Relion® 650 series

Bay control
REC650
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 2004/108/EC) and concerning electrical equipment for use within specified voltage limits (Low-voltage directive 2006/95/EC).

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This product is designed and produced for industrial use.

Table of contents

Section 1 Introduction

1.1 This manual

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also be used when calculating settings.

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 communication and protocols.

1.3 Product documentation

1.3.1 Product documentation set

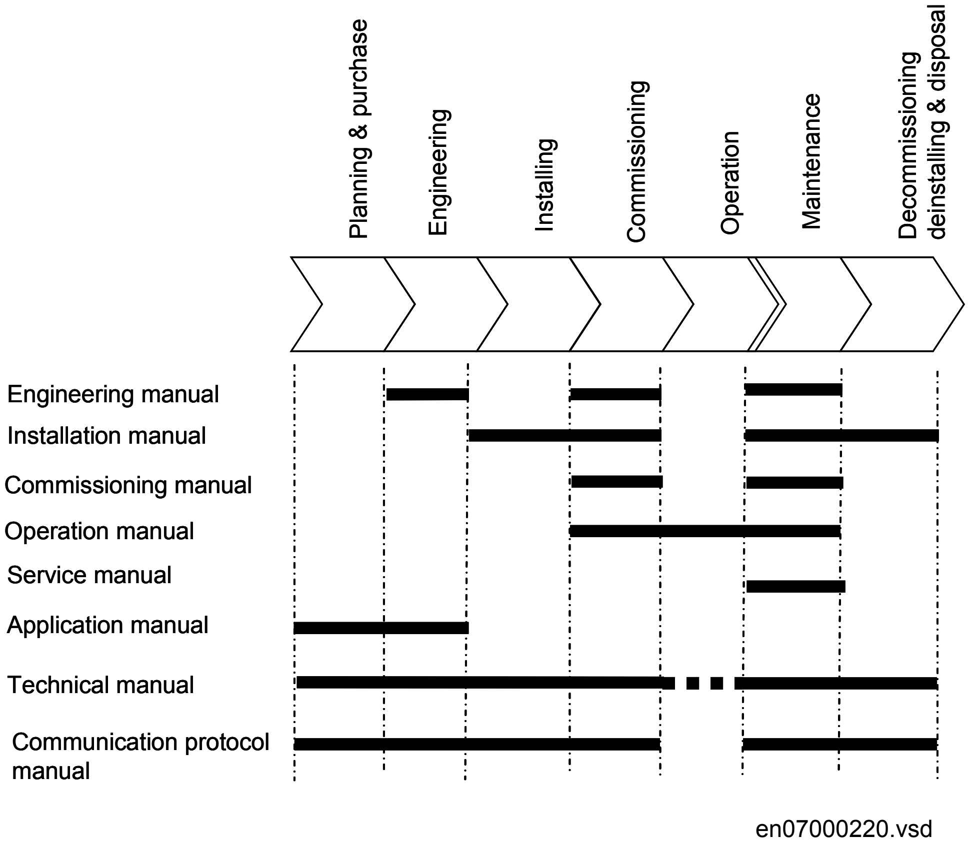

Figure 1: The intended use of manuals in different lifecycles

The engineering manual contains instructions on how to engineer the IEDs using the different tools in PCM600. The manual provides instructions on how to set up a PCM600 project and insert IEDs to the project structure. The manual also recommends a sequence for engineering of protection and control functions, LHMI functions as well as communication engineering for IEC 61850 and DNP3.

The installation manual contains instructions on how to install the IED. The manual provides procedures for mechanical and electrical installation. The chapters are organized in chronological order in which the IED should be installed.

The commissioning manual contains instructions on how to commission the IED. The manual can also be used by system engineers and maintenance personnel for assistance during the testing phase. The manual provides procedures for checking of external circuitry and energizing the IED, parameter setting and configuration as well as verifying settings by secondary injection. The manual describes the process of testing an IED in a substation which is not in service. The chapters are organized in chronological order in which the IED should be commissioned.

The operation manual contains instructions on how to operate the IED once it has been commissioned. The manual provides instructions for monitoring, controlling and setting the IED. The manual also describes how to identify disturbances and how to view calculated and measured power grid data to determine the cause of a fault.

The service manual contains instructions on how to service and maintain the IED. The manual also provides procedures for de-energizing, de-commissioning and disposal of the IED.

The application manual contains application descriptions and setting guidelines sorted per function. The manual can be used to find out when and for what purpose a typical protection function can be used. The manual can also be used when calculating settings.

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

The communication protocol manual describes a communication protocol supported by the IED. The manual concentrates on vendor-specific implementations.

The point list manual describes the outlook and properties of the data points specific to the IED. The manual should be used in conjunction with the corresponding communication protocol manual.

The service manual is not available yet.

1.3.2 Document revision history

Document revision/date	Product version	History
-/September 2009	1.0	First release

1.3.3 Related documents

Documents related to REC650	Identity number
Commissioning manual	1MRK 511 209-UEN
Technical manual	1MRK 511 204-UEN
Application manual	1MRK 511 203-UEN

Table continues on next page

Documents related to REC650	Identity number
Product Guide, configured	1MRK 511 211-BEN
Type test certificate	1MRK 511 211-TEN

650 series manuals	Identity number
Operation manual	1MRK 500 088-UEN
Communication protocol manual, DNP3	1MRK 511 224-UEN
Communication protocol manual, IEC 61850	1MRK 511 205-UEN
Engineering manual	1MRK 511 206-UEN
Installation manual	1MRK 514 013-UEN
Point list manual, DNP3	1MRK 511 225-UEN

1.4 Symbols and conventions

1.4.1 Safety indication 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 to 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 should be understood that operation of damaged equipment could, under certain operational conditions, result in degraded process performance leading to personal injury or death. Therefore, comply fully with all warning and caution notices.

1.4.2 Manual conventions

Conventions used in IED manuals. A particular convention may not be used in this manual.

- Abbreviations and acronyms in this manual are spelled out in Glossary. Glossary also contains definitions of important terms.
- Push button navigation in the LHMI menu structure is presented by using the push button icons, for example:
  To navigate between the options, use  and .
- HMI menu paths are presented in bold, for example:
  Select **Main menu/Settings**.
- LHMI messages are shown in Courier font, for example:
  To save the changes in non-volatile memory, select `Yes` and press .
- Parameter names are shown in italics, for example:
  The function can be enabled and disabled with the *Operation* setting.
- The ^ character in front of an input or output signal name in the function block symbol given for a function, indicates that the user can set an own signal name in PCM600.
- The * character after an input or output signal name in the function block symbol given for a function, indicates that the signal must be connected to another function block in the application configuration to achieve a valid application configuration.

Section 2 Application

2.1 REC650 application

REC650 is used for the control, protection and monitoring of different types of bays in power networks. The IED is especially suitable for applications in distributed control systems with high demands on reliability. It is intended mainly for sub-transmission stations. It is suitable for the control of all apparatuses in single busbar single CB, double busbar single CB switchgear arrangement.

The control is performed from remote (SCADA/Station) through the communication bus or locally from a graphical HMI on the front of the IED showing the single line diagram. Different control configurations can be used, and one control IED can be used per bay. Interlocking modules are available for common types of switchgear arrangements. The control is based on the select before execute principle to give highest possible security. A synchronism control function is available to interlock breaker closing.

A number of protection functions are available for flexibility in use for different station types and busbar arrangements. The auto-reclose includes priority circuits for single-breaker arrangements. It co-operates with the synchrocheck function with high-speed or delayed reclosing.

High set instantaneous phase and earth overcurrent, 4 step directional or non-directional delayed phase and earth overcurrent, thermal overload and two step under- and overvoltage functions are examples of the available functions allowing user to fulfill any application requirement.

Disturbance recording is available to allow independent post-fault analysis after primary disturbances.

Three packages have been defined for following applications:

- Single breaker for single busbar (A01)
- Single breaker for double busbar (A02)
- Bus coupler for double busbar (A07)

The packages are configured and ready for direct use. Analog and control circuits have been pre-defined. Other signals need to be applied as required for each application. The main differences between the packages above are the interlocking modules and the number of apparatuses to control.

The graphical configuration tool ensures simple and fast testing and commissioning.

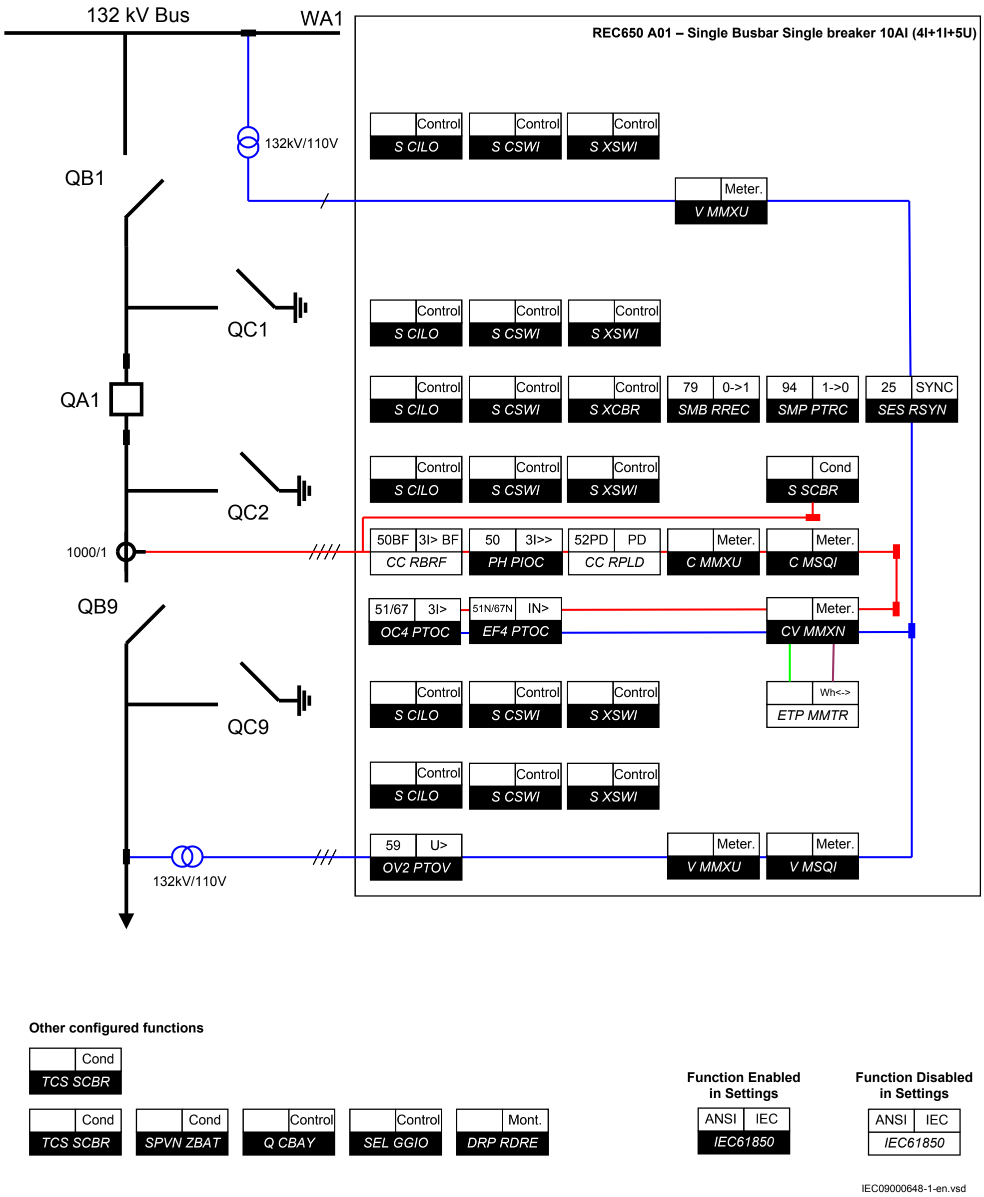

Figure 2: A typical protection and control application for a single busbar in single breaker arrangement

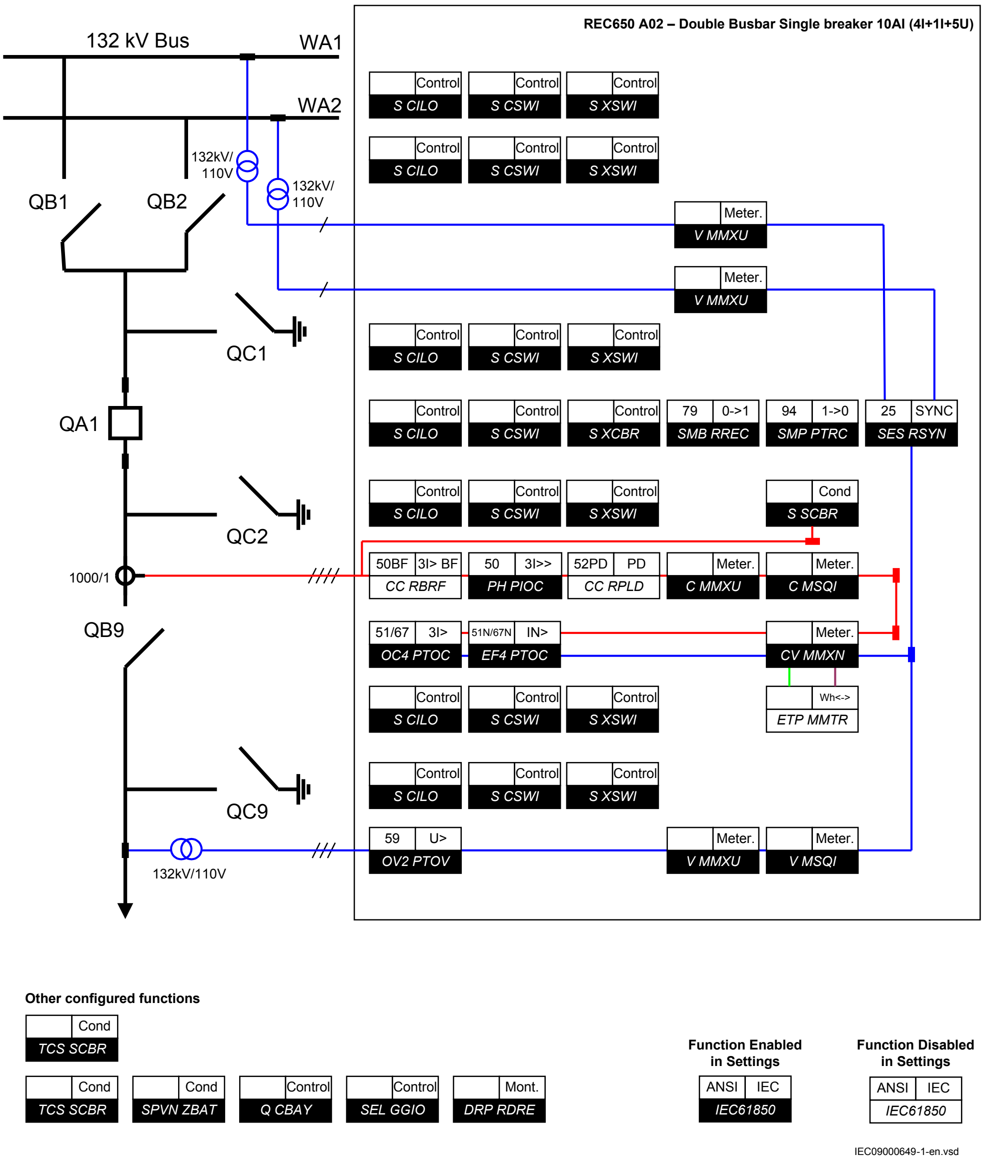

Figure 3: A typical protection and control application for a double busbar in single breaker arrangement

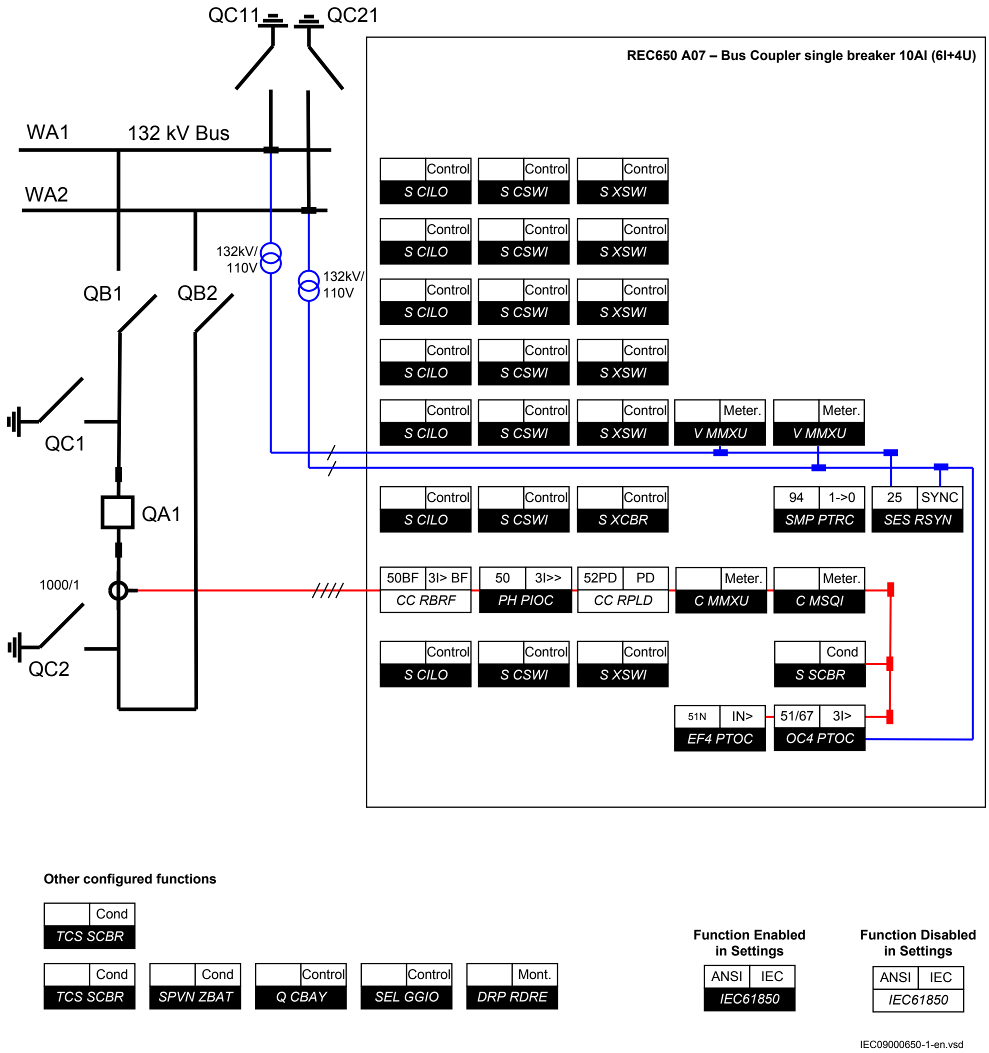

Figure 4: A typical protection and control application for a bus coupler in single breaker arrangement

2.2 Available functions

2.2.1 Control and monitoring functions

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
Control					
SESRSYN	25	Synchrocheck, energizing check, and synchronizing	1	1	1
SMBRREC	79	Autorecloser	1	1	1
SCILO	3	Logical node for interlocking	8	8	8
BB_ES	3	Interlocking for busbar earthing switch	3	3	3
A1A2_BS	3	Interlocking for bus-section breaker	2	2	2
A1A2_DC	3	Interlocking for bus-section disconnector	3	3	3
ABC_BC	3	Interlocking for bus-coupler bay	1	1	1
BH_CONN	3	Interlocking for 1 1/2 breaker diameter	1	1	1
BH_LINE_A	3	Interlocking for 1 1/2 breaker diameter	1	1	1
BH_LINE_B	3	Interlocking for 1 1/2 breaker diameter	1	1	1
DB_BUS_A	3	Interlocking for double CB bay	1	1	1
DB_BUS_B	3	Interlocking for double CB bay	1	1	1
DB_LINE	3	Interlocking for double CB bay	1	1	1
ABC_LINE	3	Interlocking for line bay	1	1	1
AB_TRAFO	3	Interlocking for transformer bay	1	1	1
SCSWI		Switch controller	8	8	8
SXCBR		Circuit breaker	3	3	3
SXSWI		Circuit switch	7	7	7
POS_EVAL		Evaluation of position indication	8	8	8
SELGGIO		Select release	1	1	1
QCBAY		Bay control	1	1	1
LOCREM		Handling of LR-switch positions	1	1	1
LOCREMCTRL		LHMI control of PSTO	1	1	1
SLGGIO		Logic Rotating Switch for function selection and LHMI presentation	15	15	15
VSGGIO		Selector mini switch extension	20	20	20
DPGGIO		IEC 61850 generic communication I/O functions double point	16	16	16
SPC8GGIO		Single point generic control 8 signals	5	5	5
AUTOBITS		AutomationBits, command function for DNP3.0	3	3	3
Secondary system supervision					
CCSRDIF	87	Current circuit supervision	1	1	1

Table continues on next page

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
SDDRFUF		Fuse failure supervision	1	1	1
TCSSCBR		Breaker close/trip circuit monitoring	3	3	3
Logic					
SMPPTRC	94	Tripping logic	1	1	1
TMAGGIO		Trip matrix logic	12	12	12
OR		Configurable logic blocks, OR	283	283	283
INVERTER		Configurable logic blocks, Inverter	140	140	140
PULSETIMER		Configurable logic blocks, PULSETIMER	40	40	40
GATE		Configurable logic blocks, Controllable gate	40	40	40
XOR		Configurable logic blocks, exclusive OR	40	40	40
LOOPDELAY		Configurable logic blocks, loop delay	40	40	40
TimeSet		Configurable logic blocks, timer	40	40	40
AND		Configurable logic blocks, AND	280	280	280
SRMEMORY		Configurable logic blocks, set-reset memory	40	40	40
RSMEMORY		Configurable logic blocks, reset-set memory	40	40	40
ANDQT		Configurable logic Q/T, ANDQT	120	120	120
ORQT		Configurable logic Q/T, ORQT	120	120	120
INVERTERQT		Configurable logic Q/T, INVERTERQT	120	120	120
XORQT		Configurable logic Q/T, XORQT	40	40	40
SRMEMORYQT		Configurable logic Q/T, set-reset with memory	40	40	40
RSMEMORYQT		Configurable logic Q/T, reset-set with memory	40	40	40
TIMERSETQT		Configurable logic Q/T, settable timer	40	40	40
PULSETIMERQT		Configurable logic Q/T, pulse timer	40	40	40
INVALIDQT		Configurable logic Q/T, INVALIDQT	12	12	12
INDCOMBSPQT		Configurable logic Q/T, single indication signal combining	20	20	20
INDEXTSPQT		Configurable logic Q/T, single indication signal extractor	20	20	20
FXDSIGN		Fixed signal function block	1	1	1
B16I		Boolean 16 to Integer conversion	16	16	16
B16IFCVI		Boolean 16 to integer conversion with logic node representation	16	16	16
IB16A		Integer to Boolean 16 conversion	16	16	16
IB16FCVB		Integer to boolean 16 conversion with logic node representation	16	16	16
Monitoring					
CVMMXN		Measurements	6	6	6
CMMXU		Phase current measurement	10	10	10
VMMXU		Phase-phase voltage measurement	6	6	6
CMSQI		Current sequence component measurement	6	6	6

Table continues on next page

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
VMSQI		Voltage sequence measurement	6	6	6
VNMMXU		Phase-neutral voltage measurement	6	6	6
CNTGGIO		Event counter	5	5	5
DRPRDRE		Disturbance report	1	1	1
AxRADR		Analog input signals	1	1	1
BxRBDR		Binary input signals	1	1	1
SPGGIO		IEC 61850 generic communication I/O functions	64	64	64
SP16GGIO		IEC 61850 generic communication I/O functions 16 inputs	16	16	16
MVGGIO		IEC 61850 generic communication I/O functions	16	16	16
MVEXP		Measured value expander block	66	66	66
SPVNZBAT		Station battery supervision	1	1	1
SSIMG	63	Insulation gas monitoring function	1	1	1
SSIML	71	Insulation liquid monitoring function	1	1	1
SSCBR		Circuit breaker condition monitoring	1	1	1
Metering					
PCGGIO		Pulse counter logic	16	16	16
ETPMMTR		Function for energy calculation and demand handling	3	3	3

2.2.2 Back-up protection functions

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
Current protection					
PHPIOC	50	Instantaneous phase overcurrent protection	1	1	1
OC4PTOC	51/67	Four step directional phase overcurrent protection	1	1	1
EFPIOC	50N	Instantaneous residual overcurrent protection	1	1	1
EF4PTOC	51N/67N	Four step directional residual overcurrent protection	1	1	
SDEPSDE	67N	Sensitive directional residual overcurrent and power protection	1	1	1
LPTTR	26	Thermal overload protection, one time constant	1	1	1
CCRBRF	50BF	Breaker failure protection	1	1	1
STBPTOC	50STB	Stub protection	1	1	1
CCRPLD	52PD	Pole discordance protection	1	1	1
BRCPTOC	46	Broken conductor check	1	1	1

Table continues on next page

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
GUPPDUP	37	Directional underpower protection	1	1	1
GOPPDOP	32	Directional overpower protection	1	1	1
DNSPTOC	46	Negative sequence based overcurrent function	1	1	1
Voltage protection					
UV2PTUV	27	Two step undervoltage protection	1	1	1
OV2PTOV	59	Two step overvoltage protection	1	1	1
ROV2PTOV	59N	Two step residual overvoltage protection	1	1	1
LOVPTUV	27	Loss of voltage check	1	1	1
Frequency protection					
SAPTUF	81	Underfrequency function	2	2	2
SAPTOF	81	Overfrequency function	2	2	2
SAPFRC	81	Rate-of-change frequency protection	2	2	2

2.2.3 Designed to communicate

IEC 61850	ANSI	Function description	Bay		
			REC650 (A01) 1CBA	REC650 (A02) 1CBAB	REC650 (A07) BCAB
Station communication					
		IEC 61850 communication protocol	1	1	1
		DNP3.0 for TCP/IP communication protocol	1	1	1
GOOSEINTLK RCV		Horizontal communication via GOOSE for interlocking	59	59	59
GOOSEBINR CV		GOOSE binary receive	4	4	4

2.2.4 Basic IED functions

IEC 61850	Function description	
Basic functions included in all products		
INTERRSIG	Self supervision with internal event list	1
	Time synchronization	1
SETGRPS	Setting group handling	1
ACTVGRP	Parameter setting groups	1
TESTMODE	Test mode functionality	1
Table continues on next page		

IEC 61850	Function description	
CHNGLCK	Change lock function	1
ATHSTAT	Authority status	1
ATHCHCK	Authority check	1

2.3 REC650 application examples

2.3.1 Adaptation to different applications

The IED has pre-defined configurations mainly for sub-station control applications. There is however the possibility to integrate back-up protection functions in the IED. In sub-transmission systems it can be valuable to have another IED for line or transformer application, giving the main protection functionality and the bay control IED giving control functionality together with back-up protection.

The IED is available in three different versions:

- A01: for a single breaker bay connected to single busbar
- A02: for a single breaker bay connected to double busbar
- A07: for a bus coupler bay

A selection of common applications are described below.

- Application 1: Single breaker line bay, single busbar or double, in solidly earthed network
- Application 2: Single breaker line bay, single or double busbar, in high impedance earthed network
- Application 3: Bus coupler in solidly earthed network
- Application 4: Bus coupler in a high impedance earthed network

2.3.2 Single breaker line bay, single busbar or double, in solidly earthed network

Normally the following fault scenarios require back-up protection functions:

- Close in line short circuits: For close in faults the instantaneous phase overcurrent protection should be used. As the fault current is often high at this fault case fast tripping is essential. It is however important to base the setting on fault calculations considering different operational states.
- Short circuits on the whole line length. For these faults the four step phase overcurrent protection should be used. The four step phase overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations

considering different operational states as well as time delay co-ordination with other protections in the system.
- Close in line phase to earth faults: For close in faults the instantaneous residual overcurrent protection should be used. As the fault current is often high at this fault case fast tripping is essential. It is however important to base the setting on fault calculations considering different operational states.
- Phase to earth faults on the whole line length. For these faults the four step residual overcurrent protection should be used. The four step residual overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations considering different operational states as well as time delay co-ordination with other protections in the system.
- Failure of the circuit beaker to interrupt fault current after protection trip. The breaker failure protection function is essential in a protection system using local redundancy.
- Autoreclosing is normally used on power lines as most faults are transient, i.e. the arcing fault will extinguish after a short zero voltage interval.

2.3.3 Single breaker line bay, single or double busbar, in high impedance earthed network

Normally the following fault scenarios require back-up protection functions:

- Close in line short circuits: For close in faults the instantaneous phase overcurrent protection should be used. As the fault current is often high at this fault case fast tripping is essential. It is however important to base the setting on fault calculations considering different operational states
- Short circuits on the whole line length. For these faults the four step phase overcurrent protection should be used. The four step phase overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations considering different operational states as well as time delay co-ordination with other protections in the system
- Phase-to-earth faults. In high impedance earthed networks the fault current at a single phase-to-earth fault is small. For these faults the sensitive residual overcurrent protection should be used. The sensitive residual overcurrent protection has the possibility of directional function. It is important to base the setting on fault calculations considering different operational states as well as time delay co-ordination with other protections in the system. As a second protection a residual voltage protection is often used.
- Failure of the circuit beaker to interrupt fault current after protection trip. The breaker failure protection function is essential in a protection system using local redundancy.
- Autoreclosing is normally used on power lines as most faults are transient, that is the arcing fault will extinguish after a short zero voltage interval.

The recommendations in table 1 have the following meaning:

On: It is recommended to have the function activated in the application

Off: It is recommended to have the function deactivated in the application

Application dependent.: The decision to have the function activated or not is dependent on the specific conditions in each case

Application 1 and Application 2 in table 1 are according to application examples given in previous sections.

Table 1: Functionality table

Function	Application 1	Application 2
Instantaneous phase overcurrent protection PHPIOC	On	On
Four step phase overcurrent protection OC4PTOC	On	On
Instantaneous residual overcurrent protection EFPIOC	On	Off
Four step residual overcurrent protection EF4PTOC	On	Off
Sensitive directional residual overcurrent and power protection SDEPSDE	Off	On
Thermal overload protection LPTTR	Application dependent	Application dependent
Breaker failure protection CCRBRF	On	On
Pole discordance protection CCRPLD	Application dependent	Application dependent
Broken conductor check BRCPTOC	Application dependent	Application dependent
Directional under-power protection GUPPDUP	Application dependent	Application dependent
Directional over-power protection GOPPDOP	Application dependent	Application dependent
Negative sequence based overcurrent protection DNSPTOC	Application dependent	Application dependent
Two step undervoltage protection UV2PTUV	Application dependent	Application dependent
Two step overvoltage protection OV2PTOV	Application dependent	Application dependent
Two step residual overvoltage protection ROV2PTOV	Off	On
Under frequency protection SAPTUF (instance 1)	Application dependent	Application dependent
Under frequency protection SAPTUF (instance 2)	Application dependent	Application dependent
Over frequency protection SAPTOF (instance 1)	Application dependent	Application dependent
Over frequency protection SAPTOF (instance 2)	Application dependent	Application dependent

Table continues on next page

Function	Application 1	Application 2
Rate-of-change of frequency protection SAPFRC (instance 1)	Application dependent	Application dependent
Rate-of-change of frequency protection SAPFRC (instance 2)	Application dependent	Application dependent
Current circuit supervision CCSRDIF	On	On
Fuse failure supervision SDDRFUF	On	On
Breaker close/trip circuit monitoring TCSSCBR	On	On
Synchrocheck, energizing check, and synchronizing SESRSYN	Application dependent	Application dependent
Autorecloser SMBRREC	On	On

2.3.4 Bus coupler in a solidly earthed network

Normally the following fault scenarios require back-up protection functions:

- Short circuits on one of the busbar sections and short circuits on outgoing lines. For these faults the four step phase overcurrent protection should be used. The four step phase overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations considering different operational states as well as time delay coordination with other protections in the system.
- Phase-to-earth faults one of the busbar sections and phase-to-earth faults on outgoing lines. For these faults the four step residual overcurrent protection should be used. The four step residual overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations considering different operational states as well as time delay coordination with other protections in the system.
- Failure of the circuit beaker to interrupt fault current after protection trip. The breaker failure protection function is essential in a protection system using local redundancy.

2.3.5 Bus coupler in a high impedance earthed network

Normally the following fault scenarios require back-up protection functions:

- Short circuits on one of the busbar sections and short circuits on outgoing lines. For these faults the four step phase overcurrent protection should be used. The four step phase overcurrent protection has the possibility of directional function as well as different time delay characteristics. It is important to base the setting on fault calculations considering different operational states as well as time delay co-ordination with other protections in the system.

- Phase to earth faults. In high impedance earthed networks the fault current at a single phase to earth fault is small. For these faults the sensitive residual overcurrent protection should be used. The sensitive residual overcurrent protection has the possibility of directional function. It is important to base the setting on fault calculations considering different operational states as well as time delay co-ordination with other protections in the system. As a second protection a residual voltage protection is often used.
- Failure of the circuit beaker to interrupt fault current after protection trip. The breaker failure protection function is essential in a protection system using local redundancy.

The recommendations in table 1 have the following meaning:

On: It is recommended to have the function activated in the application

Off: It is recommended to have the function deactivated in the application

Application dependent.: The decision to have the function activated or not is dependent on the specific conditions in each case

Application 3 and Application 4 in table 1 are according to application examples given in previous sections.

Table 2: Functionality table

Function	Application 3	Application 4
Instantaneous phase overcurrent protection PHPIOC	Off	Off
Four step phase overcurrent protection OC4PTOC	Off	Off
Instantaneous residual overcurrent protection EFPIOC	On	On
Four step residual overcurrent protection EF4PTOC	On	Off
Sensitive directional residual overcurrent protection SDEPSDE	Off	On
Thermal overload protection LPTTR	Application dependent	Application dependent
Breaker failure protection CCRBRF	On	On
Pole discordance protection CCRPLD	Application dependent	Application dependent
Broken conductor check BRCPTOC	Application dependent	Application dependent
Directional under-power protection GUPPDUP	Application dependent	Application dependent
Directional over-power protection GOPPDOP	Application dependent	Application dependent

Table continues on next page

Function	Application 3	Application 4
Negative sequence overcurrent protection DNSPTOC	Application dependent	Application dependent
Two step Undervoltage Protection UV2PTUV	Application dependent	Application dependent
Two step Overvoltage Protection OV2PTOV	Application dependent	Application dependent
Two step Residual Overvoltage Protection ROV2PTOV	Off	On
Under frequency protection SAPTUF (instance 1)	Application dependent	Application dependent
Under frequency protection SAPTUF (instance 2)	Application dependent	Application dependent
Over frequency protection SAPTOF (instance 1)	Application dependent	Application dependent
Over frequency protection SAPTOF (instance 2)	Application dependent	Application dependent
Rate-of-change of frequency protection SAPFRC (instance 1)	Application dependent	Application dependent
Rate-of-change of frequency protection SAPFRC (instance 2)	Application dependent	Application dependent
Current circuit supervision CCSRDIF	On	On
Fuse failure supervision SDDRFUF	On	On
Breaker close/trip circuit monitoring TCSSCBR	On	On
Synchrocheck, energizing check, and synchronizing SESRSYN	Application dependent	Application dependent
Autorecloser SMBRREC	Off	Off

Section 3 REC650 setting examples

3.1 Setting example when REC650 is used as back-up protection in a transformer protection application

The application example has a 145/22 kV transformer as shown in figure 5.

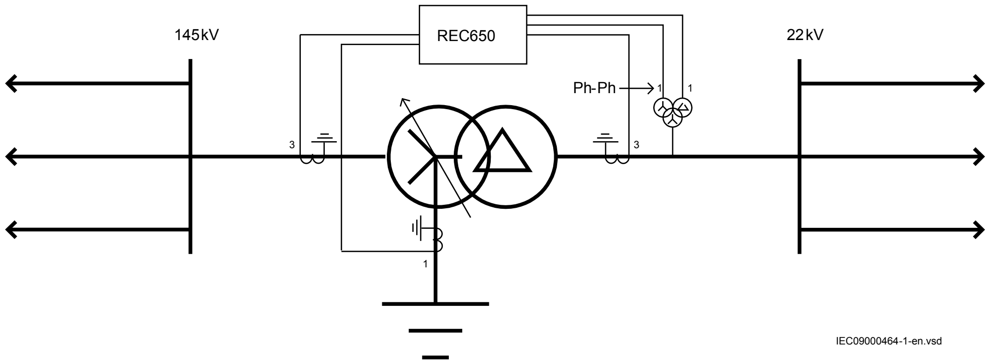

Figure 5: Two-winding HV/MV transformer, Y/Δ-transformer

Table 3: Typical data for the transformer application

The following data is assumed:

Item	Data
Transformer rated power SN	60 MVA
Transformer high voltage side rated voltage UN1	145 kV ±9 · 1.67 % (with on load tap changer)
Transformer low voltage side rated voltage UN2	22 kV
Transformer vector group	YNd11
Transformer short circuit voltage at tap changer mid point: ek	12 %
Maximum allowed continuous overload	1,30 · SN
Phase CT ratio at 145 kV level	300/1 A
CT at 145 kV earth point	300/1 A
Phase CT ratio at 22 kV level	2 000/1 A
22 kV VT ratio	$\frac{22}{\sqrt{3}} / \frac{0.11}{\sqrt{3}} / \frac{0.11}{3}$ kV
High positive sequence source impedance at the HV side	j10 Ω (about 2 100 MVA)
Low positive sequence source impedance at the HV side	j3.5 Ω (about 6 000 MVA)
Table continues on next page	

Item	Data
High zero sequence source impedance at the HV side	j20 Ω
Low zero sequence source impedance at the HV side	j15 Ω
Positive sequence source impedance at the LV side	∞ (no generation in the 22 kV network)

Only settings that need adjustment due to the specific application are described in setting examples. It is recommended to keep the default values for all settings that are not described. Refer to Technical manual for setting tables for each protection and control function.

Refer to setting guideline section in Application manual for guidelines on how to set functions that are not presented in setting examples.

Use parameter setting tool in PCM600 to set the IED according to calculations for the particular application.

3.1.1 Calculating general settings for analogue inputs 8I 2U

The analogue input has the capability of 8 current inputs (1 A) and 2 voltage inputs.

The 145 kV current CTs (three phase current transformer group) are connected to inputs 1 – 3 (L1, L2, L3).

The 22 kV current CTs (three phase current transformer group) are connected to inputs 4 – 6 (L1, L2, L3).

The 145 kV neutral point CT is connected to input 7 (IN).

The input 8 is not used. The input is used for connection of low voltage side CT (not in this application)

The 22 kV phase-to-phase (L1 – L2) VT is connected to input 9.

The 22 kV open delta connected VT (residual voltage) is connected to input 10.

1. Set the 145 kV current transformer input 1.
    1.1. Set *CTStarPoint1* to *ToObject*

(The CT secondary is earthed towards the protected transformer)

1.2. Set *CTSec1* to *1 A*
(The rated secondary current of the CT)

1.3. Set *CTPrim1* to *300 A*
(The rated primary current of the CT)

2. Set current inputs 2 and 3 to the same values as for current input 1.
3. Set the 22 kV current transformer input 4.

   3.1. Set *CTStarPoint4* to *ToObject*
   (The CT secondary is earthed towards the protected transformer)

   3.2. Set *CTSec4* to *1 A*
   (The rated secondary current of the CT)

   3.3. Set *CTPrim4* to *2000 A*
   (The rated primary current of the CT)

4. Set current inputs 5 and 6 to the same values as for current input 4.
5. Set the 145 kV neutral point current transformer input 7.

   5.1. Set *CTStarPoint7* to *ToObject*
   (The CT secondary is earthed towards the protected line)

   5.2. Set *CTSec7* to *1 A*
   (The rated secondary current of the CT)

   5.3. Set *CTPrim7* to *300 A*
   (The rated primary current of the CT)

Current input 8 is intended for connection of low voltage side CT. In this application the input is not used.

6. Set the voltage transformer inputs 9 and 10.

   6.1. Set *VTSec9* to *110 V*
   (The rated secondary voltage of the VT, given as phase-phase voltage)

   6.2. Set *VTPrim9* to *22 kV*
   (The rated secondary voltage of the VT, given as phase-phase voltage)

   6.3. Set *VTSec10* to *110 V/√3*
   (The rated secondary voltage of the VT, given as phase-phase voltage)

   6.4. Set *VTPrim10* to *22 kV*
   (The rated secondary voltage of the VT, given as phase-phase voltage)

3.1.2 Calculating settings for global base values GBASVAL

Each function uses primary base values for reference of settings. The base values are defined in Global base values for setting GBASVAL function. It is possible to include up to six Global base values for settings functions. In this application GBASVAL instance 1 is used to define the base for 145 kV inputs and GBASVAL instance 2 for 22 kV inputs.

For transformer protection it is recommended to set the base parameters according to the power transformer primary rated values:

1. Set Global Base 1
   1.1. Set *IBase* to *239 A*
   1.2. Set *UBase* to *145 kV*
   1.3. Set *SBase* to *60 MVA* (*SBase*=√3·*UBase*·*IBase*)
2. Set Global Base 2
   2.1. Set *IBase* to *1575 A*
   2.2. Set *UBase* to *22 kV*
   2.3. Set *SBase* to *60 MVA* (*SBase*=√3·*UBase*·*IBase*)

The *GlobalBaseSel* setting in a protection and control function references a Global base values for setting function for reference of primary values.

3.1.3 Calculating settings for instantaneous phase overcurrent protection, HV-side, PHPIOC

1. Set *GlobalBaseSel* to 1
   To relate the settings to the rated data of the transformer the (HV) winding data should be related to Global base 1.
2. Set *IP>>* to *1000 %* of *IBase*
   The instantaneous phase overcurrent protection on the high voltage side is used for fast trip of high current transformer internal faults. The protection shall be selective to the protections of the outgoing 22 kV feeders. Therefore the maximum 145 kV current at three-phase short circuit on the 22 kV side of the transformer is calculated:

$$I = \frac{145}{\sqrt{3} \cdot (Z_{net} + Z_T)} = \frac{145}{\sqrt{3} \cdot (3.8 + \frac{145^2}{60} \cdot 0.12)} = 1.83\ kA$$

(Equation 1)

   The dynamic overreach, due to fault current DC-component, shall be considered in the setting. This factor is less that 5 %. The setting is chosen with a safety margin of 1.2:
   $I_{set} \geq 1.2 \cdot 1.05 \cdot 1\ 830 = 2\ 306$ A
   Setting *IP>> = 1000 %* of *IBase*

3.1.4 Calculating settings for four step phase overcurrent protection, HV-side, OC4PTOC

The phase overcurrent protection is difficult to set as the short circuit current is highly dependent of the switching state in the power system as well as of the fault type. In order to achieve setting that assure selective fault clearance a large number of calculations have to be made with different fault locations, different switching states in the system and different fault types.

The 145 kV phase overcurrent protection have the following tasks:

- Backup protection for short circuits on the transformer
- Backup protection for short circuits on 22 kV busbar
- Backup protection for short circuits on outgoing 22 kV feeders (if possible)

The reach of phase overcurrent line protection depends on the operation state and the fault type. Therefore the setting must be based on fault calculations made for different faults, fault points and switching states in the network. Although it is possible to make hand calculations of the different faults it is recommended to use computer based fault calculations. Different time delay principles can be used. This is due to different praxis.

The following principle for the phase overcurrent protection is proposed:

- Only one step (step 1) is used. The time delay principle is chosen according to network praxis, in this case inverse time characteristics using IEC Normal inverse.

3.1.4.1 Calculating general settings

1. Set *GlobalBaseSel* to *1*
   The settings are made in primary values. These values are given in the base settings in Global base 1.
2. Set *DirMode1* to *non-directional*
   The function shall be non-directional
3. Set *Characterist1* to *IEC Norm.Inv.*
   For the choice of time delay characteristic IEC Normal inverse is used in this network.

3.1.4.2 Calculating settings for step 1

1. Set *I1>* to *140%* of *IBase* (334 A primary current)

The first requirement is that the phase overcurrent protection shall never trip for load current during the extreme high load situations. It is assumed that the transformer shall be able to be operated up to 130 % of the rated power during limited time. Further shall the protection resetting ratio be considered. The resetting ratio is 0.95. The minimum setting can be calculated as:

$$I_{pu} \geq 1.3 \cdot \frac{1}{0.95} \cdot \frac{60 \cdot 1000}{\sqrt{3} \cdot 145} = 327\ A$$

(Equation 2)

The next requirement is that the protection shall be able to detect all short circuits within the defined protected zone. In this case it is required, if possible, that the protection shall detect phase-to-phase short circuit at the most remote point of the outgoing feeders as shown in figure 6.

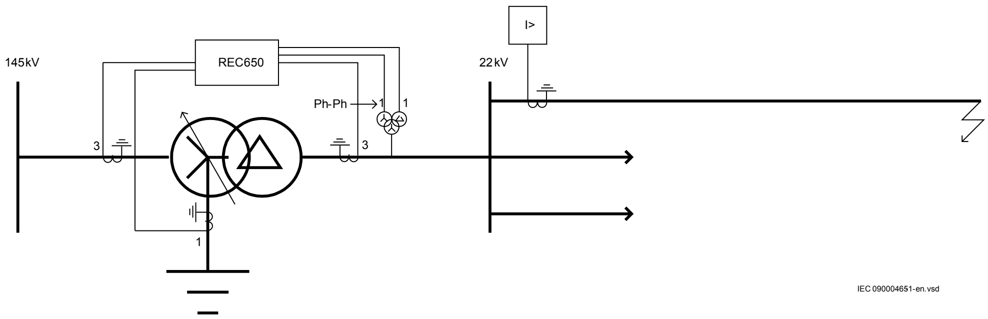

Figure 6: Fault calculation for phase overcurrent protection setting

The following fault is applied: phase-phase-earth short circuit. In this calculation should the short circuit power in the feeding substation be minimized (the source impedance maximized).
The longest 22 kV feeder has the impedance Z = 3 + j10 Ω. The external network has the maximum source impedance Z_{sc} = j10 Ω (145 kV level). This impedance is transformed to 22 kV level:

$$Z_{sc,22} = \left(\frac{22}{145}\right)^2 \cdot j10 = j0.23\ \Omega$$

(Equation 3)

The transformer impedance, referred to 22 kV level, is:

$$Z_{T,22} = j\frac{22^2}{60} \cdot 0.12 = j0.97\ \Omega$$

(Equation 4)

The fault current can be calculated:

$$I_{sc2ph} = \frac{\sqrt{3}}{2} \cdot \left| \frac{22000/\sqrt{3}}{j0.23 + j0.97 + 3 + j10} \right| = 948\ A$$

(Equation 5)

This fault current is recalculated to the 145 kV level:

$$I_{sc2ph,145} = \frac{22}{145} \cdot 948 = 144\ A$$

(Equation 6)

This current is smaller than the required minimum setting to avoid unwanted trip at large load current. This means that the 145 kV phase overcurrent protection cannot serve as complete back-up protection for the 22 kV feeders out from the substation.

2. Set *k1* to *0.15*
The time setting must be coordinated with the feeder protections to assure selectivity. It can be stated that there is no need for selectivity between the high voltage side phase overcurrent protection and the low voltage side phase overcurrent protection.
The feeder short circuit protections have the following setting:
I>: 300 A which corresponds to 45 A on 145 kV level.
I>>: 6 000 A which corresponds to 910 A on 145 kV level.
Characteristic: IEC Normal Inverse with k-factor = 0.25
The setting of the k-factor for the 145 kV phase overcurrent protection is derived from graphical study of the inverse time curves. It is required that the smallest time difference between the inverse time curves shall be 0.4 s. With the setting k = 0.15 the time margin between the characteristics is about 0.4 s as shown in figure 7.

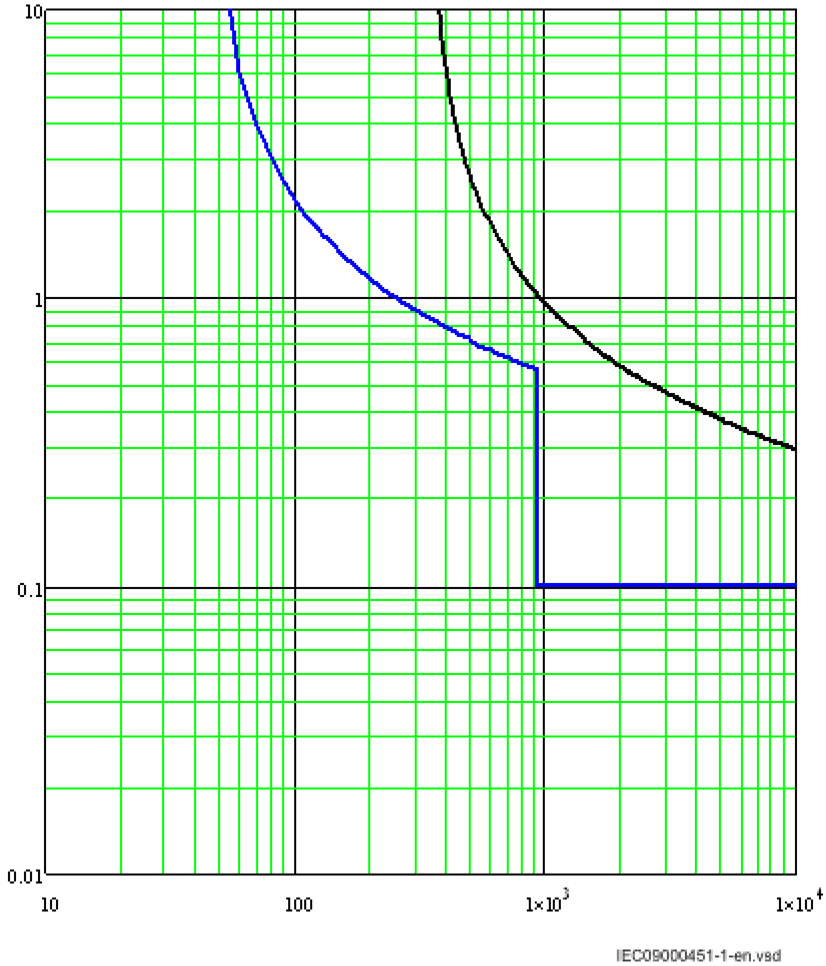

Figure 7: Inverse time operation characteristics for selectivity

3.1.5 Calculating settings for four step phase overcurrent protection, LV-side OC4PTOC

The 22 kV phase overcurrent protection has the following purpose:

- Main protection for short circuits on 22 kV busbar
- Backup protection for short circuits on outgoing 22 kV feeders (if possible)

The reach of phase overcurrent line protection is dependent of the operation state and the fault type. Therefore the setting must be based on fault calculations made for different faults, fault points and switching states in the network. Although it is possible to make manual calculations of the different faults it is recommended to use computer based fault calculations. Different time delay principles can be used. This is due to different praxis.

The following principle for the phase overcurrent protection is proposed:

- Step 1 serves as main protection for the 22 kV busbar. This step has a short delay and also has blocking input from the phase overcurrent protections of the 22 kV feeders. This is a way to achieve fast trip of 22 kV busbar short circuits and the selectivity is realized by means of the blocking from the feeder protections.
- Step 4 is used as back-up short circuit protection for the 22 kV feeders as far as possible. The time delay principle is chosen according to network praxis, in this case inverse time characteristics using IEC Normal inverse. As the step shall have inverse time characteristic the step 4 function is used.

3.1.5.1 Calculating general settings

1. Set *GlobalBaseSel* to *2*
   The settings are made in primary values. These values are given in the base settings in Global base 2.
2. Set directional mode
   2.1. Set *DirMode1* to *Non-directional*
   2.2. Set *DirMode4* to *Non-directional*

   The function shall be non-directional. Step 4 is used to achieve inverse time characteristic which is not available for step 2 and 3.
3. Set *Characterist1* to *IEC Def.Time*
   Step 1 shall have definite time delay
4. Set *Characterist4* to *IEC Norm.Inv*
   Step 4: For the choice of time delay characteristic IEC Normal inverse is used in this network.

3.1.5.2 Calculating settings for step 1

1. Set *I1>* to *500 %* of *IBase*
   The requirement is that step 1 shall detect all short circuits on the 22 kV busbar. The external network has the maximum source impedance Z_{sc} = j10 Ω (145 kV level). This impedance is transformed to 22 kV level:

$$Z_{sc,22} = \left(\frac{22}{145}\right)^2 \cdot j10 = j0.23\,\Omega$$

(Equation 7)

The transformer impedance, referred to 22 kV level, is:

$$Z_{T,22} = j\frac{22^2}{60} \cdot 0.12 = j0.97\,\Omega$$

(Equation 8)

Calculation of a phase-to-phase short circuit at this busbar:

$$I_{sc2ph} = \frac{\sqrt{3}}{2} \cdot \left| \frac{22000/\sqrt{3}}{j0.23 + j0.97} \right| = 9167\ A$$

(Equation 9)

The setting is chosen to 5 *IBase* with corresponds to 7 875 A primary current.

2. Set *t1* to *0.1 s*
   The time delay must be chosen so that the blocking signal shall be able to prevent unwanted operation at feeder short circuits. 0.1 s should be sufficient.

3.1.5.3 Calculating settings for step 2

The first requirement is that the phase overcurrent protection shall never trip for load current during the extreme high load situations. It is assumed that the transformer shall be able to be operated up to 130 % of the rated power during limited time. Further shall the protection resetting ratio be considered. The resetting ratio is 0.95. The minimum setting can be calculated as follows:

$$I_{pu} \geq 1.3 \cdot \frac{1}{0.95} \cdot \frac{60 \cdot 1000}{\sqrt{3} \cdot 22} = 2155\ A$$

(Equation 10)

The next requirement is that the protection shall be able to detect all short circuits within the defined protected zone. In this case it is required, if possible, that the protection shall detect phase-to-phase short circuit at the most remote point of the outgoing feeders as shown in figure 8.

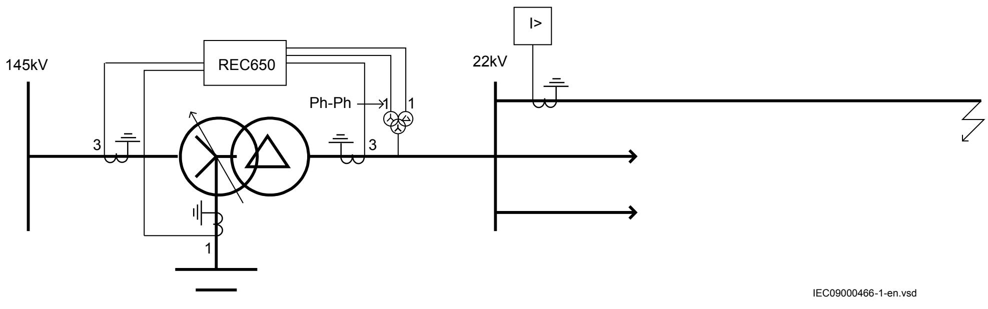

Figure 8: Fault calculation for phase overcurrent protection

The following fault is applied: phase-phase-earth short circuit. In this calculation should the short circuit power in the feeding substation be minimized (the source impedance maximized).

1. Set *I2>* to *140 %* of *IBase*
   2205 A primary current.

The longest 22 kV feeder has the impedance Z = 3 + j10 Ω. The external network has the maximum source impedance Zsc = j10 Ω (145 kV level). This impedance is transformed to 22 kV level:

$$Z_{sc,22} = \left(\frac{22}{145}\right)^2 \cdot j10 = j0.23\,\Omega$$

(Equation 11)

The transformer impedance, referred to 22 kV level, is:
The phase-to-phase fault current can be calculated:

$$I_{sc2ph} = \frac{\sqrt{3}}{2} \cdot \left| \frac{22000/\sqrt{3}}{j0.23 + j0.97 + 3 + j10} \right| = 949\ A$$

(Equation 12)

This current is smaller than the required minimum setting to avoid unwanted trip at large load current. This means that the 22 kV phase overcurrent protection cannot serve as complete back-up protection for the 22 kV feeders out from the substation.

2. Set *k4* to *0.15*
   The feeder short circuit protections have the following setting:
   I>: 300 A.
   I>>: 6 000 A.
   Characteristic: IEC Normal Inverse with k-factor = 0.25
   The setting of the k-factor for the 22 kV phase overcurrent protection is derived from graphical study of the inverse time curves. It is required that the smallest time difference between the inverse time curves is 0.4 s. With the setting k = 0.15 the time margin between the characteristics is about 0.4 s as shown in figure 9.

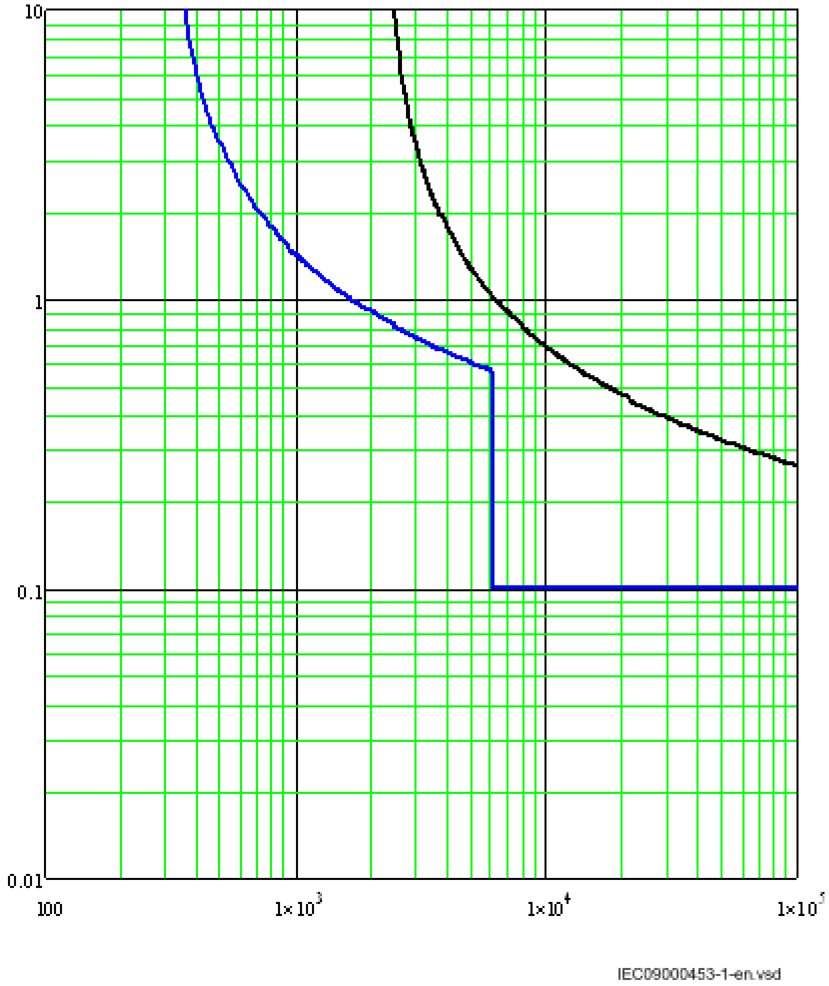

Figure 9: Inverse time operation characteristics for selectivity

3.1.6 Calculating settings for four step residual overcurrent protection HV-side EF4PTOC

The protection is fed from the 145 kV neutral point of the current transformer.

The residual overcurrent protection is more difficult to set as the earth-fault current is highly dependent of the switching state in the power system. In order to achieve setting that assure selective fault clearance a large number of calculations have to be made with different fault locations, different switching states in the system and different earth-fault types. Below one example of setting of residual overcurrent protection for a line in a meshed solidly earthed system is given.

If there is no generation at the low voltage side of the generator the transformer can only feed earth-fault currents as long as any of the non faulted lines are still in operation. If there is generation connected to the low voltage side of the transformer the transformer can feed 145 kV earth-faults alone.

The residual overcurrent protection has the following purpose:

- Fast and sensitive protection for earth-faults on the 145 kV busbar
- Backup protection for earth-faults in the 145 kV transformer winding
- Backup protection for earth-faults on the 145 kV lines out from the substation
- Sensitive detection of high resistive earth-faults and series faults in the 145 kV network

The reach of residual overcurrent line protection is dependent of the operation state and the fault type. Therefore the setting must be based on fault calculations made for different faults, fault points and switching states in the network. Although it is possible to make hand calculations of the different faults it is recommended to use computer based fault calculations. Different time delay principles can be used. This is due to different praxis.

The following principle for the residual overcurrent protection is proposed:

- Step 1 (*IN1>*) with high current setting and a short delay (about 0.4 s). Step 1 has non-directional function. This step gives fast trip for the busbar earth-faults and some earth-faults on the lines.
- Step 2 (*IN2>*) with a current setting, if possible, that enables detection of earth-faults on the 145 kV lines out from the substation. Step 2 has non-directional function. The function has a delay to enable selectivity to the line protections.
- Step 3 (*IN4>*) with a current setting that enables detection of high resistive earth-faults and series faults in the network. Step 3 has non-directional function. The function has a longer delay to enable selectivity.

3.1.6.1 Calculating general settings

The settings are made in primary values. These values are given in the base settings in Global base 1.

1. Set *GlobalBaseSel* to *1*
2. Set *DirMode1*, *DirMode2* and *DirMode4* to *Non-directional*
3. Set *DirMode3* to *Off*

3.1.6.2 Calculating settings for step 1

Set operating residual current level and time delay

1. Set *IN1>* to *650%* of *IBase*, corresponding to 1553 A
   Faults are applied at the 145 kV busbar as shown in figure 10.

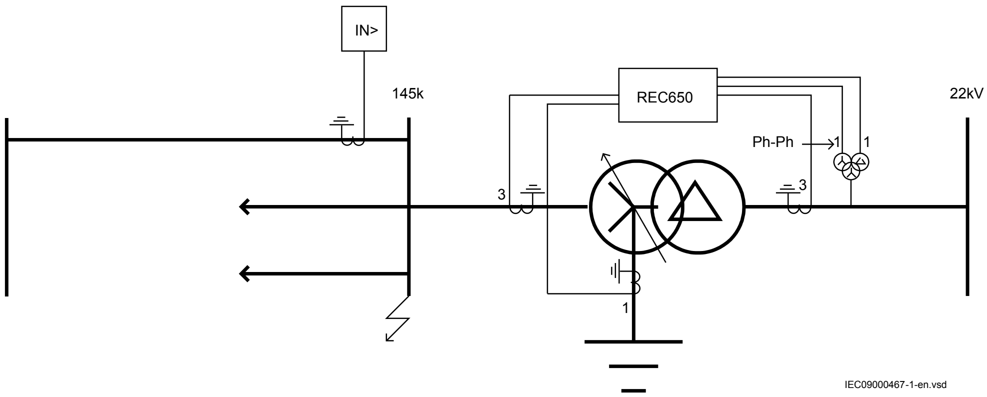

Figure 10: Fault calculation for 145 kV residual overcurrent protection setting

The following fault types are applied: phase-phase-earth short circuit and phase-earth-fault. The source impedance (both positive sequence and zero sequence) at the 145 kV level gives the following residual current from the transformer at phase-to-earth busbar fault (the current is hand-calculated but is normally calculated in a computer).
The zero sequence transformer impedance is assumed to be equal to the positive sequence short circuit impedance:

$$Z_{0T} = j\frac{U_N^2}{S_N}\cdot e_k = j\frac{145^2}{60}\cdot 0.12 = j42\,\Omega$$

(Equation 13)

The residual current from the transformer at single phase-earth-fault and maximum short circuit power is:

$$3I_{0T} = \frac{Z_{0,net}}{Z_{0,net}+Z_{0T}}\cdot\frac{\sqrt{3}\cdot U}{2\cdot Z_{1,net}+\dfrac{Z_{0,net}\cdot Z_{0T}}{Z_{0,net}+Z_{0T}}} = \frac{j15}{j15+j42}\cdot\frac{\sqrt{3}\cdot 145}{2\cdot j3.5+\dfrac{j15\cdot j42}{j15+j42}} = 3.7\ kA$$

(Equation 14)

The residual current from the transformer at single phase-earth-fault and minimum short circuit power is:

$$3I_{0T} = \frac{Z_{0,net}}{Z_{0,net}+Z_{0T}}\cdot\frac{\sqrt{3}\cdot U}{2\cdot Z_{1,net}+\dfrac{Z_{0,net}\cdot Z_{0T}}{Z_{0,net}+Z_{0T}}} = \frac{j20}{j20+j42}\cdot\frac{\sqrt{3}\cdot 145}{2\cdot j10+\dfrac{j20\cdot j42}{j20+j42}} = 2.4\ kA$$

(Equation 15)

The residual current from the transformer at phase-to-phase to earth-fault and maximum short circuit power is:

$$3I_{0T} = \frac{Z_{0,net}}{Z_{0,net}+Z_{0T}}\cdot\frac{\sqrt{3}\cdot U}{Z_{1,net}+2\cdot\dfrac{Z_{0,net}\cdot Z_{0T}}{Z_{0,net}+Z_{0T}}} = \frac{j15}{j15+j42}\cdot\frac{\sqrt{3}\cdot 145}{j3.5+2\cdot\dfrac{j15\cdot j42}{j15+j42}} = 2.6\ kA$$

(Equation 16)

The residual current from the transformer at phase-to-phase to earth-fault and minimum short circuit power is:

$$3I_{0T} = \frac{Z_{0,net}}{Z_{0,net} + Z_{0T}} \cdot \frac{\sqrt{3} \cdot U}{Z_{1,net} + 2 \cdot \dfrac{Z_{0,net} \cdot Z_{0T}}{Z_{0,net} + Z_{0T}}} = \frac{j20}{j20 + j42} \cdot \frac{\sqrt{3} \cdot 145}{j10 + 2 \cdot \dfrac{j20 \cdot j42}{j20 + j42}} = 2.2\ kA$$

(Equation 17)

To assure that the protection detects all earth-faults on the 145 kV busbar the protection should be set:
Setting: *IN1> ≤ 0.75 · 2.2 = 1.65 kA*

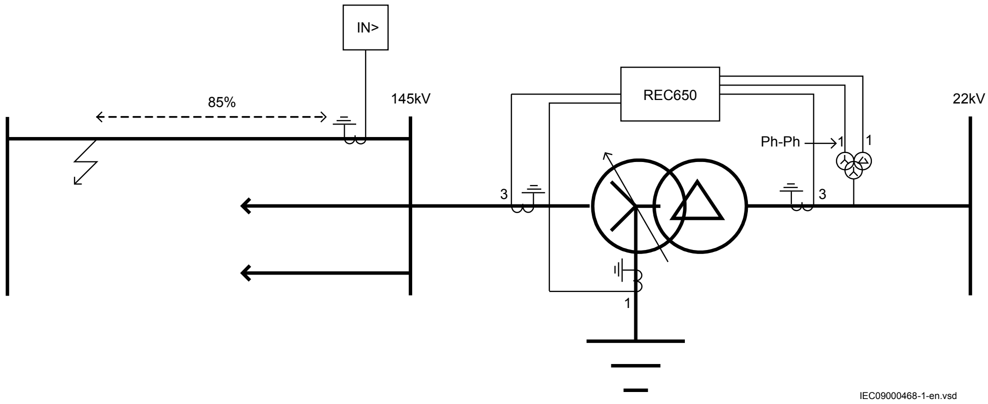

Figure 11: Fault calculation for 145 kV residual overcurrent protection selectivity

The calculations show the largest residual current from the transformer = 1.2 kA.
To assure selectivity the setting must fulfil:
$I_{high,set} \geq 1.2 \cdot k \cdot 3I_{0\,max}$
which gives about 1 500 A ,where k is the transient overreach (due to fault current DC-component) of the overcurrent function. For the four step phase overcurrent function; k = 1.05.

2. Set *t1* to *0.4 s*
   Characteristic 1: ANSI Def. time
   As the protection should be set for a time delay of 0.4 s the selectivity to the line protections should be assured. Therefore earth-faults should be calculated where the fault point on the lines is at zone 1 reach (about 85 % out on the line).

3.1.6.3 Calculating settings for step 2

1. Set *IN2>* to *400%* of *IBase*, corresponding to 956 A
   To assure that step 2 detects all earth-faults on the outgoing lines earth-faults calculations are made where single phase-faults and phase-to-phase-to earth-faults are applied to the adjacent busbars.

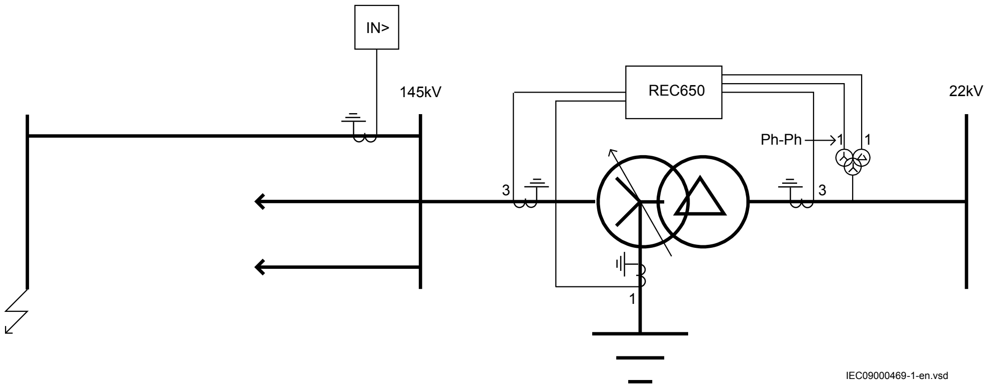

Figure 12: Fault calculation for sufficient reach of the 145 kV residual overcurrent protection

The minimum residual current to detect works out as $3I_{0AB,min}$ = 1.0 kA.

2. Set *t2* to *0.8 s*
   Characteristic 2: ANSI Def. time
   The delay of IN2> should be set longer than the distance protection zone 2 (normally 0,4 s). 0.8 s is proposed.

3.1.6.4 Calculating settings for step 4

1. Set *IN4>* to *42 %* of *IBase*, corresponding to 100 A
   The current setting of step 4 should be chosen according to standard procedure in the grid. From experience it can be concluded that the setting down to about 100 A can be used. This setting is however highly dependent on the line configuration, manly if the line is transposed or not.
   The delay of *IN4>* should be set larger than the delay of sensitive residual current protection of the lines.
2. Set *k4* to *0.3*
   Characteristic 4: RD Type
3. Set *t4Min* to *1.2 s*
4. Select *inverse time delay of type RD* to *logarithmic*
   If definite time delay is used there is some risk of unselective tip at high resistive earth-faults or series faults. If dependent time delay (inverse time) is used some degree of selectivity can be achieved.
   Here, inverse time delay of type RD is selected: logarithmic

3.1.7 Calculating settings for two step residual overvoltage protection LV-side, ROV2PTOV

The residual overvoltage protection is fed from the open delta connected voltage transformer at the 22 kV side of the transformer.

The residual overvoltage protection has the following purpose:

- Back-up protection for earth-faults on the 22 kV feeders out from the substation.
- Main protection for earth-faults on the 22 kV busbar
- Main protection for earth-faults on the 22 kV transformer winding

The residual voltage protection has two steps. In this application step 1 should trip the 22 kV circuit breaker and if the earth-fault is situated in the transformer 22 kV winding or between the transformer and the 22 kV breaker the 145 kV breaker is tripped from step 2.

The voltage setting of the protection is depending on the required sensitivity and the system earthing. The 22 kV system has earthing with a Petersen coil (connected to the system via a separate earthing transformer) and a parallel neutral point resistor. The Petersen coil is tuned to compensate for the capacitive earth-fault current in the 22 kV system. The neutral point resistor gives 10 A earth-fault current at zero resistance earth-fault. This means that the resistance is

$$_N = \frac{22000/\sqrt{3}}{10} = 1270\ \Omega$$

(Equation 18)

The total zero sequence impedance of the 22 kV system is

$Z_0 = 3R_N // j3X_N // — jX_C\ \Omega / phase$

As the Petersen coil is tuned the zero sequence impedance is:

$Z_0 = 3R_N\ \Omega / phase$

The Residual voltage at resistive earth-fault in the 22 kV system is:

$$U_o = \frac{U_{Phase}}{1 + \frac{3 \cdot R_f}{Z_0}} \ or\ \frac{U_0}{U_{phase}} = \frac{1}{1 + \frac{3 \cdot R_f}{Z_0}}$$

(Equation 19)

In our case the requirement is that earth-faults with resistance up to 5 000 Ω shall be detected. This gives:

$$\frac{U_0}{U_{phase}} = \frac{1}{1 + \frac{3 \cdot 5000}{3 \cdot 1270}} = 0.20$$

(Equation 20)

Step 1 and step 2 is given the same voltage setting but step 2 shall have longer time delay.

The residual earth-fault protection shall have definite time delay. The time setting is set longer than the time delay of the earth-fault protection of the outgoing feeders having maximum 2 s delay. Time delay for step 1 is set to 3 s and the time delay for step 2 is set to 4 s.

1. Set *GlobalBaseSel* to *2*
   The settings are made in primary values. These values are given in the base settings in Global base 2.
2. Set *Characteristic1* to *Definite time*
3. Set *U1>* to *20 %* of *UBase*
4. Set *t1* to *3.0 s*
5. Set *U2>* to *20 %* of *UBase*
6. Set *t2* to *4.0 s*

3.1.8 Calculating settings for breaker failure protection HV-side, CCRBRF

The breaker failure protection can use either contact function in the circuit breaker or current measurement to detect correct breaker function. For line protections it seems to be most suitable function is to use current measurement breaker check.

1. Set *GlobalBaseSel* to *1*
   The settings are made in primary values. These values are given in the base settings in Global base 1.
2. Set *Function mode* to *Current*
3. Set *BuTripMode* to *1 out of 4*
   In the current measurement the three-phase currents out on the line is used. It is also possible to measure the residual current (analogue input 4). The logics to detect failure of the circuit breaker can be chosen:
   1 out of 3: at least one of the three-phase current shall be larger than the set level to detect failure to break
   1 out of 4: at least one of the three-phase current and the residual current shall be larger than the set level to detect failure to break
   2 out of 4: at least two of the three-phase current and the residual current shall be larger than the set level to detect failure to break As the residual current protection is one of the protection functions to initiate the breaker failure protection the setting *1 out of 4* is chosen.
4. Set *Ip>* to *20 %* of *IBase*
   IP> should be set lower than the smallest current to be detected by the differential protection which is set 25 % of *IBase*.
5. Set *IN>* to *20 %* of *IBase*

IN> should be set lower than the smallest current to be detected by the most sensitive step of the residual ovecurrent protection which is 100 A.

6. Set the re-tip time delay *t1* to *0*
7. Set *t2* to *0.17 s*
   The delay time of the breaker failure protection (BuTrip) is chosen according to figure 13.
   The maximum open time of the circuit breaker is considered to be 100 ms.
   The BFP reset time is maximum 15 ms.
   The margin should be chosen to about 2 cycles. This gives about 155 ms minimum setting of back-up trip delay *t2*.

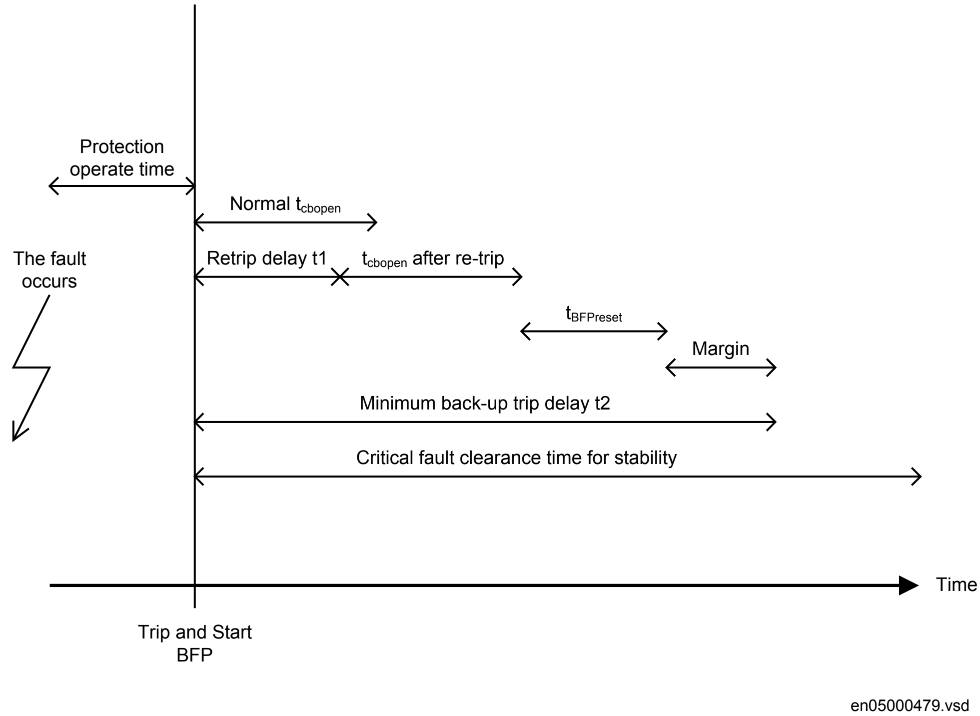

Figure 13: Overexcitation protection characteristics

3.1.9 Calculating settings for breaker failure protection LV-side CCRBRF

The breaker failure protection can use either contact function in the circuit breaker or current measurement to detect correct breaker function. For line protections it seems to be most suitable function is to use current measurement breaker check.

1. Set *GlobalBaseSel* to *2*

The settings are made in primary values. These values are given in the base settings in Global base 2.

2. Set *Function mode* to *Current*
3. Set *BuTripMode* to *1 out of 3*
   In the current measurement the three-phase currents out on the line is used. It is also possible to measure the residual current (analogue input 4). The logics to detect failure of the circuit breaker can be chosen:
   1 out of 3: at least one of the three-phase current shall be larger than the set level to detect failure to break
   1 out of 4: at least one of the three-phase current and the residual current shall be larger than the set level to detect failure to break
   2 out of 4: at least two of the three-phase current and the residual current shall be larger than the set level to detect failure to break.
   There is no residual current measurement protection on the 22 kV side of the transformer. Therefore *1 out of 3* is chosen.
4. Set *Ip>* to *20 % of IBase*
   IP> should be set lower than the smallest current to be detected by the differential protection which is set 25 % of *IBase*.
5. Set the re-tip time delay *t1* to *0*
6. Set the re-tip time delay *t1* to *0 s*
7. Set *t2* to *0.17 s*
   The delay time of the breaker failure protection (BuTrip) is chosen according to figure 13.
   The maximum open time of the circuit breaker is considered to be 100 ms.
   The breaker failure protection reset time is maximum 15 ms.
   The margin should be chosen to about 2 cycles.
   This gives about 155 ms minimum setting of back-up trip delay t2.

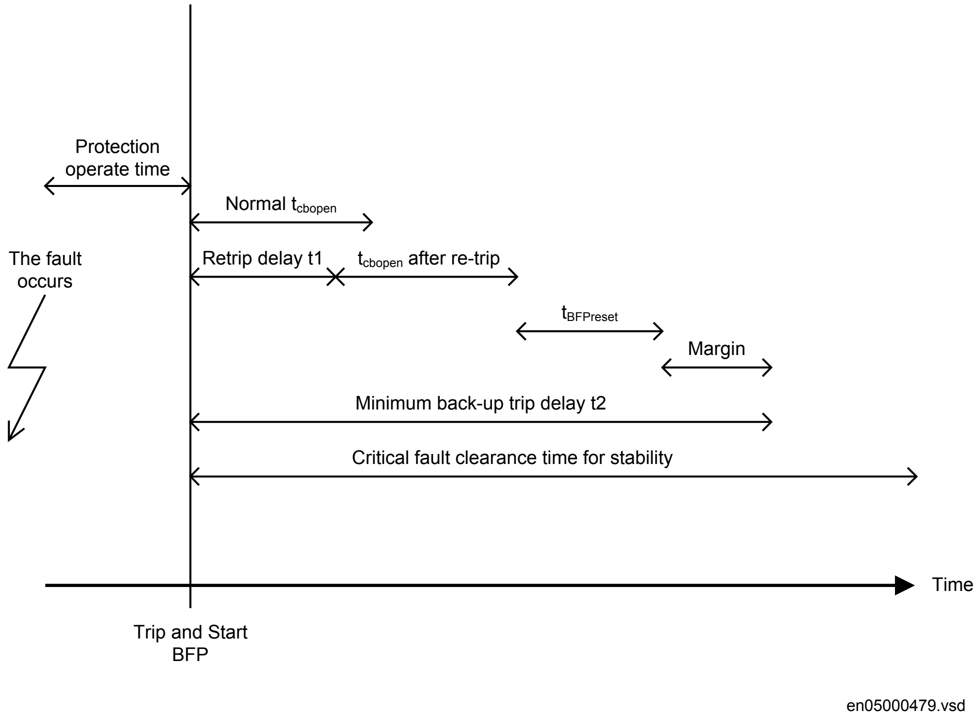

Figure 14: Time sequences for breaker failure protection setting

Section 4 Local human-machine interface

4.1 Local HMI

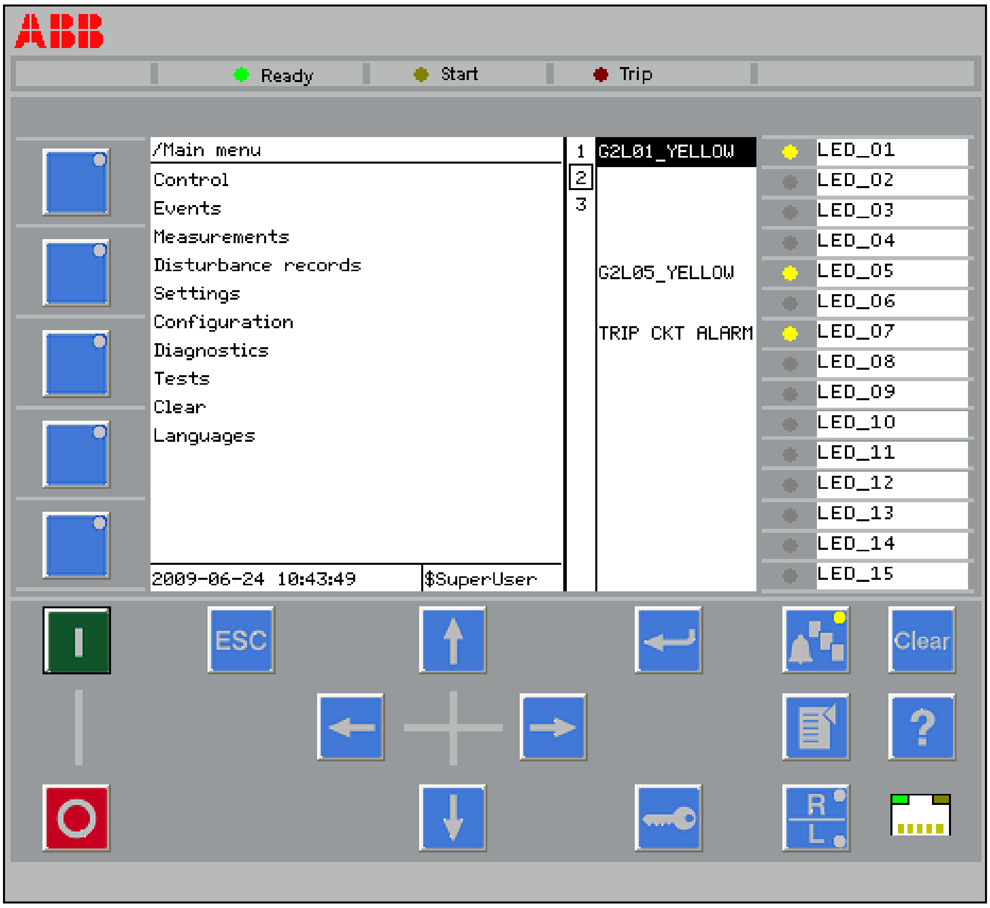

Figure 15: Local human-machine interface

The LHMI of the IED contains the following elements:

- Display (LCD)
- Buttons
- LED indicators
- Communication port

The LHMI is used for setting, monitoring and controlling.

4.1.1 LCD

The LHMI includes a graphical monochrome LCD with a resolution of 320 x 240 pixels. The character size can vary. The amount of characters and rows fitting the view depends on the character size and the view that is shown.

The display view is divided into four basic areas.

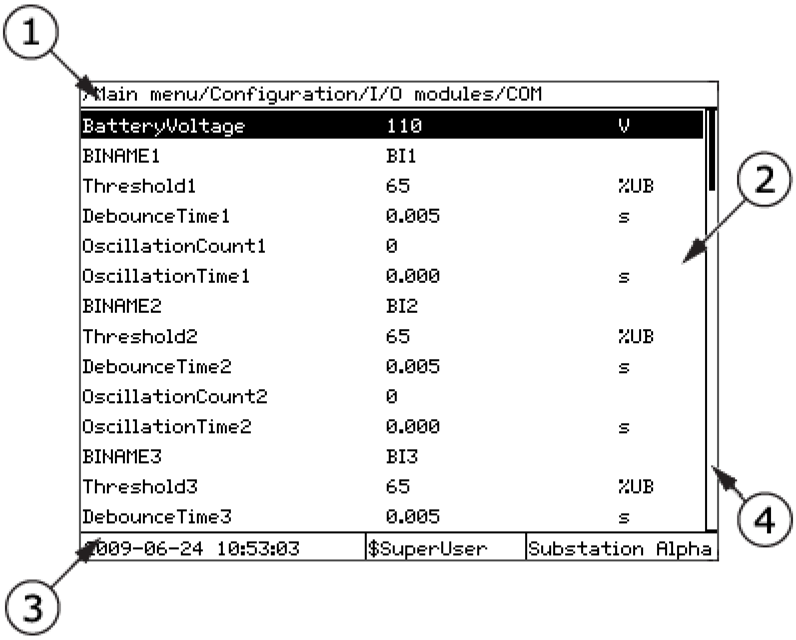

Figure 16: Display layout

1 Path

2 Content

3 Status

4 Scroll bar (appears when needed)

The function button panel shows on request what actions are possible with the function buttons. Each function button has a LED indication that can be used as a feedback signal for the function button control action. The LED is connected to the required signal with PCM600.

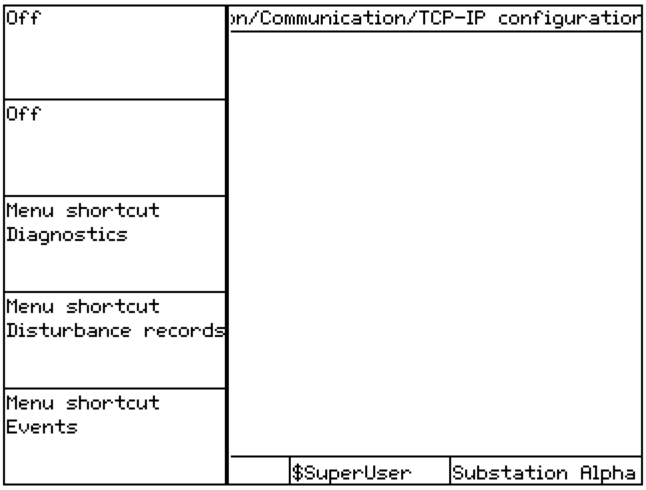

Figure 17: Function button panel

The alarm LED panel shows on request the alarm text labels for the alarm LEDs.

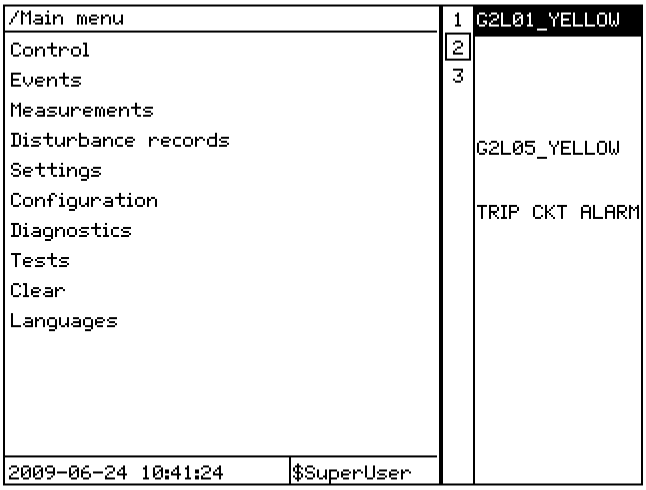

Figure 18: Alarm LED panel

The function button and alarm LED panels are not visible at the same time. Each panel is shown by pressing one of the LCD function buttons or the Multipage button. Pressing the ESC button clears the panel from the display. Both the panels have dynamic width that depends on the label string length that the panel contains.

4.1.2 LEDs

The LHMI includes three protection indicators above the display: Ready, Start and Trip.

There are also 15 matrix programmable alarm LEDs on front of the LHMI. Each LED can indicate three states with the colors: green, yellow and red. The alarm texts related to each three-color LED are divided into three pages. The 15 physical three-color LEDs in one LED group can indicate 45 different signals. Altogether, 135 signals can be indicated since there are three LED groups. The LEDs can be configured with PCM600 and the operation mode can be selected with the LHMI or PCM600.

4.1.3 Keypad

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

The keypad also contains programmable push-buttons that can be configured either as menu shortcut or control buttons.

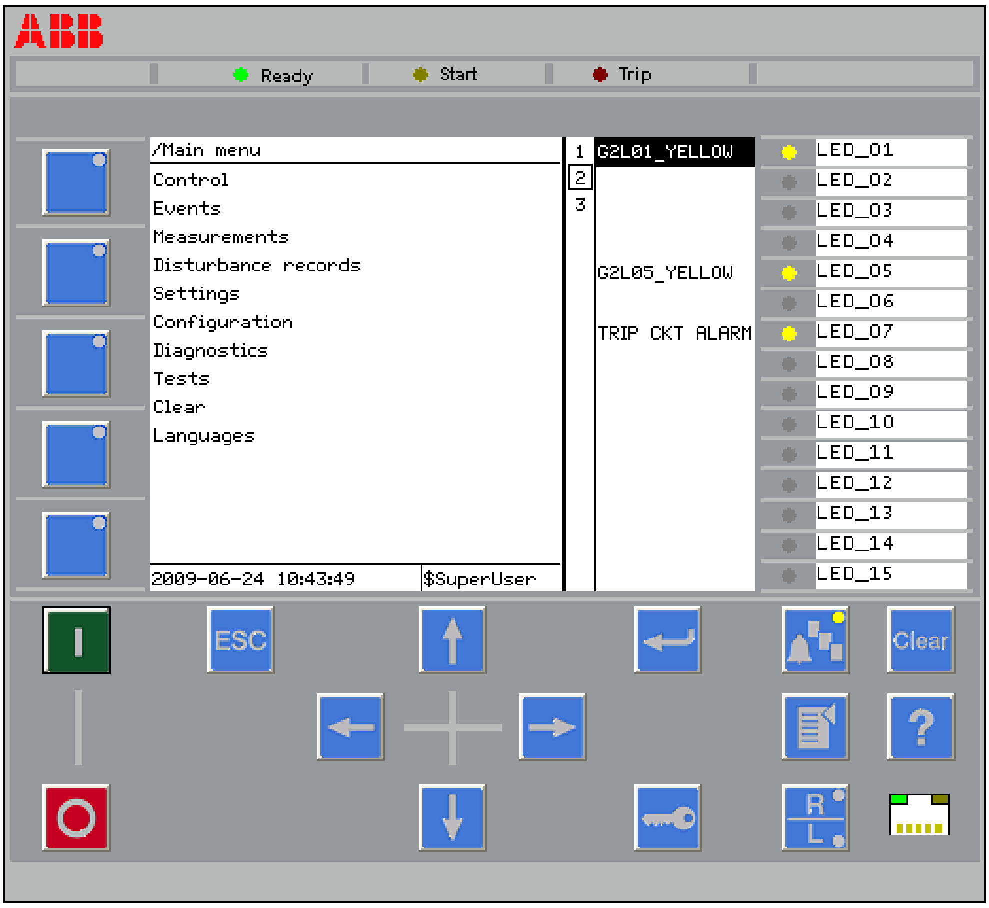

Figure 19: LHMI keypad

4.1.4 Local HMI functionality

4.1.4.1 Protection and alarm indication

Protection indicators

Protection indicator LEDs are Ready, Start and Trip.

Configure the disturbance recorder to enable the start and trip LEDs.

Table 4: Ready LED (green)

LED state	Description
Off	Auxiliary supply voltage is disconnected.
On	Normal operation.
Flashing	Internal fault has occurred.

Table 5: Start LED (yellow)

LED state	Description
Off	Normal operation.
On	A protection function has started and an indication message is displayed. • The start indication is latching and must be reset via communication or by pressing Clear.
Flashing	A flashing yellow LED has a higher priority than a steady yellow LED. The IED is in test mode and protection functions are blocked. • The indication disappears when the IED is no longer in test mode and blocking is removed.

Table 6: Trip LED (red)

LED state	Description
Off	Normal operation.
On	A protection function has tripped and an indication message is displayed. • The trip indication is latching and must be reset via communication or by pressing Clear.

Alarm indicators

The 15 programmable three-color LEDs are used for alarm indication. An individual alarm/status signal, connected to any of the LED function blocks, can be assigned to one of the three LED colors when configuring the IED.

Table 7: Alarm indications

LED state	Description
Off	Normal operation. All activation signals are off.
On	• Follow-S sequence: The activation signal is on. • LatchedColl-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedAck-F-S sequence: The indication has been acknowledged, but the activation signal is still on. • LatchedAck-S-F sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedReset-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged.
Flashing	• Follow-F sequence: The activation signal is on. • LatchedAck-F-S sequence: The activation signal is on, or it is off but the indication has not been acknowledged. • LatchedAck-S-F sequence: The indication has been acknowledged, but the activation signal is still on.

4.1.4.2 Parameter management

The LHMI is used to access the IED parameters. Three types of parameters can be read and written.

- Numerical values
- String values
- Enumerated values

Numerical values are presented either in integer or in decimal format with minimum and maximum values. Character strings can be edited character by character. Enumerated values have a predefined set of selectable values.

4.1.4.3 Front communication

The RJ-45 port in the LHMI enables front communication.

- The green uplink LED on the left is lit when the cable is successfully connected to the port.

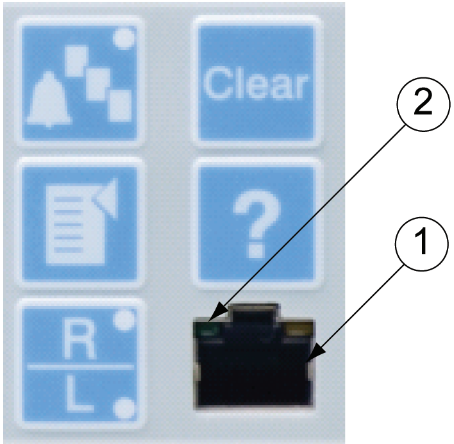

Figure 20: RJ-45 communication port and green indicator LED

1 RJ-45 connector

2 Green indicator LED

When a computer is connected to the IED front port with a crossed-over cable, the IED's DHCP server for the front interface assigns an IP address to the computer if *DHCPServer* = *On*. The default IP address for the front port is 10.1.150.3 .

Do not connect the IED front port to LAN. Connect only a single local PC with PCM600 to front port.

4.1.4.4 Single-line diagram

Single-line diagram is used for bay monitoring and/or control. It shows a graphical presentation of the bay which is configured with PCM600.

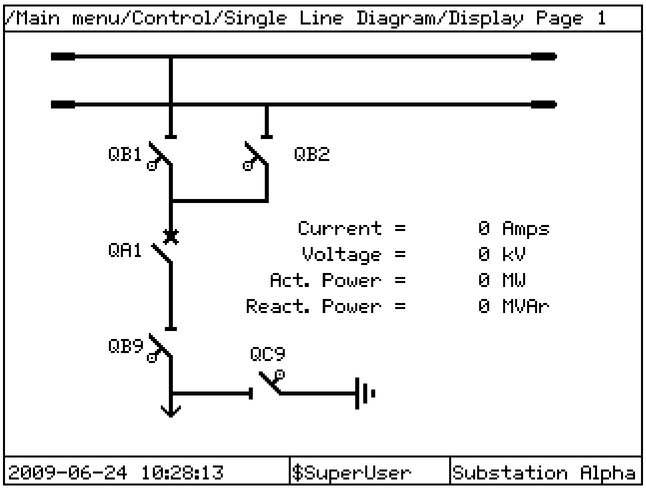

Figure 21: Single-line diagram

Section 5 Current protection

5.1 Instantaneous phase overcurrent protection PHPIOC

5.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Instantaneous phase overcurrent protection	PHPIOC	3I>>	50

5.1.2 Application

Long transmission lines often transfer great quantities of electric power from production to consumption areas. The unbalance of the produced and consumed electric power at each end of the transmission line is very large. This means that a fault on the line can easily endanger the stability of a complete system.

The transient stability of a power system depends mostly on three parameters (at constant amount of transmitted electric power):

- The type of the fault. Three-phase faults are the most dangerous, because no power can be transmitted through the fault point during fault conditions.
- The magnitude of the fault current. A high fault current indicates that the decrease of transmitted power is high.
- The total fault clearing time. The phase angles between the EMFs of the generators on both sides of the transmission line increase over the permitted stability limits if the total fault clearing time, which consists of the protection operating time and the breaker opening time, is too long.

The fault current on long transmission lines depends mostly on the fault position and decreases with the distance from the generation point. For this reason the protection must operate very quickly for faults very close to the generation (and relay) point, for which very high fault currents are characteristic.

The instantaneous phase overcurrent protection (PHPIOC) can operate in 10 ms for faults characterized by very high currents.

5.1.3 Setting guidelines

The parameters for Instantaneous phase overcurrent protection (PHPIOC) are set via the local HMI or Protection and Control Manager (PCM600).

This protection function must operate only in a selective way. So check all system and transient conditions that could cause its unwanted operation.

Only detailed network studies can determine the operating conditions under which the highest possible fault current is expected on the line. In most cases, this current appears during three-phase fault conditions. But also examine single-phase-to-earth and two-phase-to-earth conditions.

Also study transients that could cause a high increase of the line current for short times. A typical example is a transmission line with a power transformer at the remote end, which can cause high inrush current when connected to the network and can thus also cause the operation of the built-in, instantaneous, overcurrent protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

IP>>: Set operate current in % of *IBase*.

5.1.3.1 Meshed network without parallel line

The following fault calculations have to be done for three-phase, single-phase-to-earth and two-phase-to-earth faults. With reference to figure 22, apply a fault in B and then calculate the current through fault phase current I_{fB}. The calculation should be done using the minimum source impedance values for Z_A and the maximum source impedance values for Z_B in order to get the maximum through fault current from A to B.

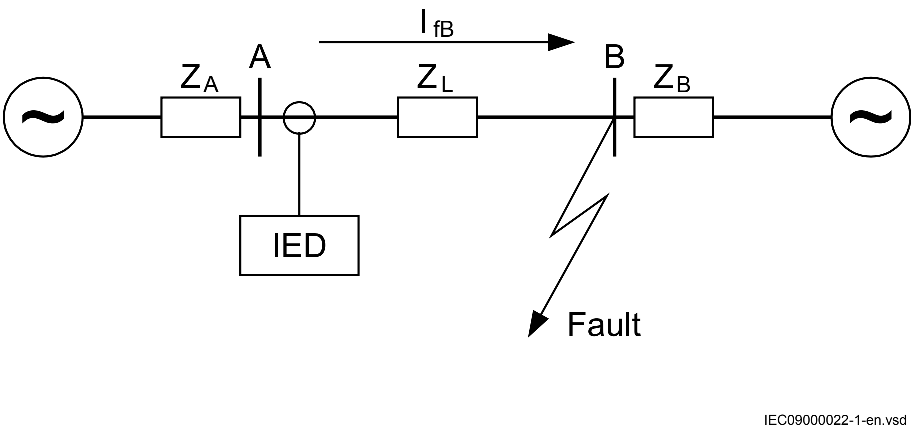

Figure 22: Through fault current from A to B: I_{fB}

Then a fault in A has to be applied and the through fault current I_{fA} has to be calculated, figure 23. In order to get the maximum through fault current, the minimum value for Z_B and the maximum value for Z_A have to be considered.

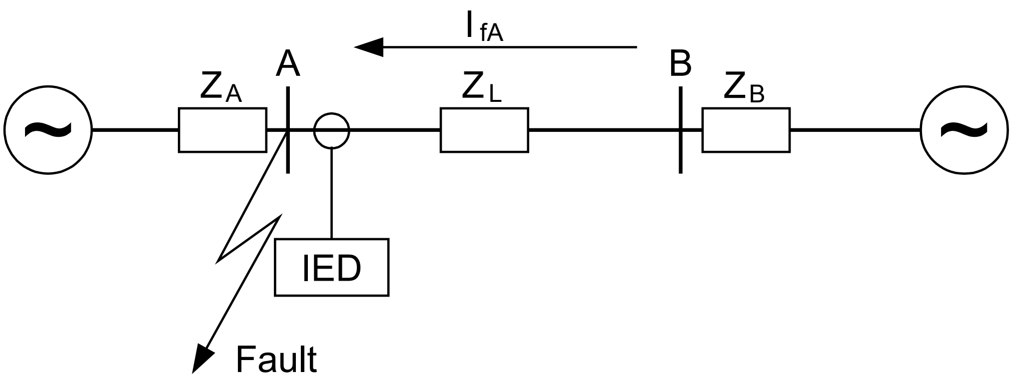

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Figure 23: Through fault current from B to A: I_{fA}

The IED must not trip for any of the two through fault currents. Hence the minimum theoretical current setting (Imin) will be:

$$Imin \geq MAX(I_{fA}, I_{fB})$$

(Equation 21)

A safety margin of 5% for the maximum protection static inaccuracy and a safety margin of 5% for the maximum possible transient overreach have to be introduced. An additional 20% is suggested due to the inaccuracy of the instrument transformers under transient conditions and inaccuracy in the system data.

The minimum primary setting (Is) for the instantaneous phase overcurrent protection is then:

$$Is \geq 1,3 \cdot Imin$$

(Equation 22)

The protection function can be used for the specific application only if this setting value is equal to or less than the maximum fault current that the IED has to clear, I_F in figure 24.

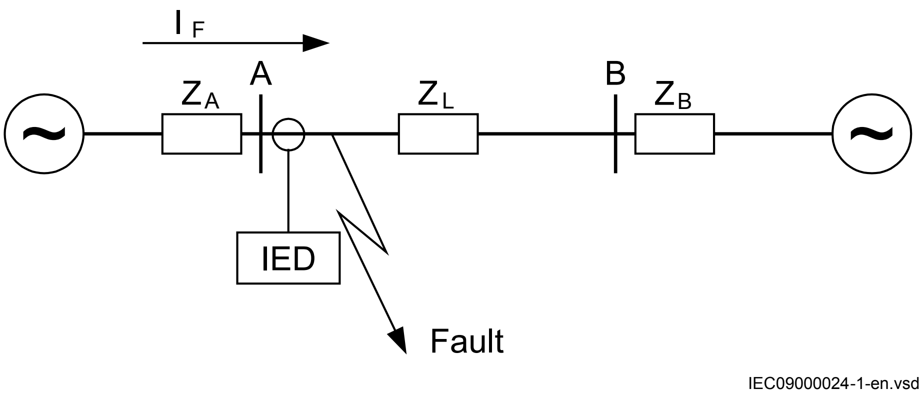

Figure 24: Fault current: I_F

The IED setting value *IP>>* is given in percentage of the primary base current value, *IBase*. The value for *IP>>* is given from this formula:

$$IP >> = \frac{Is}{IBase} \; x100$$

(Equation 23)

5.1.3.2 Meshed network with parallel line

In case of parallel lines, the influence of the induced current from the parallel line to the protected line has to be considered. One example is given in figure 25 where the two lines are connected to the same busbars. In this case the influence of the induced fault current from the faulty line (line 1) to the healthy line (line 2) is considered together with the two through fault currents I_{fA} and I_{fB} mentioned previously. The maximal influence from the parallel line for the IED in figure 25 will be with a fault at the C point with the C breaker open.

A fault in C has to be applied, and then the maximum current seen from the IED (I_M) on the healthy line (this applies for single-phase-to-earth and two-phase-to-earth faults) is calculated.

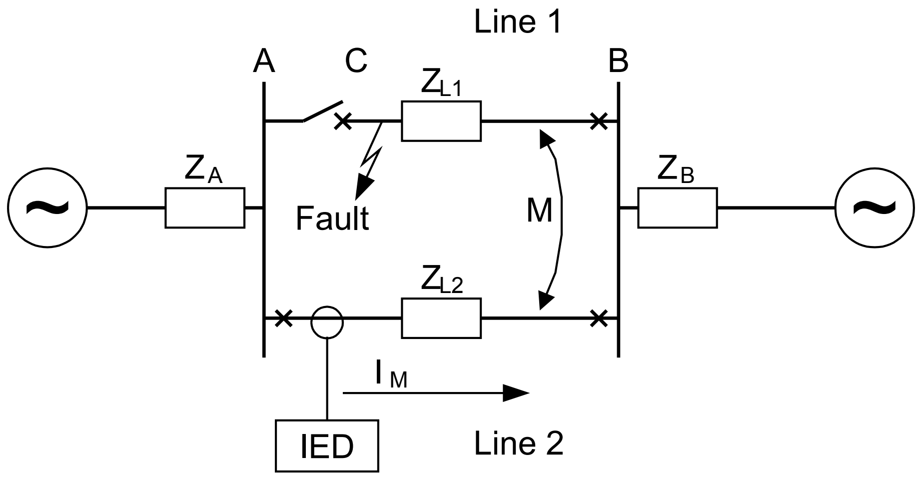

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Figure 25: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting for the overcurrent protection function (Imin) will be:

$$Imin \geq MAX(I_{fA}, I_{fB}, I_M)$$

(Equation 24)

Where I_{fA} and I_{fB} have been described in the previous paragraph. Considering the safety margins mentioned previously, the minimum setting (Is) for the instantaneous phase overcurrent protection is then:

$$Is \geq 1.3 \cdot Imin$$

(Equation 25)

The protection function can be used for the specific application only if this setting value is equal or less than the maximum phase fault current that the IED has to clear.

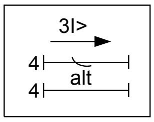
The IED setting value *IP>>* is given in percentage of the primary base current value, *IBase*. The value for *IP>>* is given from this formula:

$$IP >> = \frac{Is}{IBase} \; x100$$

(Equation 26)

5.2 Four step phase overcurrent protection OC4PTOC

5.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step phase overcurrent protection	OC4PTOC		51/67

5.2.2 Application

The four step phase overcurrent protection (OC4PTOC) is used in several applications in the power system. Some applications are:

- Short circuit protection of feeders in distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up short circuit protection of transmission lines.
- Back-up short circuit protection of power transformers.
- Short circuit protection of different kinds of equipment connected to the power system such as; shunt capacitor banks, shunt reactors, motors and others.
- Back-up short circuit protection of power generators.

If VT inputs are not available or not connected, setting parameter *DirModex* (*x*=step 1, 2, 3 or 4) shall be left to default value, *Non-directional*, or set to *Off*.

In many applications several steps with different current pick up levels and time delays are needed. OC4PTOC can have up to four different, individual settable, steps. The flexibility of each step of the OC4PTOC function is great. The following options are possible:

Non-directional / Directional function: In most applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary.

Choice of delay time characteristics: There are several types of delay time characteristics available such as definite time delay and different types of inverse time delay characteristics. The selectivity between different overcurrent functions is normally enabled by co-ordination between the function time delays of the different functions. To enable optimal co-ordination between all overcurrent functions, they should have the same time delay characteristic. Therefore a wide range of standardised inverse time characteristics are available: IEC and ANSI.

The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

5.2.3 Setting guidelines

The parameters for four step phase overcurrent protection (OC4PTOC) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the four step phase overcurrent protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

MeasType: Selection of discrete Fourier filtered (DFT) or true RMS filtered (RMS) signals. RMS is used when the harmonic contents are to be considered, for example in applications with shunt capacitors.

Operation: The protection can be set to *Off* or *On*

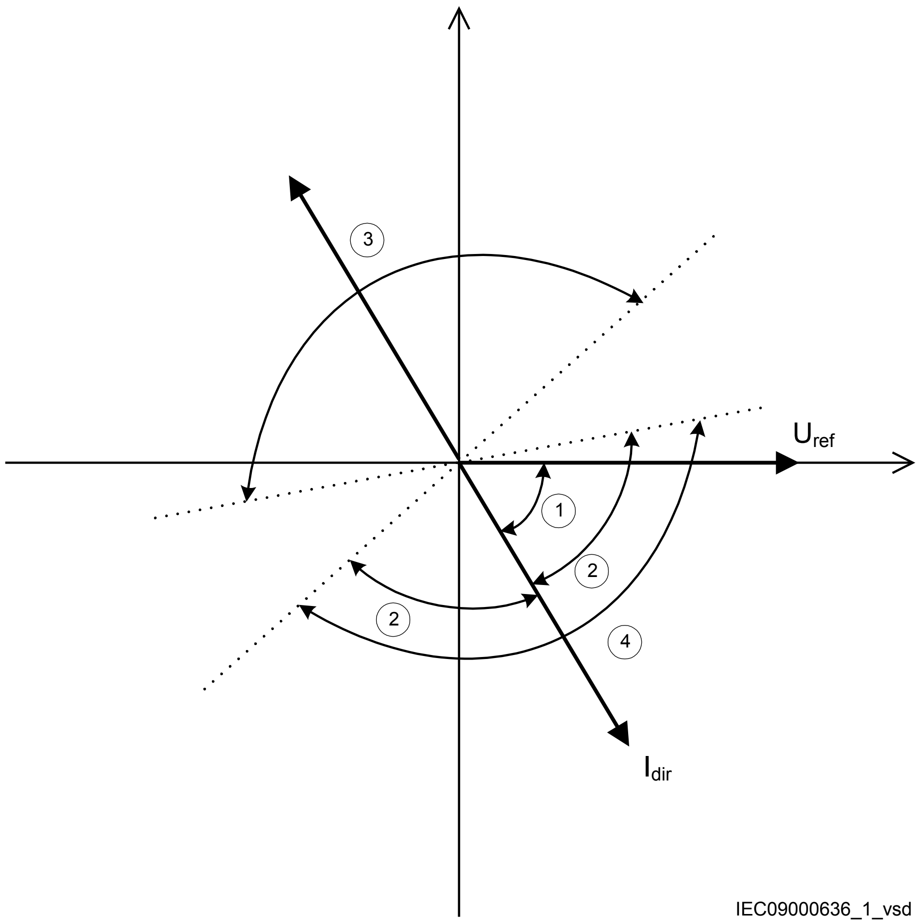


Figure 26: Directional function characteristic

1 RCA = Relay characteristic angle

2 ROA = Relay operating angle

3 Reverse

4 Forward

5.2.3.1 Settings for steps 1 to 4

n means step 1 and 4. *x* means step 1, 2, 3 and 4.

DirModex: The directional mode of step *x*. Possible settings are *Off/Non-directional/Forward/Reverse*.

Characteristn: Selection of time characteristic for step *n*. Definite time delay and different types of inverse time characteristics are available according to table 8. Step 2 and 3 are always definite time delayed.

Table 8: Inverse time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical manual.

Ix>: Operation phase current level for step *x* given in % of *IBase*.

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

kn: Time multiplier for inverse time delay for step *n*.

IMinn: Minimum operate current for step *n* in % of *IBase*.

tnMin: Minimum operation time for all inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step can never be shorter than the setting.

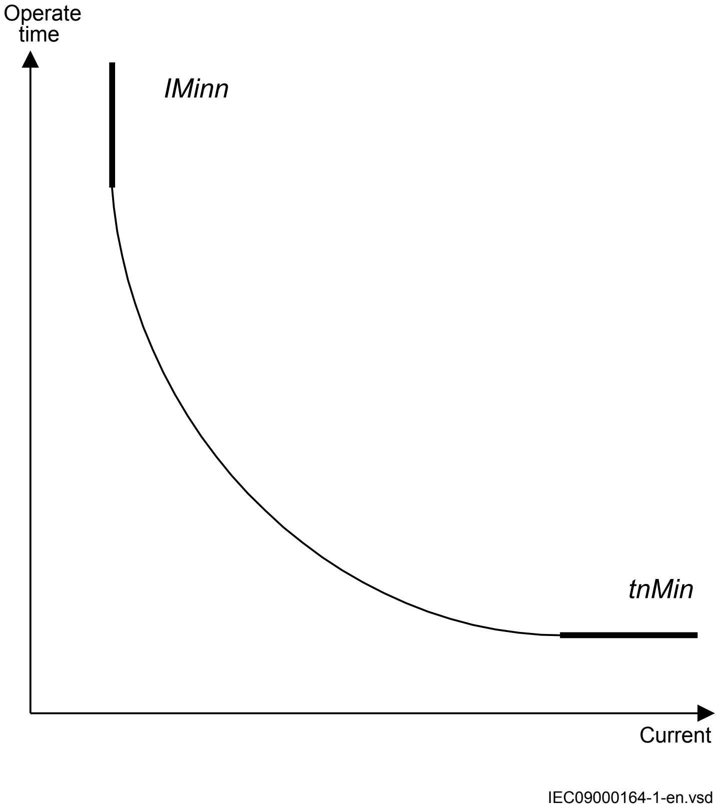


Figure 27: Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter *tnMin* shall be set to the value which is equal to the operating time of the selected inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *kn*.

5.2.3.2 Current applications

The four step phase overcurrent protection can be used in different ways, depending on the application where the protection is used. A general description is given below.

The **operating current** setting inverse time protection or the lowest current step constant inverse time protection must be given a current setting so that the highest possible load current does not cause protection operation. Here consideration also has to be taken to the protection reset current, so that a short peak of overcurrent does not cause operation of the protection even when the overcurrent has ceased. This phenomenon is described in figure 28.

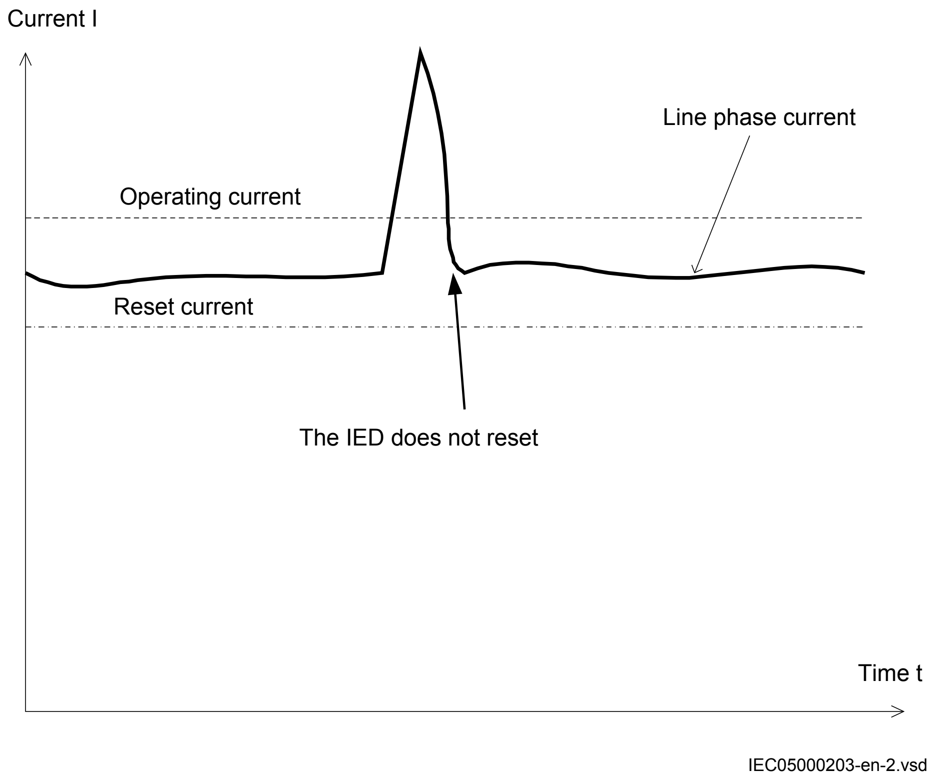


Figure 28: Operating and reset current for an overcurrent protection

The lowest setting value can be written according to equation 27.

$$Ipu \geq 1.2 \cdot \frac{Imax}{k}$$

(Equation 27)

where:

1.2	is a safety factor,
k	is the resetting ratio of the protection, and
Imax	is the maximum load current.

The maximum load current on the line has to be estimated. There is also a demand that all faults, within the zone that the protection shall cover, must be detected by the phase overcurrent protection. The minimum fault current Iscmin, to be detected by the protection, must be calculated. Taking this value as a base, the highest pick up current setting can be written according to equation 28.

$$Ipu \leq 0.7 \cdot Isc\min$$

(Equation 28)

where:

0.7 is a safety factor and

Iscmin is the smallest fault current to be detected by the overcurrent protection.

As a summary the operating current shall be chosen within the interval stated in equation 29.

$$1.2 \cdot \frac{Im\,ax}{k} \leq Ipu \leq 0.7 \cdot Isc\min$$

(Equation 29)

The **high current function** of the overcurrent protection, which only has a short delay of the operation, must be given a current setting so that the protection is selective to other protection in the power system. It is desirable to have a rapid tripping of faults within as large portion as possible of the part of the power system to be protected by the protection (primary protected zone). A fault current calculation gives the largest current of faults, Iscmax, at the most remote part of the primary protected zone. Considerations have to be made to the risk of transient overreach, due to a possible DC component of the short circuit current. The lowest current setting of the most rapid stage, of the phase overcurrent protection, can be written according to

$$I_{high} \geq 1.2 \cdot k_t \cdot I_{sc\max}$$

(Equation 30)

where:

1.2 is a safety factor,

k_t is a factor that takes care of the transient overreach due to the DC component of the fault current and can be considered to be less than 1.1

Iscmax is the largest fault current at a fault at the most remote point of the primary protection zone.

The operate times of the phase overcurrent protection has to be chosen so that the fault time is so short that protected equipment will not be destroyed due to thermal overload, at the same time as selectivity is assured. For overcurrent protection, in a radial fed network, the time setting can be chosen in a graphical way. This is mostly used in the case of inverse time overcurrent protection. Figure 29 shows how the time-versus-current curves are plotted in a diagram. The time setting is chosen to get the shortest fault time with maintained selectivity. Selectivity is assured if the time difference between the curves is larger than a critical time difference.

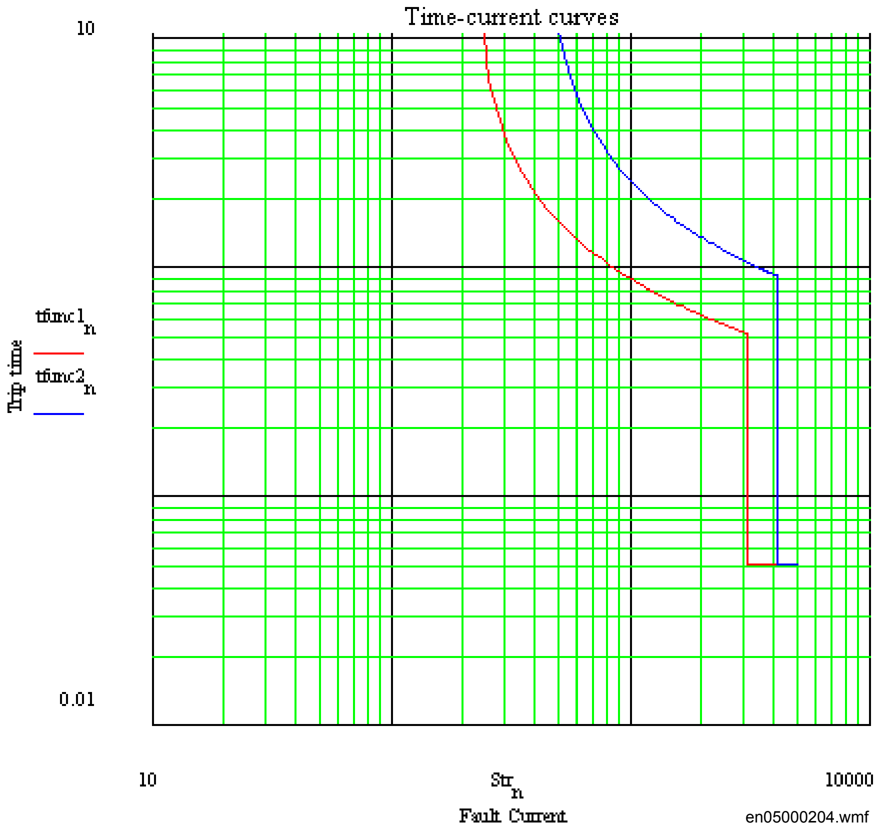


Figure 29: Fault time with maintained selectivity

To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

Example

Assume two substations A and B directly connected to each other via one line, as shown in the figure 30. Consider a fault located at another line from the station B. The fault current to the overcurrent protection of IED B1 has a magnitude so that the protection will have instantaneous function. The overcurrent protection of IED A1 must have a delayed function. The sequence of events during the fault can be described using a time axis, see figure 30.

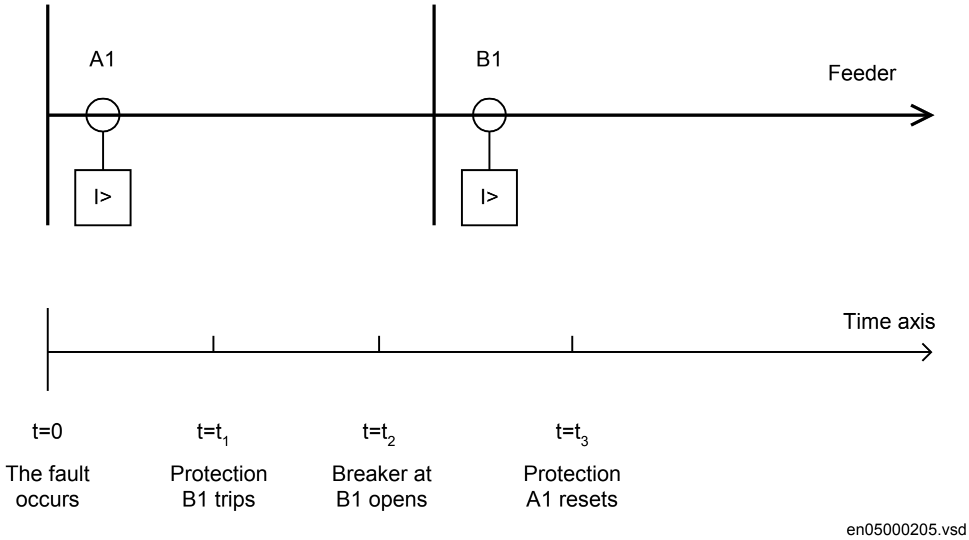


Figure 30: Sequence of events during fault

where:

t=0	is when the fault occurs,
$t=t_1$	is when the trip signal from the overcurrent protection at IED B1 is sent to the circuit breaker. The operation time of this protection is t_1,
$t=t_2$	is when the circuit breaker at IED B1 opens. The circuit breaker opening time is $t_2 - t_1$ and
$t=t_3$	is when the overcurrent protection at IED A1 resets. The protection resetting time is $t_3 - t_2$.

To ensure that the overcurrent protection at IED A1, is selective to the overcurrent protection at IED B1, the minimum time difference must be larger than the time t_3. There are uncertainties in the values of protection operation time, breaker opening time and protection resetting time. Therefore a safety margin has to be included. With normal values the needed time difference can be calculated according to equation 31.

$$\Delta t \geq 40\,ms + 100\,ms + 40\,ms + 40\,ms = 220\,ms$$

(Equation 31)

where it is considered that:

the operation time of overcurrent protection B1	is 40 ms
the breaker open time	is 100 ms
the resetting time of protection A1	is 40 ms and
the additional margin	is 40 ms

5.3 Instantaneous residual overcurrent protection EFPIOC

5.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Instantaneous residual overcurrent protection	EFPIOC	*IN*>>	50N

5.3.2 Application

In many applications, when fault current is limited to a defined value by the object impedance, an instantaneous earth fault protection can provide fast and selective tripping.

The instantaneous residual overcurrent (EFPIOC), which can operate in 15 ms (50 Hz nominal system frequency) for faults characterized by very high currents, is included in the IED.

5.3.3 Setting guidelines

The parameters for the instantaneous residual overcurrent protection function (EFPIOC) are set via the local HMI or Protection and Control Manager (PCM600).

Some guidelines for the choice of setting parameter for the instantaneous residual overcurrent protection (EFPIOC) function is given.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

The setting of the function is limited to the operation residual current to the protection (*IN*>>).

The basic requirement is to assure selectivity, that is the EFPIOC function shall not be allowed to operate for faults at other objects than the protected object (line).

For a normal line in a meshed system single-phase-to-earth faults and phase-to-phase-to-earth faults shall be calculated as shown in figure 31 and figure 32. The residual currents ($3I_0$) to the protection are calculated. For a fault at the remote line end this fault current is I_{fB}. In this calculation the operational state with high source impedance Z_A and low source impedance Z_B should be used. For the fault at the home busbar this fault current is I_{fA}. In this calculation the operational state with low source impedance Z_A and high source impedance Z_B should be used.

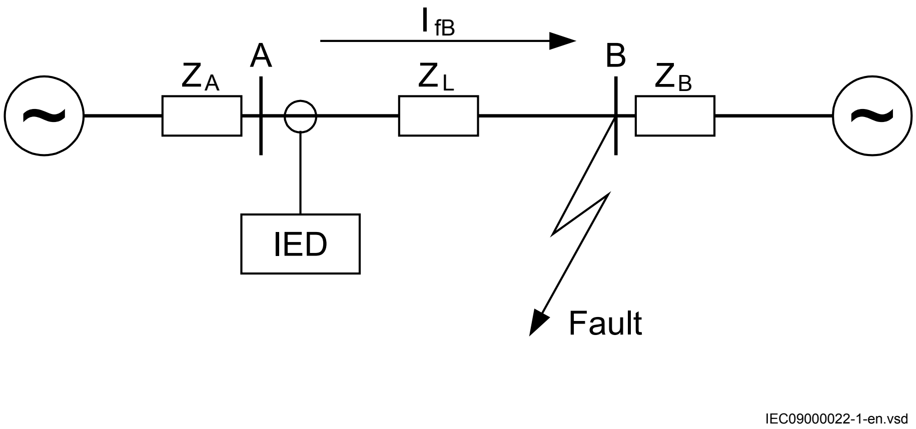


Figure 31: Through fault current from A to B: I_{fB}

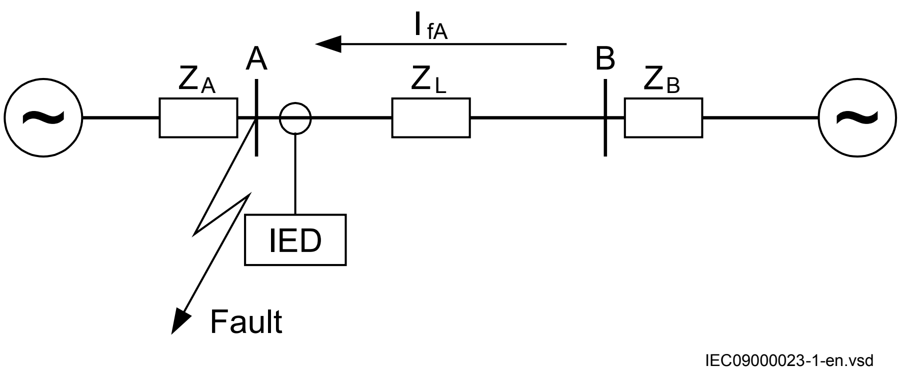


Figure 32: Through fault current from B to A: I_{fA}

The function shall not operate for any of the calculated currents to the protection. The minimum theoretical current setting (Imin) will be:

$$Imin \geq MAX(I_{fA}, I_{fA})$$

(Equation 32)

A safety margin of 5% for the maximum static inaccuracy and a safety margin of 5% for maximum possible transient overreach have to be introduced. An additional 20% is suggested due to inaccuracy of instrument transformers under transient conditions and inaccuracy in the system data.

The minimum primary current setting (Is) is:

$$Is \geq 1,3 \cdot Imin$$

(Equation 33)

In case of parallel lines with zero sequence mutual coupling a fault on the parallel line, as shown in figure 33, should be calculated.

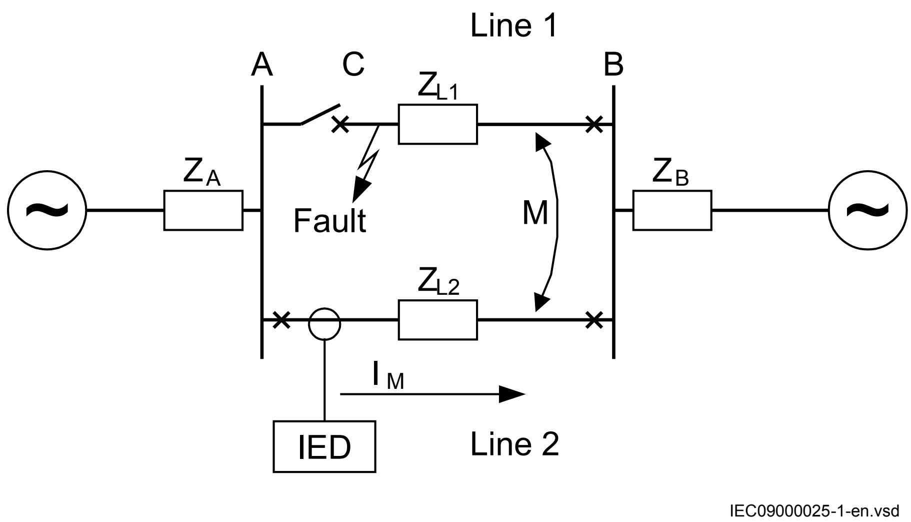


Figure 33: Two parallel lines. Influence from parallel line to the through fault current: I_M

The minimum theoretical current setting (Imin) will in this case be:

$$Imin \geq MAX(I_{fA}, I_{fB}, I_M)$$

(Equation 34)

Where:

I_{fA} and I_{fB} have been described for the single line case.

Considering the safety margins mentioned previously, the minimum setting (Is) is:

$$Is \geq 1,3 \cdot Imin$$

(Equation 35)

Transformer inrush current shall be considered.

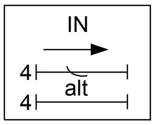
The setting of the protection is set as a percentage of the base current (*IBase*).

On/*Off*: set the protection to *On* or *Off*.

IN>>: Set operate current in % of *IBase*. *IBase* is a global parameter valid for all functions in the IED.

5.4 Four step residual overcurrent protection EF4PTOC

5.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Four step residual overcurrent protection	EF4PTOC		51N/67N

5.4.2 Application

The Four step residual overcurrent protection (EF4PTOC) is used in several applications in the power system. Some applications are:

- Earth-fault protection of feeders in effectively earthed distribution and subtransmission systems. Normally these feeders have radial structure.
- Back-up earth-fault protection of transmission lines.
- Sensitive earth-fault protection of transmission lines. EF4PTOC can have better sensitivity to detect resistive phase-to-earth-faults compared to distance protection.
- Back-up earth-fault protection of power transformers.
- Earth-fault protection of different kinds of equipment connected to the power system such as shunt capacitor banks, shunt reactors and others.

In many applications several steps with different current operating levels and time delays are needed. EF4PTOC can have up to four, individual settable steps. The flexibility of each step of EF4PTOC function is great. The following options are possible:

Non-directional/Directional function: In some applications the non-directional functionality is used. This is mostly the case when no fault current can be fed from the protected object itself. In order to achieve both selectivity and fast fault clearance, the directional function can be necessary. This can be the case for earth-fault protection in meshed and effectively earthed transmission systems. The directional residual overcurrent protection is also well suited to operate in teleprotection communication schemes, which enables fast clearance of earth-faults on transmission lines. The directional function uses the polarizing quantity as decided by setting. Voltage polarizing ($-3U_0$) is most commonly used but alternatively current polarizing where currents in transformer neutrals providing the neutral (zero sequence) source (ZN) is used to polarize (IN*ZN) the function. Dual polarizing where the sum of both voltage and current components is allowed to polarize can also be selected.

Choice of time characteristics: There are several types of time characteristics available such as definite time delay and different types of inverse time characteristics. The selectivity between different overcurrent protections is normally enabled by co-ordination between the operating time of the different protections. To enable optimal co-ordination all overcurrent relays, to be co-ordinated against each other, should have the same time characteristic. Therefore a wide range of standardized inverse time characteristics are available: IEC and ANSI. The time characteristic for step 1 and 4 can be chosen as definite time delay or inverse time characteristic. Step 2 and 3 are always definite time delayed and are used in system where IDMT is not needed.

Table 9: Inverse time characteristics

Curve name
ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite Time
ASEA RI
RXIDG (logarithmic)

Power transformers can have a large inrush current, when being energized. This inrush current can have residual current components. The phenomenon is due to saturation of the transformer magnetic core during parts of the cycle. There is a risk that inrush current will give a residual current that reaches level above the operating current of the residual overcurrent protection. The inrush current has a large second harmonic content. This can be used to avoid unwanted operation of the protection. Therefore, EF4PTOC function has a possibility of second harmonic restrain *2ndHarmStab* if the level of this harmonic current reaches a value above a set percentage of the fundamental current.

5.4.3 Setting guidelines

The parameters for the four step residual overcurrent protection (EF4PTOC) are set via the local HMI or Protection and Control Manager (PCM600).

The following settings can be done for the four step residual overcurrent protection:

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Sets the protection to *On* or *Off*.

5.4.3.1 Settings for steps 1 and 4

n means step 1 and 4.

Characteristn: Selection of time characteristic for step *n*. Definite time delay and different types of inverse time characteristics are available.

Inverse time characteristic enables fast fault clearance of high current faults at the same time as selectivity to other inverse time phase overcurrent protections can be assured. This is mainly used in radial fed networks but can also be used in meshed networks. In meshed networks the settings must be based on network fault calculations.

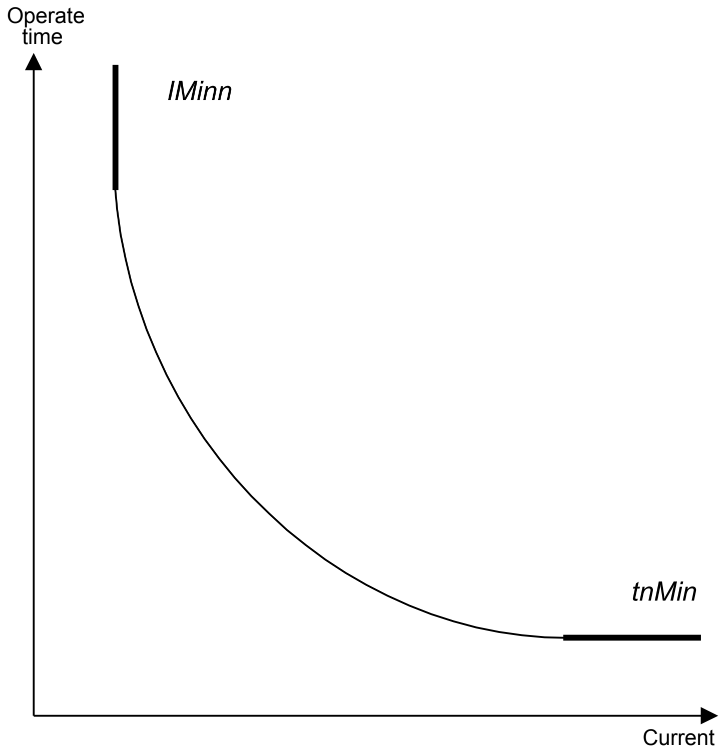
To assure selectivity between different protections, in the radial network, there have to be a minimum time difference Δt between the time delays of two protections. The minimum time difference can be determined for different cases. To determine the shortest possible time difference, the operation time of protections, breaker opening time and protection resetting time must be known. These time delays can vary significantly between different protective equipment. The following time delays can be estimated:

Protection operation time:	15-60 ms
Protection resetting time:	15-60 ms
Breaker opening time:	20-120 ms

The different characteristics are described in the Technical Manual (TM).

kn: Time multiplier for the dependent (inverse) characteristic for step *n*.

tnMin: Minimum operation time for inverse time characteristics. At high currents the inverse time characteristic might give a very short operation time. By setting this parameter the operation time of the step *n* can never be shorter than the setting.



IEC09000164-1-en.vsd

Figure 34: Minimum operate current and operation time for inverse time characteristics

In order to fully comply with curves definition setting parameter *tnMin* shall be set to the value which is equal to the operating time of the selected IEC inverse curve for measured current of twenty times the set current pickup value. Note that the operating time value is dependent on the selected setting value for time multiplier *kn*.

5.4.3.2 Common settings for all steps

x means step 1, 2, 3 and 4.

DirModex: The directional mode of step *x*. Possible settings are *Off*/*Non-directional*/*Forward*/*Reverse*.

INx>: Operation residual current level for step *x* given in % of *IBase*.

tx: Definite time delay for step *x*. Used if definite time characteristic is chosen.

IMinx: Minimum operate current for step *x* in % of *IBase*.

HarmRestrainx: Enable block of step *x* from the harmonic restrain function *2ndHarmStabx*. This function should be used when there is a risk of unwanted trip caused by power transformer inrush currents. *2ndHarmStabx* can be set *Off* or *On*.

AngleRCA: Relay characteristic angle given in degree. This angle is defined as shown in figure 35. The angle is defined positive when the residual current lags the reference voltage (Upol = -3U_0)

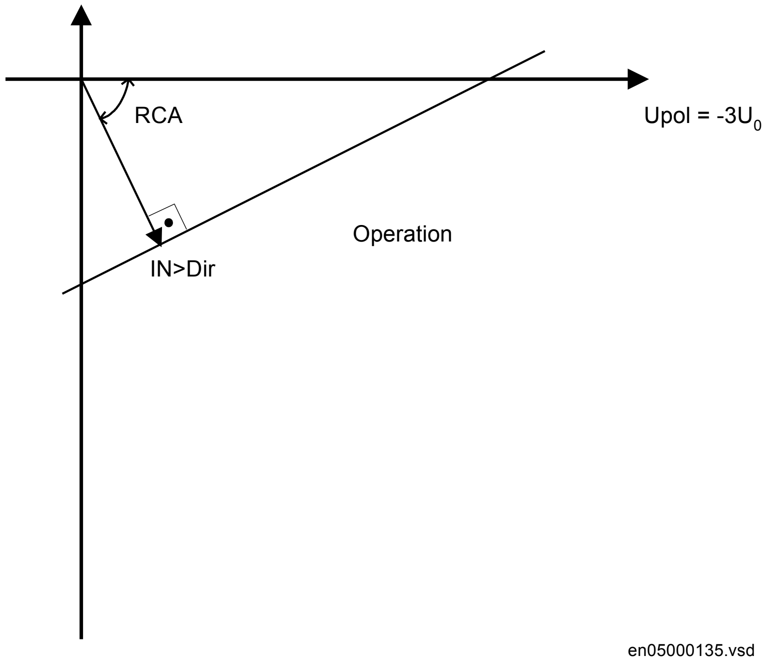


Figure 35: Relay characteristic angle given in degree

In a normal transmission network a normal value of RCA is about 65°. The setting range is -180° to +180°.

polMethod: Defines if the directional polarization is from voltage (-3U_0), current (3I_0xZNpol where ZNpol is RNpol+jXNpol) or both currents and voltage (dual polarizing, -3U0+3I_0xZNpol). Normally voltage polarizing from the residual sum or an external open delta is used. Current polarizing is useful when the local source is strong and a high sensitivity is required. In such cases the polarizing voltage (-3U_0) can be below 1% and it is then necessary to use current polarizing or dual polarizing. Multiply the required set current (primary) with the minimum impedance (ZNpol) and check that the percentage of the phase-to-earth voltage is definitely higher than 1% (minimum 3U_0>*UpolMin* setting) as a verification.

RNPol, XNPol: The zero sequence source is set in primary ohms as base for the current polarizing. The polarizing voltage is then achieved as 3I_0xZNpol. The ZNpol can be defined as (ZS_1-ZS_0)/3, that is the earth return impedance of the source behind the protection. The maximum earth-fault current at the local source can be used to calculate the value of ZN as $U/(\sqrt{3}*3I_0)$ Typically, the minimum ZNPol (3xzero sequence source) is set. Setting is in primary ohms.

When the dual polarizing method is used it is important that the setting *INx>* or the product $3I_0$xZNpol is not greater than $3U_0$. If so, there is a risk for incorrect operation for faults in the reverse direction.

IPolMin: is the minimum earth-fault current accepted for directional evaluation. For smaller currents than this value the operation will be blocked. Typical setting is 5-10% of *IBase*.

UPolMin: Minimum polarization (reference) residual voltage for the directional function, given in % of *UBase*.

IN>Dir: Operating residual current release level in % of *IBase* for directional comparison scheme. The setting is given in % of *IBase*. The output signals, STFW and STRV can be used in a teleprotection scheme. The appropriate signal should be configured to the communication scheme block.

5.4.3.3 Second harmonic restrain

If a power transformer is energized there is a risk that the current transformer core will saturate during part of the period, resulting in an inrush transformer current. This will give a declining residual current in the network, as the inrush current is deviating between the phases. There is a risk that the residual overcurrent function will give an unwanted trip. The inrush current has a relatively large ratio of 2^{nd} harmonic component. This component can be used to create a restrain signal to prevent this unwanted function.

At current transformer saturation a false residual current can be measured by the protection. Also here the 2^{nd} harmonic restrain can prevent unwanted operation.

2ndHarmStab: The rate of second harmonic current content for activation of the 2^{nd} harmonic restrain signal. The setting is given in % of the fundamental frequency residual current.

5.4.3.4 Line application example

The four step residual overcurrent protection can be used in different ways. Below is described one application possibility to be used in meshed effectively earthed systems.

The protection measures the residual current out on the protected line. The protection function has a directional function where the residual voltage (zero sequence voltage) is the polarizing quantity.

The residual voltage can be internally generated when a three-phase set of voltage transformers are used.

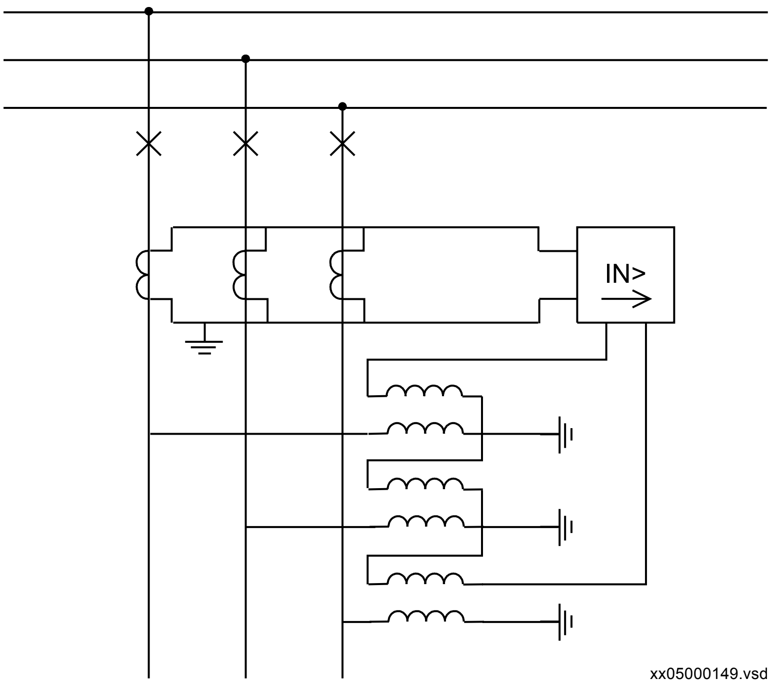


Figure 36: Connection of polarizing voltage from an open delta

The different steps can be described as follows.

Step 1

This step has directional instantaneous function. The requirement is that overreaching of the protected line is not allowed.

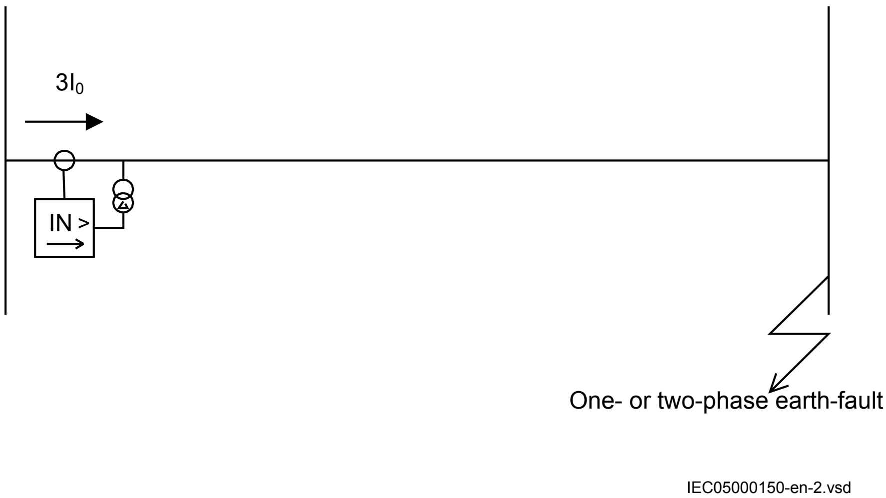


Figure 37: Step 1, first calculation

The residual current out on the line is calculated at a fault on the remote busbar (one- or two- phase-to-earth-fault). To assure selectivity it is required that step 1 shall not give a trip at this fault. The requirement can be formulated according to equation 36.

$$I_{step1} \geq 1.2 * 3I_0 \text{ (remote busbar)}$$

(Equation 36)

As a consequence of the distribution of zero sequence current in the power system, the current to the protection might be larger if one line out from the remote busbar is taken out of service, see figure 38.

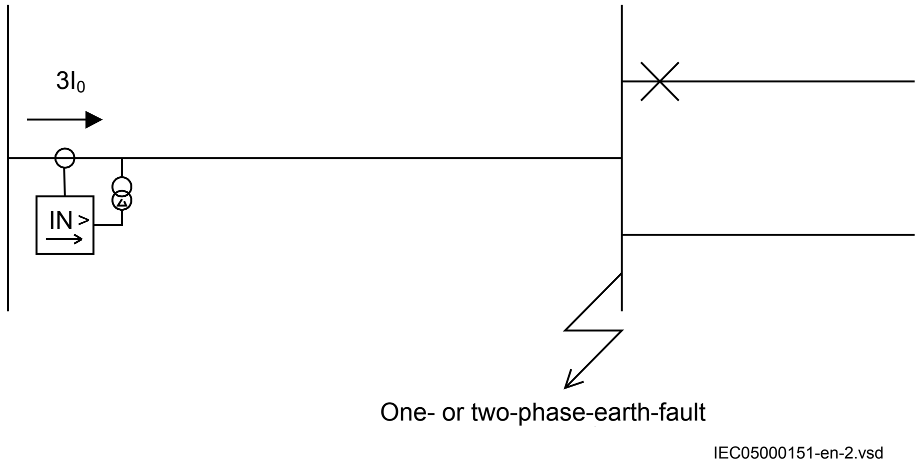


Figure 38: Step 1, second calculation. Remote busbar with, one line taken out of service

The requirement is now according to equation 37.

$$I_{step1} \geq 1.2 * 3I_0 \text{ (remote busbar with, one line out)}$$

(Equation 37)

A higher value of step1 might occur if a big power transformer (Y0/D) at remote bus bar is disconnected.

A special case occurs at double circuit lines, with mutual zero sequence impedance between the parallel lines, see figure 39.

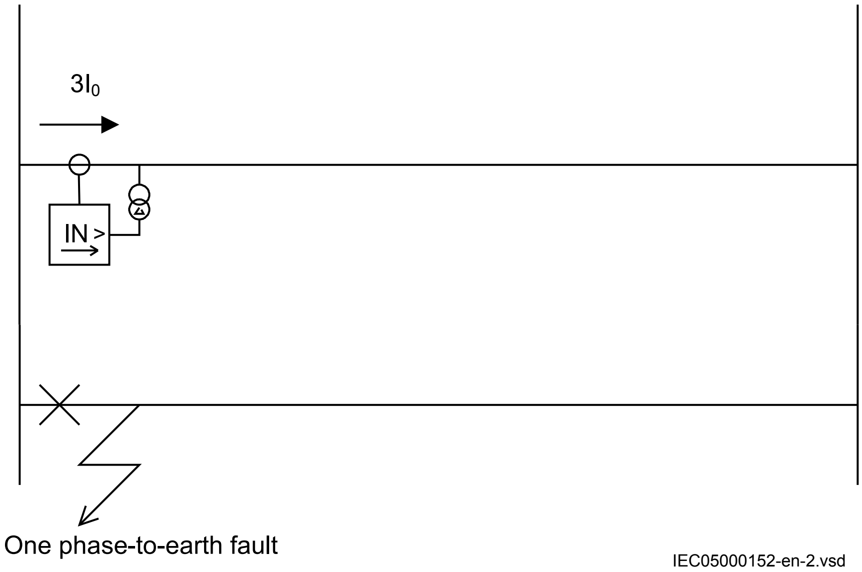


Figure 39: Step 1, third calculation

In this case the residual current out on the line can be larger than in the case of earth-fault on the remote busbar.

$$I_{step1} \geq 1.2 * 3I_0$$

(Equation 38)

The current setting for step 1 is chosen as the largest of the above calculated residual currents, measured by the protection.

Step 2

This step has directional function and a short time delay, often about 0.4 s. Step 2 shall securely detect all earth-faults on the line, not detected by step 1.

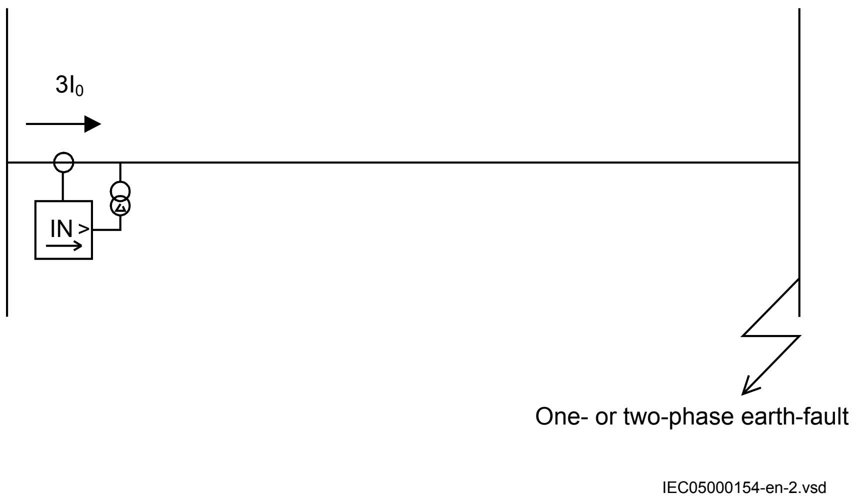


Figure 40: Step 2, check of reach calculation

The residual current, out on the line, is calculated at an operational case with minimal earth-fault current. The requirement that the whole line shall be covered by step 2 can be formulated according to equation 39.

$$I_{step1} \geq 0.7 * 3I_0 \text{ (at remote busbar)}$$

(Equation 39)

To assure selectivity the current setting must be chosen so that step 2 does not operate at step 2 for faults on the next line from the remote substation. Consider a fault as shown in figure 41.

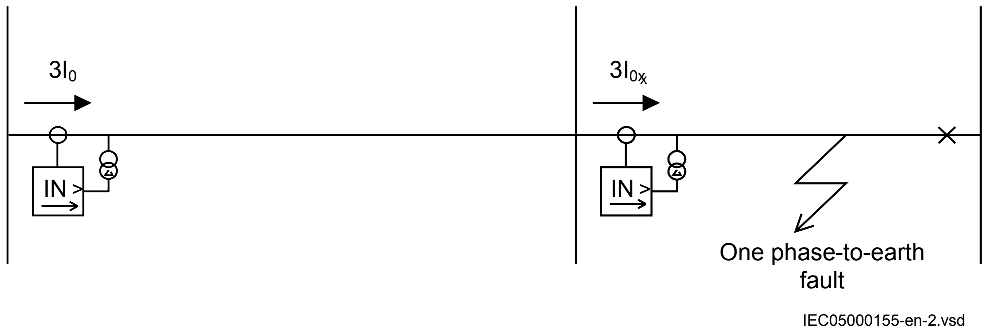


Figure 41: Step 2, selectivity calculation

A second criterion for step 2 is according to equation 40.

$$Istep2 \geq 1.2 * \frac{3I_0}{3I_{0x}} * Istep1x$$

(Equation 40)

where:

Istep1x is the current setting for step 1 on the faulted line.

Step 3

This step has directional function and a time delay slightly larger than step 2, often 0.8 s. Step 3 shall enable selective trip of earth-faults having some fault resistance to earth, so that step 2 is not activated. The requirement on step 3 is selectivity to other earth-fault protections in the network. One criterion for setting is shown in figure 42.

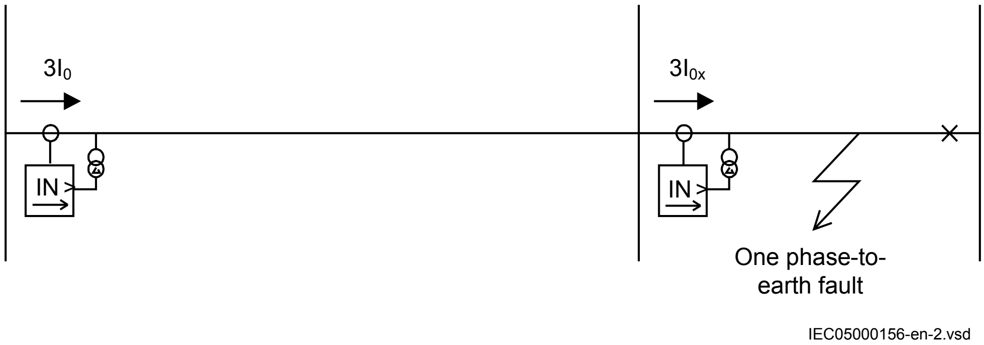


Figure 42: Step 3, Selectivity calculation

$$Istep3 \geq 1.2 * \frac{3I_0}{3I_{0x}} * Istep2x$$

(Equation 41)

where:

Istep2x is the chosen current setting for step 2 on the faulted line.

Step 4

This step normally has non-directional function and a relatively long time delay. The task for step 4 is to detect and initiate trip for earth-faults with large fault resistance, for example tree faults. Step 4 shall also detect series faults where one or two poles, of a breaker or other switching device, are open while the other poles are closed.

Both high resistance earth-faults and series faults give zero sequence current flow in the network. Such currents give disturbances on telecommunication systems and current to earth. It is important to clear such faults both concerning personal security as well as risk of fire.

The current setting for step 4 is often set down to about 100 A (primary $3I_0$). In many applications definite time delay in the range 1.2 - 2.0 s is used. In other applications a current dependent inverse time characteristic is used. This enables a higher degree of selectivity also for sensitive earth-fault current protection.

5.5 Sensitive directional residual overcurrent and power protection SDEPSDE

5.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Sensitive directional residual over current and power protection	SDEPSDE	-	67N

5.5.2 Application

In networks with high impedance earthing, the phase-to-earth fault current is significantly smaller than the short circuit currents. Another difficulty for earth-fault protection is that the magnitude of the phase-to-earth fault current is almost independent of the fault location in the network.

Directional residual current can be used to detect and give selective trip of phase-to-earth faults in high impedance earthed networks. The protection uses the residual current component $3I_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the residual voltage (-3U0), compensated with a characteristic angle. Alternatively, the function can be set to strict $3I_0$ level with an check of angle $3I_0$ and cos φ.

Directional residual power can also be used to detect and give selective trip of phase-to-earth faults in high impedance earthed networks. The protection uses the residual power component $3I_0 \cdot 3U_0 \cdot \cos \varphi$, where φ is the angle between the residual current and the reference residual voltage, compensated with a characteristic angle.

A normal non-directional residual current function can also be used with definite or inverse time delay.

A back-up neutral point voltage function is also available for non-directional sensitive back-up protection.

In an isolated network, that is, the network is only coupled to earth via the capacitances between the phase conductors and earth, the residual current always has -90º phase shift compared to the reference residual voltage. The characteristic angle is chosen to -90º in such a network.

In resistance earthed networks or in Petersen coil earthed, with a parallel resistor, the active residual current component (in phase with the residual voltage) should be used for the earth fault detection. In such networks the characteristic angle is chosen to 0º.

As the amplitude of the residual current is independent of the fault location the selectivity of the earth-fault protection is achieved by time selectivity.

When should the sensitive directional residual overcurrent protection be used and when should the sensitive directional residual power protection be used? Consider the following facts:

- Sensitive directional residual overcurrent protection gives possibility for better sensitivity
- Sensitive directional residual power protection gives possibility to use inverse time characteristics. This is applicable in large high impedance earthed networks, with large capacitive earth fault current
- In some power systems a medium size neutral point resistor is used, for example, in low impedance earthed system. Such a resistor will give a resistive earth-fault current component of about 200 - 400 A at a zero resistive phase-to-earth fault. In such a system the directional residual power protection gives better possibilities for selectivity enabled by inverse time power characteristics.

5.5.3 Setting guidelines

The sensitive earth-fault protection is intended to be used in high impedance earthed systems, or in systems with resistive earthing where the neutral point resistor gives an earth-fault current larger than what normal high impedance gives but smaller than the phase-to-phase short circuit current.

In a high impedance system the fault current is assumed to be limited by the system zero sequence shunt impedance to earth and the fault resistance only. All the series impedances in the system are assumed to be zero.

In the setting of earth-fault protection, in a high impedance earthed system, the neutral point voltage (zero sequence voltage) and the earth-fault current will be calculated at the desired sensitivity (fault resistance). The complex neutral point voltage (zero sequence) can be calculated as:

$$U_0 = \frac{U_{phase}}{1 + \frac{3 \cdot R_f}{Z_0}}$$

(Equation 42)

Where

U_{phase} is the phase voltage in the fault point before the fault,

R_f is the resistance to earth in the fault point and

Z_0 is the system zero sequence impedance to earth

The fault current, in the fault point, can be calculated as:

$$I_j = 3I_0 = \frac{3 \cdot U_{phase}}{Z_0 + 3 \cdot R_f}$$

(Equation 43)

The impedance Z_0 is dependent on the system earthing. In an isolated system (without neutral point apparatus) the impedance is equal to the capacitive coupling between the phase conductors and earth:

$$Z_0 = -jX_c = -j\frac{3 \cdot U_{phase}}{I_j}$$

(Equation 44)

Where

I_j	is the capacitive earth-fault current at a non-resistive phase to earth-fault
X_c	is the capacitive reactance to earth

In a system with a neutral point resistor (resistance earthed system) the impedance Z_0 can be calculated as:

$$Z_0 = \frac{-jX_c \cdot 3R_n}{-jX_c + 3R_n}$$

(Equation 45)

Where

R_n	is the resistance of the neutral point resistor

In many systems there is also a neutral point reactor (Petersen coil) connected to one or more transformer neutral points. In such a system the impedance Z_0 can be calculated as:

$$Z_0 = -jX_c // 3R_n // j3X_n = \frac{9R_n X_n X_c}{3X_n X_c + j3R_n \cdot \left(3X_n - X_c\right)}$$

(Equation 46)

Where

X_n	is the reactance of the Petersen coil. If the Petersen coil is well tuned we have $3X_n = X_c$ In this case the impedance Z_0 will be: $Z_0 = 3R_n$

Now consider a system with an earthing via a resistor giving higher earth-fault current than the high impedance earthing. The series impedances in the system can no longer be neglected. The system with a single phase to earth-fault can be described as in figure 43.

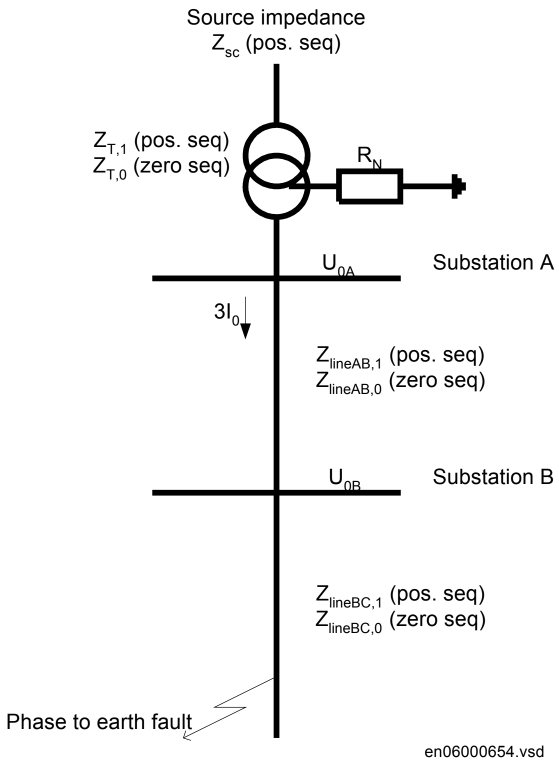


Figure 43: Equivalent of power system for calculation of setting

The residual fault current can be written:

$$3I_0 = \frac{3U_{phase}}{2 \cdot Z_1 + Z_0 + 3 \cdot R_f}$$

(Equation 47)

Where

U_{phase}	is the phase voltage in the fault point before the fault
Z_1	is the total positive sequence impedance to the fault point. $Z_1 = Z_{sc}+Z_{T,1}+Z_{lineAB,1}+Z_{lineBC,1}$
Z_0	is the total zero sequence impedance to the fault point. $Z_0 = Z_{T,0}+3R_N+Z_{lineAB,0}+Z_{lineBC,0}$
R_f	is the fault resistance.

The residual voltages in stations A and B can be written:

$$U_{0A} = 3I_0 \cdot \left(Z_{T,0} + 3R_N\right)$$

(Equation 48)

$$U_{OB} = 3I_0 \cdot (Z_{T,0} + 3R_N + Z_{lineAB,0})$$

(Equation 49)

The residual power, measured by the sensitive earth-fault protections in A and B will be:

$$S_{0A} = 3U_{0A} \cdot 3I_0$$

(Equation 50)

$$S_{0B} = 3U_{0B} \cdot 3I_0$$

(Equation 51)

The residual power is a complex quantity. The protection will have a maximum sensitivity in the characteristic angle RCA. The apparent residual power component in the characteristic angle, measured by the protection, can be written:

$$S_{0A,prot} = 3U_{0A} \cdot 3I_0 \cdot \cos \varphi_A$$

(Equation 52)

$$S_{0B,prot} = 3U_{0B} \cdot 3I_0 \cdot \cos \varphi_B$$

(Equation 53)

The angles φ_A and φ_B are the phase angles between the residual current and the residual voltage in the station compensated with the characteristic angle RCA.

The protection will use the power components in the characteristic angle direction for measurement, and as base for the inverse time delay.

The inverse time delay is defined as:

$$t_{inv} = \frac{kSN \cdot (3I_0 \cdot 3U_0 \cdot \cos\varphi(\text{reference}))}{3I_0 \cdot 3U_0 \cdot \cos\varphi(\text{measured})}$$

(Equation 54)

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

The function can be set *On/Off* with the setting of *Operation*.

With the setting *OpMode* the principle of directional function is chosen.

With *OpMode* set to *3I0cosfi* the current component in the direction equal to the characteristic angle *RCADir* is measured. The characteristic for *RCADir* is equal to 0° is shown in figure 44.

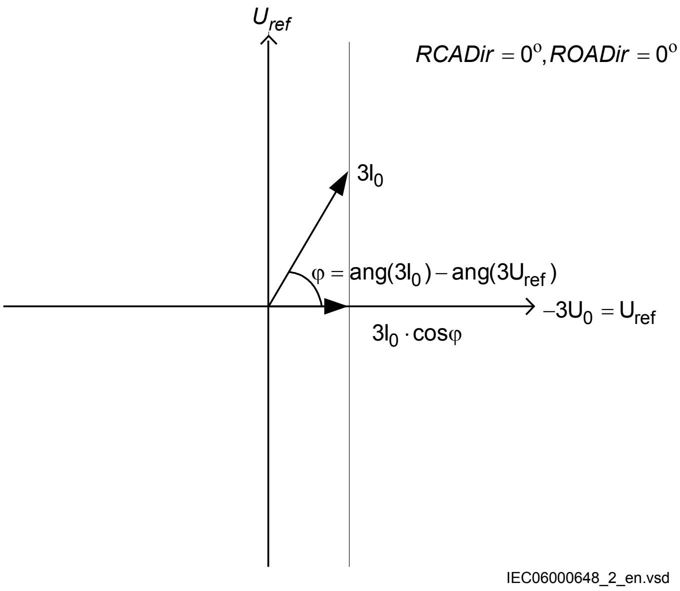


Figure 44: Characteristic for RCADir equal to 0°

The characteristic is for *RCADir* equal to -90° is shown in figure 45.

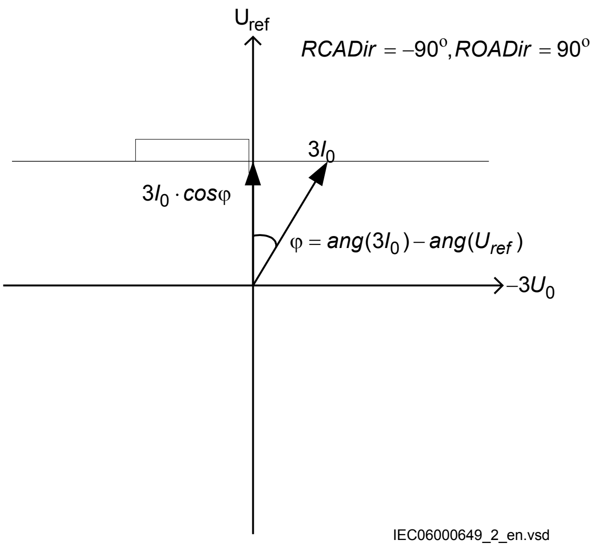


Figure 45: Characteristic for RCADir equal to -90°

When *OpMode* is set to *3U03I0cosfi*the apparent residual power component in the direction is measured.

When *OpMode* is set to *3I0 and fi* the function will operate if the residual current is larger than the setting *INDir>* and the residual current angle is within the sector *RCADir* ± *ROADir*.

The characteristic for *RCADir* = 0° and *ROADir* = 80° is shown in figure 46.

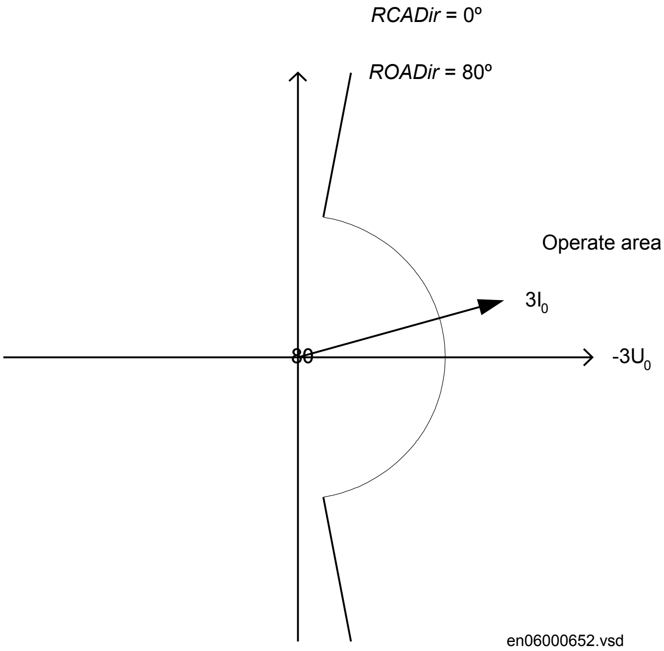


Figure 46: Characteristic for RCADir = 0° and ROADir = 80°

DirMode is set *Forward* or *Reverse* to set the direction of the trip function from the directional residual current function.

All the directional protection modes have a residual current release level setting *INRel>* which is set in % of *IBase*. This setting should be chosen smaller than or equal to the lowest fault current to be detected.

All the directional protection modes have a residual voltage release level setting *UNRel>* which is set in % of *UBase*. This setting should be chosen smaller than or equal to the lowest fault residual voltage to be detected.

tDef is the definite time delay, given in s, for the directional residual current protection if definite time delay is chosen.

The characteristic angle of the directional functions *RCADir* is set in degrees. *RCADir* is normally set equal to 0° in a high impedance earthed network with a neutral point resistor as the active current component is appearing out on the faulted feeder only. *RCADir* is set equal to -90° in an isolated network as all currents are mainly capacitive.

The relay open angle *ROADir* is set in degrees. For angles differing more than *ROADir* from *RCADir* the function from the protection is blocked. The setting can be used to prevent unwanted function for non-faulted feeders, with large capacitive earth-fault current contributions, due to CT phase angle error.

INCosPhi> is the operate current level for the directional function when *OpMode* is set *3I0Cosfi*. The setting is given in % of *IBase*. The setting should be based on calculation of the active or capacitive earth-fault current at required sensitivity of the protection.

SN> is the operate power level for the directional function when *OpMode* is set *3I03U0Cosfi*. The setting is given in % of *IBase*. The setting should be based on calculation of the active or capacitive earth-fault residual power at required sensitivity of the protection.

If the time delay for residual power is chosen the delay time is dependent on two setting parameters. *SRef* is the reference residual power, given in % of *SBase*. *kSN* is the time multiplier. The time delay will follow the following expression:

$$t_{inv} = \frac{kSN \cdot Sref}{3I_0 \cdot 3U_0 \cdot \cos\varphi(measured)}$$

(Equation 55)

INDir> is the operate current level for the directional function when *OpMode* is set *3I0 and fi*. The setting is given in % of *IBase*. The setting should be based on calculation of the earth-fault current at required sensitivity of the protection.

OpINNonDir> is set *On* to activate the non-directional residual current protection.

INNonDir> is the operate current level for the non-directional function. The setting is given in % of *IBase*. This function can be used for detection and clearance of cross-country faults in a shorter time than for the directional function. The current setting should be larger than the maximum single-phase residual current out on the protected line.

TimeChar is the selection of time delay characteristic for the non-directional residual current protection. Definite time delay and different types of inverse time characteristics are available:

ANSI Extremely Inverse
ANSI Very Inverse
ANSI Normal Inverse
ANSI Moderately Inverse
ANSI/IEEE Definite time
ANSI Long Time Extremely Inverse
ANSI Long Time Very Inverse
ANSI Long Time Inverse
Table continues on next page

IEC Normal Inverse
IEC Very Inverse
IEC Inverse
IEC Extremely Inverse
IEC Short Time Inverse
IEC Long Time Inverse
IEC Definite time
ASEA RI
RXIDG (logarithmic)

The different characteristics are described in Technical Manual.

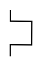
tINNonDir is the definite time delay for the non directional earth-fault current protection, given in s.

OpUN> is set *On* to activate the trip function of the residual voltage protection.

tUN is the definite time delay for the trip function of the residual voltage protection, given in s.

5.6 Thermal overload protection, one time constant LPTTR

5.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Thermal overload protection, one time constant	LPTTR		26

5.6.2 Application

Lines and cables in the power system are designed for a certain maximum load current level. If the current exceeds this level the losses will be higher than expected. As a consequence the temperature of the conductors will increase. If the temperature of the lines and cables reaches too high values the equipment might be damaged:

- The sag of overhead lines can reach unacceptable value.
- If the temperature of conductors, for example aluminium conductors, get too high the material will be destroyed.
- In cables the insulation can be damaged as a consequence of the overtemperature. As a consequence of this phase to phase or phase to earth faults can occur

In stressed situations in the power system it can be required to overload lines and cables for a limited time. This should be done without risks.

The thermal overload protection provides information that makes a temporary overloading of cables and lines possible. The thermal overload protection estimates the conductor temperature continuously. This estimation is made by using a thermal model of the line/cable based on the current measurement.

If the temperature of the protected object reaches a set warning level *AlarmTemp*, a signal ALARM can be given to the operator. This enables actions in the power system to be taken before dangerous temperatures are reached. If the temperature continues to increase to the trip value *TripTemp*, the protection initiates trip of the protected line.

5.6.3 Setting guidelines

The parameters for the thermal overload protection (LPTTR) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the thermal overload protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

IRef: Reference, steady state current, given in % of *IBase* that will give a steady state (end) temperature *TRef*. It is suggested to set this current to the maximum steady state current allowed for the line/cable under emergency operation (a few hours per year).

TRef: Reference temperature (end temperature) corresponding to the steady state current *IRef*. From cable manuals current values with corresponding conductor temperature are often given. These values are given for conditions such as earth temperature, ambient air temperature, way of laying of cable and earth thermal resistivity. From manuals for overhead conductor temperatures and corresponding current is given.

Tau: The thermal time constant of the protected circuit given in minutes. Please refer to manufacturers manuals for details.

TripTemp: Temperature value for trip of the protected circuit. For cables a maximum allowed conductor temperature is often stated to be 90°C. For overhead lines the critical temperature for aluminium conductor is about 90 - 100°C. For a copper conductor a normal figure is 70°C.

AlarmTemp: Temperature level for alarm of the protected circuit. ALARM signal can be used as a warning before the circuit is tripped. Therefore the setting shall be lower than the trip level. It shall at the same time be higher than the maximum conductor temperature at normal operation. For cables this level is often given to 65°C. Similar values are stated for overhead lines. A suitable setting can be about 15°C below the trip value.

ReclTemp: Temperature where lockout signal LOCKOUT from the protection is released. When the thermal overload protection trips a lock-out signal is activated. This signal is intended to block switch in of the protected circuit as long as the conductor temperature is high. The signal is released when the estimated temperature is below the set value. This temperature value should be chosen below the alarm temperature.

5.7 Breaker failure protection CCRBRF

5.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Breaker failure protection	CCRBRF	3I>BF	50BF

5.7.2 Application

In the design of the fault clearance system the N-1 criterion is often used. This means that a fault needs to be cleared even if any component in the fault clearance system is faulty. One necessary component in the fault clearance system is the circuit breaker. It is from practical and economical reason not feasible to duplicate the circuit breaker for the protected component. Instead a breaker failure protection is used.

Breaker failure protection (CCRBRF) will issue a back-up trip command to adjacent circuit breakers in case of failure to trip of the “normal” circuit breaker for the protected component. The detection of failure to break the current through the breaker is made by means of current measurement or as detection of remaining trip signal (unconditional).

CCRBRF can also give a re-trip. This means that a second trip signal is sent to the protected circuit breaker. The re-trip function can be used to increase the probability of operation of the breaker, or it can be used to avoid back-up trip of many breakers in case of mistakes during relay maintenance and test.

5.7.3 Setting guidelines

The parameters for Breaker failure protection (CCRBRF) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the breaker failure protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

FunctionMode This parameter can be set *Current/Contact*. This states the way the detection of failure of the breaker is performed. In the mode current the current measurement is used for the detection. In the mode *Contact* the long duration of breaker position signal is used as indicator of failure of the breaker. The mode *Current and Contact* means that both ways of detections are activated. *Contact* mode can be usable in applications where the fault current through the circuit breaker is small. This can be the case for some generator protection application (for example reverse power protection) or in case of line ends with weak end infeed.

RetripMode: This setting states how the re-trip function shall operate. *Retrip Off* means that the re-trip function is not activated. *CB Pos Check* (circuit breaker position check) and *Current* means that a phase current must be larger than the operate level to allow re-trip. CB Pos Check (circuit breaker position check) and *Contact* means re-trip is done when circuit breaker is closed (breaker position is used). *No CB Pos Check* means re-trip is done without check of breaker position.

Table 10: Dependencies between parameters RetripMode and FunctionMode

RetripMode	*FunctionMode*	Description
Retrip Off	N/A	the re-trip function is not activated
CB Pos Check	*Current*	a phase current must be larger than the operate level to allow re-trip
	Contact	re-trip is done when circuit breaker is closed (breaker position is used) and a long duration of a trip signal indicates breaker failure
	Current&Contact	both methods are used

Table continues on next page

RetripMode	*FunctionMode*	Description
No CB Pos Check	*Current*	re-trip is done without check of breaker position
	Contact	re-trip is done without check of breaker position
	Current&Contact	both methods are used

BuTripMode: Back-up trip mode is given to state sufficient current criteria to detect failure to break. For *Current* operation *2 out of 4* means that at least two currents, of the three phase-currents and the residual current, shall be high to indicate breaker failure. *1 out of 3* means that at least one current of the three phase-currents shall be high to indicate breaker failure. *1 out of 4* means that at least one current of the three phase currents or the residual current shall be high to indicate breaker failure. In most applications *1 out of 3* is sufficient. For *Contact* operation means back-up trip is done when circuit breaker is closed (breaker position is used).

IP>: Current level for detection of breaker failure, set in % of *IBase*. This parameter should be set so that faults with small fault current can be detected. The setting can be chosen in accordance with the most sensitive protection function to start the breaker failure protection. Typical setting is 10% of *IBase*.

I>BlkCont: If any contact based detection of breaker failure is used this function can be blocked if any phase current is larger than this setting level. If the*FunctionMode* is set *Current and Contact* breaker failure for high current faults are safely detected by the current measurement function. To increase security the contact based function should be disabled for high currents. The setting can be given within the range 5 – 200% of *IBase*.

IN>: Residual current level for detection of breaker failure set in % of *IBase*. In high impedance earthed systems the residual current at phase to earth-faults are normally much smaller than the short circuit currents. In order to detect breaker failure at single-phase earth faults in these systems it is necessary to measure the residual current separately. Also in effectively earthed systems the setting of the earth-fault current protection can be chosen to relatively low current level. The *BuTripMode* is set *1 out of 4*. The current setting should be chosen in accordance to the setting of the sensitive earth fault protection. The setting can be given within he range 2 – 200 % of *IBase*.

t1: Time delay of the re-trip. The setting can be given within the range 0 – 60 s in steps of 0.001 s. Typical setting is 0 – 50 ms.

t2: Time delay of the back-up trip. The choice of this setting is made as short as possible at the same time as unwanted operation must be avoided. Typical setting is 90 – 200 ms (also dependent of re-trip timer).

The minimum time delay for the re-trip can be estimated as:

$$t2 \geq t1 + t_{cbopen} + t_{BFP\_reset} + t_{margin}$$

(Equation 56)

where:

t_{cbopen}	is the maximum opening time for the circuit breaker
t_{BFP_reset}	is the maximum time for breaker failure protection to detect correct breaker function (the current criteria reset)
t_{margin}	is a safety margin

It is often required that the total fault clearance time shall be less than a given critical time. This time is often dependent of the ability to maintain transient stability in case of a fault close to a power plant.

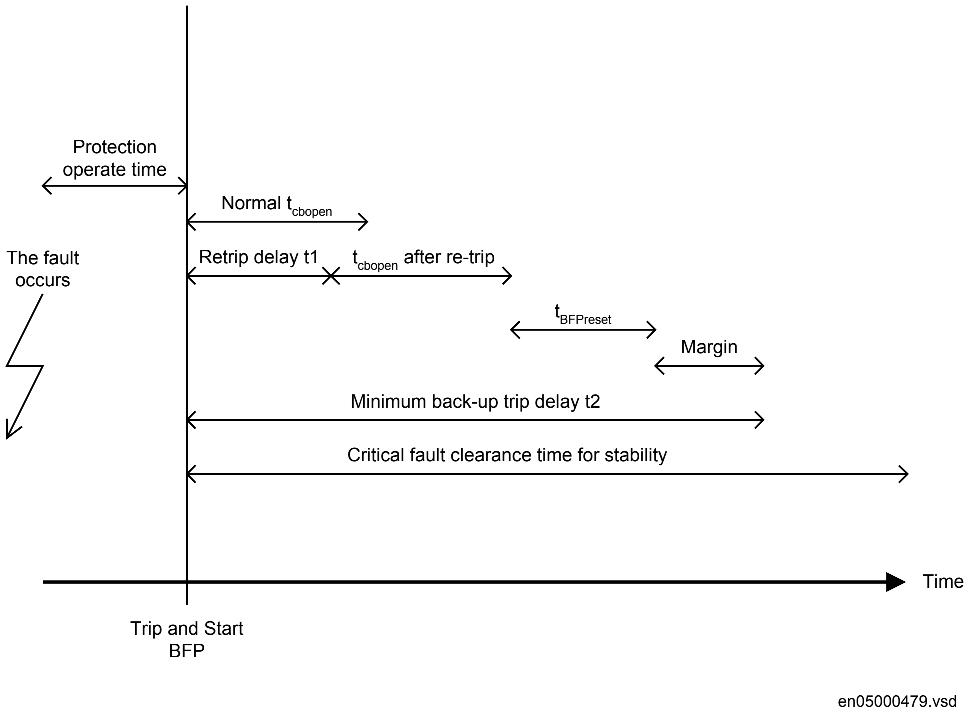


Figure 47: Time sequence

5.8 Stub protection STBPTOC

5.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Stub protection	STBPTOC	*3I>STUB*	50STB

5.8.2 Application

The stub protection (STBPTOC) is a simple phase overcurrent protection, fed from the two current transformer groups feeding the object taken out of service. The stub protection is only activated when the disconnector of the object is open. The stub protection enables fast fault clearance of faults at the section between the CTs and the open disconnector.

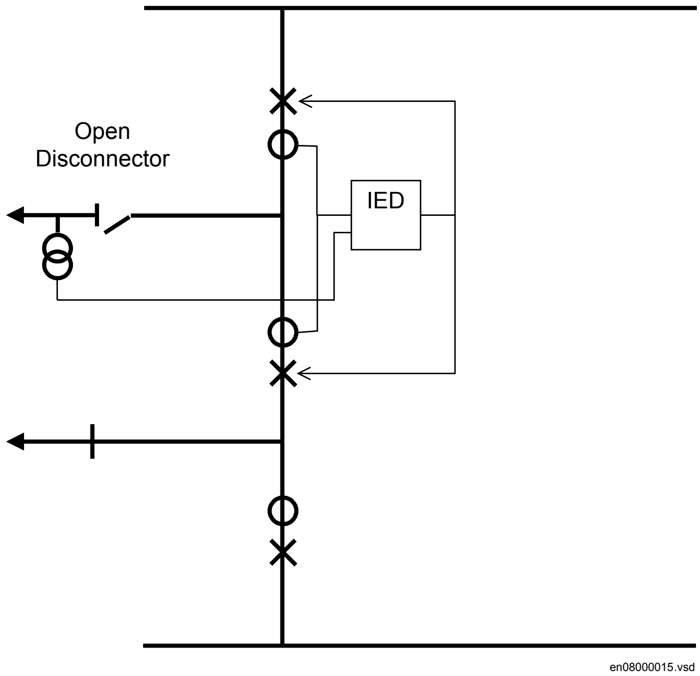


Figure 48: Typical connection for stub protection in 1½-breaker arrangement.

5.8.3 Setting guidelines

The parameters for the stub protection function (STBPTOC) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the stub protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

I>: Current level for the Stub protection, set in % of *IBase*. This parameter should be set so that all faults on the stub can be detected. The setting should thus be based on fault calculations.

5.9 Pole discordance protection CCRPLD

5.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pole discordance protection	CCRPLD	PD	52PD

5.9.2 Application

There is a risk that a circuit breaker will get discordance between the poles at circuit breaker operation: closing or opening. One pole can be open and the other two closed, or two poles can be open and one closed. Pole discordance of a circuit breaker will cause unsymmetrical currents in the power system. The consequence of this can be:

- Negative sequence currents that will give stress on rotating machines
- Zero sequence currents that might give unwanted operation of sensitive earth-fault protections in the power system.

It is therefore important to detect situations with pole discordance of circuit breakers. When this is detected the breaker should be tripped directly.

The pole discordance protection will detect situation with deviating positions of the poles of the protected circuit breaker. The protection has two different options to make this detection:

- By connecting the auxiliary contacts in the circuit breaker so that a logic is created and a signal can be sent to the pole discordance protection, indicating pole discordance.
- Each phase current through the circuit breaker is measured. If the difference between the phase currents is larger than a *CurrUnsymLevel* this is an indication of pole discordance, and the protection will operate.

5.9.3 Setting guidelines

The parameters for the pole discordance protection function (CCRPLD) are set via the local HMI or Protection and Control IED Manager (PCM600).

The following settings can be done for the pole discordance protection.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

tTrip: Time delay of the operation.

ContSel: Operation of the contact based pole discordance protection. Can be set: *Off*/*PD signal fromCB*. If *PD signal fromCB* is chosen the logic to detect pole discordance is made in the vicinity to the breaker auxiliary contacts and only one signal is connected to the pole discordance function.

CurrSel: Operation of the current based pole discordance protection. Can be set: *Off*/*CB oper monitor/Continuous monitor*. In the alternative *CB oper monitor* the function is activated only directly in connection to breaker open or close command (during 200 ms). In the alternative *Continuous monitor* function is continuously activated.

CurrUnsymLevel: Unsymmetrical magnitude of lowest phase current compared to the highest, set in % of the highest phase current.

CurrRelLevel: Current magnitude for release of the function in % of *IBase*.

5.10 Broken conductor check BRCPTOC

5.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Broken conductor check	BRCPTOC	-	46

5.10.2 Application

Conventional protection functions can not detect the broken conductor condition. Broken conductor check (BRCPTOC) function, consisting of continuous current unsymmetry check on the line where the IED connected will give alarm or trip at detecting broken conductors.

5.10.3 Setting guidelines

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Broken conductor check (BRCPTOC) must be set to detect open phase/s (series faults) with different loads on the line. It must be at the same time not operate for maximum unsymmetry which can exist due to, for example, not transposed power lines.

All settings are in primary values or percentage.

Set minimum operating level per phase *IP>* to typically 10-20% of rated current.

Set the unsymmetry current which is relation between the difference of the minimum and maximum phase currents to the maximum phase current to typical *Iub>*=50%. Note that it must be set to avoid problem with unsymmetry under minimum operating conditions. Set the time delay *tOper*=5-20 seconds.

5.11 Directional over-/under-power protection GOPPDOP/GUPPDUP

5.11.1 Application

The task of a generator in a power plant is to convert mechanical energy available as a torque on a rotating shaft to electric energy.

Sometimes, the mechanical power from a prime mover may decrease so much that it does not cover bearing losses and ventilation losses. Then, the synchronous generator becomes a synchronous motor and starts to take electric power from the rest of the power system. This operating state, where individual synchronous machines operate as motors, implies no risk for the machine itself. If the generator under consideration is very large and if it consumes lots of electric power, it may be desirable to disconnect it to ease the task for the rest of the power system.

Often, the motoring condition may imply that the turbine is in a very dangerous state. The task of the reverse power protection is to protect the turbine and not to protect the generator itself.

Steam turbines easily become overheated if the steam flow becomes too low or if the steam ceases to flow through the turbine. Therefore, turbo-generators should have reverse power protection. There are several contingencies that may cause reverse power: break of a main steam pipe, damage to one or more blades in the steam turbine or inadvertent closing of the main stop valves. In the last case, it is highly desirable to have a reliable reverse power protection. It may prevent damage to an otherwise undamaged plant.

During the routine shutdown of many thermal power units, the reverse power protection gives the tripping impulse to the generator breaker (the unit breaker). By doing so, one prevents the disconnection of the unit before the mechanical power has become zero. Earlier disconnection would cause an acceleration of the turbine generator at all routine shutdowns. This should have caused overspeed and high centrifugal stresses.

When the steam ceases to flow through a turbine, the cooling of the turbine blades will disappear. Now, it is not possible to remove all heat generated by the windage losses. Instead, the heat will increase the temperature in the steam turbine and especially of the blades. When a steam turbine rotates without steam supply, the electric power consumption will be about 2% of rated power. Even if the turbine rotates in vacuum, it will soon become overheated and damaged. The turbine overheats within minutes if the turbine loses the vacuum.

The critical time to overheating of a steam turbine varies from about 0.5 to 30 minutes depending on the type of turbine. A high-pressure turbine with small and thin blades will become overheated more easily than a low-pressure turbine with long and heavy blades. The conditions vary from turbine to turbine and it is necessary to ask the turbine manufacturer in each case.

Power to the power plant auxiliaries may come from a station service transformer connected to the primary side of the step-up transformer. Power may also come from a start-up service transformer connected to the external network. One has to design the reverse power protection so that it can detect reverse power independent of the flow of power to the power plant auxiliaries.

Hydro turbines tolerate reverse power much better than steam turbines do. Only Kaplan turbine and bulb turbines may suffer from reverse power. There is a risk that the turbine runner moves axially and touches stationary parts. They are not always strong enough to withstand the associated stresses.

Ice and snow may block the intake when the outdoor temperature falls far below zero. Branches and leaves may also block the trash gates. A complete blockage of the intake may cause cavitation. The risk for damages to hydro turbines can justify reverse power protection in unattended plants.

A hydro turbine that rotates in water with closed wicket gates will draw electric power from the rest of the power system. This power will be about 10% of the rated power. If there is only air in the hydro turbine, the power demand will fall to about 3%.

Diesel engines should have reverse power protection. The generator will take about 15% of its rated power or more from the system. A stiff engine may require perhaps 25% of the rated power to motor it. An engine that is well run in might need no more than 5%. It is necessary to obtain information from the engine manufacturer and to measure the reverse power during commissioning.

Gas turbines usually do not require reverse power protection.

Figure 49 illustrates the reverse power protection with under-power protection and with over-power protection. The under-power protection gives a higher margin and should provide better dependability. On the other hand, the risk for unwanted operation immediately after synchronization may be higher. One should set the under-power protection to trip if the active power from the generator is less than about 2%. One should set the over-power protection to trip if the power flow from the network to the generator is higher than 1%.

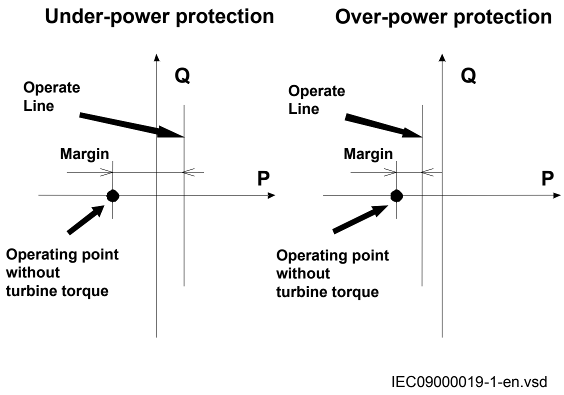


Figure 49: Reverse power protection with under-power or over-power protection

5.11.2 Directional over-power protection GOPPDOP

5.11.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional over-power protection	GOPPDOP	P > →	32

5.11.2.2 Setting guidelines

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: With the parameter *Operation* the function can be set On/Off.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 11.

Table 11: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
L1, L2, L3	$\bar{S} = \bar{U}_{L1} \cdot \bar{I}_{L1}^{*} + \bar{U}_{L2} \cdot \bar{I}_{L2}^{*} + \bar{U}_{L3} \cdot \bar{I}_{L3}^{*}$ (Equation 57)
Arone	$\bar{S} = \bar{U}_{L1L2} \cdot \bar{I}_{L1}^{*} - \bar{U}_{L2L3} \cdot \bar{I}_{L3}^{*}$ (Equation 58)
PosSeq	$\bar{S} = 3 \cdot \bar{U}_{PosSeq} \cdot \bar{I}_{PosSeq}^{*}$ (Equation 59)
L1L2	$\bar{S} = \bar{U}_{L1L2} \cdot (\bar{I}_{L1}^{*} - \bar{I}_{L2}^{*})$ (Equation 60)
L2L3	$\bar{S} = \bar{U}_{L2L3} \cdot (\bar{I}_{L2}^{*} - \bar{I}_{L3}^{*})$ (Equation 61)
L3L1	$\bar{S} = \bar{U}_{L3L1} \cdot (\bar{I}_{L3}^{*} - \bar{I}_{L1}^{*})$ (Equation 62)
L1	$\bar{S} = 3 \cdot \bar{U}_{L1} \cdot \bar{I}_{L1}^{*}$ (Equation 63)
L2	$\bar{S} = 3 \cdot \bar{U}_{L2} \cdot \bar{I}_{L2}^{*}$ (Equation 64)
L3	$\bar{S} = 3 \cdot \bar{U}_{L3} \cdot \bar{I}_{L3}^{*}$ (Equation 65)

The function has two stages with the same setting parameters.

OpMode1(2) is set to define the function of the stage. Possible settings are:

On: the stage is activated *Off*: the stage is disabled

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is larger than the set pick up power value *Power1(2)*

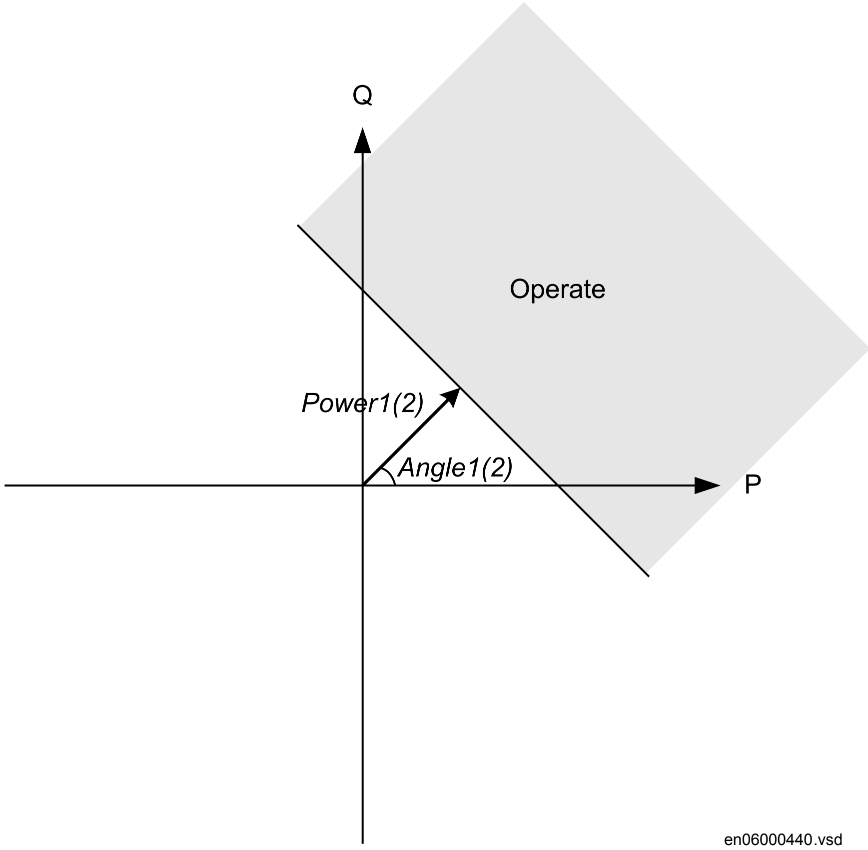


Figure 50: Over-power mode

The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in pu of the generator rated power, see equation 66.

$$S_N = \sqrt{3} \cdot UBase \cdot IBase$$

(Equation 66)

The setting *Angle1(2)* gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 180° should be used for generator reverse power protection.

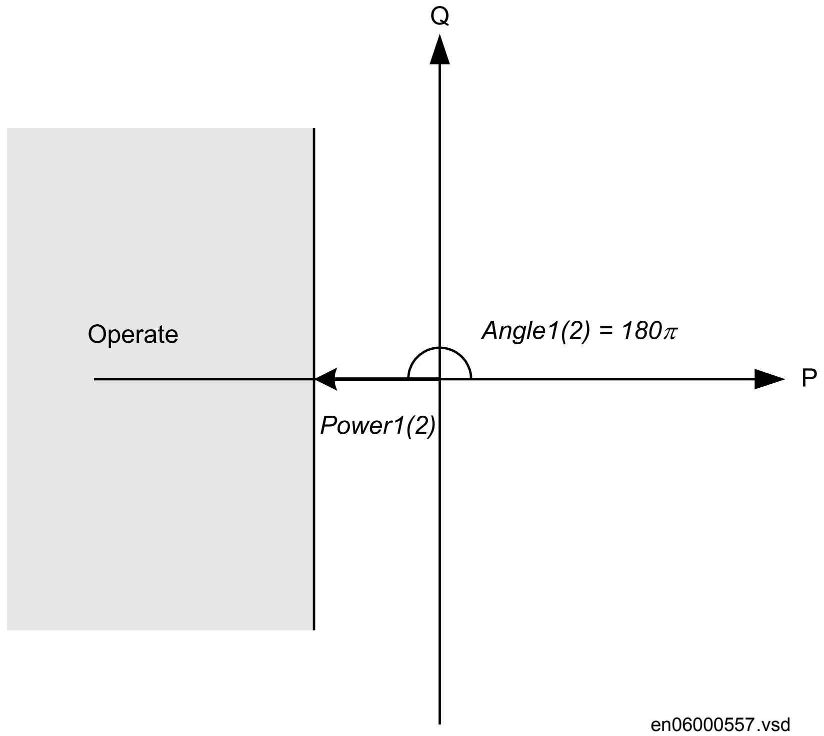


Figure 51: For reverse power the set angle should be 180° in the over-power function

TripDelay1(2) is set in seconds to give the time delay for trip of the stage after pick up.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = k \cdot S_{Old} + (1 - k) \cdot S_{Calculated}$$

(Equation 67)

Where	
S	is a new measured value to be used for the protection function
S_{old}	is the measured value given from the function in previous execution cycle
$S_{Calculated}$	is the new calculated value in the present execution cycle
k	is settable parameter

The value of *k=0.92* is recommended in generator applications as the trip delay is normally quite long.

5.11.3 Directional under-power protection GUPPDUP

5.11.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Directional under-power protection	GUPPDUP	P < →	37

5.11.3.2 Setting guidelines

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: With the parameter *Operation* the function can be set On/Off.

Mode: The voltage and current used for the power measurement. The setting possibilities are shown in table 12.

Table 12: Complex power calculation

Set value *Mode*	Formula used for complex power calculation
L1, L2, L3	$\bar{S} = \bar{U}_{L1} \cdot \bar{I}_{L1}^{*} + \bar{U}_{L2} \cdot \bar{I}_{L2}^{*} + \bar{U}_{L3} \cdot \bar{I}_{L3}^{*}$ (Equation 68)
Arone	$\bar{S} = \bar{U}_{L1L2} \cdot \bar{I}_{L1}^{*} - \bar{U}_{L2L3} \cdot \bar{I}_{L3}^{*}$ (Equation 69)
PosSeq	$\bar{S} = 3 \cdot \bar{U}_{PosSeq} \cdot \bar{I}_{PosSeq}^{*}$ (Equation 70)
L1L2	$\bar{S} = \bar{U}_{L1L2} \cdot (\bar{I}_{L1}^{*} - \bar{I}_{L2}^{*})$ (Equation 71)
L2L3	$\bar{S} = \bar{U}_{L2L3} \cdot (\bar{I}_{L2}^{*} - \bar{I}_{L3}^{*})$ (Equation 72)
L3L1	$\bar{S} = \bar{U}_{L3L1} \cdot (\bar{I}_{L3}^{*} - \bar{I}_{L1}^{*})$ (Equation 73)
Table continues on next page	

Set value *Mode*	Formula used for complex power calculation
L1	$$\overline{S} = 3 \cdot \overline{U}_{L1} \cdot \overline{I}_{L1}^{*}$$ (Equation 74)
L2	$$\overline{S} = 3 \cdot \overline{U}_{L2} \cdot \overline{I}_{L2}^{*}$$ (Equation 75)
L3	$$\overline{S} = 3 \cdot \overline{U}_{L3} \cdot \overline{I}_{L3}^{*}$$ (Equation 76)

The function has two stages with the same setting parameters.

OpMode1(2) is set to define the function of the stage. Possible settings are:

On: the stage is activated *Off*: the stage is disabled

The function gives trip if the power component in the direction defined by the setting *Angle1(2)* is smaller than the set pick up power value *Power1(2)*

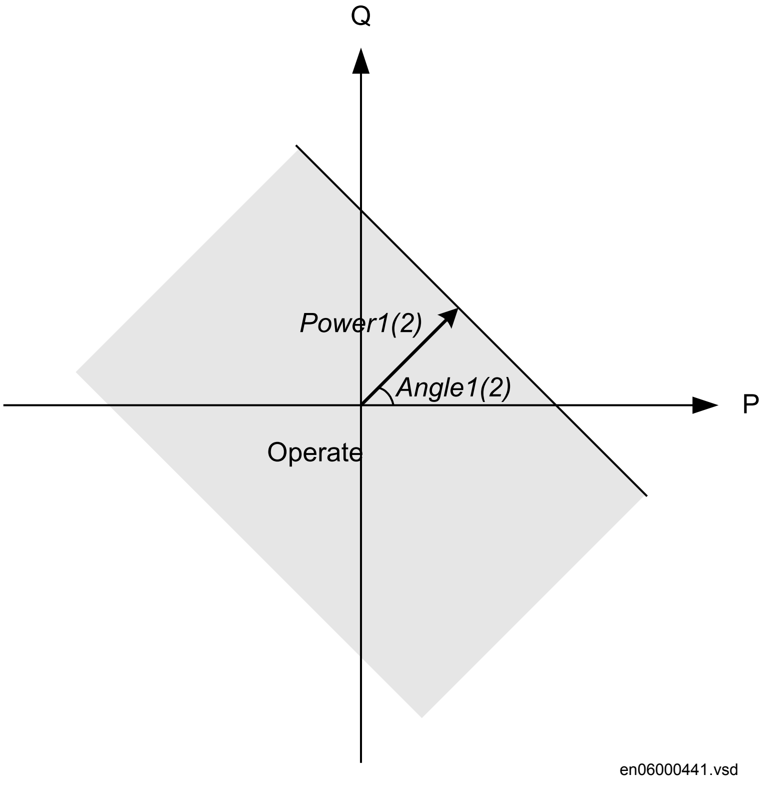


Figure 52: Under-power mode

The setting *Power1(2)* gives the power component pick up value in the *Angle1(2)* direction. The setting is given in pu of the generator rated power, see equation 77.

$$S_N = \sqrt{3} \cdot UBase \cdot IBase$$

(Equation 77)

The setting *Angle1(2)* gives the characteristic angle giving maximum sensitivity of the power protection function. The setting is given in degrees. For active power the set angle should be 0° or 180°. 0° should be used for generator low forward active power protection.

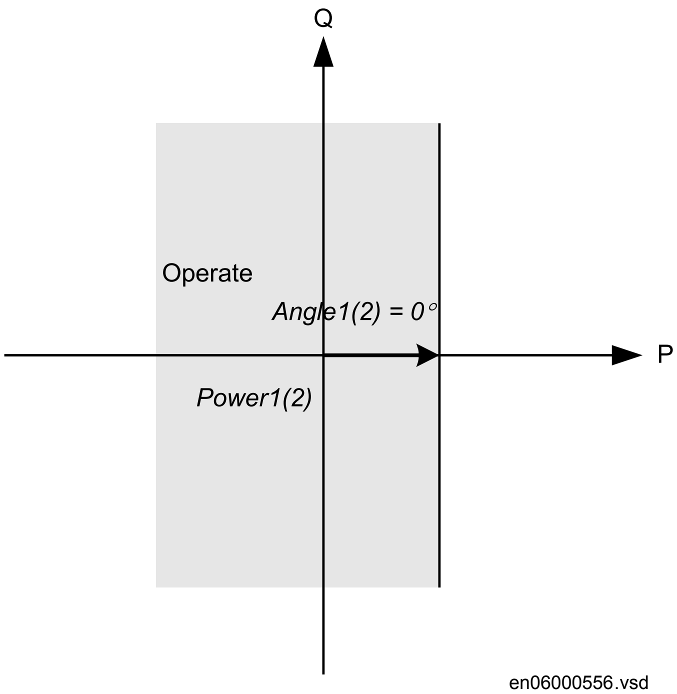


Figure 53: For low forward power the set angle should be 0° in the under-power function

TripDelay1(2) is set in seconds to give the time delay for trip of the stage after pick up.

The possibility to have low pass filtering of the measured power can be made as shown in the formula:

$$S = k \cdot S_{Old} + (1 - k) \cdot S_{Calculated}$$

(Equation 78)

Where

S	is a new measured value to be used for the protection function
S_{old}	is the measured value given from the function in previous execution cycle
$S_{Calculated}$	is the new calculated value in the present execution cycle
k	is settable parameter

The value of *k=0.92* is recommended in generator applications as the trip delay is normally quite long.

5.12 Negative sequence based overcurrent function DNSPTOC

5.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Negative sequence based overcurrent function	DNSPTOC	I2>	46

5.12.2 Application

Negative sequence based overcurrent function (DNSPTOC) is typically used as sensitive earth-fault protection of power lines, where incorrect zero sequence polarization may result from mutual induction between two or more parallel lines.

Additionally, it is used in applications on underground cables, where zero sequence impedance depends on the fault current return paths, but the cable negative sequence impedance is practically constant.

DNSPTOC protects against all unbalance faults including phase-to-phase faults. Always remember to set the minimum pickup current of the function above natural system unbalance level.

5.12.3 Setting guidelines

Below is an example of Negative sequence based overcurrent function (DNSPTOC) used as a sensitive earth-fault protection for power lines. The following settings must be done in order to ensure proper operation of the protection:

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

- setting *RCA_DIR* to value *+65 degrees*, that is, the negative sequence current typically lags the inverted negative sequence voltage for this angle during the fault
- setting *ROA_DIR* to value *90 degrees*
- setting *LowVolt_VM* to value *2%*, that is, the negative sequence voltage level above which the directional element will be enabled

- setting *Operation_OC1* to *On*
- setting *StartCurr_OC1* to value between *3-10%*, (typical values)
- setting *tDef_OC1* to insure proper time coordination with other earth-fault protections installed in the vicinity of this power line
- setting *DirMode_OC1* to *Forward*
- setting *DirPrinc_OC1* to *IcosPhi&U*
- setting*ActLowVolt1_VM* to *Block*

DNSPTOC is used in directional comparison protection scheme for the power line protection, when communication channels to the remote end of this power line are available. In that case, two negative sequence overcurrent steps are required - one in forward and another in reverse direction. The OC1 stage is used to detect faults in forward direction and the OC2 stage is used to detect faults in reverse direction.

However, the following must be noted for such application:

- setting *RCA_Dir* and *ROA_Dir* are applicable for both steps OC1 and OC2
- setting *DirMode_OC1* must be set to *Forward*
- setting *DirMode_OC2* must be set to *Reverse*
- setting *StartCurr_OC2* must be made more sensitive than *pickup* value of the forward OC1 element, that is, typically 60% of *StartCurr_OC1* set pickup level in order to insure proper operation of the directional comparison scheme during current reversal situations
- the start signals STOC1 and STOC2 from OC1 and OC2 elements is used to send forward and reverse signals to the remote end of the power line
- the available scheme communications function block within IED is used between the protection function and the teleprotection communication equipment, in order to insure proper conditioning of the above two start signals.

Section 6 Voltage protection

6.1 Two step undervoltage protection UV2PTUV

6.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step undervoltage protection	UV2PTUV	3U<	27

6.1.2 Application

Two-step undervoltage protection function (UV2PTUV) is applicable in all situations, where reliable detection of low phase voltages is necessary. It is used also as a supervision and fault detection function for other protection functions, to increase the security of a complete protection system.

UV2PTUV is applied to power system elements, such as generators, transformers, motors and power lines in order to detect low voltage conditions. Low voltage conditions are caused by abnormal operation or fault in the power system. It is used in combination with overcurrent protections, either as restraint or in logic "and gates" of the trip signals issued by the two functions. Other applications are the detection of "no voltage" condition, for example, before the energization of a HV line or for automatic breaker trip in case of a blackout. UV2PTUV is also used to initiate voltage correction measures, like insertion of shunt capacitor banks to compensate for reactive load and thereby increasing the voltage. The function has a high measuring accuracy and setting hysteresis to allow applications to control reactive load.

UV2PTUV is used to disconnect from the network apparatuses, like electric motors, which will be damaged when subject to service under low voltage conditions. UV2PTUV deals with low voltage conditions at power system frequency, which can be caused by the following reasons:

1. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease)
2. Overload (symmetrical voltage decrease)
3. Short circuits, often as phase-to-earth faults (unsymmetrical voltage decrease)

UV2PTUV prevents sensitive equipment from running under conditions that could cause their overheating and thus shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

6.1.3 Setting guidelines

The parameters for two-step undervoltage protection (UV2PTUV) are set via the local HMI or Protection and Control IED Manager (PCM600).

All the voltage conditions in the system where UV2PTUV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general undervoltage functions are used. All voltage related settings are made as a percentage of the global settings base voltage *UBase* and base current *IBase*, which normally is set to the primary nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The setting for UV2PTUV is normally not critical, since there must be enough time available for the main protection to clear short-circuits and earth-faults.

Some applications and related setting guidelines for the voltage level are described in the following sections.

6.1.3.1 Equipment protection, such as for motors and generators

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage for the equipment.

6.1.3.2 Disconnected equipment detection

The setting must be below the lowest occurring "normal" voltage and above the highest occurring voltage, caused by inductive or capacitive coupling, when the equipment is disconnected.

6.1.3.3 Power supply quality

The setting must be below the lowest occurring "normal" voltage and above the lowest acceptable voltage, due to regulation, good practice or other agreements.

6.1.3.4 Voltage instability mitigation

This setting is very much dependent on the power system characteristics, and thorough studies have to be made to find the suitable levels.

6.1.3.5 Backup protection for power system faults

The setting must be below the lowest occurring "normal" voltage and bove the highest occurring voltage during the fault conditions under consideration.

6.1.3.6 Settings for Two step undervoltage protection

The following settings can be done for two step undervoltage protection (UV2PTUV).

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

ConnType: Sets whether the measurement shall be phase-to-earth fundamental value, phase-to-phase fundamental value, phase-to-earth RMS value or phase-to-phase RMS value.

Operation: *Off/On*.

UV2PTUV measures selectively phase-to-earth voltages, or phase-to-phase voltage chosen by the setting *ConnType*.

This means operation for phase-to-earth voltage if:

$$U < (\%) \cdot UBase(kV) \Big/ \sqrt{3}$$

(Equation 79)

and operation for phase-to-phase voltage if:

$$\mathrm{U} < (\%) \cdot \mathrm{UBase(kV)}$$

(Equation 80)

Characteristic1: This parameter gives the type of time delay to be used for step 1. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be below the set level to give operation for step *n* (*n*=step 1 and 2). The setting can be *1 out of 3*, *2 out of 3* or *3 out of 3*. In most applications it is sufficient that one phase voltage is low to give operation. If the function shall be insensitive for single phase-to-earth faults *2 out of 3* can be chosen.

Un<: Set operate undervoltage operation value for step *n* (*n*=step 1 and 2), given as % of the global parameter *UBase*. The setting is highly dependent of the protection application. Here it is essential to consider the minimum voltage at non-faulted situations. Normally this voltage is larger than 90% of nominal voltage.

tn: time delay for step *n* (*n*=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications the protection function shall not directly trip in case of short circuits or earth-faults in the system. The time delay must be co-ordinated to the short circuit protections.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very low voltages the undervoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

k1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

6.2 Two step overvoltage protection OV2PTOV

6.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step overvoltage protection	OV2PTOV	3U>	59

6.2.2 Application

Two-step overvoltage protection (OV2PTOV) is applicable in all situations, where reliable detection of high voltage is necessary. OV2PTOV is used for supervision and detection of abnormal conditions, which, in combination with other protection functions, increase the security of a complete protection system.

High voltage conditions are caused by abnormal situations in the power system. OV2PTOV is applied to power system elements, such as generators, transformers, motors and power lines in order to detect high voltage conditions. OV2PTOV is used in combination with low current signals, to identify a transmission line, open in the remote end. In addition to that, OV2PTOV is also used to initiate voltage correction measures, like insertion of shunt reactors, to compensate for low load, and thereby decreasing the voltage. The function has a high measuring accuracy and setting hysteresis to allow applications to control reactive load.

OV2PTOV is used to disconnect, from the network, apparatuses, like electric motors, which will be damaged when subject to service under high voltage conditions. It deals with high voltage conditions at power system frequency, which can be caused by:

1. Different kinds of faults, where a too high voltage appears in a certain power system, like metallic connection to a higher voltage level (broken conductor falling down to a crossing overhead line, transformer flash over fault from the high voltage winding to the low voltage winding and so on).
2. Malfunctioning of a voltage regulator or wrong settings under manual control (symmetrical voltage decrease).
3. Low load compared to the reactive power generation (symmetrical voltage decrease).
4. Earth-faults in high impedance earthed systems causes, beside the high voltage in the neutral, high voltages in the two non-faulted phases, (unsymmetrical voltage increase).

OV2PTOV prevents sensitive equipment from running under conditions that could cause their overheating or stress of insulation material, and, thus, shorten their life time expectancy. In many cases, it is a useful function in circuits for local or remote automation processes in the power system.

6.2.3 Setting guidelines

The parameters for Two-step overvoltage protection (OV2PTOV) are set via the local HMI or Protection and Control IED Manager (PCM600).

All the voltage conditions in the system where OV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general overvoltage functions are used. All voltage related settings are made as a percentage of a settable base primary voltage, which normally is set to the nominal voltage level (phase-to-phase) of the power system or the high voltage equipment under consideration.

The time delay for the OV2PTOV can sometimes be critical and related to the size of the overvoltage - a power system or a high voltage component can withstand smaller overvoltages for some time, but in case of large overvoltages the related equipment should be disconnected more rapidly.

Some applications and related setting guidelines for the voltage level are given below:

Equipment protection, such as for motors, generators, reactors and transformers

High voltage can cause overexcitation of the core and deteriorate the winding insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the equipment.

Equipment protection, capacitors

High voltage can deteriorate the dielectricum and the insulation. The setting must be above the highest occurring "normal" voltage and below the highest acceptable voltage for the capacitor.

High impedance earthed systems

In high impedance earthed systems, earth-faults cause a voltage increase in the non-faulty phases. OV2PTOV is used to detect such faults. The setting must be above the highest occurring "normal" voltage and below the lowest occurring voltage during faults. A metallic single-phase earth-fault causes the non-faulted phase voltages to increase a factor of √3.

The following settings can be done for Two step overvoltage protection

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

ConnType: Sets whether the measurement shall be phase-to-earth fundamental value, phase-to-phase fundamental value, phase-to-earth RMS value or phase-to-phase RMS value.

Operation: Off/On .

OV2PTOV measures the phase-to-earth voltages, or phase-to-phase voltages as selected. The function will operate if the voltage gets higher than the set percentage of the global set base voltage *UBase*. This means operation for phase-to-earth voltage over:

$$U > (\%) \cdot UBase(kV) / \sqrt{3}$$

(Equation 81)

and operation for phase-to-phase voltage over:

$$\mathrm{U} > (\%) \cdot \mathrm{UBase(kV)}$$

(Equation 82)

Characteristic1: This parameter gives the type of time delay to be used. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B/Inverse Curve C*. The choice is highly dependent of the protection application.

OpModen: This parameter describes how many of the three measured voltages that should be above the set level to give operation for step n (n=step 1 and 2). The setting can be *1 out of 3, 2 out of 3 or 3 out of 3*. In most applications it is sufficient that one phase voltage is high to give operation. If the function shall be insensitive for single phase-to-earth faults *3 out of 3* can be chosen, because the voltage will normally rise in the non-faulted phases at single phase-to-earth faults.

Un>: Set operate overvoltage operation value for step n (n=step 1 and 2), given as % of the global parameter *UBase*. The setting is highly dependent of the protection application. Here it is essential to consider the Maximum voltage at non-faulted situations. Normally this voltage is less than 110% of nominal voltage.

tn: time delay for step n (n=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications the protection function has the task to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

k1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

6.3 Two step residual overvoltage protection ROV2PTOV

6.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Two step residual overvoltage protection	ROV2PTOV	$\boxed{3U0}$	59N

6.3.2 Application

Two-step residual overvoltage protection (ROV2PTOV) is primarily used in high impedance earthed distribution networks, mainly as a backup for the primary earth-fault protection of the feeders and the transformer. To increase the security for different earth-fault related functions, the residual overvoltage signal can be used as a release signal. The residual voltage can be measured either at the transformer neutral or from a voltage transformer open delta connection. The residual voltage can also be calculated internally, based on measurement of the three-phase voltages.

In high impedance earthed systems the system neutral voltage, that is, the residual voltage, will increase in case of any fault connected to earth. Depending on the type of fault and fault resistance the residual voltage will reach different values. The highest residual voltage, equal to the phase-to-earth voltage, is achieved for a single phase-to-earth fault. The residual voltage increases approximately the same amount in the whole system and does not provide any guidance in finding the faulted component. Therefore, ROV2PTOV is often used as a backup protection or as a release signal for the feeder earth-fault protection.

6.3.3 Setting guidelines

The parameters for Two-step residual overvoltage protection (ROV2PTOV) are set via the local HMI or Protection and Control IED Manager (PCM600).

All the voltage conditions in the system where ROV2PTOV performs its functions should be considered. The same also applies to the associated equipment, its voltage and time characteristic.

There is a very wide application area where general single input or residual overvoltage functions are used. All voltage related settings are made as a percentage of a settable base voltage, which can be set to the primary nominal voltage (phase-phase) level of the power system or the high voltage equipment under consideration.

The time delay for ROV2PTOV are seldom critical, since residual voltage is related to earth-faults in a high impedance earthed system, and enough time must normally be given for the primary protection to clear the fault. In some more specific situations, where the single overvoltage protection is used to protect some specific equipment, the time delay is shorter.

Some applications and related setting guidelines for the residual voltage level are given below.

6.3.3.1 Equipment protection, such as for motors, generators, reactors and transformers

High residual voltage indicates earth-fault in the system, perhaps in the component to which Two step residual overvoltage protection (ROV2PTOV) is connected. After a period of time delay, to give the primary protection for the faulted device a chance to trip, ROV2PTOV must trip the component. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the equipment

6.3.3.2 Equipment protection, capacitors

High voltage will deteriorate the dielectric and the insulation. Two step residual overvoltage protection (ROV2PTOV) has to be connected to a neutral or open delta winding. The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage for the capacitor.

6.3.3.3 Power supply quality

The setting must be above the highest occurring "normal" residual voltage and below the highest acceptable residual voltage, due to regulation, good practice or other agreements.

6.3.3.4 High impedance earthed systems

In high impedance earthed systems, earth-faults cause a neutral voltage in the feeding transformer neutral. Two step residual overvoltage protection (ROV2PTOV) is used to trip the transformer, as a backup protection for the feeder earth-fault protection, and as a backup for the transformer primary earth-fault protection. The setting must be above the highest occurring "normal" residual voltage, and below the lowest occurring residual voltage during the faults under consideration. A metallic single-phase earth-fault causes a transformer neutral to reach a voltage equal to the normal phase-to-earth voltage.

The voltage transformers measuring the phase-to-earth voltages measure zero voltage in the faulty phase. The two healthy phases will measure full phase-to-phase voltage, as the earth is available on the faulty phase and the neutral has a full phase-to-earth voltage. The residual overvoltage will be three times the phase-to-earth voltage. See figure 54.

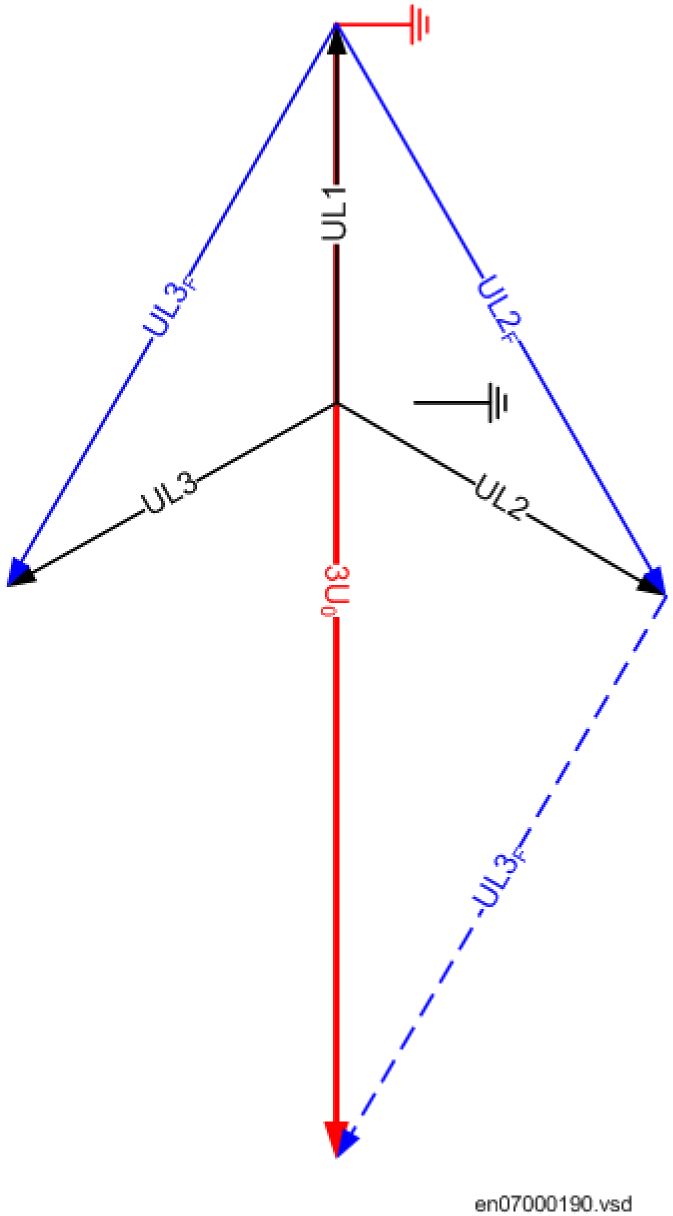


Figure 54: Non-effectively earthed systems

6.3.3.5 Direct earthed system

In direct earthed systems, an earth-fault on one phase indicates a voltage collapse in that phase. The two healthy phases will have normal phase-to-earth voltages. The residual sum will have the same value as phase-to-earth voltage. See figure 55 .

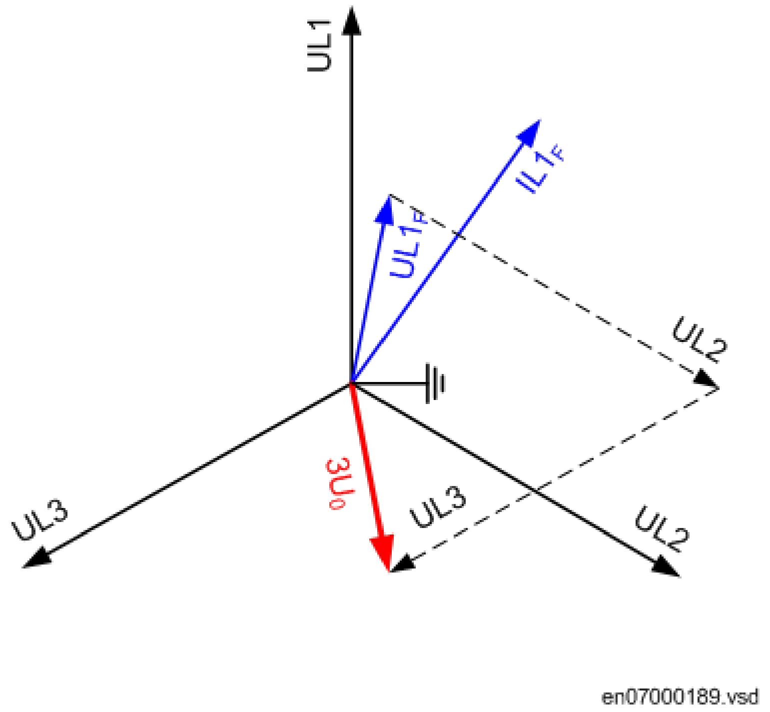


Figure 55: Direct earthed system

6.3.3.6 Settings for Two step residual overvoltage protection

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

Global setting *UBase* is used as voltage reference for the voltage. The voltage can be fed to the IED in different ways:

$$UBase = Uph * \sqrt{3}$$

1.The IED is fed from a normal voltage transformer group where the residual voltage is created from the phase-to-earth voltages within the protection software.

2.The IED is fed from a broken delta connection normal voltage transformer group. In a open delta connection the protection is fed by the voltage 3U0 (single input). The setting of the analogue input is given as the ratio of the voltage transformer e.g 230/√3/110 or 230/√3 /(110/3).

3.The IED is fed from a single voltage transformer connected to the neutral point of a power transformer in the power system. In this connection the protection is fed by the voltage UN (single input). The setting of the analogue input is given as primary phase-to-earth voltage and secondary phase-to-earth voltage. ROV2PTOV will measure the residual voltage corresponding nominal phase-to-earth voltage. The measurement will be based on the neutral voltage displacement.

Characteristic1: This parameter gives the type of time delay to be used. The setting can be. *Definite time/Inverse Curve A/Inverse Curve B/Inverse Curve C* The choice is highly dependent of the protection application.

Un>: Set operate overvoltage operation value for step *n* (*n*=step 1 and 2), given as % of residual voltage corresponding to global set parameter *UBase*:

$U > (\%) \cdot UBase(kV) / \sqrt{3}$

The setting is dependent of the required sensitivity of the protection and the system earthing. In non-effectively earthed systems the residual voltage can be maximum the rated phase-to-earth voltage, which should correspond to 100%.

In effectively earthed systems this value is dependent of the ratio Z0/Z1. The required setting to detect high resistive earth-faults must be based on network calculations.

tn: time delay of step *n* (*n*=step 1 and 2), given in s. The setting is highly dependent of the protection application. In many applications, the protection function has the task to prevent damages to the protected object. The speed might be important for example in case of protection of transformer that might be overexcited. The time delay must be co-ordinated with other automated actions in the system.

t1Min: Minimum operation time for inverse time characteristic for step 1, given in s. For very high voltages the overvoltage function, using inverse time characteristic, can give very short operation time. This might lead to unselective trip. By setting *t1Min* longer than the operation time for other protections such unselective tripping can be avoided.

k1: Time multiplier for inverse time characteristic. This parameter is used for co-ordination between different inverse time delayed undervoltage protections.

6.4 Loss of voltage check LOVPTUV

6.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Loss of voltage check	LOVPTUV	-	27

6.4.2 Application

The trip of the circuit breaker at a prolonged loss of voltage at all the three phases is normally used in automatic restoration systems to facilitate the system restoration after a major blackout. Loss of voltage check (LOVPTUV) generates a TRIP signal only if the voltage in all the three phases is low for more than the set time. If the trip to the circuit breaker is not required, LOVPTUV is used for signallization only through an output contact or through the event recording function.

6.4.3 Setting guidelines

Loss of voltage check (LOVPTUV) is in principle independent of the protection functions. It requires to be set to open the circuit breaker in order to allow a simple system restoration following a main voltage loss of a big part of the network and only when the voltage is lost with breakers still closed.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

All settings are in primary values or per unit. Set operating level per phase to typically 70% of the global parameter *UBase* level. Set the time delay *tTrip*=5-20 seconds.

6.4.4 Advanced users settings

For advanced users the following parameters need also to be set. Set the length of the trip pulse to typical *tPulse*=0.15 sec. The blocking time to block Loss of voltage check (LOVPTUV) if some but not all voltage are low *tBlock*=5.0 sec. set the time delay for enabling the function after restoration *tRestore* = 3 - 40 seconds.

Section 7 Frequency protection

7.1 Under frequency protection SAPTUF

7.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Under frequency protection	SAPTUF	f <	81

7.1.2 Application

Under frequency protection (SAPTUF) is applicable in all situations, where reliable detection of low fundamental power system voltage frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. Low fundamental frequency in a power system indicates that the available generation is too low to fully supply the power demanded by the load connected to the power grid. SAPTUF detects such situations and provides an output signal, suitable for load shedding, generator boosting, HVDC-set-point change, gas turbine start up and so on. Sometimes shunt reactors are automatically switched in due to low frequency, in order to reduce the power system voltage and hence also reduce the voltage dependent part of the load. SAPTUF is very sensitive and accurate and is used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough. The under frequency signal is also used for overexcitation detection. This is especially important for generator step-up transformers, which might be connected to the generator but disconnected from the grid, during a roll-out sequence. If the generator is still energized, the system will experience overexcitation, due to the low frequency.

7.1.3 Setting guidelines

The parameters for Under frequency protection (SAPTUF) are set via the local HMI or Protection and Control IED Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where the SAPTUF performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are especially two application areas for SAPTUF:

1. to protect equipment against damage due to low frequency, such as generators, transformers, and motors. Overexcitation is also related to low frequency
2. to protect a power system, or a part of a power system, against breakdown, by shedding load, in generation deficit situations.

The under frequency START value is set in Hz. All voltage magnitude related settings are made as a percentage of a global base voltage parameter.

SAPTUF is not instantaneous, since the frequency is related to movements of the system inertia, but the time and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting has to be well below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for the equipment.

Power system protection, by load shedding

The setting has to be below the lowest occurring "normal" frequency and well above the lowest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/ or in frequency) depends very much on the characteristics of the power system under consideration. The size of the "largest loss of production" compared to "the size of the power system" is a critical parameter. In large systems, the load shedding can be set at a fairly high frequency level, and the time delay is normally not critical. In smaller systems the frequency START level has to be set at a lower value, and the time delay must be rather short.

7.2 Over frequency protection SAPTOF

7.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Over frequency protection	SAPTOF	$\boxed{f >}$	81

7.2.2 Application

Over frequency protection (SAPTOF) function is applicable in all situations, where reliable detection of high fundamental power system voltage frequency is needed. The power system frequency, and rate of change of frequency, is a measure of the unbalance between the actual generation and the load demand. High fundamental frequency in a power system indicates that the available generation is too large compared to the power demanded by the load connected to the power grid. SAPTOF detects such situations and provides an output signal, suitable for generator shedding, HVDC-set-point change and so on. SAPTOF is very sensitive and accurate and can also be used to alert operators that frequency has slightly deviated from the set-point, and that manual actions might be enough.

7.2.3 Setting guidelines

The parameters for Over frequency protection (SAPTOF) are set via local HMI or Protection and Control IED Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPTOF performs its functions must be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are especially two application areas for SAPTOF:

1. to protect equipment against damage due to high frequency, such as generators, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding generation, in generation surplus situations.

The over frequency start value is set in Hz. All voltage magnitude related settings are made as a percentage of a settable global base voltage parameter UBase.

SAPTOF is not instantaneous, since the frequency is related to movements of the system inertia, but the time and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Some applications and related setting guidelines for the frequency level are given below:

Equipment protection, such as for motors and generators

The setting must be above the highest occurring "normal" frequency and below the highest acceptable frequency for the equipment.

Power system protection, by generator shedding

The setting must be above the highest occurring "normal" frequency and below the highest acceptable frequency for power stations, or sensitive loads. The setting level, the number of levels and the distance between two levels (in time and/or in frequency) depend very much on the characteristics of the power system under consideration. The size of the "largest loss of load" compared to "the size of the power system" is a critical parameter. In large systems, the generator shedding can be set at a fairly low frequency level, and the time delay is normally not critical. In smaller systems the frequency START level has to be set at a higher value, and the time delay must be rather short.

7.3 Rate-of-change frequency protection SAPFRC

7.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Rate-of-change frequency protection	SAPFRC	$df/dt \gtrless$	81

7.3.2 Application

Rate-of-change frequency protection (SAPFRC), is applicable in all situations, where reliable detection of change of the fundamental power system voltage frequency is needed. SAPFRC can be used both for increasing frequency and for decreasing frequency. SAPFRC provides an output signal, suitable for load shedding or generator shedding, generator boosting, HVDC-set-point change, gas turbine start up, etc. Very often SAPFRC is used in combination with a low frequency signal, especially in smaller power systems, where loss of a fairly large generator will require quick remedial actions to secure the power system integrity. In such situations load shedding actions are required at a rather high frequency level, but in combination with a large negative rate-of-change of frequency the underfrequency protection can be used - at a rather high setting.

7.3.3 Setting guidelines

The parameters for Rate-of-change frequency protection (SAPFRC) are set via local HMI or Protection and Control IED Manager (PCM600).

All the frequency and voltage magnitude conditions in the system where SAPFRC performs its functions should be considered. The same also applies to the associated equipment, its frequency and time characteristic.

There are especially two application areas for SAPFRC:

1. to protect equipment against damage due to high or to low frequency, such as generators, transformers, and motors
2. to protect a power system, or a part of a power system, against breakdown, by shedding load or generation, in situations where load and generation are not in balance.

Rate-of-change frequency protection (SAPRFC) is normally used together with an over-frequency or under-frequency function, in small power systems, where a single event can cause a large imbalance between load and generation. In such situations load or generation shedding has to take place very quickly, and there might not be enough time to wait until the frequency signal has reached an abnormal value. Actions are therefore taken at a frequency level closer to the primary nominal level, if the rate-of-change of frequency is large (with respect to sign).

SAPFRC START value is set in Hz/s. All voltage magnitude related settings are made as a percentage of a settable base voltage, which normally is set to the primary nominal voltage level (phase-phase) of the power system or the high voltage equipment under consideration.

SAPFRC function is not instantaneous, since the function needs some time to supply a stable value. It is recommended to have a time delay long enough to take care of signal noise. However, the time, rate-of-change of frequency and frequency steps between different actions might be critical, and sometimes a rather short operation time is required, for example, down to 70 ms.

Smaller industrial systems might experience rate-of-change of frequency as large as 5 Hz/s, due to a single event. Even large power systems may form small islands with a large imbalance between load and generation, when severe faults (or combinations of faults) are cleared - up to 3 Hz/s has been experienced when a small island was isolated from a large system. For more "normal" severe disturbances in large power systems, rate-of-change of frequency is much less, most often just a fraction of 1.0 Hz/s.

Section 8 Secondary system supervision

8.1 Current circuit supervison CCSRDIF

8.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Current circuit supervision	CCSRDIF	-	-

8.1.2 Application

Open or short circuited current transformer cores can cause unwanted operation of many protection functions such as differential, earth fault current and negative sequence current functions. When currents from two independent 3-phase sets of CT's, or CT cores, measuring the same primary currents are available, reliable current circuit supervision can be arranged by comparing the currents from the two sets. If an error in any CT circuit is detected, the protection functions concerned can be blocked and an alarm given.

In case of large currents, unequal transient saturation of CT cores with different remanence or different saturation factor may result in differences in the secondary currents from the two CT sets. Unwanted blocking of protection functions during the transient stage must then be avoided.

Current circuit supervison (CCSRDIF) must be sensitive and have short operate time in order to prevent unwanted tripping from fast-acting, sensitive numerical protections in case of faulty CT secondary circuits.

Open CT circuits creates extremely high voltages in the circuits which may damage the insulation and cause new problems. The application shall, thus, be done with this in consideration, specially if protection functions are blocked.

8.1.3 Setting guidelines

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Current circuit supervison (CCSRDIF) compares the residual current from a three phase set of current transformer cores with the neutral point current on a separate input taken from another set of cores on the same current transformer.

The minimum operate current, *IMinOp*, must be set as a minimum to twice the residual current in the supervised CT circuits under normal service conditions and rated primary current.

The parameter *Ip>Block* is normally set at 150% in order to block the function during transient conditions.

The FAIL output is connected in the PCM configuration to the blocking input of the protection function to be blocked at faulty CT secondary circuits.

8.2 Fuse failure supervision SDDRFUF

8.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fuse failure supervision	SDDRFUF	-	-

8.2.2 Application

Different protection functions within the protection IED, operates on the basis of the measured voltage in the relay point. Examples are:

- distance protection function
- under/over-voltage function
- synchrocheck function and voltage check for the weak infeed logic.

These functions can operate unnecessarily if a fault occurs in the secondary circuits between the voltage instrument transformers and the IED.

It is possible to use different measures to prevent such unwanted operations. Miniature circuit breakers in the voltage measuring circuits, located as close as possible to the voltage instrument transformers, are one of them. Separate fuse-failure monitoring relays or elements within the protection and monitoring devices are another possibilities. These solutions are combined to get the best possible effect in the fuse failure supervision function (SDDRFUF).

The fuse-failure supervision function as built into the IED products can operate on the basis of external binary signals from the miniature circuit breaker or from the line disconnector. The first case influences the operation of all voltage-dependent functions while the second one does not affect the impedance measuring functions.

The negative sequence detection algorithm, based on the negative-sequence measuring quantities, a high value of voltage 3 U2 without the presence of the negative-sequence current 3 I2, is recommended for use in isolated or high-impedance earthed networks.

The zero sequence detection algorithm, based on the zero sequence measuring quantities, a high value of voltage $3U_0$ without the presence of the residual current $3I_0$, is recommended for use in directly or low impedance earthed networks. A criterion based on delta current and delta voltage measurements can be added to the fuse failure supervision function in order to detect a three phase fuse failure, which in practice is more associated with voltage transformer switching during station operations. In cases where the line can have a weak-infeed of zero sequence current this function shall be avoided.

A separate operation mode selector *OpMode* has been introduced for better adaptation to system requirements. The mode selector makes it possible to select interactions between the negative sequence and zero sequence algorithm. In normal applications the *OpMode* is set to either *UNsINs* for selecting negative sequence algorithm or *UZsIZs* for zero sequence based algorithm. If system studies or field experiences shows that there is a risk that the fuse failure function will not be activated due to the system conditions, the dependability of the fuse failure function can be increased if the *OpMode* is set to *UZsIZs OR UNsINs* or *OptimZsNs*. In mode *UZsIZs OR UNsINs* both the negative and zero sequence based algorithm is activated and working in an OR-condition. Also in mode *OptimZsNs* both the negative and zero sequence algorithm are activated and the one that has the highest magnitude of measured negative sequence current will operate.

If there is a requirement to increase the security of the fuse failure function *OpMode* can be selected to *UZsIZs AND UNsINs* which gives that both negative and zero sequence algorithm is activated working in an AND-condition, that is, both algorithm must give condition for block in order to activate the output signals BLKU or BLKZ.

8.2.3 Setting guidelines

8.2.3.1 General

The negative and zero sequence voltages and currents always exist due to different non-symmetries in the primary system and differences in the current and voltage instrument transformers. The minimum value for the operation of the current and voltage measuring elements must always be set with a safety margin of 10 to 20%, depending on the system operating conditions.

Pay special attention to the dissymmetry of the measuring quantities when the function is used on longer untransposed lines, on multicircuit lines and so on.

8.2.3.2 Setting of common parameters

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

The settings of negative sequence, zero sequence and delta algorithm are in percent of the global base voltage and global base current for the function, *UBase* and *IBase* respectively.

The voltage threshold *UPh>* is used to identify low voltage condition in the system. Set *UPh>* below the minimum operating voltage that might occur during emergency conditions. We propose a setting of approximately 70% of the global parameter *UBase*.

8.2.3.3 Negative sequence based

The setting of *3U2>* should not be set lower than according to equation 83.

$$3U2 >= \frac{\Delta U2}{UBase} \cdot 100$$

(Equation 83)

where:

ΔU2	is maximal negative sequence voltage during normal operation condition
UBase	is setting of the global base voltage for all functions in the IED.

The setting of the current limit *3I2>* is done in percentage of the global parameter *IBase*. The setting of *3I2>* must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 84.

$$3I2 >= \frac{\Delta I2}{IBase} \cdot 100$$

(Equation 84)

where:

ΔI2	is maximal negative sequence current during normal operating condition
IBase	is setting of base current for the function

8.2.3.4 Zero sequence based

The relay setting value *3U0>* is given in percentage of the global parameter *UBase*. The setting of *3U0>* should not be set lower than according to equation 85.

$$3U0 > = \Delta U0 \cdot \frac{100}{UBase}$$

(Equation 85)

where:

ΔU0	is maximal zero sequence voltage during normal operation condition
UBase	is setting of global base voltage all functions in the IED.

The setting of the current limit *3I0>* is done in percentage of the global parameter *IBase*. The setting of *3I0>* must be higher than the normal unbalance current that might exist in the system. The setting can be calculated according to equation 86.

$$3I0 > = \frac{\Delta I0}{IBase} \cdot 100$$

(Equation 86)

where:

ΔI0	is maximal zero sequence current during normal operating condition
IBase	is setting of global base current all functions in the IED.

8.2.3.5 du/dt and di/dt

The setting of du/dt is done in percentage of the global parameter *UBase*. The setting of *DU>* should be set high (approximately 60% of *UBase*) to avoid unwanted operation and the current threshold dI/dt low (approximately 10% of the global parameter *IBase*) but higher than the setting of *IMinOp* (the minimum operate current of the IED). It shall always be used together with either the negative or zero sequence algorithm. If USetprim is the primary voltage for operation of dU/dt and ISetprim the primary current for operation of dI/dt, the setting of *DU>* and *DI>* will be given according to equation 87 and equation 88.

$$DU > = \frac{USet_{prim}}{UBase} \cdot 100$$

(Equation 87)

$$DI > = \frac{ISet_{prim}}{IBase} \cdot 100$$

(Equation 88)

Set the operation mode selector *OperationDUDI* to *On* if the delta function shall be in operation.

The current threshold *IPh>* shall be set lower than the *IMinOp* for the distance protection function. A 5-10% lower value is recommended.

8.2.3.6 Dead line detection

The condition for operation of the dead line detection is set by the parameters *IDLD<* for the current threshold and *UDLD<* for the voltage threshold.

Set the *IDLD<* with a sufficient margin below the minimum expected load current. A safety margin of at least 15-20% is recommended. The operate value must however exceed the maximum charging current of an overhead line, when only one phase is disconnected (mutual coupling to the other phases).

Set the *UDLD<* with a sufficient margin below the minimum expected operating voltage. A safety margin of at least 15% is recommended.

8.3 Breaker close/trip circuit monitoring TCSSCBR

8.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip circuit supervision	TCSSCBR	-	-

8.3.2 Application

TCSSCBR detects faults in the electrical control circuit of the circuit breaker. The function can supervise both open and closed coil circuits. This kind of supervision is necessary to find out the vitality of the control circuits continuously.

Figure 56 shows an application of the trip-circuit supervision function use. The best solution is to connect an external R_{ext} shunt resistor in parallel with the circuit breaker internal contact. Although the circuit breaker internal contact is open, TCS can see the trip circuit through R_{ext}. The R_{ext} resistor should have such a resistance that the current through the resistance remains small, that is, it does not harm or overload the circuit breaker's trip coil.

Trip circuit supervision generates a current of approximately 1.0 mA through the supervised circuit. It must be ensured that this current will not cause a latch up of the controlled object.

To protect the trip circuit supervision circuits in the IED, the output contacts are provided with parallel transient voltage suppressors. The breakdown voltage of these suppressors is 400 +/– 20 V DC.

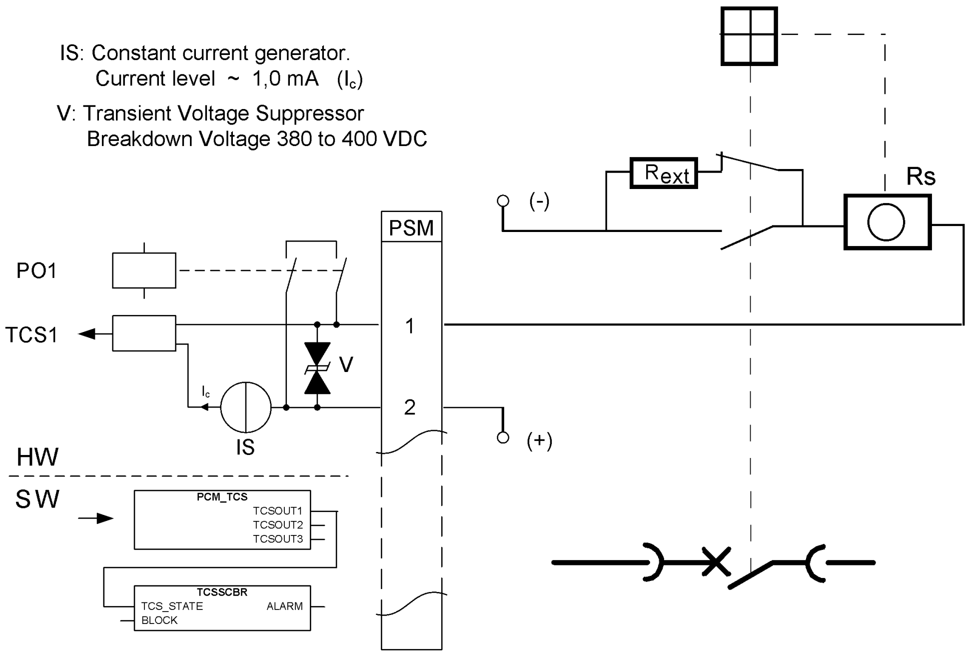


Figure 56: Operating principle of the trip-circuit supervision with an external resistor. The TCSSCBR blocking switch is not required since the external resistor is used.

If TCS is required only in a closed position, the external shunt resistance can be omitted. When the circuit breaker is in the open position, TCS sees the situation as a faulty circuit. One way to avoid TCS operation in this situation would be to block the supervision function whenever the circuit breaker is open.

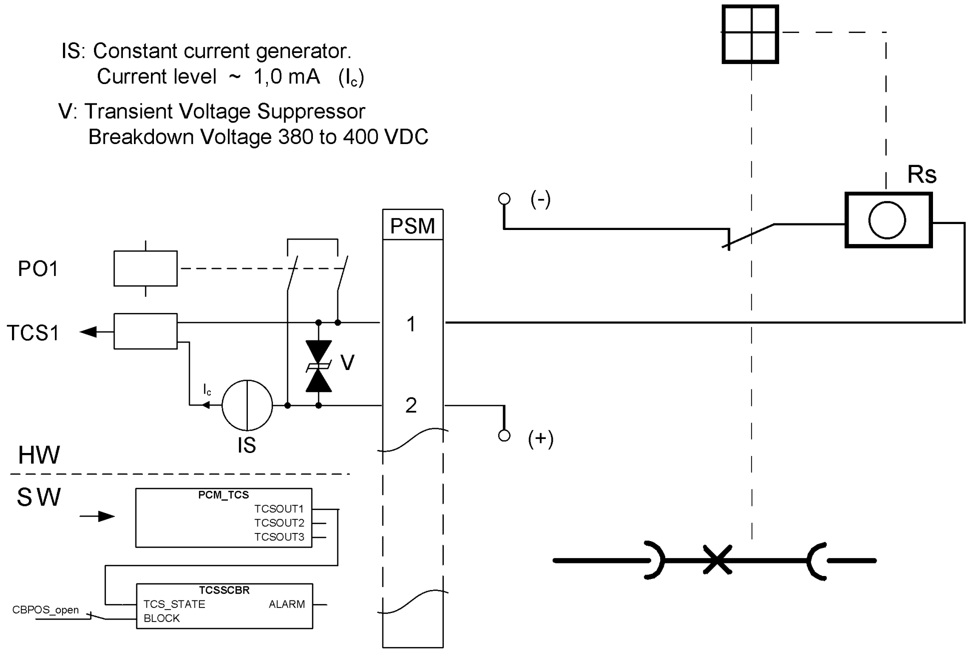


Figure 57: Operating principle of the trip-circuit supervision without an external resistor. The circuit breaker open indication is set to block TCSSCBR when the circuit breaker is open.

Trip-circuit supervision and other trip contacts

It is typical that the trip circuit contains more than one trip contact in parallel, for example in transformer feeders where the trip of a Buchholz relay is connected in parallel with the feeder terminal and other relays involved.

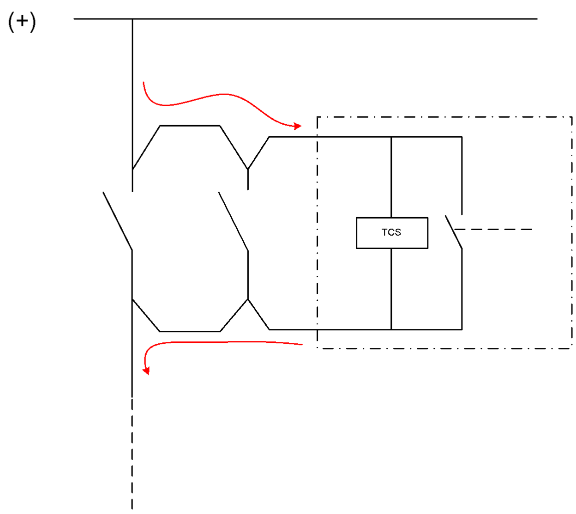


Figure 58: Constant test current flow in parallel trip contacts and trip-circuit supervision

Several trip-circuit supervision functions parallel in circuit

Not only the trip circuit often have parallel trip contacts, it is also possible that the circuit has multiple TCS circuits in parallel. Each TCS circuit causes its own supervising current to flow through the monitored coil and the actual coil current is a sum of all TCS currents. This must be taken into consideration when determining the resistance of R_{ext}.

Trip-circuit supervision with auxiliary relays

Many retrofit projects are carried out partially, that is, the old electromechanical relays are replaced with new ones but the circuit breaker is not replaced. This creates a problem that the coil current of an old type circuit breaker can be too high for the protection IED trip contact to break.

The circuit breaker coil current is normally cut by an internal contact of the circuit breaker. In case of a circuit breaker failure, there is a risk that the protection IED trip contact is destroyed since the contact is obliged to disconnect high level of electromagnetic energy accumulated in the trip coil.

An auxiliary relay can be used between the protection IED trip contact and the circuit breaker coil. This way the breaking capacity question is solved, but the TCS circuit in the protection IED monitors the healthy auxiliary relay coil, not the circuit breaker coil. The separate trip circuit supervision relay is applicable for this to supervise the trip coil of the circuit breaker.

Dimensioning of the external resistor

Under normal operating conditions, the applied external voltage is divided between the relay’s internal circuit and the external trip circuit so that at the minimum 10 V (3...10 V) remains over the relay’s internal circuit. Should the external circuit’s resistance be too high or the internal circuit’s too low, for example due to welded relay contacts, the fault is detected.

Mathematically, the operation condition can be expressed as:

$$U_c - (R_{ext} + R_s) \times I_c \geq 10V\ DC$$

(Equation 89)

U_c	Operating voltage over the supervised trip circuit
I_c	Measuring current through the trip circuit, appr. 1.0 mA (0.85...1.20 mA)
R_{ext}	external shunt resistance
R_s	trip coil resistance

If the external shunt resistance is used, it has to be calculated not to interfere with the functionality of the supervision or the trip coil. Too high a resistance causes too high a voltage drop, jeopardizing the requirement of at least 20 V over the internal circuit, while a resistance too low can enable false operations of the trip coil.

Table 13: Values recommended for the external resistor R_{ext}

Operating voltage U_c	Shunt resistor R_{ext}
48 V DC	10 kΩ, 5 W
60 V DC	22 kΩ, 5 W
110 V DC	33 kΩ, 5 W
220 V DC	68 kΩ, 5 W

Due to the requirement that the voltage over the TCS contact must be 20V or higher, the correct operation is not guaranteed with auxiliary operating voltages lower than 48V DC because of the voltage drop in the R_{ext} and operating coil or even voltage drop of the feeding auxiliary voltage system which can cause too low voltage values over the TCS contact. In this case, erroneous alarming can occur.

At lower (<48V DC) auxiliary circuit operating voltages, it is recommended to use the circuit breaker position to block unintentional operation of TCS. The use of the position indication is described earlier in this chapter.

Section 9 Control

9.1 Synchrocheck, energizing check, and synchronizing SESRSYN

9.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Synchrocheck, energizing check, and synchronizing	SESRSYN	sc/vc	25

9.1.2 Application

9.1.2.1 Synchronizing

To allow closing of breakers between asynchronous networks a synchronizing function is provided. The breaker close command is issued at the optimum time when conditions across the breaker are satisfied in order to avoid stress on the network and its components.

The systems are defined to be asynchronous when the frequency difference between bus and line is larger than an adjustable parameter. If the frequency difference is less than this threshold value the system is defined to have a parallel circuit and the synchrocheck function is used.

The synchronizing function measures the difference between the U-line and the U-bus. It operates and enables a closing command to the circuit breaker when the calculated closing angle is equal to the measured phase angle and the following conditions are simultaneously fulfilled:

- The voltages U-line and U-bus are higher than the standard preset minimum values for line and bus voltage.
- The difference in the voltage is smaller than the functions standard value.
- The difference in frequency is less than the set value of *FreqDiffMax* and larger than the set value of *FreqDiffMin*. If the frequency is less than *FreqDiffMin* the synchrocheck is used and the value of *FreqDiffMin* must thus be identical to the value *FreqDiffM* resp *FreqDiffA* for synchrocheck function. The bus and line frequencies must also be within a range of +/- 5 Hz from the rated frequency. When the synchronizing option is included also for auto-

reclose there is no reason to have different frequency setting for the manual and automatic reclosing and the frequency difference values for synchronism check should be kept low.
- The frequency rate of change is less than set value for both U-bus and U-line.
- The closing angle is decided by the calculation of slip frequency and required pre-closing time.

The synchronizing function compensates for measured slip frequency as well as the circuit breaker closing delay. The phase advance is calculated continuously. Closing angle is the change in angle during the set breaker closing operate time *tBreaker*.

The reference voltage can be phase-neutral L1, L2, L3 or phase-phase L1-L2, L2-L3, L3-L1. The bus voltage must then be connected to the same phase or phases as are chosen on the HMI or a compensation angle set to compensate for the difference.

9.1.2.2 Synchrocheck

The main purpose of the synchrocheck function is to provide control over the closing of circuit breakers in power networks in order to prevent closing if conditions for synchronism are not detected. It is also used to prevent the re-connection of two systems, which are divided after islanding and after a three pole reclosing.

Single pole auto-reclosing does not require any synchrocheck since the system is tied together by two phases.

Do not configure inputs LNQOPEN and LNQCLD, since they are not supported in the IED.

The synchrocheck function block includes both the synchronism check function and the energizing function to allow closing when one side of the breaker is dead. The synchrocheck function also includes a built in voltage selection scheme which allows simple application in all types of busbar arrangements.

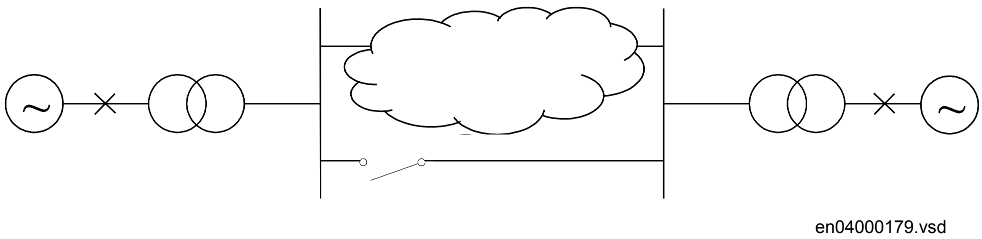


Figure 59: Two interconnected power systems

Figure 59 shows two interconnected power systems. The cloud means that the interconnection can be further away, that is, a weak connection through other stations. The need for a check of synchronization increases as the meshed system decreases since the risk of the two networks being out of synchronization at manual or automatic closing is greater.

The synchrocheck function measures the conditions across the circuit breaker and compares them to set limits. Output is generated only when all measured conditions are within their set limits simultaneously. The check consists of:

- Live line and live bus.
- Voltage level difference.
- Frequency difference (slip). The bus and line frequency must also be within a range of ±5 Hz from rated frequency.
- Phase angle difference.

A time delay is available to ensure that the conditions are fulfilled for a minimum period of time.

In very stable power systems the frequency difference is insignificant or zero for manually initiated closing or closing by automatic restoration. In steady conditions a bigger phase angle difference can be allowed as this is sometimes the case in a long and loaded parallel power line. For this application we accept a synchrocheck with a long operation time and high sensitivity regarding the frequency difference. The phase angle difference setting can be set for steady state conditions.

Another example, is when the operation of the power net is disturbed and high-speed auto-reclosing after fault clearance takes place. This can cause a power swing in the net and the phase angle difference may begin to oscillate. Generally, the frequency difference is the time derivative of the phase angle difference and will, typically oscillate between positive and negative values. When the circuit breaker needs to be closed by auto-reclosing after fault-clearance some frequency difference should be tolerated, to a greater extent than in the steady condition mentioned in the case above. But if a big phase angle difference is allowed at the same time, there is some risk that auto-reclosing will take place when the phase angle difference is big and increasing. In this case it should be safer to close when the phase angle difference is smaller.

To fulfill the above requirements the synchrocheck function is provided with duplicate settings, one for steady (Manual) conditions and one for operation under disturbed conditions (Auto).

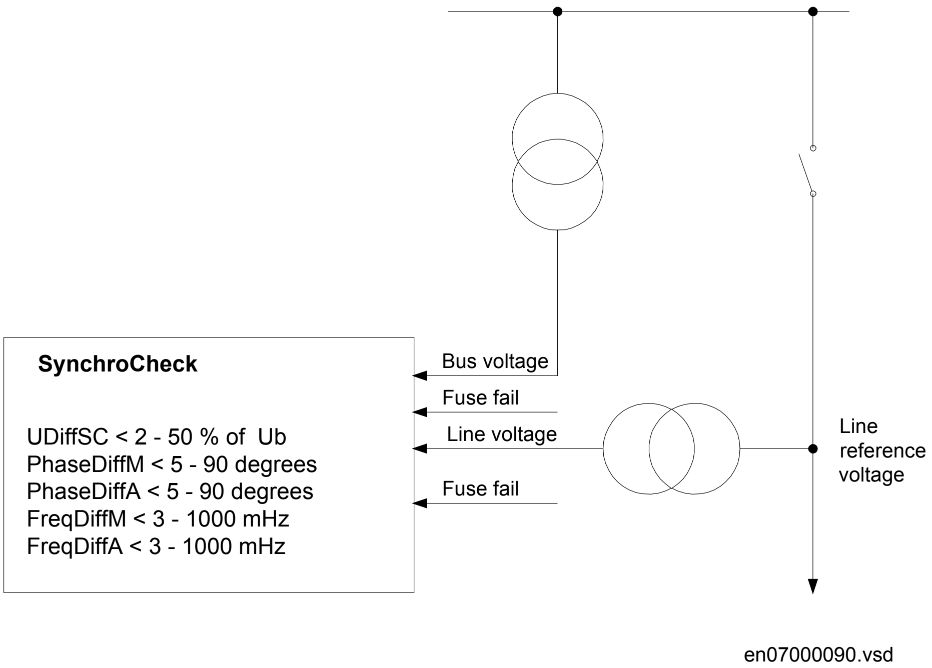


Figure 60: Principle for the synchrocheck function

9.1.2.3 Energizing check

The main purpose of the energizing check function is to facilitate the controlled re-connection of disconnected lines and buses to energized lines and buses.

The energizing check function measures the bus and line voltages and compares them to both high and low threshold values. The output is given only when the actual measured conditions match the set conditions. Figure 61 shows two power systems, where one (1) is energized and the other (2) is not energized. Power system 2 is energized (DLLB) from system 1 via the circuit breaker A.

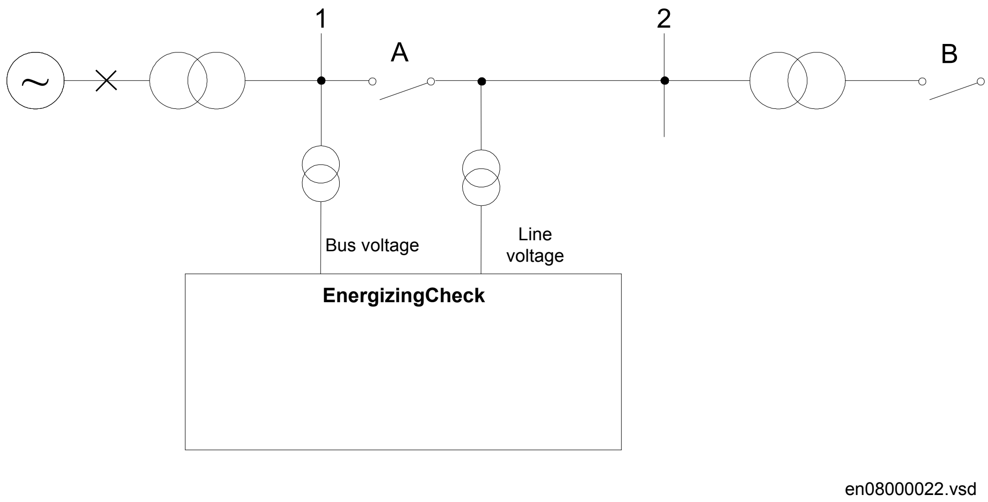


Figure 61: Principle for the energizing check function

The energizing operation can operate in the dead line live bus (DLLB) direction, dead bus live line (DBLL) direction, or in both directions over the circuit breaker. Energizing from different directions can be different for automatic reclosing and manual closing of the circuit breaker. For manual closing it is also possible to allow closing when both sides of the breaker are dead, Dead Bus Dead Line (DBDL).

The equipment is considered energized if the voltage is above a set value, for example, 80% of the base voltage, and non-energized if it is below a set value, for example, 30% of the base voltage. A disconnected line can have a considerable potential because of factors such as induction from a line running in parallel, or feeding via extinguishing capacitors in the circuit breakers. This voltage can be as high as 50% or more of the base voltage of the line. Normally, for breakers with single breaking elements (<330kV) the level is well below 30%.

When the energizing direction corresponds to the settings, the situation has to remain constant for a certain period of time before the close signal is permitted. The purpose of the delayed operate time is to ensure that the dead side remains de-energized and that the condition is not due to temporary interference.

9.1.2.4 Voltage selection

The voltage selection function is used for the connection of appropriate voltages to the synchrocheck and energizing check functions. For example, when the IED is used in a double bus arrangement, the voltage that should be selected depends on the status of the breakers and/or disconnectors. By checking the status of the disconnectors auxiliary contacts, the right voltages for the synchronizing, synchrocheck and energizing check functions can be selected.

The voltages from busbars and lines must be physically connected to the voltage inputs in the IED and connected, using the control software, to each of the maximum two synchrocheck functions available in the IED.

9.1.2.5 External fuse failure

External fuse-failure signals or signals from a tripped fuse switch/MCB are connected to binary inputs that are configured to inputs of the synchronizing functions in the IED. The internal fuse failure supervision module can also be used, for at least the line voltage supply. The signal FUSE-VTSU is then used and connected to the blocking input of the energizing check function block. In case of a fuse failure, thesynchronizing, synchrocheck and energizing check functions are blocked.

The UB1OK/UB2OK and UB1FF/UB2FF inputs are related to the busbar voltage and the ULNOK and ULNFF inputs are related to the line voltage.

External selection of energizing direction

The energizing can be selected by use of the available logic function blocks. Below is an example where the choice of mode is done from a symbol on the local HMI through selector switch function block, but alternatively there can for example, be a physical selector switch on the front of the panel which is connected to a binary to integer function block (B16I).

If the PSTO input is used, connected to the Local-Remote switch on the LHMI, the choice can also be from the station HMI system, typically ABB Microscada through IEC 61850 communication.

The connection example for selection of the manual energizing mode is shown in figure 62. Selected names are just examples but note that the symbol on LHMI can only show three signs.

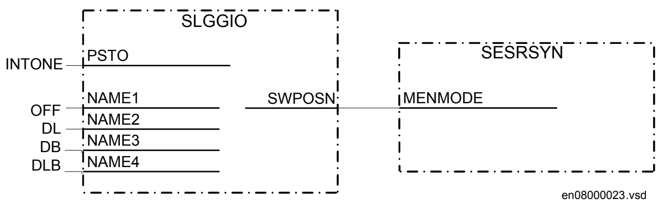


Figure 62: Selection of the energizing direction from a LHMI symbol through a selector switch function block.

9.1.3 Application examples

The synchronizing function block can also be used in some switchyard arrangements, but with different parameter settings. Below are some examples of how different arrangements are connected to the IED analogue inputs and to the function block (SESRSYN). One function block is used per circuit breaker. The IED can be provided with one or two function blocks.

The input used below in example are typical and can be changed by use of configuration and signal matrix tools.

9.1.3.1 Single circuit breaker with single busbar

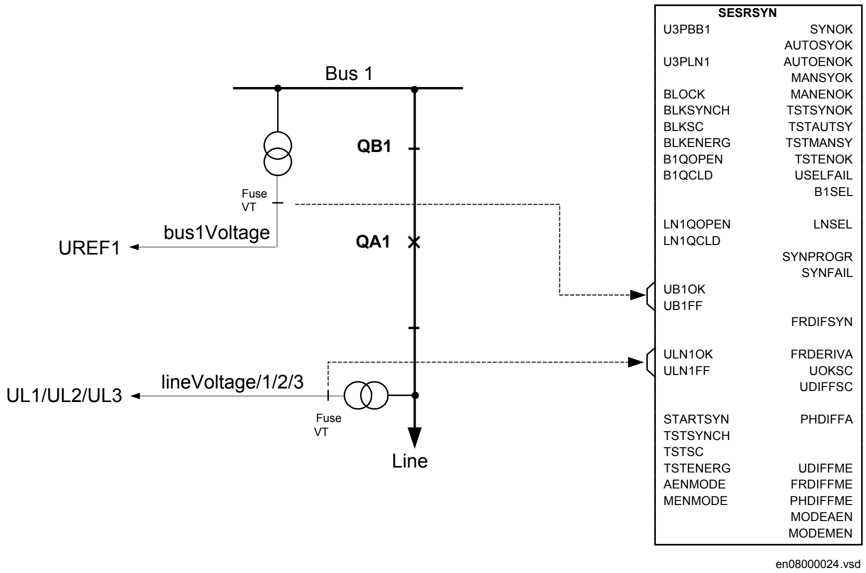


Figure 63: Connection of the Synchrocheck function block in a single busbar arrangement

Figure 63 illustrates connection principles. For the synchronizing and energizing check function (SESRSYN) there is one voltage transformer on each side of the circuit breaker. The voltage transformer circuit connections are straightforward; no special voltage selection is necessary. For the synchronizing and energizing check, the voltage from the busbar VT is connected to analog input UREF1 on the analog input module. The line voltage is connected as a three-phase voltage to the analog inputs UL1, UL2 and UL3.

9.1.3.2 Single circuit breaker with double busbar, external voltage selection

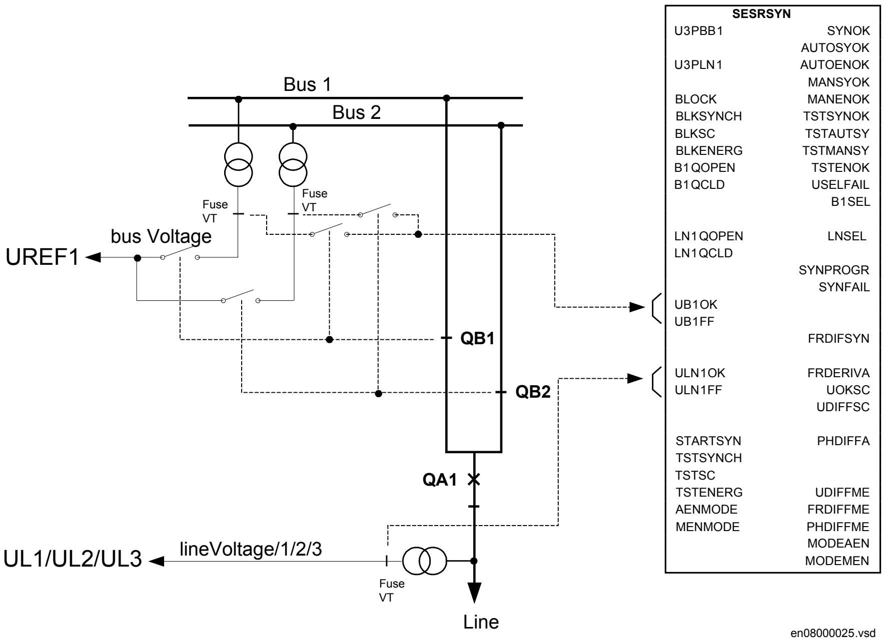


Figure 64: Connection of the Synchrocheck function block in a single breaker, double busbar arrangement with external voltage selection.

In this type of arrangement no internal voltage selection is required. The voltage selection is made by external relays typically connected according to figure 64. Suitable voltage and VT fuse failure supervision from the two busbars are selected based on the position of the busbar disconnectors. That means that the connections to the function block will be the same as for the single busbar arrangement.

9.1.3.3 Single circuit breaker with double busbar, internal voltage selection

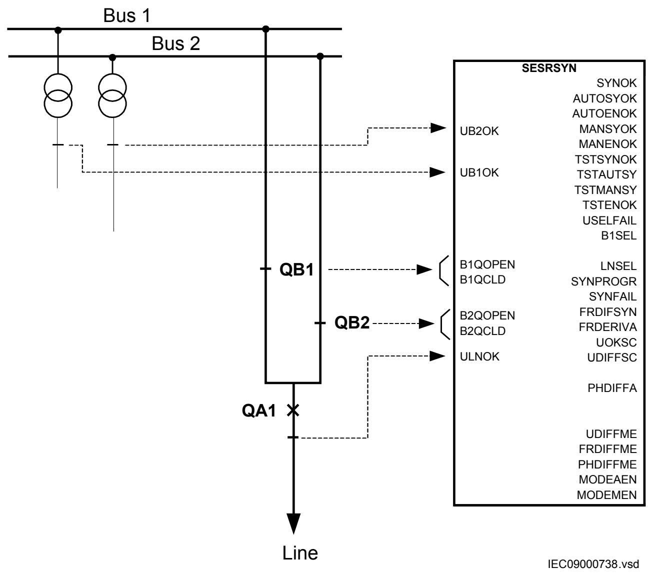


Figure 65: Connection of the Synchrocheck function block in a single breaker, double busbar arrangement with internal selection.

With the configuration according to figure 65, the voltage selection is made internally based on the signals from QB1 and QB2.

9.1.4 Setting guidelines

The setting parameters for the synchronizing, synchrocheck and energizing check function (SESRSYN) are set via the local HMI, or Protection and Control IED Manager (PCM600).

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation

The operation mode can be set *On/Off* from the PST. The setting *Off* disables the whole function.

SelPhaseBus1 and *SelPhaseBus2*

Configuration parameters for selection of measuring phase of the voltage for the busbar 1 and 2 respectively, which can be a single-phase (phase-neutral) or two-phase (phasephase) voltage.

SelPhaseLine1

Configuration parameters for selection of measuring phase of the voltage for the line, which can be a single-phase (phase-neutral) or two-phase (phase-phase) voltage.

PhaseShift

This setting is used to compensate for a phase shift caused by a line transformer between the two measurement points for bus voltage and line voltage. The set value is added to the measured line phase angle. The bus voltage is reference voltage.

URatio

The *URatio* is defined as *URatio=bus voltage/line voltage*. A typical use of the setting is to compensate for the voltage difference caused if one wishes to connect the bus voltage phase-phase and line voltage phase-neutral. The *SelPhaseBus1* setting should then be set to phase-phase and the *URatio* setting to *sqr3=1.73*. This setting scales up the line voltage to equal level with the bus voltage.

OperationSynch

The setting *Off* disables the Synchronizing function. With the setting *On*, the function is in service and the output signal depends on the input conditions.

FreqDiffMax

The setting *FreqDiffMax* is the maximum slip frequency at which synchronizing is accepted. 1/FreqDiffMax shows the time for the vector to move 360 degrees, one turn on the synchronoscope and is called the Beat time A typical value for the *FreqDiffMax* is 200-250 mHz which gives beat times on 4-5 seconds. Higher values should be avoided as the two networks normally are regulated to nominal frequency independent of each other so the frequency difference shall be small.

FreqDiffMin

The setting *FreqDiffMin* is the minimum frequency difference where the system are defined to be asynchronous. For frequency difference lower than this value the systems are considered to be in parallel. A typical value for the *FreqDiffMin* is 10 mHz. Generally the value should be low if both synchronizing and synchrocheck function is provided as it is better to let synchronizing function close as it will close at the exact right instance if the networks runs with a frequency difference. The syncrocheck function will at such a case close to the set phase angle difference value which can be 35 degrees from the correct angle.

Note! The *FreqDiffMin* shall be set to the same value as *FreqDiffM* resp *FreqDiffA* for the Synchrocheck function dependent of whether the functions are used for manual operation, auto-reclosing or both.

tBreaker

The *tBreaker* shall be set to match the closing time for the circuit breaker and should also include the possible auxiliary relays in the closing circuit. It is important to check that no slow logic components are used in the configuration of the IED as there then can be big variations in closing time due to those components. Typical setting is 80-150 ms depending on the breaker closing time.

tMinSynch

The *tMinSynch* is set to limit the minimum time at which synchronizing closing attempt is given. The setting will not give a closing should a condition fulfilled occur within this time from the synchronizing function is started. Typical setting is 200 ms.

tMaxSynch

The *tMaxSynch* is set to reset the operation of the synchronizing function if the operation does not take place within this time. The setting must allow for the setting of *FreqDiffMin* which will decide how long it will take maximum to reach phase equality. At a setting of 10ms the beat time is 100 seconds and the setting would thus need to be at least tMinSynch plus 100 seconds. If the network frequencies are expected to be outside the limits from start a margin needs to be added. Typical setting 300 seconds.

OperationSC

The *OperationSC* setting *Off* disables the synchrocheck function and sets the outputs AUTOSYOK, MANSYOK, TSTAUTSY and TSTMANSY to low.

With the setting *On*, the function is in service and the output signal depends on the input conditions.

UDiffSC

Setting for voltage difference between line and bus.

FreqDiffM and FreqDiffA

The frequency difference level settings, *FreqDiffM* and *FreqDiffA*, shall be chosen depending on the condition in the network. At steady conditions a low frequency difference setting is needed, where the *FreqDiffM* setting is used. Four auto-reclosing a bigger frequency difference setting is preferable, where the *FreqDiffA* setting is used. A typical value for the *FreqDiffM* can 10 mHz and a typical value for the *FreqDiffA* can be 100-200 mHz.

PhaseDiffM and PhaseDiffA

The phase angle difference level settings, *PhaseDiffM* and *PhaseDiffA*, shall also be chosen depending on conditions in the network. The phase angle setting must be chosen to allow closing under maximum load condition. A typical maximum value in heavy loaded networks can be 45 degrees whereas in most networks the maximum occurring angle is below 25 degrees.

tSCM and tSCA

The purpose of the timer delay settings, *tSCM* and *tSCA*, is to ensure that the synchrocheck conditions remains constant and that the situation is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the synchrocheck situation has remained constant throughout the set delay setting time. Under stable conditions a longer operation time delay setting is needed, where the *tSCM* setting is used. During auto-reclosing a shorter operation time delay setting is preferable, where the *tSCA* setting is used. A typical value for the *tSCM* may be 1 second and a typical value for the *tSCA* may be 0.1 second.

AutoEnerg and *ManEnerg*

Two different settings can be used for automatic and manual closing of the circuit breaker. The settings for each of them are:

- *Off*, the energizing function is disabled.
- *DLLB*, Dead Line Live Bus, the line voltage is below a standard value.
- *DBLL*, Dead Bus Live Line, the bus voltage is below a standard value.
- *Both*, energizing can be done in both directions, *DLLB* or *DBLL*.

tAutoEnerg and *tManEnerg*

The purpose of the timer delay settings, *tAutoEnerg* and *tManEnerg*, is to ensure that the dead side remains de-energized and that the condition is not due to a temporary interference. Should the conditions not persist for the specified time, the delay timer is reset and the procedure is restarted when the conditions are fulfilled again. Circuit breaker closing is thus not permitted until the energizing condition has remained constant throughout the set delay setting time.

ManEnergDBDL

If the parameter is set to *On*, manual closing is enabled.

9.2 Autorecloser SMBRREC

9.2.1 Identification

Function Description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Autorecloser	SMBRREC	O->I	79

9.2.2 Application

Automatic reclosing is a well-established method for the restoration of service in a power system after a transient line fault. The majority of line faults are flashover arcs, which are transient by nature. When the power line is switched off by the operation of line protection and line breakers, the arc de-ionizes and recovers its ability to withstand voltage at a somewhat variable rate. Thus, a certain dead time with a de-energized line is necessary. Line service can then be resumed by automatic reclosing of the line breakers. The dead time selected should be long enough to ensure a high probability of arc de-ionization and successful reclosing.

For individual line breakers, auto-reclosing equipment or functions, the auto-reclosing open time is used to determine line “dead time”. When simultaneous tripping and reclosing at the two line ends occurs, auto-reclosing open time is approximately equal to the line “dead time”. If the open time and dead time differ then, the line will be energized until the breakers at both ends have opened.

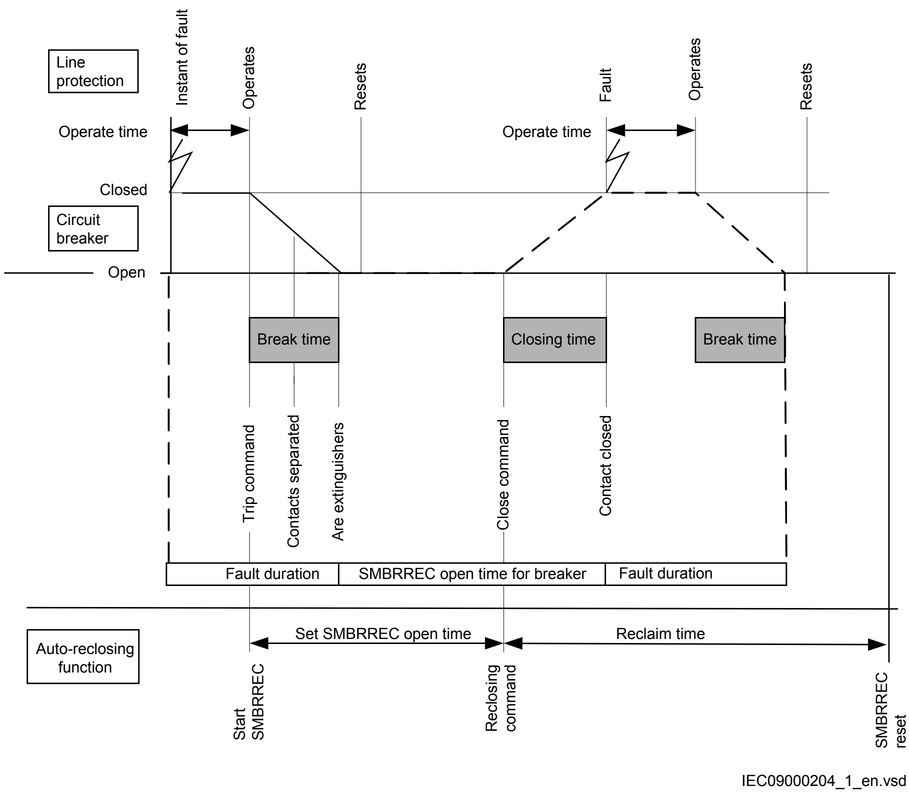


Figure 66: Single-shot automatic reclosing at a permanent fault

Three-phase automatic reclosing can be performed with or without the use of a synchrocheck, and an energizing check, such as dead line or dead busbar check.

For the individual line breakers and auto-reclosing equipment, the ”auto-reclosing open time” expression is used. This is the dead time setting for the Auto-Recloser. During simultaneous tripping and reclosing at the two line ends, auto-reclosing open time is approximately equal to the line dead time. Otherwise these two times may differ as one line end might have a slower trip than the other end which means that the line will not be dead until both ends have opened.

If the fault is permanent, the line protection will trip again when reclosing is attempted in order to clear the fault.

It is common to use one automatic reclosing function per line circuit-breaker (CB). When one CB per line end is used, then there is one auto-reclosing function per line end. If auto-reclosing functions are included in duplicated line protection, which means two auto-reclosing functions per CB, one should take measures to avoid uncoordinated reclosing commands. In 1 1/2 breaker, double-breaker and ring bus arrangements, two CBs per line end are operated. One auto-reclosing function per CB is recommended. Arranged in such a way, sequential reclosing of the two CBs can be arranged with a priority circuit available in the auto-reclose function. In case of a permanent fault and unsuccessful reclosing of the first CB, reclosing of the second CB is cancelled and thus the stress on the power system is limited. Another advantage with the breaker connected auto-recloser is that checking that the breaker closed before the sequence, breaker prepared for an auto-reclose sequence etc. is much simpler.

The auto-reclosing function performs three-phase automatic-reclosing with single-shot or multiple-shots.

In power transmission systems it is common practise to apply single and/or three phase, single-shot Auto-Reclosing. In Sub-transmission and Distribution systems tripping and auto-reclosing are usually three-phase. The mode of automatic-reclosing varies however. Single-shot and multi-shot are in use. The first shot can have a short delay, HSAR, or a longer delay, DAR. The second and following reclosing shots have a rather long delay. When multiple shots are used the dead time must harmonize with the breaker duty-cycle capacity.

Automatic-reclosing is usually started by the line protection and in particular by instantaneous tripping of such protection. The auto-reclosing function can be inhibited (blocked) when certain protection functions detecting permanent faults, such as shunt reactor, cable or busbar protection are in operation. Back-up protection zones indicating faults outside the own line are also connected to inhibit the Auto-Reclose.

Automatic-reclosing should not be attempted when closing a CB and energizing a line onto a fault (SOTF), except when multiple-shots are used where shots 2 etc. will be started at SOTF. Likewise a CB in a multi-breaker busbar arrangement which was not closed when a fault occurred should not be closed by operation of the Auto-Reclosing function. Auto-Reclosing is often combined with a release condition from synchrocheck and dead line or dead busbar check. In order to limit the stress on turbo-generator sets from Auto-Reclosing onto a permanent fault, one can arrange to combine Auto-Reclosing with a synchrocheck on line terminals close to such power stations and attempt energizing from the side furthest away from the power station and perform the synchrocheck at the local end if the energizing was successful.

Transmission protection systems are usually sub-divided and provided with two redundant protection IEDs. In such systems it is common to provide auto-reclosing in only one of the sub-systems as the requirement is for fault clearance and a failure to reclose because of the auto-recloser being out of service is not considered a major disturbance. If two auto-reclosers are provided on the same breaker, the application must be carefully checked and normally one must be the master and be connected to inhibit the other auto-recloser if it has started. This inhibit can for example be done from SMBRREC In progress.

A permanent fault will cause the line protection to trip again when it recloses in an attempt to clear the fault.

The auto-reclosing function allows a number of parameters to be adjusted.

Examples:

- number of auto-reclosing shots
- auto-reclosing open times (dead time) for each shot

9.2.2.1 Auto-reclosing operation Off and On

Operation of the automatic reclosing can be set OFF and ON by a setting parameter and by external control. Parameter *Operation= Off*, or *On* sets the function OFF and ON. In setting *Operation=ExternalCtrl* OFF and ON control is made by input signal pulses, for example, from the control system or from the binary input (and other systems).

When the function is set ON and operative (other conditions such as CB closed and CB Ready are also fulfilled), the output SETON is activated (high). When the function is ready to accept a reclosing start.

9.2.2.2 Start auto-reclosing and conditions for start of a reclosing cycle

The usual way to start a reclosing cycle, or sequence, is to start it at tripping by line protection by applying a signal to the input START. Starting signals can be either, General Trip signals or, only the conditions for Differential, Distance protection Zone 1 and Distance protection Aided trip. In some cases also Directional Earth fault function Aided trip can be connected to start an Auto-Reclose attempt.

A number of conditions need to be fulfilled for the start to be accepted and a new auto-reclosing cycle to be started. They are linked to dedicated inputs. The inputs are:

- CBREADY, CB ready for a reclosing cycle, for example, charged operating gear.
- CBPOS to ensure that the CB was closed when the line fault occurred and start was applied.
- No signal at input INHIBIT that is, no blocking or inhibit signal present. After the start has been accepted, it is latched in and an internal signal “Started” is set. It can be interrupted by certain events, like an “Inhibit” signal.

9.2.2.3 Start auto-reclosing from CB open information

If a user wants to initiate auto-reclosing from the "CB open" position instead of from protection trip signals, the function offers such a possibility. This starting mode is selected with the setting parameter *StartByCBOpen=On*. It is then necessary to block reclosing for all manual trip operations. Typically *CBAuxContType=NormClosed* is also set and a CB auxiliary contact of type NC (normally closed) is connected to inputs CBPOS and START. When the signal changes from “CB closed” to “CB open” an auto-reclosing start pulse is generated and latched in the function, subject to the usual checks. Then the reclosing sequence continues as usual. One needs to connect signals from manual tripping and other functions, which shall prevent reclosing, to the input INHIBIT.

9.2.2.4 Blocking of the autorecloser

Auto-Reclose attempts are expected to take place only in the event of transient faults on the own line. The Auto-Recloser must be blocked for the following conditions:

- Tripping from Delayed Distance protection zones
- Tripping from Back-up protection functions
- Tripping from Breaker failure function
- Intertrip received from remote end Breaker failure function
- Busbar protection tripping

Depending of the starting principle (General Trip or only Instantaneous trip) adopted above the delayed and back-up zones might not be required. Breaker failure local and remote must however always be connected.

9.2.2.5 Control of the auto-reclosing open time

There are settings for the three-phase auto-reclosing open time, *t1 3Ph to t5 3Ph*.

9.2.2.6 Long trip signal

In normal circumstances the trip command resets quickly because of fault clearance. The user can set a maximum trip pulse duration *tTrip*. A long trip signal interrupts the reclosing sequence in the same way as a signal to input INHIBIT.

9.2.2.7 Maximum number of reclosing shots

The maximum number of reclosing shots in an auto-reclosing cycle is selected by the setting parameter *NoOfShots*.

9.2.2.8 3-phase reclosing, one to five shots according to setting NoOfShots.

While any of the auto-reclosing open time timers are running, the output INPROGR is activated. When the "open time" timer runs out, the respective internal signal is transmitted to the output module for further checks and to issue a closing command to the circuit breaker.

When issuing a CB closing command a “reclaim” timer tReclaim is started. If no tripping takes place during that time the auto-reclosing function resets to the “Ready” state and the signal ACTIVE resets. If the first reclosing shot fails, 2nd to 5th reclosing shots will follow, if selected.

9.2.2.9 Reclosing reclaim timer

The reclaim timer *tReclaim* defines the time it takes from issue of the reclosing command, until the reclosing function resets. Should a new trip occur during this time, it is treated as a continuation of the first fault. The reclaim timer is started when the CB closing command is given.

9.2.2.10 Transient fault

After the Reclosing command the reclaim timer keeps running for the set time. If no tripping occurs within this time, *tReclaim*, the Auto-Reclosing will reset. The CB remains closed and the operating gear recharges. The input signals CBPOS and CBREADY will be set

9.2.2.11 Permanent fault and reclosing unsuccessful signal

If a new trip occurs, and a new input signal START or TRSOTF appears, after the CB closing command, the output UNSUCCL (unsuccessful closing) is set high. The timer for the first shot can no longer be started. Depending on the set number of Reclosing shots further shots may be made or the Reclosing sequence is ended. After reclaim timer time-out the Auto-Reclosing function resets, but the CB remains open. The “CB closed” information through the input CBPOS is missing. Thus, the reclosing function is not ready for a new reclosing cycle.

Normally, the signal UNSUCCL appears when a new trip and start is received after the last reclosing shot has been made and the auto-reclosing function is blocked. The signal resets after reclaim time. The “unsuccessful” signal can also be made to depend on CB position input. The parameter *UnsucClByCBChk* should then be set to *CBCheck*, and a timer *tUnsucCl* should be set too. If the CB does not respond to the closing command and does not close, but remains open, the output UNSUCCL is set high after time *tUnsucCl*. The Unsuccessful output can for example, be used in Multi-Breaker arrangement to cancel the auto-reclosing function for the second breaker, if the first breaker closed onto a persistent fault. It can also be used to generate a Lock-out of manual closing until the operator has reset the Lock-out, see separate section.

9.2.2.12 Lock-out initiation

In many cases there is a requirement that a Lock-out is generated when the Auto-Reclosing attempt fails. This is done with logic connected to the in- and outputs of the Auto-Reclose function and connected to Binary IO as required. Many alternative ways of performing the logic exist depending on whether manual closing is interlocked in the IED, whether an external physical Lock-out relay exists and whether the reset is hardwired, or carried out by means of communication. There are also different alternatives regarding what shall generate Lock-out. Examples of questions are:

- Shall back-up time delayed trip give Lock-out (normally yes)
- Shall Lock-out be generated when closing onto a fault (mostly)
- Shall Lock-out be generated when the Auto-Recloser was OFF at the fault
- Shall Lock-out be generated if the Breaker did not have sufficient operating power for an Auto-Reclosing sequence (normally not as no closing attempt has been given)

In figures 67 and 68 the logic shows how a closing Lock-out logic can be designed with the Lock-out relay as an external relay alternatively with the Lock-out created internally with the Manual closing going through the Synchro-check function. An example of Lock-out logic.

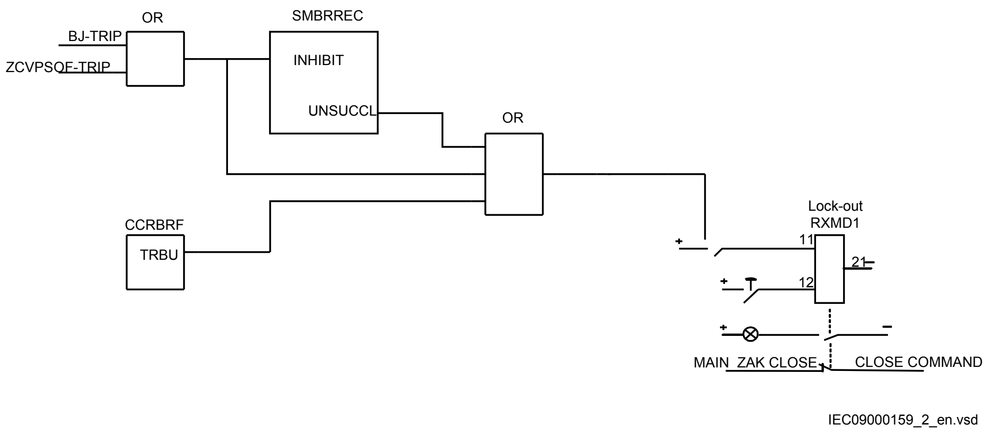


Figure 67: Lock-out arranged with an external Lock-out relay.

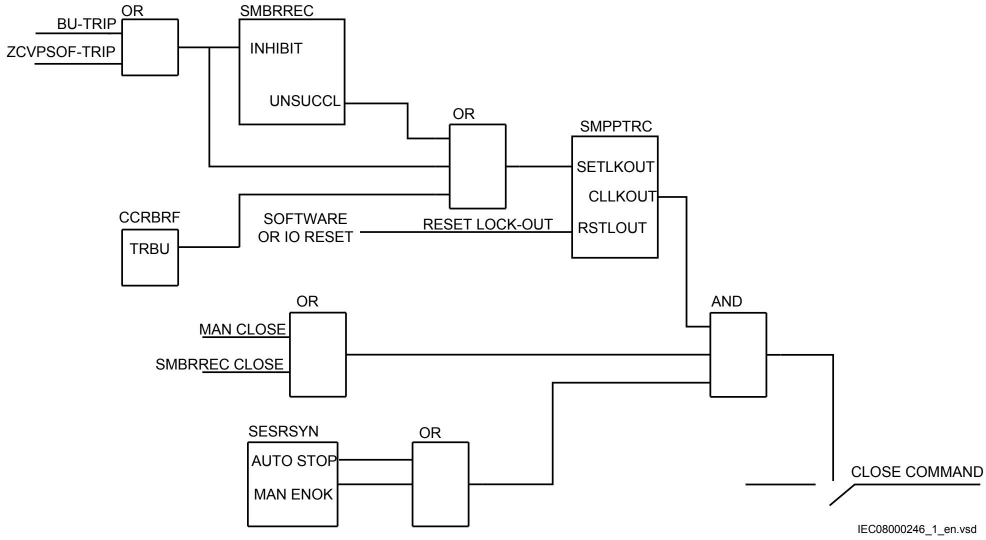


Figure 68: Lock-out arranged with internal logic with manual closing going through in IED

9.2.2.13 Automatic continuation of the reclosing sequence

The Auto-Reclosing function can be programmed to proceed to the following reclosing shots (if multiple shots are selected) even if start signals are not received from the protection functions, but the breaker is still not closed. This is done by setting parameter *AutoCont = On and tAutoContWait* to the required delay for the function to proceed without a new start.

9.2.2.14 Thermal overload protection holding the auto-reclosing function back

If the input THOLHOLD (thermal overload protection holding reclosing back) is activated, it will keep the reclosing function on a hold until it is reset. There may thus be a considerable delay between start of Auto-Reclosing and reclosing command to the circuit-breaker. An external logic limiting the time and sending an inhibit to the INHIBIT input can be used. The input can also be used to set the Auto-Reclosing on hold for a longer or shorter period.

9.2.3 Setting guidelines

9.2.3.1 Configuration

Use the PCM600 configuration tool to configure signals.

Autorecloser function parameters are set via the local HMI or Parameter Setting Tool (PST). Parameter Setting Tool is a part of PCM600.

Recommendations for input signals

Please see examples in figure 69.

ON and OFF

These inputs can be connected to binary inputs or to a communication interface block for external control.

START

It should be connected to the trip output protection function, which starts the auto-reclosing function. It can also be connected to a binary input for start from an external contact. A logical OR-gate can be used to combine the number of start sources.

If *StartByCBOpen* is used, the CB Open condition shall also be connected to the input START.

INHIBIT

To this input shall be connected signals that interrupt a reclosing cycle or prevent a start from being accepted. Such signals can come from protection for a line connected shunt reactor, from transfer trip receive, from back-up protection functions, busbar protection trip or from breaker failure protection. When the CB open position is set to start the Auto-Recloser, then manual opening must also be connected here. The inhibit is often a combination of signals from external IEDs via the IO and internal functions. An OR gate is then used for the combination.

CBPOS and CBREADY

These should be connected to binary inputs to pick-up information from the CB. The CBPOS input is interpreted as CB Closed, if parameter *CBAuxContType* is set *NormOpen*, which is the default setting. At three operating gears in the breaker (single pole operated breakers) the connection should be “All poles closed” (series connection of the NO contacts) or “At least one pole open” (parallel connection of NC contacts) if the *CBAuxContType* is set to *NormClosed*. The “CB Ready” is a signal meaning that the CB is ready for a reclosing operation, either Close-Open (CO), or Open-Close-Open (OCO). If the available signal is of type “CB not charged” or “not ready”, an inverter can be inserted in front of the CBREADY input.

SYNC

This is connected to the internal synchrocheck function when required. It can also be connected to a binary input for synchronization from an external device. If neither internal nor external synchronism or energizing check is required, it can be connected to a permanently high source, TRUE. The signal is required for three phase shots 1-5 to proceed .

TRSOTF

This is the signal "Trip by Switch Onto Fault". It is usually connected to the "switch onto fault" output of line protection if multi-shot Auto-Reclose attempts are used. The input will start the shots 2-5. For single shot applications the input is set to FALSE.

THOLHOLD

Signal "Thermal overload protection holding back Auto-Reclosing". It is normally set to FALSE. It can be connected to a thermal overload protection trip signal which resets only when the thermal content has gone down to an acceptable level, for example, 70%. As long as the signal is high, indicating that the line is hot, the Auto-Reclosing is held back. When the signal resets, a reclosing cycle will continue. Please observe that this have a considerable delay. Input can also be used for other purposes if for some reason the Auto-Reclose shot is halted.

WAIT

Used to hold back reclosing of the "low priority unit" during sequential reclosing. See "Recommendation for multi-breaker arrangement" below. The signal is activated from output WFMASTER on the second breaker Auto-Recloser in multi-breaker arrangements.

BLKON

Used to block the Auto-Reclosing function for example, when certain special service conditions arise. Input is normally set to FALSE. When used, blocking must be reset with BLOCKOFF.

BLOCKOFF

Used to Unblock the Auto-Reclosing function when it has gone to Block due to activating input BLKON or by an unsuccessful Auto-Reclose attempt if the setting *BlockUnsuc* is set to On. Input is normally set to FALSE.

RESET

Used to Reset the Auto-Recloser to start condition. Possible Thermal overload Hold etc. will be reset. Positions, setting On-Off etc. will be started and checked with set times. Input is normally set to FALSE.

Recommendations for output signals

Please see figure 69.

SETON

Indicates that the auto-reclose function is switched *On* and operative.

BLOCKED

Indicates that the auto-reclose function is temporarily or permanently blocked.

ACTIVE

Indicates that SMBRREC is active, from start until end of Reclaim time.

INPROGR

Indicates that a sequence is in progress, from start until reclosing command.

UNSUCCL

Indicates unsuccessful reclosing.

CLOSECB

Connect to a binary output for circuit-breaker closing command.

READY

Indicates that the Auto-reclosing function is ready for a new and complete reclosing sequence. It can be connected to the zone extension of a line protection should extended zone reach before automatic reclosing be necessary.

3PT1,-3PT2,-3PT3,-3PT4 and -3PT5

Indicates that three-phase automatic reclosing shots 1-5 are in progress. The signals can be used as an indication of progress or for own logic.

WFMASTER

Wait from master is used in high priority units to hold back reclosing of the low priority unit during sequential reclosing.

Other outputs

The other outputs can be connected for indication, disturbance recording etc. as required.

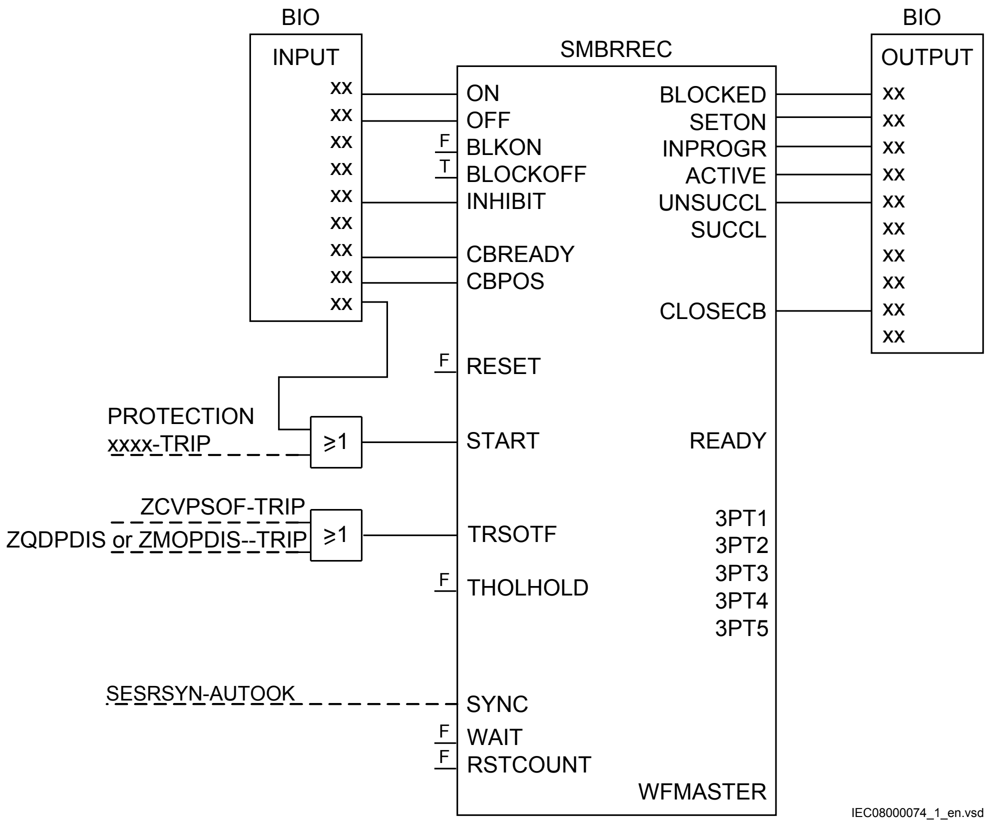


Figure 69: Example of I/O-signal connections at a three-phase reclosing function

9.2.3.2 Auto-recloser parameter settings

Operation

The operation of the Auto-reclose function can be switched on and off. The setting “external control” makes it possible to switch it on or off using an external switch via IO or communication ports.

NoOfShots, Number of reclosing shots

In sub-transmission 1 shot is mostly used. In most cases one reclosing shot is sufficient as the majority of arcing faults will cease after the first reclosing shot. In power systems with many other types of faults caused by other phenomena, for example wind, a greater number of reclose attempts (shots) can be motivated.

Auto-reclosing open times, dead times

Three-phase shot 1 delay: For three-phase High-Speed Auto-Reclosing (HSAR) a typical open time is 400 ms. Different local phenomena, such as moisture, salt, pollution etc. can influence the required dead time. Some users apply Delayed Auto-Reclosing (DAR) with delays of 10 s or more. The delay of reclosing shot 2 and possible later shots are usually set at 30 s or more. A check that the CB duty cycle can manage the selected setting must be done. The setting can in some cases be restricted by national regulations. For multiple shots the setting of shots 2-5 must be longer than the circuit breaker duty cycle time.

tSync, Maximum wait time for synchronizationcheck

The time window should be coordinated with the operate time and other settings of the synchronization check function. Attention should also be paid to the possibility of a power swing when reclosing after a line fault. Too short a time may prevent a potentially successful reclosing. A typical setting may be 2.0 s.

tTrip, Long trip pulse

Usually the trip command and start auto-reclosing signal reset quickly as the fault is cleared. A prolonged trip command may depend on a CB failing to clear the fault. A trip signal present when the CB is reclosed will result in a new trip. At a setting somewhat longer than the auto-reclosing open time, this facility will not influence the reclosing. A typical setting of *tTrip* could be close to the auto-reclosing open time.

tInhibit, Inhibit resetting delay

A typical setting is *tInhibit = 5.0 s* to ensure reliable interruption and temporary blocking of the function. Function will be blocked during this time after the *tinhibit* has been activated.

tReclaim, Reclaim time

The Reclaim time sets the time for resetting the function to its original state, after which a line fault and tripping will be treated as an independent new case with a new reclosing cycle. One may consider a nominal CB duty cycle of for instance, O-0.3sec CO- 3 min. – CO. However the 3 minute (180 s) recovery time is usually not critical as fault levels are mostly lower than rated value and the risk of a new fault within a short time is negligible. A typical time may be *tReclaim = 60 or 180 s* dependent of the fault level and breaker duty cycle.

StartByCBOpen

The normal setting is Off. It is used when the function is started by protection trip signals *Follow CB = Off*, *Follow CB = On*.

FollowCB

The usual setting is *Follow CB = Off*. The setting “ON” can be used for delayed reclosing with long delay, to cover the case when a CB is being manually closed during the “auto-reclosing open time” before the auto-reclosing function has issued its CB closing command.

tCBClosedMin

A typical setting is 5.0 s. If the CB has not been closed for at least this minimum time, a reclosing start will not be accepted.

CBAuxContType, CB auxiliary contact type

It shall be set to correspond to the CB auxiliary contact used. A NormOPen contact is recommended in order to generate a positive signal when the CB is in the closed position.

CBReadyType, Type of CB ready signal connected

The selection depends on the type of performance available from the CB operating gear. At setting “OCO” (CB ready for an Open – Close – Open cycle), the condition is checked only at the start of the reclosing cycle. The signal will disappear after tripping, but the CB will still be able to perform the C-O sequence. For the selection “CO” (CB ready for a Close – Open cycle) the condition is also checked after the set auto-reclosing dead time. This selection has a value first of all at multi-shot reclosing to ensure that the CB is ready for a C-O sequence at shot 2 and further shots. During single-shot reclosing, the “OCO” selection can be used. A breaker shall according to its duty cycle always have storing energy for a CO operation after the first trip. (IEC 56 duty cycle is O-0.3secCO-3minCO).

tPulse, Breaker closing command pulse duration

The pulse should be long enough to ensure reliable operation of the CB. A typical setting may be *tPulse=200 ms*. A longer pulse setting may facilitate dynamic indication at testing, for example in “Debug” mode of PCM600 Application Configuration Tool (ACT) .

BlockUnsuc

Setting of whether an Unsuccessful Auto-Reclose attempt shall set the Auto-Reclose in Block. If used the inputs BLKOFF must be configured to unblock the function after an unsuccessful Reclosing attempt. Normal setting is Off.

UnsucClByCBCheck, Unsuccessful closing by CB check

The normal setting is *NoCBCheck*. The “auto-reclosing unsuccessful” event is then decided by a new trip within the reclaim time after the last reclosing shot. If one wants to get the UNSUCCL (Unsuccessful closing) signal in the case the CB does not respond to the closing command, CLOSECB, one can set *UnsucClByCBCheck= CBCheck* and set *tUnsucCl* for instance to 1.0 s.

Priority and time tWaitForMaster

In single CB applications, one sets *Priority = None*. At sequential reclosing the function of the first CB, e.g. near the busbar, is set *Priority = High* and for the second CB *Priority = Low*. The maximum waiting time, *tWaitForMaster* of the second CB is set longer than the “auto-reclosing open time” and a margin for synchrocheck at the first CB. Typical setting is *tWaitForMaster=2sec*.

AutoCont and tAutoContWait, Automatic continuation to the next shot if the CB is not closed within the set time

The normal setting is *AutoCont = OFF*. The *tAutoContWait* is the length of time SMBRREC waits to see if the breaker is closed when *AutoCont* is set to On. Normally the setting can be *tAutoContWait = 2 sec*.

9.3 Apparatus control APC

9.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Switch controller	SCSWI	-	-
Circuit breaker	SXCBR	-	-
Circuit switch	SXSWI	-	-
Position evaluation	POS_EVAL	-	-
Select release	SELGGIO	-	-
Bay control	QCBAY	-	-
Local remote	LOCREM	-	-
Local remote control	LOCREMCTRL	-	-

9.3.2 Application

The apparatus control is a function for control and supervising of circuit breakers, disconnectors, and earthing switches within a bay. Permission to operate is given after evaluation of conditions from other functions such as interlocking, synchrocheck, operator place selection and external or internal blockings.

Figure 70 gives an overview from what places the apparatus control function receive commands. Commands to an apparatus can be initiated from the Control Centre (CC), the station HMI or the local HMI on the IED front.

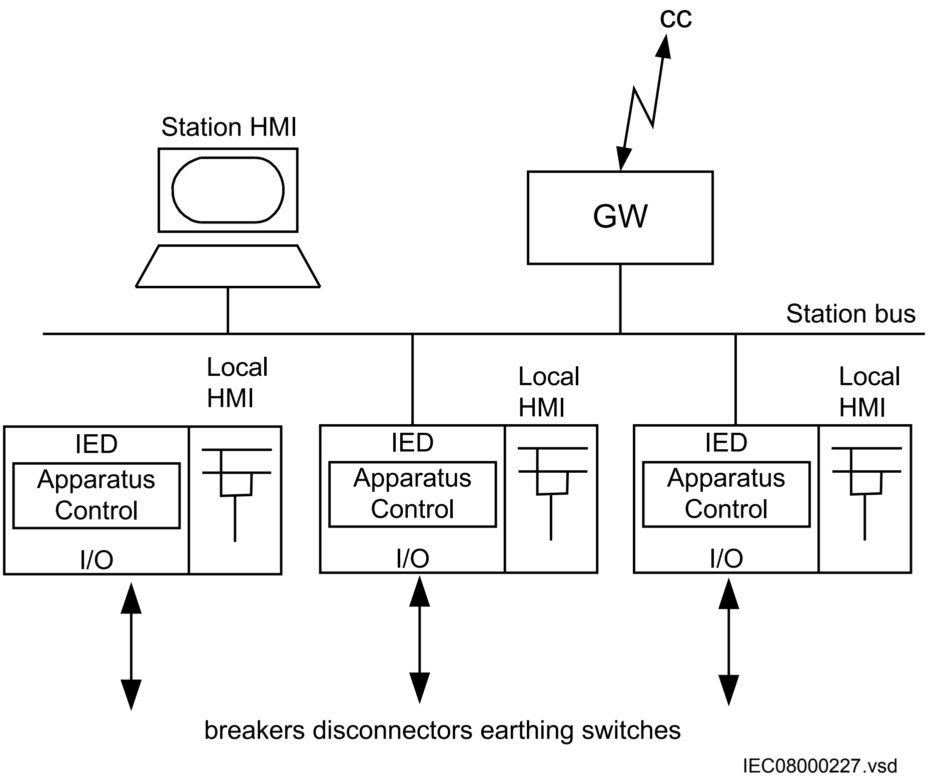


Figure 70: Overview of the apparatus control functions.

Features in the apparatus control function:

- Operation of primary apparatuses
- Select-Execute principle to give high security
- Selection function to prevent simultaneous operation
- Selection and supervision of operator place
- Command supervision
- Block/deblock of operation
- Block/deblock of updating of position indications
- Substitution of position indications
- Overriding of interlocking functions
- Overriding of synchrocheck
- Operation counter
- Suppression of Mid position

The apparatus control function is realized by means of a number of function blocks designated:

- Switch controller SCSWI
- Circuit breaker SXCBR
- Circuit switch SXSWI
- Position evaluation POS_EVAL
- Select release SELGGIO

- Bay control QCBAY
- Local remote LOCREM
- Local remote control LOCREMCTRL

SCSWI, SXCBR, QCBAY, SXSWI and SELGGIO are logical nodes according to IEC 61850. The signal flow between these function blocks appears in figure 71. The function Logical node Interlocking (SCILO) in the figure below is the logical node for interlocking.

Control operation can be performed from the LHMI. If the administrator has defined users with the UM tool, then the local/remote switch is under authority control. If not, the default (factory) user is the SuperUser, that can perform control operations from the LHMI without LogOn. The default position of the local/remote switch is on remote.

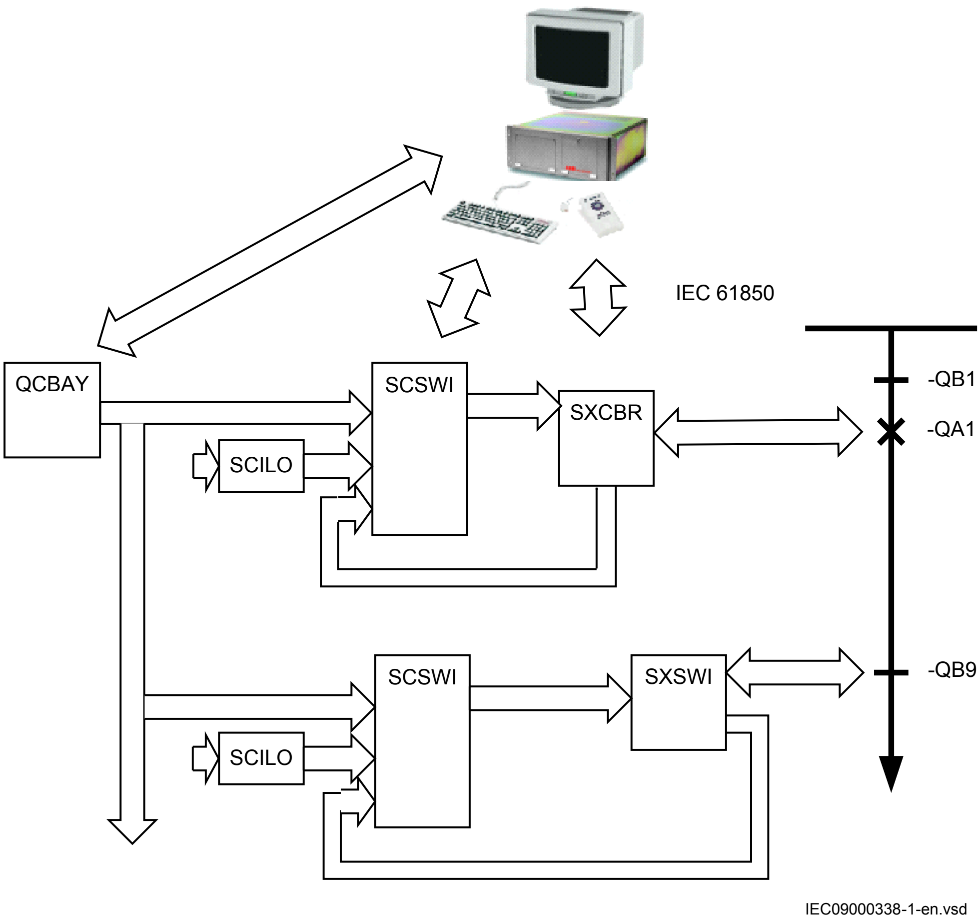


Figure 71: Signal flow between apparatus control function blocks

Switch controller (SCSWI)

The Switch controller (SCSWI) initializes and supervises all functions to properly select and operate switching primary apparatuses. The Switch controller may handle and operate on one three-phase device.

After the selection of an apparatus and before the execution, the switch controller performs the following checks and actions:

- A request initiates to reserve other bays to prevent simultaneous operation.
- Actual position inputs for interlocking information are read and evaluated if the operation is permitted.
- The synchrocheck/synchronizing conditions are read and checked, and performs operation upon positive response.
- The blocking conditions are evaluated
- The position indications are evaluated according to given command and its requested direction (open or closed).

The command sequence is supervised regarding the time between:

- Select and execute.
- Select and until the reservation is granted.
- Execute and the final end position of the apparatus.
- Execute and valid close conditions from the synchrocheck.

At error the command sequence is cancelled.

The mid position of apparatuses can be suppressed at the (SCSWI) by setting the *tIntermediate* at (SXCBR/SXSWI) to an appropriate value.

The switch controller is not dependent on the type of switching device SXCBR or SXSWI. The switch controller represents the content of the SCSWI logical node (according to IEC 61850) with mandatory functionality.

Switch (SXCBR/SXSWI)

The Switch is a function used to close and interrupt an ac power circuit under normal conditions, or to interrupt the circuit under fault, or emergency conditions. The intention with this function is to represent the lowest level of a power-switching device with or without short circuit breaking capability, for example, circuit breakers, disconnectors, earthing switches etc.

The purpose of this function is to provide the actual status of positions and to perform the control operations, that is, pass all the commands to the primary apparatus via output boards and to supervise the switching operation and position.

The Switch has this functionality:

- Local/Remote switch intended for the switchyard
- Block/deblock for open/close command respectively
- Update block/deblock of position indication
- Substitution of position indication
- Supervision timer that the primary device starts moving after a command
- Supervision of allowed time for intermediate position
- Definition of pulse duration for open/close command respectively

The realization of this function is performed with SXCBR representing a circuit breaker and with SXSWI representing a circuit switch that is, a disconnector or an earthing switch.

The content of this function is represented by the IEC 61850 definitions for the logical nodes Circuit breaker (SXCBR) and Circuit switch (SXSWI) with mandatory functionality.

Reservation function (SELGGIO)

The purpose of the reservation function is to grant permission to operate only one device at a time in a group, like a bay or a station, thereby preventing double operation.

For interlocking evaluation in a substation, the position information from switching devices, such as circuit breakers, disconnectors and earthing switches can be required from the same bay or from several other bays. When information is needed from other bays, it is exchanged over the serial station bus between the distributed IEDs. The problem that arises, even at a high speed of communication, is a time interval during which the information about the position of the switching devices are uncertain. The interlocking function uses this information for evaluation, which means that also the interlocking conditions will be uncertain.

To ensure that the interlocking information is correct at the time of operation, a reservation method is available in the IEDs. With this reservation method the reserved signal can be used for evaluation of permission to select and operate the apparatus.

This functionality is realized over the station bus by means of the function block SELGGIO.

The SELECTED output signal from the respective SCSWI function block in the own bay is connected to the inputs of the SELGGIO function block. The output signal RESERVED from SELGGIO is connected to the input RES_EXT of the SCSWI function block. If the bay is not currently reserved, the SELGGIO output signal RESERVED is FALSE. Selection for operation on the SCSWI block is now possible. Once any SCSWI block is selected, and if its output SELECTED is connected to the SELGGIO block, then other SCSWI functions as configured are blocked for selection. The RESERVED signal from SELGGIO is also sent to other bay devices.

Due to the design of the plant, some apparatus might need reservation of the own bay as well as reservations from other bays. Received reservation from other bays are handled by a logical OR together with own bay reservation from the SELGGIO function block that checks whether the own bay is currently reserved.

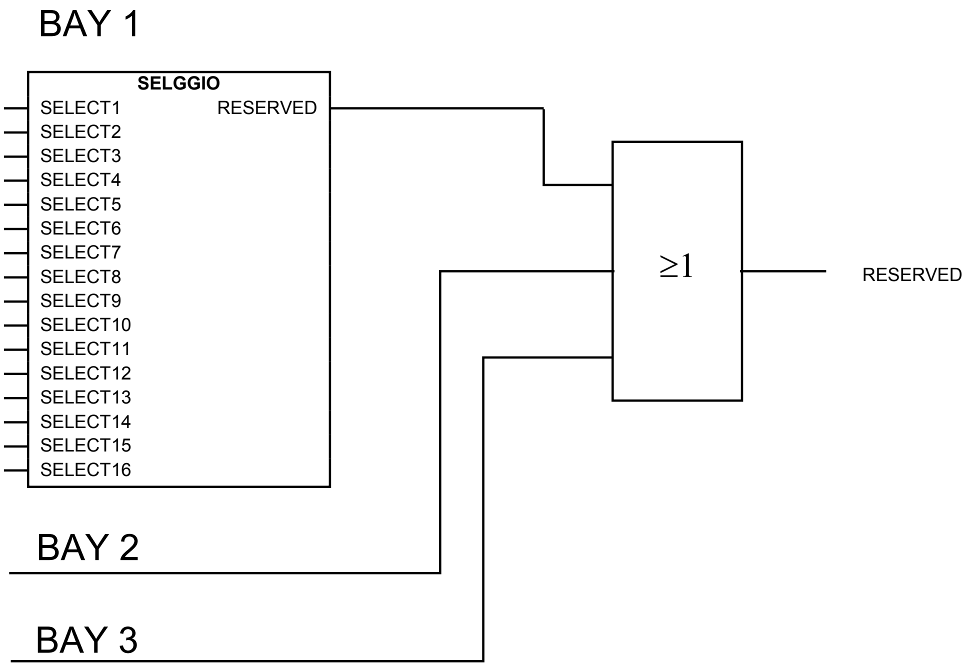


Figure 72: Reservations from own and other bays

The reservation can also be realized with external wiring according to the application example in figure 73. This solution is realized with external auxiliary relays and extra binary inputs and outputs in each IED.

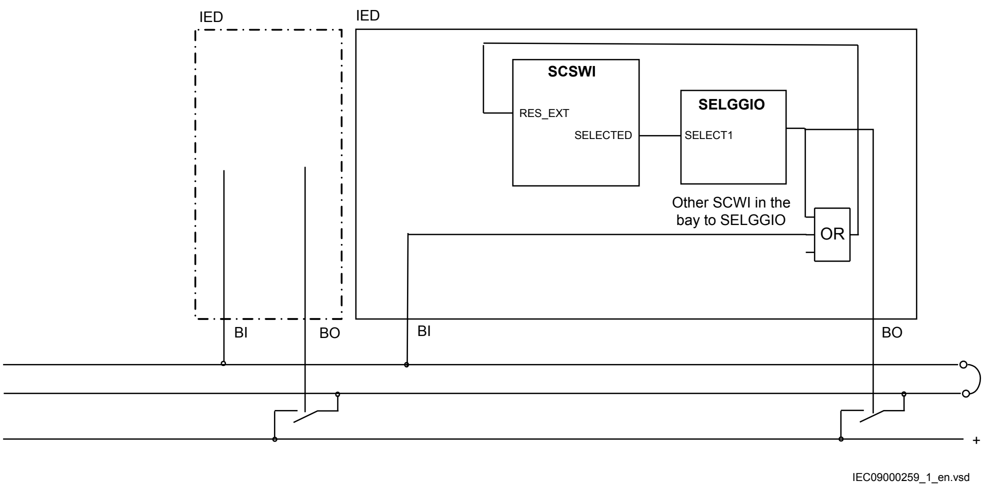


Figure 73: Application principles for reservation with external wiring

The solution in figure 73 can also be realized over the station bus according to the application example in figure 74.

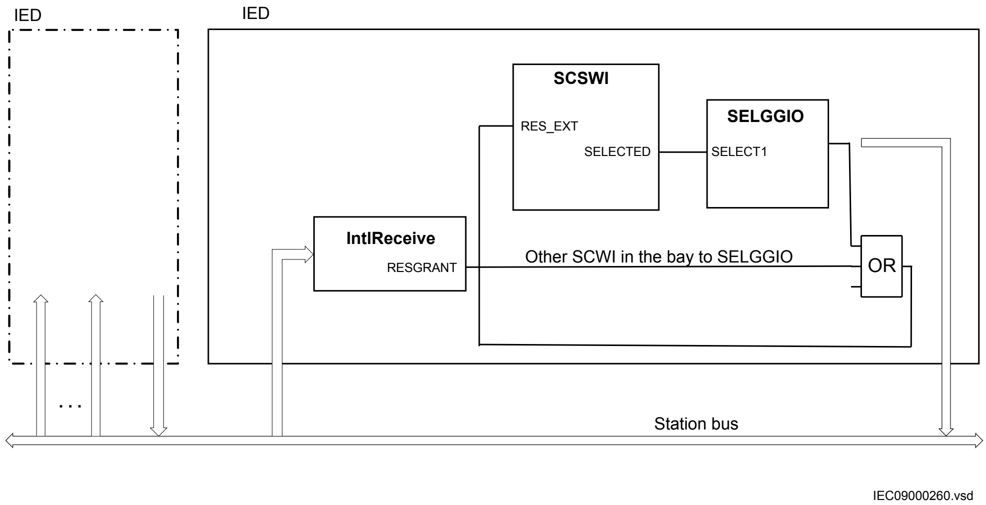


Figure 74: Application principle for an alternative reservation solution

Bay control (QCBAY)

The Bay control (QCBAY) is used to handle the selection of the operator place for the bay. The function gives permission to operate from two types of locations either from Remote (for example, control center or station HMI) or from Local (local HMI on the IED) or from all (Local and Remote). The Local/Remote switch position can also be set to Off, which means no operator place selected that is, operation is not possible neither from local nor from remote.

QCBAY also provides blocking functions that can be distributed to different apparatuses within the bay. There are four different blocking alternatives:

- Total block of the function
- Blocking of update of positions
- Blocking of commands

The function does not have a corresponding functionality defined in the IEC61850 standard, which means that this function is included as a vendor specific logical node.

9.3.3 Interaction between modules

A typical bay with apparatus control function consists of a combination of logical nodes or functions that are described here:

- The Switch controller (SCSWI), initializes all operations for one apparatus and performs the actual switching and is more or less the interface to the drive of one apparatus. It includes the position handling as well as the control of the position.
- The Circuit breaker (SXCBR), is the process interface to the circuit breaker for the apparatus control function.
- The Circuit switch (SXSWI), is the process interface to the disconnector or the earthing switch for the apparatus control function.

- The Bay control (QCBAY), fulfils the bay-level functions for the apparatuses, such as operator place selection and blockings for the complete bay.
- The function (SELGGIO), deals with reservation of the bay.
- The Four step overcurrent protection (OC4PTOC), trips the breaker.
- The Protection trip logic (SMPPTRC), connects the "trip" outputs of one or more protection functions to a common "trip" to be transmitted to SXCBR.
- The Autorecloser (SMBRREC), consists of the facilities to automatically close a tripped breaker with respect to a number of configurable conditions.
- The logical node Interlocking (SCILO), provides the information to SCSWI whether it is permitted to operate due to the switchyard topology. The interlocking conditions are evaluated with separate logic and connected to SCILO.
- The Synchrocheck, energizing check, and synchronizing (SESRSYN) calculates and compares the voltage phasor difference from both sides of an open breaker with predefined switching conditions (synchrocheck). Also the case that one side is dead (energizing-check) is included.
- The logical node Generic Automatic Process Control, GAPC, is an automatic function that reduces the interaction between the operator and the system. With one command, the operator can start a sequence that will end with a connection of a process object (e.g. line) to one of the possible busbars.

The overview of the interaction between these functions is shown in figure 75 below.

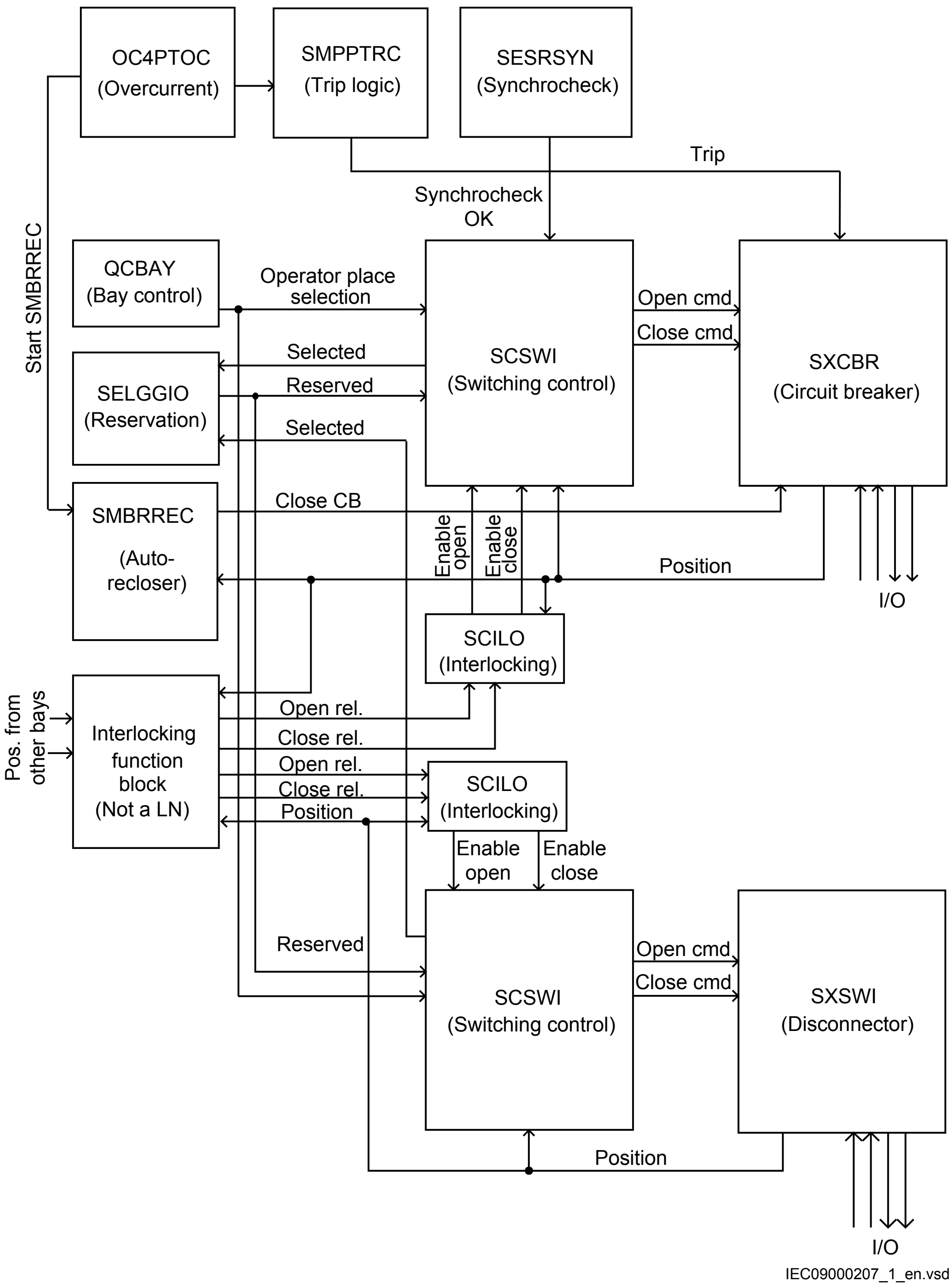


Figure 75: Example overview of the interactions between functions in a typical bay

9.3.4 Setting guidelines

The setting parameters for the apparatus control function are set via the local HMI or Protection and Control IED Manager (PCM600).

9.3.4.1 Switch controller (SCSWI)

The parameter *CtlModel* specifies the type of control model according to IEC 61850. For normal control of circuit breakers, disconnectors and earthing switches the control model is set to SBO Enh (Select-Before-Operate) with enhanced security.

When the operation shall be performed in one step, the model direct control with normal security is used.

At control with enhanced security there is an additional supervision of the status value by the control object, which means that each command sequence must be terminated by a termination command.

The parameter *PosDependent* gives permission to operate depending on the position indication, that is, at Always permitted it is always permitted to operate independent of the value of the position. At Not perm at 00/11 it is not permitted to operate if the position is in bad or intermediate state.

tSelect is the maximum time between the select and the execute command signal, that is, the time the operator has to perform the command execution after the selection of the object to operate. When the time has expired, the selected output signal is set to false and a cause-code is given over IEC 61850.

tSynchrocheck is the allowed time for the synchrocheck function to fulfil the close conditions. When the time has expired, the control function is reset.

The timer *tSynchronizing* supervises that the signal synchronizing in progress is obtained in SCSWI after start of the synchronizing function. The start signal for the synchronizing is obtained if the synchrocheck conditions are not fulfilled. When the time has expired, the control function is reset. If no synchronizing function is included, the time is set to 0, which means no start of the synchronizing function.

tExecutionFB is the maximum time between the execute command signal and the command termination. When the time has expired, the control function is reset.

9.3.4.2 Switch (SXCBR/SXSWI)

tStartMove is the supervision time for the apparatus to start moving after a command execution. When the time has expired, the switch function is reset.

During the *tIntermediate* time the position indication is allowed to be in an intermediate (00) state. When the time has expired, the switch function is reset. The indication of the mid-position at SCSWI is suppressed during this time period when the position changes from open to close or vice-versa.

If the parameter *AdaptivePulse* is set to Adaptive the command output pulse resets when a new correct end position is reached. If the parameter is set to Not adaptive the command output pulse remains active until the timer tClose(Open)Pulse has elapsed.

tOpenPulse is the output pulse length for an open command. The default length is set to 200 ms for a circuit breaker (SXCBR) and 200 ms for a disconnector or earthing switch (SXSWI).

tClosePulse is the output pulse length for a close command.The default length is set to 200 ms for a circuit breaker (SXCBR) and 200 ms for a disconnector or earthing switch (SXSWI).

SuppressMidPos when ON will suppress the mid-position during the time *tIntermediate*.

SwitchType is an enumeration according to IEC 61850-7-4 to indicate the switch type assigned to SXSWI

9.3.4.3 Bay control (QCBAY)

If the parameter *AllPSTOValid* is set to No priority, all originators from local and remote are accepted without any priority.

9.4 Interlocking

9.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logical node for interlocking	SCILO	-	-
Interlocking for busbar earthing switch	BB_ES	-	-
Interlocking for bus-section breaker	A1A2_BS	-	-
Interlocking for bus-section disconnector	A1A2_DC	-	-
Interlocking for bus-coupler bay	ABC_BC	-	-
Interlocking for 1 1/2 breaker diameter	BH_CONN	-	-
Interlocking for 1 1/2 breaker diameter	BH_LINE_A	-	-
Interlocking for 1 1/2 breaker diameter	BH_LINE_B	-	-
Interlocking for double CB bay	DB_BUS_A	-	-
Interlocking for double CB bay	DB_BUS_B	-	-
Interlocking for double CB bay	DB_LINE	-	-
Interlocking for line bay	ABC_LINE	-	-
Interlocking for transformer bay	AB_TRAFO	-	-

9.4.2 Application

The main purpose of switchgear interlocking is:

- To avoid the dangerous or damaging operation of switchgear
- To enforce restrictions on the operation of the substation for other reasons for example, load configuration. Examples of the latter are to limit the number of parallel transformers to a maximum of two or to ensure that energizing is always from one side, for example, the high voltage side of a transformer.

This section only deals with the first point, and only with restrictions caused by switching devices other than the one to be controlled. This means that switch interlock, because of device alarms, is not included in this section.

Disconnectors and earthing switches have a limited switching capacity. Disconnectors may therefore only operate:

- With basically zero current. The circuit is open on one side and has a small extension. The capacitive current is small (for example, < 5A) and power transformers with inrush current are not allowed.
- To connect or disconnect a parallel circuit carrying load current. The switching voltage across the open contacts is thus virtually zero, thanks to the parallel circuit (for example, < 1% of rated voltage). Paralleling of power transformers is not allowed.

Earthing switches are allowed to connect and disconnect earthing of isolated points. Due to capacitive or inductive coupling there may be some voltage (for example < 40% of rated voltage) before earthing and some current (for example < 100A) after earthing of a line.

Circuit breakers are usually not interlocked. Closing is only interlocked against running disconnectors in the same bay, and the bus-coupler opening is interlocked during a busbar transfer.

The positions of all switching devices in a bay and from some other bays determine the conditions for operational interlocking. Conditions from other stations are usually not available. Therefore, a line earthing switch is usually not fully interlocked. The operator must be convinced that the line is not energized from the other side before closing the earthing switch. As an option, a voltage indication can be used for interlocking. Take care to avoid a dangerous *enable* condition at the loss of a VT secondary voltage, for example, because of a blown fuse.

The switch positions used by the operational interlocking logic are obtained from auxiliary contacts or position sensors. For each end position (open or closed) a true indication is needed - thus forming a double indication. The apparatus control function continuously checks its consistency. If neither condition is high (1 or TRUE), the switch may be in an intermediate position, for example, moving. This dynamic state may continue for some time, which in the case of disconnectors may be up to 10 seconds. Should both indications stay low for a longer period, the position indication will be interpreted as *unknown*. If both indications stay high, something is wrong, and the state is again treated as *unknown*.

In both cases an alarm is sent to the operator. Indications from position sensors shall be self-checked and system faults indicated by a fault signal. In the interlocking logic, the signals are used to avoid dangerous *enable* or *release* conditions. When the switching state of a switching device cannot be determined operation is not permitted.

9.4.3 Configuration guidelines

The following sections describe how the interlocking for a certain switchgear configuration can be realized in the IED by using standard interlocking modules and their interconnections. They also describe the configuration settings. The inputs for delivery specific conditions (Qx_EXy) are set to 1=TRUE if they are not used, except in the following cases:

- QB9_EX2 and QB9_EX4 in modules BH_LINE_A and BH_LINE_B
- QA1_EX3 in module AB_TRAFO

when they are set to 0=FALSE.

9.4.4 Interlocking for busbar earthing switch BB_ES

9.4.4.1 Application

The Interlocking for busbar earthing switch (BB_ES) module is used for one busbar earthing switch on any busbar parts according to figure 76.

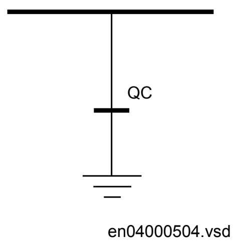


Figure 76: Switchyard layout BB_ES

The signals from other bays connected to the module BB_ES are described below.

9.4.4.2 Signals in single breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus-section are open.

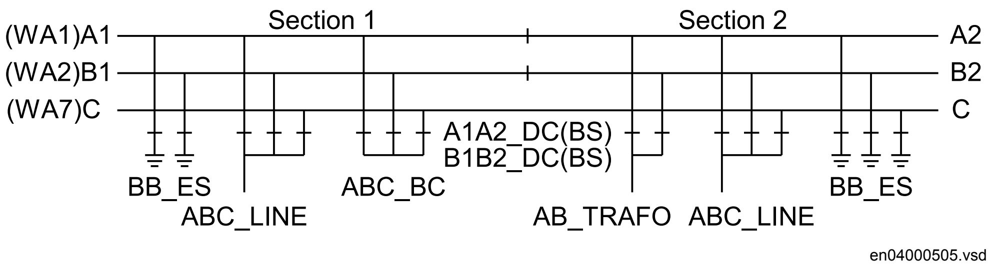


Figure 77: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series cannot handle the transfer bus (WA7)C.

To derive the signals:

Signal	
BB_DC_OP	All disconnectors on this part of the busbar are open.
VP_BB_DC	The switch status of all disconnector on this part of the busbar are valid.
EXDU_BB	No transmission error from any bay containing the above information.

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and each bus-coupler bay (ABC_BC) are needed:

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open (AB_TRAFO, ABC_LINE)
QB220OTR	QB2 and QB20 are open (ABC_BC)
QB7OPTR	QB7 is open.
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
VQB220TR	The switch status of QB2and QB20 are valid.
VPQB7TR	The switch status of QB7 is valid.
EXDU_BB	No transmission error from the bay that contains the above information.

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnectors A1A2_DC and B1B2_DC.

Signal	
DCOPTR	The bus-section disconnector is open.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

If no bus-section disconnector exists the signal DCOPTR, VPDCTR and EXDU_DC are set to 1 (TRUE).

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS) rather than the bus-section disconnector bay (A1A2_DC) must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open.
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
EXDU_BS	No transmission error from the bay BS (bus-section coupler bay) that contains the above information.

For a busbar earthing switch, these conditions from the A1 busbar section are valid:

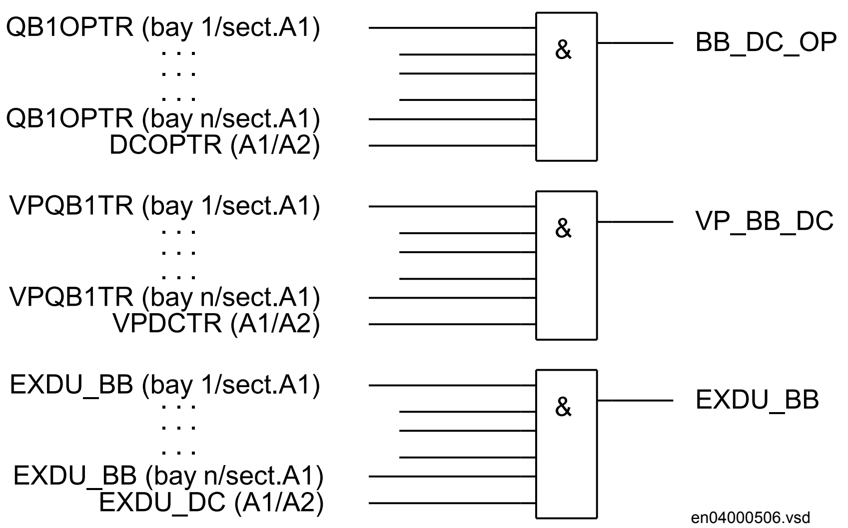


Figure 78: Signals from any bays in section A1 to a busbar earthing switch in the same section

For a busbar earthing switch, these conditions from the A2 busbar section are valid:

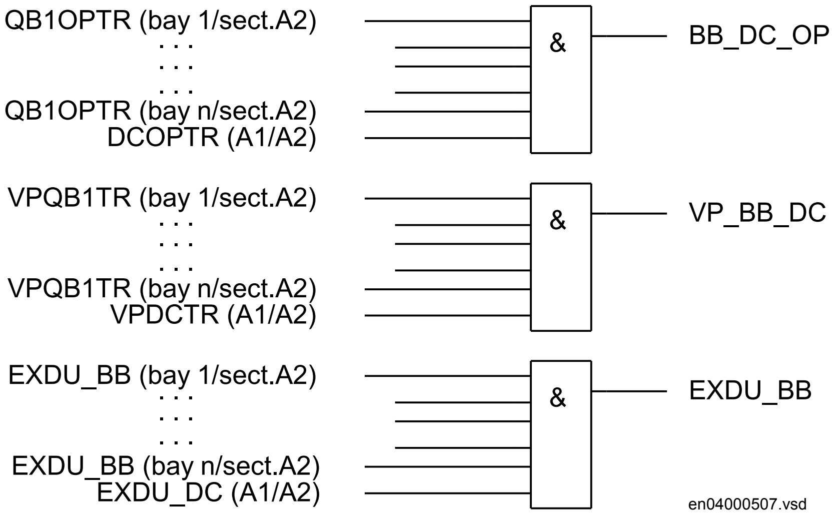


Figure 79: Signals from any bays in section A2 to a busbar earthing switch in the same section

For a busbar earthing switch, these conditions from the B1 busbar section are valid:

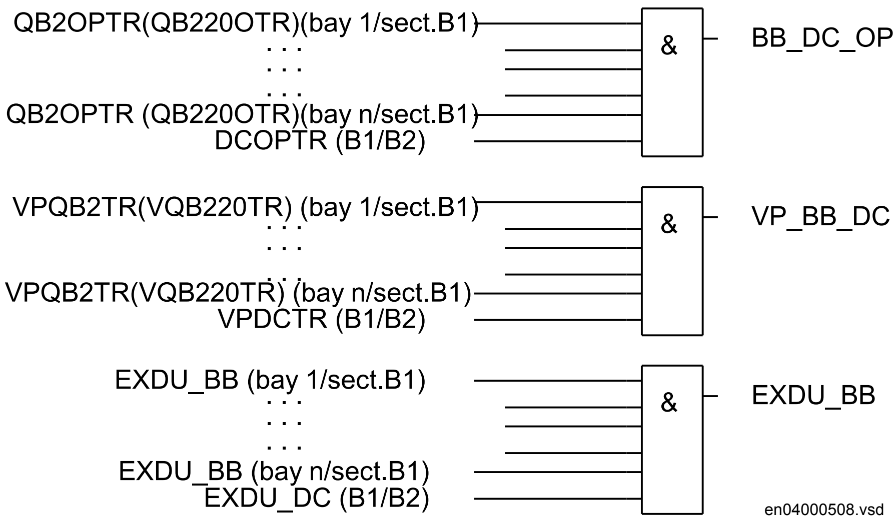


Figure 80: Signals from any bays in section B1 to a busbar earthing switch in the same section

For a busbar earthing switch, these conditions from the B2 busbar section are valid:

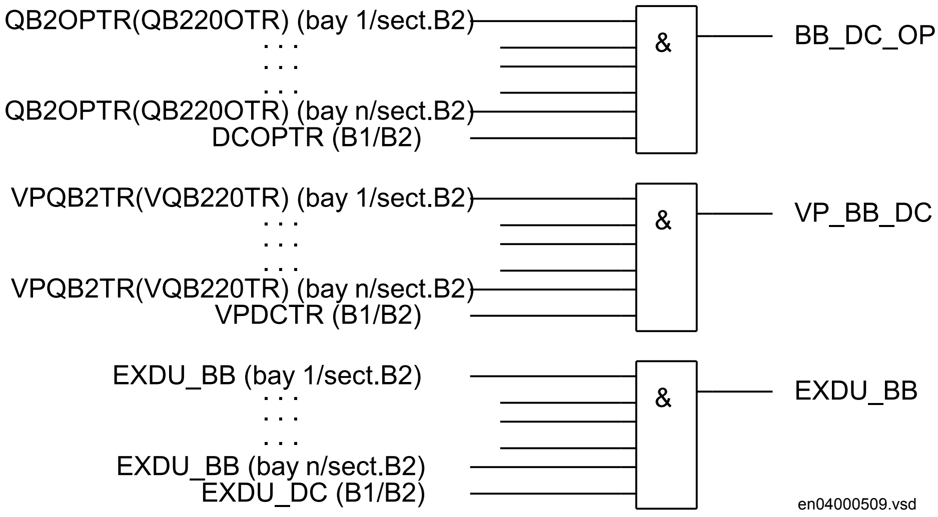


Figure 81: Signals from any bays in section B2 to a busbar earthing switch in the same section

For a busbar earthing switch on bypass busbar C, these conditions are valid:

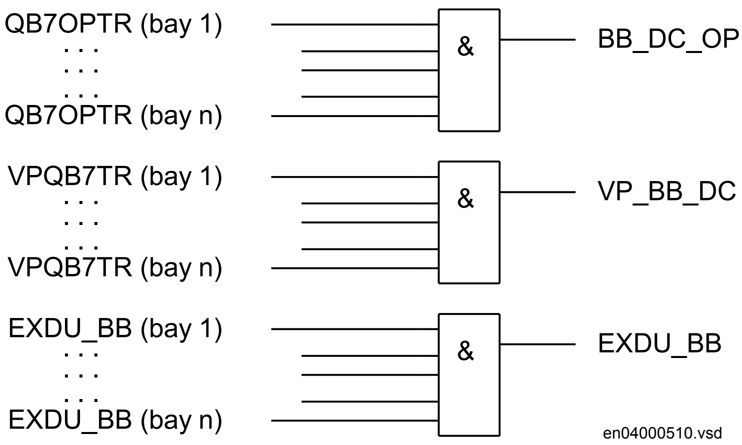


Figure 82: Signals from bypass busbar to busbar earthing switch

9.4.4.3 Signals in double-breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus section are open.

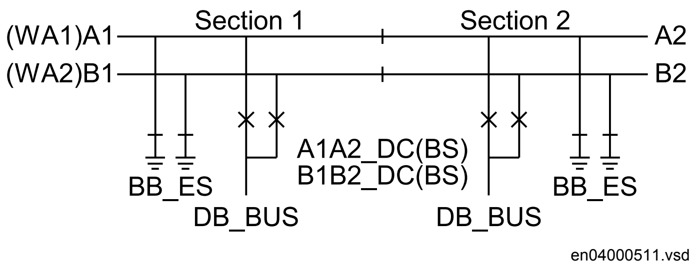


Figure 83: Busbars divided by bus-section disconnectors (circuit breakers)

To derive the signals:

Signal	
BB_DC_OP	All disconnectors of this part of the busbar are open.
VP_BB_DC	The switch status of all disconnectors on this part of the busbar are valid.
EXDU_BB	No transmission error from any bay that contains the above information.

These signals from each double-breaker bay (DB_BUS) are needed:

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open.
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
EXDU_DB	No transmission error from the bay that contains the above information.

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnectors A1A2_DC and B1B2_DC.

Signal	
DCOPTR	The bus-section disconnector is open.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

The logic is identical to the double busbar configuration described in section “Signals in single breaker arrangement”.

9.4.4.4 Signals in 1 1/2 breaker arrangement

The busbar earthing switch is only allowed to operate if all disconnectors of the bus-section are open.

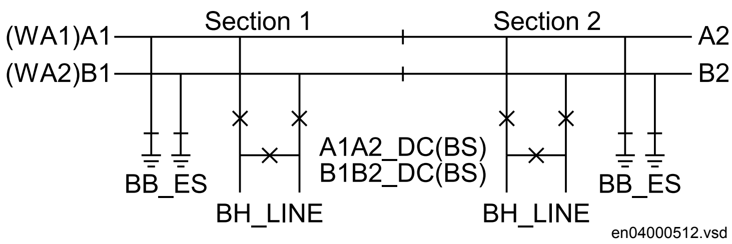


Figure 84: Busbars divided by bus-section disconnectors (circuit breakers)

The project-specific logic are the same as for the logic for the double busbar configuration described in section “Signals in single breaker arrangement”.

Signal	
BB_DC_OP	All disconnectors on this part of the busbar are open.
VP_BB_DC	The switch status of all disconnectors on this part of the busbar is valid.
EXDU_BB	No transmission error from any bay that contains the above information.

9.4.5 Interlocking for bus-section disconnector A1A2_BS

9.4.5.1 Application

The Interlocking for bus-section breaker (A1A2_BS) module is used for one bus-section circuit breaker between section 1 and 2 according to figure 85. The module can be used for different busbars, which includes a bus-section circuit breaker.

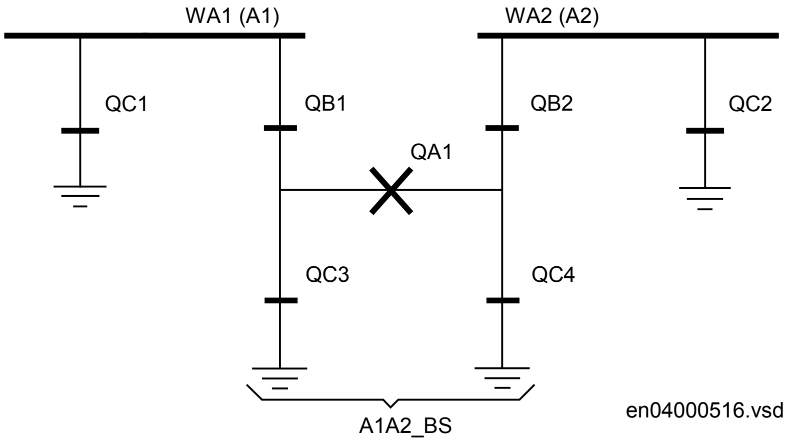


Figure 85: Switchyard layout A1A2_BS

The signals from other bays connected to the module A1A2_BS are described below.

9.4.5.2 Signals from all feeders

If the busbar is divided by bus-section circuit breakers into bus-sections and both circuit breakers are closed, the opening of the circuit breaker must be blocked if a bus-coupler connection exists between busbars on one bus-section side and if on the other bus-section side a busbar transfer is in progress:

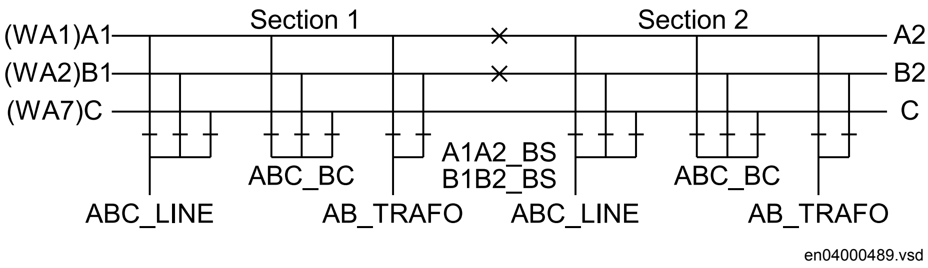


Figure 86: Busbars divided by bus-section circuit breakers

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

To derive the signals:

Signal	
BBTR_OP	No busbar transfer is in progress concerning this bus-section.
VP_BBTR	The switch status of BBTR is valid.
EXDU_12	No transmission error from any bay connected to busbar 1(A) and 2(B).

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and bus-coupler bay (ABC_BC) are needed:

Signal	
QB12OPTR	QB1 or QB2 or both are open.
VPQB12TR	The switch status of QB1 and QB2 are valid.
EXDU_12	No transmission error from the bay that contains the above information.

These signals from each bus-coupler bay (ABC_BC) are needed:

Signal	
BC12OPTR	No bus-coupler connection through the own bus-coupler between busbar WA1 and WA2.
VPBC12TR	The switch status of BC_12 is valid.
EXDU_BC	No transmission error from the bay that contains the above information.

These signals from the bus-section circuit breaker bay (A1A2_BS, B1B2_BS) are needed.

Signal	
S1S2OPTR	No bus-section coupler connection between bus-sections 1 and 2.
VPS1S2TR	The switch status of bus-section coupler BS is valid.
EXDU_BS	No transmission error from the bay that contains the above information.

For a bus-section circuit breaker between A1 and A2 section busbars, these conditions are valid:

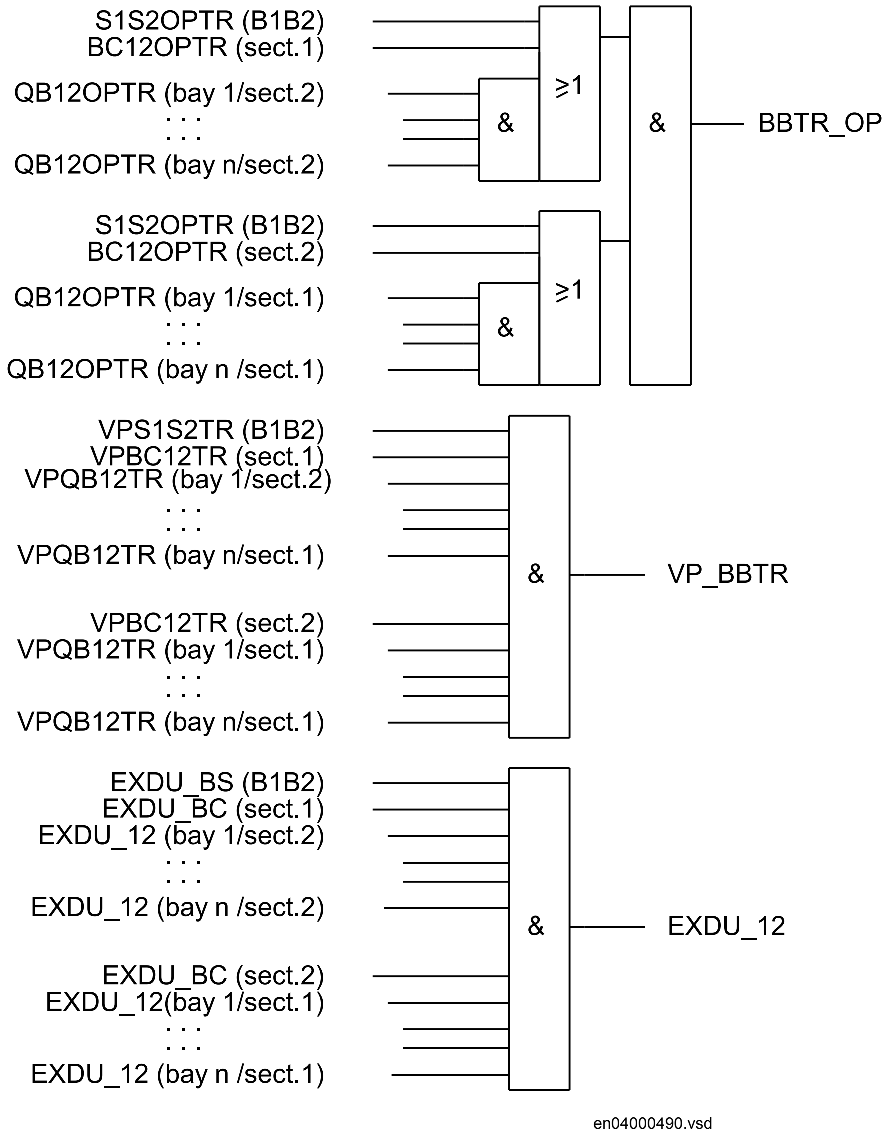


Figure 87: Signals from any bays for a bus-section circuit breaker between sections A1 and A2

For a bus-section circuit breaker between B1 and B2 section busbars, these conditions are valid:

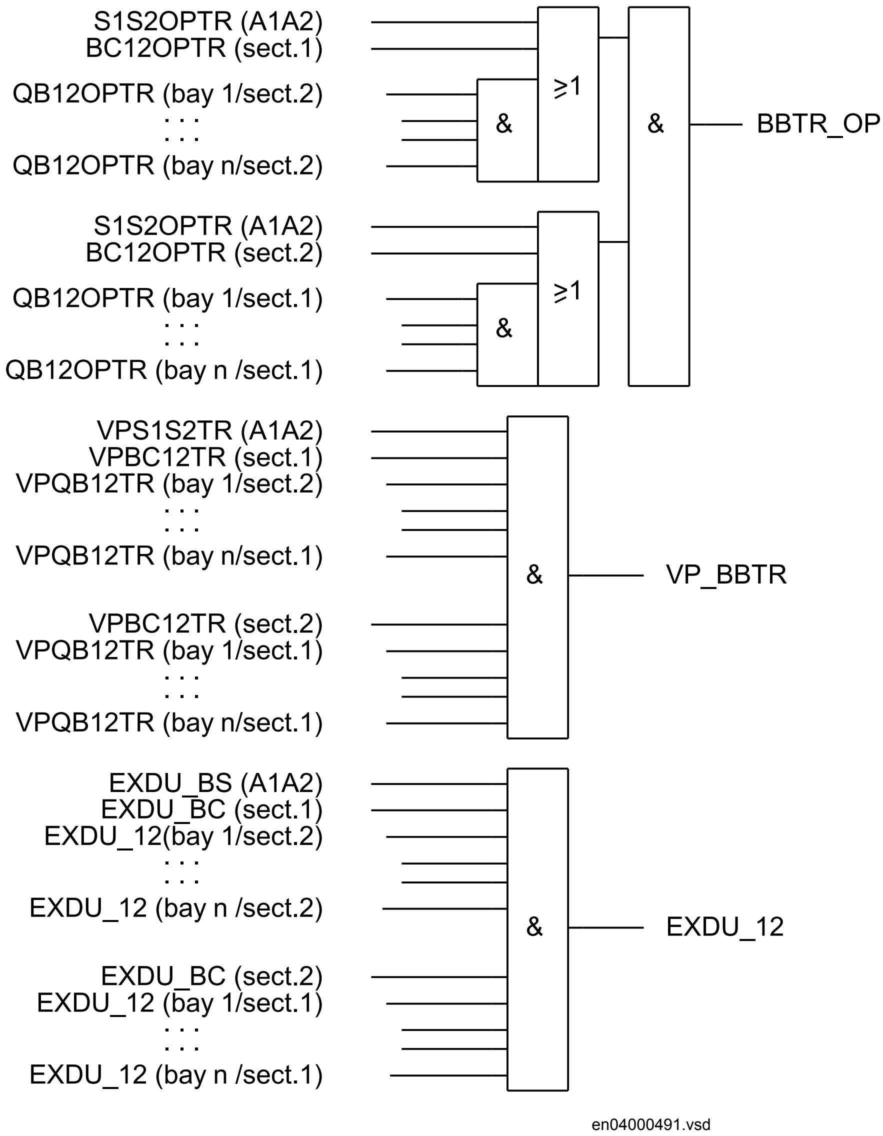


Figure 88: Signals from any bays for a bus-section circuit breaker between sections B1 and B2

9.4.5.3 Configuration setting

If there is no other busbar via the busbar loops that are possible, then either the interlocking for the QA1 open circuit breaker is not used or the state for BBTR is set to open. That is, no busbar transfer is in progress in this bus-section:

- BBTR_OP = 1
- VP_BBTR = 1

9.4.6 Interlocking for bus-section disconnector A1A2_DC

9.4.6.1 Application

The Interlocking for bus-section disconnector (A1A2_DC) module is used for one bus-section disconnector between section 1 and 2 according to figure 89. The module can be used for different busbars, which includes a bus-section disconnector.

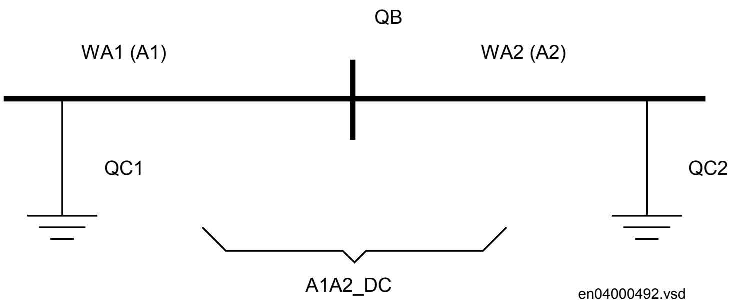


Figure 89: Switchyard layout A1A2_DC

The signals from other bays connected to the module A1A2_DC are described below.

9.4.6.2 Signals in single breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition *no other disconnector connected to the bus-section* must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

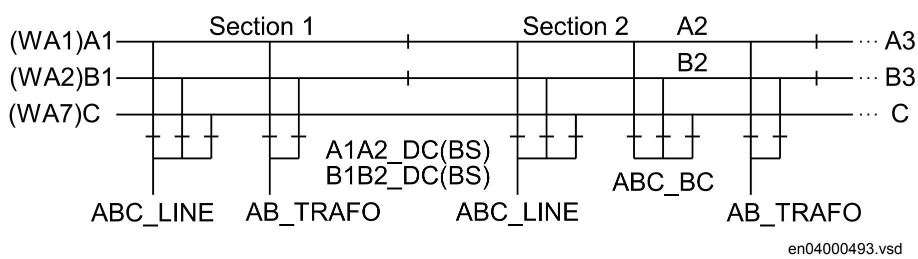


Figure 90: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

To derive the signals:

Signal	
S1DC_OP	All disconnectors on bus-section 1 are open.
S2DC_OP	All disconnectors on bus-section 2 are open.
VPS1_DC	The switch status of disconnectors on bus-section 1 are valid.
VPS2_DC	The switch status of disconnectors on bus-section 2 are valid.
EXDU_BB	No transmission error from any bay that contains the above information.

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and each bus-coupler bay (ABC_BC) are needed:

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open (AB_TRAFO, ABC_LINE).
QB220OTR	QB2 and QB20 are open (ABC_BC).
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
VQB220TR	The switch status of QB2 and QB20 are valid.
EXDU_BB	No transmission error from the bay that contains the above information.

If there is an additional bus-section disconnector, the signal from the bus-section disconnector bay (A1A2_DC) must be used:

Signal	
DCOPTR	The bus-section disconnector is open.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

If there is an additional bus-section circuit breaker rather than an additional bus-section disconnector the signals from the bus-section, circuit-breaker bay (A1A2_BS) rather than the bus-section disconnector bay (A1A2_DC) must be used:

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open.
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
EXDU_BS	No transmission error from the bay BS (bus-section coupler bay) that contains the above information.

For a bus-section disconnector, these conditions from the A1 busbar section are valid:

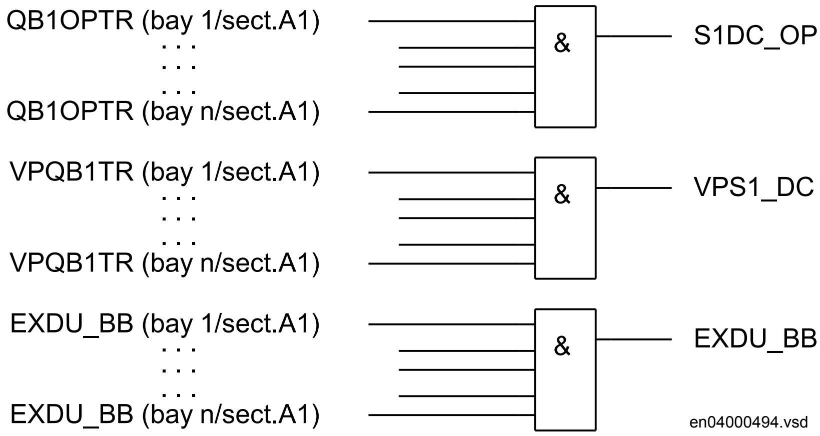


Figure 91: Signals from any bays in section A1 to a bus-section disconnector

For a bus-section disconnector, these conditions from the A2 busbar section are valid:

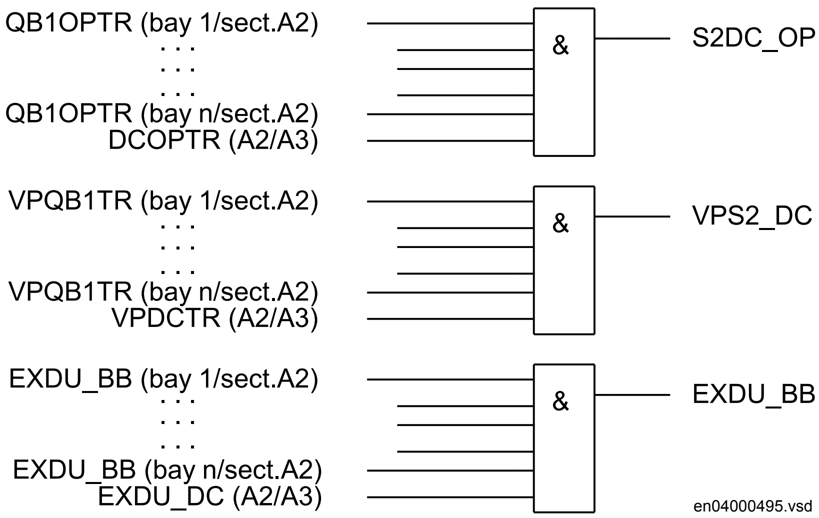


Figure 92: Signals from any bays in section A2 to a bus-section disconnector

For a bus-section disconnector, these conditions from the B1 busbar section are valid:

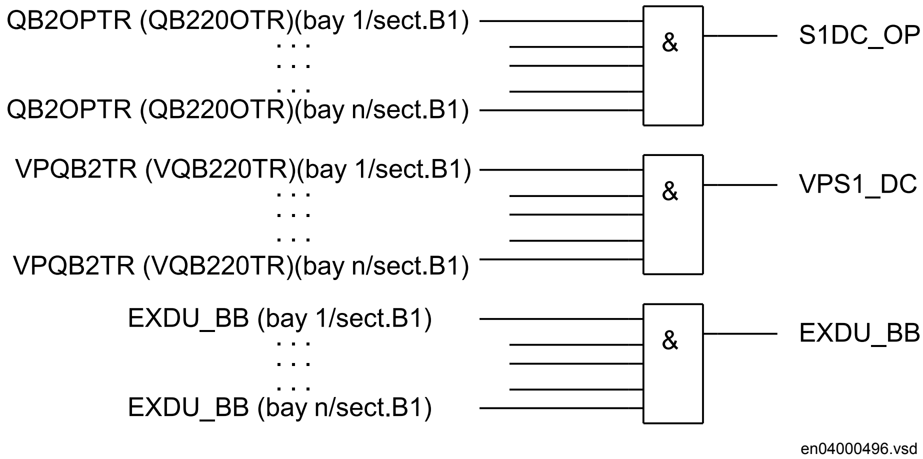


Figure 93: Signals from any bays in section B1 to a bus-section disconnector

For a bus-section disconnector, these conditions from the B2 busbar section are valid:

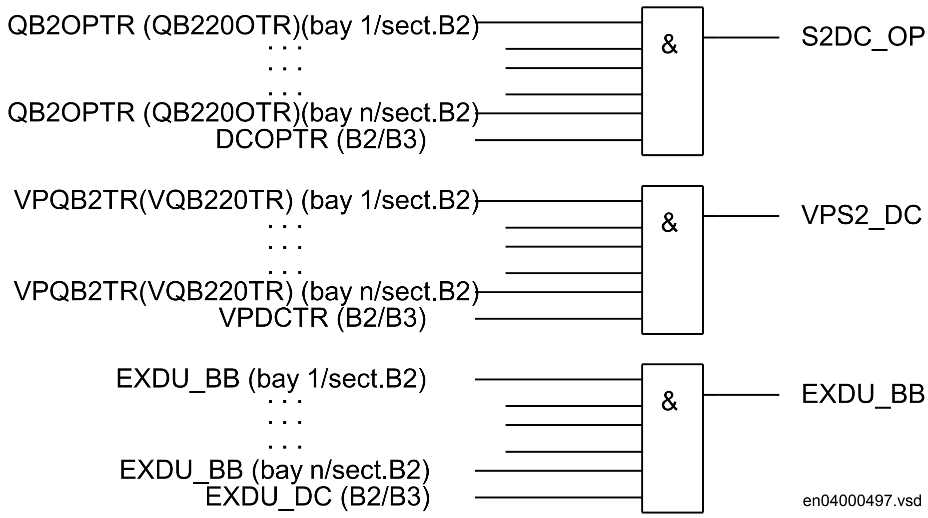


Figure 94: Signals from any bays in section B2 to a bus-section disconnector

9.4.6.3 Signals in double-breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition for the busbar disconnector bay *no other disconnector connected to the bus-section* must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

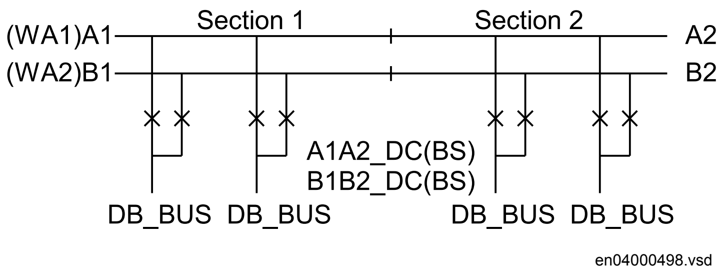


Figure 95: Busbars divided by bus-section disconnectors (circuit breakers)

To derive the signals:

Signal	
S1DC_OP	All disconnectors on bus-section 1 are open.
S2DC_OP	All disconnectors on bus-section 2 are open.
VPS1_DC	The switch status of all disconnectors on bus-section 1 are valid.
VPS2_DC	The switch status of all disconnectors on bus-section 2 are valid.
EXDU_BB	No transmission error from double-breaker bay (DB) that contains the above information.

These signals from each double-breaker bay (DB_BUS) are needed:

Signal	
QB1OPTR	QB1 is open.
QB2OPTR	QB2 is open.
VPQB1TR	The switch status of QB1 is valid.
VPQB2TR	The switch status of QB2 is valid.
EXDU_DB	No transmission error from the bay that contains the above information.

The logic is identical to the double busbar configuration “Signals in single breaker arrangement”.

For a bus-section disconnector, these conditions from the A1 busbar section are valid:

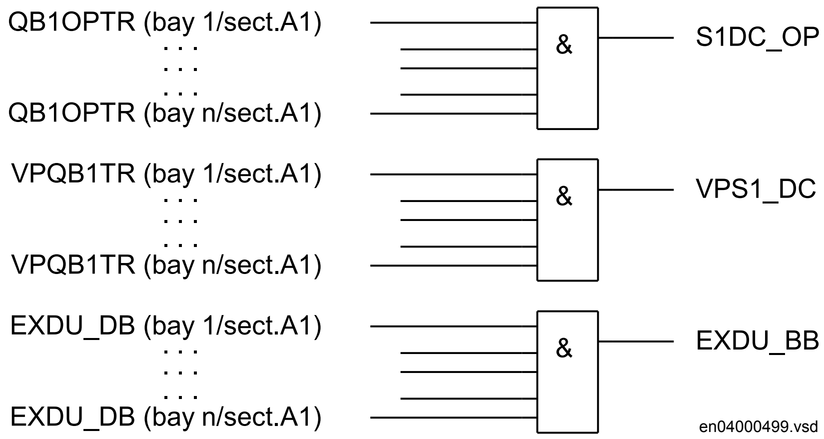


Figure 96: Signals from double-breaker bays in section A1 to a bus-section disconnector

For a bus-section disconnector, these conditions from the A2 busbar section are valid:

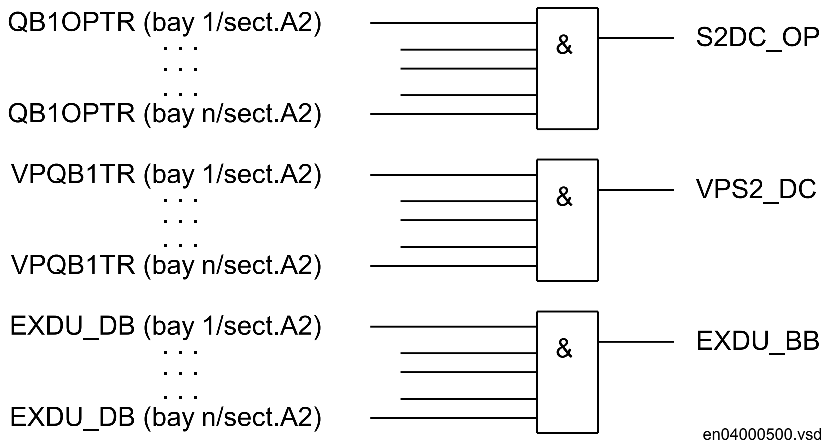


Figure 97: Signals from double-breaker bays in section A2 to a bus-section disconnector

For a bus-section disconnector, these conditions from the B1 busbar section are valid:

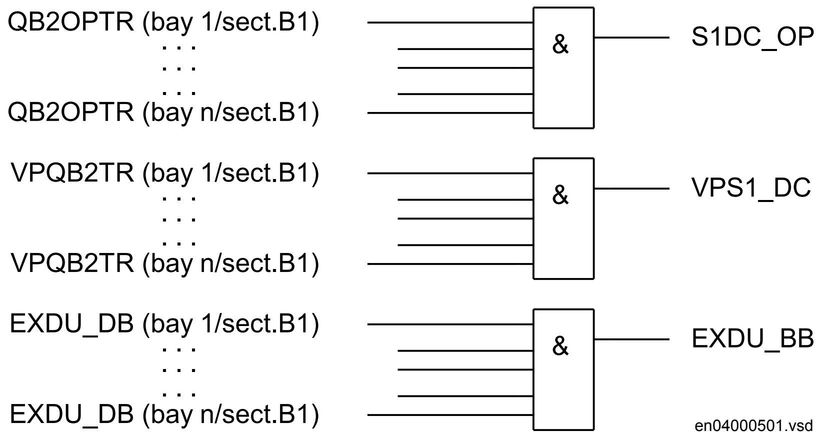


Figure 98: Signals from double-breaker bays in section B1 to a bus-section disconnector

For a bus-section disconnector, these conditions from the B2 busbar section are valid:

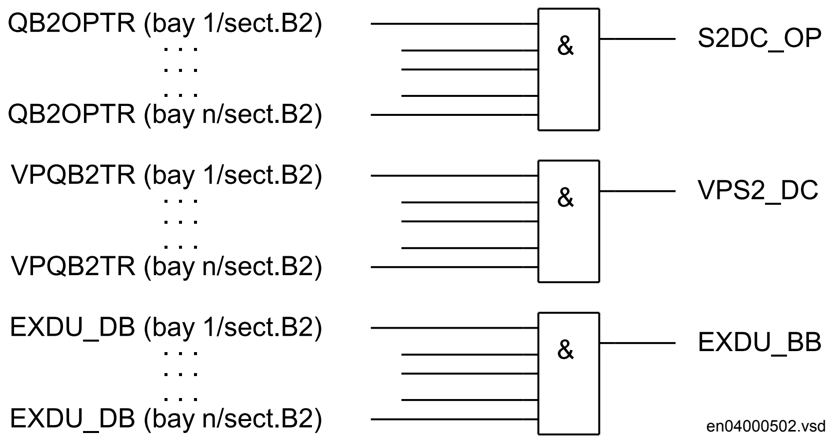


Figure 99: Signals from double-breaker bays in section B2 to a bus-section disconnector

9.4.6.4 Signals in 1 1/2 breaker arrangement

If the busbar is divided by bus-section disconnectors, the condition for the busbar disconnector bay *no other disconnector connected to the bus-section* must be made by a project-specific logic.

The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC. But for B1B2_DC, corresponding signals from busbar B are used.

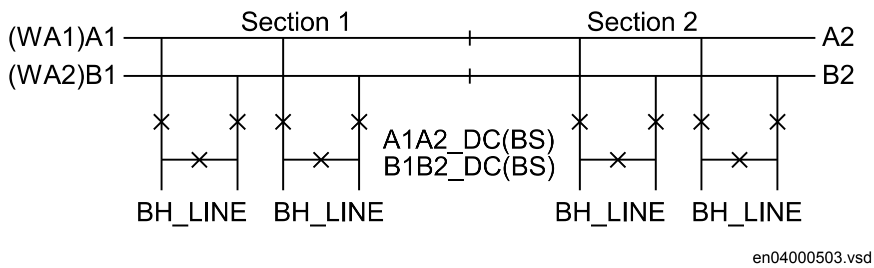


Figure 100: Busbars divided by bus-section disconnectors (circuit breakers)

The project-specific logic are the same as for the logic for the double-breaker configuration.

Signal	
S1DC_OP	All disconnectors on bus-section 1 are open.
S2DC_OP	All disconnectors on bus-section 2 are open.
VPS1_DC	The switch status of disconnectors on bus-section 1 are valid.
VPS2_DC	The switch status of disconnectors on bus-section 2 are valid.
EXDU_BB	No transmission error from breaker and a half (BH) that contains the above information.

9.4.7 Interlocking for bus-coupler bay ABC_BC

9.4.7.1 Application

The Interlocking for bus-coupler bay (ABC_BC) module is used for a bus-coupler bay connected to a double busbar arrangement according to figure 101. The module can also be used for a single busbar arrangement with transfer busbar or double busbar arrangement without transfer busbar.

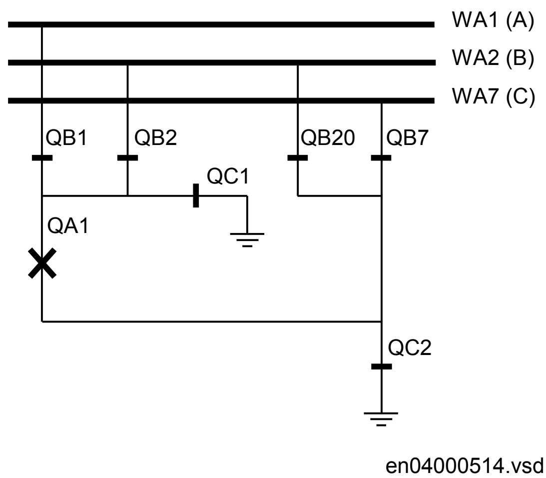


Figure 101: Switchyard layout ABC_BC

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

9.4.7.2 Configuration

The signals from the other bays connected to the bus-coupler module ABC_BC are described below.

9.4.7.3 Signals from all feeders

To derive the signals:

Signal	
BBTR_OP	No busbar transfer is in progress concerning this bus-coupler.
VP_BBTR	The switch status is valid for all apparatuses involved in the busbar transfer.
EXDU_12	No transmission error from any bay connected to the WA1/WA2 busbars.

These signals from each line bay (ABC_LINE), each transformer bay (AB_TRAFO), and bus-coupler bay (ABC_BC), except the own bus-coupler bay are needed:

Signal	
QQB12OPTR	QB1 or QB2 or both are open.
VPQB12TR	The switch status of QB1 and QB2 are valid.
EXDU_12	No transmission error from the bay that contains the above information.

For bus-coupler bay n, these conditions are valid:

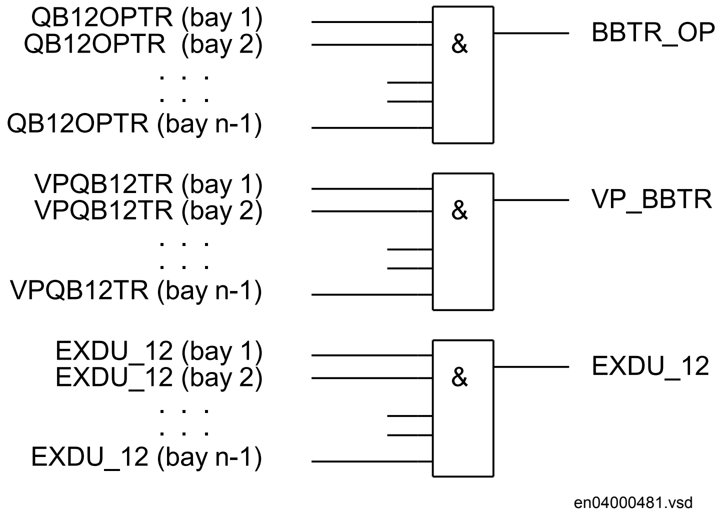


Figure 102: Signals from any bays in bus-coupler bay n

If the busbar is divided by bus-section disconnectors into bus-sections, the signals BBTR are connected in parallel - if both bus-section disconnectors are closed. So for the basic project-specific logic for BBTR above, add this logic:

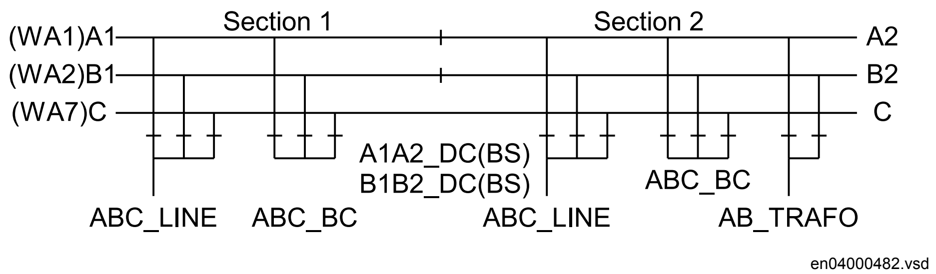


Figure 103: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series cannot handle the transfer bus (WA7)C.

The following signals from each bus-section disconnector bay (A1A2_DC) are needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

Signal	
DCOPTR	The bus-section disconnector is open.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC), have to be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

Signal	
S1S2OPTR	No bus-section coupler connection between bus-sections 1 and 2.
VPS1S2TR	The switch status of bus-section coupler BS is valid.
EXDU_BS	No transmission error from the bay that contains the above information.

For a bus-coupler bay in section 1, these conditions are valid:

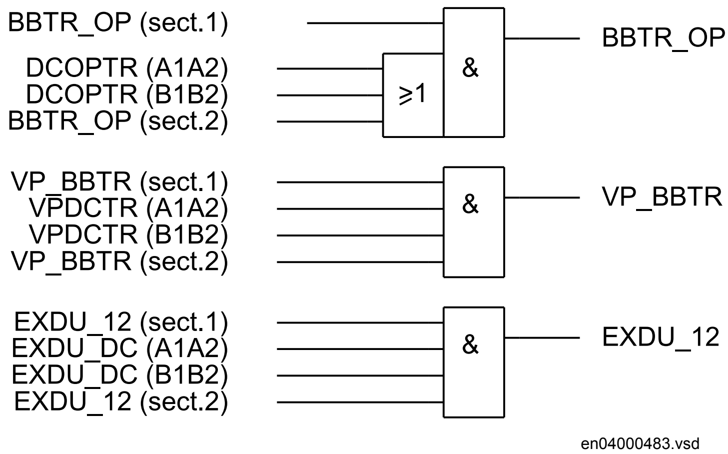


Figure 104: Signals to a bus-coupler bay in section 1 from any bays in each section

For a bus-coupler bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

9.4.7.4 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus-sections, the signals BC_12 from the busbar coupler of the other busbar section must be transmitted to the own busbar coupler if both disconnectors are closed.

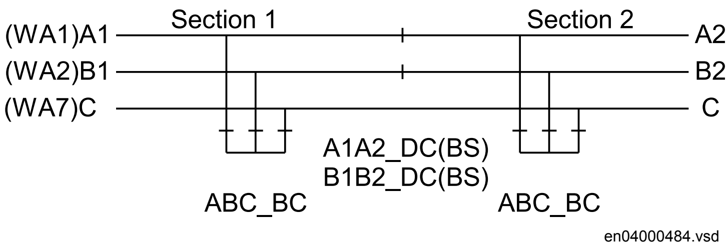


Figure 105: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

To derive the signals:

Signal	
BC_12_CL	Another bus-coupler connection exists between busbar WA1 and WA2.
VP_BC_12	The switch status of BC_12 is valid.
EXDU_BC	No transmission error from any bus-coupler bay (BC).

These signals from each bus-coupler bay (ABC_BC), except the own bay are needed:

Signal	
BC12CLTR	A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA2.
VPBC12TR	The switch status of BC_12 is valid.
EXDU_BC	No transmission error from the bay that contains the above information.

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

Signal	
DCCLTR	The bus-section disconnector is closed.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC), must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

Signal	
S1S2CLTR	A bus-section coupler connection exists between bus sections 1 and 2.
VPS1S2TR	The switch status of bus-section coupler BS is valid.
EXDU_BS	No transmission error from the bay containing the above information.

For a bus-coupler bay in section 1, these conditions are valid:

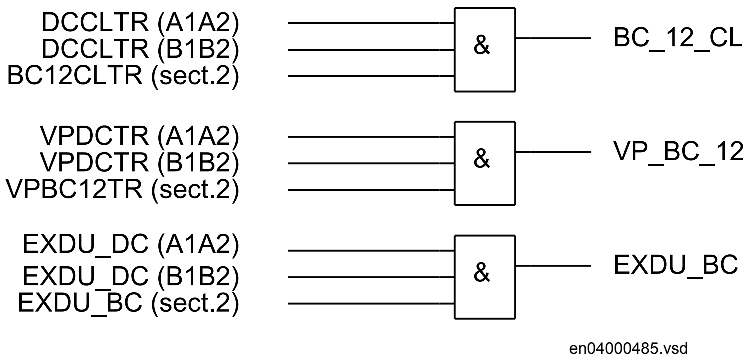


Figure 106: Signals to a bus-coupler bay in section 1 from a bus-coupler bay in an other section

For a bus-coupler bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

9.4.7.5 Configuration setting

If there is no bypass busbar and therefore no QB2 and QB7 disconnectors, then the interlocking for QB2 and QB7 is not used. The states for QB2, QB7, QC71 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB2_OP = 1
- QB2_CL = 0

- QB7_OP = 1
- QB7_CL = 0

- QC71_OP = 1
- QC71_CL = 0

If there is no second busbar B and therefore no QB2 and QB20 disconnectors, then the interlocking for QB2 and QB20 are not used. The states for QB2, QB20, QC21, BC_12, BBTR are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB2_OP = 1
- QB2_CL = 0

- QB20_OP = 1
- QB20_CL = 0

- QC21_OP = 1
- QC21_CL = 0

- BC_12_CL = 0
- VP_BC_12 = 1

- BBTR_OP = 1
- VP_BBTR = 1

9.4.8 Interlocking for 1 1/2 breaker CB diameter

9.4.8.1 Application

The Interlocking for 1 1/2 breaker diameter (BH_CONN, BH_LINE_A, BH_LINE_B) modules are used for lines connected to a 1 1/2 breaker diameter according to figure 107.

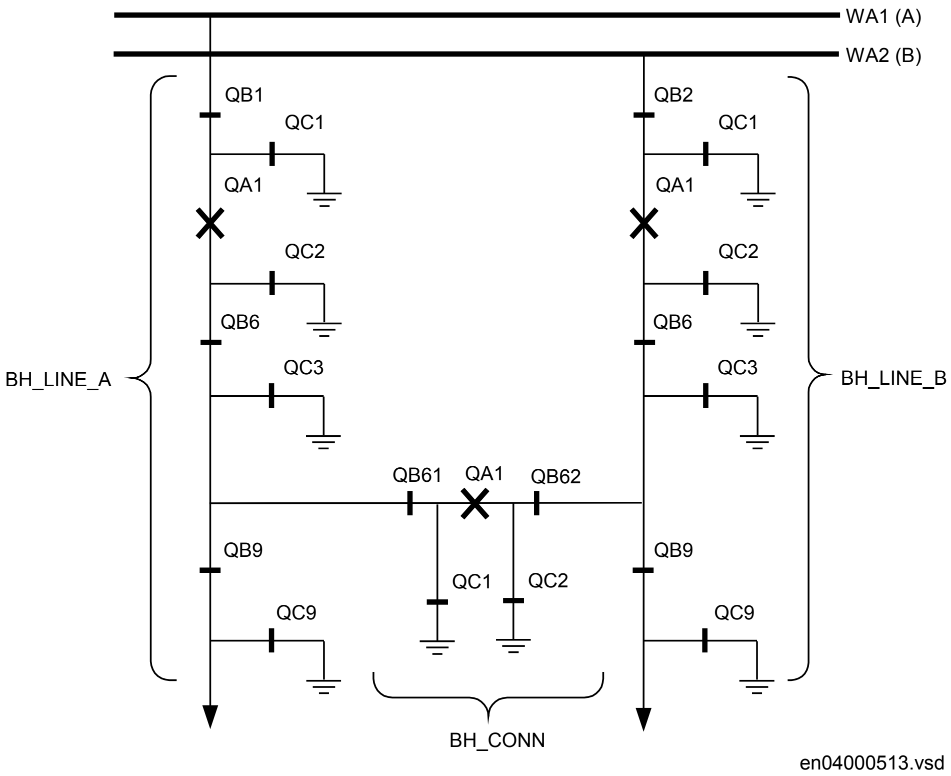


Figure 107: Switchyard layout 1 1/2 breaker

Three types of interlocking modules per diameter are defined. BH_LINE_A and BH_LINE_B are the connections from a line to a busbar. BH_CONN is the connection between the two lines of the diameter in the1 1/2 breaker switchyard layout.

For a 1 1/2 breaker arrangement, the modules BH_LINE_A, BH_CONN and BH_LINE_B must be used.

9.4.8.2 Configuration setting

For application without QB9 and QC9, just set the appropriate inputs to open state and disregard the outputs. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB9_OP = 1
- QB9_CL = 0

- QC9_OP = 1
- QC9_CL = 0

If, in this case, a line voltage supervision is added, then rather than setting QB9 to open state, specify the state of the voltage supervision:

- QB9_OP = VOLT_OFF
- QB9_CL = VOLT_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

- VOLT_OFF = 1
- VOLT_ON = 0

9.4.9 Interlocking for double CB bay

9.4.9.1 Application

The Interlocking for 1 1/2 breaker diameter (DB_BUS_A, DB_BUS_B, DB_LINE) modules are used for a line connected to a double circuit breaker arrangement according to figure 108.

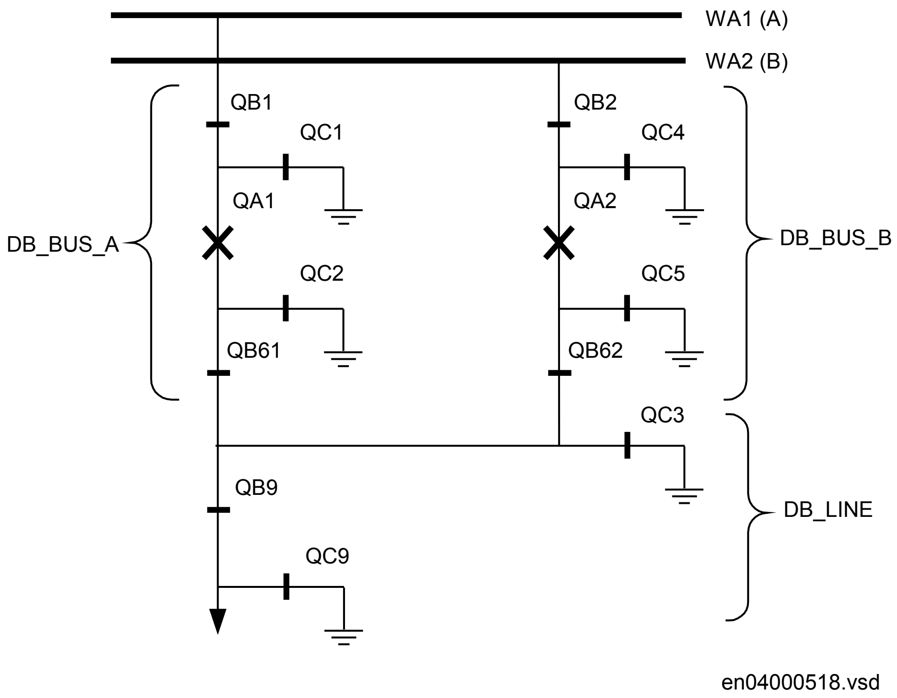


Figure 108: Switchyard layout double circuit breaker.

Three types of interlocking modules per double circuit breaker bay are defined. DB_LINE is the connection from the line to the circuit breaker parts that are connected to the busbars. DB_BUS_A and DB_BUS_B are the connections from the line to the busbars.

For a double circuit-breaker bay, the modules DB_BUS_A, DB_LINE and DB_BUS_B must be used.

9.4.9.2 Configuration setting

For application without QB9 and QC9, just set the appropriate inputs to open state and disregard the outputs. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB9_OP = 1
- QB9_CL = 0

- QC9_OP = 1
- QC9_CL = 0

If, in this case, a line voltage supervision is added, then rather than setting QB9 to open state, specify the state of the voltage supervision:

- QB9_OP = VOLT_OFF
- QB9_CL = VOLT_ON

If there is no voltage supervision, then set the corresponding inputs as follows:

- VOLT_OFF = 1
- VOLT_ON = 0

9.4.10 Interlocking for line bay ABC_LINE

9.4.10.1 Application

Interlocking for line bay (ABC_LINE) module is used for a line connected to a double busbar arrangement with a transfer busbar according to figure 109. The module can also be used for a double busbar arrangement without transfer busbar or a single busbar arrangement with/without transfer busbar.

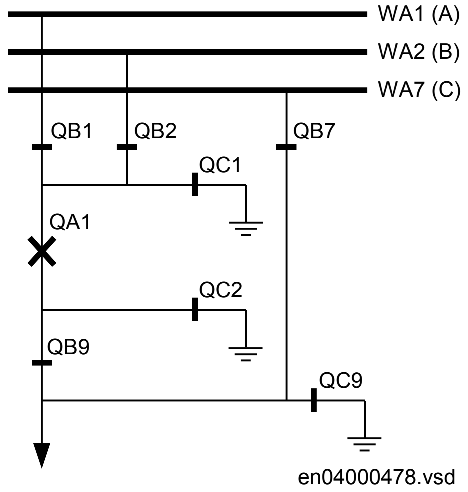


Figure 109: Switchyard layout ABC_LINE

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

The signals from other bays connected to the module ABC_LINE are described below.

9.4.10.2 Signals from bypass busbar

To derive the signals:

Signal	
BB7_D_OP	All line disconnectors on bypass WA7 except in the own bay are open.
VP_BB7_D	The switch status of disconnectors on bypass busbar WA7 are valid.
EXDU_BPB	No transmission error from any bay containing disconnectors on bypass busbar WA7

These signals from each line bay (ABC_LINE) except that of the own bay are needed:

Signal	
QB7OPTR	Q7 is open
VPQB7TR	The switch status for QB7 is valid.
EXDU_BPB	No transmission error from the bay that contains the above information.

For bay n, these conditions are valid:

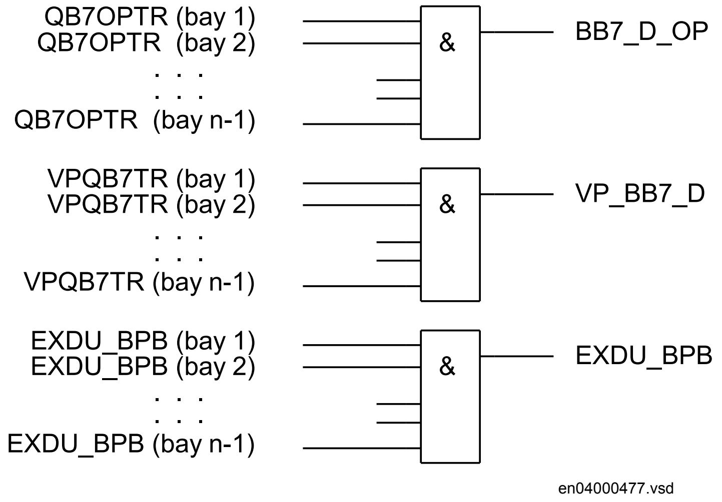


Figure 110: Signals from bypass busbar in line bay n.

9.4.10.3 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus sections, the busbar-busbar connection could exist via the bus-section disconnector and bus-coupler within the other bus section.

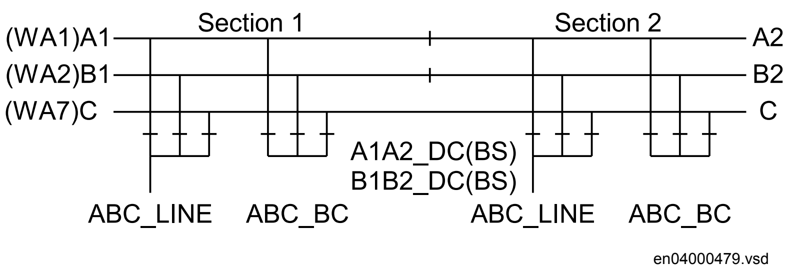


Figure 111: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series can not handle the transfer bus (WA7)C.

To derive the signals:

Signal	
BC_12_CL	A bus-coupler connection exists between busbar WA1 and WA2.
BC_17_OP	No bus-coupler connection between busbar WA1 and WA7.
BC_17_CL	A bus-coupler connection exists between busbar WA1and WA7.
BC_27_OP	No bus-coupler connection between busbar WA2 and WA7.

Table continues on next page

Signal	
BC_27_CL	A bus-coupler connection exists between busbar WA2 and WA7.
VP_BC_12	The switch status of BC_12 is valid.
VP_BC_17	The switch status of BC_17 is valid.
VP_BC_27	The switch status of BC_27 is valid.
EXDU_BC	No transmission error from any bus-coupler bay (BC).

These signals from each bus-coupler bay (ABC_BC) are needed:

Signal	
BC12CLTR	A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA2.
BC17OPTR	No bus-coupler connection through the own bus-coupler between busbar WA1 and WA7.
BC17CLTR	A bus-coupler connection through the own bus-coupler exists between busbar WA1 and WA7.
BC27OPTR	No bus-coupler connection through the own bus-coupler between busbar WA2 and WA7.
BC27CLTR	A bus-coupler connection through the own bus-coupler exists between busbar WA2 and WA7.
VPBC12TR	The switch status of BC_12 is valid.
VPBC17TR	The switch status of BC_17 is valid.
VPBC27TR	The switch status of BC_27 is valid.
EXDU_BC	No transmission error from the bay that contains the above information.

These signals from each bus-section disconnector bay (A1A2_DC) are also needed. For B1B2_DC, corresponding signals from busbar B are used. The same type of module (A1A2_DC) is used for different busbars, that is, for both bus-section disconnector A1A2_DC and B1B2_DC.

Signal	
DCOPTR	The bus-section disconnector is open.
DCCLTR	The bus-section disconnector is closed.
VPDCTR	The switch status of bus-section disconnector DC is valid.
EXDU_DC	No transmission error from the bay that contains the above information.

If the busbar is divided by bus-section circuit breakers, the signals from the bus-section coupler bay (A1A2_BS), rather than the bus-section disconnector bay (A1A2_DC) must be used. For B1B2_BS, corresponding signals from busbar B are used. The same type of module (A1A2_BS) is used for different busbars, that is, for both bus-section circuit breakers A1A2_BS and B1B2_BS.

Signal	
S1S2OPTR	No bus-section coupler connection between bus-sections 1 and 2.
S1S2CLTR	A bus-section coupler connection exists between bus-sections 1 and 2.
VPS1S2TR	The switch status of bus-section coupler BS is valid.
EXDU_BS	No transmission error from the bay that contains the above information.

For a line bay in section 1, these conditions are valid:

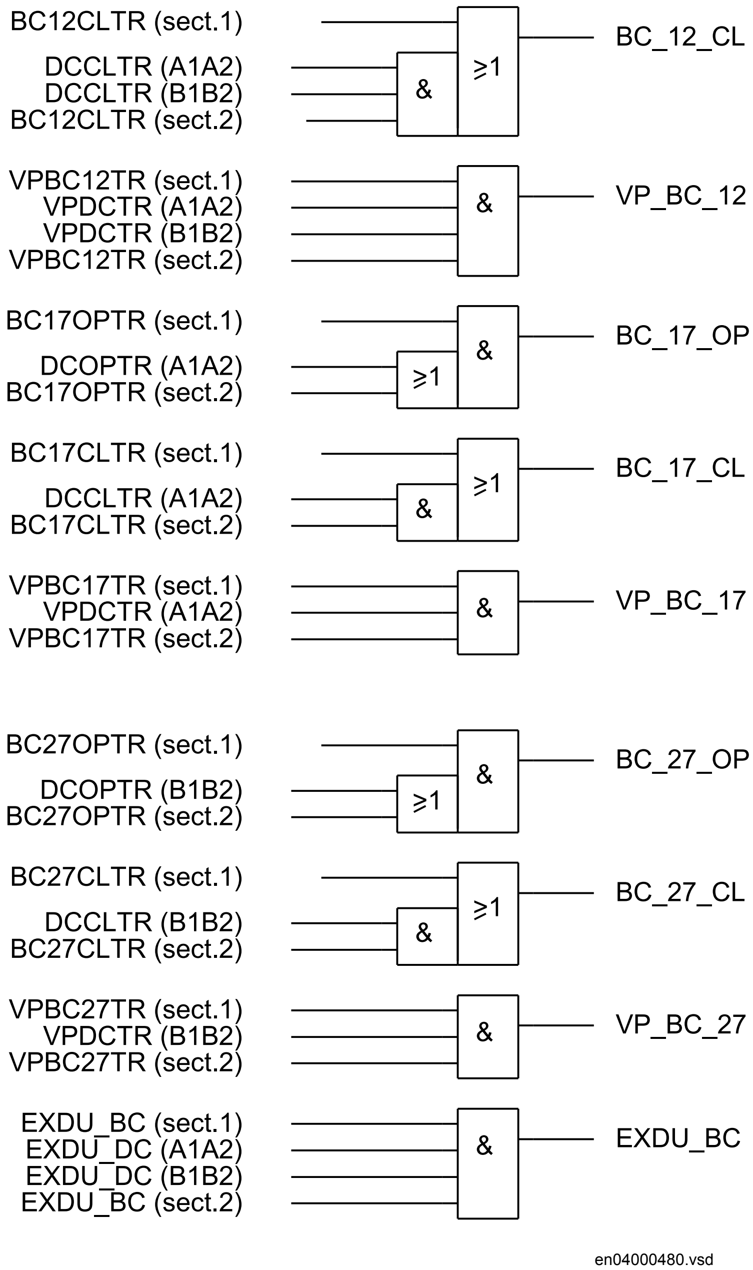


Figure 112: Signals to a line bay in section 1 from the bus-coupler bays in each section

For a line bay in section 2, the same conditions as above are valid by changing section 1 to section 2 and vice versa.

9.4.10.4 Configuration setting

If there is no bypass busbar and therefore no QB7 disconnector, then the interlocking for QB7 is not used. The states for QB7, QC71, BB7_D, BC_17, BC_27 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB7_OP = 1
- QB7_CL = 0

- QC71_OP = 1
- QC71_CL = 0

- BB7_D_OP = 1

- BC_17_OP = 1
- BC_17_CL = 0
- BC_27_OP = 1
- BC_27_CL = 0

- EXDU_BPB = 1

- VP_BB7_D = 1
- VP_BC_17 = 1
- VP_BC_27 = 1

If there is no second busbar WA2 and therefore no QB2 disconnector, then the interlocking for QB2 is not used. The state for QB2, QC21, BC_12, BC_27 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB2_OP = 1
- QB2_CL = 0

- QC21_OP = 1
- QC21_CL = 0

- BC_12_CL = 0
- BC_27_OP = 1
- BC_27_CL = 0

- VP_BC_12 = 1

9.4.11 Interlocking for transformer bay AB_TRAFO

9.4.11.1 Application

The Interlocking for transformer bay (AB_TRAFO) module is used for a transformer bay connected to a double busbar arrangement according to figure 113. The module is used when there is no disconnector between circuit breaker and transformer. Otherwise, the Interlocking for line bay (ABC_LINE) module can be used. This module can also be used in single busbar arrangements.

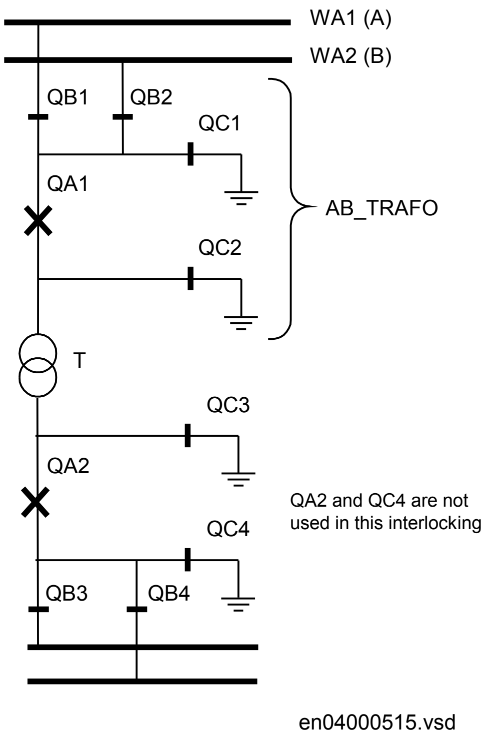


Figure 113: Switchyard layout AB_TRAFO

The signals from other bays connected to the module AB_TRAFO are described below.

9.4.11.2 Signals from bus-coupler

If the busbar is divided by bus-section disconnectors into bus-sections, the busbar-busbar connection could exist via the bus-section disconnector and bus-coupler within the other bus-section.

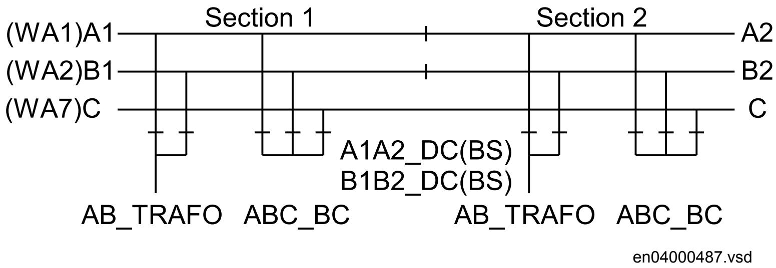


Figure 114: Busbars divided by bus-section disconnectors (circuit breakers)

The interlocking functionality in 650 series cannot handle the transfer bus (WA7)C.

The project-specific logic for input signals concerning bus-coupler are the same as the specific logic for the line bay (ABC_LINE):

Signal	
BC_12_CL	A bus-coupler connection exists between busbar WA1 and WA2.
VP_BC_12	The switch status of BC_12 is valid.
EXDU_BC	No transmission error from bus-coupler bay (BC).

The logic is identical to the double busbar configuration “Signals from bus-coupler“.

9.4.11.3 Configuration setting

If there is no second busbar B and therefore no QB2 disconnector, then the interlocking for QB2 is not used. The state for QB2, QC21, BC_12 are set to open by setting the appropriate module inputs as follows. In the functional block diagram, 0 and 1 are designated 0=FALSE and 1=TRUE:

- QB2_OP = 1
- QB2QB2_CL = 0

- QC21_OP = 1
- QC21_CL = 0

- BC_12_CL = 0
- VP_BC_12 = 1

If there is no second busbar B at the other side of the transformer and therefore no QB4 disconnector, then the state for QB4 is set to open by setting the appropriate module inputs as follows:

- QB4_OP = 1
- QB4_CL = 0

9.5 Logic rotating switch for function selection and LHMI presentation SLGGIO

9.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic rotating switch for function selection and LHMI presentation	SLGGIO	-	-

9.5.2 Application

The Logic rotating switch for function selection and LHMI presentation (SLGGIO) function block (or the selector switch function block, as it is also known) is used within the ACT tool in order to get a selector switch functionality similar with the one provided by a hardware selector switch. Hardware selector switches are used extensively by utilities, in order to have different functions operating on pre-set values. Hardware switches are however sources for maintenance issues, lower system reliability and extended purchase portfolio. The virtual selector switches eliminate all these problems.

The SLGGIO function block has two operating inputs (UP and DOWN), one blocking input (BLOCK) and one operator position input (PSTO).

The SLGGIO function can be activated both from the LHMI and from external sources (switches), via the IED binary inputs. It also allows the operation from remote (like the station computer). The SWPOSN is an integer value output, giving the actual output number. Since the number of positions of the switch can be established by settings (see below), one must be careful in coordinating the settings with the configuration (if one sets the number of positions to x in settings – for example, there will be only the first x outputs available from the block in the configuration). Also the frequency of the (UP or DOWN) pulses should be lower than the setting *tPulse*.

From the LHMI, there are two modes of operating the switch: from the menu and from the Single-line diagram (SLD).

9.5.3 Setting guidelines

The following settings are available for the Logic rotating switch for function selection and LHMI presentation function:

Operation: Sets the operation of the function *On* or *Off*.

NrPos: Sets the number of positions in the switch (max. 32). This setting influence the behavior of the switch when changes from the last to the first position.

OutType: Steady or Pulsed.

tPulse: In case of a pulsed output, it gives the length of the pulse (in seconds).

tDelay: The delay between the UP or DOWN activation signal positive front and the output activation.

StopAtExtremes: Sets the behavior of the switch at the end positions – if set to 0, when pressing UP while on first position, the switch will jump to the last position; when pressing DOWN at the last position, the switch will jump to the first position; when set to 1, no jump will be allowed.

9.6 Selector mini switch VSGGIO

9.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Selector mini switch	VSGGIO	-	-

9.6.2 Application

Selector mini switch (VSGGIO) function is a multipurpose function used in the configuration tool in PCM600 for a variety of applications, as a general purpose switch. VSGGIO can be used for both acquiring an external switch position (through the IPOS1 and the IPOS2 inputs) and represent it through the single line diagram symbols (or use it in the configuration through the outputs POS1 and POS2) as well as, a command function (controlled by the PSTO input), giving switching commands through the CMDPOS12 and CMDPOS21 outputs.

The output POSITION is an integer output, showing the actual position as an integer number 0 – 3.

An example where VSGGIO is configured to switch Autorecloser on–off from a button symbol on the local HMI is shown in figure 115. The I and O buttons on the local HMI are used for on–off operations.

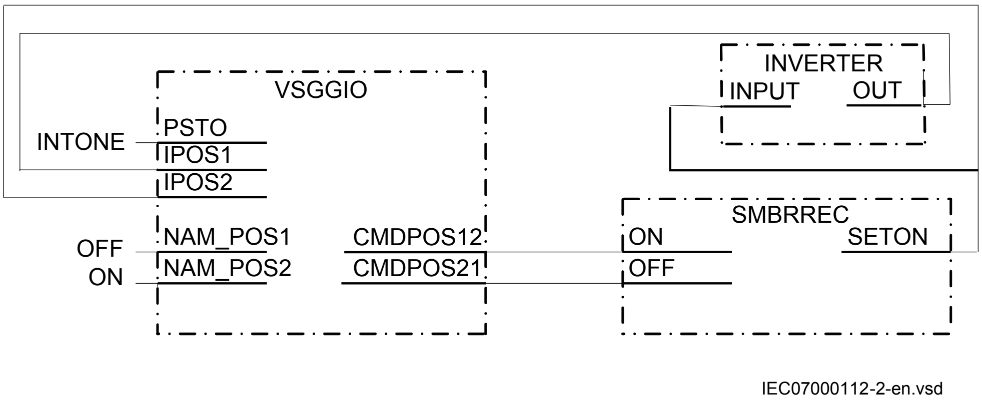


Figure 115: Control of Autorecloser from local HMI through Selector mini switch

9.6.3 Setting guidelines

Selector mini switch (VSGGIO) function can generate pulsed or steady commands (by setting the *Mode* parameter). When pulsed commands are generated, the length of the pulse can be set using the *tPulse* parameter. Also, being accessible on the single line diagram (SLD), this function block has two control modes (settable through *CtlModel*): Direct and Select-Before-Execute.

9.7 IEC61850 generic communication I/O functions DPGGIO

9.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	DPGGIO	-	-

9.7.2 Application

The IEC61850 generic communication I/O functions (DPGGIO) function block is used to send three logical outputs to other systems or equipment in the substation. The three outputs are named “OPEN”, “CLOSE” and “VALID”, since this function block is intended to be used as a position indicator block in interlocking and reservation station-wide logics.

9.7.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

9.8 Single point generic control 8 signals SPC8GGIO

9.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single point generic control 8 signals	SPC8GGIO	-	-

9.8.2 Application

The Single point generic control 8 signals (SPC8GGIO) function block is a collection of 8 single point commands, designed to bring in commands from REMOTE (SCADA) to those parts of the logic configuration that do not need complicated function blocks that have the capability to receive commands (for example SCSWI). In this way, simple commands can be sent directly to the IED outputs, without confirmation. Confirmation (status) of the result of the commands is supposed to be achieved by other means, such as binary inputs and SPGGIO function blocks.

PSTO is the universal operator place selector for all control functions. Even if PSTO can be configured to allow LOCAL or ALL operator positions, the only functional position usable with the SP8GGIO function block is REMOTE.

9.8.3 Setting guidelines

The parameters for the Single point generic control 8 signals function are set via the local HMI or Protection and Control IED Manager (PCM600).:

Operation: turning the function operation *On/Off*.

There are two settings for every command output (totally 8):

Latchedx: decides if the command signal for output *x* is latched (steady) or pulsed.

tPulsex: if *Latchedx* is set to *pulsed*, then *tPulsex* will set the length of the pulse (in seconds).

9.9 Automation bits AUTOBITS

9.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Automation bits	AUTOBITS	-	-

9.9.2 Application

The AUTOBITS function block (or the automation bits function block) is used within PCM600 in order to get into the configuration the commands coming through the DNP3.0 protocol. The AUTOBITS function block have 32 individual outputs which each can be mapped as a Binary Output point in DNP. The output is operated by a "Object 12" in DNP. This object contains parameters for control-code, count, on-time and off-time. To operate an AUTOBITS output point, send a control-code of latch-On, latch-Off, pulse-On, pulse-Off, Trip or Close. The remaining parameters will be regarded were appropriate. ex: pulse-On, on-time=100, off-time=300, count=5 would give 5 positive 100 ms pulses, 300 ms apart.

See Communication manual for a detailed description och the DNP 3.0 protocol.

9.9.3 Setting guidelines

The AUTOBITS function block has one setting, *(Operation: On/Off)* enabling or disabling the function. A user defined name for each command signal can be set in ACT. These names will be seen in the DNP communication configuration tool in PCM600.

Section 10 Logic

10.1 Tripping logic SMPPTRC

10.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Tripping logic	SMPPRTC	I->O	94

10.1.2 Application

All trip signals from the different protection functions shall be routed through the trip logic. In its simplest alternative the logic will only link the TRIP signal and make sure that it is long enough.

Tripping logic (SMPPTRC) in the IED for protection, control and monitoring offers three-phase tripping.

The three-phase trip for all faults offers a simple solution and is often sufficient in well meshed transmission systems and in sub-transmission systems.

One SMPPTRC function block should be used for each breaker, if the line is connected to the substation via more than one breaker.

To prevent closing of a circuit breaker after a trip the function can block the closing.

10.1.2.1 Three phase tripping

A simple application with three-phase tripping from the logic block utilizes a part of the function block. Connect the inputs from the protection function blocks to the input TRIN. If necessary (normally the case) use a logic OR block to combine the different function outputs to this input. Connect the output TRIP to the digital Output/s on the IO board.

For special applications such as Lock-out refer to the separate section below. The typical connection is shown below in figure 116. Signals that are not used are dimmed.

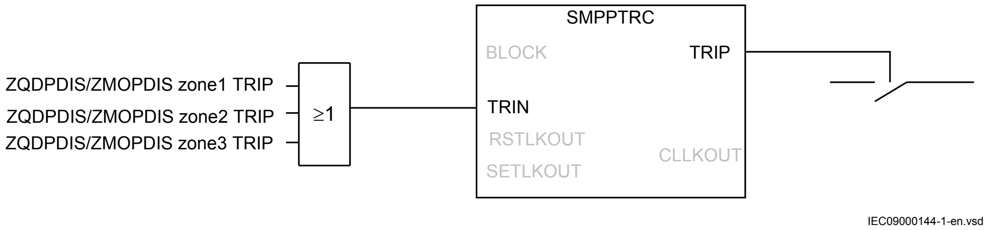


Figure 116: Tripping logic (SMPPTRC) function is used for a simple three phase tripping application

10.1.2.2 Lock-out

This function block is provided with possibilities to initiate lock-out. The lock-out can be set to only activate the block closing output CLLKOUT or initiate the block closing output and also maintain the trip signal (latched trip).

The lock-out can then be manually reset after checking the primary fault by activating the input reset Lock-Out RSTLKOUT.

If external conditions are required to initiate Lock-out but not initiate trip this can be achieved by activating input SETLKOUT. The setting *Auto-Lock = OFF* will mean that the internal trip will not activate lock-out so only initiation of the input SETLKOUT will result in lock-out. This is normally the case for overhead line protection where most faults are transient. Unsuccessful auto-reclose and back-up zone tripping can in such cases be connected to initiate Lock-out by activating the input SETLKOUT.

10.1.2.3 Blocking of the function block

Blocking can be initiated internally by logic, or by the operator using a communication channel. Total blockage of Tripping logic (SMPPTRC) function is done by activating the input BLOCK and can be used to block the output of SMPPTRC in the event of internal failures.

10.1.3 Setting guidelines

The parameters for Tripping logic (SMPPTRC) function are set via the local HMI or Protection and Control IED Manager (PCM600).

The following trip parameters can be set to regulate tripping.

Operation: Sets the mode of operation. *Off* switches the tripping off. The normal selection is *On*.

TripLockout: Sets the scheme for lock-out. *Off* only activates lock-out output. *On* activates the lock-out output and latching output contacts. The normal selection is *Off*.

AutoLock: Sets the scheme for lock-out. *Off* only activates lock-out through the input SETLKOUT. *On*also allows activation from trip function itself and activates the lockout output. The normal selection is *Off*.

tTripMin: Sets the required minimum duration of the trip pulse. It should be set to ensure that the breaker is tripped and if a signal is used to start breaker failure protection (CCRBRF) function longer than the back-up trip timer in the CCRBRF. Normal setting is *0.150s*.

10.2 Trip matrix logic TMAGGIO

10.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Trip matrix logic	TMAGGIO	-	-

10.2.2 Application

Trip matrix logic (TMAGGIO) function is used to route trip signals and/or other logical output signals to different output contacts on the IED.

TMAGGIO output signals and the physical outputs are available in PCM600 and this allows the user to adapt the signals to the physical tripping outputs according to the specific application needs.

10.2.3 Setting guidelines

Operation: Operation of function On/off.

PulseTime: Defines the pulse time delay. When used for direct tripping of circuit breaker(s) the pulse time delay shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

OnDelay: Used to prevent output signals to be given for spurious inputs. Normally set to 0 or a low value.

OffDelay: Defines a minimum on time for the outputs. When used for direct tripping of circuit breaker(s) the off delay time shall be set to approximately 0.150 seconds in order to obtain satisfactory minimum duration of the trip pulse to the circuit breaker trip coils.

ModeOutputx: Defines if output signal OUTPUTx (where x=1-3) is steady or pulsed.

10.3 Configurable logic blocks

10.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
OR Function block	OR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Inverter function block	INVERTER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
PULSETIMER function block	PULSETIMER	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Controllable gate function block	GATE	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Exclusive OR function block	XOR	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Logic loop delay function block	LOOPDELAY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Timer function block	TIMERSET	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
AND function block	AND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Set-reset memory function block	SRMEMORY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Reset-set with memory function block	RSMEMORY	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
ORQT function block	ORQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
INVERTERQT function block	INVERTERQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse timer function block	PULSTIMERQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
XORQT function block	XORQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Settable timer function block	TIMERSETQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
ANDQT function block	ANDQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Set/reset logic component	SRMEMORYQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Reset/set logic component	RSMEMORYQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
INVALIDQT function block	INVALIDQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single indication signal combining function block	INDCOMBSPQT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Single indication signal extractor function block	INDEXTSPQT	-	-

10.3.2 Application

Two sets of logic blocks and timers are available for adapting the IED configuration to the specific application needs. One set consists of standard logic blocks like AND, OR etc and another set of blocks that, beside the normal logical function, also have the capability to propagate timestamp and quality. Those blocks have a designation including the letters QT, like ANDQT, ORQT etc.

There are no settings for AND gates, OR gates, inverters or XOR gates as well as, for ANDQT gates, ORQT gates or XORQT gates.

For normal On/Off delay and pulse timers the time delays and pulse lengths are set from the local HMI or via the PST tool.

Both timers in the same logic block (the one delayed on pick-up and the one delayed on drop-out) always have a common setting value.

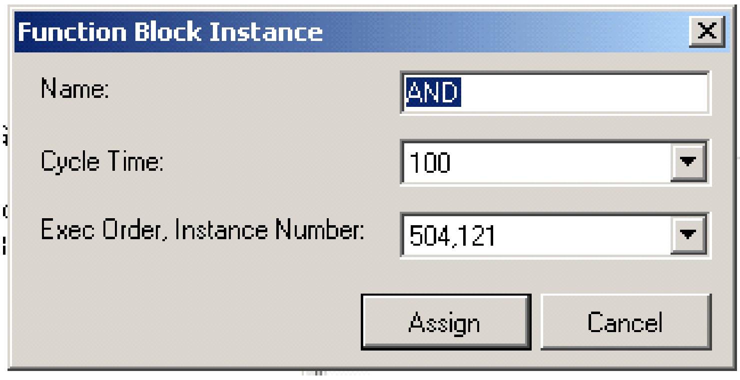
For controllable gates, settable timers and SR flip-flops with memory, the setting parameters are accessible via the local HMI or via the PST tool.

10.3.3.1 Configuration

Logic is configured using the ACT configuration tool.

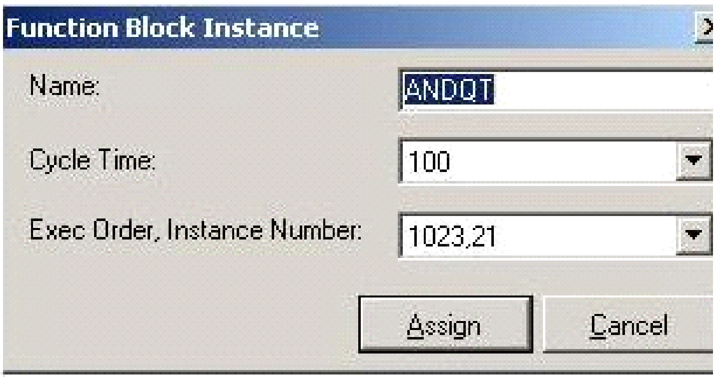
Execution of functions as defined by the configurable logic blocks runs according to a fixed sequence with different cycle times.

For each cycle time, the function block is given an serial execution number. This is shown when using the ACT configuration tool with the designation of the function block and the cycle time, see example below.



IEC09000695-1-en.vsd

Figure 117: Example designation, serial execution number and cycle time for logic function



IEC09000310-1-en.vsd

Figure 118: Example designation, serial execution number and cycle time for logic function that also propagates timestamp and quality of input signals

The execution of different function blocks within the same cycle is determined by the order of their serial execution numbers. Always remember this when connecting two or more logical function blocks in series.

Always be careful when connecting function blocks with a fast cycle time to function blocks with a slow cycle time.
Remember to design the logic circuits carefully and always check the execution sequence for different functions. In other cases, additional time delays must be introduced into the logic schemes to prevent errors, for example, race between functions.
Default value on all four inputs of the AND and ANDQT gate are logical 1 which makes it possible for the user to just use the required number of inputs and leave the rest un-connected. The

output OUT has a default value 0 initially, which will suppress one cycle pulse if the function has been put in the wrong execution order.

10.4 Fixed signals FXDSIGN

10.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Fixed signals	FXDSIGN	-	-

10.4.2 Application

The Fixed signals function (FXDSIGN) generates a number of pre-set (fixed) signals that can be used in the configuration of an IED, either for forcing the unused inputs in other function blocks to a certain level/value, or for creating a certain logic.

Example for use of GRP_OFF signal in FXDSIGN

The Restricted earth fault function can be used both for auto-transformers and normal transformers.

When used for auto-transformers, information from both windings parts, together with the neutral point current, needs to be available to the function. This means that three inputs are needed.

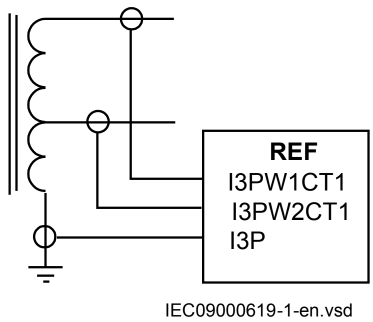


Figure 119: Restricted earth fault protection function inputs for autotransformer application

For normal transformers only one winding and the neutral point is available. This means that only two inputs are used. Since all group connections are mandatory to be connected, the third input needs to be connected to something, which is the GRP_OFF signal in FXDSIGN function block.

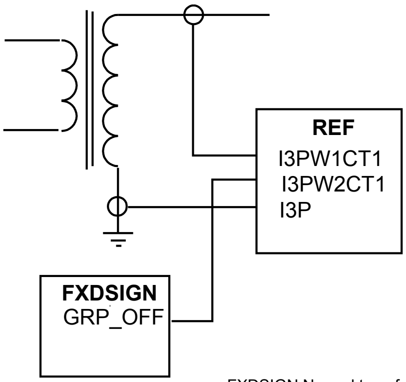


Figure 120: Restricted earth fault protection function inputs for normal transformer application

10.5 Boolean 16 to integer conversion B16I

10.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion	B16I	-	-

10.5.2 Application

Boolean 16 to integer conversion function (B16I) is used to transform a set of 16 binary (logical) signals into an integer. It can be used – for example, to connect logical output signals from a function (like distance protection) to integer inputs from another function (like line differential protection). B16I function does not have a logical node mapping.

10.5.3 Settings

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600)

10.6 Boolean 16 to integer conversion with logic node representation B16IFCVI

10.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Boolean 16 to integer conversion with logic node representation	B16IFCVI	-	-

10.6.2 Application

Boolean 16 to integer conversion with logic node representation function (B16IFCVI) is used to transform a set of 16 binary (logical) signals into an integer. B16IFCVI function can receive an integer from a station computer – for example, over IEC61850. These functions are very useful when you want to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. B16IFCVI function has a logical node mapping in IEC61850.

10.6.3 Settings

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600)

10.7 Integer to boolean 16 conversion IB16A

10.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion	IB16A	-	-

10.7.2 Application

Integer to boolean 16 conversion function (IB16A) is used to transform an integer into a set of 16 binary (logical) signals. It can be used – for example, to connect integer output signals from a function (like distance protection) to binary (logical) inputs in another function (like line differential protection). IB16A function does not have a logical node mapping.

10.7.3 Settings

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600)

10.8 Integer to boolean 16 conversion with logic node representation IB16FCVB

10.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Integer to boolean 16 conversion with logic node representation	IB16FCVB	-	-

10.8.2 Application

Integer to boolean 16 conversion with logic node representation function (IB16FCVB) is used to transform an integer into a set of 16 binary (logical) signals. IB16FCVB function can receive an integer from a station computer – for example, over IEC61850. These functions are very useful when you want to generate logical commands (for selector switches or voltage controllers) by inputting an integer number. IB16FCVB function has a logical node mapping in IEC61850.

10.8.3 Settings

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600)

Section 11 Monitoring

11.1 IEC61850 generic communication I/O functions SPGGIO

11.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	SPGGIO	-	-

11.1.2 Application

IEC 61850 generic communication I/O functions (SPGGIO) function is used to send one single logical output to other systems or equipment in the substation. It has one visible input, that should be connected in ACT tool.

11.1.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

11.2 IEC61850 generic communication I/O functions 16 inputs SP16GGIO

11.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions 16 inputs	SP16GGIO	-	-

11.2.2 Application

The SP16GGIO function block is used to send up to 16 logical signals to other systems or equipment in the substation. Inputs should be connected in ACT.

11.2.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

11.3 IEC61850 generic communication I/O functions MVGGIO

11.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850 generic communication I/O functions	MVGGIO	-	-

11.3.2 Application

IEC 61850 generic communication I/O functions (MVGGIO) function is used to send the instantaneous value of an analog output to other systems or equipment in the substation. It can also be used inside the same IED, to attach a RANGE aspect to an analog value and to permit measurement supervision on that value.

11.3.3 Setting guidelines

The settings available for IEC61850 generic communication I/O functions (MVGGIO) function allows the user to choose a deadband and a zero deadband for the monitored signal. Values within the zero deadband are considered as zero.

The high and low limit settings provides limits for the high-high-, high, normal, low and low-low ranges of the measured value. The actual range of the measured value is shown on the range output of MVGGIO function block. When a measured value expander block (MVEXP) is connected to the range output, the logical outputs of the MVEXP are changed accordingly.

11.4 Measurements

11.4.1 Application

Measurement functions is used for power system measurement, supervision and reporting to the local HMI, monitoring tool within PCM600 or to station level for example, via IEC 61850. The possibility to continuously monitor measured values of active power, reactive power, currents, voltages, frequency, power factor etc. is vital for efficient production, transmission and distribution of electrical energy. It provides to the system operator fast and easy overview of the present status of the power system. Additionally, it can be used during testing and commissioning of protection and control IEDs in order to verify proper operation and connection of instrument transformers (CTs & VTs). During normal service by periodic comparison of the measured value from the IED with other independent meters the proper operation of the IED analogue measurement chain can be verified. Finally, it can be used to verify proper direction orientation for distance or directional overcurrent protection function.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

All measured values can be supervised with four settable limits that is, low-low limit, low limit, high limit and high-high limit. A zero clamping reduction is also supported, that is, the measured value below a settable limit is forced to zero which reduces the impact of noise in the inputs. There are no interconnections regarding any settings or parameters, neither between functions nor between signals within each function.

Zero clampings are handled by *ZeroDb* for each signal separately for each of the functions. For example, the zero clamping of U12 is handled by *UL12ZeroDb* in VMMXU, zero clamping of I1 is handled by *ILZeroDb* in CMMXU.

Dead-band supervision can be used to report measured signal value to station level when change in measured value is above set threshold limit or time integral of all changes since the last time value updating exceeds the threshold limit. Measure value can also be based on periodic reporting.

The measurement function, CVMMXN, provides the following power system quantities:

- P, Q and S: three phase active, reactive and apparent power
- PF: power factor
- U: phase-to-phase voltage amplitude
- I: phase current amplitude
- F: power system frequency

The output values are displayed in the local HMI under **Main menu/Tests/ Function status/Monitoring/CVMMXN/Outputs**

The measuring functions CMMXU, VNMMXU and VMMXU provides physical quantities:

- I: phase currents (amplitude and angle) (CMMXU)
- U: voltages (phase-to-earth and phase-to-phase voltage, amplitude and angle) (VMMXU, VNMMXU)

It is possible to calibrate the measuring function above to get better then class 0.5 presentation. This is accomplished by angle and amplitude compensation at 5, 30 and 100% of rated current and at 100% of rated voltage.

The power system quantities provided, depends on the actual hardware, (TRM) and the logic configuration made in PCM600.

The measuring functions CMSQI and VMSQI provides sequential quantities:

- I: sequence currents (positive, zero, negative sequence, amplitude and angle)
- U: sequence voltages (positive, zero and negative sequence, amplitude and angle).

The CVMMXN function calculates three-phase power quantities by using fundamental frequency phasors (DFT values) of the measured current respectively voltage signals. The measured power quantities are available either, as instantaneously calculated quantities or, averaged values over a period of time (low pass filtered) depending on the selected settings.

11.4.2 Setting guidelines

The available setting parameters of the measurement function CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

The parameters for the Measurement functions CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU are set via the local HMI or PCM600.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On. Every function instance (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) can be taken in operation (On) or out of operation (Off). Default setting is Off.

The following general settings can be set for the **Measurement function** (CVMMXN).

PowAmpFact: Amplitude factor to scale power calculations. The setting range is 0.000-6.000. Default setting is 1.000, which also is a typical setting.

PowAngComp: Angle compensation for phase shift between measured I & U. The setting range is ±180 degrees. Default setting is 0 degree, which also is a typical setting.

Mode: Selection of measured current and voltage. There are 9 different ways of calculating monitored three-phase values depending on the available VT inputs connected to the IED. See parameter group setting table. Default setting expects complete VT information (L1,L2,L3).

k: Low pass filter coefficient for power measurement, U and I. The setting range is 0.0-1.0. Default setting is 0.0 that is, no filtering, which also is a typical setting.

UAmpCompY: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100. The setting range is ± 10%. Default setting is 0.

IAmpCompY: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100. The setting range is ± 10%. Default setting is 0.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100. The setting range is ± 10 degrees. Default setting is 0.

The following general settings can be set for the **Phase-phase current measurement** (CMMXU).

IAmpCompY: Amplitude compensation to calibrate current measurements at Y% of Ir, where Y is equal to 5, 30 or 100. The setting range is ± 10%. Default setting is 0.

IAngCompY: Angle compensation to calibrate angle measurements at Y% of Ir, where Y is equal to 5, 30 or 100. The setting range is ± 10 degrees. Default setting is 0.

The following general settings can be set for the **Phase-phase voltage measurement** (VMMXU).

UAmpCompY: Amplitude compensation to calibrate voltage measurements at Y% of Ur, where Y is equal to 5, 30 or 100. The setting range is ± 10%. Default setting is 0.

UAngCompY: Angle compensation to calibrate angle measurements at Y% of Ur, where Y is equal to 5, 30 or 100. The setting range is ± 10 degrees. Default setting is 0.

The following general settings can be set for **all monitored quantities** included in the functions (CVMMXN, CMMXU, VMMXU, CMSQI, VMSQI, VNMMXU) X in setting names below equals S, P, Q, PF, U, I, F, IL1-3, UL1-3UL12-31, I1, I2, 3I0, U1, U2 or 3U0.

Xmin: Minimum value for analogue signal X.

Xmax: Maximum value for analogue signal *X*.

Xmin and *Xmax* values are directly set in applicable measuring unit, V, A etc. for all measurement functions, except CVMMXN where *Xmin* and *Xmax* values are set in % of *SBase*.

XZeroDb: Zero point clamping. A signal value less than *XZeroDb* is forced to zero. The setting range is 0-100000 in steps of 0.001% related to measuring range. Default setting is 0.

XRepTyp: Reporting type. Cyclic (*Cyclic*), amplitude deadband (*Dead band*) or integral deadband (*Int deadband*). The reporting interval is controlled by the parameter *XDbRepInt*. Default setting is *Cyclic*.

XDbRepInt: Reporting deadband setting. Cyclic reporting is the setting value and is reporting interval in seconds. Amplitude deadband is the setting value in % of measuring range. Integral deadband setting is the integral area, that is, measured value in % of measuring range multiplied by the time between two measured values. Default setting is 10.

Limits are directly set in applicable measuring unit, V, A etc. for all measurement functions, except CVMMXN where limits are set in % of *SBase*.

XHiHiLim: High-high limit. The setting range is ±10000000000 in steps of 0.001. Default setting is $900 \cdot 10^{6}$ (900 MW/MVar/MVA).

XHiLim: High limit. Default setting is $800 \cdot 10^{6}$ (800 MW/MVar/MVA).

XLowLim: Low limit. Default setting is $-800 \cdot 10^{6}$.

XLowLowLim: Low-low limit. Default setting is $-900 \cdot 10^{6}$.

XLimHyst: Hysteresis value in % of range and is common for all limits. The setting range is 0-100 in steps of 0.001. Default setting is 5%.

All phase angles are presented in relation to defined reference channel. The parameter *PhaseAngleRef* defines the reference, see settings for analog input modules in PCM600.

Calibration curves

It is possible to calibrate the functions (CVMMXN, CMMXU, VNMMXU and VMMXU) to get class 0.5 presentations of currents, voltages and powers. This is accomplished by amplitude and angle compensation at 5, 30 and 100% of rated current and voltage. The compensation curve will have the characteristic for amplitude and angle compensation of currents as shown in figure 121 (example). The first phase will be used as reference channel and compared with the curve for calculation of factors. The factors will then be used for all related channels.

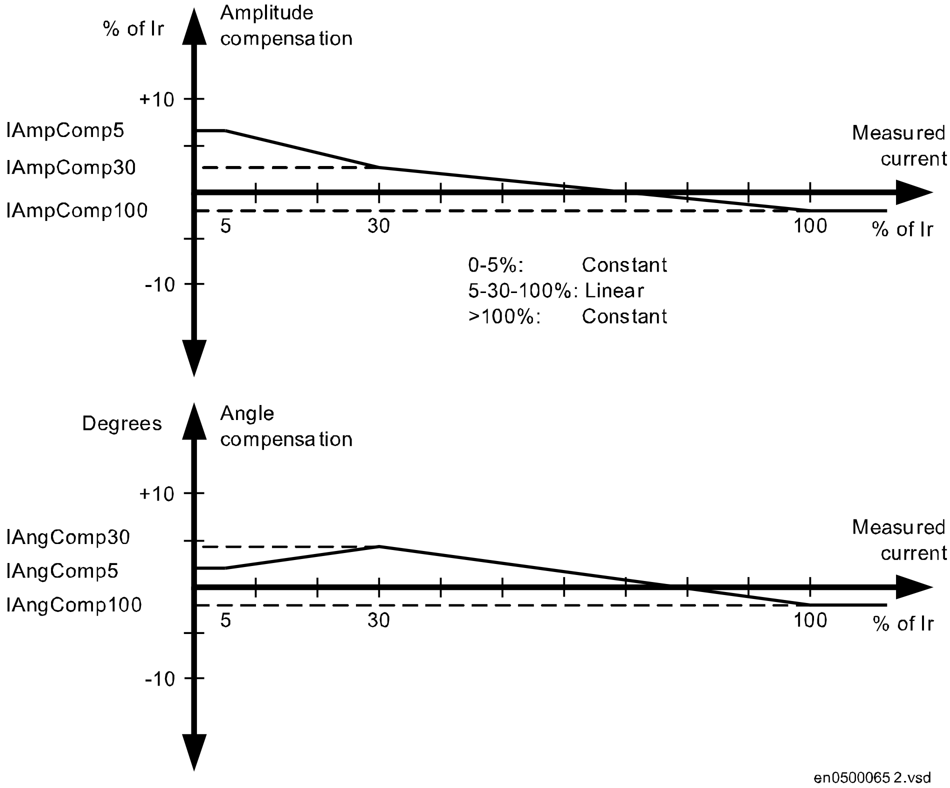


Figure 121: Calibration curves

11.4.3 Setting examples

Three setting examples, in connection to Measurement function (CVMMXN), are provided:

- Measurement function (CVMMXN) application for a 400 kV OHL
- Measurement function (CVMMXN) application on the secondary side of a transformer
- Measurement function (CVMMXN) application for a generator

For each of them detail explanation and final list of selected setting parameters values will be provided.

The available measured values of an IED are depending on the actual hardware (TRM) and the logic configuration made in PCM600.

11.4.3.1 Measurement function application for a 400 kV OHL

Single line diagram for this application is given in the figure 122:

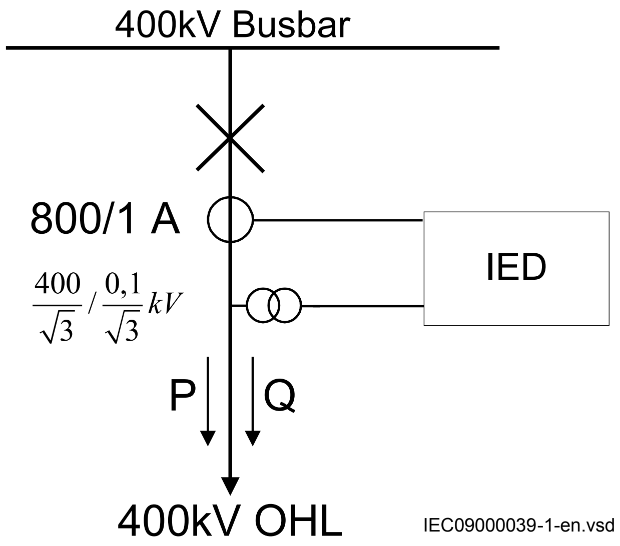


Figure 122: Single line diagram for 400 kV OHL application

In order to monitor, supervise and calibrate the active and reactive power as indicated in the above figure it is necessary to do the following:

1. Set correctly CT and VT data and phase angle reference channel *PhaseAngleRef*(see settings for analog input modules in PCM600) using PCM600 for analogue input channels
2. Connect, in PCM600, measurement function to three-phase CT and VT inputs
3. Set under General settings parameters for the Measurement function Report:
    - general settings as shown in table 14.
    - level supervision of active power as shown in table 15.
    - calibration parameters as shown in table 16.

Table 14: General settings parameters for the Measurement function

Setting	Short Description	Selected value	Comments
Operation	Operation Off/On	On	Function must be "On"
PowAmpFact	Amplitude factor to scale power calculations	1.000	It can be used during commissioning to achieve higher measurement accuracy. Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & U	0.0	It can be used during commissioning to achieve higher measurement accuracy. Typically no angle compensation is required. As well here required direction of P & Q measurement is towards protected object (as per IED internal default direction)
Mode	Selection of measured current and voltage	L1, L2, L3	All three phase to earth VT inputs are available
k	Low pass filter coefficient for power measurement, U and I	0.00	Typically no additional filtering is required

Table 15: Settings parameters for level supervision

Setting	Short Description	Selected value	Comments
PMin	Minimum value	-750	Minimum expected load
PMax	Minimum value	750	Maximum expected load
PZeroDb	Zero point clamping in 0.001% of range	3000	Set zero point clamping to 45 MW that is, 3% of 1500 MW
PRepTyp	Reporting type	db	Select amplitude deadband supervision
PDbRepInt	Cycl: Report interval (s), Db: In % of range, Int Db: In %s	2	Set ±Δdb=30 MW that is, 2% (larger changes than 30 MW will be reported)
PHiHiLim	High High limit (physical value)	600	High alarm limit that is, extreme overload alarm
PHiLim	High limit (physical value)	500	High warning limit that is, overload warning
PLowLim	Low limit (physical value)	-800	Low warning limit. Not active
PLowLowlLim	Low Low limit (physical value)	-800	Low alarm limit. Not active
PLimHyst	Hysteresis value in % of range (common for all limits)	2	Set ±ΔHysteresis MW that is, 2%

Table 16: Settings for calibration parameters

Setting	Short Description	Selected value	Comments
IAmpComp5	Amplitude factor to calibrate current at 5% of Ir	0.00	
IAmpComp30	Amplitude factor to calibrate current at 30% of Ir	0.00	
IAmpComp100	Amplitude factor to calibrate current at 100% of Ir	0.00	
UAmpComp5	Amplitude factor to calibrate voltage at 5% of Ur	0.00	
UAmpComp30	Amplitude factor to calibrate voltage at 30% of Ur	0.00	
UAmpComp100	Amplitude factor to calibrate voltage at 100% of Ur	0.00	
IAngComp5	Angle calibration for current at 5% of Ir	0.00	
IAngComp30	Angle pre-calibration for current at 30% of Ir	0.00	
IAngComp100	Angle pre-calibration for current at 100% of Ir	0.00	

11.4.3.2 Measurement function application for a power transformer

Single line diagram for this application is given in figure 123.

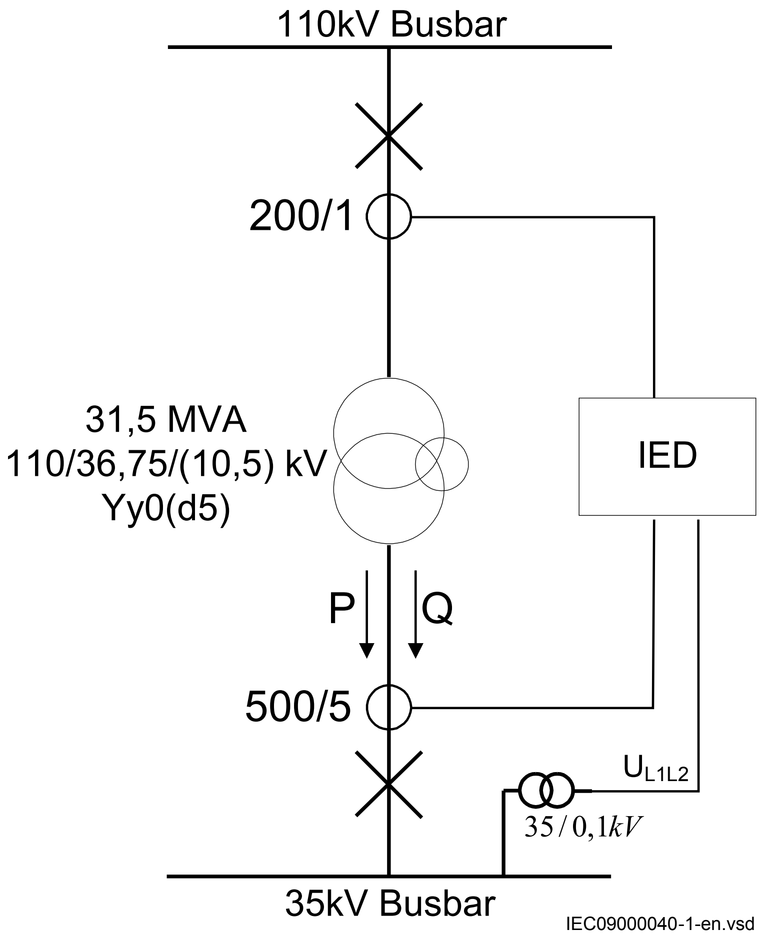


Figure 123: Single line diagram for transformer application

In order to measure the active and reactive power as indicated in the above figure, it is necessary to do the following:

1. Set correctly all CT and VT and phase angle reference channel *PhaseAngleRef* (see settings for analog input modules in PCM600) data using PCM600 for analogue input channels
2. Connect, in PCM600, measurement function to LV side CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

Table 17: General settings parameters for the Measurement function

Setting	Short description	Selected value	Comment
Operation	Operation Off/On	On	Function must be "On"
PowAmpFact	Amplitude factor to scale power calculations	1.000	Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & U	180.0	Typically no angle compensation is required. However here the required direction of P & Q measurement is towards busbar (Not per IED internal default direction). Therefore angle compensation have to be used in order to get measurements in aliment with the required direction.
Mode	Selection of measured current and voltage	L1L2	Only UL1L2 phase-to-phase voltage is available
k	Low pass filter coefficient for power measurement, U and I	0.00	Typically no additional filtering is required

11.4.3.3 Measurement function application for a generator

Single line diagram for this application is given in figure 124.

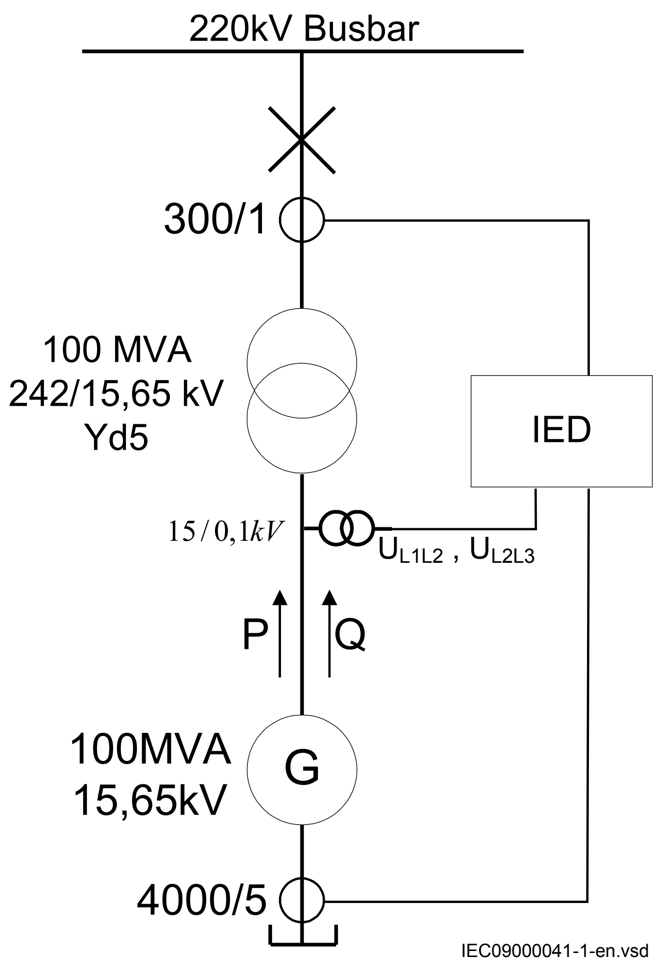


Figure 124: Single line diagram for generator application

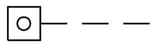
In order to measure the active and reactive power as indicated in the above figure, it is necessary to do the following:

1. Set correctly all CT and VT data and phase angle reference channel *PhaseAngleRef*(see settings for analog input modules in PCM600) using PCM600 for analogue input channels
2. Connect, in PCM600, measurement function to the generator CT & VT inputs
3. Set the setting parameters for relevant Measurement function as shown in the following table:

Table 18: General settings parameters for Measurement function

Setting	Short description	Selected value	Comment
Operation	Operation Off/On	On	Function must be “On"
PowAmpFact	Amplitude factor to scale power calculations	1.000	Typically no scaling is required
PowAngComp	Angle compensation for phase shift between measured I & U	0.0	Typically no angle compensation is required. As well here required direction of P & Q measurement is towards protected object (as per IED internal default direction)
Mode	Selection of measured current and voltage	Arone	Generator VTs are connected between phases (V-connected)
k	Low pass filter coefficient for power measurement, U and I	0.00	Typically no additional filtering is required

11.5 Event counter CNTGGIO

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Event counter	CNTGGIO		-

11.5.1 Application

Event counter (CNTGGIO) has six counters which are used for storing the number of times each counter has been activated. CNTGGIO can be used to count how many times a specific function, for example the tripping logic, has issued a trip signal. All six counters have a common blocking and resetting feature.

11.5.2 Setting guidelines

Operation: Sets the operation of Event counter (CNTGGIO) *On* or *Off*.

11.6 Disturbance report

11.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Disturbance report	DRPRDRE	-	-
Analog input signals	A1RADR	-	-
Analog input signals	A2RADR	-	-
Table continues on next page			

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Analog input signals	A3RADR	-	-
Analog input signals	A4RADR	-	-
Binary input signals	B1RBDR	-	-
Binary input signals	B2RBDR	-	-
Binary input signals	B3RBDR	-	-
Binary input signals	B4RBDR	-	-
Binary input signals	B5RBDR	-	-
Binary input signals	B6RBDR	-	-

11.6.2 Application

To get fast, complete and reliable information about disturbances in the primary and/or in the secondary system it is very important to gather information on fault currents, voltages and events. It is also important having a continuous event-logging to be able to monitor in an overview perspective. These tasks are accomplished by Disturbance Report function and facilitate a better understanding of the power system behaviour and related primary and secondary equipment during and after a disturbance. An analysis of the recorded data provides valuable information that can be used to explain a disturbance, basis for change of IED setting plan, improve existing equipment etc. This information can also be used in a longer perspective when planning for and designing new installations, that is, a disturbance recording could be a part of Functional Analysis (FA).

Disturbance Report , always included in the IED, acquires sampled data of all selected analog input and binary signals connected to the function blocks that is, maximum 30 external analog, 10 internal derived analog and 96 binary signals.

Disturbance Report function is a common name for several functions that is, Indications, Event recorder, Event List, Trip Value recorder, Disturbance recorder.

Disturbance Report function is characterized by great flexibility as far as configuration, starting conditions, recording times, and large storage capacity are concerned. Thus, disturbance report is not dependent on the operation of protective functions, and it can record disturbances that were not discovered by protective functions for one reason or another. Disturbance Report can be used as an advanced stand-alone disturbance recorder.

Every disturbance report recording is saved in the IED. The same applies to all events, which are continuously saved in a ring-buffer. Local HMI is used to get information about the recordings, and the disturbance report files may be uploaded to the PCM600 and further analysis using Disturbance handling tool.

If the IED is connected to a station bus (IEC 61850-8-1), according to IEC 61850, disturbance recorder and fault location information will be available on the bus.

11.6.3 Setting guidelines

The setting parameters for the Disturbance Report function are set via local HMI or PCM600.

It is possible to handle up to 40 analog and 96 binary signals, either internal signals or signals coming from external inputs. The binary signals are identical in all functions that is, Disturbance recorder, Event Recorder, Indication, Trip Value Recorder and Event List function.

User-defined names of binary and analog input signals is set using PCM600. The analog and binary signals appear with their user-defined names. The name is used in all related functions (Disturbance recorder, Event Recorder, Indication, Trip Value Recorder and Event List).

Figure 125 shows the relations between Disturbance Report, included functions and function blocks. Event List, Event Recorder and Indication uses information from the binary input function blocks (BxRBDR). Trip Value Recorder uses analog information from the analog input function blocks (AxRADR). Disturbance report function acquires information from both AxRADR and BxRBDR .

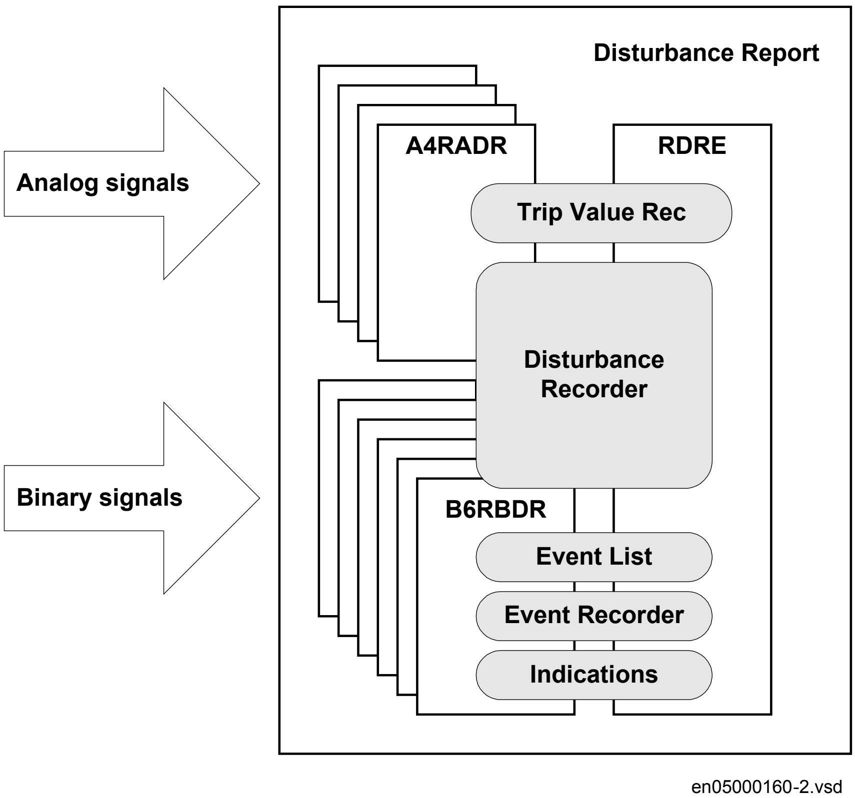


Figure 125: Disturbance report functions and related function blocks

For Disturbance Report function there are a number of settings which also influences the sub-functions.

Three LED indications placed above the LCD screen makes it possible to get quick status information about the IED. The information:

Green LED:	Steady light	In Service
	Flashing light	Internal failure
	Dark	No power supply
Yellow LED:	Function controlled by SetLEDn setting in Disturbance report function.	
Red LED:	Function controlled by SetLEDn setting in Disturbance report function.	

Operation

The operation of Disturbance Report function has to be set *On* or *Off*. If *Off* is selected, note that no disturbance report is registered, and none sub-function will operate (the only general parameter that influences Event list).

Operation=Off:

- Disturbance reports are not stored.
- LED information (yellow - start, red - trip) is not stored or changed.

Operation=On:

- Disturbance report are stored, disturbance data can be read from local HMI and from a PC using PCM600.
- LED information (yellow - start, red - trip) is stored.

Every recording will get a number (0 to 999) which is used as identifier (local HMI, disturbance handling tool and IEC 61850). An alternative recording identification is date, time and sequence number. The sequence number is automatically increased by one for each new recording and is reset to zero at midnight. The maximum number of recordings stored in the IED is 100 and the oldest will be overwritten when a new one arrives (FIFO).

To be able to delete disturbance records, *Operation* parameter has to be *On*

Recording times

The different recording times for disturbance report are set (the pre-fault time, post-fault time, and limit time). These recording times affect all sub-functions more or less but not the Event List function.

Prefault recording time (*PreFaultRecT*) is the recording time before the starting point of the disturbance. The setting should be at least 0.1 s to ensure enough samples for the estimation of pre-fault values in the Trip Value Recorder function.

Postfault recording time (*PostFaultRecT*) is the maximum recording time after the disappearance of the trig-signal (does not influence the Trip Value Recorder function).

Recording time limit (*TimeLimit*) is the maximum recording time after trig. The parameter limits the recording time if some trigging condition (fault-time) is very long or permanently set (does not influence the Trip Value Recorder function).

Post retrigger (*PostRetrig*) can be set to *On* or *Off*. Makes it possible to choose performance of Disturbance Report function if a new trig signal appears in the post-fault window.

PostRetrig = Off

The function is insensitive for new trig signals during post fault time.

PostRetrig = On

The function completes current report and starts a new complete report that is, the latter will include:

- new pre-fault- and fault-time (which will overlap previous report)
- events and indications might be saved in the previous report too, due to overlap
- new trip value calculations if installed, in operation and started

Operation in test mode

If the IED is in test mode and *OpModeTest=Off*. Disturbance Report function does not save any recordings and no LED information is displayed.

If the IED is in test mode and *OpModeTest=On*. Disturbance Report function works in normal mode and the status is indicated in the saved recording.

11.6.3.1 Binary input signals

Up to 96 binary signals can be selected among internal logical and binary input signals. The configuration tool is used to configure the signals.

For each of the 96 signals, it is also possible to select if the signal is to be used as a trigger for the start of disturbance report and if the trigger should be activated on positive (1) or negative (0) slope.

OperationN Disturbance Report may trig for binary input N (*On*) or not (*Off*).

TrigLevelN: Trig on positive (*Trig on 1*) or negative (*Trig on 0*) slope for binary input N.

11.6.3.2 Analog input signals

Up to 40 analog signals can be selected among internal analog and analog input signals. PCM600 is used to configure the signals.

The analog trigger of Disturbance report is not affected if analog input M is to be included in the disturbance recording or not (*OperationM= On/Off*).

If *OperationM=Off*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM=On*, waveform (samples) will also be recorded and reported in graph.

*NomValue*M: Nominal value for input M.

OverTrigOpM, *UnderTrigOpM*: Over or Under trig operation, Disturbance Report may trig for high/low level of analog input M (*On*) or not (*Off*).

OverTrigLevelM, *UnderTrigLevelM*: Over or under trig level, Trig high/low level relative nominal value for analog input M in percent of nominal value.

11.6.3.3 Sub-function parameters

All functions are in operation as long as disturbance report is in operation.

Indications

IndicationMaN: Indication mask for binary input N. If set (*Show*), a status change of that particular input, will be fetched and shown in the disturbance summary on local HMI. If not set (*Hide*), status change will not be indicated.

SetLEDN: Set yellow "START" and red “TRIP” LED on local HMI in front of the IED if binary input N changes status.

Disturbance recorder

OperationM: Analog channel M is to be recorded by the disturbance recorder (*On*) or not (*Off*).

If *OperationM=Off*, no waveform (samples) will be recorded and reported in graph. However, Trip value, pre-fault and fault value will be recorded and reported. The input channel can still be used to trig the disturbance recorder.

If *OperationM=On*, waveform (samples) will also be recorded and reported in graph.

Event recorder

Event recorder function has no dedicated parameters.

Trip Value recorder

ZeroAngleRef: The parameter defines which analog signal that will be used as phase angle reference for all other analog input signals. This signal will also be used for frequency measurement and the measured frequency is used when calculating trip values. It is suggested to point out a sampled voltage input signal, for example, a line or busbar phase voltage (channel 1-30).

Event List

Event List function has no dedicated parameters.

11.6.3.4 Consideration

The density of recording equipment in power systems is increasing, since the number of modern IEDs, where recorders are included, is increasing. This leads to a vast number of recordings at every single disturbance and a lot of information has to be handled if the recording functions don't have proper settings. The goal is to optimize the settings in each IED to be able to capture just valuable disturbances and to maximize the number that is possible to save in the IED.

The recording time should not be longer than necessary (*PostFaultrecT* and *TimeLimit*).

- Should the function record faults only for the protected object or cover more?
- How long is the longest expected fault clearing time?
- Is it necessary to include reclosure in the recording or should a persistent fault generate a second recording (*PostRetrig*)?

Minimize the number of recordings:

- Binary signals: Use only relevant signals to start the recording that is, protection trip, carrier receive and/or start signals.
- Analog signals: The level triggering should be used with great care, since unfortunate settings will cause enormously number of recordings. If nevertheless analog input triggering is used, chose settings by a sufficient margin from normal operation values. Phase voltages are not recommended for trigging.

Remember that values of parameters set elsewhere are linked to the information on a report. Such parameters are, for example, station and object identifiers, CT and VT ratios.

11.7 Measured value expander block MVEXP

11.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Measured value expander block	MVEXP	-	-

11.7.2 Application

The current and voltage measurements functions (CVMMXN, CMMXU, VMMXU and VNMMXU), current and voltage sequence measurement functions (CMSQI and VMSQI) and IEC 61850 generic communication I/O functions (MVGGIO) are provided with measurement supervision functionality. All measured values can be supervised with four settable limits, that is low-low limit, low limit, high limit and high-high limit. The measure value expander block (MVEXP) has been introduced to be able to translate the integer output signal from the measuring functions to 5 binary signals, that is below low-low limit, below low limit, normal, above high-high limit or above high limit. The output signals can be used as conditions in the configurable logic.

11.7.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

11.8 Station battery supervision SPVNZBAT

11.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Station battery supervision function	SPVNZBAT	U<>	-

11.8.2 Application

Usually, the load on the DC system is a constant resistance load, for example, lamps, LEDs, electronic instruments and electromagnetic contactors in a steady state condition. A transient RL load exists when breakers are tripped or closed.

The battery voltage has to be continuously monitored as the batteries can withstand moderate overvoltage and undervoltage only for a short period of time.

- If the battery is subjected to a prolonged or frequent overvoltage, it leads to the ageing of the battery, which may lead to the earlier failure of the battery. The other occurrences may be the thermal runaway, generation of heat or increased amount of hydrogen gas and the depletion of fluid in case of valve regulated batteries.

- If the value of the charging voltage drops below the minimum recommended float voltage of the battery, the battery does not receive sufficient charging current to offset internal losses, resulting in a gradual loss of capacity.
    - If a lead acid battery is subjected to a continuous undervoltage, heavy sulfation occurs on the plates, which leads to the loss of the battery capacity.

11.9 Insulation gas monitoring function SSIMG

11.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation gas monitoring function	SSIMG	-	63

11.9.2 Application

Insulation gas monitoring function (SSIMG) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed gas in the circuit breaker is very important. When the pressure becomes too low compared to the required value, the circuit breaker operation gets blocked to avoid disaster. Binary information based on the gas pressure in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

11.10 Insulation liquid monitoring function SSIML

11.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Insulation liquid monitoring function	SSIML	-	71

11.10.2 Application

Insulation liquid monitoring function (SSIML) is used for monitoring the circuit breaker condition. Proper arc extinction by the compressed oil in the circuit breaker is very important. When the level becomes too low, compared to the required value, the circuit breaker operation is blocked to avoid disaster. Binary information based on the oil level in the circuit breaker is used as input signals to the function. In addition to that, the function generates alarms based on received information.

11.11 Circuit breaker condition monitoring SSCBR

11.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Circuit breaker condition monitoring	SSCBR	-	-

11.11.2 Application

SSCBR includes different metering and monitoring subfunctions.

Circuit breaker status

Circuit breaker status monitors the position of the circuit breaker, that is, whether the breaker is in an open, closed or intermediate position.

Circuit breaker operation monitoring

The purpose of the circuit breaker operation monitoring is to indicate that the circuit breaker has not been operated for a long time. The function calculates the number of days the circuit breaker has remained inactive, that is, has stayed in the same open or closed state. There is also the possibility to set an initial inactive day.

Breaker contact travel time

High travelling times indicate the need for maintenance of the circuit breaker mechanism. Therefore, detecting excessive travelling time is needed. During the opening cycle operation, the main contact starts opening. The auxiliary contact A opens, the auxiliary contact B closes, and the main contact reaches its opening position. During the closing cycle, the first main contact starts closing. The auxiliary contact B opens, the auxiliary contact A closes, and the main contact reaches its close position. The travel times are calculated based on the state changes of the auxiliary contacts and the adding correction factor to consider the time difference of the main contact's and the auxiliary contact's position change.

Operation counter

Routine maintenance of the breaker, such as lubricating breaker mechanism, is generally based on a number of operations. A suitable threshold setting, to raise an alarm when the number of operation cycle exceeds the set limit, helps preventive maintenance. This can also be used to indicate the requirement for oil sampling for dielectric testing in case of an oil circuit breaker.

The change of state can be detected from the binary input of the auxiliary contact. There is a possibility to set an initial value for the counter which can be used to initialize this functionality after a period of operation or in case of refurbished primary equipment.

Accumulation of I^yt

Accumulation of I^yt calculates the accumulated energy ΣI^yt where the factor y is known as the current exponent. The factor y depends on the type of the circuit breaker. For oil circuit breakers the factor y is normally 2. In case of a high-voltage system, the factor y can be 1.4...1.5.

Remaining life of the breaker

Every time the breaker operates, the life of the circuit breaker reduces due to wearing. The wearing in the breaker depends on the tripping current, and the remaining life of the breaker is estimated from the circuit breaker trip curve provided by the manufacturer.

Example for estimating the remaining life of a circuit breaker

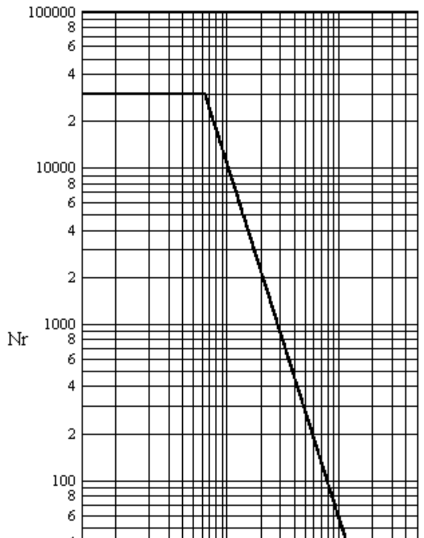


Figure 126: Trip Curves for a typical 12 kV, 630 A, 16 kA vacuum interrupter

Nr	the number of closing-opening operations allowed for the circuit breaker
Ia	the current at the time of tripping of the circuit breaker

Calculation of Directional Coef

The directional coefficient is calculated according to the formula:

$$Directional\,Coef = \frac{\log\left(\frac{B}{A}\right)}{\log\left(\frac{I_f}{I_r}\right)} = -2.2609$$

(Equation 90)

I_r	Rated operating current = 630 A
I_f	Rated fault current = 16 kA
A	Op number rated = 30000
B	Op number fault = 20

Calculation for estimating the remaining life

The equation shows that there are 30,000 possible operations at the rated operating current of 630 A and 20 operations at the rated fault current 16 kA. Therefore, if the tripping current is 10 kA, one operation at 10 kA is equivalent to 30,000/500=60 operations at the rated current. It is also assumed that prior to this tripping, the remaining life of the circuit breaker is 15,000 operations. Therefore, after one operation of 10 kA, the remaining life of the circuit breaker is 15,000-60=14,940 at the rated operating current.

Spring charged indication

For normal operation of the circuit breaker, the circuit breaker spring should be charged within a specified time. Therefore, detecting long spring charging time indicates that it is time for the circuit breaker maintenance. The last value of the spring charging time can be used as a service value.

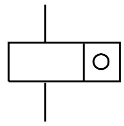
Gas pressure supervision

The gas pressure supervision monitors the gas pressure inside the arc chamber. When the pressure becomes too low compared to the required value, the circuit breaker operations are locked. A binary input is available based on the pressure levels in the function, and alarms are generated based on these inputs.

Section 12 Metering

12.1 Pulse counter PCGGIO

12.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Pulse counter	PCGGIO		-

12.1.2 Application

Pulse counter (PCGGIO) function counts externally generated binary pulses, for instance pulses coming from an external energy meter, for calculation of energy consumption values. The pulses are captured by the binary input module (BIO), and read by the PCGGIO function. The number of pulses in the counter is then reported via the station bus to the substation automation system or read via the station monitoring system as a service value. When using IEC 61850, a scaled service value is available over the station bus.

The normal use for this function is the counting of energy pulses from external energy meters. An optional number of inputs from the binary input module in IED can be used for this purpose with a frequency of up to 10 Hz. PCGGIO can also be used as a general purpose counter.

12.1.3 Setting guidelines

From the Protection and Control IED Manager (PCM600), these parameters can be set individually for each pulse counter:

- *Operation: Off/On*
- *tReporting: 0-3600s*
- *Event Mask: NoEvents/ReportEvents*

The configuration of the inputs and outputs of PCGGIO function block is made with PCM600.

On the binary input module, the debounce filter default time is set to 5 ms, that is, the counter suppresses pulses with a pulse length less than 5 ms. The binary input channels on the binary input output module (BIO) have individual settings for debounce time, oscillation count and oscillation time. The values can be changed in the local HMI and PCM600 under:

Main menu/Configuration/I/O modules

The setting isindividual for all input channels on the binary input output module (BIO), that is, if changes of the limits are made for inputs not connected to the pulse counter, it will not influence the inputs used for pulse counting.

12.2 Energy calculation and demand handling EPTMMTR

12.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Energy calculation and demand handling	ETPMMTR	-	-

12.2.2 Application

Energy calculation and demand handling (ETPMMTR) function is intended for statistics of the forward and reverse active and reactive energy. It has a high accuracy basically given by the Measurements (CVMMXN) function. ETPMMTR has a site calibration possibility to further increase the total accuracy.

The function is connected to the instantaneous outputs of the Measurement function as shown in figure 127.

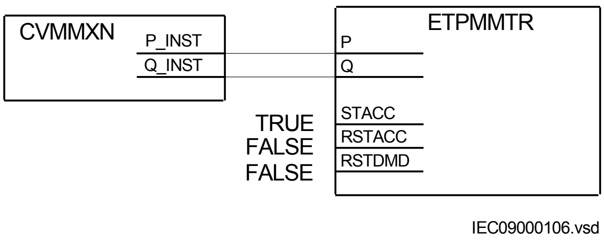


Figure 127: Connection of Energy calculation and demand handling (ETPMMTR) function to the Measurements function (CVMMXN)

The energy values can be read through communication in MWh and MVarh in monitoring tool of PCM600 and/or alternatively the values can be presented on the local HMI. The local HMI graphical display is configured with PCM600 Graphical display editor tool (GDE) with a measuring value which is selected to the active and reactive component as preferred. All four values can also be presented.

Maximum demand values are presented in MWh or MVarh in the same way.

Alternatively, the values can be presented with use of the pulse counters function (PCGGIO). The output values are scaled with the pulse output setting values *EAFAccPlsQty, EARAccPlsQty, ERFAccPlsQty and ERRAccPlsQty* of the energy metering function and then the pulse counter can be set-up to present the correct values by scaling in this function. Pulse counter values can then be presented on the local HMI in the same way and/or sent to the SA system through communication where the total energy then is calculated by summation of the energy pulses. This principle is good for very high values of energy as the saturation of numbers else will limit energy integration to about one year with 50 kV and 3000 A. After that the accumulation will start on zero again.

12.2.3 Setting guidelines

The parameters are set via the local HMI or Protection and Control IED Manager PCM600.

The following settings can be done for Energy calculation and demand handling (ETPMMTR) function:

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

Operation: Off/On

tEnergy: Time interval when energy is measured.

StartAcc: Off/On is used to switch the accumulation of energy on and off.

The input signal STACC is used to start accumulation. Input signal STACC cannot be used to halt accumulation. The energy content is reset every time STACC is activated. STACC can for example, be used when an external clock is used to switch two active energy measuring function blocks on and off to have indication of two tariffs.

tEnergyOnPls: gives the pulse length on time of the pulse. It should be at least 100 ms when connected to the Pulse counter function block. Typical value can be 100 ms.

tEnergyOffPls: gives the Off time between pulses. Typical value can be 100 ms.

EAFAccPlsQty and *EARAccPlsQty*: gives the MWh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

ERFAccPlsQty and *ERRAccPlsQty*: gives the MVarh value in each pulse. It should be selected together with the setting of the Pulse counter (PCGGIO) settings to give the correct total pulse value.

For the advanced user there are a number of settings for direction, zero clamping, max limit etc. Normally, the default values are suitable for these parameters.

Section 13 Station communication

13.1 IEC61850-8-1 communication protocol

13.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IEC 61850-8-1 communication protocol	IEC 61850-8-1	-	-

13.1.2 Application

IEC 61850-8-1 communication protocol allows vertical communication to HSI clients and allows horizontal communication between two or more intelligent electronic devices (IEDs) from one or several vendors to exchange information and to use it in the performance of their functions and for correct co-operation.

GOOSE (Generic Object Oriented Substation Event), which is a part of IEC 61850–8–1 standard, allows the IEDs to communicate state and control information amongst themselves, using a publish-subscribe mechanism. That is, upon detecting an event, the IED(s) use a multi-cast transmission to notify those devices that have registered to receive the data. An IED can, by publishing a GOOSE message, report it's status. It can also request a control action to be directed at any device in the network.

Figure 128 shows the topology of an IEC 61850–8–1 configuration. IEC 61850–8–1 specifies only the interface to the substation LAN. The LAN itself is left to the system integrator.

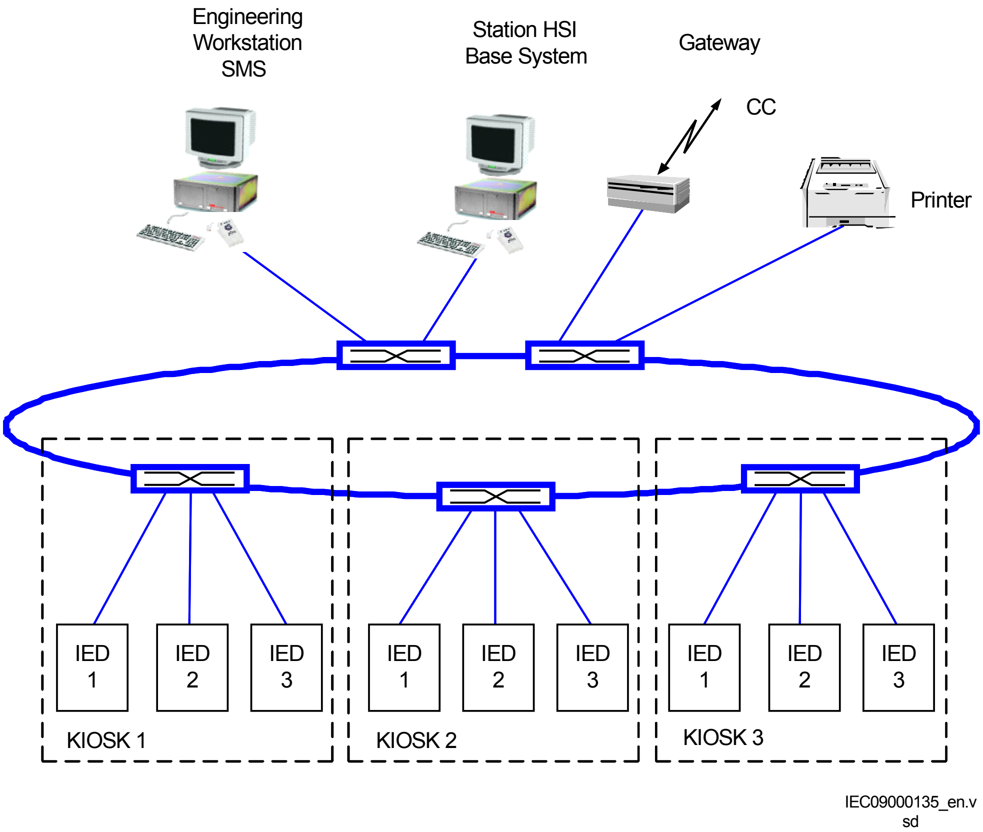


Figure 128: Example of a communication system with IEC 61850

Figure 129 shows the GOOSE peer-to-peer communication.

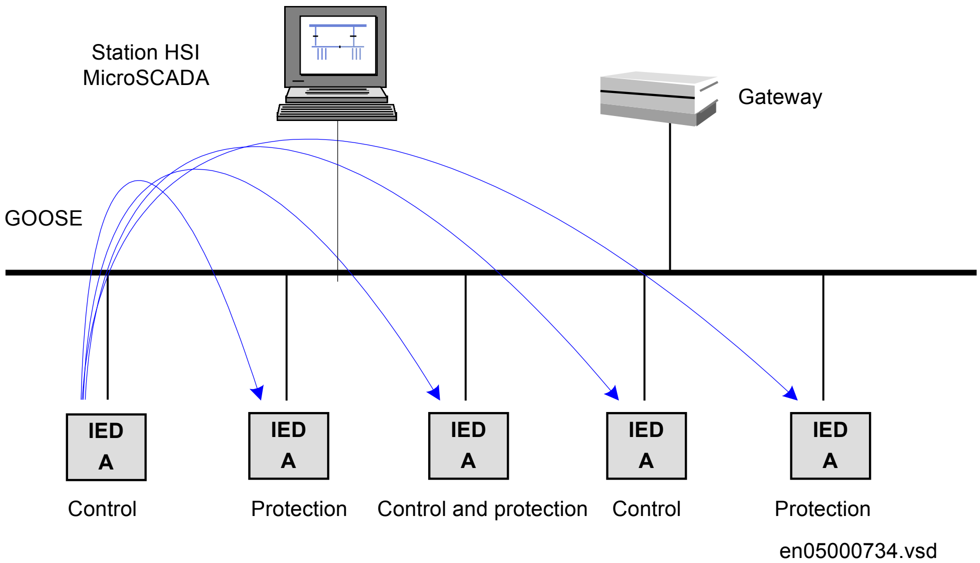


Figure 129: Example of a broadcasted GOOSE message

13.1.2.1 Horizontal communication via GOOSE

GOOSE messages are sent in horizontal communication between the IEDs. The information, which is exchanged, is used for station wide interlocking, breaker failure protection, busbar voltage selection and so on.

The simplified principle is shown in Figure 130 and can be described as follows. When IED1 has decided to transmit the data set it forces a transmission via the station bus. All other IEDs will receive the data set, but only those who have this data set in their address list will take it and keeps it in a input container. It is defined, that the receiving IED will take the content of the received data set and makes it available for the application configuration.

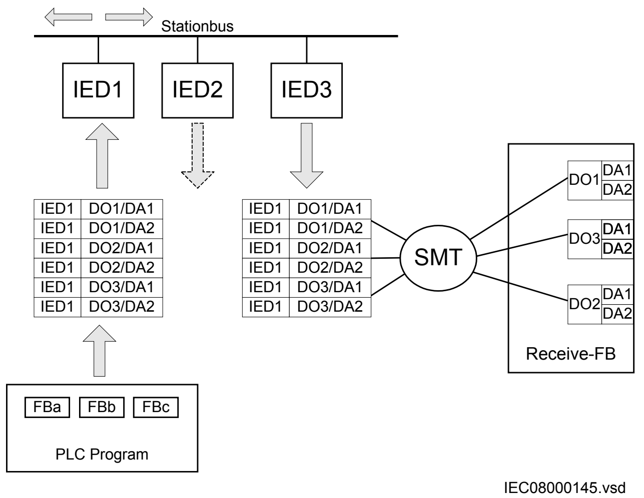
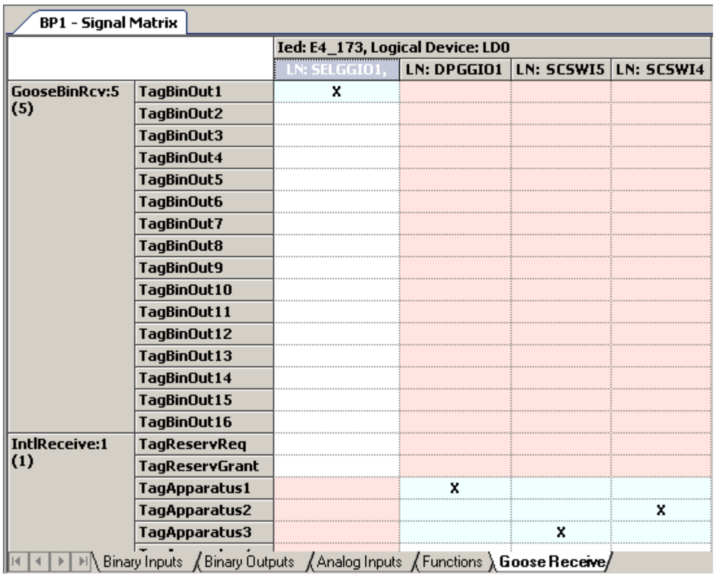


Figure 130: SMT: GOOSE principle and signal routing with SMT

Special function blocks take the data set and present it via the function block as output signals for application functions in the application configuration. Different GOOSE receive function blocks are available for the specific tasks.

SMT links the different data object attributes (for example stVal or magnitude) to the output signal to make it available for functions in the application configuration. When a matrix cell array is marked red the IEC 61850 data attribute type does not fit together, even if the GOOSE receive function block is the partner. SMT checks this on the content of the received data set. See Figure 131



IEC08000174.vsd

Figure 131: SMT: GOOSE marshalling with SMT

GOOSE receive function blocks extract process information, received by the data set, into single attribute information that can be used within the application configuration. Crosses in the SMT matrix connect received values to the respective function block signal in SMT, see Figure 132

The corresponding quality attribute is automatically connected by SMT. This quality attribute is available in ACT, through the OUTxVAL outputs of the GOOSEBINRCV and GOOSEINTLKRCV function block.

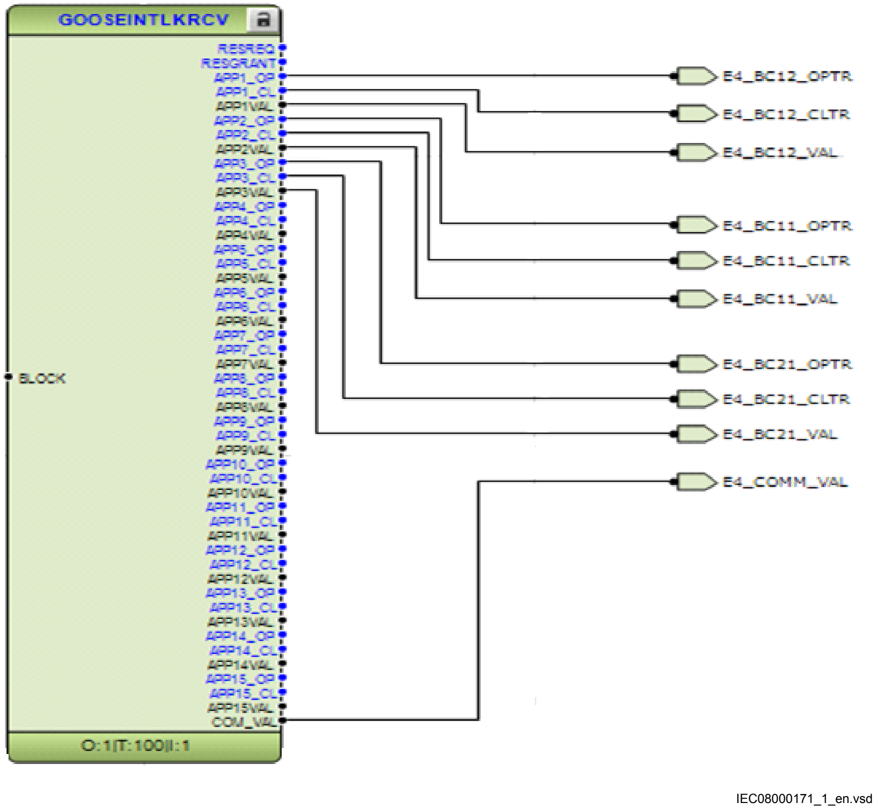


Figure 132: SMT: GOOSE receive function block with converted signals

13.1.3 Setting guidelines

There are two settings related to the IEC 61850–8–1 protocol:

Operation User can set IEC 61850 communication to *On* or *Off*.

GOOSE has to be set to the Ethernet link where GOOSE traffic shall be send and received.

IEC 61850–8–1 specific data (logical nodes etc.) per included function in an IED can be found in the communication protocol manual for IEC 61850.

13.2 DNP3 protocol

DNP3 (Distributed Network Protocol) is a set of communications protocols used to communicate data between components in process automation systems. For a detailed description of the DNP3 protocol, see the DNP3 Communication protocol manual.

Section 14 Basic IED functions

14.1 Self supervision with internal event list

14.1.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Internal error signal	INTERRSIG	-	-
Internal event list	SELFSUPEVLST	-	-

14.1.2 Application

The protection and control IEDs have many included functions. Self supervision with internal event list (SELFSUPEVLST) and internal error signals (INTERRSIG) function provide supervision of the IED. The fault signals make it easier to analyze and locate a fault.

Both hardware and software supervision is included and it is also possible to indicate possible faults through a hardware contact on the power supply module and/or through the software communication.

Internal events are generated by the built-in supervisory functions. The supervisory functions supervise the status of the various modules in the IED and, in case of failure, a corresponding event is generated. Similarly, when the failure is corrected, a corresponding event is generated.

Apart from the built-in supervision of the various modules, events are also generated when the status changes for the:

- built-in real time clock (in operation/out of order).
- external time synchronization (in operation/out of order).
- Change lock (on/off)

Events are also generated:

- whenever any setting in the IED is changed.

The internal events are time tagged with a resolution of 1 ms and stored in a list. The list can store up to 40 events. The list is based on the FIFO principle, that is, when it is full, the oldest event is overwritten. The list can be cleared via the local HMI .

The list of internal events provides valuable information, which can be used during commissioning and fault tracing.

The list of internal events can be found in the LHMI or viewed in PCM600 using the Event viewer tool.

14.2 Time synchronization

14.2.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization	TIMESYNCHGEN	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time begins	DTSBEGIN	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time system, summer time ends	DTSEND	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via IRIG-B	IRIG-B	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time synchronization via SNTP	SNTP	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Time zone from UTC	TIMEZONE	-	-

14.2.2 Application

Use time synchronization to achieve a common time base for the IEDs in a protection and control system. This makes comparison of events and disturbance data between all IEDs in the system possible.

Time-tagging of internal events and disturbances are an excellent help when evaluating faults. Without time synchronization, only the events within the IED can be compared to one another. With time synchronization, events and disturbances within the entire station, and even between line ends, can be compared at evaluation.

In the IED, the internal time can be synchronized from a number of sources:

- SNTP
- IRIG-B
- DNP

Micro SCADA OPC server should not be used as a time synchronization source.

14.2.3 Setting guidelines

System time

The time is set with years, month, day, hour, minute and second.

Synchronization

The setting parameters for the real-time clock with external time synchronization (TIME) are set via the local HMI or the PCM 600 tool.

TimeSynch

When the source of the time synchronization is selected on the LHMI, the parameter is called *TimeSynch*. The time synchronization source can also be set from PCM600. The setting alternatives are:

FineSyncSource which can have the following values:

- *Off*
- *SNTP*
- *IRIG-B*

CoarseSyncSrc which can have the following values:

- *Off*
- *SNTP*
- *DNP*

The system time can be set manually, either via the LHMI or via any of the communication ports. The time synchronization fine tunes the clock.

14.3 Parameter setting group handling

14.3.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Setting group handling	SETGRPS	-	-
Parameter setting groups	ACTVGRP	-	-

14.3.2 Application

Four sets of settings are available to optimize IED operation for different system conditions. By creating and switching between fine tuned setting sets, either from the local HMI or configurable binary inputs, results in a highly adaptable IED that can cope with a variety of system scenarios.

Different conditions in networks with different voltage levels require highly adaptable protection and control units to best provide for dependability, security and selectivity requirements. Protection units operate with a higher degree of availability, especially, if the setting values of their parameters are continuously optimized according to the conditions in the power system.

Operational departments can plan for different operating conditions in the primary equipment. The protection engineer can prepare the necessary optimized and pre-tested settings in advance for different protection functions. Four different groups of setting parameters are available in the IED. Any of them can be activated through the different programmable binary inputs by means of external or internal control signals.

14.3.3 Setting guidelines

The setting *ActiveSetGrp*, is used to select which parameter group to be active. The active group can also be selected with configured input to the function block ACTVGRP.

The parameter *MaxNoSetGrp* defines the maximum number of setting groups in use to switch between. Only the selected number of setting groups will be available in PST for activation with the ACTVGRP function block.

14.4 Test mode functionality TESTMODE

14.4.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Test mode functionality	TESTMODE	-	-

14.4.2 Application

The protection and control IEDs have a complex configuration with many included functions. To make the testing procedure easier, the IEDs include the feature which allows to individually block a single, several or all functions.

This means that it is possible to see when a function is activated or trips. It also enables the user to follow the operation of several related functions to check correct functionality and to check parts of the configuration etc.

14.4.3 Setting guidelines

Remember always that there are two possible ways to place the IED in the "Test mode: On" state. If, the IED is set to normal operation (*TestMode*=*Off*), but the functions are still shown being in the test mode, the input signal INPUT on the TESTMODE function block might be activated in the configuration.

Forcing of binary output signals is only possible when the IED is in test mode.

14.5 Change lock CHNGLCK

14.5.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Change lock function	CHNGLCK	-	-

14.5.2 Application

Change lock function (CHNGLCK) is used to block further changes to the IED configuration once the commissioning is complete. The purpose is to make it impossible to perform inadvertent IED configuration changes beyond a certain point in time.

However, when activated, CHNGLCK will still allow the following changes of the IED state that does not involve reconfiguring of the IED:

- Monitoring
- Reading events
- Resetting events
- Reading disturbance data
- Clear disturbances
- Reset LEDs
- Reset counters and other runtime component states
- Control operations
- Set system time
- Enter and exit from test mode
- Change of active setting group

The binary input controlling the function is defined in ACT or SMT. The CHNGLCK function is configured using ACT.

LOCK	Binary input signal that will activate/deactivate the function, defined in ACT or SMT.
ACTIVE	Output status signal
OVERRIDE	Set if function is overridden

When CHNGLCK has a logical one on its input, then all attempts to modify the IED configuration will be denied and the message "Error: Changes blocked" will be displayed on the LHMI; in PCM600 the message will be "Operation denied by active ChangeLock". The CHNGLCK function should be configured so that it is controlled by a signal from a binary input card. This guarantees that by setting that signal to a logical zero, CHNGLCK is deactivated. If any logic is included in the signal path to the CHNGLCK input, that logic must be designed so that it cannot permanently issue a logical one on the CHNGLCK input. If such a situation would occur in spite of these precautions, then please contact the local ABB representative for remedial action.

14.5.3 Setting guidelines

The Change lock function (CHNGLCK) does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600)

14.6 IED identifiers TERMINALID

14.6.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
IED identifiers	TERMINALID	-	-

14.6.2 Application

14.6.2.1 Customer specific settings

The customer specific settings are used to give the IED an unique name and address. The settings are used by a central control system to communicate with the IED. The customer specific identifiers are found in the local HMI under:

Configuration/Power system/Identifiers/TERMINALID

The settings can also be made from the PCM600 tool. For more information about the available identifiers, see Technical manual.

Use only characters A - Z, a - z and 0 - 9 in station, unit and object names.

14.7 Product information PRODINF

14.7.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Product information	PRODINF	-	-

14.7.2 Application

14.7.2.1 Factory defined settings

The factory defined settings are very useful for identifying a specific version and very helpful in the case of maintenance, repair, interchanging IEDs between different Substation Automation Systems and upgrading. The factory made settings can not be changed by the customer. They can only be viewed. The settings are found in the local HMI under:

Main menu/Diagnostics/IED status/Product identifiers

The following identifiers are available:

- IEDProdType
  - Describes the type of the IED (like REL, REC or RET). Example: *REL650*
- ProductDef
  - Describes the release number, from the production. Example: *1.0.0.0*
- FirmwareVer
  - Describes the firmware version. Example: *1.4.51*
  - Firmware versions numbers are “running” independently from the release production numbers. For every release numbers (like *1.0.0.0*) there can be one or more firmware versions, depending on the small issues corrected in between releases.
- SerialNo
- OrderingNo
- ProductionDate

14.8 Primary system values PRIMVAL

14.8.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Primary system values	PRIMVAL	-	-

14.8.2 Application

The rated system frequency and phasor rotation are set under **Main menu/ Configuration/ Power system/ Primary values/PRIMVAL** in PCM600 parameter setting tree.

14.9 Signal matrix for analog inputs SMAI

14.9.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Signal matrix for analog inputs	SMAI_20_1	-	-

14.9.2 Application

Signal matrix for analog inputs (SMAI) function (or the pre-processing function) is used within PCM600 in direct relation with SMT or ACT (see the overview of the engineering process in the *Engineering manual*). SMT represents the way analog inputs are brought in for one IED configuration.

14.9.3 Setting guidelines

The parameters for the signal matrix for analog inputs (SMAI) functions are set via the local HMI, PCM600.

Every SMAI function block can receive four analog signals (three phases and one neutral value), either voltage or current. SMAI outputs give information about every aspect of the 3ph analog signals acquired (phase angle, RMS value, frequency and frequency derivates, etc. – 244 values in total). Besides the block “group name”, the analog inputs type (voltage or current) and the analog input names that can be set directly in ACT.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

DFTRefExtOut: Parameter valid for function block SMAI_20_1:1, SMAI_20_1:2 and SMAI_80_1 only. Reference block for external output (SPFCOUT function output).

DFTReference: Reference DFT for the block.

These DFT reference block settings decide DFT reference for DFT calculations (*Internal DFTRef* will use fixed DFT reference based on set system frequency. *DFTRefGrpn* will use DFT reference from the selected group block, when own group selected adaptive DFT reference will be used based on calculated signal frequency from own group. *ExternalDFTRef* will use reference based on input DFTSPFC.

ConnectionType: Connection type for that specific instance (n) of the SMAI (if it is *Ph-N* or *Ph-Ph*). Depending on connection type setting the not connected *Ph-N* or *Ph-Ph* outputs will be calculated.

Negation: If the user wants to negate the 3ph signal, it is possible to choose to negate only the phase signals *Negate3Ph*, only the neutral signal *NegateN* or both *Negate3Ph+N*; negation means rotation with 180° of the vectors.

MinValFreqMeas: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *GlobeBasUaGrp(n)* (for each instance n).

Settings *DFTRefExtOut* and *DFTReference* shall be set to default value *InternalDFTRef* if no VT inputs are available.

Example of adaptive frequency tracking

Task time group 1	
SMAI instance	**3 phase group**
SMAI_20_1:1	1
SMAI_20_2:1	2
SMAI_20_3:1	3
SMAI_20_4:1	4
SMAI_20_5:1	5
SMAI_20_6:1	6
SMAI_20_7:1	7
SMAI_20_8:1	8
SMAI_20_9:1	9
SMAI_20_10:1	10
SMAI_20_11:1	11
SMAI_20_12:1	12

DFTRefGrp7

Task time group 2	
SMAI instance	**3 phase group**
SMAI_20_1:2	1
SMAI_20_2:2	2
SMAI_20_3:2	3
SMAI_20_4:2	4
SMAI_20_5:2	5
SMAI_20_6:2	6
SMAI_20_7:2	7
SMAI_20_8:2	8
SMAI_20_9:2	9
SMAI_20_10:2	10
SMAI_20_11:2	11
SMAI_20_12:2	12

IEC09000029_1_en.vsd

Figure 133: SMAI instances as organized in different task time groups and the corresponding parameter numbers

The example shows a situation with adaptive frequency tracking with one reference selected for all instances. In practice each instance can be adapted to the needs of the actual application.

Example 1

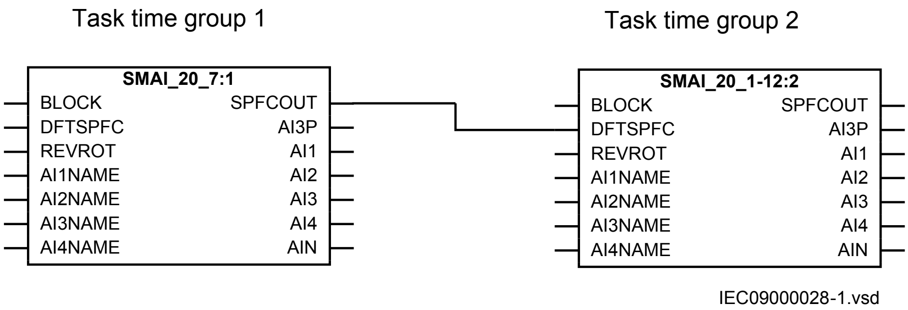


Figure 134: Configuration for using an instance in task time group 1 as DFT reference

Assume instance SMAI_20_7:1 in task time group 1 has been selected in the configuration to control the frequency tracking (For the SMAI_20_x task time groups). Observe that the selected reference instance must be a voltage type.

For task time group 1 this gives the following settings (see Figure 133 for numbering):

SMAI_20_7:1: *DFTRefExtOut* = *DFTRefGrp7* to route SMAI_20_7:1 reference to the SPFCOUT output, *DFTReference* = *DFTRefGrp7* for SMAI_20_7:1 to use SMAI_20_7:1 as reference (see Figure 134). .

SMAI_20_2:1 - SMAI_20_12:1 *DFTReference* = *DFTRefGrp7* for SMAI_20_2:1 - SMAI_20_12:1 to use SMAI_20_7:1 as reference.

For task time group 2 this gives the following settings:

SMAI_20_1:2 - SMAI_20_12:2 *DFTReference* = *ExternalDFTRef* to use DFTSPFC input as reference (SMAI_20_7:1)

14.10 Summation block 3 phase 3PHSUM

14.10.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Summation block 3 phase	3PHSUM	-	-

14.10.2 Application

Summation block 3 phase function (3PHSUM) is used in order to get the sum of two sets of 3 phase analog signals (of the same type) for those IED functions that might need it.

14.10.3 Setting guidelines

The summation block receives the 3ph signals from the SMAI blocks. The summation block has several settings.

Common base IED values for primary current (setting *IBase*), primary voltage (setting *UBase*) and primary power (setting *SBase*) are set in a Global base values for settings function GBASVAL. Setting *GlobalBaseSel* is used to select a GBASVAL function for reference of base values.

SummationType: Summation type (*Group 1+ Group2*, *Group 1 – Group 2*, *Group 2- Group 1* or *–(Group1 + Group 2)*).

DFTReference: The reference DFT block (*InternalDFT Ref*, *Grp1AdDFTRef* or *External DFT ref*) .

FreqMeasMinVal: The minimum value of the voltage for which the frequency is calculated, expressed as percent of *UBase* (for each instance n).

14.11 Global base values GBASVAL

14.11.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Global base values	GBASVAL	-	-

14.11.2 Application

Global base values function (GBASVAL) is used to provide global values, common for all applicable functions within the IED. One set of global values consists of values for current, voltage and apparent power and it is possible to have six different sets.

This is an advantage since all applicable functions in the IED use a single source of base values. This facilitates consistency throughout the IED and also facilitates a single point for updating values when necessary.

Each applicable function in the IED has a parameter, *GlobalBaseSel*, defining one out of the six sets of Global base value functions.

14.11.3 Setting guidelines

UBase: Phase-to-phase voltage value to be used as a base value for applicable functions throughout the IED

IBase: Phase current value to be used as a base value for applicable functions throughout the IED

SBase: Standard apparent power value to be used as a base value for applicable functions throughout the IED, typically $SBase = \sqrt{3} \cdot UBase \cdot IBase$

14.12 Authority check ATHCHCK

14.12.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority check	ATHCHCK	-	-

14.12.2 Application

To safeguard the interests of our customers, both the IED and the tools that are accessing the IED are protected, subject of authorization handling. The concept of authorization, as it is implemented in the IED and in PCM600 is based on the following facts:

There are two types of access points to the IED:

- local, through the local HMI
- remote, through the communication ports

14.12.2.1 Authorization handling in the IED

At delivery the default user is the SuperUser. No Log on is required to operate the IED until a user has been created with the User Management Tool (UMT).

Once a user is created and downloaded into the IED, that user can perform a Log on, using the password assigned in the tool. Then the default user will be Guest.

If there is no user created, an attempt to log on will display a message box: “No user defined!”

If one user leaves the IED without logging off, then after the timeout (set in **Main menu/Configuration/HMI/Screen/1:SCREEN**) elapses, the IED will return to a Guest state, when only reading is possible. By factory default, the display timeout is set to 60 minutes.

If one or more users are created with the UMT and downloaded into the IED, then, when a user attempts a Log on by pressing the  key or when the user attempts to perform an operation that is password protected, the Log on window will appear.

The cursor is focused on the “User identity” field, so upon pressing the key, one can change the user name, by browsing the list of users, with the “up” and “down” arrows. After choosing the right user name, the user must press the key again. When it comes to password, upon pressing the key, the following characters will show up: “✳✳✳✳✳✳✳✳”. The user must scroll for every letter in the password. After all the letters are introduced (passwords are case sensitive) choose OK and press key again.

At successful Log on the local HMI shows the new username in the statusbar at the bottom of the LCD. If the Log on is OK, when required to change for example a password protected setting, the local HMI returns to the actual setting folder. If the LogOn has failed, an "Error Access Denied" message will pop-up. If a user enters an incorrect password three times, that user will be blocked for ten minutes before a new attempt to log in can be performed. The user will be blocked from logging in, both from the local HMI as well as, from PCM600 tool. However, other users will be able to log in during this period.

14.13 Authority status ATHSTAT

14.13.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Authority status	ATHSTAT	-	-

14.13.2 Application

Authority status (ATHSTAT) function is an indication function block, which informs about two events related to the IED and the user authorization:

- the fact that at least one user has tried to log on wrongly into the IED and it was blocked (the output USRBLKED)
- the fact that at least one user is logged on (the output LOGGEDON)

The two outputs of ATHSTAT function can be used in the configuration for different indication and alarming reasons, or can be sent to the station control for the same purpose.

14.14 Denial of service

14.14.1 Identification

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for front port	DOSFRNT	-	-

Function description	IEC 61850 identification	IEC 60617 identification	ANSI/IEEE C37.2 device number
Denial of service, frame rate control for LAN1 port	DOSLAN1	-	-

14.14.2 Application

The Denial of service functions (DOSLAN1 and DOSFRNT) are designed to limit the CPU load that can be produced by Ethernet network traffic on the IED. The communication facilities must not be allowed to compromise the primary functionality of the device. All inbound network traffic will be quota controlled so that too heavy network loads can be controlled. Heavy network load might for instance be the result of malfunctioning equipment connected to the network.

The DOSLAN1 and DOSFRNT functions measures the IED load from communication and, if necessary, limit it for not jeopardizing the IEDs control and protection functionality due to high CPU load. The function has the following outputs:

- LINKUP indicates the ethernet link status
- WARNING indicates that communication (frame rate) is higher than normal
- ALARM indicates that the IED limits communication

14.14.3 Setting guidelines

The function does not have any parameters available in Local HMI or Protection and Control IED Manager (PCM600).

Section 15 Requirements for measurement transformers

15.1 Current transformer requirements

The performance of a protection function will depend on the quality of the measured current signal. Saturation of the current transformer (CT) will cause distortion of the current signal and can result in a failure to operate or cause unwanted operations of some functions. Consequently CT saturation can have an influence on both the dependability and the security of the protection. This protection IED has been designed to permit heavy CT saturation with maintained correct operation.

15.1.1 Current transformer classification

To guarantee correct operation, the current transformers (CTs) must be able to correctly reproduce the current for a minimum time before the CT will begin to saturate. To fulfil the requirement on a specified time to saturation the CTs must fulfil the requirements of a minimum secondary e.m.f. that is specified below.

There are several different ways to specify CTs. Conventional magnetic core CTs are usually specified and manufactured according to some international or national standards, which specify different protection classes as well. There are many different standards and a lot of classes but fundamentally there are three different types of CTs:

- High remanence type CT
- Low remanence type CT
- Non remanence type CT

The high remanence type has no limit for the remanent flux. This CT has a magnetic core without any airgap and a remanent flux might remain almost infinite time. In this type of transformers the remanence can be up to around 80% of the saturation flux. Typical examples of high remanence type CT are class P, PX, TPS, TPX according to IEC, class P, X according to BS (old British Standard) and nongapped class C, K according to ANSI/IEEE.

The low remanence type has a specified limit for the remanent flux. This CT is made with a small airgap to reduce the remanence to a level that does not exceed 10% of the saturation flux. The small airgap has only very limited influence on the other properties of the CT. Class PR, TPY according to IEC are low remanence type CTs.

The non remanence type CT has practically negligible level of remanent flux. This type of CT has relatively big airgaps in order to reduce the remanence to practically zero level. In the same time, these airgaps reduce the influence of the DC-component from the primary fault current. The airgaps will also decrease the measuring accuracy in the non-saturated region of operation. Class TPZ according to IEC is a non remanence type CT.

Different standards and classes specify the saturation e.m.f. in different ways but it is possible to approximately compare values from different classes. The rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 60044 – 6 standard is used to specify the CT requirements for the IED. The requirements are also specified according to other standards.

15.1.2 Conditions

The requirements are a result of investigations performed in our network simulator. The current transformer models are representative for current transformers of high remanence and low remanence type. The results may not always be valid for non remanence type CTs (TPZ).

The performances of the protection functions have been checked in the range from symmetrical to fully asymmetrical fault currents. Primary time constants of at least 120 ms have been considered at the tests. The current requirements below are thus applicable both for symmetrical and asymmetrical fault currents.

Depending on the protection function phase-to-earth, phase-to-phase and three-phase faults have been tested for different relevant fault positions e.g. close in forward and reverse faults, zone 1 reach faults, internal and external faults. The dependability and security of the protection was verified by checking e.g. time delays, unwanted operations, directionality, overreach and stability.

The remanence in the current transformer core can cause unwanted operations or minor additional time delays for some protection functions. As unwanted operations are not acceptable at all maximum remanence has been considered for fault cases critical for the security, e.g. faults in reverse direction and external faults. Because of the almost negligible risk of additional time delays and the non-existent risk of failure to operate the remanence have not been considered for the dependability cases. The requirements below are therefore fully valid for all normal applications.

It is difficult to give general recommendations for additional margins for remanence to avoid the minor risk of an additional time delay. They depend on the performance and economy requirements. When current transformers of low remanence type (e.g. TPY, PR) are used, normally no additional margin is needed. For current transformers of high remanence type (e.g. P, PX, TPS, TPX) the small probability of fully asymmetrical faults, together with high remanence in the same direction as the flux generated by the fault, has to be kept in mind at the decision of an additional margin. Fully asymmetrical fault current will be achieved when the fault occurs at approximately zero voltage (0°). Investigations have shown that

95% of the faults in the network will occur when the voltage is between 40° and 90°. In addition fully asymmetrical fault current will not exist in all phases at the same time.

15.1.3 Fault current

The current transformer requirements are based on the maximum fault current for faults in different positions. Maximum fault current will occur for three-phase faults or single-phase-to-earth faults. The current for a single phase-to-earth fault will exceed the current for a three-phase fault when the zero sequence impedance in the total fault loop is less than the positive sequence impedance.

When calculating the current transformer requirements, maximum fault current for the relevant fault position should be used and therefore both fault types have to be considered.

15.1.4 Secondary wire resistance and additional load

The voltage at the current transformer secondary terminals directly affects the current transformer saturation. This voltage is developed in a loop containing the secondary wires and the burden of all relays in the circuit. For earth faults the loop includes both the phase and neutral wire, normally twice the resistance of the single secondary wire. For three-phase faults the neutral current is zero and it is just necessary to consider the resistance up to the point where the phase wires are connected to the common neutral wire. The most common practice is to use four wires secondary cables so it normally is sufficient to consider just a single secondary wire for the three-phase case.

The conclusion is that the loop resistance, twice the resistance of the single secondary wire, must be used in the calculation for phase-to-earth faults and the phase resistance, the resistance of a single secondary wire, may normally be used in the calculation for three-phase faults.

As the burden can be considerable different for three-phase faults and phase-to-earth faults it is important to consider both cases. Even in a case where the phase-to-earth fault current is smaller than the three-phase fault current the phase-to-earth fault can be dimensioning for the CT depending on the higher burden.

In isolated or high impedance earthed systems the phase-to-earth fault is not the dimensioning case and therefore the resistance of the single secondary wire always can be used in the calculation, for this case.

15.1.5 General current transformer requirements

The current transformer ratio is mainly selected based on power system data like e.g. maximum load. However, it should be verified that the current to the protection is higher than the minimum operating value for all faults that are to be detected with the selected CT ratio. The minimum operating current is different for different functions and normally settable so each function should be checked.

The current error of the current transformer can limit the possibility to use a very sensitive setting of a sensitive residual overcurrent protection. If a very sensitive setting of this function will be used it is recommended that the current transformer should have an accuracy class which have an current error at rated primary current that is less than ±1% (e.g. 5P). If current transformers with less accuracy are used it is advisable to check the actual unwanted residual current during the commissioning.

15.1.6 Rated equivalent secondary e.m.f. requirements

With regard to saturation of the current transformer all current transformers of high remanence and low remanence type that fulfill the requirements on the rated equivalent secondary e.m.f. E_{al} below can be used. The characteristic of the non remanence type CT (TPZ) is not well defined as far as the phase angle error is concerned. If no explicit recommendation is given for a specific function we therefore recommend contacting ABB to confirm that the non remanence type can be used.

The CT requirements for the different functions below are specified as a rated equivalent limiting secondary e.m.f. E_{al} according to the IEC 60044-6 standard. Requirements for CTs specified in different ways are given at the end of this section.

15.1.6.1 Breaker failure protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 91)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

15.1.6.2 Non-directional instantaneous and definitive time, phase and residual overcurrent protection

The CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 1,5 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 92)

where:

I_{op}	The primary operate value (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

15.1.6.3 Non-directional inverse time delayed phase and residual overcurrent protection

The requirement according to Equation 93 and Equation 94 does not need to be fulfilled if the high set instantaneous or definitive time stage is used. In this case Equation 92 is the only necessary requirement.

If the inverse time delayed function is the only used overcurrent protection function the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = 20 \cdot I_{op} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 93)

where

I_{op}	The primary current set value of the inverse time function (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)

Table continues on next page

I_r	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). S_R=0.010 VA/channel for I_r=1 A and S_R=0.250 VA/channel for I_r=5 A

Independent of the value of I_{op} the maximum required E_{al} is specified according to the following:

$$E_{al} \geq E_{alreq\,max} = I_{k\,max} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 94)

where

I_{kmax}	Maximum primary fundamental frequency current for close-in faults (A)

15.1.6.4 Directional phase and residual overcurrent protection

If the directional overcurrent function is used the CTs must have a rated equivalent secondary e.m.f. E_{al} that is larger than or equal to the required equivalent secondary e.m.f. E_{alreq} below:

$$E_{al} \geq E_{alreq} = I_{k\,max} \cdot \frac{I_{sn}}{I_{pn}} \cdot \left(R_{CT} + R_L + \frac{S_R}{I_r^2} \right)$$

(Equation 95)

where:

I_{kmax}	Maximum primary fundamental frequency current for close-in forward and reverse faults (A)
I_{pn}	The rated primary CT current (A)
I_{sn}	The rated secondary CT current (A)
I_r	The rated current of the protection IED (A)
R_{CT}	The secondary resistance of the CT (Ω)
R_L	The resistance of the secondary cable and additional load (Ω). The loop resistance containing the phase and neutral wires, must be used for faults in solidly earthed systems. The resistance of a single secondary wire should be used for faults in high impedance earthed systems.
S_R	The burden of an IED current input channel (VA). S_r=0.010 VA/channel for I_r=1 A and S_r=0.250 VA/channel for I_r=5 A

15.1.7 Current transformer requirements for CTs according to other standards

All kinds of conventional magnetic core CTs are possible to use with the IEDs if they fulfill the requirements corresponding to the above specified expressed as the rated equivalent secondary e.m.f. E_{al} according to the IEC 60044-6 standard. From different standards and available data for relaying applications it is possible to approximately calculate a secondary e.m.f. of the CT comparable with E_{al}. By comparing this with the required secondary e.m.f. E_{alreq} it is possible to judge if the CT fulfills the requirements. The requirements according to some other standards are specified below.

15.1.7.1 Current transformers according to IEC 60044-1, class P, PR

A CT according to IEC 60044-1 is specified by the secondary limiting e.m.f. E_{2max}. The value of the E_{2max} is approximately equal to the corresponding E_{al} according to IEC 60044-6. Therefore, the CTs according to class P and PR must have a secondary limiting e.m.f. E_{2max} that fulfills the following:

$$E_{2\max} > \text{maximum of } E_{alreq}$$

(Equation 96)

15.1.7.2 Current transformers according to IEC 60044-1, class PX, IEC 60044-6, class TPS (and old British Standard, class X)

CTs according to these classes are specified approximately in the same way by a rated knee-point e.m.f. E_{knee} (E_k for class PX, E_{kneeBS} for class X and the limiting secondary voltage U_{al} for TPS). The value of the E_{knee} is lower than the corresponding E_{al} according to IEC 60044-6. It is not possible to give a general relation between the E_{knee} and the E_{al} but normally the E_{knee} is approximately 80 % of the E_{al}. Therefore, the CTs according to class PX, X and TPS must have a rated knee-point e.m.f. E_{knee} that fulfills the following:

$$E_{knee} \approx E_k \approx E_{kneeBS} \approx U_{al} > 0.8 \cdot (\text{maximum of } E_{alreq})$$

(Equation 97)

15.1.7.3 Current transformers according to ANSI/IEEE

Current transformers according to ANSI/IEEE are partly specified in different ways. A rated secondary terminal voltage U_{ANSI} is specified for a CT of class C. U_{ANSI} is the secondary terminal voltage the CT will deliver to a standard burden at 20 times rated secondary current without exceeding 10 % ratio correction. There are a number of standardized U_{ANSI} values e.g. U_{ANSI} is 400 V for a C400 CT. A corresponding rated equivalent limiting secondary e.m.f. E_{alANSI} can be estimated as follows:

$$E_{alANSI} = \left|20 \cdot I_{sn} \cdot R_{CT} + U_{ANSI}\right| = \left|20 \cdot I_{sn} \cdot R_{CT} + 20 \cdot I_{sn} \cdot Z_{bANSI}\right|$$

(Equation 98)

where:

Z_{bANSI}	The impedance (i.e. complex quantity) of the standard ANSI burden for the specific C class (Ω)
U_{ANSI}	The secondary terminal voltage for the specific C class (V)

The CTs according to class C must have a calculated rated equivalent limiting secondary e.m.f. E_{alANSI} that fulfills the following:

$$E_{alANSI} > \text{max imum of } E_{alreq}$$

(Equation 99)

A CT according to ANSI/IEEE is also specified by the knee-point voltage $U_{kneeANSI}$ that is graphically defined from an excitation curve. The knee-point voltage $U_{kneeANSI}$ normally has a lower value than the knee-point e.m.f. according to IEC and BS. $U_{kneeANSI}$ can approximately be estimated to 75 % of the corresponding E_{al} according to IEC 60044 6. Therefore, the CTs according to ANSI/IEEE must have a knee-point voltage $U_{kneeANSI}$ that fulfills the following:

$$E_{kneeANSI} > 0.75 \cdot (\text{maximum of } E_{alreq})$$

(Equation 100)

15.2 Voltage transformer requirements

The performance of a protection function will depend on the quality of the measured input signal. Transients caused by capacitive voltage transformers (CVTs) can affect some protection functions.

Magnetic or capacitive voltage transformers can be used.

The capacitive voltage transformers (CVTs) should fulfill the requirements according to the IEC 60044–5 standard regarding ferro-resonance and transients. The ferro-resonance requirements of the CVTs are specified in chapter 7.4 of the standard.

The transient responses for three different standard transient response classes, T1, T2 and T3 are specified in chapter 15.5 of the standard. CVTs according to all classes can be used.

The protection IED has effective filters for these transients, which gives secure and correct operation with CVTs.

15.3 SNTP server requirements

The SNTP server to be used is connected to the local network, that is not more than 4-5 switches or routers away from the IED. The SNTP server is dedicated for its task, or at least equipped with a real-time operating system, that is not a PC with SNTP server software. The SNTP server should be stable, that is, either synchronized from a stable source like GPS, or local without synchronization. Using a local SNTP server without synchronization as primary or secondary server in a redundant configuration is not recommended.

Section 16 Glossary

AC	Alternating current
ACT	Application configuration tool within PCM600
A/D converter	Analog to digital converter
ADBS	Amplitude dead-band supervision
ANSI	American National Standards Institute
AR	Autoreclosing
ASCT	Auxiliary summation current transformer
ASD	Adaptive signal detection
AWG	American Wire Gauge standard
BR	External bi-stable relay
BS	British standard
CAN	Controller Area Network. ISO standard (ISO 11898) for serial communication
CB	Circuit breaker
CCITT	Consultative Committee for International Telegraph and Telephony. A United Nations sponsored standards body within the International Telecommunications Union.
CCVT	Capacitive Coupled Voltage Transformer
Class C	Protection Current Transformer class as per IEEE/ ANSI
CMPPS	Combined mega pulses per second
CO cycle	Close-open cycle
Co-directional	Way of transmitting G.703 over a balanced line. Involves two twisted pairs making it possible to transmit information in both directions
COMTRADE	Standard format according to IEC 60255-24
Contra-directional	Way of transmitting G.703 over a balanced line. Involves four twisted pairs of with two are used for transmitting data in both directions, and two pairs for transmitting clock signals
CPU	Central processor unit
CR	Carrier receive
CRC	Cyclic redundancy check
CS	Carrier send

CT	Current transformer
CVT	Capacitive voltage transformer
DAR	Delayed auto-reclosing
DARPA	Defense Advanced Research Projects Agency (The US developer of the TCP/IP protocol etc.)
DBDL	Dead bus dead line
DBLL	Dead bus live line
DC	Direct current
DFT	Discrete Fourier transform
DIP-switch	Small switch mounted on a printed circuit board
DLLB	Dead line live bus
DNP	Distributed Network Protocol as per IEEE/ANSI Std. 1379-2000
DR	Disturbance recorder
DRAM	Dynamic random access memory
DRH	Disturbance report handler
DSP	Digital signal processor
DTT	Direct transfer trip scheme
EHV network	Extra high voltage network
EIA	Electronic Industries Association
EMC	Electro magnetic compatibility
EMF	Electro motive force
EMI	Electro magnetic interference
EnFP	End fault protection
ESD	Electrostatic discharge
FOX 20	Modular 20 channel telecommunication system for speech, data and protection signals
FOX 512/515	Access multiplexer
FOX 6Plus	Compact, time-division multiplexer for the transmission of up to seven duplex channels of digital data over optical fibers
G.703	Electrical and functional description for digital lines used by local telephone companies. Can be transported over balanced and unbalanced lines
GCM	Communication interface module with carrier of GPS receiver module
GDE	Graphical display editor within PCM600

GI	General interrogation command
GIS	Gas insulated switchgear
GOOSE	Generic object oriented substation event
GPS	Global positioning system
HDLC protocol	High level data link control, protocol based on the HDLC standard
HFBR connector type	Plastic fiber connector
HMI	Human machine interface
HSAR	High speed auto reclosing
HV	High voltage
HVDC	High voltage direct current
IDBS	Integrating dead band supervision
IEC	International Electrical Committee
IEC 60044-6	IEC Standard, Instrument transformers – Part 6: Requirements for protective current transformers for transient performance
IEC 61850	Substation Automation communication standard
IEEE	Institute of Electrical and Electronics Engineers
IEEE 802.12	A network technology standard that provides 100 Mbits/s on twisted-pair or optical fiber cable
IEEE P1386.1	PCI Mezzanine card (PMC) standard for local bus modules. References the CMC (IEEE P1386, also known as Common mezzanine card) standard for the mechanics and the PCI specifications from the PCI SIG (Special Interest Group) for the electrical EMF Electro Motive Force.
IED	Intelligent electronic device
I-GIS	Intelligent gas insulated switchgear
Instance	When several occurrences of the same function are available in the IED they are referred to as instances of that function. One instance of a function is identical to another of the same kind but will have a different number in the IED user interfaces. The word instance is sometimes defined as an item of information that is representative of a type. In the same way an instance of a function in the IED is representative of a type of function.
IP	1. Internet protocol. The network layer for the TCP/IP protocol suite widely used on Ethernet networks. IP is a connectionless, best-effort packet switching protocol. It

	provides packet routing, fragmentation and re-assembly through the data link layer. 2. Ingression protection according to IEC standard
IP 20	Ingression protection, according to IEC standard, level 20
IP 40	Ingression protection, according to IEC standard, level 40
IP 54	Ingression protection, according to IEC standard, level 54
IRF	Internal fail signal
IRIG-B:	InterRange Instrumentation Group Time code format B, standard 200
ITU	International Telecommunications Union
LAN	Local area network
LIB 520	High voltage software module
LCD	Liquid crystal display
LDD	Local detection device
LED	Light emitting diode
MCB	Miniature circuit breaker
MCM	Mezzanine carrier module
MVB	Multifunction vehicle bus. Standardized serial bus originally developed for use in trains.
NCC	National Control Centre
OCO cycle	Open-close-open cycle
OCP	Overcurrent protection
OLTC	On load tap changer
OV	Over voltage
Overreach	A term used to describe how the relay behaves during a fault condition. For example a distance relay is over-reaching when the impedance presented to it is smaller than the apparent impedance to the fault applied to the balance point, i.e. the set reach. The relay “sees” the fault but perhaps it should not have seen it.
PCI	Peripheral component interconnect, a local data bus
PCM	Pulse code modulation
PCM600	Protection and control IED manager
PC-MIP	Mezzanine card standard
PISA	Process interface for sensors & actuators
PMC	PCI Mezzanine card
POTT	Permissive overreach transfer trip

Process bus	Bus or LAN used at the process level, that is, in near proximity to the measured and/or controlled components
PSM	Power supply module
PST	Parameter setting tool within PCM600
PT ratio	Potential transformer or voltage transformer ratio
PUTT	Permissive underreach transfer trip
RASC	Synchrocheck relay, COMBIFLEX
RCA	Relay characteristic angle
REVAL	Evaluation software
RFPP	Resistance for phase-to-phase faults
RFPE	Resistance for phase-to-earth faults
RISC	Reduced instruction set computer
RMS value	Root mean square value
RS422	A balanced serial interface for the transmission of digital data in point-to-point connections
RS485	Serial link according to EIA standard RS485
RTC	Real time clock
RTU	Remote terminal unit
SA	Substation Automation
SC	Switch or push-button to close
SCS	Station control system
SCT	System configuration tool according to standard IEC 61850
SMA connector	Subminiature version A, A threaded connector with constant impedance.
SMT	Signal matrix tool within PCM600
SMS	Station monitoring system
SNTP	Simple network time protocol – is used to synchronize computer clocks on local area networks. This reduces the requirement to have accurate hardware clocks in every embedded system in a network. Each embedded node can instead synchronize with a remote clock, providing the required accuracy.
SRY	Switch for CB ready condition
ST	Switch or push-button to trip
Starpoint	Neutral point of transformer or generator
SVC	Static VAr compensation
TC	Trip coil

TCS	Trip circuit supervision
TCP	Transmission control protocol. The most common transport layer protocol used on Ethernet and the Internet.
TCP/IP	Transmission control protocol over Internet Protocol. The de facto standard Ethernet protocols incorporated into 4.2BSD Unix. TCP/IP was developed by DARPA for internet working and encompasses both network layer and transport layer protocols. While TCP and IP specify two protocols at specific protocol layers, TCP/IP is often used to refer to the entire US Department of Defense protocol suite based upon these, including Telnet, FTP, UDP and RDP.
TNC connector	Threaded Neill Concelman, A threaded constant impedance version of a BNC connector
TPZ, TPY, TPX, TPS	Current transformer class according to IEC
Underreach	A term used to describe how the relay behaves during a fault condition. For example a distance relay is under-reaching when the impedance presented to it is greater than the apparent impedance to the fault applied to the balance point, i.e. the set reach. The relay does not “see” the fault but perhaps it should have seen it. See also Overreach.
U/I-PISA	Process interface components that deliver measured voltage and current values
UTC	Coordinated universal time. A coordinated time scale, maintained by the Bureau International des Poids et Mesures (BIPM), which forms the basis of a coordinated dissemination of standard frequencies and time signals. UTC is derived from International Atomic Time (TAI) by the addition of a whole number of "leap seconds" to synchronize it with Universal Time 1 (UT1), thus allowing for the eccentricity of the Earth"s orbit, the rotational axis tilt (23.5 degrees), but still showing the Earth"s irregular rotation, on which UT1 is based. The Coordinated Universal Time is expressed using a 24-hour clock and uses the Gregorian calendar. It is used for aeroplane and ship navigation, where it also sometimes known by the military name, "Zulu time". "Zulu" in the phonetic alphabet stands for "Z" which stands for longitude zero.
UV	Undervoltage
WEI	Weak end infeed logic
VT	Voltage transformer
X.21	A digital signalling interface primarily used for telecom equipment

$3I_O$	Three times zero-sequence current. Often referred to as the residual or the earth-fault current
$3U_O$	Three times the zero sequence voltage. Often referred to as the residual voltage or the neutral point voltage

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