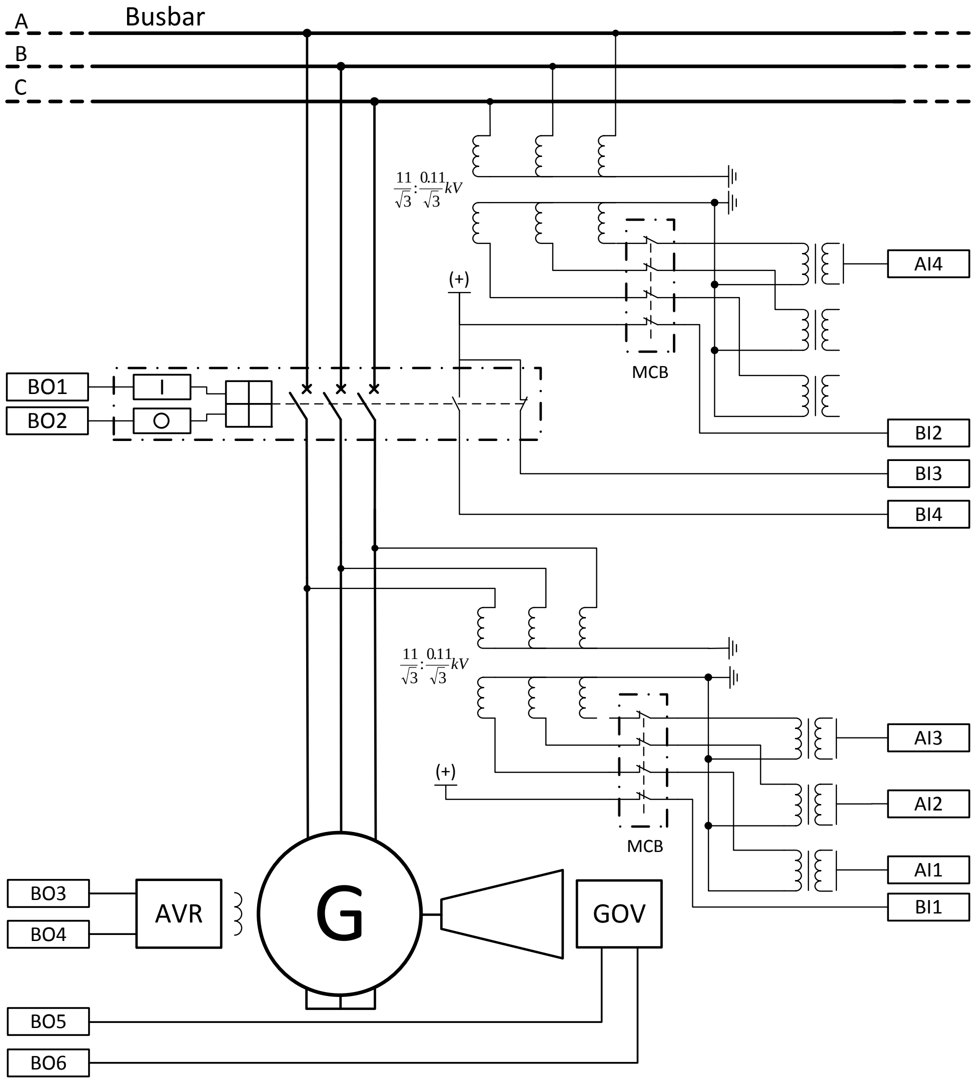

Figure 127: Relay interfaces and VT connections for a single generator synchronization

12.3.1.1 Analog input signals

Table 304: Physical analog input signals for implementing the example case

Analog input	Description
AI1	Generator terminal's phase-to-earth voltage measurement, U_A voltage
AI2	Generator terminal's phase-to-earth voltage measurement, U_B voltage
AI3	Generator terminal's phase-to-earth voltage measurement, U_C voltage
AI4	Busbar phase-to-earth voltage measurement, U_A voltage

12.3.1.2 Binary input signals

Table 305: Physical binary input signals for implementing the example case

Binary input	Description
BI1	Generator terminal VT circuit MCB position. This signal becomes TRUE when MCB is tripped. In such a faulty situation, autosynchronization must be blocked.
BI2	Busbar VT circuit MCB position. This signal becomes TRUE when MCB is tripped. In such faulty situation, autosynchronization must be blocked.
BI3	GCB open position. TRUE state of this signal indicates GCB is open.
BI4	GCB closed position. TRUE state of this signal indicates GCB is closed.

12.3.1.3 Binary output signals

Table 306: Physical binary output signals for implementing the example case

Binary output	Description
BO1	Close GCB. Connected to the closing coil of the GCB. TRUE state closes the breaker.
BO2	Open GCB. Connected to the opening coil of the GCB. TRUE state opens the breaker.
BO3	AVR raise. Connected to the AVR voltage raise input. When the bus voltage is greater than the generator voltage, TRUE state pulses are used to raise the generator voltage.
BO4	AVR lower. Connected to the AVR voltage lower input. When the bus voltage is lesser than the generator voltage, TRUE state pulses are used to lower the generator voltage.
BO5	Governor raise. Connected to the governor's speed raise input. When the bus frequency is greater than the generator frequency, TRUE state pulses are used to raise the generator's speed.
BO6	Governor lower. Connected to the governor's speed lower input. When the bus frequency is lesser than the generator frequency, TRUE state pulses are used to lower the generator's speed.

12.3.1.4 Recommended alarms

Table 307 presents a proposal for LHMI and WHMI alarm handling. The table lists the functions, and events under the functions, which should be tagged as alarms using Event Filtering in PCM600.

Table 307: Alarm list for the example case

Event container	Event	Description
ASGCSYN1	CL_FAIL_AL	Circuit breaker close fail alarm
ASGCSYN1	CMD_FAIL_AL	Circuit breaker close command fail alarm
ASGCSYN1	CB_CL_BLKD	Circuit breaker close blocked
UTVTR1	ALARM	Voltage preprocessing fault
UTVTR1	WARNING	Voltage preprocessing fault
UTVTR2	ALARM	Voltage preprocessing fault
UTVTR2	WARNING	Voltage preprocessing fault

12.3.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 308: Function blocks used in the application example

Function block	Description
UTVTR1	Voltage preprocessing function for measuring generator voltages
UTVTR2	Voltage preprocessing function for measuring busbar voltage
ASGCSYN1	Autosynchronizer for generator breaker
CBXCBR1	Generator circuit-breaker control

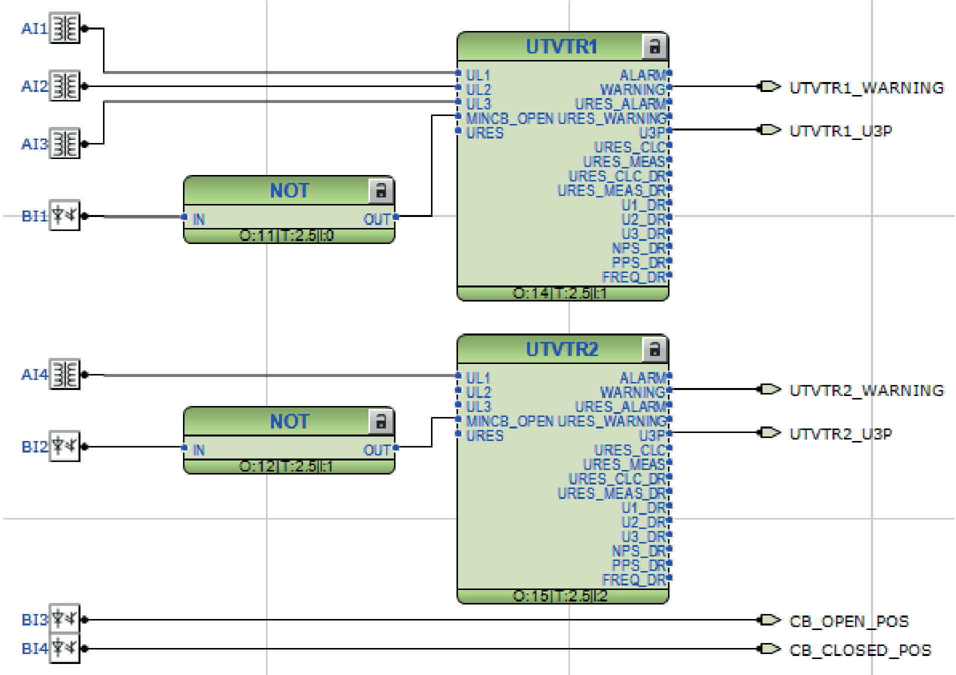

Figure 128: Relay inputs and preprocessing connections

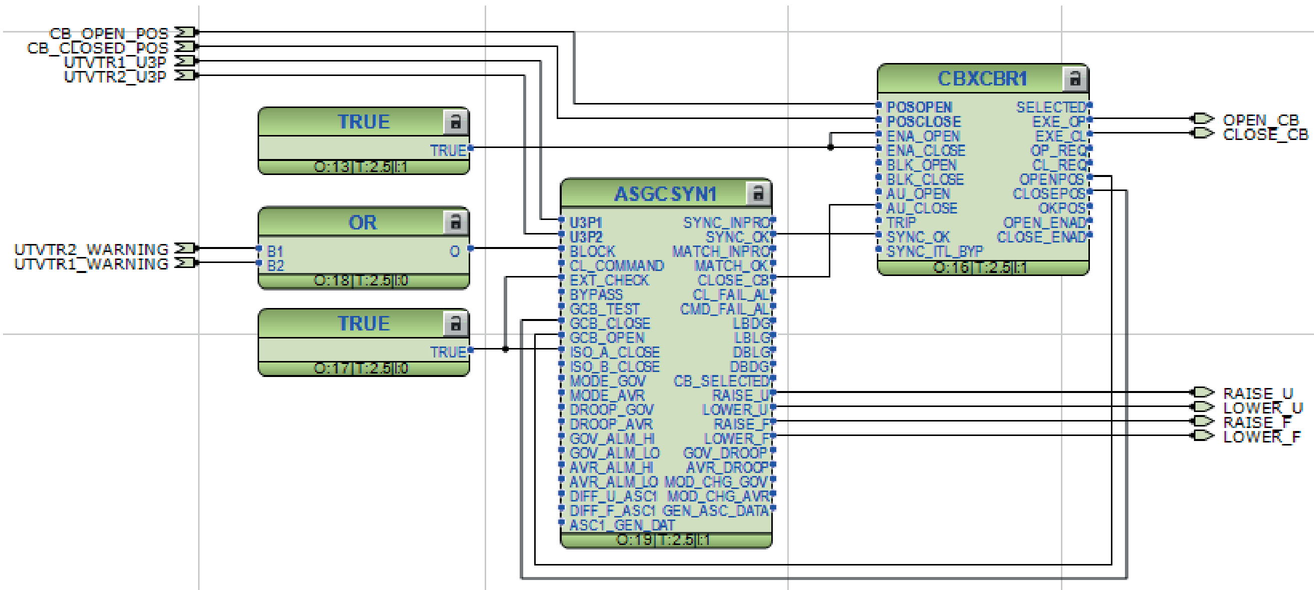

Figure 129: Application function block connections

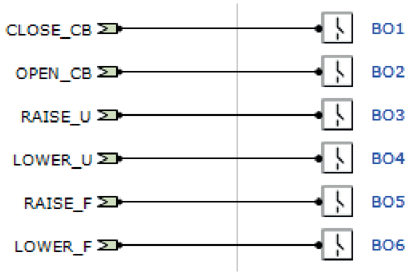

Figure 130: Relay output connections

12.3.1.6 Function blocks and setting values

Generic control settings

Generator applications typically use frequency adaptive measurements due to the generator's start-up and shutdown phases where the generator frequency deviates from nominal. By activating frequency adaptivity, accurate measurements are guaranteed independently of the generator's frequency. Table 309 shows recommended setting values; all other settings can be kept at default values. These generic control settings are located under **Configuration/System**.

Table 309: Global control settings

Setting	Suggested value	Description
Frequency adaptivity	Enable	Enabling frequency adaptivity

UTVTR1 and UTVTR2 – Phase and residual voltage preprocessing

UTVTR is the analog signal preprocessing function for measured voltages. One function instance is needed for the generator's three-phase voltages and the second one for the busbar voltage. Preprocessing functions allow to set up measurement channels according to voltage levels and selected voltage transducers.

The `WARNING` output is used in the relay configuration to block the ASGCSYN function. The output is activated when the miniature circuit breaker is tripped. If `WARNING` is set to TRUE, autosynchronization must be cancelled. See the technical manual for more details.

Frequency adaptivity needs to be activated for UTVTR1. Table 310 and Table 311 show recommended setting values; all other settings can be kept at default values.

Table 310: UTVTR1 settings

Setting	Suggested values	Description
Primary voltage	6.4 kV	Primary voltage value
Secondary voltage	64 V	Secondary voltage value
VT connection	1=Wye	Voltage transducer measurement connection
Frequency adaptivity	Main frequency Source	Frequency adaptivity selection. This setting is available in UTVTR.

Table 311: UTVTR2 settings

Setting	Suggested values	Description
Primary voltage	6.4 kV	Primary voltage value
Secondary voltage	64 V	Secondary voltage value
VT connection	1=Wye	Voltage transducer measurement connection

ASGCSYN1 – Autosynchronizer for generator breaker

ASGCSYN checks the conditions across the circuit breaker from the generator and busbar side and issues the pulse commands to automatic voltage regulator and prime mover governor for matching the voltage and frequency conditions if required. Once the synchronization check and close CB conditions are fulfilled, the function gives the permission to close the circuit breaker. ASGCSYN includes the functionality of energizing check, synchronization check and voltage and frequency matching.

The generator breaker closing is usually implemented so that the generator has slightly higher frequency than the busbar, that is, the generator is oversynchronous. Thus the governor and the automatic voltage control have little time to react when the load increases in order to avoid a reverse power situation. The oversynchronous generator can be selected with setting *Synchronization Dir*. Table 312 shows recommended setting values; all other settings can be kept at default values.

Table 312: ASGCSYN setting

Setting	Suggested values	Description
Synchronization Dir	Always over synchronous	Forces the generator's frequency to be higher than the grid frequency during breaker closing
Auto Syn mode	Automatic synchronizing mode	Selection for automatic synchronization

12.3.2 Use of generator synchronization application

Two use cases are provided in this chapter: automatic synchronization and manual synchronization. The starting point for both cases is the same: the generator breaker is open and the busbar is energized.

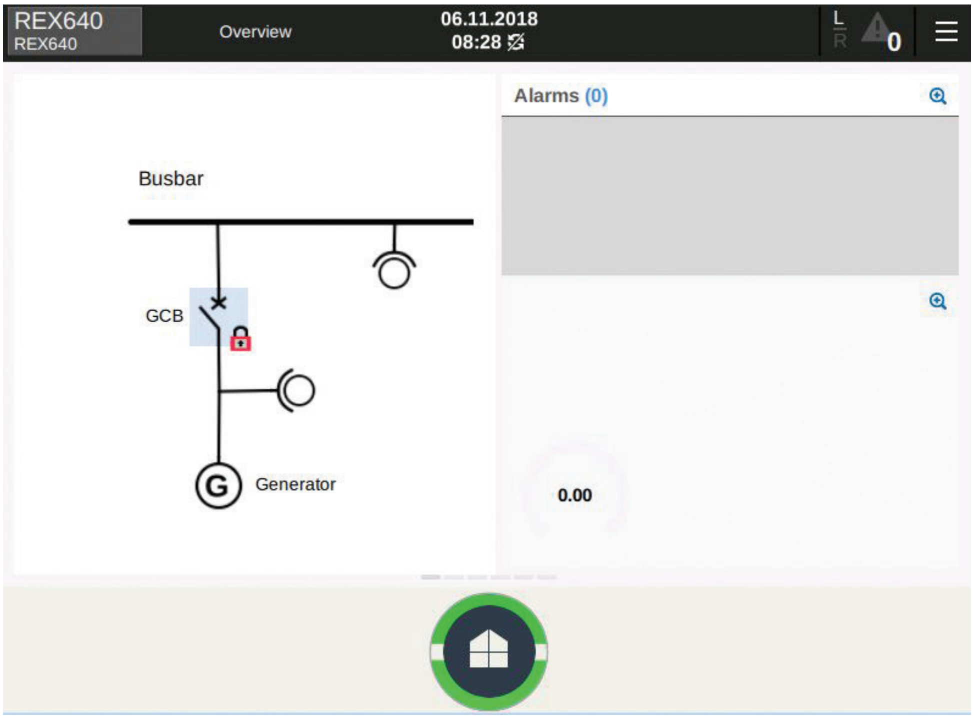

Figure 131: Generator breaker is open

12.3.2.1 Synchronizing generator breaker automatically

1. Tap the generator breaker on the relay display.
2. Set *Auto Syn mode* to "Automatic synchronising mode" and *Live dead mode* to "Off".

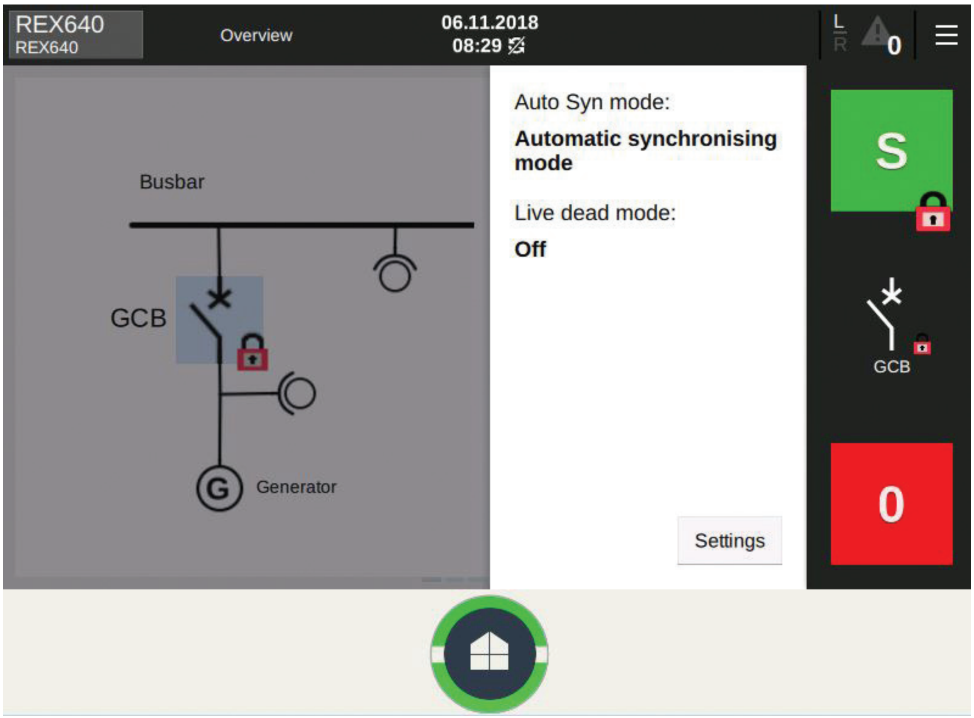

Figure 132: Generator breaker is selected for autosynchronization

3. Tap **S** to start the automatic synchronization.

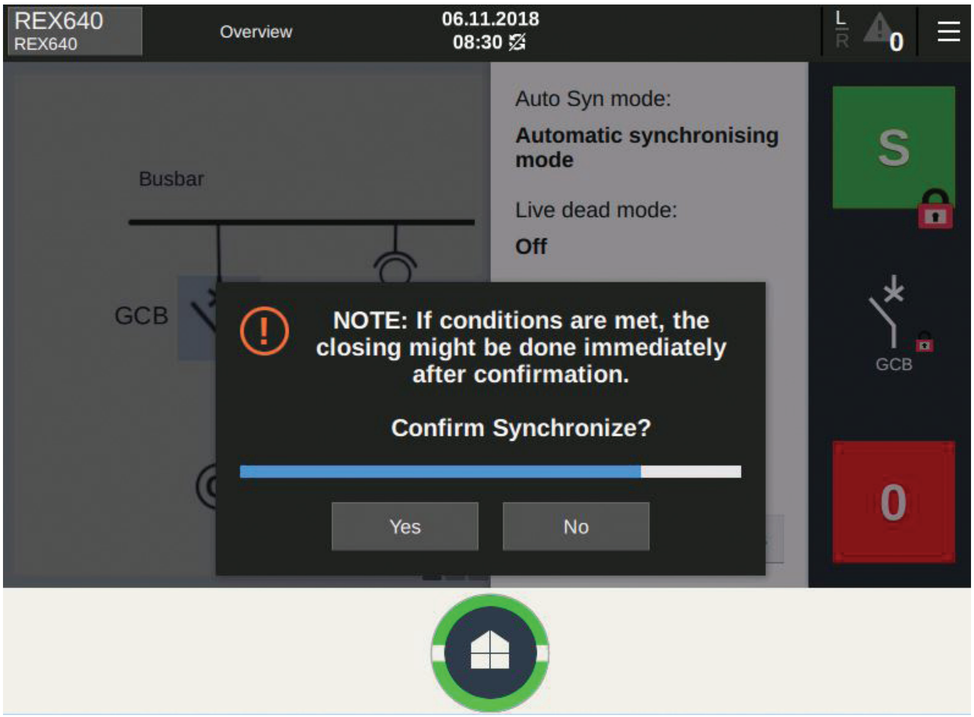

Figure 133: Synchronization dialog

4. Tap **Yes** to confirm the synchronization process.
   The automatic synchronization of the voltage and frequency with the busbar is in progress.

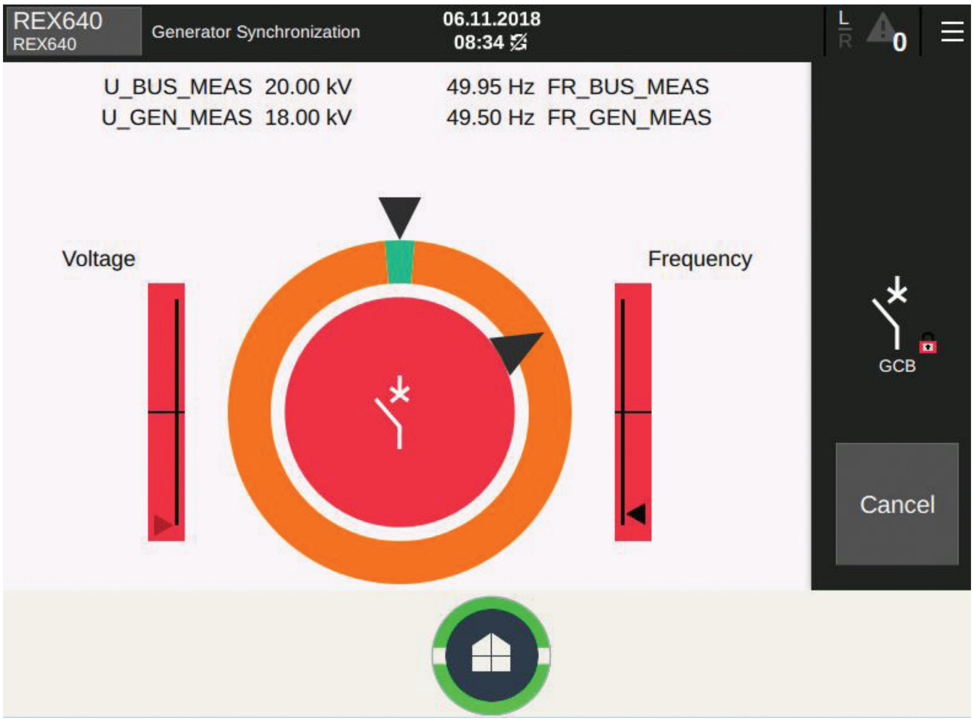

Figure 134: Autosynchronization in progress

After the automatic autosynchronization is completed, ASGCSYN issues the close command to the generator breaker.

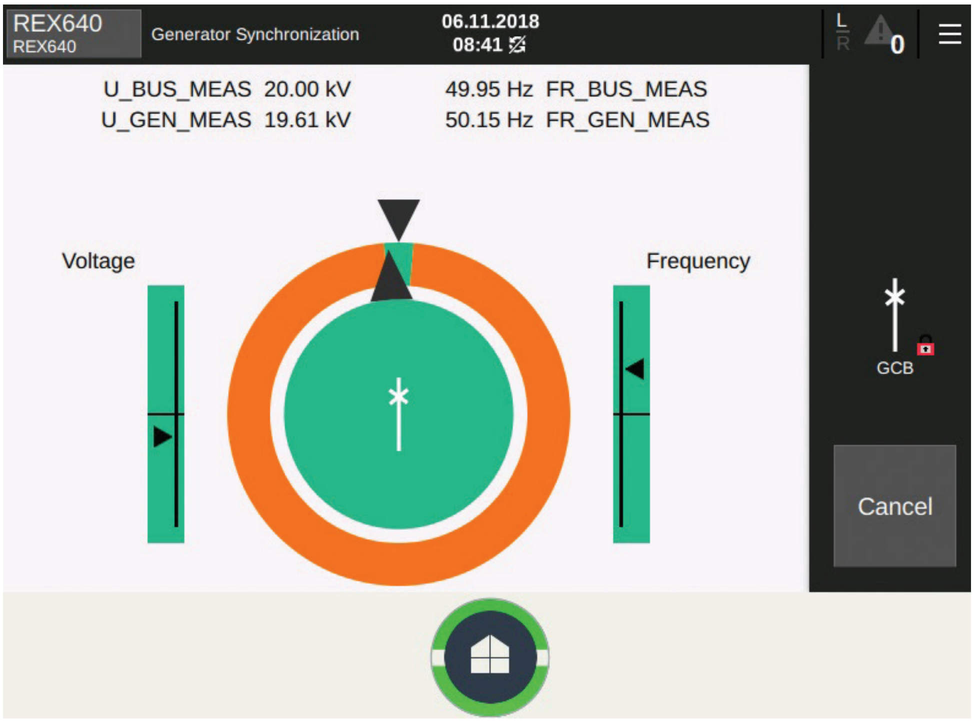

Figure 135: Autosynchronization process is completed and the breaker is closed

12.3.2.2 Synchronizing generator breaker manually

1. Press the generator breaker on the relay display.
2. Set *Auto Syn mode* to "Manual mode" and *Live dead mode* to "Off".

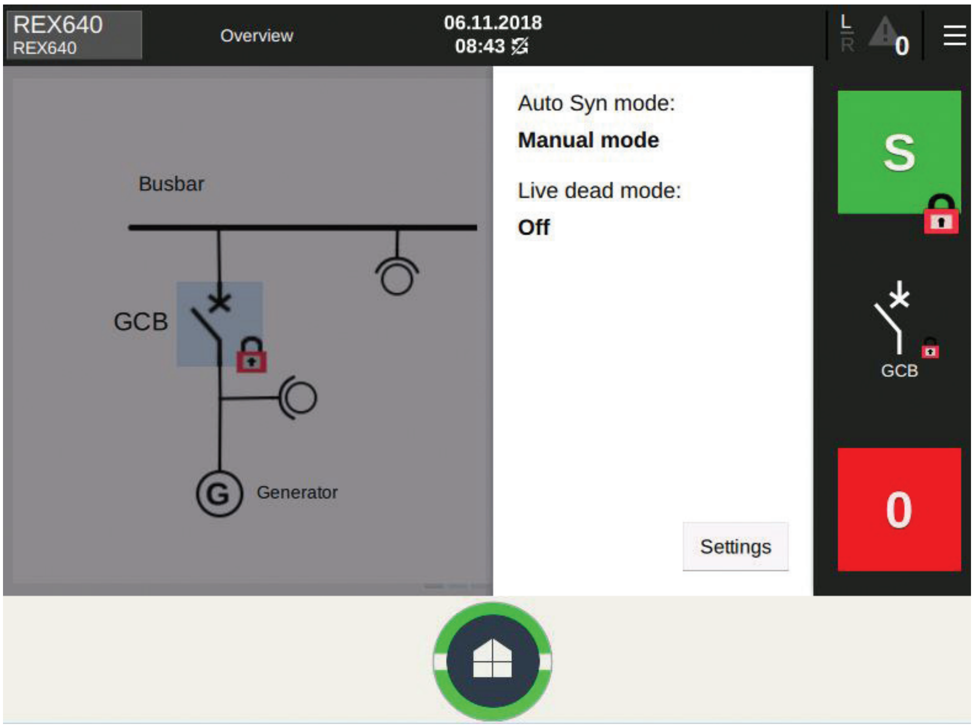

Figure 136: Settings for manual synchronization

3. Press **S**.
   The Confirm Synchronize dialog opens.

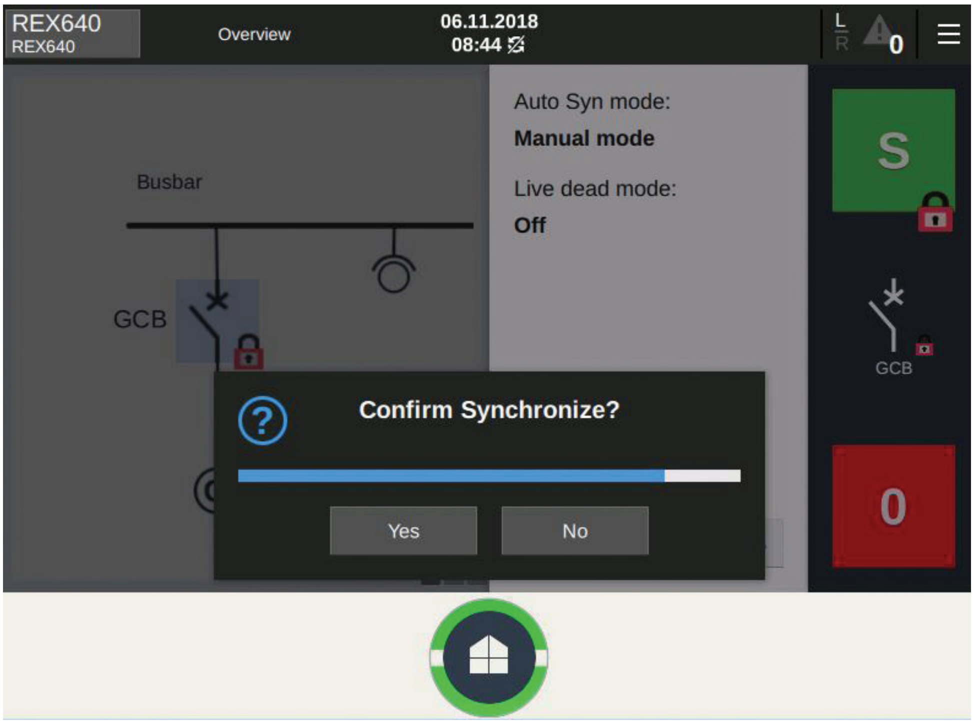

Figure 137: Confirm synchronization view

4. Press **Yes** to open the Synchroscope view.

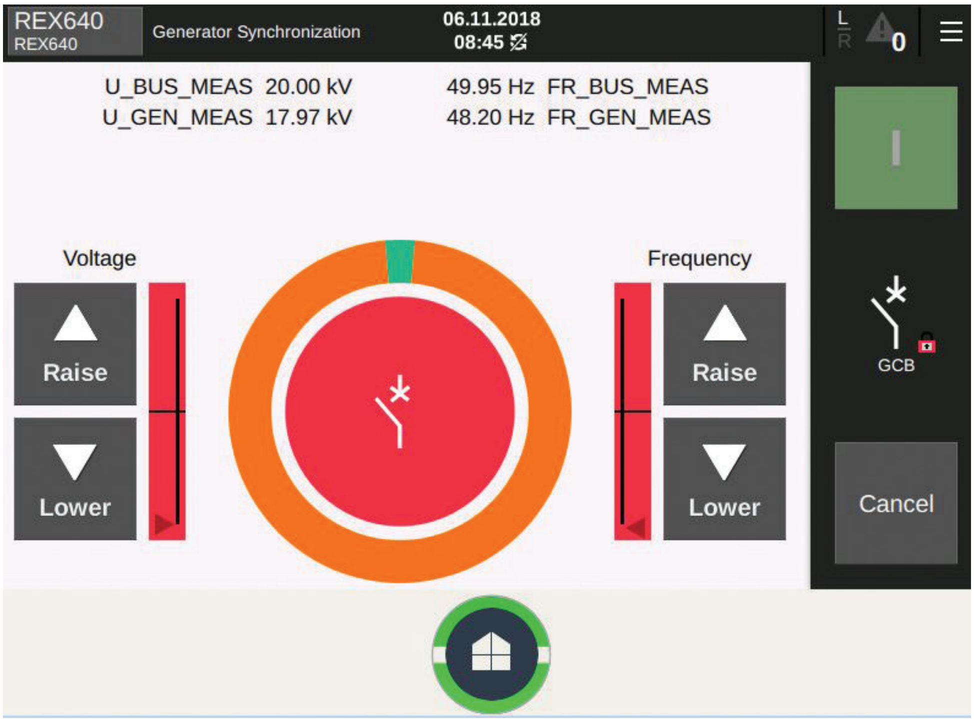

Figure 138: Synchroscope for manual pulses

5. Press the voltage and frequency **Raise** buttons to decrease the voltage and frequency difference between the generator and the bus.

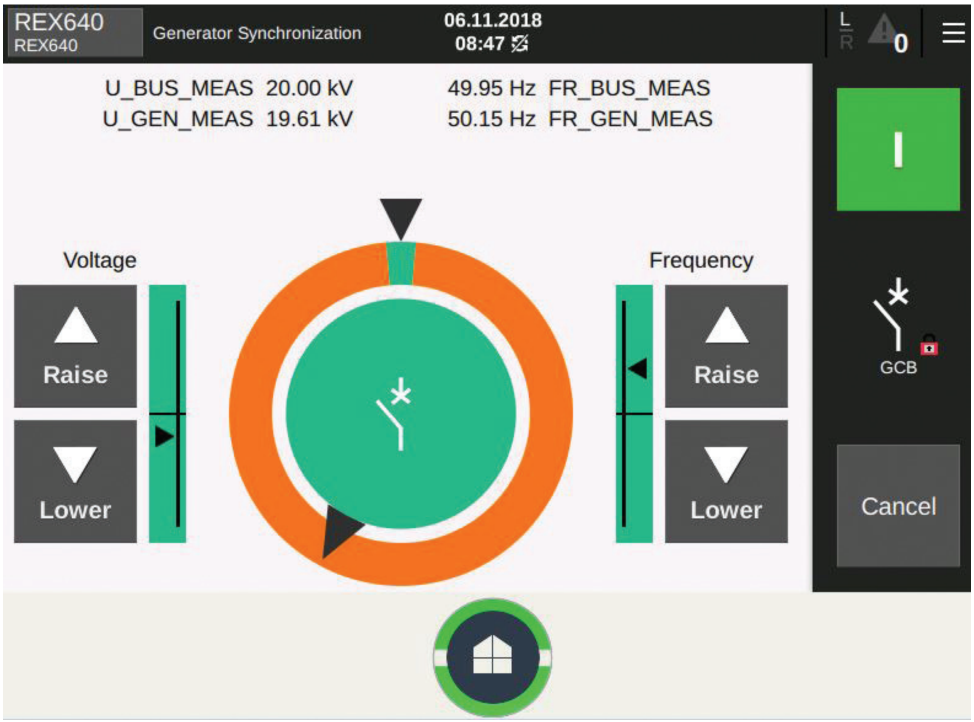

Figure 139: Conditions met for breaker closing

The voltage and frequency difference is now level which allows the breaker closing.

6. Press **I** to close the breaker. The relay starts to search for the earliest moment to close the breaker.

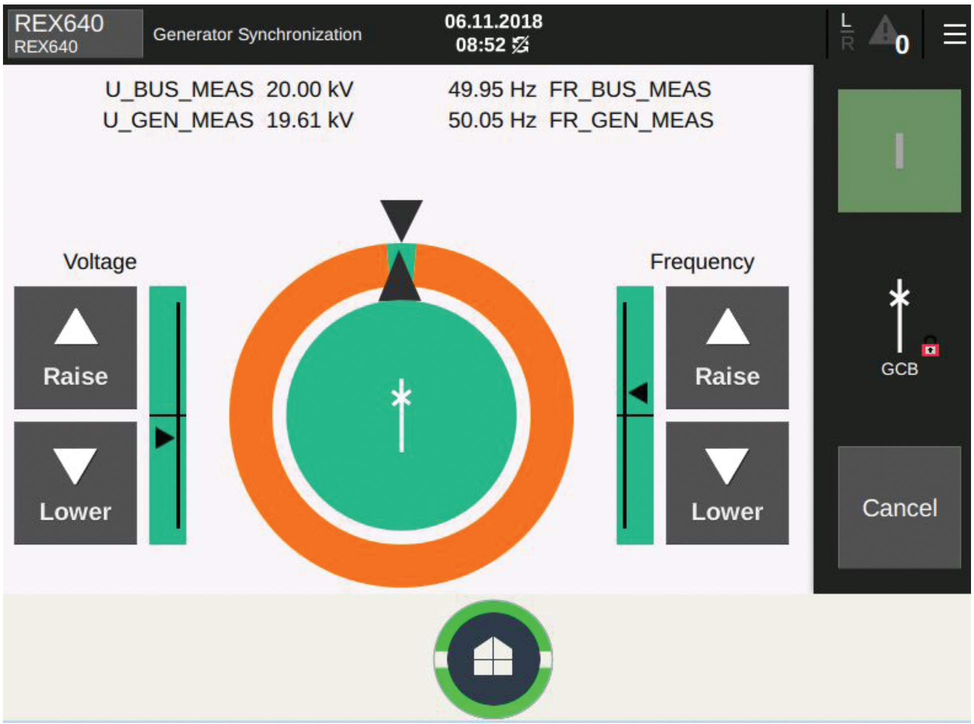

Figure 140: Synchronization complete and breaker closed

Section 13 Non-generator breaker autosynchronization

13.1 Introduction to application

Besides generator breaker synchronization, the relay offers functionality for synchronizing non-generator circuit breakers, that is, non-source circuit breakers (NSCB) such as grid connection or bus coupler circuit breakers.

The relay provides dedicated functions, ASGCSYN, ASNSCSYN and ASCGAPC, for automatic synchronization of applications of various sizes. ASGCSYN is used for generator circuit breaker (GCB) synchronization. ASNSCSYN is used for non-generator (for example, grid connection or bus coupler) circuit breaker synchronization. ASCGAPC is a coordination function which is necessary if the application contains non-generator circuit breakers.

This application example handles the use cases where control operations are performed on the local relay display (relay L/R state = L). The generator relay must be in remote mode if it participates in NSCB autosynchronization.

Control operations can also be done remotely, for example, with a distributed control system. However, this is not in the scope of this application example.

13.2 Description of the example case

Figure 141 presents a 11 kV network with grid connection, local power generation and loads. GCB and NSCB couple together two independent network parts. These two network parts have to be synchronized in terms of frequency, voltage and angle difference before the closing of the circuit breaker can be allowed. To illustrate a more realistic application, also two feeder loads are shown. However, those feeder relays do not have any dependency on the autosynchronization system and therefore those are not explained in this application example.

The circuit breaker synchronization requires the two network parts to be energized and at least one side to contain local adjustable power generation. It must also be possible to close the circuit breaker if one side is de-energized; this is typically referred to as "dead-bus/live-line" closing.

The relay configuration for the GCB relay is based on the application example for generator breaker autosynchronization (see elsewhere in this manual). Additional signaling has been added to receive status signals from the automatic voltage regulator (AVR) and the prime mover governor (GOV). In the relay configuration, a dedicated coordinator functionality has been added to allow communication between the relays connected to the autosynchronization system.

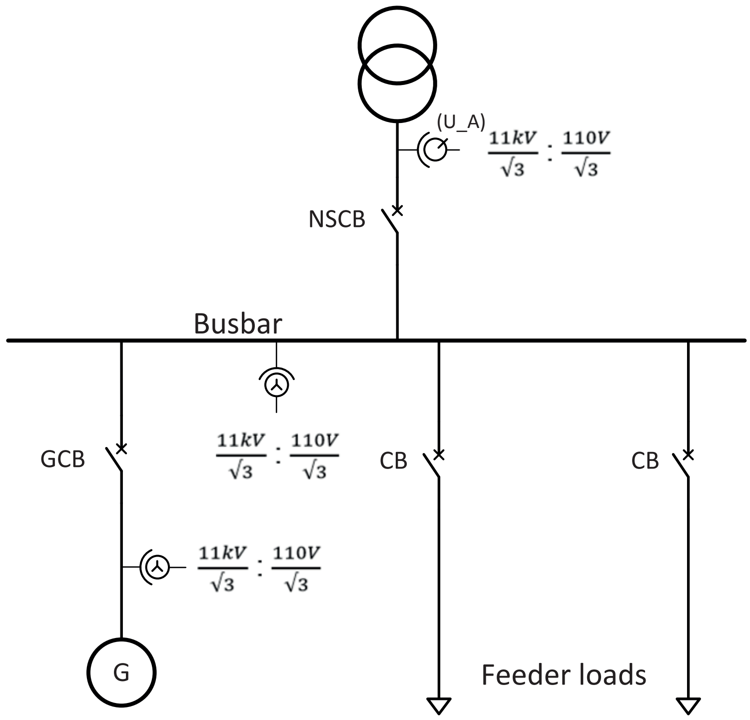

Figure 141: Example configuration of NSCB autosynchronization

13.3 Relay as non-source circuit breaker autosynchronizer

This chapter provides detailed information about the configuration for the relays necessary in this application example: the relay interfaces, the relay configuration diagram and parameter settings along with information on how the generator synchronization can be achieved for the given example.

13.3.1 Relay interface, configuration and settings

The relay interface to physical hardware is shown in Figure 142. The interfaces are defined from the autosynchronization point of view. Voltage measurements are needed from the grid side as well as from busbar side using the respective voltage transformers. In this example case of busbar side, phase-to-earth voltages are measured by a set of three VTs connected to relay inputs AI1, AI2 and AI3. Grid side phase-to-earth voltage U_A is measured by a single VT connected to relay input AI4. The breaker control is implemented with relay outputs BO1 and BO2. The breaker position information is wired to the relay's binary inputs BI3 and BI4.

MCB statuses on the voltage measurement circuit are wired to binary inputs BI1 and BI2. Additionally, the application requires inter-relay communication implemented with IEC 61850-8-1 GOOSE which uses a station bus to share information between the participating relays.

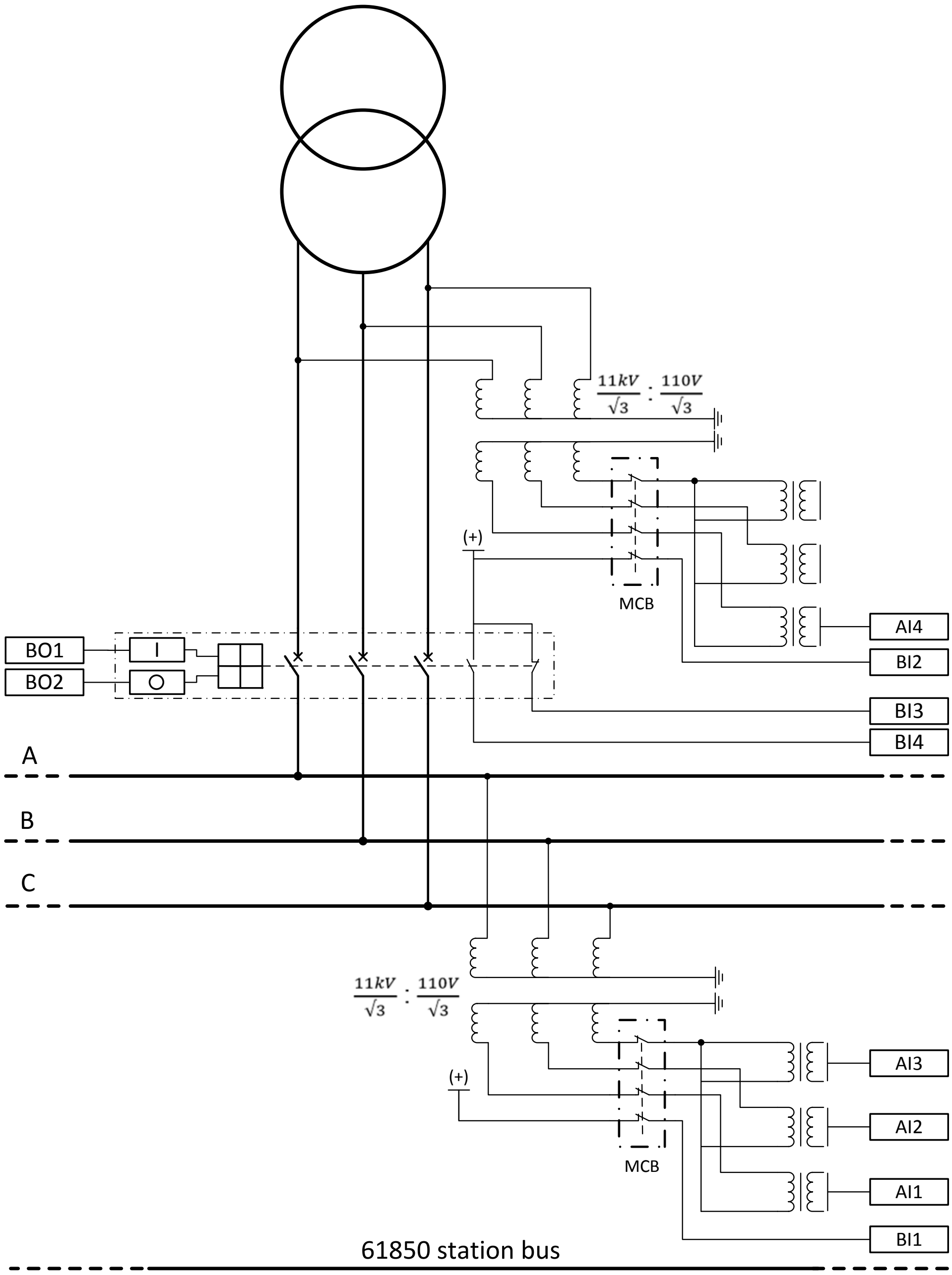

Figure 142: Relay interfaces and VT connections for the example case

13.3.1.1 Analog input signals

Table 313: Physical analog input signals for implementing the example case

Analog input	Description
AI1	Bus voltage measurement, U_A voltage
AI2	Bus voltage measurement, U_B voltage
AI3	Bus voltage measurement, U_C voltage
AI4	Grid voltage measurement, U_A voltage

13.3.1.2 Binary input signals

Table 314: Physical binary input signals for implementing the example case

Binary input	Description
BI1	Grid side VT circuit MCB position. FALSE state indicates the VT measurement circuit is open.
BI2	Busbar side VT circuit MCB position. FALSE state indicates the VT measurement circuit is open.
BI3	Network breaker position opened to confirm NSCB is open. TRUE state of this signal indicates NSCB is opened.
BI4	Network breaker position closed to confirm NSCB is closed. TRUE state of this signal indicates NSCB is closed.

13.3.1.3 Binary output signals

Table 315: Physical binary output signals for implementing the application example

Binary output	Description
BO1	Close NSCB. Connected to the closing coil of the NSCB. TRUE state closes the breaker.
BO2	Open NSCB. Connected to the opening coil of the NSCB. TRUE state opens the breaker.

13.3.1.4 Recommended alarms

Table 316 presents a proposal for WHMI and LHMI alarm handling. The table lists the functions, and events under the functions, which should be tagged as alarms using Event Filtering in PCM600.

Table 316: Alarm list for implementing the application example

Function name	Event	Description
Voltage (3U,VT)	WARNING	Busbar voltage measurement circuit MCB open
Voltage (3UB,VT)	WARNING	Grid voltage measurement circuit MCB open
ASNSCSYN1	CL_FAIL_AL	Circuit breaker close fail alarm
ASNSCSYN1	CMD_FAIL_AL	Circuit breaker close command fail alarm
ASNSCSYN1	CB_CL_BLKD	Circuit breaker close blocked
ASCGAPC1	AS_CONFLICT[1)]	Conflicting condition in autosynchronization coordination

1) See the technical manual for more information.

13.3.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600. The simple logic blocks are not listed in Table 317.

Table 317: Function blocks used in the application example

Function block	Description
UTVTR1	Voltage preprocessing function for measuring busbar voltages
UTVTR2	Voltage preprocessing function for measuring the grid voltage
ASNSCSYN1	Autosynchronizer for network breaker
ASCGAPC1	Autosynchronizer co-ordinator
CBXCBR1	Grid circuit breaker control
GOOSERCV_INT32	IEC 61850-8-1 GOOSE receiver for INT32 type data

Figure 143, Figure 144, Figure 145 and Figure 146 present the relay configuration implemented with ACT.

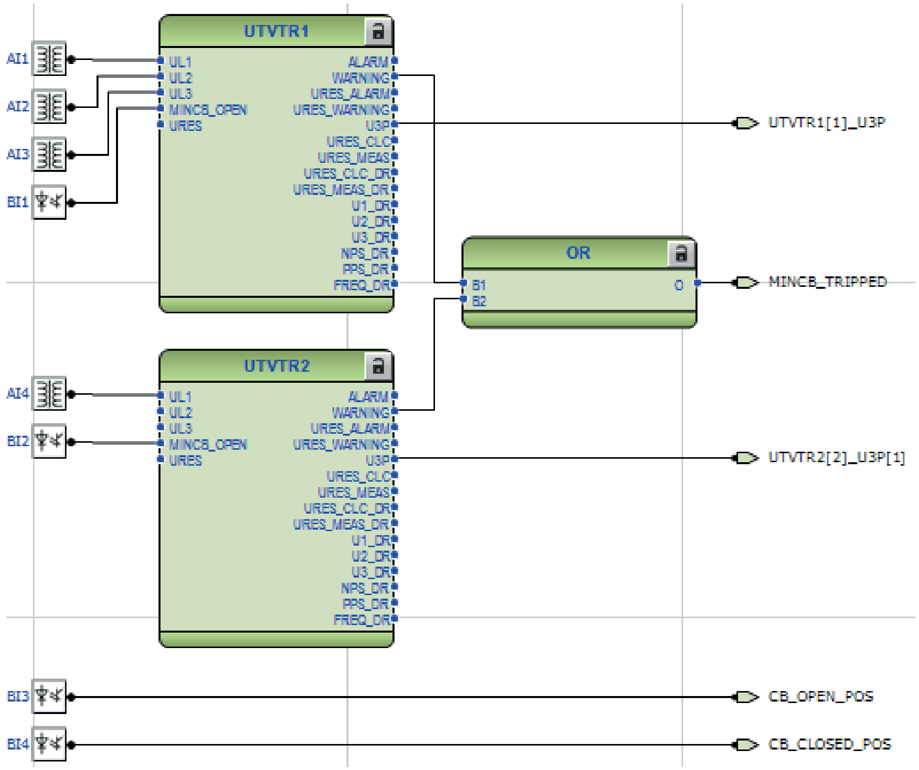

Figure 143: Input section

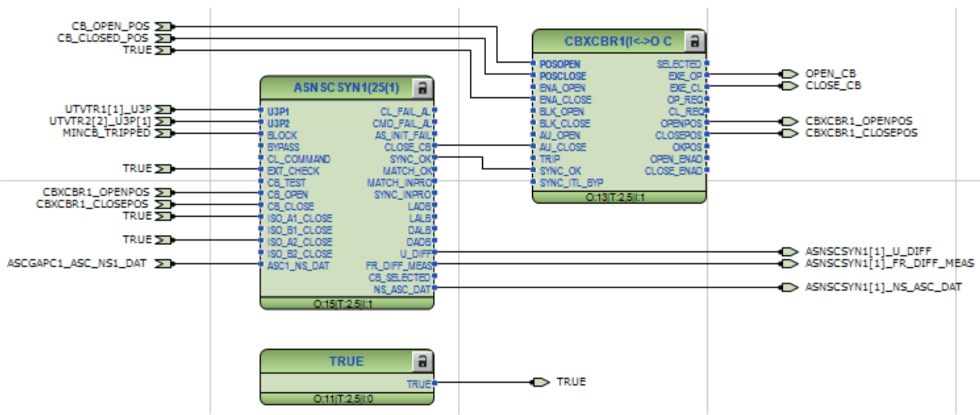

Figure 144: Autosynchronization control section

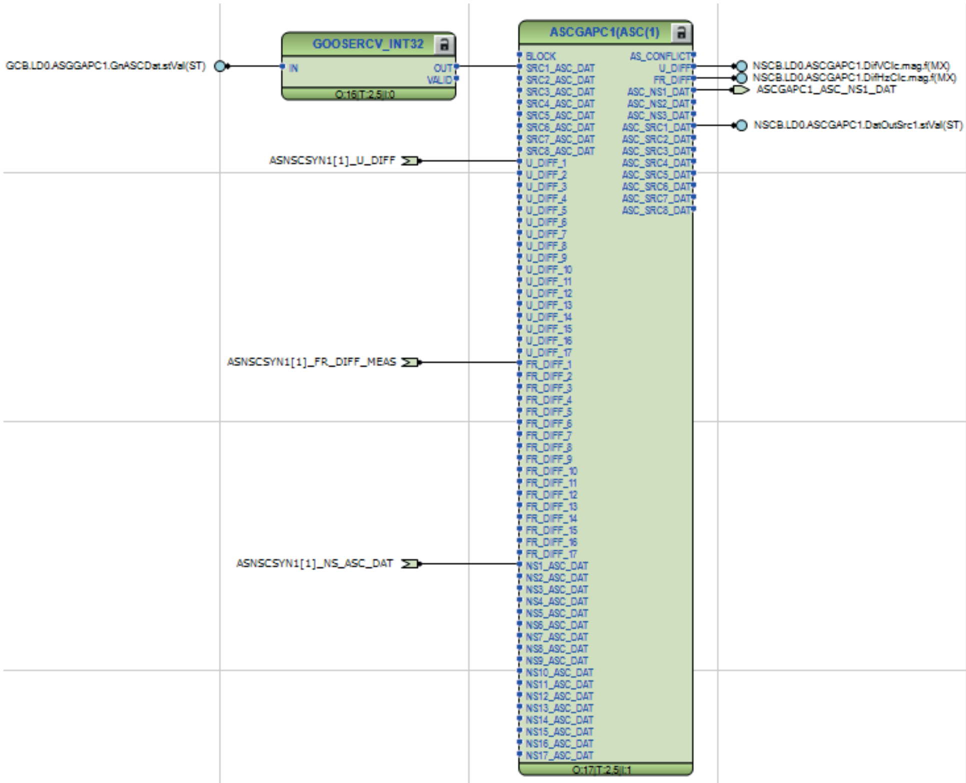

Figure 145: Autosynchronization coordinator section

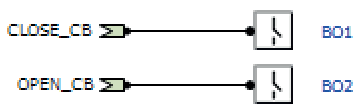

Figure 146: Relay output connections

13.3.1.6 Function blocks and setting values

UTVTR1 and UTVTR2 – Phase and residual voltage preprocessing

UTVTR is the analog signal preprocessing function for measured voltages. One function instance is needed for the busbar's three phase-to-earth voltages and a second one for a single grid's phase-to-earth voltage. Preprocessing functions allow to set up measurement channels according to voltage levels and selected voltage transducers.

UTVTR `WARNING` output is used in relay configuration to block ASNSCSYN1. `WARNING` output is activated when the MCB is tripped. Autosynchronization must be cancelled if `WARNING` is set to TRUE.

Table 318 shows recommended setting values; all other settings can be kept at default values.

Table 318: UTVTR1 and UTVTR2 settings

Setting	Suggested values		Description
	UTVTR1	UTVTR2	
Voltage input type	Voltage trafo	Voltage trafo	Type of the voltage input
Primary voltage	11 kV	11 kV	Primary voltage value
Secondary voltage	110 V	110 V	Secondary voltage value
VT connection	Wye	Wye	Voltage transducer measurement connection

ASNSCSYN1 – Autosynchronizer for network breaker

ASNSCSYN1 checks the conditions across the circuit breaker from the busbar and grid side. The function communicates the measured voltage and frequency difference and control requests to coordinator function ASCGAPC. Once the synchronization check and close CB conditions are fulfilled, the function gives permission to close the circuit breaker. ASNSCSYN1 includes the functionality of energizing check and synchronization check.

Table 319 shows recommended setting values; all other settings can be kept at default values.

Table 319: Non-default setting values for ASNSCSYN1

Setting	Suggested values	Description
Auto Syn mode	Automatic synchronising mode	The autosynchronization operation mode is set to have automatic matching and automatic issue of the CB closing command.

ASCGAPC1 – Autosynchronizer co-ordinator

ASCGAPC1 handles the control request and shares information in the application where multiple relays are connected to the autosynchronization system. Table 320 shows recommended setting values; all other settings can be kept at default values.

Table 320: Non-default setting values for ASCGAPC1

Setting	Suggested values	Description
Number of sources	1	Total number of sources in the system
Number of NonSrc CB	1	Number of bus coupler or grid transformer CBs in the system
Src1 bus A Num	Bus 1	Source1 CB connected bus A number
NonSrc1 bus A1 Num	Bus 1	Non-source CB1 connected bus A1 number
NonSrc1 Bus A2 Num	Grid	Non-source CB1 connected bus A2 number

CBXCBR1 – Circuit-breaker control

CBXCBR1 interfaces the autosynchronization closing request to the circuit breaker. All setting values can be kept on their default.

13.3.1.7 IEC 61850-8-1 GOOSE configuration

GOOSE signals are used to implement communication between the participating relays.

Table 321: IEC 61850-8-1 GOOSE input signals for non-generator relay

Source data in other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input
GCB	ASGCSYN1	GEN_ASC_DATA	LD0.ASGGAPC1.GnASCDat.stVal[1)]	Control data from the generator relay	ASCGAPC1	SRC1_ASC_DAT

1) Input signal is received via GOOSERCV_INT32.

Table 322: IEC 61850-8-1 GOOSE output signals for non-generator relay

Function block	Output	Data	Description
ASCGAPC1	U_DIFF	LD0.ASCGAPC1.DifVClc.mag.f	Measured voltage difference to be sent to the generator relay
ASCGAPC1	FR_DIFF	LD0.ASCGAPC1.DifHzClc.mag.f	Measured frequency difference to be sent to the generator relay
ASCGAPC1	ASC_SRC1_DAT	LD0.ASCGAPC1.DatOutSrc1.stVal	Control data to be sent to the generator relay

13.4 Relay as generator breaker synchronizer

This chapter provides detailed information about the configuration for the relays necessary in this application example: the relay interfaces, the relay configuration diagram and parameter settings along with information on how the generator synchronization can be achieved for the given example.

13.4.1 Relay interface, configuration and settings

The relay interface to physical hardware is shown in Figure 147. In this example case of generator side, phase-to-earth voltages are measured by a set of three VTs connected to relay inputs AI1, AI2 and AI3. Bus side phase-to-earth voltage U_A is measured by a single VT connected to relay input AI4. MCB statuses on the voltage measurement circuit are wired to binary inputs BI1 and BI2. The breaker control is implemented with relay outputs BO1 and BO2. The breaker position information is wired to the relay's binary inputs BI3 and BI4.

Binary outputs BO3 and BO4 are reserved for AVR control. Binary inputs BI5 and BI6 are used for monitoring AVR overresponsiveness. Binary input BI7 indicates the AVR droop mode selection.

Binary outputs BO5 and BO6 are reserved for GOV control. Binary inputs BI8 and BI9 are used for monitoring GOV overresponsiveness. Binary input BI10 indicates the GOV droop mode selection.

Additionally, the application requires inter-relay communication implemented with IEC 61850-8-1 GOOSE which uses a station bus to share information between the participating relays.

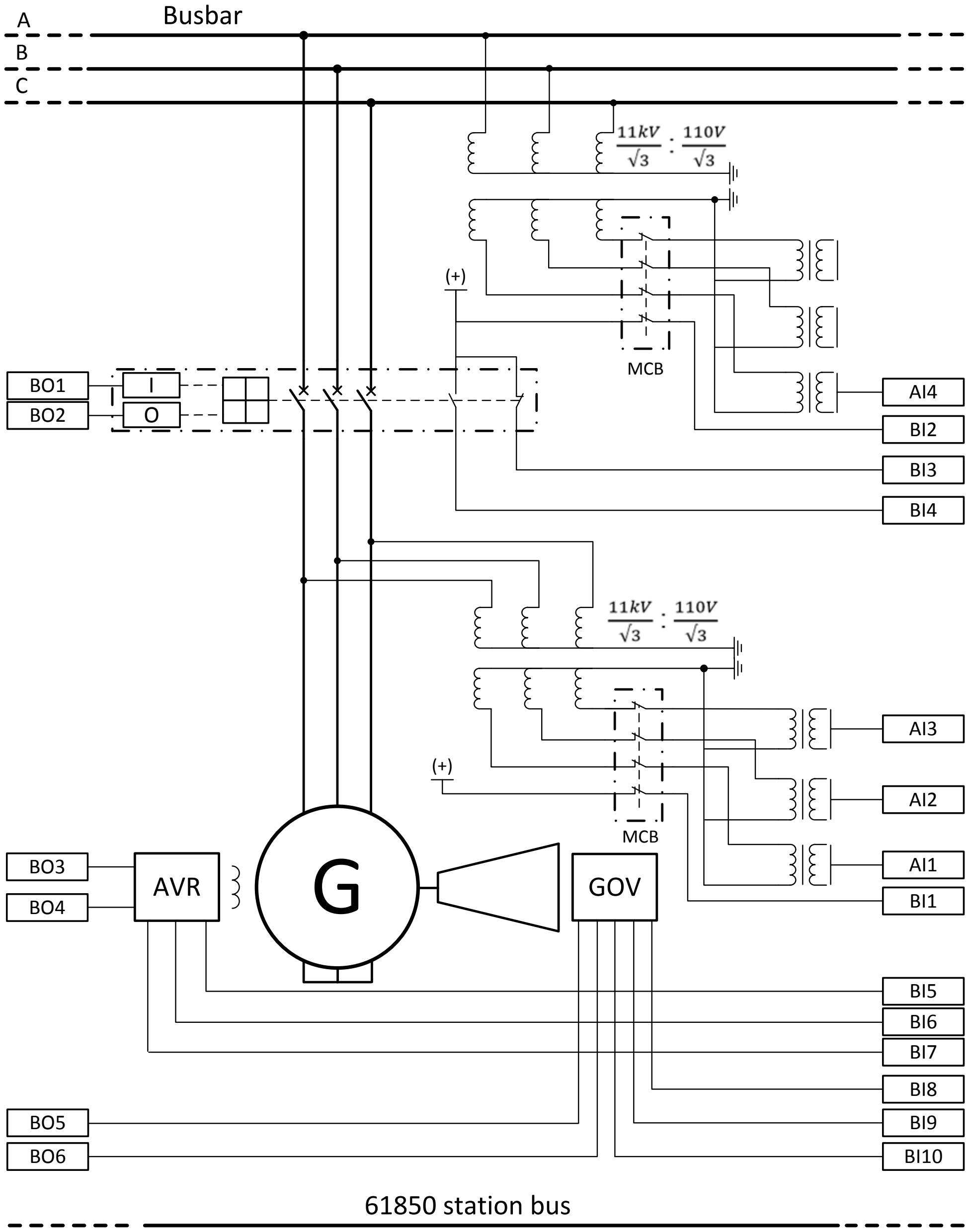

Figure 147: Relay connection points to the primary process

13.4.1.1 Analog input signals

Table 323: Physical analog input signals for implementing the example case

Analog input	Description
AI1	Generator voltage measurement, U_A voltage
AI2	Generator voltage measurement, U_B voltage
AI3	Generator voltage measurement, U_C voltage
AI4	Busbar voltage measurement, U_A voltage

13.4.1.2 Binary input signals

Table 324: Physical binary input signals for implementing the example case

Binary input	Description
BI1 and BI2	Generator and Bus B VT circuit MCB position respectively. FALSE state indicates VT circuit MCB is open and synchronization must be blocked.
BI3	Generator breaker position opened to confirm GCB is open. TRUE state of this signal indicates GCB is open.
BI4	Generator breaker position closed to confirm GCB is closed. TRUE state of this signal indicates GCB is closed.
BI5	AVR overresponsive to increment. TRUE state indicates voltage control raise pulse causes too large voltage increment on the generator.
BI6	AVR overresponsive to decrement. TRUE state indicates voltage control lower pulse causes too large voltage decrement on the generator.
BI7	AVR droop state. TRUE state indicates AVR is in droop mode.
BI8	GOV overresponsive to decrement. TRUE state indicates GOV raise pulse causes too large speed decrement on the generator.
BI9	GOV overresponsive to increment. TRUE state indicates GOV raise pulse causes too large speed increment on the generator.
BI10	GOV droop state. TRUE state indicates GOV is in droop mode.

13.4.1.3 Binary output signals

Table 325: Physical binary output signals for implementing the application example

Binary output	Description
BO1	Close GCB. Connected to closing coil of the GCB. TRUE state closes the breaker.
BO2	Open GCB. Connected to opening coil of the GCB. TRUE state opens the breaker.
BO3	AVR raise. Connected to AVR voltage raise input. When the bus voltage is greater than the generator voltage, TRUE state pulses are purposed for raising the generator voltage.
Table continues on next page	

Binary output	Description
BO4	AVR lower. Connected to AVR voltage lower input. When the bus voltage is lesser than the generator voltage, TRUE state pulses are purposed for lowering the generator voltage.
BO5	GOV raise. Connected to GOV speed raise input. When the bus frequency is greater than the generator frequency, TRUE state pulses are purposed for raising the generator speed.
BO6	GOV lower. Connected to GOV speed lower input. When the bus frequency is lesser than the generator frequency, TRUE state pulses are purposed for lowering the generator speed.

13.4.1.4 Recommended alarms

Table 326 presents a proposal for WHMI and LHMI alarm handling. The table lists the functions, and events under the functions, which should be tagged as alarms using Event Filtering in PCM600.

Table 326: Alarm list for implementing the application example

Function name	Event	Description
Voltage (3U,VT)	WARNING	Generator VT circuit MCB open
Voltage (3UB,VT)	WARNING	Busbar VT circuit MCB open
ASCGAPC1	AS_CONFLICT	Conflicting condition in autosynchronization coordination[1)]

1) See the technical manual for more information.

13.4.1.5 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 327: Function blocks used in the application example

Function block	Description
UTVTR1	Voltage preprocessing function for measuring generator voltages
UTVTR2	Voltage preprocessing function for measuring busbar voltage
ASGCSYN1	Autosynchronizer for generator breaker
ASCGAPC1	Autosynchronizer co-ordinator
CBXCBR1	Generator circuit breaker control
GOOSERCV_MV	IEC 61850-8-1 GOOSE receiver for MV type data
GOOSERCV_INT32	IEC 61850-8-1 GOOSE receiver for INT32 type data
TRUE	Constant TRUE signal

Figure 148, Figure 149, Figure 150 and Figure 151 present the relay configuration implemented with ACT.

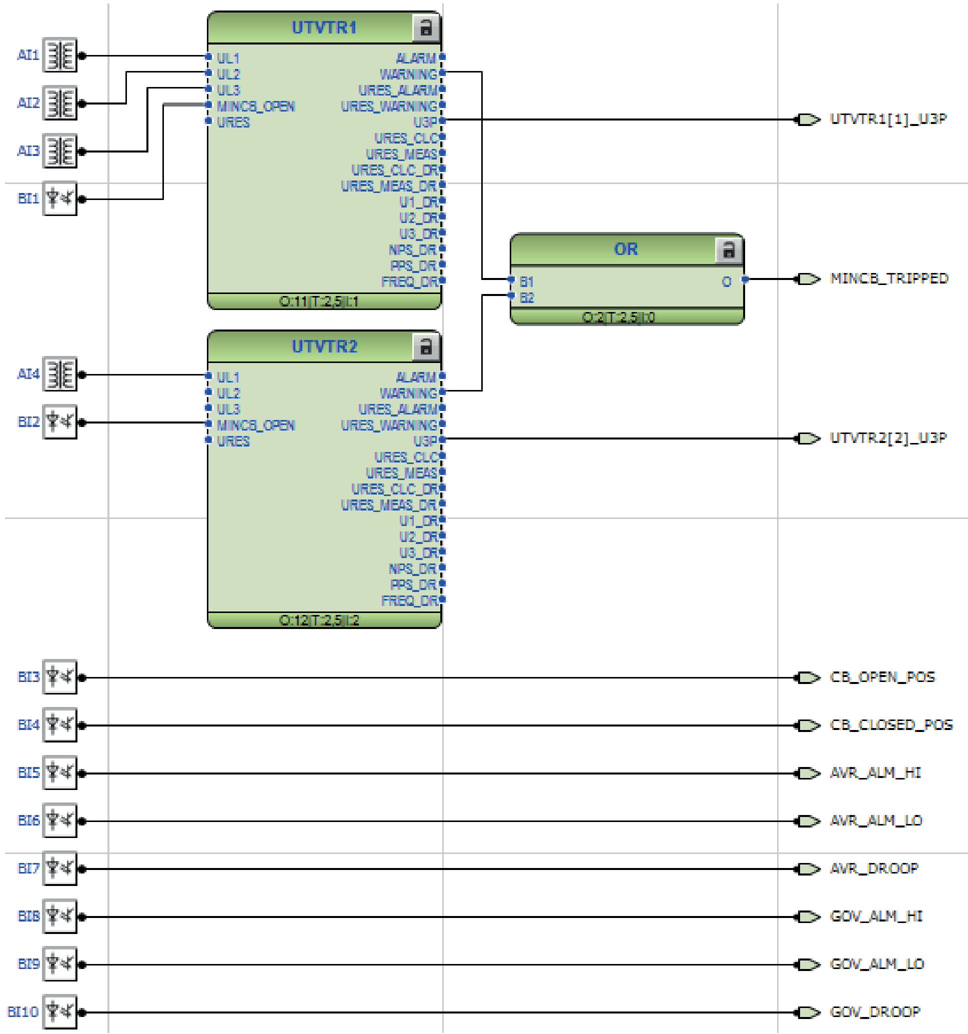

Figure 148: Input section

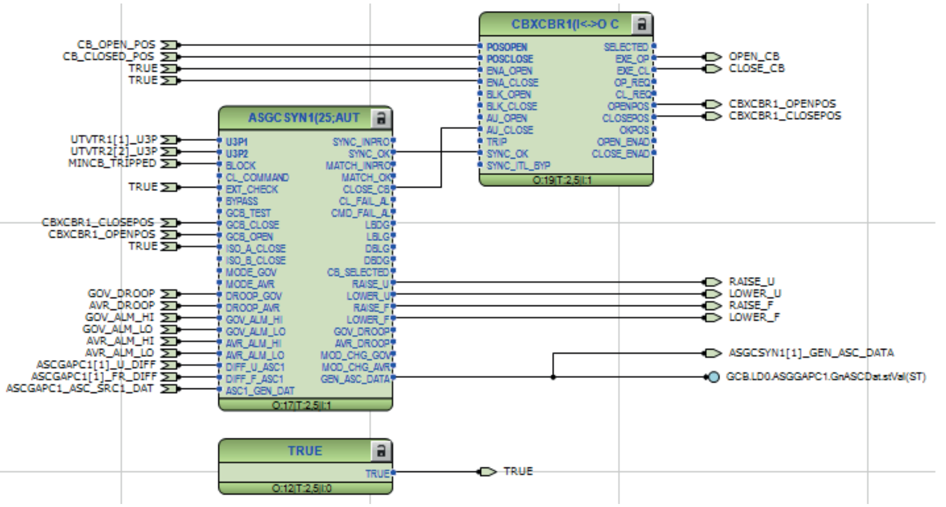

Figure 149: Autosynchronization control section

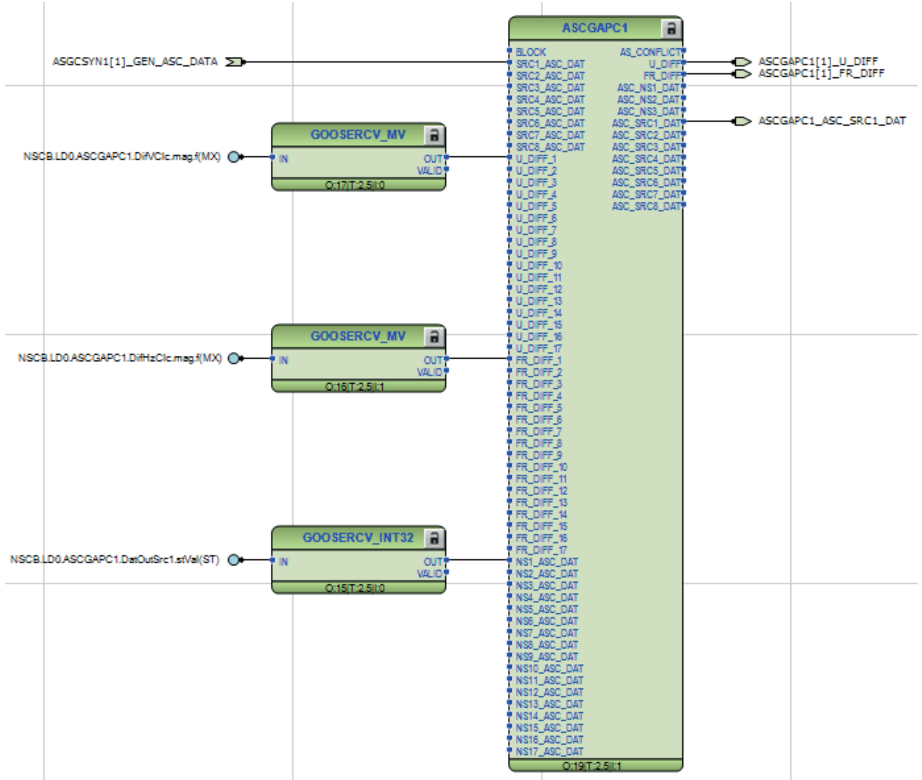

Figure 150: Autosynchronization coordinator section

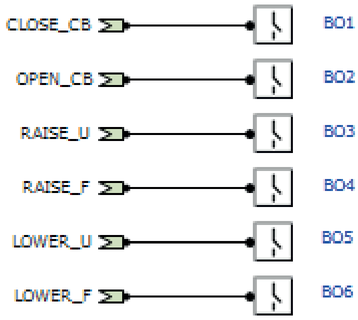

Figure 151: Output section

13.4.1.6 Function blocks and settings values

Generic control settings

The generic control settings are located under **Configuration/System**. Generator applications typically use frequency adaptive measurements due to the generator's start-up and shutdown phases where the generator frequency deviates from nominal. By activating frequency adaptivity, accurate measurements are guaranteed independently of the generator frequency. Table 328 gives the setting value for the application example; all the other settings are left to their default values.

Table 328: Non-default global control setting value

Setting	Suggested value	Description
Frequency adaptivity	Enable	Enabling frequency adaptivity

UTVTR1 and UTVTR2 – Phase and residual voltage preprocessing

UTVTR is the analog signal preprocessing function for measured voltages. One function instance is needed for the generator's three-phase voltages and a second one for the busbar voltage. Preprocessing functions allow to set up measurement channels according to voltage levels and selected voltage transducers.

UTVTR `WARNING` output is used in relay configuration to block ASGCSYN. `WARNING` output is activated when the MCB is tripped. Autosynchronization must be cancelled if `WARNING` is set to TRUE. See the UTVTR section in the technical manual for more details.

Frequency adaptivity needs to be activated for UTVTR1 as explained in section Generic control settings. Table 329 and Table 330 show recommended setting values; all other settings can be kept at default values.

Table 329: Non-default UTVTR1 setting values

Setting	Suggested values	Description
Primary voltage	11 kV	Primary voltage value
Secondary voltage	110 V	Secondary voltage value
VT connection	1=Wye	Voltage transducer measurement connection
Frequency adaptivity	Main frequency source	Frequency adaptivity selection

Table 330: Non-default UTVTR2 setting values

Setting	Suggested values	Description
Primary voltage	11 kV	Primary voltage value
Secondary voltage	110 V	Secondary voltage value
VT connection	1=Wye	Voltage transducer measurement connection

ASGCSYN1 – Autosynchronizer for generator breaker

In this example case, ASGCSYN1 can be used as a standalone autosynchronizer for the generator breaker or it can participate in voltage and frequency matching for the non-source breaker synchronization. In the latter case, the generator relay's ASCGAPC1 receives data over IEC 61850-8-1 GOOSE from the non-source breaker relay's ASCGAPC1. Voltage and frequency adjustment signals are sent to AVR and GOV to bring the voltage and frequency differences across non-source breaker to the conditions of synchronism.

The generator breaker closing is usually implemented so that the generator has slightly higher frequency than the busbar, that is, the generator is oversynchronous. This way a small time window is provided for GOV and AVR to react to increasing load and to avoid a reverse power situation. The oversynchronous generator can be selected with setting *Synchronization Dir*. Table 331 shows recommended setting values; all other settings can be kept at default values.

Table 331: Non-default setting values for ASGCSYN1

Setting	Suggested values	Description
Synchronization Dir	Always over synchronous	Forces the generator's frequency to be higher than the grid frequency during breaker closing
Auto Syn mode	Automatic synchronizing mode	The autosynchronization operation mode is used to have automatic matching and automatic issue of the CB closing command.

ASCGAPC – Autosynchronizer co-ordinator

ASCGAPC handles the control request and shares information in the application where multiple relays are connected to the autosynchronization system.

Table 332: Non-default setting values for ASCGAPC1

Setting	Suggested values	Description
ASC CB Num1	Source CB 1	ASC1 host circuit breaker number 1
Number of sources	1	Total number of sources in the system
Number of NonSrc CB	1	Number of bus coupler or grid transformer CBs in the system

CBXCBR1 – Circuit-breaker control

CBXCBR1 interfaces the autosynchronization closing request to the circuit breaker. All setting values can be kept on their default.

13.4.1.7 IEC 61850-8-1 GOOSE configuration

Table 333: IEC 61850-8-1 GOOSE input signals

Source data in other relay configuration					Destination in this relay configuration	
Relay name	Function block	Output	Data	Description	Function block	Input name
NSCB	ASCGAPC1	U_DIFF	LD0.ASCGAPC1.DiffVClc.mag.f1)	Measured voltage difference received from non-source breaker relay	ASCGAPC1	U_DIFF_1
NSCB	ASCGAPC1	FR_DIFF	LD0.ASCGAPC1.DiffHzClc.mag.f1)	Measured frequency difference received from non-source breaker relay	ASCGAPC1	FR_DIFF_1
NSCB	ASCGAPC1	ASC_SRC1_DAT	LD0.ASCGAPC1.DatOutSrc1.stVal2)	Control data received from the generator relay	ASCGAPC1	NS1_ASC_DAT

1) Input signal is received via GOOSERCV_MV function block
2) Input signal is received via GOOSERCV_INT32 function block

Table 334: IEC 61850-8-1 GOOSE output signals

Function block	Output name	Data	Description
ASGCSYN	GEN_ASC_DATA	LD0.ASGGAPC1.GnASCDat.stVal	Control signal to be sent to non-source breaker relay

13.5 Use of non-generator synchronization application

13.5.1 Circuit breaker autosynchronization

For operating a generator breaker, see the Generator breaker synchronization section in this manual.

This chapter presents how to operate non-source breaker autosynchronization. Two use cases are presented.

1. Live bus autosynchronization to grid
2. Dead bus closing to grid

13.5.1.1 Autosynchronizing live bus to grid

There are several prerequisites for starting non-source breaker autosynchronization.

- The grid breaker is open. See Figure 152.
- Generator is running and is connected to busbar.
- AVR and GOV are in droop mode.
- Generator relay is in remote mode.

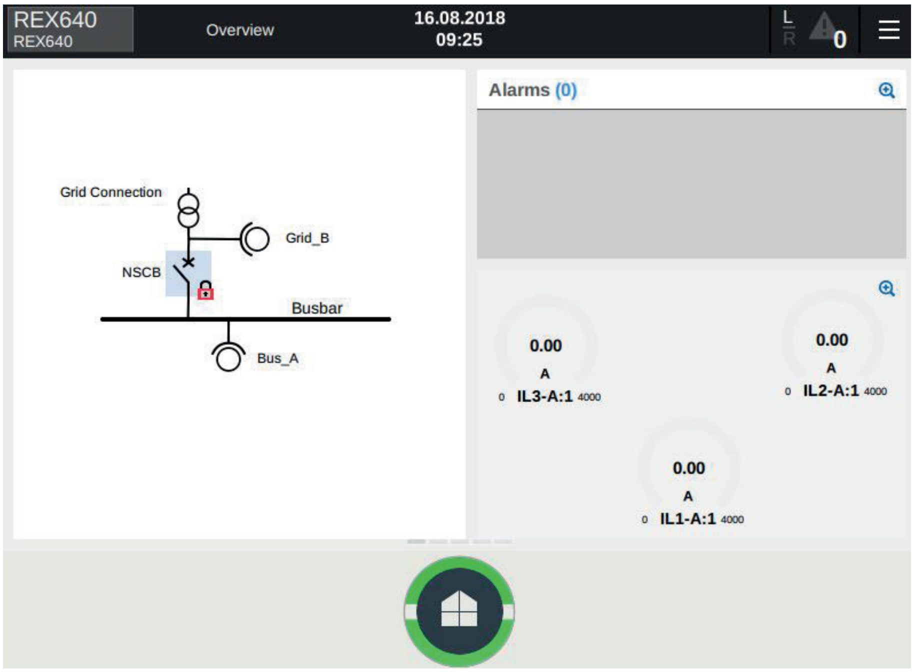

Figure 152: Grid transformer breaker is open

1. Tap the transformer grid breaker symbol to select the breaker for control.

A synchronizing dialog opens.

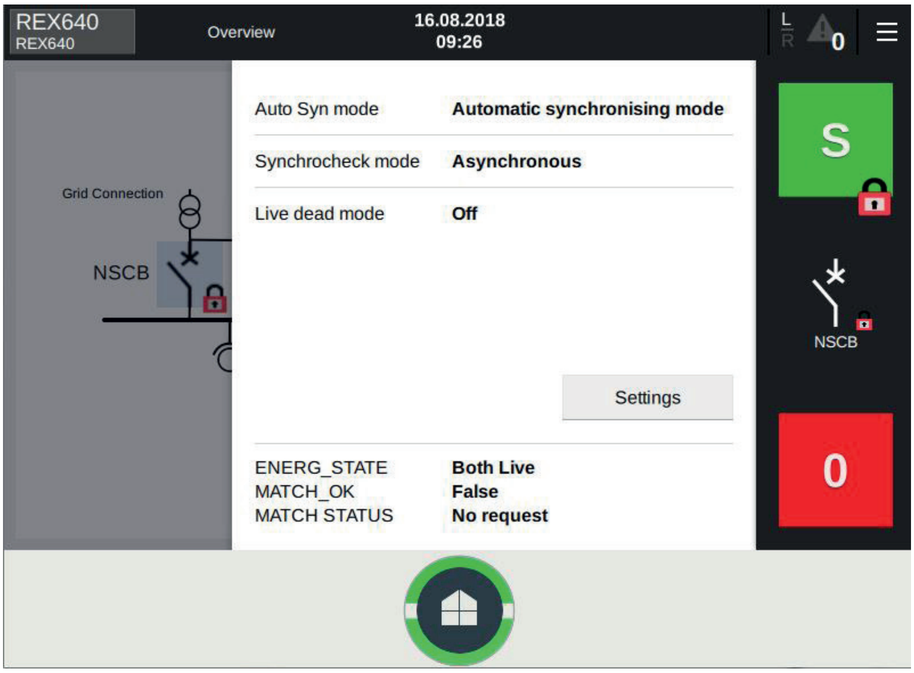

Figure 153: Synchronizing dialog

2. Press **S** to start the closing of the breaker.
   A dialog opens where participating generators can be selected.

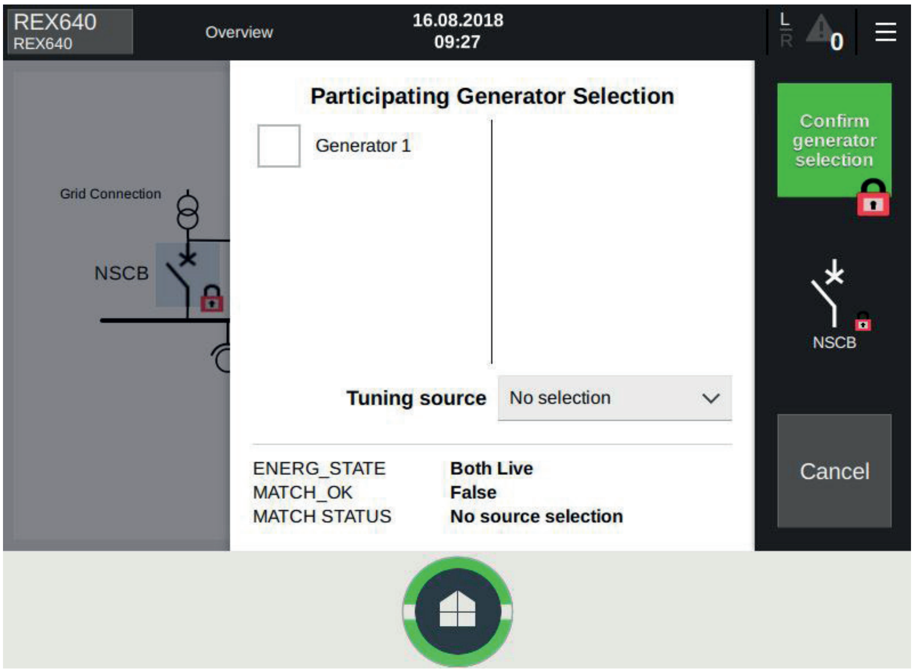

Figure 154: Participating Generator Selection

Participating Generator Selection view is automatically updated. A generator is available for participation in the voltage and frequency matching if the corresponding ASGCSYN function is in “Semi-automatic” or “Automatic” synchronizing mode and the relay is in remote mode.

3. Select the generator and the tuning source and press **Confirm generator selection**.
   A synchroscope view opens.

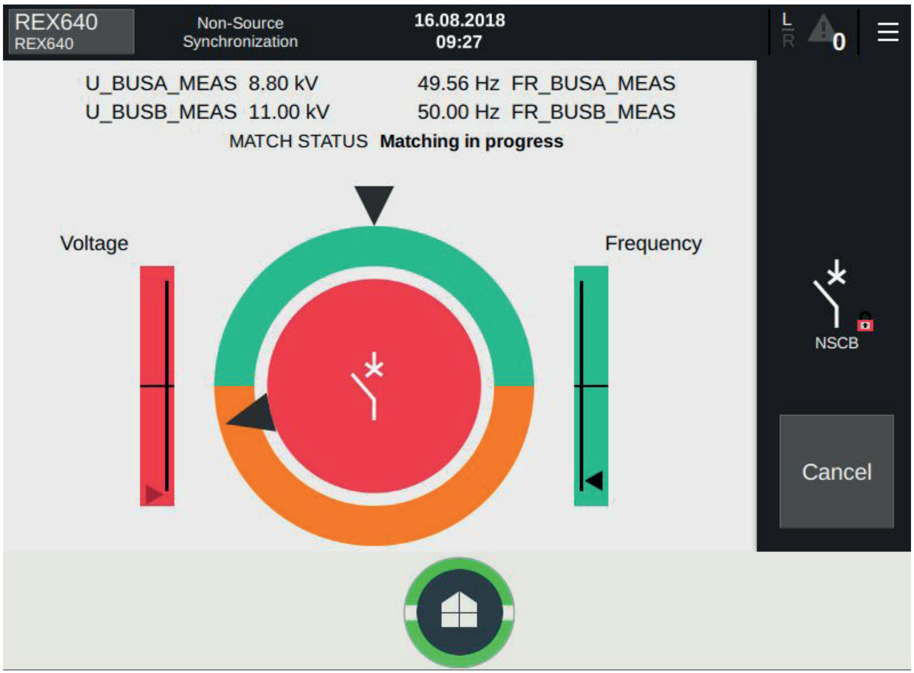

Figure 155: Synchroscope view

The transformer grid breaker is closed automatically once the programmed conditions allow it and the single-line diagram view opens.

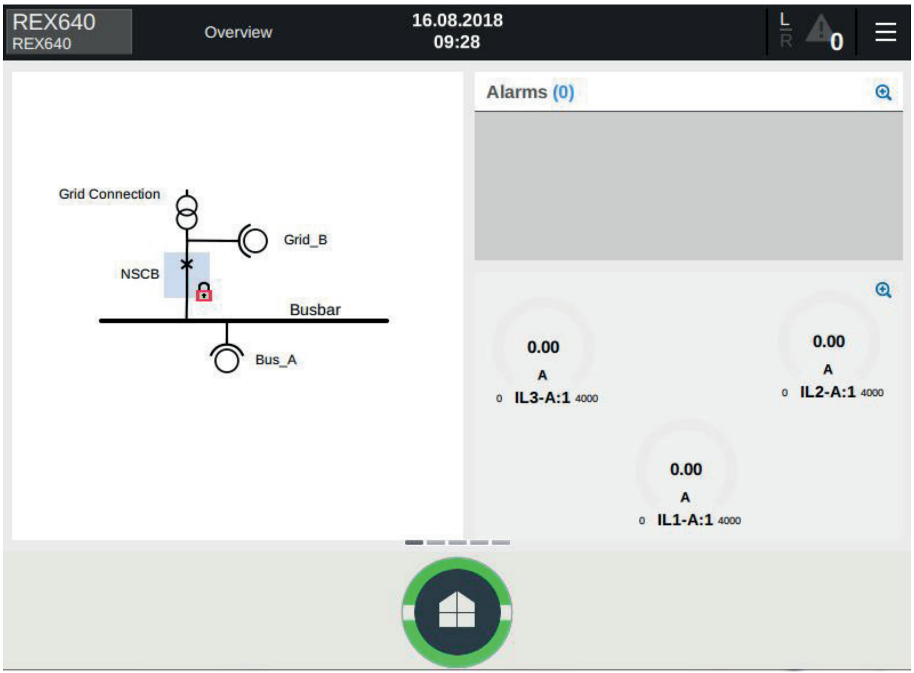

Figure 156: Transformer grid breaker is closed

13.5.1.2 Closing dead bus to grid

In this use case, a dead busbar is energized from the grid.

1. Tap the grid transformer breaker symbol in the single-line diagram.
   This dialog opens.

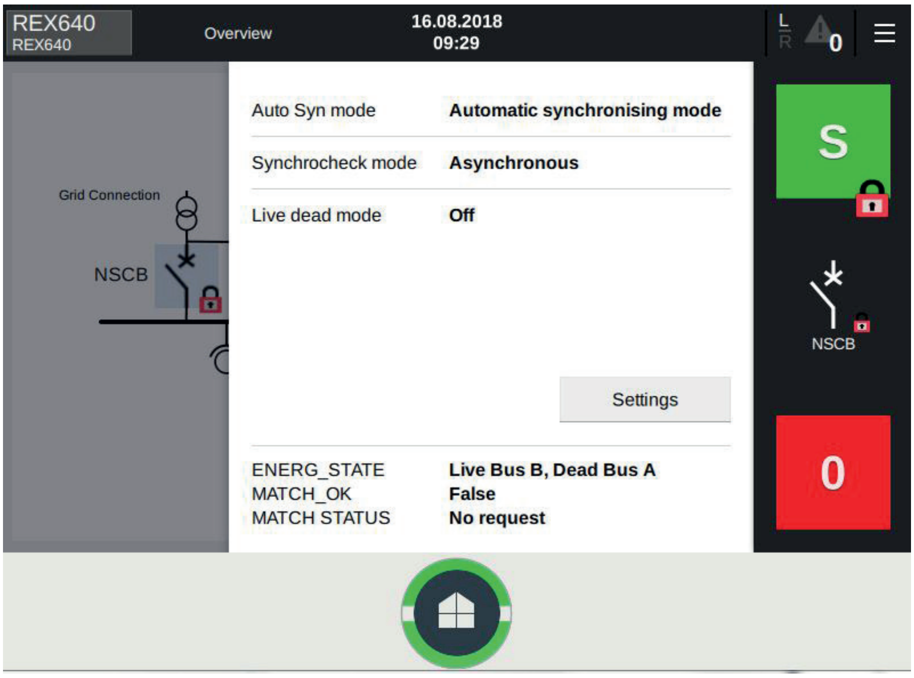

Figure 157: Grid transformer breaker selected

2. Set the *Live dead mode* setting to "Live B, Dead A" which allows normal energizing checking only.

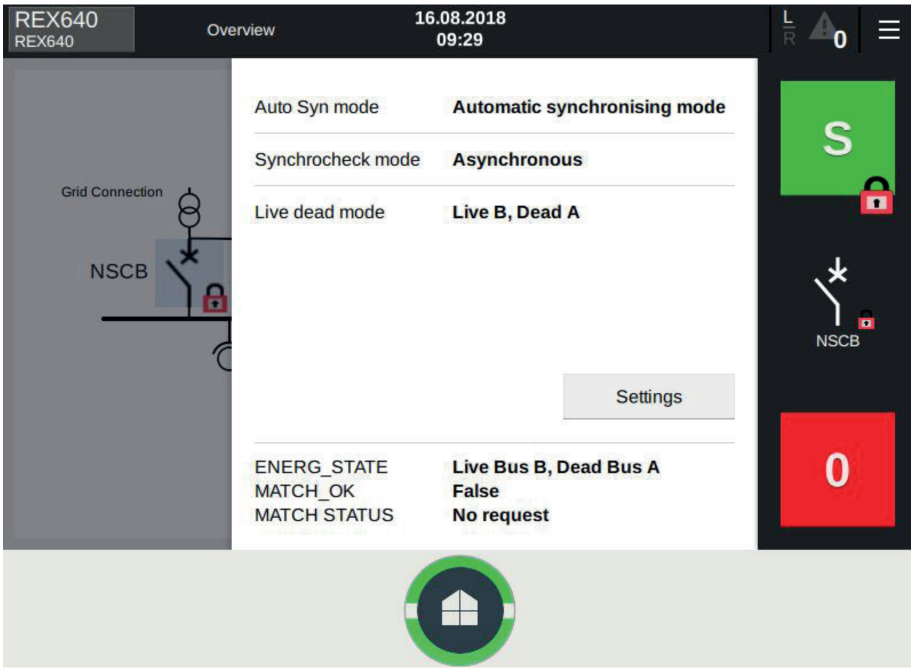

Figure 158: Setting value for energizing check

3. Tap **S** to close the breaker.
   The breaker is closed and the single-line diagram is updated.

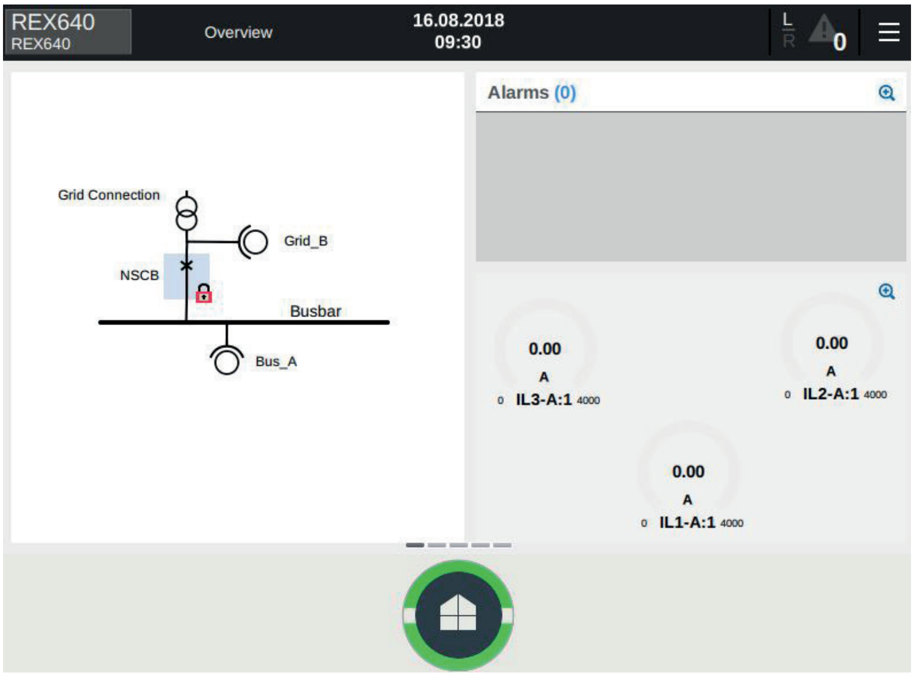

Figure 159: Breaker is closed

Section 14 Petersen coil controller

14.1 Introduction to application

An efficient method for mitigating earth fault effects in a distribution network is earth-fault current compensation. It is carried out by inserting an inductive coil, that is, arc suppression coil (ASC, Petersen coil) between the system neutral point and earth in order to compensate the capacitive earth fault current produced by the outgoing feeders. Usually the neutral point is formed by using a dedicated earthing transformer at the substation.

Earth-fault current compensation increases the probability of the arc extinction in case of a temporary earth fault. The arc suppression coil is effective only if its value is tuned according to the total earth-fault current capacity of the network so that they are in approximate resonance state and, as a consequence, the earth-fault current is very low at the fault location. Since most of the faults in distribution networks are single-phase-to-earth faults, the introduction of the compensated neutral can reduce the number of outages significantly. Also, safety is improved as decreased touch and step voltages are present at the fault location. Moreover, compensation of earth-fault current reduces the cost of protective earthing as the fault current is reduced significantly compared to an unearthed neutral.

In an ideal network the phase-to-earth capacitances of conductors are equal in magnitude, that is, the conductors are fully transposed. In such a network, there is no neutral point voltage. In reality, there is usually some unbalance between the phase-to-earth capacitances of different phases. The relay offers the coil controller function PASANCR for the automatic adjustment of the arc suppression coil compensation current based on the measured coil voltage and the desired compensation degree. PASANCR controls arc suppression coils in compensated networks with unbalance between the phases. Usually this asymmetry is present in a network that consists of overhead lines or overhead lines and cable feeders. PASANCR uses this natural asymmetry in order to automatically determine the total uncompensated earth-fault current of the network.

If the temporary earth fault is not eliminated by ASC, it might be required to trip the faulty feeder. However, residual currents in compensated networks are usually very low making it difficult to select the faulty line. To avoid sensitivity problems, the parallel resistor is often used to increase the residual current which allows an earth-fault protection to locate the faulty line. Traditionally, three types of resistor control sequences are applied.

1. The resistor is disconnected during the healthy-state operation of the network but it is switched on with delay after the earth fault has occurred. This approach allows the arc self-extinction during the delay time. If the arc does

not disappear, the parallel resistor increases the active current component and the selection of the faulty feeder is possible.

2. The resistor is connected to the network during the healthy-state operation but switched off temporarily after the earth fault has occurred. This approach can be used if the healthy-state zero-sequence voltage is too high and it needs to be lowered. Switching off the resistor during the earth fault improves the probability of the arc self-extinction.
3. The resistor is connected to the network during the healthy-state operation and earth-fault conditions. When using this simplest approach, it should be ensured that the resistor and the ASC power auxiliary winding (PAW) are continuously able to withstand the zero-sequence current of the network.

PASANCR allows to implement these resistor control sequences, but the resistor can also be controlled manually.

The compensated neutral principle described above is an efficient method for mitigating earth faults effects occurring in the network. Moreover, the compensation equipment itself needs protection. Usually the compensation equipment is protected with overcurrent protection functions. The relay offers non-directional overcurrent protection function PHxPTOC.

14.2 Description of the example case

In this example case, an adjustable ASC is connected to a network with natural asymmetry. The coil is located at the substation, that is, it represents a centralized earth-fault current compensation solution. The coil is tuned close to the resonance point of the network allowing the arc self-extinction. Additionally, the coil is equipped with a parallel resistor which is a typical installation.

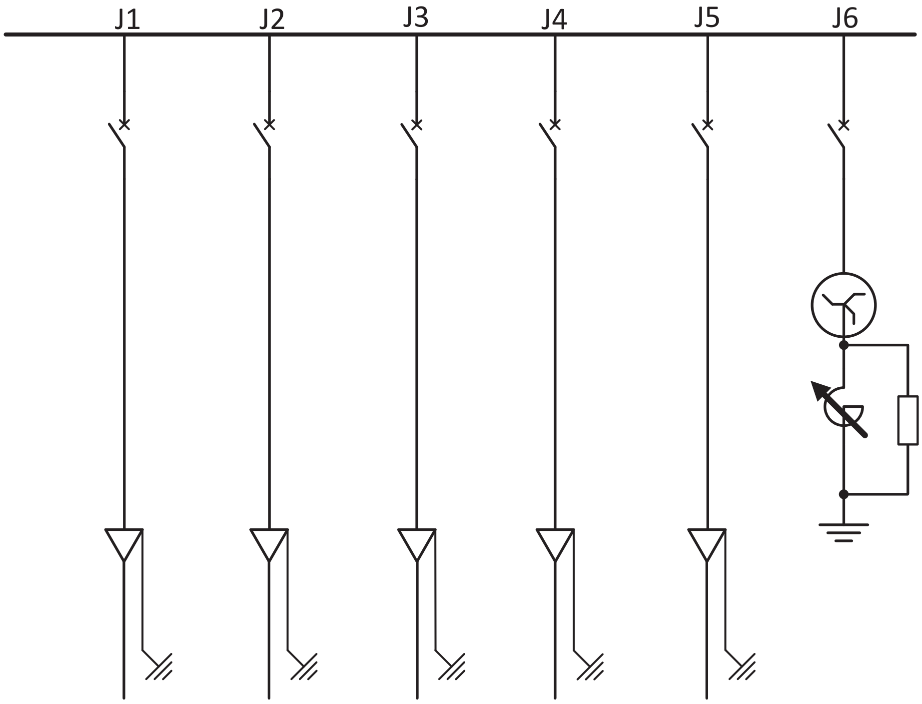

Figure 160: Single-line diagram of the example case

This example case is based on the following assumptions about the network:

- Nominal phase-to-phase voltage of the network is 20 kV.
- Total uncompensated earth-fault current of the feeders is 50 A.
- ASC is adjustable between 10…100 A.
- Network is operated 5 A overcompensated, that is, the coil inductive current is set to a higher value than the total earth-fault current of all outgoing feeders.
- Maximum healthy-state neutral point voltage is 5 percent of the nominal phase-to-earth voltage.
- Parallel resistor having a value of 2.5 Ω is installed in the power auxiliary winding of the ASC. The resistor is permanently connected, that is, it is connected both during healthy-state and fault conditions.
- Earthing transformer zero-sequence reactance is 16 Ω/phase.
- ASC position, that is, the inductive current is indicated using a dedicated potentiometer which is installed near the coil motor drive. Potentiometer terminals are usually available at the coil control cabinet. The potentiometer value provides information about the coil position. The ASC datasheet contains position information provided by the coil manufacturer. The data used in this example case is presented in Table 335.

Table 335: ASC position information

Current [A]	Potentiometer value [Ω]
10	100
20	180
40	270
60	360
80	460
100	599

- ASC datasheet contains information about the coil losses which are on average 1 percent of the corresponding inductive current.

14.3 ASC controller

14.3.1 Relay interface, configuration and settings

Figure 161 presents analog input (AI), binary input (BI), binary output (BO) and resistance temperature detector (RTD) signals that are used to implement the example case.

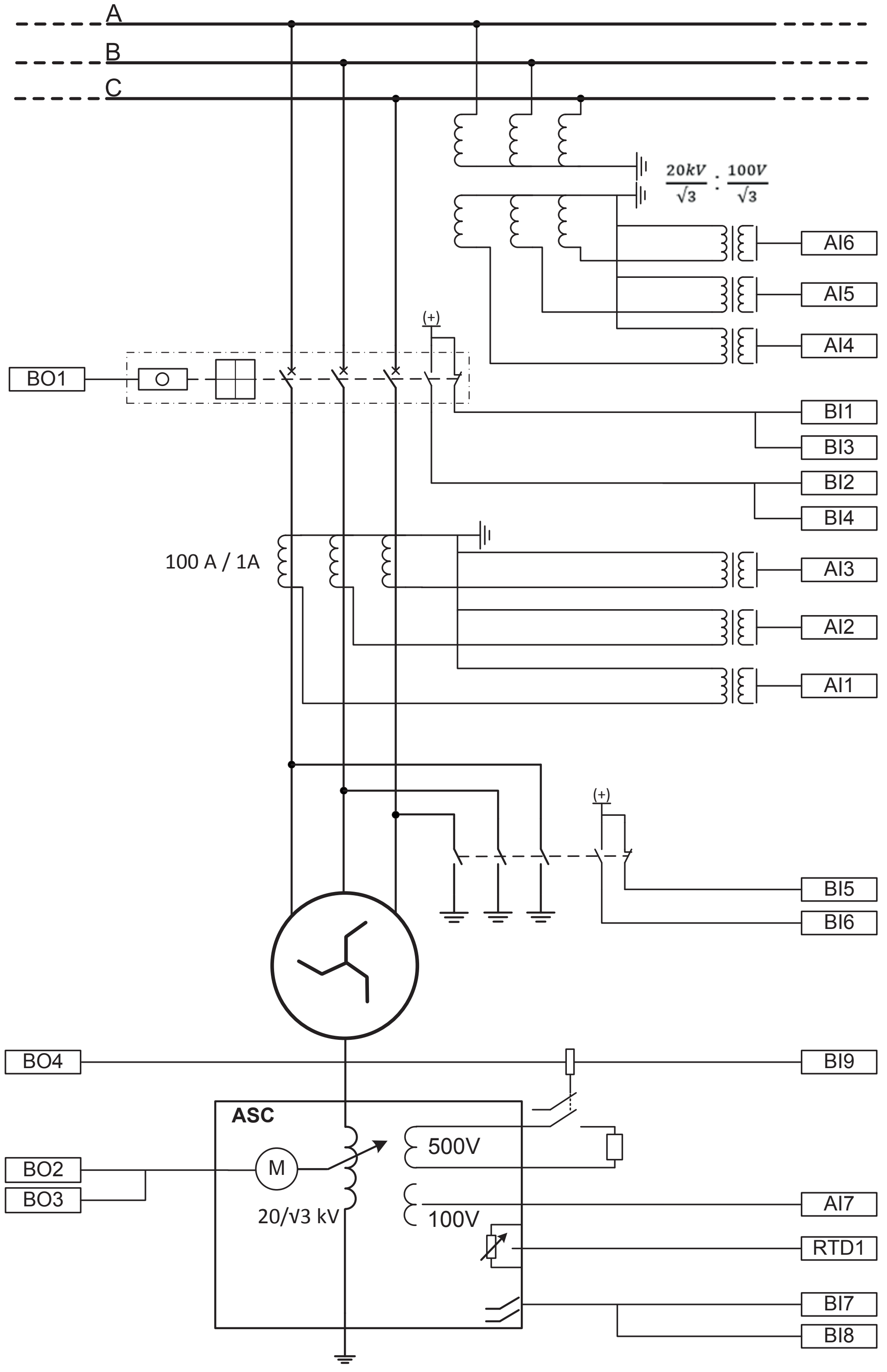

Figure 161: Relay interface for a Petersen coil controller example

14.3.1.1 Analog input signals

In this example, PASANCR uses the measured phase-to-earth voltages U_A, U_B and U_C (AI4, AI5 and AI6) to generate reference for coil voltage. The coil voltage is measured from the ASC measurement winding (AI7). Phase currents (AI1, AI2 and AI3) are measured for basic overcurrent protection functions protecting the compensation equipment. Additionally, phase currents are used for generating the calculated neutral point current for the coil controller.

Table 336: Physical analog input signals necessary for implementing ASC example application

Analog input	Description
AI1	Current measurement, I_A
AI2	Current measurement, I_B
AI3	Current measurement, I_C
AI4	Voltage measurement, U_A
AI5	Voltage measurement, U_B
AI6	Voltage measurement, U_C
AI7	Coil voltage measured from the ASC measurement winding

14.3.1.2 RTD input signals

Table 337: RTD signals

RTD input	Description
RTD1	ASC position indication

14.3.1.3 Binary input signals

Table 338: Binary input signals

Binary input	Description
BI1	Circuit breaker open position
BI2	Circuit breaker closed position
BI3	Circuit breaker truck test position
BI4	Circuit breaker truck service position
BI5	Earthing switch open position
BI6	Earthing switch closed position
BI7	Limit switch indicating that the highest available compensation current level is reached
BI8	Limit switch indicating that the lowest available compensation current level is reached
BI9	Parallel resistor connection status. The status is indicated using the auxiliary contact of the contactor.

14.3.1.4 Binary output signals

Table 339: Binary output signals

Binary output	Description
BO1	Trip signal for opening the circuit breaker
BO2	Increase of ASC compensation current level
BO3	Decrease of ASC compensation current level
BO4	Control of ASC parallel resistor contactor

14.3.1.5 Recommended alarms

Table 340: Alarm list

Function name	Event	Description
PASANCR1	CLC_SEQ_WRN	Maximum number of tuning cycles reached
PASANCR1	ERROR_POS	Coil has been moved to its error position.
PASANCR1	ALARM	General alarm
PASANCR1	MOT_ALARM	Motor alarm
PASANCR1	POT_ALARM	Potentiometer alarm
PASANCR1	EARTH_FAULT	Earth-fault indication
PHLPTOC1	OPERATE	Operate signal from low stage non-directional overcurrent protection for earthing transformer
PHIPTOC1	OPERATE	Operate signal from instantaneous non-directional overcurrent protection for earthing transformer

14.3.1.6 Relay configuration

The relay configuration is implemented with Application Configuration in PCM600.

Table 341: Function blocks used in the relay configuration

Function block	Description
UTVTR1, ILTCTR1	Analog signal preprocessing
SlotC-RTD1	RTD input
CBXCBR1	Circuit breaker control and status
DCSXSWI1	Circuit breaker truck status
ESSXSWI1	Earthing switch status
TRPPTRC1	Master trip
Table continues on next page	

Function block	Description
PASANCR1	Petersen coil controller
PHLPTOC1	Three-phase non-directional overcurrent protection, low stage
PHIPTOC1	Three-phase non-directional overcurrent protection, instantaneous stage

Table 342: Physical analog channels of functions

Protection	Phase voltages AI4, AI5, AI6	Phase currents AI1, AI2, AI3	Coil voltage	ASC potentiometer
PASANCR1	x	x	x	x
PHLPTOC1		x		
PHIPTOC1		x		

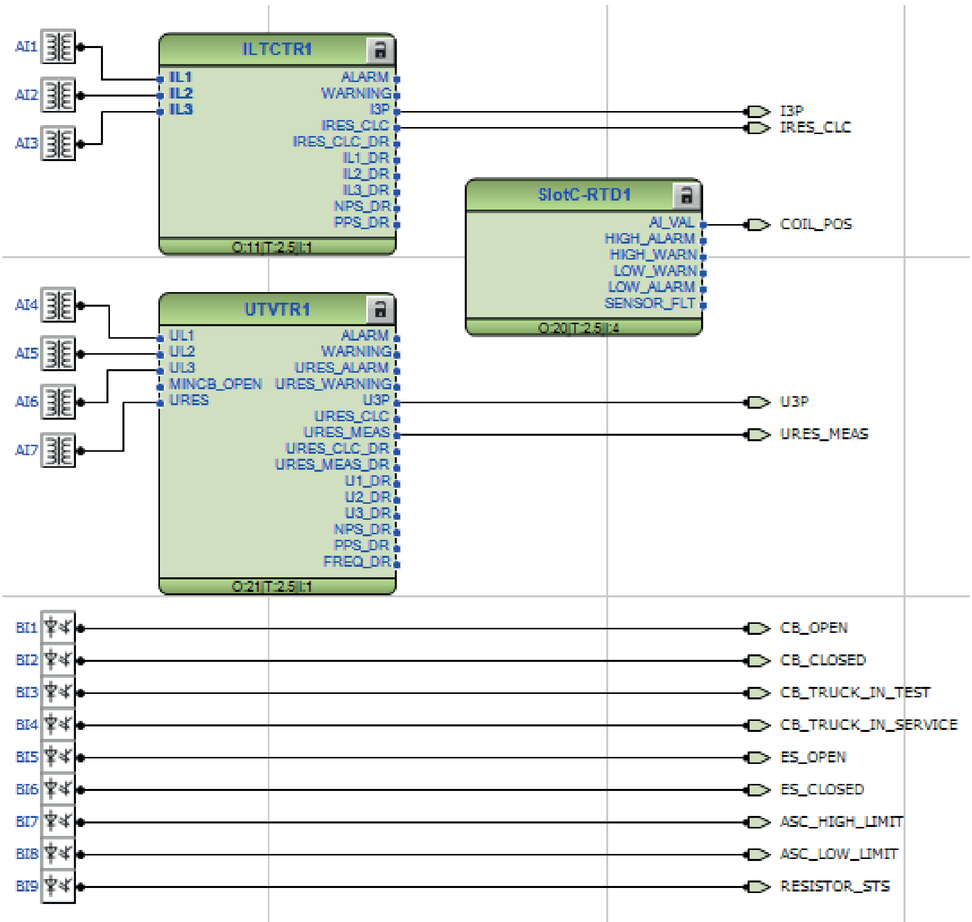

Figure 162: Analog, binary and RTD inputs

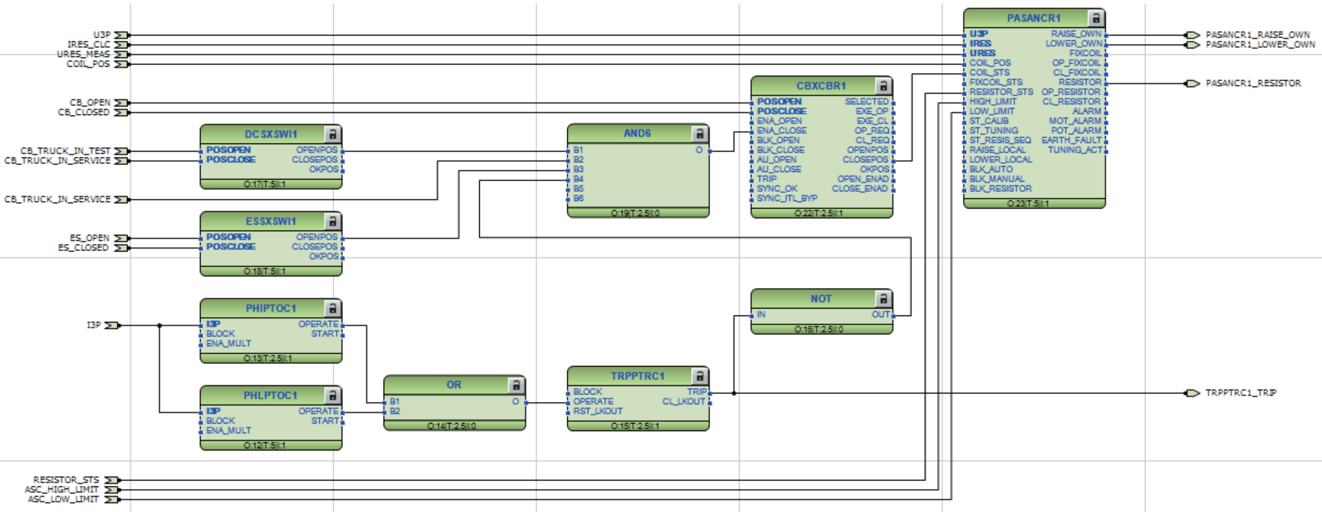

Figure 163: Application function block connections

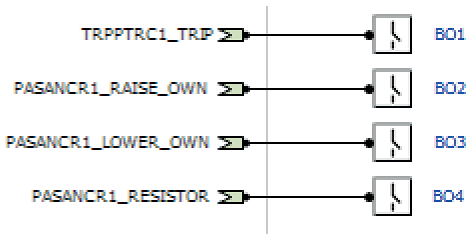

Figure 164: Binary outputs

14.3.1.7 Function blocks and setting values

ILTCTR1 – Phase current preprocessing

All settings of ILTCTR1 can be kept at default values for this example case.

UTVTR1 – Phase and residual voltage preprocessing

Table 343 shows recommended setting values; all other settings can be kept at default values.

Table 343: UTVTR1 settings for the example case

Setting	Suggested values	Description
Primary voltage	11.547	Primary rated voltage
Secondary voltage	57.73	Secondary rated voltage
VT connection	Wye	Voltage transducer measurement connection

SlotC-RTD1

Table 344 shows recommended setting values for SlotC-RTD1. All other SlotC-RTD1 settings can be kept at default values.

Table 344: SlotC-RTD1 settings for the example case

Setting	Suggested values	Description
Input mode	Resistance	Input mode
Value unit	Ohm	Selected unit for output value format

CBXCBR1 – Circuit-breaker control

All settings of CBXCBR1 can be kept at default values for this example case.

DCSXSWI1 – Disconnector position indication

All settings of DCSXSWI1 can be kept at default values for this example case.

ESSXSWI1 – Earthing switch position indication

All settings of ESSXSWI1 can be kept at default values for this example case.

PHxPTOC1 - Three-phase non-directional overcurrent protection

PHxPTOC provides basic overcurrent protection for an auxiliary transformer against short circuits. Table 345 and Table 346 show recommended setting values; all other settings can be kept at default values.

Table 345: Settings for PHLPTOC1

Setting	Suggested values	Description
Start value[1)]	0.60 xIn	Start value
Operate delay time	500 ms	Operate delay time

1) During the earth-fault, the ASC maximum current is 100 A which is split equally between phases A, B and C in the auxiliary transformer. Therefore, the maximum phase current is 100 A/3 = 33.3 A which corresponds to $0.33 \cdot I_n$.

Table 346: Settings for PHIPTOC1

Setting	Suggested values	Description
Start value	10.00 xIn	Start value

PASANCR1 - Petersen coil controller

PASANCR is an automatic controller for a continuously adjustable arc suppression coil and the parallel resistor of the coil. Table 347 shows recommended setting values; all other settings can be kept at default values.

Table 347: Settings for PASANCR1

Setting	Suggested values	Description
Detuning level	5 A	Detuning value is positive when overcompensation is used, that is, the ASC current is higher than the network capacitive earth-fault current.
V Res variation	1%	Neutral point voltage variation that the controller tries to obtain during the automatic tuning procedure by coil movement or resistor switching
V Res minimum	0.50%	Minimum neutral point voltage level that the controller tries to obtain before starting the automatic tuning procedure
V Res EF level	7 %Un	Threshold for earth-fault detection. In the example case, the maximum neutral point voltage during the healthy-state operation is 5%, that is, the setting value is chosen with an appropriate margin.
Coil V Nom	11547 V	Coil nominal voltage
Parallel resistor	TRUE	Parallel resistor installation status
Resistor control	ON	Resistor control mode ‘ON’, that is, the resistor is connected during healthy-state and faulty-state conditions
Resistor Nom value	2.5 Ω	Resistor value expressed at PAW nominal voltage level
X0 Transformer	16 Ω	Transformer zero-sequence impedance/phase
Coil losses	1.00%	Resistive losses of ASC, % of coil inductive current
Pot value 1	100 Ω	Potentiometer value 1 is the ASC potentiometer value at the lowest coil position.
Coil current 1	10 A	ASC current at potentiometer value 1
Pot value 2	180 Ω	ASC potentiometer value 2
Coil current 2	20 A	ASC current at potentiometer value 2
Pot value 3	270 Ω	ASC potentiometer value 3
Coil current 3	40 A	ASC current at potentiometer value 3
Pot value 4	360 Ω	ASC potentiometer value 4
Coil current 4	60 A	ASC current at potentiometer value 4
Pot value 5	460 Ω	ASC potentiometer value 5
Table continues on next page		

Setting	Suggested values	Description
Coil current 5	80 A	ASC current at potentiometer value 5
Pot value 6	599 Ω	ASC potentiometer value 6 is the potentiometer value at the highest coil position.
Coil current 6	100 A	ASC current at potentiometer value 6

14.3.2 Procedures before starting the application

After the function settings are set according to the example case, the coil calibration procedure can be started from the relay's LHMI under **Test and commissioning/Coil controller commissioning** menu by tapping Start calibration. During the calibration procedure the controller must be in manual mode (*Controller mode*="Manual"), but the ASC does not need to be connected to the network.

During the calibration the controller determines several coil characteristics to ensure accurate tuning operations of the coil. Determined and displayed parameters are:

- Potentiometer ohmic values corresponding to minimum and maximum compensation current of the coil
- Coil mechanical play: amount of apparent movement of the coil in amperes after the coil movement direction is reversed. Coil mechanical play is due to the slack in coil mechanical drive system.
- Coil after running: amount of amperes which the coil motor and the mechanical drive system slide after the command to increase or decrease the compensation current is deactivated
- Potentiometer gap positions: This is the case particularly with old or heavily worn potentiometers. Gaps and their locations are visible from PASANCR1 monitored data view.
- Coil movement speed: coil average movement speed in amperes per second

After the calibration, the potentiometer condition can be checked via PASANCR1 monitored data view. If the potentiometer has multiple or large gaps, it should be replaced during the next service break of the arc suppression coil in order to guarantee accurate operation of PASANCR1.

Additionally, it should be checked that the determined potentiometer values at coil end switches correspond with satisfactory accuracy to the ones given by the coil manufacturer. These values can be found in the coil routine test report. These values were entered into *Pot value 1* and *Pot value 6* settings in this example case. The potentiometer's end switch values determined during the calibration are taken into use by tapping Linearize Coil after the calibration.

14.3.3 Use of the application

After a successful calibration, the coil can be connected to the network by closing the ASC circuit breaker. Automatic coil tuning can be enabled by setting *Controller mode*="Automatic". After enabling the automatic mode, the controller starts the automatic tuning procedure where it determines the network parameters and moves the coil to the set detuning position. Further automatic tuning operations are triggered by the level detector functionality of PASANCR1.

After the automatic coil tuning procedure, the controller displays results on the HMI. The displayed graphical results are resonance curve and fault current estimate curve of the network. Additionally, the controller displays some numerical data about the network.

Table 348: Network data displayed by the controller

Data	Description
U0_INST	Instantaneous value of residual voltage [%]
I_COIL	ASC position [A]
I_FIX	Fixed parallel coil value [A]
I_DETUNING	Detuning [A]
DETUNING_REL	Relative detuning
I_DAMPING	Total resistive losses (network losses, coil losses and parallel resistor) [A]
I_RESONANCE	Coil current at resonance point [A]
I_C_NETWORK	Total capacitive current of the network [A]
I_EF	Earth-fault current at present operate point
TUNING_ST_DELAY	Countdown of tuning delay timer after tuning trigger condition has exceeded 100% [s]
TUNING_TRIGG	Instantaneous fulfillment state of tuning trigger condition [%]

Section 15 Glossary

ACT	1. Application Configuration tool in PCM600 2. Trip status in IEC 61850
AD	Active directory
AI	Analog input
ASC	Arc suppression coil
AVR	Automatic voltage regulator
BI	Binary input
BO	Binary output
CB	Circuit breaker
CBCT	Core balance current transformer
CBFP	Circuit breaker failure protection
CT	Current transformer
DC	1. Direct current 2. Disconnector 3. Double command
DCB	Directional comparison blocking scheme
DOL	Direct on line starting method of induction motors
DT	Definite time
DUTT	Direct underreach transfer trip
EMC	Electromagnetic compatibility
FPN	Flexible product naming
GCB	1. GOOSE control block 2. Generator circuit breaker
GOOSE	Generic Object-Oriented Substation Event
GOV	Generator prime mover governor
HMI	Human-machine interface
HV	High voltage
IDMT	Inverse definite minimum time
IEC	International Electrotechnical Commission
IEC 61850	International standard for substation communication and modeling

IEC 61850-8-1	A communication protocol based on the IEC 61850 standard series
IED	Intelligent electronic device
IRF	1. Internal fault 2. Internal relay fault
IRIG-B	Inter-Range Instrumentation Group's time code format B
L/R	Local/Remote
LAN	Local area network
LDC	Line drop compensation
LED	Light-emitting diode
LHMI	Local human-machine interface
LV	Low voltage
M/F	Master/Follower
MCB	Miniature circuit breaker
MCC	Minimizing circulating current
MV	Medium voltage
NRP	Negative reactance principle
NSCB	Non-source circuit breaker
OC	Overcurrent
OLTC	On-load tap changer
PAW	Power auxiliary winding
PCM600	Protection and Control IED Manager
POTT	Permissive overreach transfer trip
PUTT	Permissive underreach transfer trip
REK 510	Current injection device for earth-fault protection of a synchronous machine rotor
RIO600	Remote I/O unit
RJ-45	Galvanic connector type
RMS	Root-mean-square (value)
RS-485	Serial link according to EIA standard RS485
RSV	Rated secondary value
RTD	Resistance temperature detector
SCADA	Supervision, control and data acquisition

SDM600	A software solution for automatic management of service and cyber security relevant data across substations
SHMI	Switchgear HMI
SI	Sensor input
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.
SLD	Single-line diagram
TCS	Trip-circuit supervision
VDR	Voltage-depended resistor
VT	Voltage transformer
WAN	Wide area network
WHMI	Web human-machine interface

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