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Major changes

For information on the updates included in this release of the manual, please refer to the latest release notes.

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CHAPTER 1

INTRODUCTION

1.1 CHAPTER OVERVIEW

This chapter provides some general information about the technical manual and an introduction to the device(s) described in this technical manual.

This chapter contains the following sections:

Chapter Overview 2
Foreword 3
Product Scope 5
Features and Functions 6
Logic Diagrams 9
Functional Overview 11

1.2 FOREWORD

This technical manual provides a functional and technical description of GE Vernova's 5th Generation transmission protection IED, as well as a comprehensive set of instructions for using the device. The level at which this manual is written assumes that you are already familiar with protection engineering and have experience in this discipline. The description of principles and theory is limited to that which is necessary to understand the product. For further details on general protection engineering theory, we refer you to GE Vernova's publication, Protection and Automation Application Guide, which is available online or from our Contact Centre.

We have attempted to make this manual as accurate, comprehensive and user-friendly as possible. However we cannot guarantee that it is free from errors. Nor can we state that it cannot be improved. We would therefore be very pleased to hear from you if you discover any errors, or have any suggestions for improvement. Our policy is to provide the information necessary to help you safely specify, engineer, install, commission, maintain, and eventually dispose of this product. We consider that this manual provides the necessary information, but if you consider that more details are needed, please contact us.

All feedback should be sent to our contact centre via:

GA.support@gevernova.com

1.2.1 TARGET AUDIENCE

This manual is aimed towards all professionals charged with installing, commissioning, maintaining, troubleshooting, or operating any of the products within the specified product range. This includes installation and commissioning personnel as well as engineers who will be responsible for operating the product.

The level at which this manual is written assumes that installation and commissioning engineers have knowledge of handling electronic equipment. Also, system and protection engineers have a thorough knowledge of protection systems and associated equipment.

1.2.2 TYPOGRAPHICAL CONVENTIONS

The following typographical conventions are used throughout this manual.

- The names for special keys appear in capital letters.
  For example: ENTER
- When describing software applications, menu items, buttons, labels etc as they appear on the screen are written in bold type.
  For example: Select **Save** from the file menu.
- Filenames and paths use the courier font
  For example: `Example\File.text`
- Special terminology is written with leading capitals
  For example: Sensitive Earth Fault
- If reference is made to the IED's internal settings and signals database, the menu group heading (column) text is written in upper case italics
  For example: The *SYSTEM DATA* column
- If reference is made to the IED's internal settings and signals database, the setting cells and DDB signals are written in bold italics
  For example: The ***Language*** cell in the *SYSTEM DATA* column
- If reference is made to the IED's internal settings and signals database, the value of a cell's content is written in the Courier font
  For example: The ***Language*** cell in the *SYSTEM DATA* column contains the value *`English`*

1.2.3 NOMENCLATURE

Due to the technical nature of this manual, many special terms, abbreviations and acronyms are used throughout the manual. Some of these terms are well-known industry-specific terms while others may be special product-specific terms used by GE Vernova. The first instance of any acronym or term used in a particular chapter is explained. In addition, a separate glossary is available on the GE Vernova website, or from the GE Vernova contact centre.

We would like to highlight the following changes of nomenclature however:

- The word 'relay' is no longer used to describe the device itself. Instead, the device is referred to as the 'IED' (Intelligent Electronic Device), the 'device', or the 'product'. The word 'relay' is used purely to describe the electromechanical components within the device, i.e. the output relays.
- British English is used throughout this manual.
- The British term 'Earth' is used in favour of the American term 'Ground'.

1.2.4 COMPLIANCE

The device has undergone a range of extensive testing and certification processes to ensure and prove compatibility with all target markets. A detailed description of these criteria can be found in the Technical Specifications chapter.

1.3 PRODUCT SCOPE

The P14 feeder management IED has been designed for all applications where overcurrent and earth fault protection is required, from distribution to transmission voltage levels. Suitable for solidly-earthed, impedance-earthed, Petersen coil-earthed and isolated systems.

The device provides an extensive range of protection functions as well as a comprehensive range of additional features to aid with power system diagnosis and fault analysis.

The P14 provides a fourth VT, for autoreclose and check synchronisation which are optionally available. Due to its choice of larger case sizes, it can also provide significantly more I/O (opto-inputs and relay outputs). Model P also provides switch status and control for disconnectors, load break switches and earthing switches.

The difference in model case sizes are summarised below:

Model Features			
Case	40TE	60TE	80TE
Number of CT Inputs	5	5	5
Number of VT inputs	4	4	4
Optically coupled digital inputs	16 (max)	24 (max)	48 (max)
Standard relay output contacts	12 (max)	24 (max)	43 (max)
Function keys	0	10	10

1.3.1 PRODUCT VERSIONS

The P14 detailed in this manual belongs to the 5th Generation of P40 protection devices.

The P14 device software is based on 4th Generation software (SW):

- P14x - 91SW

Unlike previous products based on 4th Generation software, the protocol supported on the serial rear communication port (RP1) is now selectable in the settings rather than being an ordering option. The supported protocols are:

- Courier
- IEC870-5-103
- DNP3.0

Autoreclose and check synchronisation are advanced CORTEC options. Please refer to Appendix A - Ordering Options.

1.3.2 ORDERING OPTIONS

All current models and variants for this product are defined in an interactive spreadsheet called the CORTEC. This is available on the company website.

Alternatively, you can obtain it via the Contact Centre at:

GA.support@gevernova.com

A copy of the CORTEC is also supplied as a static table in the Appendices of this document. However, it should only be used for guidance as it provides a snapshot of the interactive data taken at the time of publication.

1.4 FEATURES AND FUNCTIONS

1.4.1 PROTECTION FUNCTIONS

Feature	IEC 61850	ANSI
Tripping mode (3 pole)	PTRC	
ABC and ACB phase rotation		
Phase overcurrent, with optional directionality (6 stages)	OcpPTOC/RDIR	50/51/67
Earth/Ground overcurrent stages, with optional directionality (2 elements each with 4 stages)	EfdPTOC/RDIR	50N/51N/ 67N
Admittance protection (1 stage over admittance, 1 stage over conductance, 1 stage over susceptance)		
Advanced frequency (9 stages of frequency protection, independent df/dt, supervised df/dt, supervised DELF/DELT and load restoration)		
Sensitive Earth Fault (SEF) (4 stages)	SenPTOC/RDIR	50N/51N/67N
High impedance restricted earth fault (REF)	SenRefPDIF	64
Negative sequence overcurrent stages, with optional directionality (4 stages)	NgcPTOC/RDIR	67/46
Broken conductor, used to detect open circuit faults		46
Thermal overload protection	ThmPTTR	49
Phase directional power (4 stages)	PdpPDOP/PDUP	32
Undervoltage protection (4 stages)	VtpPhsPTUV	27
Overvoltage protection (4 stages)	VtpPhsPTOV	59
Remote overvoltage protection (2 stages)	VtpCmpPTOV	59R
Residual voltage protection (4 stages)	VtpResPTOV	59N
Negative sequence overvoltage (1 stage)		
Sensitive power (2 stages)		
Sensitive overvoltage (2 stages)		
Power protection (4 stages)		
Underfrequency protection (4 stages)	FrqPTUF	81
Overfrequency protection (2 stages)	FrqPTOF	81
Rate of change of frequency protection (4 stages)	DfpPFRC	81
High speed breaker fail suitable for re-tripping and back-tripping (2 stages)	RBRF	50BF
Current Transformer supervision		46
Voltage Transformer supervision		47/27
Auto-reclose (4 shots)	RREC	79
Check synchronisation (2 stages)	RSYN	25
User curves (4)		

1.4.2 TYPOGRAPHICAL CONVENTIONS

The following typographical conventions are used throughout this manual.

- The names for special keys appear in capital letters.
  For example: ENTER
- When describing software applications, menu items, buttons, labels etc as they appear on the screen are written in bold type.
  For example: Select **Save** from the file menu.
- Filenames and paths use the courier font

For example: `Example\File.text`

- Special terminology is written with leading capitals
  For example: Sensitive Earth Fault
- If reference is made to the IEDs internal settings and signals database, the menu group heading text is written in upper case italics
  For example: The *SYSTEM DATA*
- IED menu paths are shown with \ separators
  For Example: SETPOINTS\CONTROL\AUTORECLOSE
- If reference is made to the IEDs internal settings and signals database, the value is written as follows:
  The ***Language*** setting in the *SYSTEM DATA* heading contains the value *`English`*

1.4.3 CONTROL FUNCTIONS

Feature	IEC 61850	ANSI
Watchdog contacts		
Read-only mode		
Function keys	FnkGGIO	
Programmable LEDs	LedGGIO	
Programmable hot keys		
Programmable allocation of digital inputs and outputs		
Fully customizable menu texts		
Circuit breaker control, status & condition monitoring	XCBR	52
CT supervision		
VT supervision		
Trip circuit and coil supervision		
Control inputs	PloGGIO1	
Power-up diagnostics and continuous self-monitoring		
Dual rated 1A and 5A CT inputs		
Alternative setting groups (4)		
Graphical programmable scheme logic (PSL)		
Fault locator	RFLO	

1.4.4 MEASUREMENT FUNCTIONS

Measurement Function	IEC 61850	ANSI
Measurement of all instantaneous & integrated values (Exact range of measurements depend on the device model)		MET
Disturbance recorder for waveform capture – specified in samples per cycle	RDRE	DFR
Fault Records		
Maintenance Records		
Event Records/Event logging		Event records
Time Stamping of Opto-inputs	Yes	Yes

1.4.5 COMMUNICATION FUNCTIONS

Feature	ANSI
NERC compliant cyber-security	
Front RS232 serial communication port for configuration	16S
Rear serial RS485 communication port for SCADA control	16S
2 Additional rear serial communication ports for SCADA control and teleprotection (fibre and copper) (optional)	16S
Ethernet communication (optional)	16E
Redundant Ethernet communication (optional)	16E
Rear Ethernet engineering port for configuration	16E
Courier Protocol	16S
IEC 61850 edition 1 or edition 2 (optional)	16E
IEC 60870-5-103 (optional)	16S
DNP3.0 over serial link (optional)	16S
SNMP	16E
IRIG-B time synchronisation (optional)	CLK
IEEE 1588 PTP (Edition 2 devices only)	

1.5 LOGIC DIAGRAMS

This technical manual contains many logic diagrams, which should help to explain the functionality of the device. Although this manual has been designed to be as specific as possible to the chosen product, it may contain diagrams, which have elements applicable to other products. If this is the case, a qualifying note will accompany the relevant part.

The logic diagrams follow a convention for the elements used, using defined colours and shapes. A key to this convention is provided below. We recommend viewing the logic diagrams in colour rather than in black and white. The electronic version of the technical manual is in colour, but the printed version may not be. If you need coloured diagrams, they can be provided on request by calling the contact centre and quoting the diagram number.

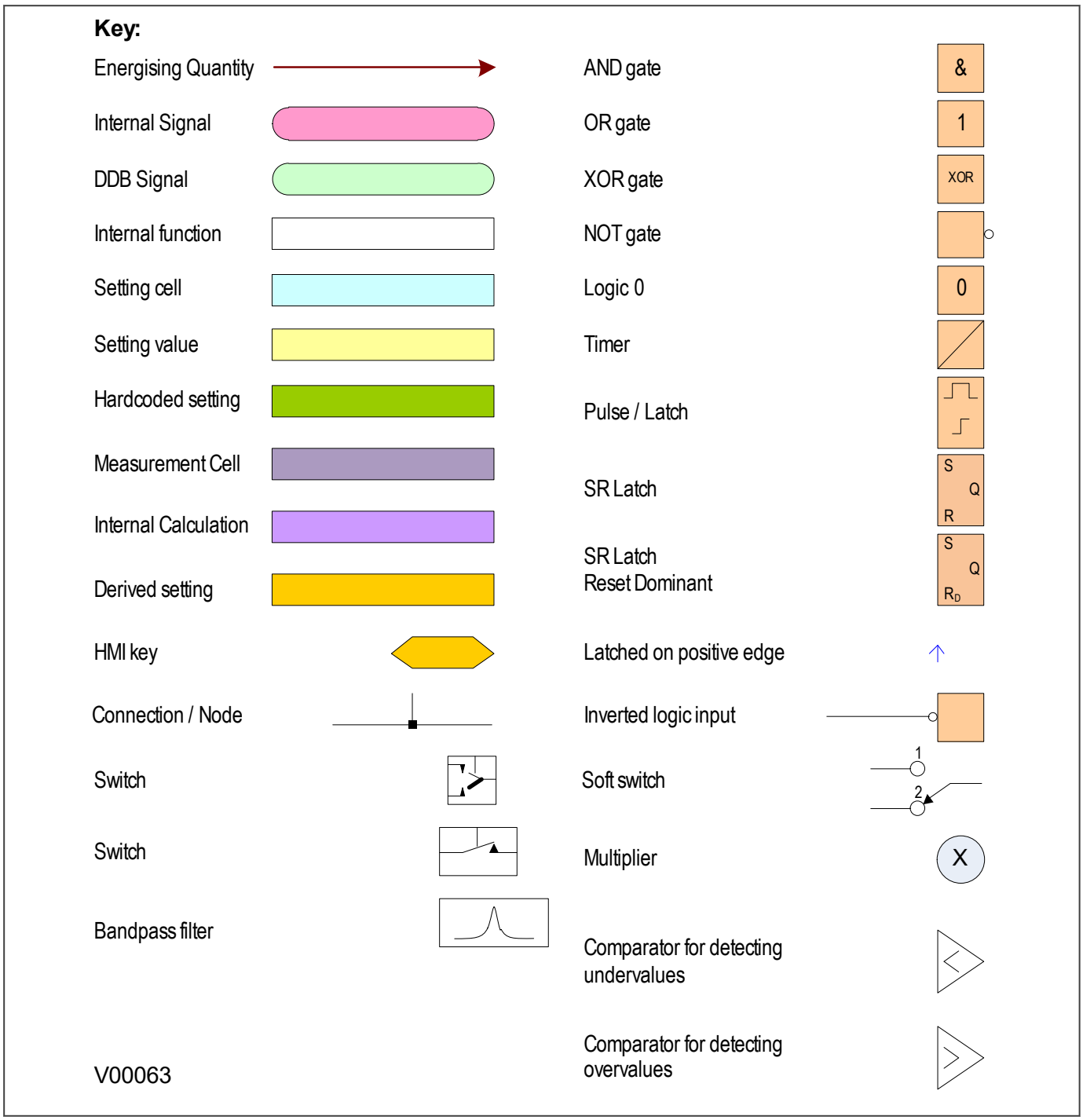


Figure 1: Key to logic diagrams

1.6 FUNCTIONAL OVERVIEW

This diagram is applicable to P14 product models. Use the key on the diagram to determine the features relevant to the product described in this technical manual.

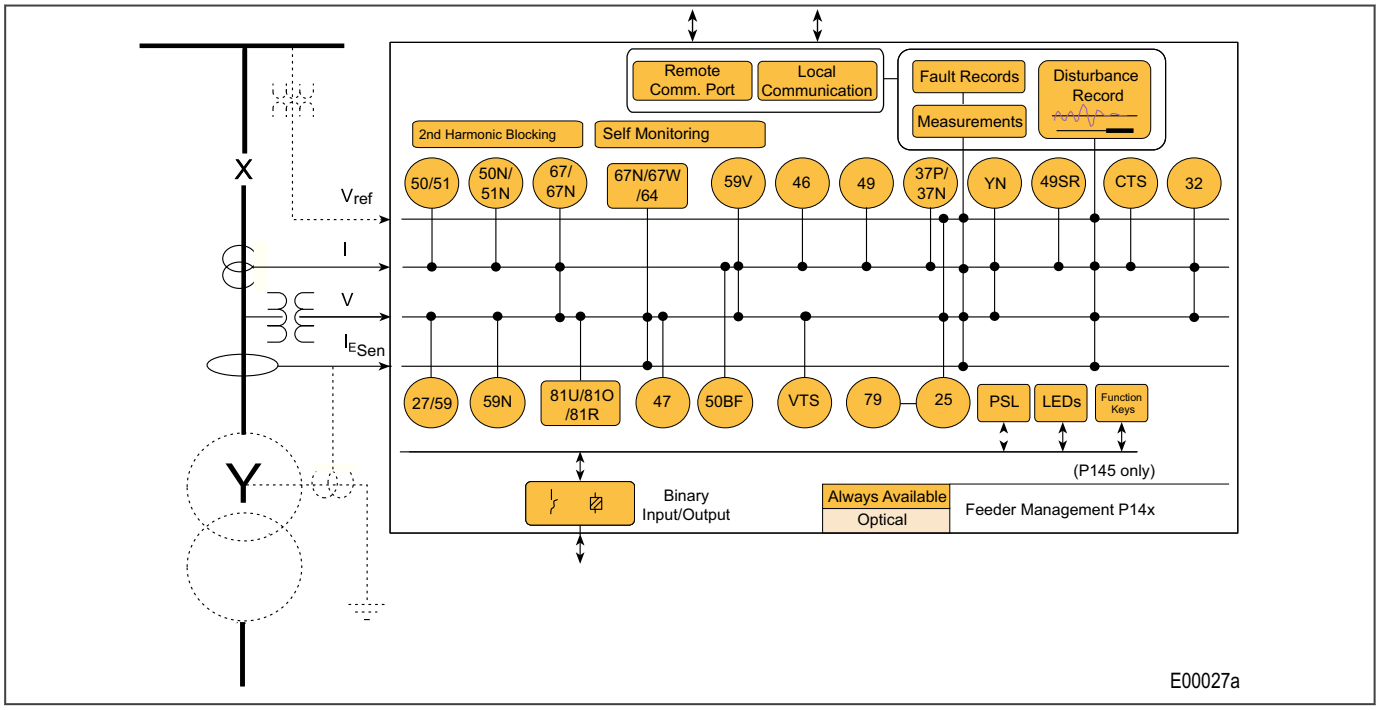


Figure 2: Functional overview

The following table lists the P14 ANSI numbers and the corresponding function descriptions:

Device Number	Function
25	Check Sychronism
27	Phase and Line Undervoltage
32	Directional Power Protection
46	Negative Sequence Overcurrent
47	Negative Sequence Overvoltage
49	Thermal Overload
50	Instantaneous Overcurrent
51	Phase Inverse-Time Overcurrent
59	Phase and Line Overvoltage
64	Restricted Earth Fault
67	Directional Phase Overcurrent
79	Autoreclose
37N	Undercurrent
37P	Underpower
49SR	
50BF	CB Failure
50N	Earth Fault Instantaneous Overcurrent
51N	Neutral/Ground Time Overcurrent

Device Number	Function
59N	Neutral Voltage Displacement
59V	
67N	Directional Neutral/Ground Overcurrent
67W	Directional Wattmetric Earth Fault
81O	Overfrequency
81R	Rate of Change of Frequency
81U	Underfrequency
CTS	CT Supervision
LEDs	Light Emitting Diode
PSL	Programmable Logic
VTS	VT Supervision
YN	

CHAPTER 2

SAFETY INFORMATION

2.1 CHAPTER OVERVIEW

This chapter provides information about the safe handling of the equipment. The equipment must be properly installed and handled in order to maintain it in a safe condition and to keep personnel safe at all times. You must be familiar with information contained in this chapter before unpacking, installing, commissioning, or servicing the equipment.

This chapter contains the following sections:

Chapter Overview 14

Health and Safety 15

Symbols 16

Installation, Commissioning and Servicing 17

Decommissioning and Disposal 23

Regulatory Compliance 24

2.2 HEALTH AND SAFETY

Personnel associated with the equipment must be familiar with the contents of this Safety Information.

When electrical equipment is in operation, dangerous voltages are present in certain parts of the equipment. Improper use of the equipment and failure to observe warning notices will endanger personnel.

Only qualified personnel may work on or operate the equipment. Qualified personnel are individuals who are:

- Familiar with the installation, commissioning, and operation of the equipment and the system to which it is being connected.
- Familiar with accepted safety engineering practises and are authorised to energise and de-energise equipment in the correct manner.
- Trained in the care and use of safety apparatus in accordance with safety engineering practises
- Tained in emergency procedures (first aid).

The documentation provides instructions for installing, commissioning and operating the equipment. It cannot, however cover all conceivable circumstances. In the event of questions or problems, do not take any action without proper authorisation. Please contact your local sales office and request the necessary information.

2.3 SYMBOLS

Throughout this manual you will come across the following symbols. You will also see these symbols on parts of the equipment.



Caution:
Refer to equipment documentation. Failure to do so could result in damage to the equipment



Warning:
Risk of electric shock



Warning:
Risk of damage to eyesight



Earth terminal. *Note: This symbol may also be used for a protective conductor (earth) terminal if that terminal is part of a terminal block or sub-assembly.*



Protective conductor (earth) terminal



Instructions on disposal requirements

Note:
The term 'Earth' used in this manual is the direct equivalent of the North American term 'Ground'.

2.4 INSTALLATION, COMMISSIONING AND SERVICING

2.4.1 LIFTING HAZARDS

Many injuries are caused by:

- Lifting heavy objects
- Lifting things incorrectly
- Pushing or pulling heavy objects
- Using the same muscles repetitively

Plan carefully, identify any possible hazards and determine how best to move the product. Look at other ways of moving the load to avoid manual handling. Use the correct lifting techniques and Personal Protective Equipment (PPE) to reduce the risk of injury.

2.4.2 ELECTRICAL HAZARDS



Caution:
All personnel involved in installing, commissioning, or servicing this equipment must be familiar with the correct working procedures.



Caution:
Consult the equipment documentation before installing, commissioning, or servicing the equipment.



Caution:
Always use the equipment as specified. Failure to do so will jeopardise the protection provided by the equipment.



Warning:
Removal of equipment panels or covers may expose hazardous live parts. Do not touch until the electrical power is removed. Take care when there is unlocked access to the rear of the equipment.



Warning:
Isolate the equipment before working on the terminal strips.



Warning:
Use a suitable protective barrier for areas with restricted space, where there is a risk of electric shock due to exposed terminals.



Caution:
Disconnect power before disassembling. Disassembly of the equipment may expose sensitive electronic circuitry. Take suitable precautions against electrostatic voltage discharge (ESD) to avoid damage to the equipment.



Warning:
NEVER look into optical fibres or optical output connections. Always use optical power meters to determine operation or signal level.



Warning:
Testing may leave capacitors charged to dangerous voltage levels. Discharge capacitors by reducing test voltages to zero before disconnecting test leads.



Caution:
Operate the equipment within the specified electrical and environmental limits.



Caution:
Before cleaning the equipment, ensure that no connections are energised. Use a lint free cloth dampened with clean water.

Note:
Contact fingers of test plugs are normally protected by petroleum jelly, which should not be removed.

2.4.3 UL/CSA/CUL REQUIREMENTS

The information in this section is applicable only to equipment carrying UL/CSA/CUL markings.



Caution:
Equipment intended for rack or panel mounting is for use on a flat surface of a Type 1 enclosure, as defined by Underwriters Laboratories (UL).



Caution:
To maintain compliance with UL and CSA/CUL, install the equipment using UL/CSA-recognised parts for: cables, protective fuses, fuse holders and circuit breakers, insulation crimp terminals, and replacement internal batteries.

2.4.4 FUSING REQUIREMENTS



Caution:
Where UL/CSA listing of the equipment is required for external fuse protection, a UL or CSA Listed fuse must be used for the auxiliary supply. The listed protective fuse type is: Class J time delay fuse, with a maximum current rating of 15 A and a minimum DC rating of 250 V dc (for example type AJT15).



Caution:
Where UL/CSA listing of the equipment is not required, a high rupture capacity (HRC) fuse type with a maximum current rating of 16 Amps and a minimum dc rating of 250 V dc may be used for the auxiliary supply (for example Red Spot type NIT or TIA).
For P50 models, use a 1A maximum T-type fuse.
For P60 models, use a 4A maximum T-type fuse.



Caution:
Digital input circuits should be protected by a high rupture capacity NIT or TIA fuse with maximum rating of 16 A. for safety reasons, current transformer circuits must never be fused. Other circuits should be appropriately fused to protect the wire used.



Caution:
CTs must NOT be fused since open circuiting them may produce lethal hazardous voltages

2.4.5 EQUIPMENT CONNECTIONS



Warning:
Terminals exposed during installation, commissioning and maintenance may present a hazardous voltage unless the equipment is electrically isolated.



Caution:
Tighten M4 clamping screws of heavy duty terminal block connectors to a nominal torque of 1.3 Nm.
Tighten captive screws of terminal blocks to 0.5 Nm minimum and 0.6 Nm maximum.



Caution:
Always use insulated crimp terminations for voltage and current connections.



Caution:
Always use the correct crimp terminal and tool according to the wire size.



Caution:
Watchdog (self-monitoring) contacts are provided to indicate the health of the device on some products. We strongly recommend that you hard wire these contacts into the substation's automation system, for alarm purposes.

2.4.6 PROTECTION CLASS 1 EQUIPMENT REQUIREMENTS



Caution:
Earth the equipment with the supplied PCT (Protective Conductor Terminal).



Caution:
Do not remove the PCT.



Caution:
The PCT is sometimes used to terminate cable screens. Always check the PCT's integrity after adding or removing such earth connections.



Caution:
Use a locknut or similar mechanism to ensure the integrity of stud-connected PCTs.



Caution:
The recommended minimum PCT wire size is 2.5 mm² for countries whose mains supply is 230 V (e.g. Europe) and 3.3 mm² for countries whose mains supply is 110 V (e.g. North America). This may be superseded by local or country wiring regulations. For P60 products, the recommended minimum PCT wire size is 6 mm². See product documentation for details.



Caution:
The PCT connection must have low-inductance and be as short as possible.



Caution:
All connections to the equipment must have a defined potential. Connections that are pre-wired, but not used, should be earthed, or connected to a common grouped potential.

2.4.7 PRE-ENERGISATION CHECKLIST



Caution:
Check voltage rating/polarity (rating label/equipment documentation).



Caution:
Check CT circuit rating (rating label) and integrity of connections.



Caution:
Check protective fuse or miniature circuit breaker (MCB) rating.



Caution:
Check integrity of the PCT connection.



Caution:
Check voltage and current rating of external wiring, ensuring it is appropriate for the application.

2.4.8 PERIPHERAL CIRCUITRY



Warning:
Do not open the secondary circuit of a live CT since the high voltage produced may be lethal to personnel and could damage insulation. Short the secondary of the line CT before opening any connections to it.

Note:
For most GE Vernova equipment with ring-terminal connections, the threaded terminal block for current transformer termination is automatically shorted if the module is removed. Therefore external shorting of the CTs may not be required. Check the equipment documentation and wiring diagrams first to see if this applies.



Caution:
Where external components such as resistors or voltage dependent resistors (VDRs) are used, these may present a risk of electric shock or burns if touched.



Warning:
Take extreme care when using external test blocks and test plugs such as the MMLG, MMLB and P990, as hazardous voltages may be exposed. Ensure that CT shorting links are in place before removing test plugs, to avoid potentially lethal voltages.



Warning:
Data communication cables with accessible screens and/or screen conductors, (including optical fibre cables with metallic elements), may create an electric shock hazard in a sub-station environment if both ends of the cable screen are not connected to the same equipotential bonded earthing system.

To reduce the risk of electric shock due to transferred potential hazards:

i. The installation shall include all necessary protection measures to ensure that no fault currents can flow in the connected cable screen conductor.

ii. The connected cable shall have its screen conductor connected to the protective conductor terminal (PCT) of the connected equipment at both ends. This connection may be inherent in the connectors provided on the equipment but, if there is any doubt, this must be confirmed by a continuity test.

iii. The protective conductor terminal (PCT) of each piece of connected equipment shall be connected directly to the same equipotential bonded earthing system.

iv. If, for any reason, both ends of the cable screen are not connected to the same equipotential bonded earth system, precautions must be taken to ensure that such screen connections are made safe before work is done to, or in proximity to, any such cables.

v. No equipment shall be connected to any download or maintenance circuits or connectors of this product except temporarily and for maintenance purposes only.

vi. Equipment temporarily connected to this product for maintenance purposes shall be protectively earthed (if the temporary equipment is required to be protectively earthed), directly to the same equipotential bonded earthing system as the product.



Warning:
Small Form-factor Pluggable (SFP) modules which provide copper Ethernet connections typically do not provide any additional safety isolation. Copper Ethernet SFP modules must only be used in connector positions intended for this type of connection.

2.4.9 UPGRADING/SERVICING



Warning:
Do not insert or withdraw modules, PCBs or expansion boards from the equipment while energised, as this may result in damage to the equipment. Hazardous live voltages would also be exposed, endangering personnel.



Caution:
Internal modules and assemblies can be heavy and may have sharp edges. Take care when inserting or removing modules into or out of the IED.

2.5 DECOMMISSIONING AND DISPOSAL



Caution:
Before decommissioning, completely isolate the equipment power supplies (both poles of any dc supply). The auxiliary supply input may have capacitors in parallel, which may still be charged. To avoid electric shock, discharge the capacitors using the external terminals before decommissioning.



Caution:
Avoid incineration or disposal to water courses. Dispose of the equipment in a safe, responsible and environmentally friendly manner, and if applicable, in accordance with country-specific regulations.

2.6 REGULATORY COMPLIANCE

Compliance with the European Commission Directive on EMC and LVD is demonstrated using a technical file.

CE

2.6.1 EMC COMPLIANCE: 2014/30/EU

The product specific Declaration of Conformity (DoC) lists the relevant harmonised standard(s) or conformity assessment used to demonstrate compliance with the EMC directive.

2.6.2 LVD COMPLIANCE: 2014/35/EU

The product specific Declaration of Conformity (DoC) lists the relevant harmonized standard(s) or conformity assessment used to demonstrate compliance with the LVD directive.

Safety related information, such as the installation I overvoltage category, pollution degree and operating temperature ranges are specified in the Technical Data section of the relevant product documentation and/or on the product labelling.

Unless otherwise stated in the Technical Data section of the relevant product documentation, the equipment is intended for indoor use only. Where the equipment is required for use in an outdoor location, it must be mounted in a specific cabinet or housing to provide the equipment with the appropriate level of protection from the expected outdoor environment.

2.6.3 R&TTE COMPLIANCE: 2014/53/EU

Radio and Telecommunications Terminal Equipment (R&TTE) directive 2014/53/EU.

Conformity is demonstrated by compliance to both the EMC directive and the Low Voltage directive, to zero volts.

2.6.4 UL/CUL COMPLIANCE

If marked with this logo, the product is compliant with the requirements of the Canadian and USA Underwriters Laboratories.

The relevant UL file number and ID is shown on the equipment.

c UL us

CHAPTER 3

HARDWARE DESIGN

3.1 CHAPTER OVERVIEW

This chapter provides information about the product's hardware design.

This chapter contains the following sections:

Chapter Overview 26
Hardware Architecture 27
Mechanical Implementation 28
Front Panel 30
Rear Panel 34
Boards and Modules 36

3.2 HARDWARE ARCHITECTURE

The main components comprising devices based on the Px4x platform are as follows:

- The housing, consisting of a front panel and connections at the rear
- The Main processor module consisting of the main CPU (Central Processing Unit), memory and an interface to the front panel HMI (Human Machine Interface)
- A selection of plug-in boards and modules with presentation at the rear for the power supply, communication functions, digital I/O, analogue inputs, and time synchronisation connectivity

All boards and modules are connected by a parallel data and address bus, which allows the processor module to send and receive information to and from the other modules as required. There is also a separate serial data bus for conveying sampled data from the input module to the CPU. These parallel and serial databuses are shown as a single interconnection module in the following figure, which shows typical modules and the flow of data between them.

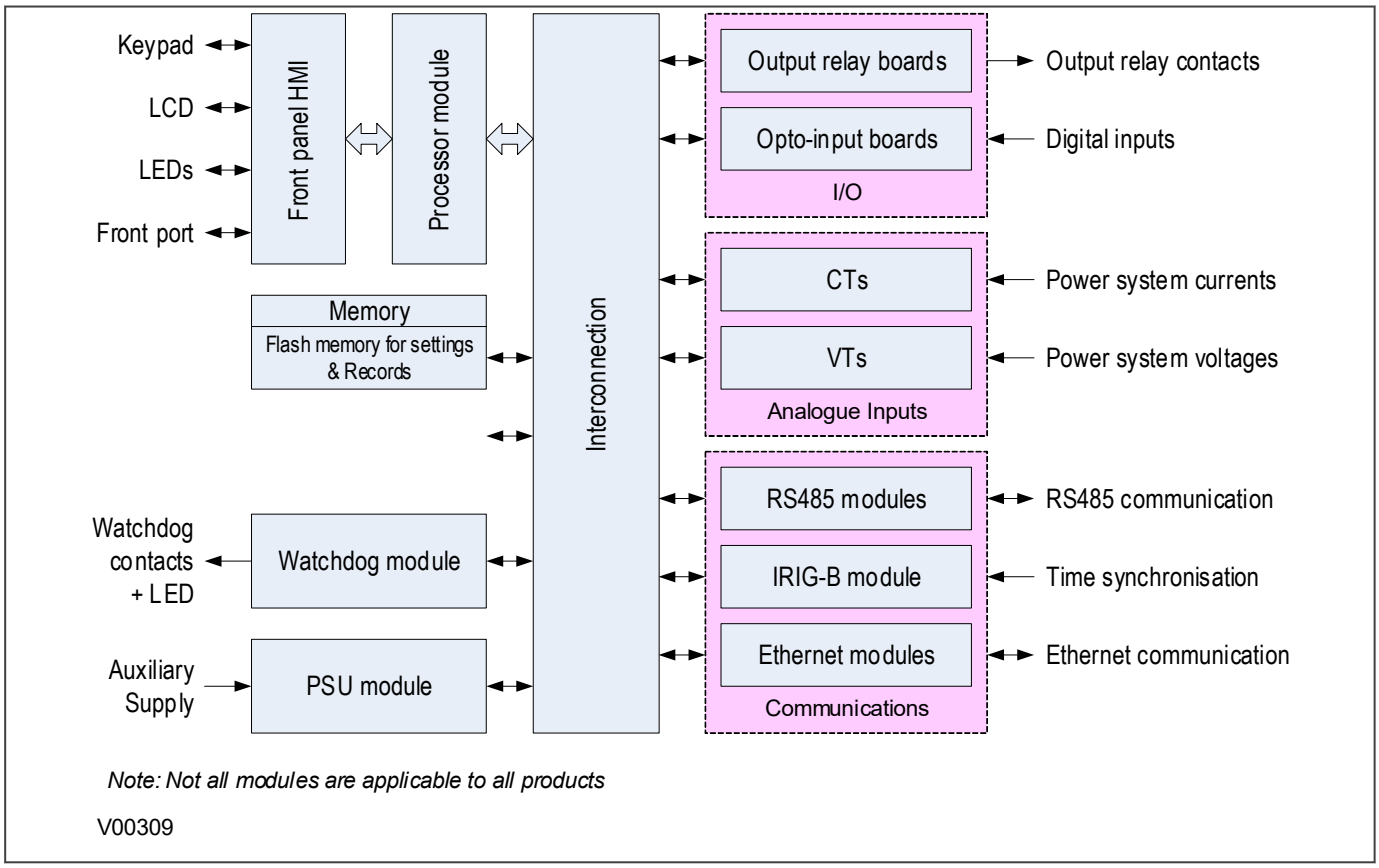


Figure 3: Hardware architecture

3.3 MECHANICAL IMPLEMENTATION

All products based on the Px4x platform have common hardware architecture. The hardware is modular and consists of the following main parts:

- Case and terminal blocks
- Boards and modules
- Front panel

The case comprises the housing metalwork and terminal blocks at the rear. The boards fasten into the terminal blocks and are connected together by a ribbon cable. This ribbon cable connects to the processor in the front panel.

The following diagram shows an exploded view of a typical product. The diagram shown does not necessarily represent exactly the product model described in this manual.

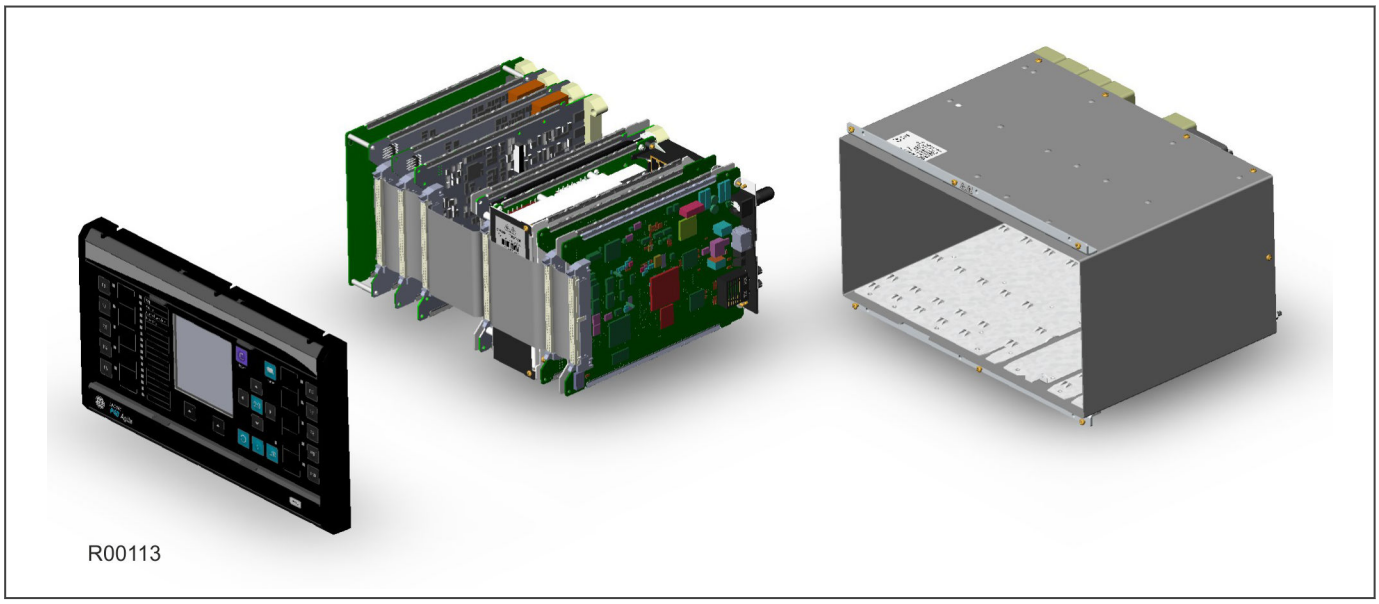


Figure 4: Exploded view of IED

3.3.1 HOUSING VARIANTS

The Px4x range of products are implemented in a range of case sizes. Case dimensions for industrial products usually follow modular measurement units based on rack sizes. These are: U for height and TE for width, where:

- 1U = 1.75 inches = 44.45 mm
- 1TE = 0.2 inches = 5.08 mm

The products are available in panel-mount or standalone versions. All products are nominally 4U high. This equates to 177.8 mm or 7 inches.

The cases are pre-finished steel with a conductive covering of aluminium and zinc. This provides good grounding at all joints, providing a low resistance path to earth that is essential for performance in the presence of external noise.

The case width depends on the product type and its hardware options. There are three different case widths for the described range of products: 40TE, 60TE and 80TE. The case dimensions and compatibility criteria are as follows:

Case width (TE)	Case width (mm)	Case width (inches)
40TE	203.2	8
60TE	304.8	12
80TE	406.4	16

Note:
Not all case sizes are available for all models.

3.3.2 LIST OF BOARDS

The product's hardware consists of several modules drawn from a standard range. The exact specification and number of hardware modules depends on the model number and variant. Depending on the exact model, the product in question will use a selection of the following boards.

Board	Use
Main Processor board - 40TE or smaller	Main Processor board - without support for function keys
Main Processor board - 60TE or larger	Main Processor board - with support for function keys
Power supply board - 24/54V DC	Power supply input. Accepts DC voltage between 24V and 54V
Power supply board - 48/125V DC	Power supply input. Accepts DC voltage between 48V and 125V
Power supply board - 110/250V DC	Power supply input. Accepts DC voltage between 110V and 125V
Transformer board	Contains the voltage and current transformers
Input board	Contains the A/D conversion circuitry
Input board with opto-inputs	Contains the A/D conversion circuitry + 8 digital opto-inputs
Output relay output board	Standard output relay board
High-break output relay board	Output relay board with high breaking capacity relays
Single Ethernet, universal IRIG-B, IEEE1588, maintenance port	Single LC duplex Ethernet port with universal IRIG-B and 1 RJ45 maintenance/ engineering port
IRIG-B board - modulated input	Interface board for modulated IRIG-B timing signal
Fibre board + IRIG-B	Interface board for fibre-based RS485 connection + demodulated IRIG-B
2nd rear communications board	Interface board for RS232/RS485 connections
2nd rear communications board with IRIG-B input	Interface board for RS232/RS485 + IRIG-B connections
Redundant Ethernet RSTP + PRP + HSR + Failover ports, serial fibre port, universal IRIG-B	2 LC duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two fibre pairs), with IEC 60870-5-103 serial fibre ST ports with on-board universal IRIG-B and 1 RJ45 maintenance/engineering port
Redundant Ethernet RSTP + PRP + HSR + Failover universal IRIG-B	2 RJ45 duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two copper pairs), with on-board universal IRIG-B and 1 RJ45 maintenance/engineering port
Redundant Ethernet RSTP + PRP + HSR + Failover ports, universal IRIG-B	2 LC duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two fibre pairs), with on-board universal IRIG-B and 1 RJ45 maintenance/ engineering port

3.4 FRONT PANEL

Depending on the exact model and chosen options, the product will be housed in either a 40TE, 60TE or 80TE case. By way of example, the following diagram shows the front panel of a typical unit. The front panels of the products based on 40TE, 60TE and 80TE cases have a lot of commonality and differ only in that the 40TE front panel does not include 10 function keys with their associated user-programmable LEDs.



Figure 5: Front panel (80TE)

The front panel consists of:

- Top and bottom compartments with hinged cover
- LCD display
- Keypad
- USB Type B port inside the bottom compartment
- Fixed function LEDs
- Function keys and LEDs (60TE and 80TE models)
- Programmable LEDs

3.4.1 FRONT PANEL COMPARTMENTS

The top compartment contains labels for the:

- Order code, Serial number and Test ID.

Note:
The Test ID on the label in the top compartment of the front panel is the serial number of the relay and consists of 6 numeric and 1 alphanumeric characters, for example 123456Z. The serial number is also shown in the System Data menu of the HMI. This serial number can be used to obtain the recovery password from the Contact Centre.
The serial number on the label in the top compartment of the front panel is the SAP manufacturing serial number and consists of 8 numeric characters, for example 37123456.

- Current and voltage ratings

The bottom compartment contains:

- USB type B port

3.4.2 HMI PANEL

The keypad provides full access to the device functionality using a range of menu options. The information is displayed on the colour LCD display.

The colour LCD display is an active matrix Thin Film Transistor (TFT) Liquid Crystal Display (LCD) that uses amorphous silicon TFT as a switching device. This module is composed of a Transmissive type TFT-LCD Panel, driver circuit and back-light unit. The resolution of the 4.0” TFT-LCD is 480x480 pixels and it can display up to 16.7M colours.

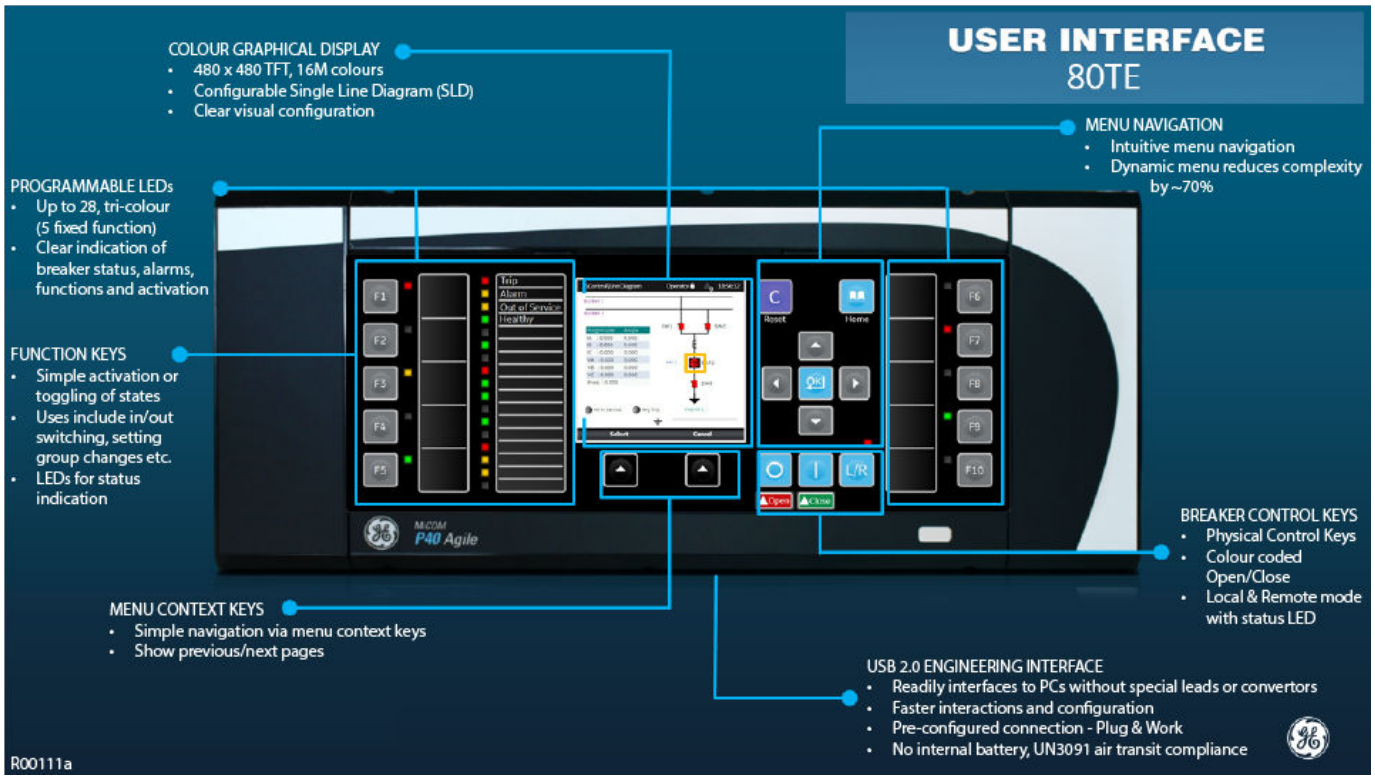
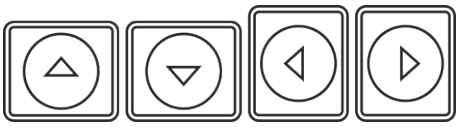
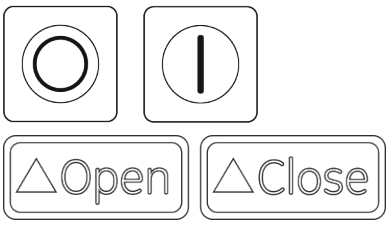


Figure 6: HMI panel

3.4.3 KEYPAD

The keypad consists of the following keys:

4 arrow keys to navigate the menus, changing values within the cell or to select the next item on the SLD (organised around the Enter key).	
An enter key for changing and executing settings. When a bottom banner menu context key label is selected, the OK key can also be used to navigate between pages.	
A clear/reset key for clearing the current setting dialogue or to navigate to the top menu.	

A home key for navigating to the default menu view.	
2 menu context keys used to navigate between pages.	
Open/Close keys (colour coded) **Note:** Colour coding is selectable via labels and configuration of PSL/ SLD.	
Local/remote key to select between local or remote modes.	

3.4.4 USB PORT

The USB port is situated inside the bottom compartment, and is used to communicate with a locally connected PC. It has two main purposes:

- To transfer settings between the PC and the device.
- For downloading firmware updates and menu text editing.

The port is intended for temporary connection during testing, installation and commissioning. It is not intended to be used for permanent SCADA communications. This port supports the Courier communication protocol only. Courier is a proprietary communication protocol to allow communication with a range of protection equipment, and between the device and the Windows-based support software package.

You can connect the unit to a PC with a USB cable up to 5 m in length.

The inactivity timer for the front port is set to 15 minutes. This controls how long the unit maintains its level of password access on the front port. If no messages are received on the front port for 15 minutes, any password access level that has been enabled is cancelled.

Note:
The front USB port does not support automatic extraction of event and disturbance records, although this data can be accessed manually.



Caution:
When not in use, always close the cover of the USB port to prevent contamination.

3.4.5 FIXED FUNCTION LEDS

Four fixed-function LEDs on the left-hand side of the front panel indicate the following conditions.

- Trip (Red) switches ON when the IED issues a trip signal. It is reset when the associated fault record is cleared from the front display. Also the trip LED can be configured as self-resetting.
- Alarm (Yellow) flashes when the IED registers an alarm. This may be triggered by a fault, event or maintenance record. The LED flashes until the alarms have been accepted (read), then changes to constantly ON. When the alarms are cleared, the LED switches OFF.
- Out of service (Yellow) is ON when the IED's functions are unavailable.
- Healthy (Green) is ON when the IED is in correct working order, and should be ON at all times. It goes OFF if the unit's self-tests show there is an error in the hardware or software. The state of the healthy LED is reflected by the watchdog contacts at the back of the unit.

3.4.6 FUNCTION KEYS

The programmable function keys are available for custom use for some models.

Factory default settings associate specific functions to these keys, but by using programmable scheme logic, you can change the default functions of these keys to fit specific needs. Adjacent to these function keys are programmable LEDs, which are usually set to be associated with their respective function keys. The device has 10 function keys in the 60TE and 80TE case size models and no function keys in the 40TE case size model.

3.4.7 PROGRAMABLE LEDS

The device has 13 of programmable LEDs, which can be associated with PSL-generated signals. The programmable LEDs are tri-colour and can be set to RED, YELLOW or GREEN.

3.5 REAR PANEL

The MiCOM Px40 series uses a modular construction. Most of the internal structure consists of boards and modules that fit into slots. Some of the boards plug into terminal blocks, which are bolted onto the rear of the unit. However, some boards such as the communications boards have their own connectors. The rear panel consists of these terminal blocks plus the rears of the communications boards.

The back panel cut-outs and slot allocations vary. This depends on the product, the type of boards and the terminal blocks needed to populate the case. The following diagram shows a typical rear view of a case populated with various boards.

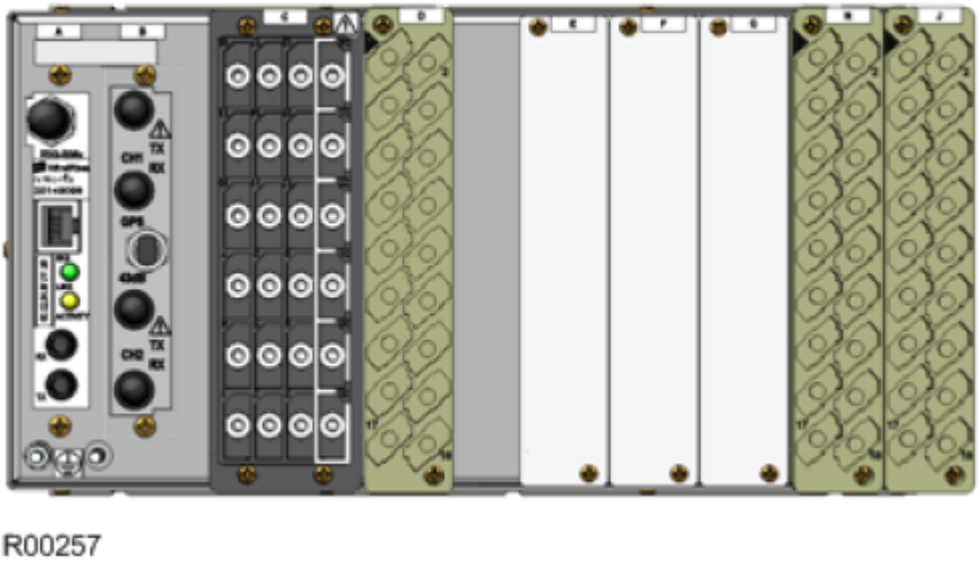


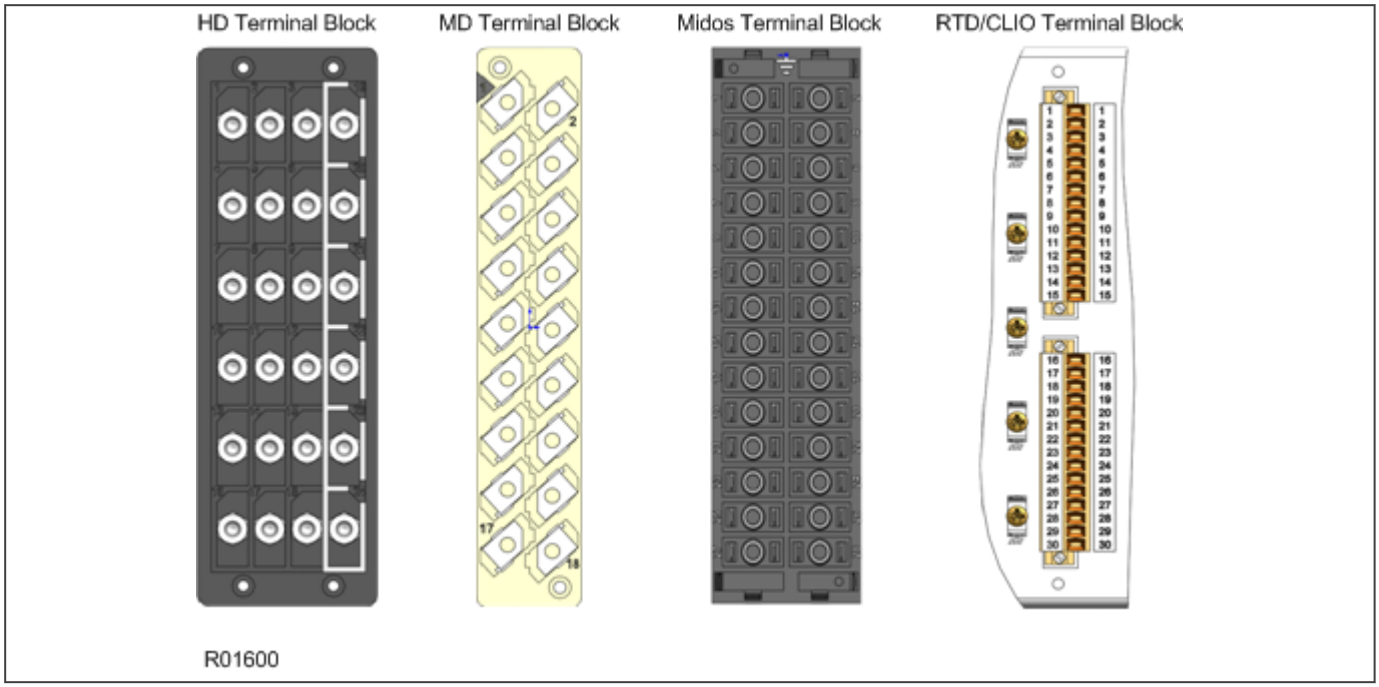
Figure 7: Rear view of populated case

Note:
This diagram is just an example and may not show the exact product described in this manual. It also does not show the full range of available boards, just a typical arrangement.

Not all slots are the same size. The slot width depends on the type of board or terminal block. For example, HD (heavy duty) terminal blocks, as required for the analogue inputs, require a wider slot size than MD (medium duty) terminal blocks. The board positions are not generally interchangeable. Each slot is designed to house a particular type of board. Again this is model-dependent.

The device may use some of the terminal block types shown in the following diagram. The terminal blocks are fastened to the rear panel with screws.

- Heavy duty (HD) terminal blocks for CT and VT circuits
- Medium duty (MD) terminal blocks for the power supply, opto-inputs, relay outputs and rear communications port
- MiDOS terminal blocks for CT and VT circuits
- RTD/CLIO terminal block for connection to analogue transducers (refer to CORTEC options)



Note:
Not all products use all types of terminal blocks. The product described in this manual may use one or more of the above types.

3.5.1 TERMINAL BLOCK INGRESS PROTECTION

IP2x shields and side cover panels are designed to provide IP20 ingress protection for MiCOM terminal blocks. The shields and covers may be attached during installation or retrofitted to upgrade existing installations - see figure below. For more information, contact your local sales office or our worldwide Contact Centre.

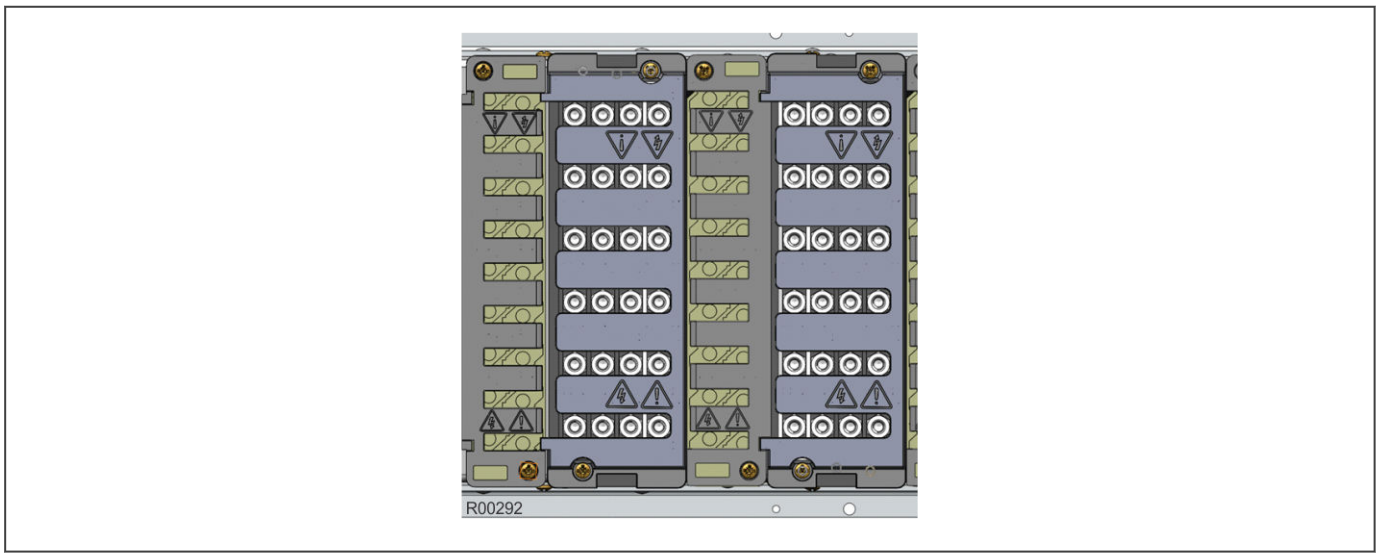


Figure 8: Example - fitted IP2x shields (cabling omitted for clarity)

3.6 BOARDS AND MODULES

Each product comprises a selection of PCBs (Printed Circuit Boards) and subassemblies, depending on the chosen configuration.

3.6.1 PCBS

A PCB typically consists of the components, a front connector for connecting into the main system parallel bus via a ribbon cable, and an interface to the rear. This rear interface may be:

- Directly presented to the outside world (as is the case for communication boards such as Ethernet Boards)
- Presented to a connector, which in turn connects into a terminal block bolted onto the rear of the case (as is the case for most of the other board types)

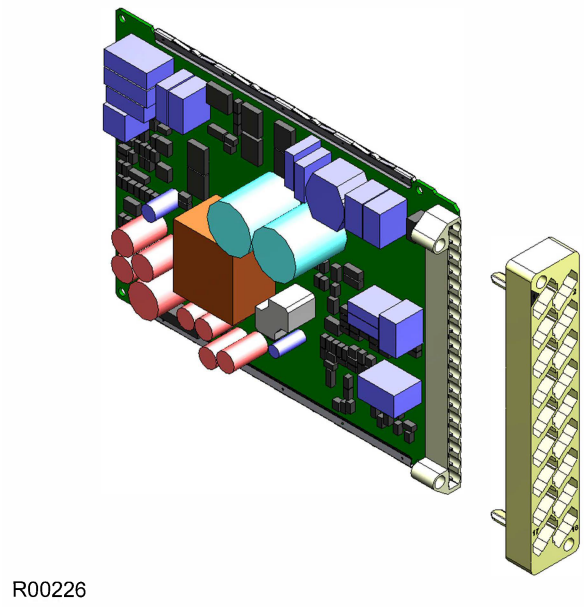


Figure 9: Rear connection to terminal block

3.6.2 SUBASSEMBLIES

A sub-assembly consists of two or more boards bolted together with spacers and connected with electrical connectors. It may also have other special requirements such as being encased in a metal housing for shielding against electromagnetic radiation.

Boards are designated by a part number beginning with ZN, whereas pre-assembled sub-assemblies are designated with a part number beginning with GN. Sub-assemblies, which are put together at the production stage, do not have a separate part number.

The products in the Px40 series typically contain two sub-assemblies:

- The power supply assembly comprising:
  - A power supply board
  - An output relay board
- The input module comprising:
  - One or more transformer boards, which contains the voltage and current transformers (partially or fully populated)
  - One or more input boards
  - Metal protective covers for EM (electromagnetic) shielding

The input module is pre-assembled and is therefore assigned a GN number, whereas the power supply module is assembled at production stage and does not therefore have an individual part number.

3.6.3 MAIN PROCESSOR BOARD

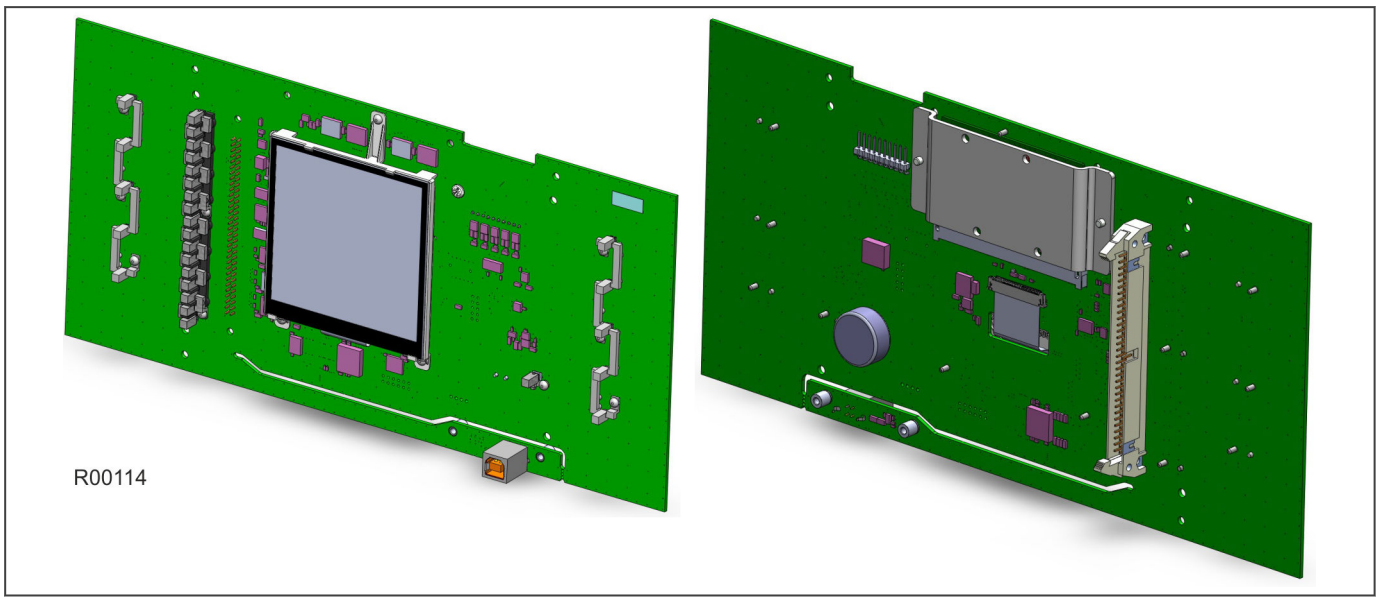


Figure 10: Main processor board

The main processor board performs all calculations and controls the operation of all other modules in the IED, including the data communication and user interfaces. This is the only board that does not fit into one of the slots. It resides in the front panel and connects to the rest of the system using an internal ribbon cable.

The LCD and LEDs are mounted on the processor board along with the front panel communication ports.

The memory on the main processor board is split into two categories: volatile and non-volatile. The volatile memory is DRAM, used by the processor to run the software and store data during calculations. The non-volatile memory is Flash memory and is used to store Product Firmware, text and configuration data including the present setting values, disturbance records, events, fault and maintenance record data.

There are two board types available depending on the size of the case:

- For models in 40TE cases
- For models in 60TE cases and larger

3.6.4 POWER SUPPLY BOARD

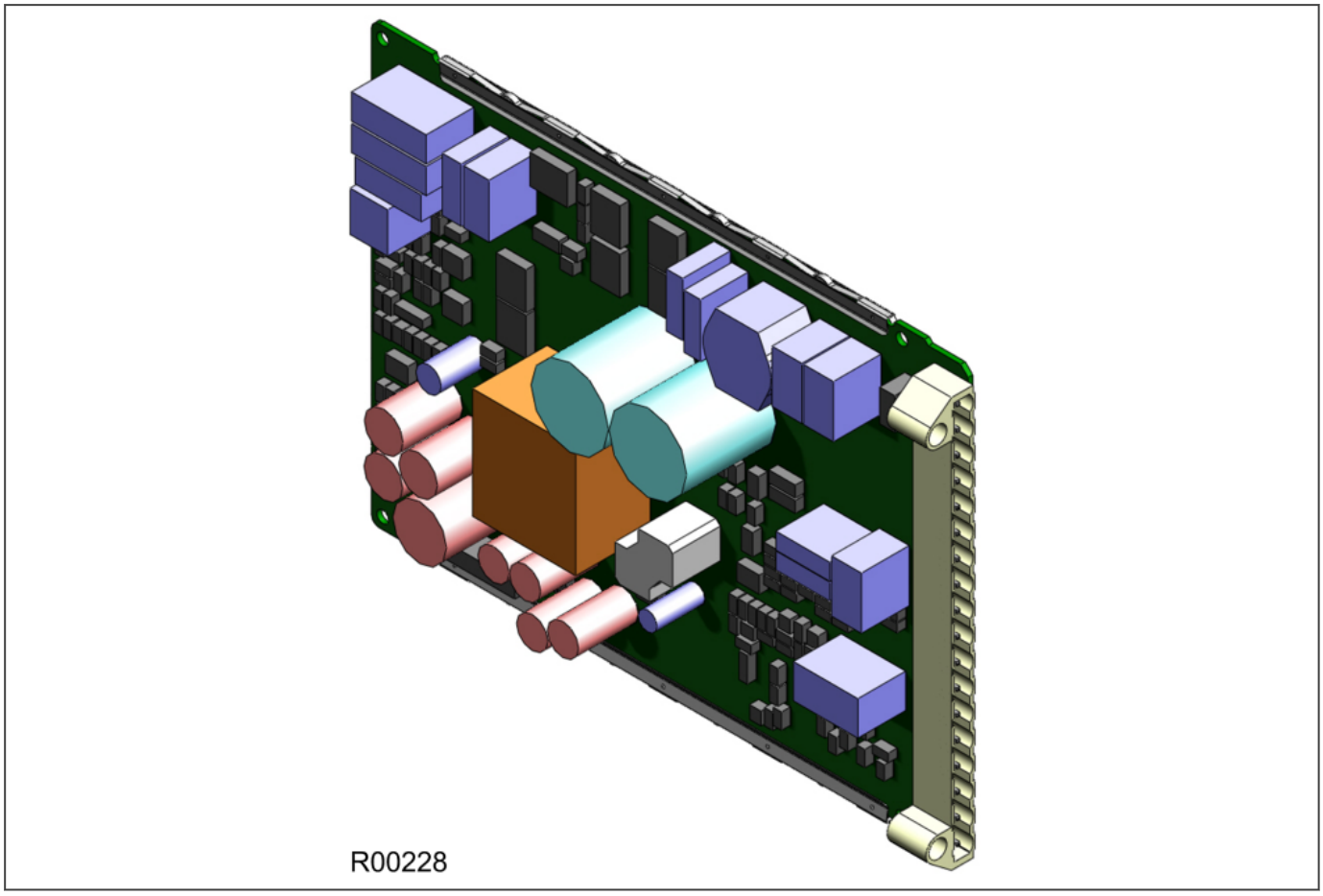


Figure 11: Power supply board

The power supply board provides power to the unit. One of three different configurations of the power supply board can be fitted to the unit. This is specified at the time of order and depends on the magnitude of the supply voltage that will be connected to it.

There are three board types, which support the following voltage ranges:

- 24/54 V DC
- 48/125 V DC or 40-100V AC
- 110/250 V DC or 100-240V AC

The power supply board connector plugs into a medium duty terminal block. This terminal block is always positioned on the right hand side of the unit looking from the rear.

The power supply board is usually assembled together with a relay output board to form a complete subassembly, as shown in the following diagram.

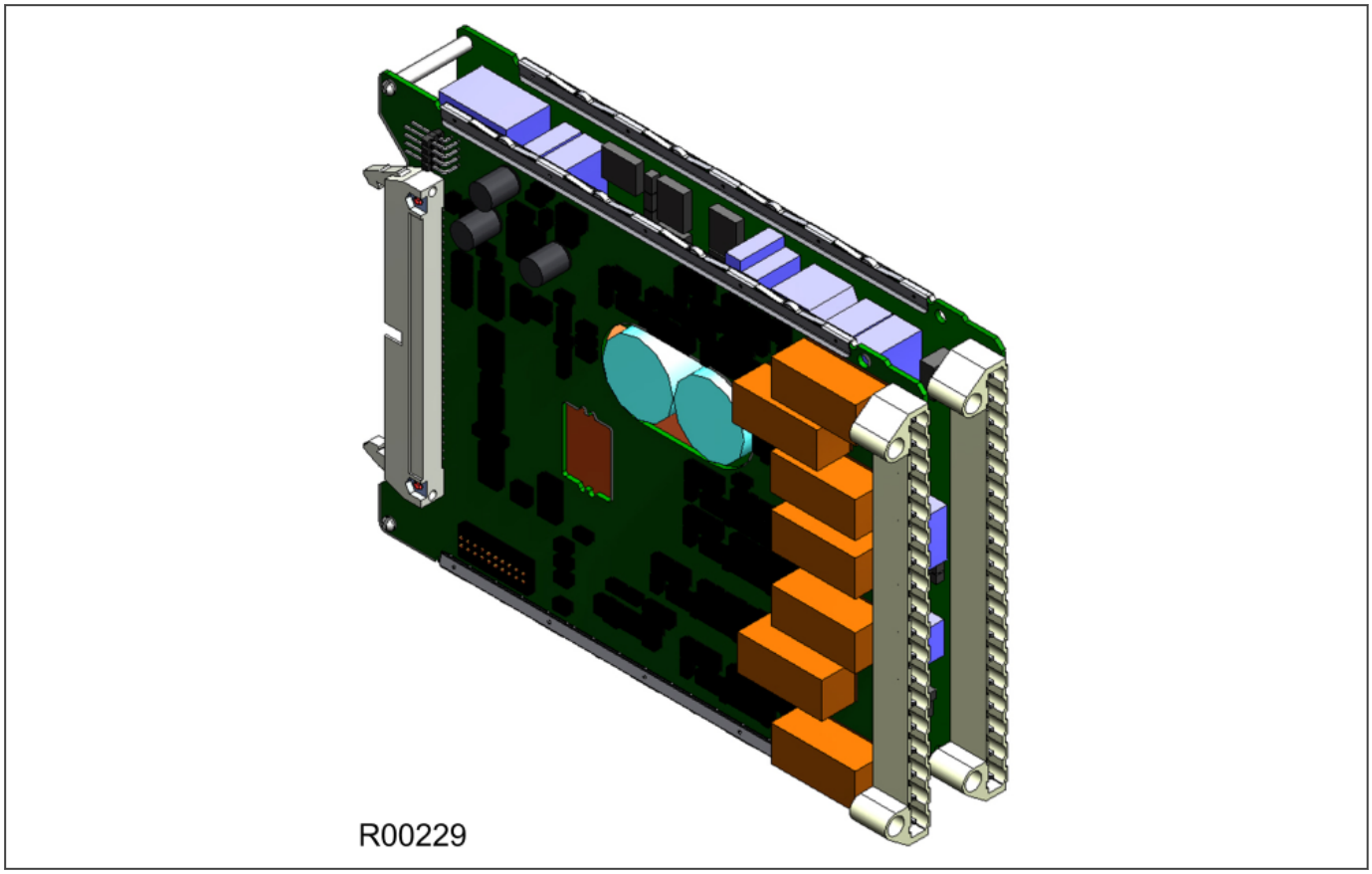


Figure 12: Power supply assembly

The power supply outputs are used to provide isolated power supply rails to the various modules within the unit. Three voltage levels are used by the unit's modules:

- 5.1 V for all of the digital circuits
- +/- 16 V for the analogue electronics such as on the input board
- 22 V for driving the output relay coils.

All power supply voltages, including the 0 V earth line, are distributed around the unit by the 64-way ribbon cable.

The power supply board incorporates inrush current limiting. This limits the peak inrush current to approximately 10 A.

Power is applied to pins 1 and 2 of the terminal block, where pin 1 is negative and pin 2 is positive. The pin numbers are clearly marked on the terminal block as shown in the following diagram.

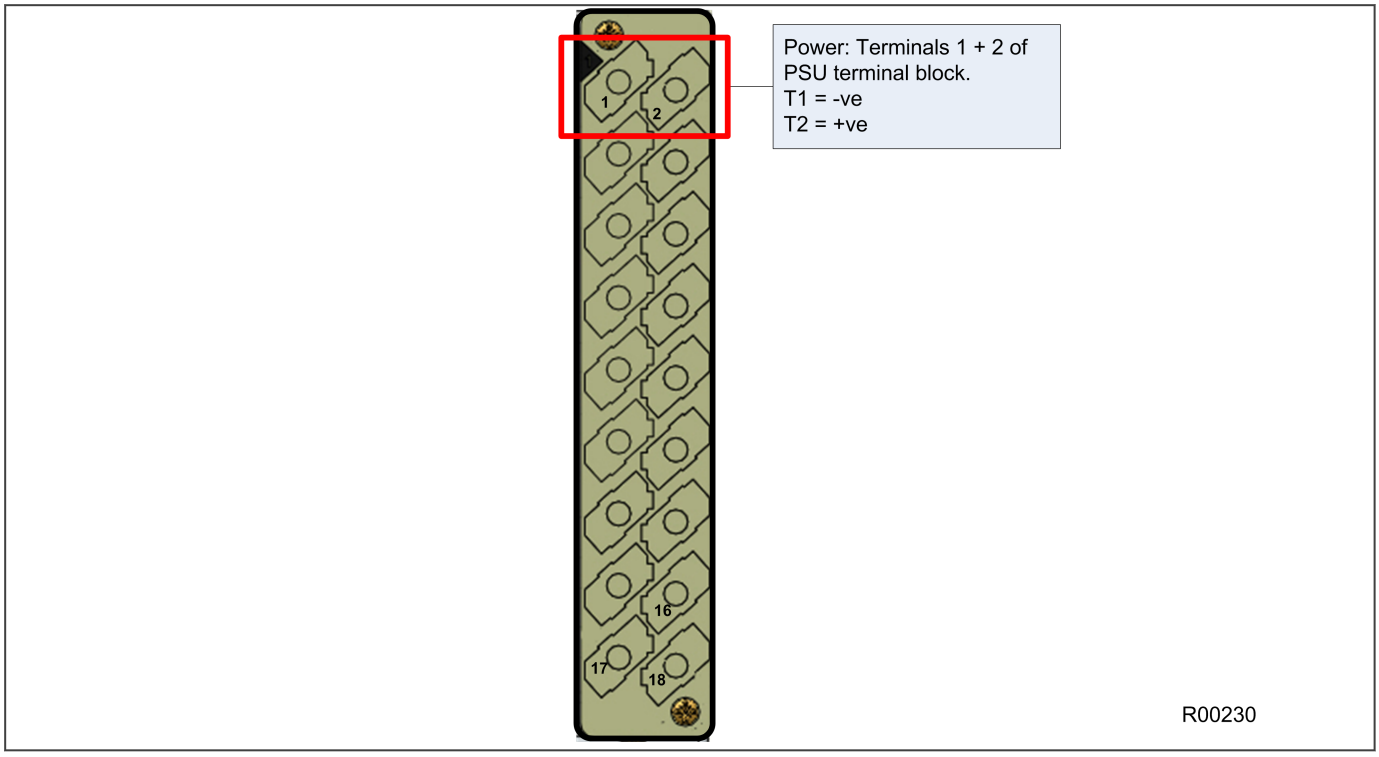


Figure 13: Power supply terminals

3.6.4.1 WATCHDOG

The Watchdog contacts are also hosted on the power supply board. The Watchdog facility provides two output relay contacts, one normally open and one normally closed. These are used to indicate the health of the device and are driven by the main processor board, which continually monitors the hardware and software when the device is in service.

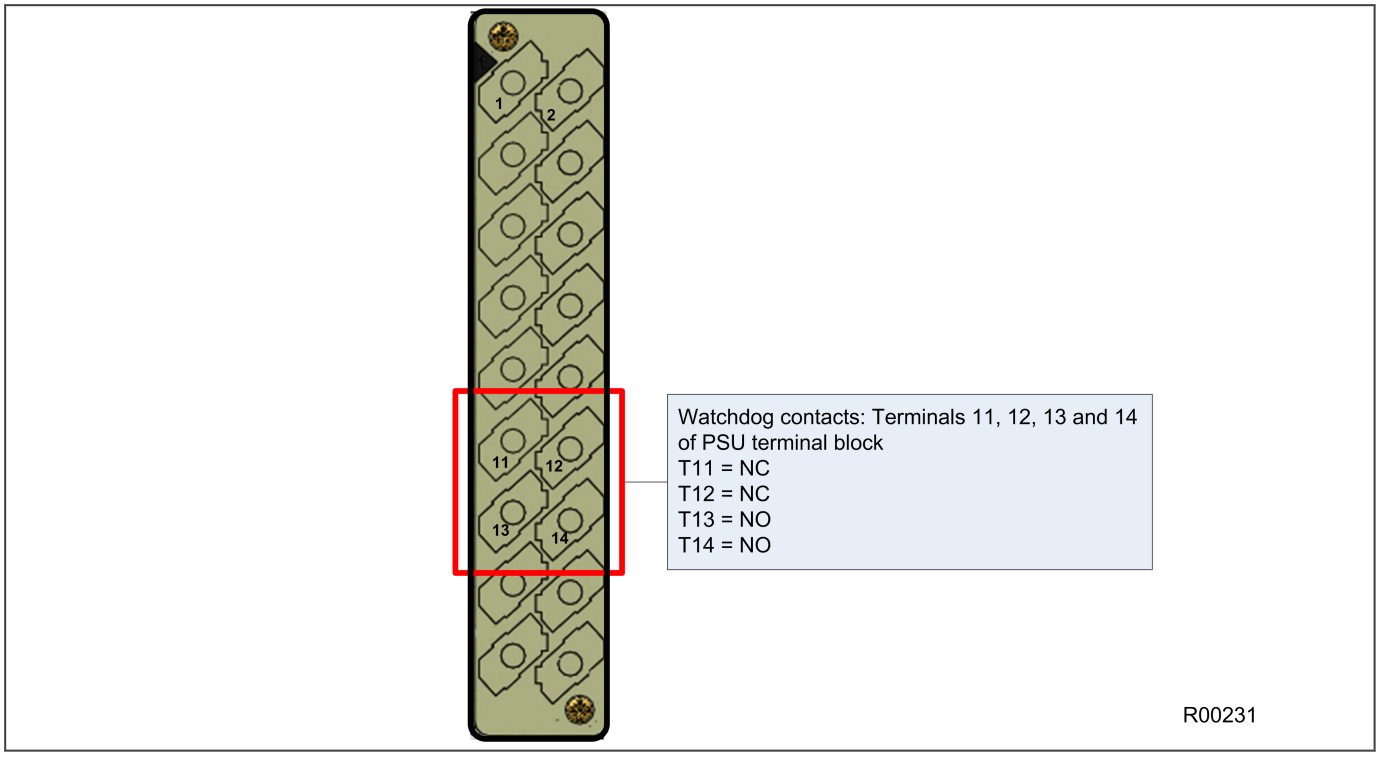


Figure 14: Watchdog contact terminals

3.6.4.2 REAR SERIAL PORT

The rear serial port (RP1) is housed on the power supply board. This is a three-terminal EIA(RS)485 serial communications port and is intended for use with a permanently wired connection to a remote control centre for SCADA communication. The interface supports half-duplex communication and provides optical isolation for the serial data being transmitted and received.

The physical connectivity is achieved using three screw terminals; two for the signal connection, and the third for the earth shield of the cable. These are located on pins 16, 17 and 18 of the power supply terminal block, which is on the far right looking from the rear. The interface can be selected between RS485 and K-bus. When the K-Bus option is selected, the two signal connections are not polarity conscious.

The polarity independent K-bus can only be used for the Courier data protocol. The polarity conscious IEC 60870-5-103 and DNP3.0 protocols need RS485.

The following diagram shows the rear serial port. The pin assignments are as follows:

- Pin 16: Earth shield
- Pin 17: Negative signal
- Pin 18: Positive signal

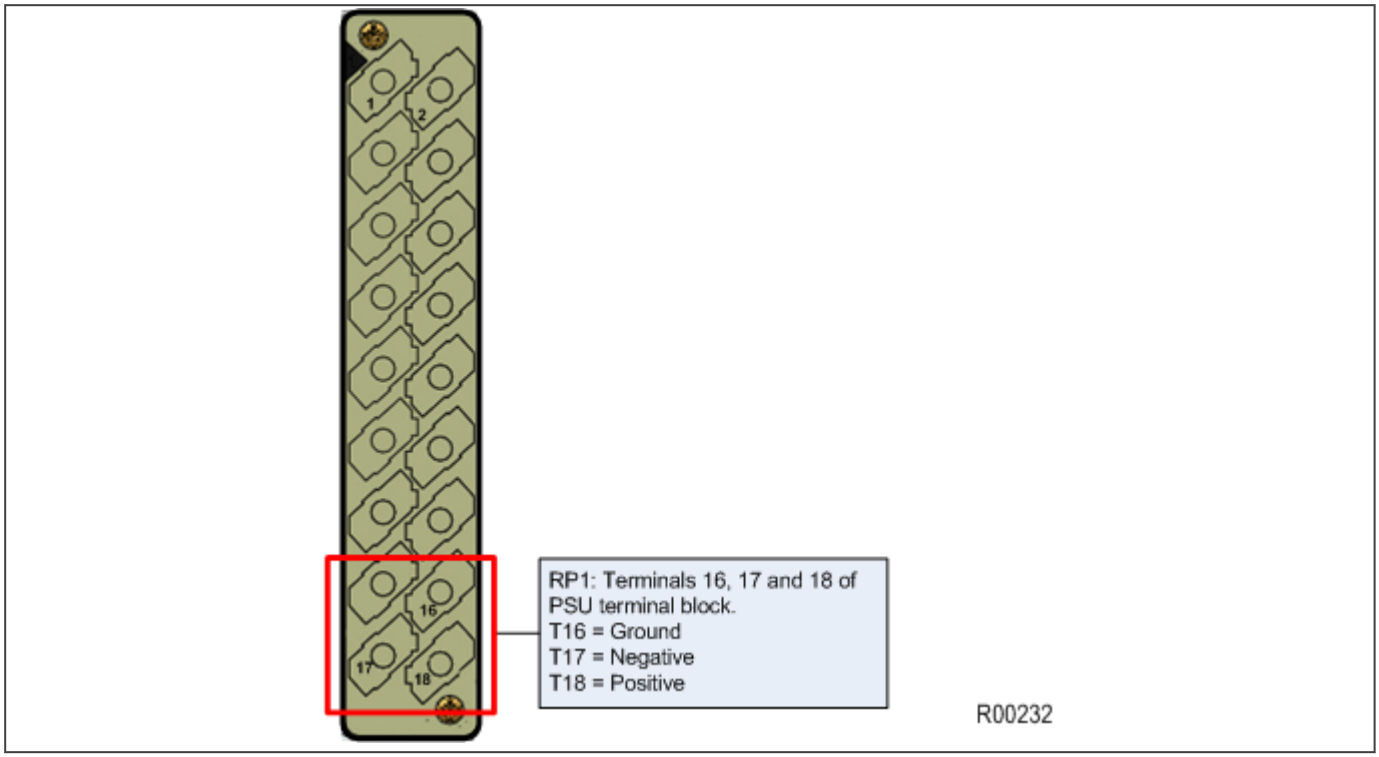


Figure 15: Rear serial port terminals

An additional serial port with D-type presentation is available as an optional board, if required.

3.6.5 INPUT MODULE - 1 TRANSFORMER BOARD

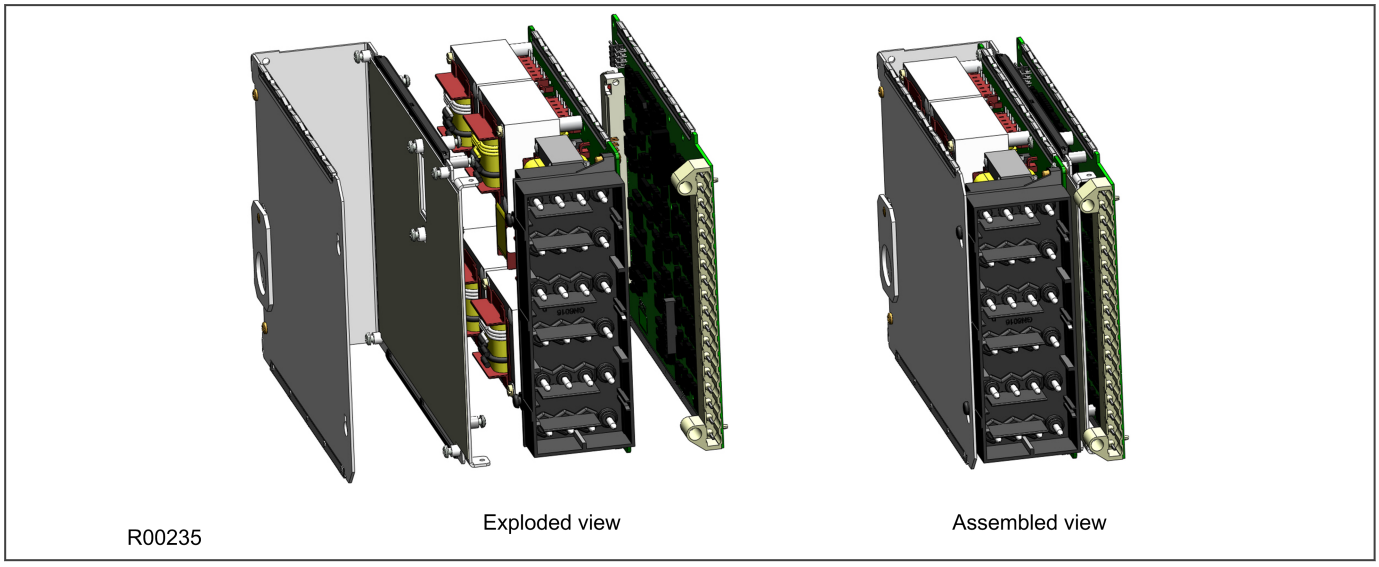


Figure 16: Input module - 1 transformer board

The input module consists of the main input board coupled together with an instrument transformer board. The instrument transformer board contains the voltage and current transformers, which isolate and scale the analogue input signals delivered by the system transformers. The input board contains the A/D conversion and digital processing circuitry, as well as eight digital isolated inputs (opto-inputs).

The boards are connected together physically and electrically. The module is encased in a metal housing for shielding against electromagnetic interference.

3.6.5.1 INPUT MODULE CIRCUIT DESCRIPTION

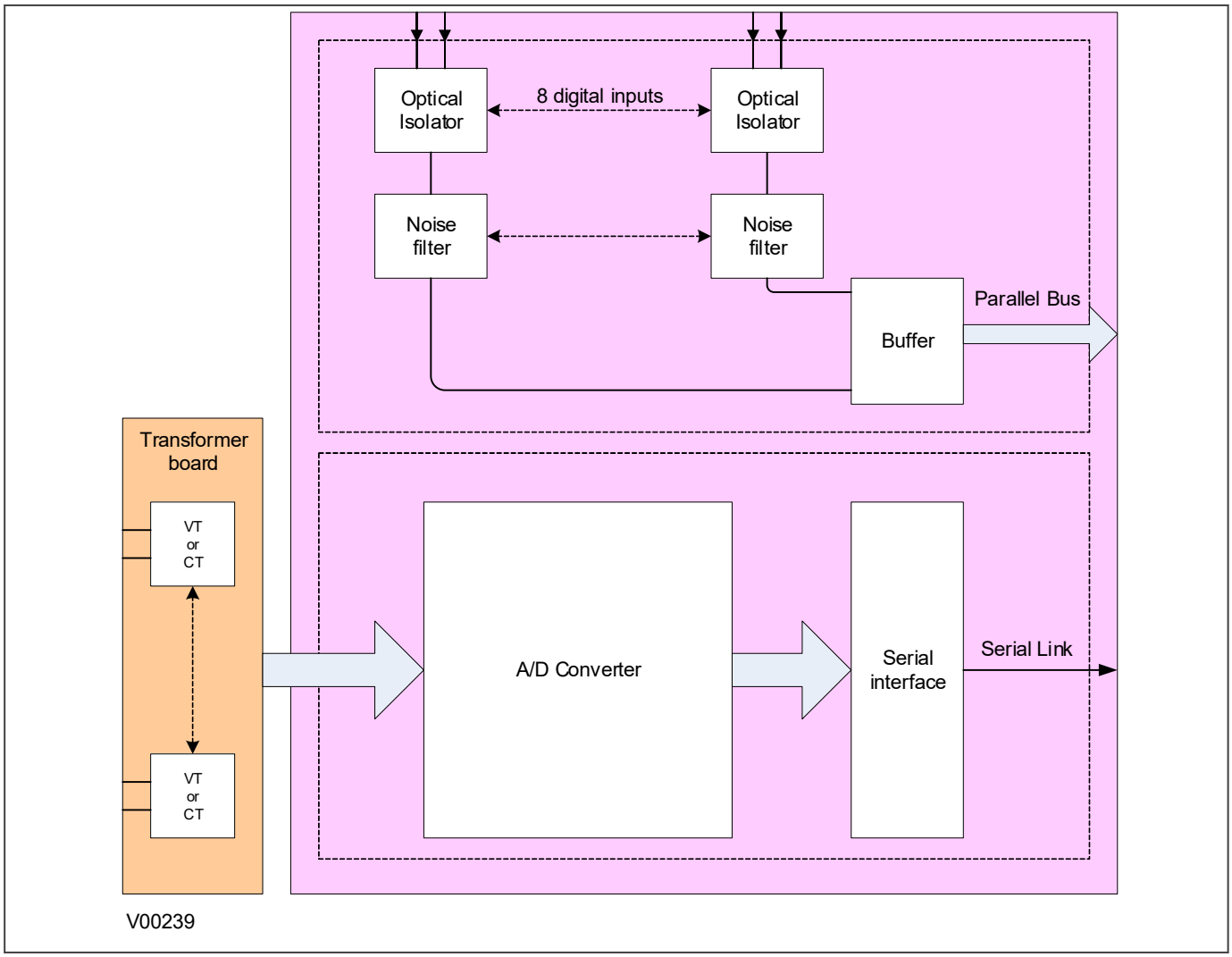


Figure 17: Input module schematic

A/D Conversion

The differential analogue inputs from the CT and VT transformers are presented to the main input board as shown. Each differential input is first converted to a single input quantity referenced to the input board's earth potential. The analogue inputs are sampled and converted to digital, then filtered to remove unwanted properties. The samples are then passed through a serial interface module which outputs data on the serial sample data bus.

The calibration coefficients are stored in non-volatile memory. These are used by the processor board to correct for any amplitude or phase errors introduced by the transformers and analogue circuitry.

Opto-isolated inputs

The other function of the input board is to read in the state of the digital inputs. As with the analogue inputs, the digital inputs must be electrically isolated from the power system. This is achieved by means of the 8 on-board optical isolators for connection of up to 8 digital signals. The digital signals are passed through an optional noise filter before being buffered and presented to the unit's processing boards in the form of a parallel data bus.

This selectable filtering allows the use of a pre-set filter of ½ cycle which renders the input immune to induced power-system noise on the wiring. Although this method is secure it can be slow, particularly for inter-tripping. This

can be improved by switching off the ½ cycle filter, in which case one of the following methods to reduce ac noise should be considered.

- Use double pole switching on the input
- Use screened twisted cable on the input circuit

The opto-isolated logic inputs can be configured for the nominal battery voltage of the circuit for which they are a part, allowing different voltages for different circuits such as signalling and tripping.

Note:
The opto-input circuitry can be provided without the A/D circuitry as a separate board, which can provide supplementary opto-inputs.

3.6.5.2 TRANSFORMER BOARD

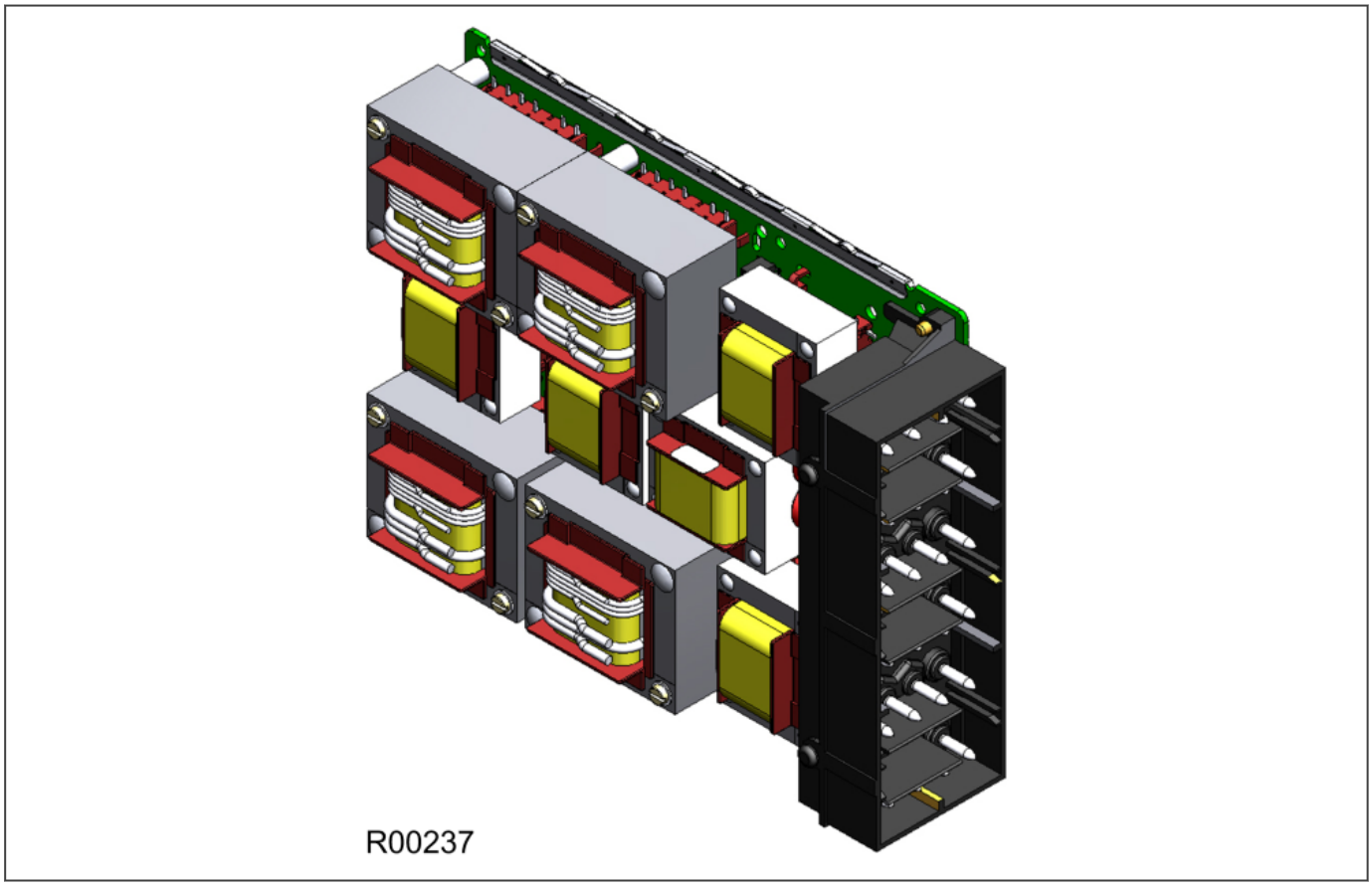


Figure 18: Transformer board

The transformer board hosts the current and voltage transformers. These are used to step down the currents and voltages originating from the power systems' current and voltage transformers to levels that can be used by the devices' electronic circuitry. In addition to this, the on-board CT and VT transformers provide electrical isolation between the unit and the power system.

The transformer board is connected physically and electrically to the input board to form a complete input module.

For terminal connections, please refer to the wiring diagrams.

3.6.5.3 INPUT BOARD

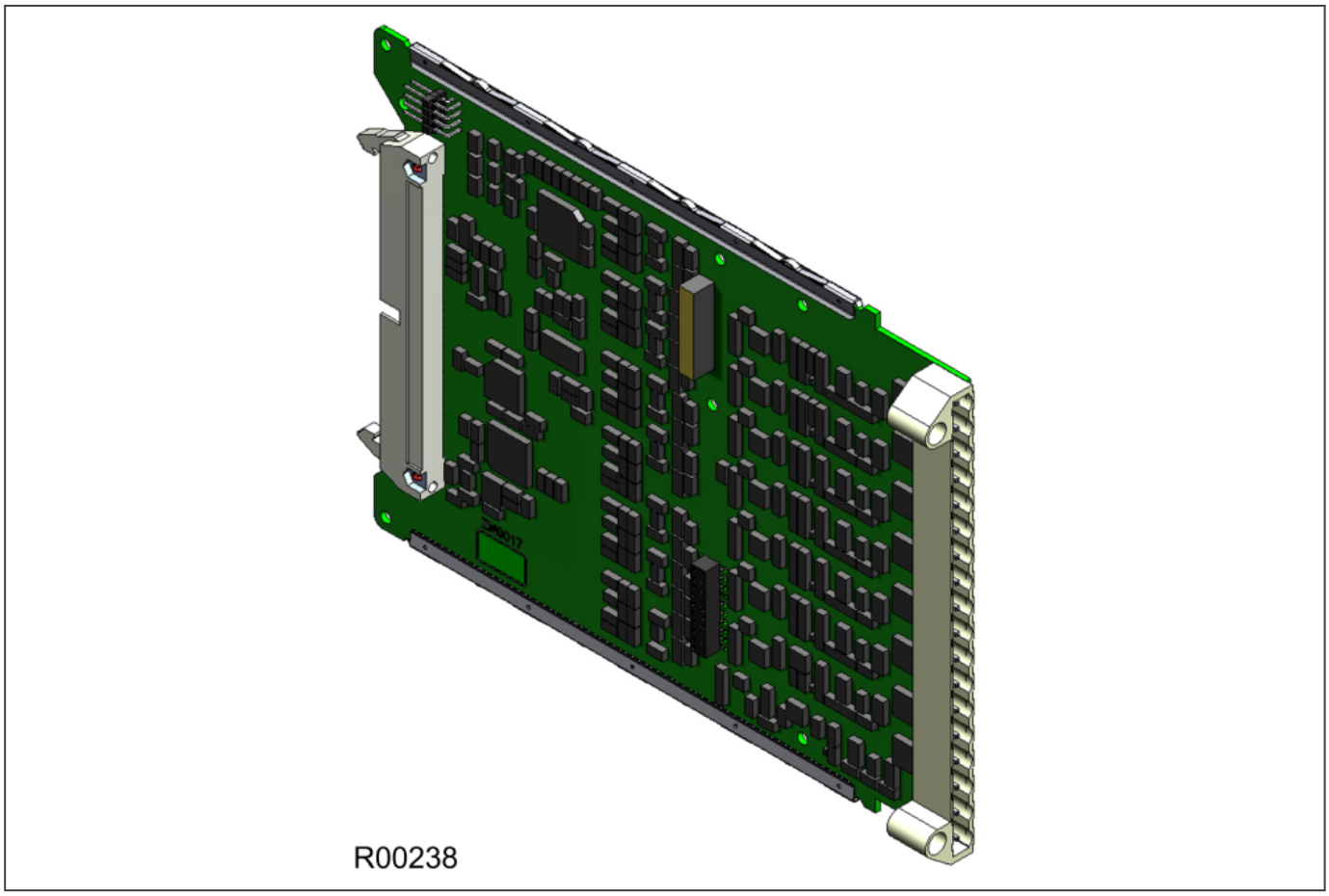


Figure 19: Input board

The input board is used to convert the analogue signals delivered by the current and voltage transformers into digital quantities used by the IED. This input board also has on-board opto-input circuitry, providing eight optically-isolated digital inputs and associated noise filtering and buffering. These opto-inputs are presented to the user by means of an MD terminal block, which sits adjacent to the analogue inputs HD terminal block.

The input board is connected physically and electrically to the transformer board to form a complete input module.

The terminal numbers of the opto-inputs are as follows:

Terminal Number	Opto-input
Terminal 1	Opto 1 -ve
Terminal 2	Opto 1 +ve
Terminal 3	Opto 2 -ve
Terminal 4	Opto 2 +ve
Terminal 5	Opto 3 -ve
Terminal 6	Opto 3 +ve
Terminal 7	Opto 4 -ve
Terminal 8	Opto 4 +ve
Terminal 9	Opto 5 -ve

Terminal Number	Opto-input
Terminal 10	Opto 5 +ve
Terminal 11	Opto 6 -ve
Terminal 12	Opto 6 +ve
Terminal 13	Opto 7 –ve
Terminal 14	Opto 7 +ve
Terminal 15	Opto 8 –ve
Terminal 16	Opto 8 +ve
Terminal 17	Common
Terminal 18	Common

3.6.6 STANDARD OUTPUT RELAY BOARD

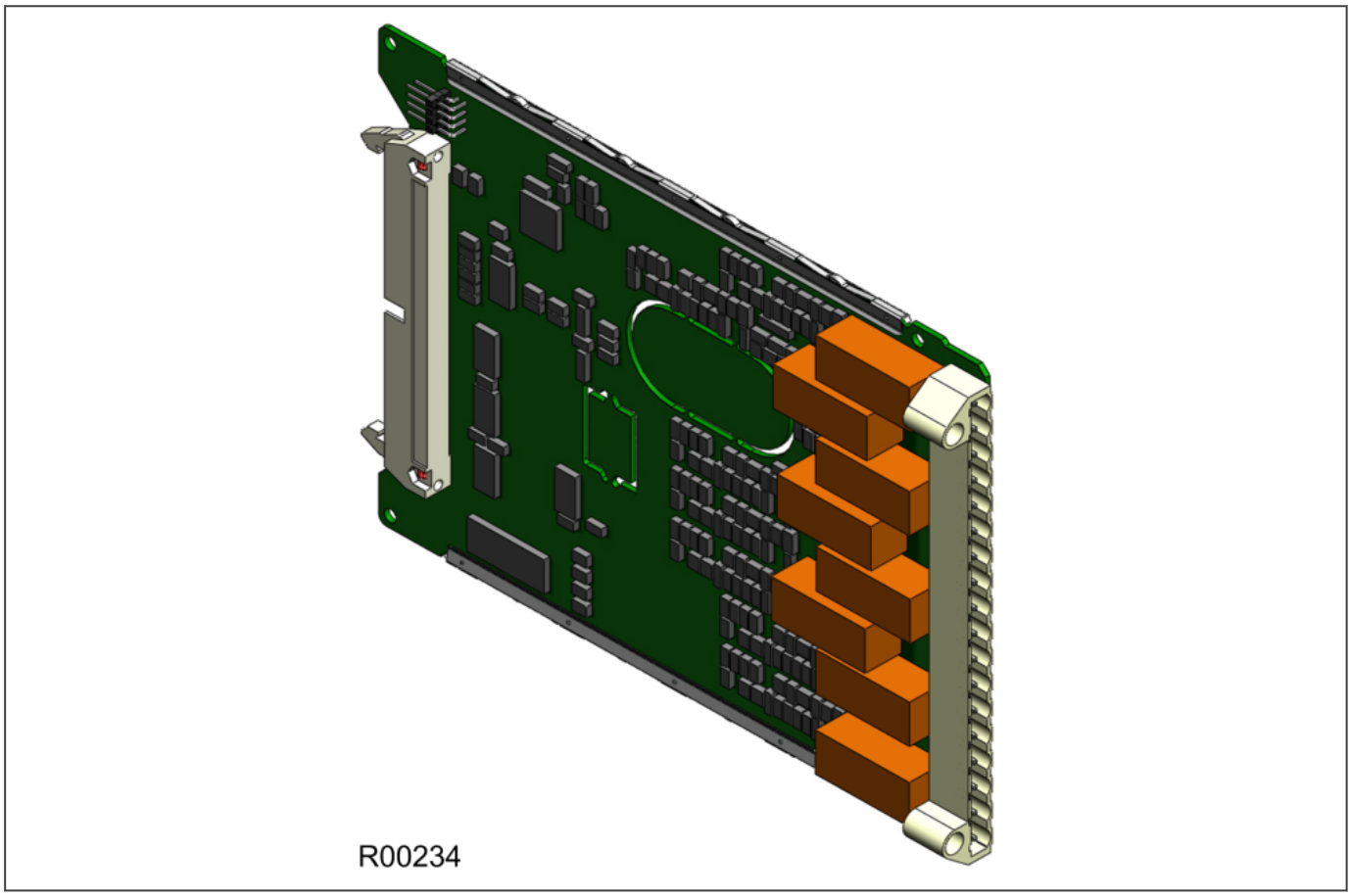


Figure 20: Standard relay output board - 8 contacts

This output relay board has 8 relays with 6 Normally Open contacts and 2 Changeover contacts.

The output relay board is provided together with the power supply board as a complete assembly, or independently for the purposes of relay output expansion.

There are two cut-out locations in the board. These can be removed to allow power supply components to protrude when coupling the output relay board to the power supply board. If the output relay board is to be used independently, these cut-out locations remain intact.

The terminal numbers are as follows:

Terminal Number	Output Relay
Terminal 1	Relay 1 NO
Terminal 2	Relay 1 NO
Terminal 3	Relay 2 NO
Terminal 4	Relay 2 NO
Terminal 5	Relay 3 NO
Terminal 6	Relay 3 NO
Terminal 7	Relay 4 NO
Terminal 8	Relay 4 NO
Terminal 9	Relay 5 NO
Terminal 10	Relay 5 NO
Terminal 11	Relay 6 NO
Terminal 12	Relay 6 NO
Terminal 13	Relay 7 changeover
Terminal 14	Relay 7 changeover
Terminal 15	Relay 7 common
Terminal 16	Relay 8 changeover
Terminal 17	Relay 8 changeover
Terminal 18	Relay 8 common

3.6.7 IRIG-B BOARD

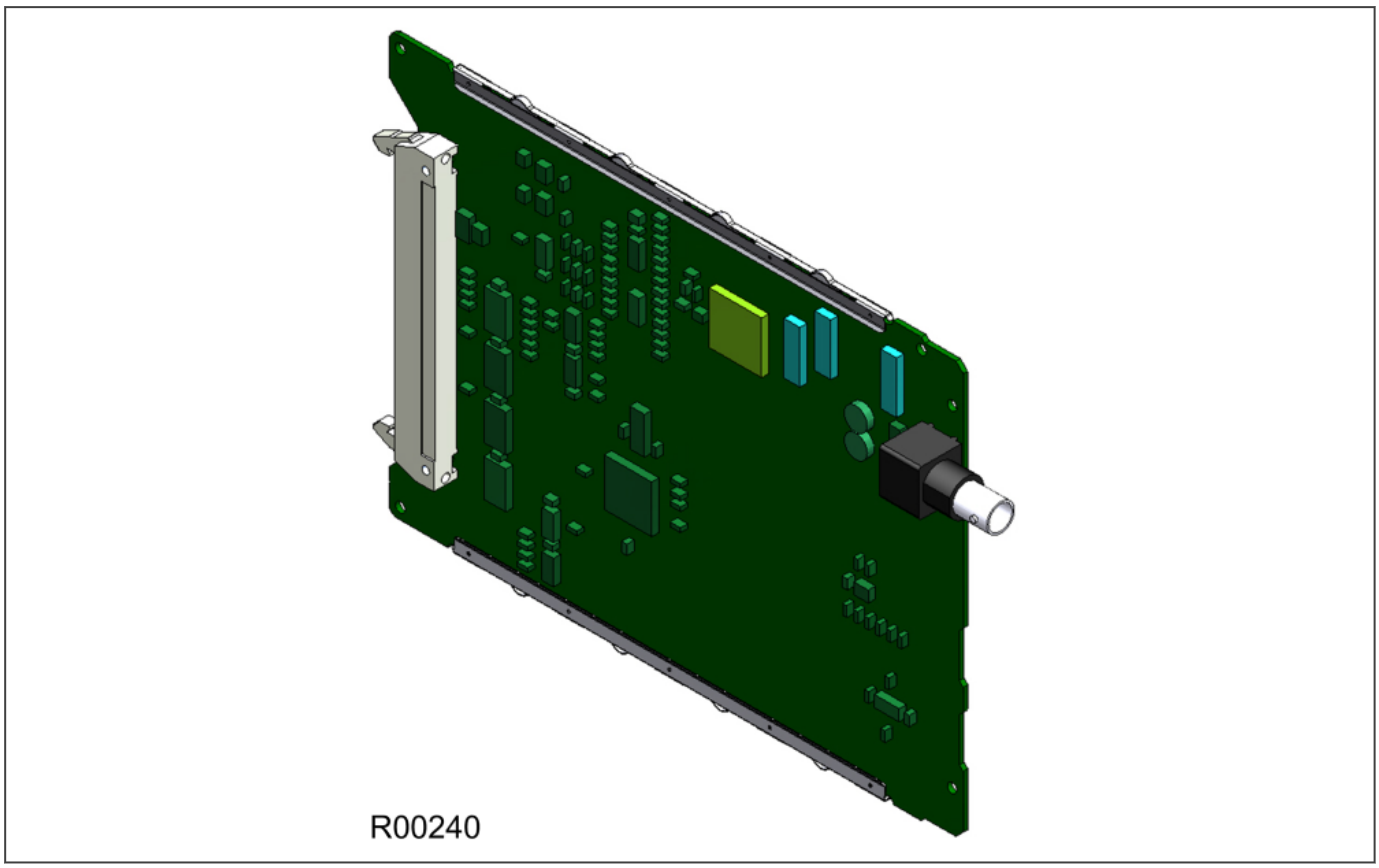


Figure 21: IRIG-B board

The IRIG-B board can be fitted to provide an accurate timing reference for the device. The IRIG-B signal is connected to the board via an BNC connector. The timing information is used to synchronise the IED's internal real-time clock to an accuracy of 1 ms. The internal clock is then used for time tagging events, fault, maintenance and disturbance records.

IRIG-B interface is available in modulated or demodulated formats.

The IRIG-B facility is provided in combination with other functionality on a number of additional boards, such as:

- Fibre board with IRIG-B
- Second rear communications board with IRIG-B
- Ethernet board with IRIG-B
- Redundant Ethernet board with IRIG-B

There are three types of each of these boards; one type which accepts a modulated IRIG-B input, one type which accepts a demodulated IRIG-B input and one type which accepts a universal IRIG-B input. The order code will indicate which variant it supports.

3.6.8 FIBRE OPTIC BOARD

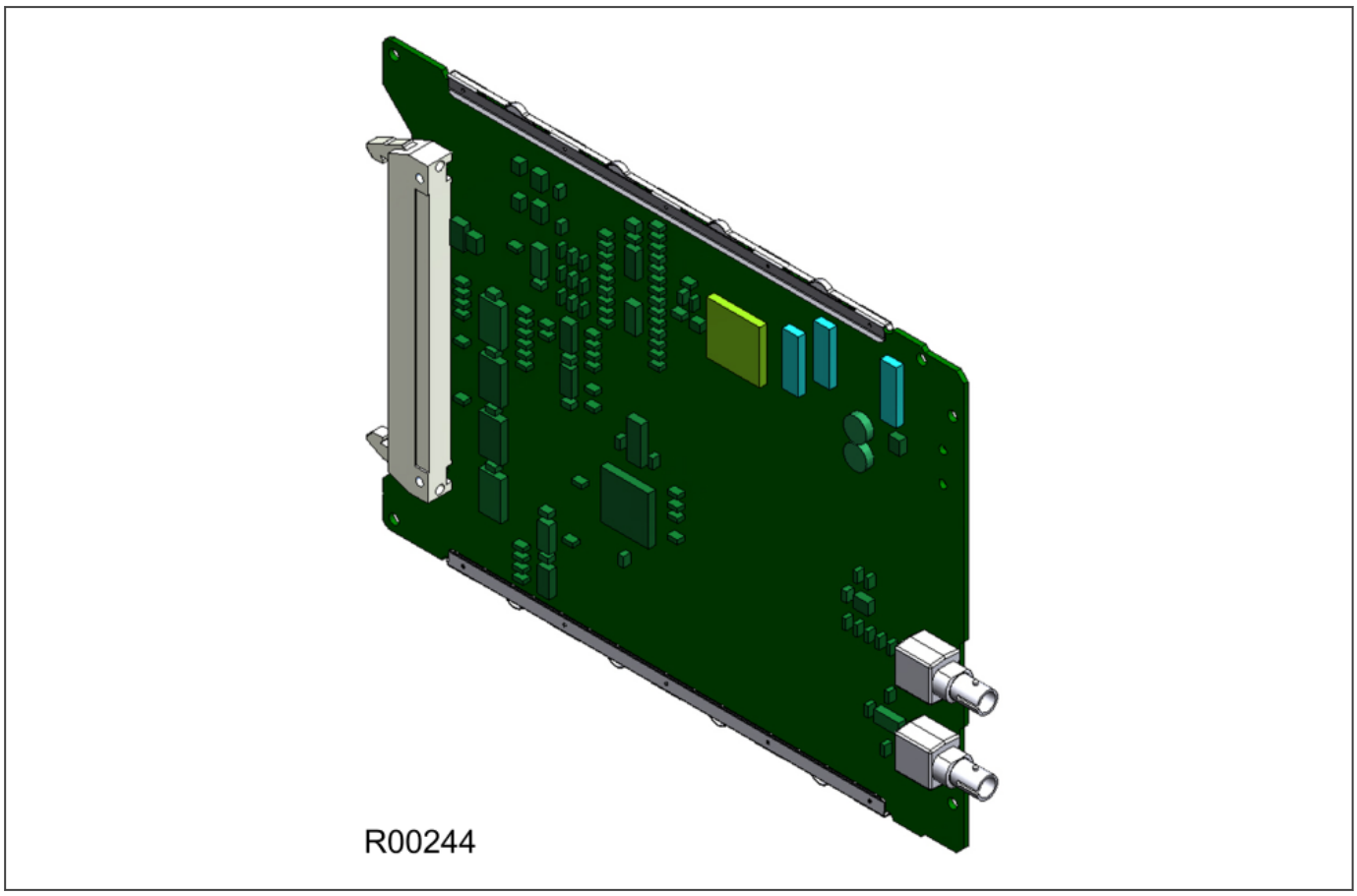


Figure 22: Fibre optic board

This board provides an interface for communicating with a master station. This communication link can use all compatible protocols (Courier, IEC 60870-5-103 and DNP 3.0). It is a fibre-optic alternative to the metallic RS485 port presented on the power supply terminal block. The metallic and fibre optic ports are mutually exclusive.

The fibre optic port uses BFOC 2.5 ST connectors.

The board comes in two varieties; one with an IRIG-B input and one without:

3.6.9 REAR COMMUNICATION BOARD

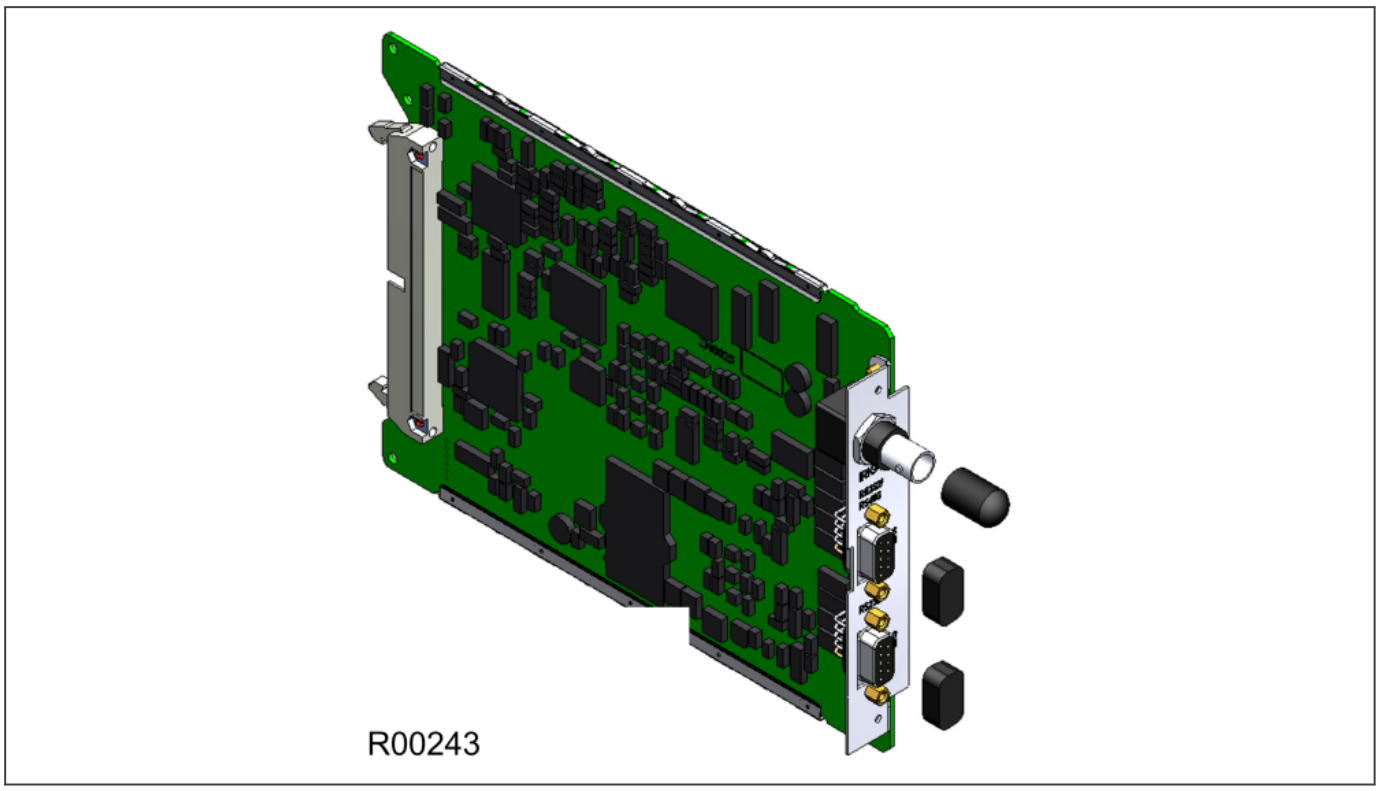


Figure 23: Rear communication board

The optional communications board containing the secondary communication ports provide two serial interfaces presented on 9 pin D-type connectors. These interfaces are known as SK4 and SK5. Both connectors are female connectors, but are configured as DTE ports. This means pin 2 is used to transmit information and pin 3 to receive.

SK4 can be used with RS232, RS485 and K-bus. SK5 can only be used with RS232 and is used for electrical teleprotection. The optional rear communications board and IRIG-B board are mutually exclusive since they use the same hardware slot. However, the board comes in two varieties; one with an IRIG-B input and one without.

3.6.10 REDUNDANT ETHERNET BOARD

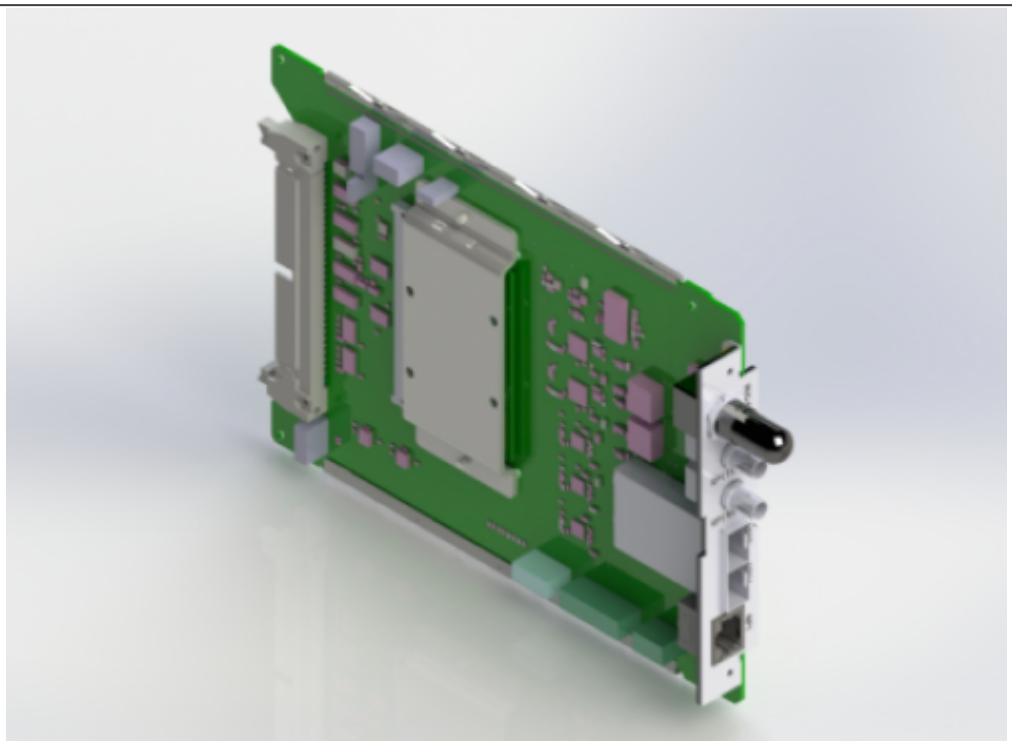




Figure 24: Redundant Ethernet board

This board provides dual redundant Ethernet (NP2A and NP2B) for station bus communications. A universal IRIG-B interface for time synchronisation and a separate Ethernet interface (NP1) for monitoring two variants. A new variant also provides serial protocol support on fiber optics (RP1).

The available redundancy protocols are:

- RSTP (Rapid Spanning Tree Protocol)
- PRP (Parallel Redundancy Protocol)
- HSR (High-availability Seamless Redundancy)
- Failover

There are several variants for this board as follows:

Two LC duplex redundant 100Mbps Ethernet ports running RSTP + PRP + HSR + Failover, with a serial protocol communications ST fibre port with on-board universal IRIG-B and one 10/100Mbps RJ45 maintenance/engineering port.

Two RJ45 duplex redundant 10/100Mbps Ethernet ports running RSTP + PRP + HSR + Failover, with on-board universal IRIG-B and one 10/100Mbps RJ45 maintenance/engineering port.

Two LC duplex redundant 100Mbps Ethernet ports running RSTP + PRP + HSR + Failover, with on-board universal IRIG-B and one 10/100Mbps RJ45 maintenance/engineering port.

The Ethernet and other connection details are described below:

UNIVERSAL IRIG-B Connector

- Centre connection: Signal
- Outer connection: Earth

LC Optical Fibre Connector (only for NP2A or NP2B when ordering fibre ports on station bus ports)

Connector	SFP
A	TX
B	RX

ST Optical Fibre Connector (only for RP1 serial communications)

Connector	Communications
RP1	TX
RP2	RX

RJ45 Connector (NP1 or NP2A/NP2B when ordering two copper ports on station bus ports only)

Pin	Signal Name	Signal Definition
1	TXP	Transmit (positive)
2	TXN	Transmit (negative)
3	RXP	Receive (positive)
4	-	Not used
5	-	Not used
6	RXN	Receive (negative)
7	-	Not used

Pin	Signal Name	Signal Definition
8	-	Not used

3.6.11 SINGLE ETHERNET BOARD

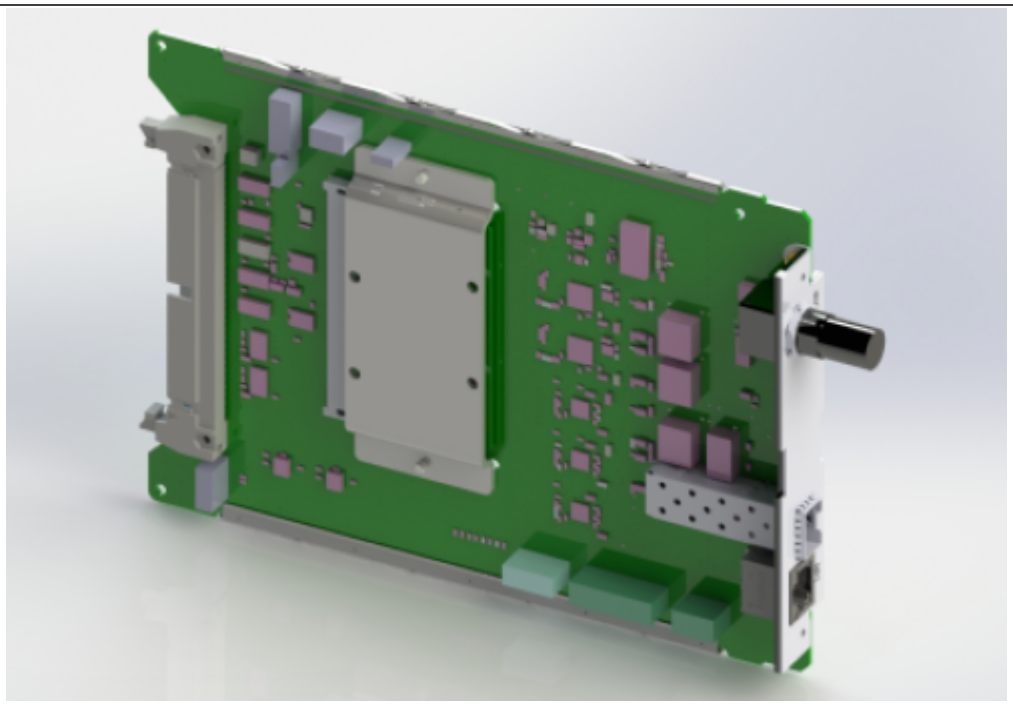




Figure 25: Ethernet board

This board provides one optical 100Mbps LC duplex Ethernet port (NP2A) for station bus communications, with a universal IRIG-B interface for time synchronisation, and a separate 10/100Mbps RJ45 Ethernet maintenance/ engineering interface (NP1) for monitoring and configuration purposes.

The Ethernet and other connection details are described below:

RJ45 Connector (NP1 only)

Pin	Signal Name	Signal Definition
1	TXP	Transmit (positive)
2	TXN	Transmit (negative)
3	RXP	Receive (positive)
4	-	Not used
5	-	Not used
6	RXN	Receive (negative)
7	-	Not used
8	-	Not used

UNIVERSAL IRIG-B Connector

- Centre connection: Signal
- Outer connection: Earth

LC Optical Fibre Connector (NP2A only)

Connector	SFP
A	TX
B	RX

3.6.12 HIGH BREAK OUTPUT RELAY BOARD

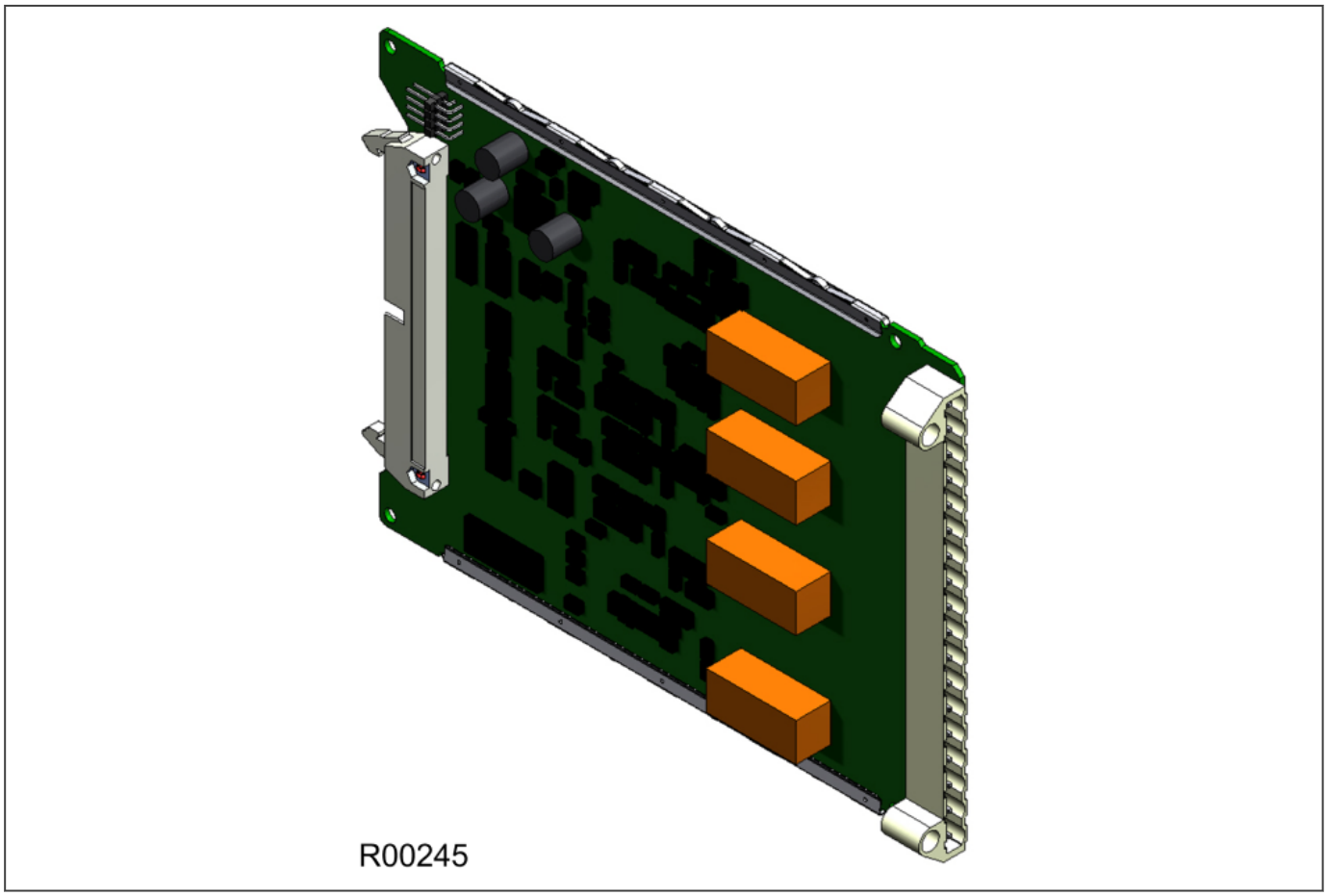


Figure 26: High break relay output board

A High Break output relay board is available as an option. It comprises four normally open output contacts, which are suitable for high breaking loads.

A High Break contact consists of a high capacity relay with a MOSFET in parallel with it. The MOSFET has a varistor placed across it to provide protection, which is required when switching off inductive loads. This is because the stored energy in the inductor causes a high reverse voltage that could damage the MOSFET, if not protected.

When there is a control input command to operate an output contact the miniature relay is operated at the same time as the MOSFET. The miniature relay contact closes in nominally 3.5 ms and is used to carry the continuous load current. The MOSFET operates in less than 0.2 ms, but is switched off after 7.5 ms.

When the control input is reset, the MOSFET is again turned on for 7.5 mS. The miniature relay resets in nominally 3.5 ms before the MOSFET. This means the MOSFET is used to break the load. The MOSFET absorbs the energy when breaking inductive loads and so limits the resulting voltage surge. This contact arrangement is for switching DC circuits only.

The board number is:

- ZN0042 001

High Break Contact Operation

The following figure shows the timing diagram for High Break contact operation.

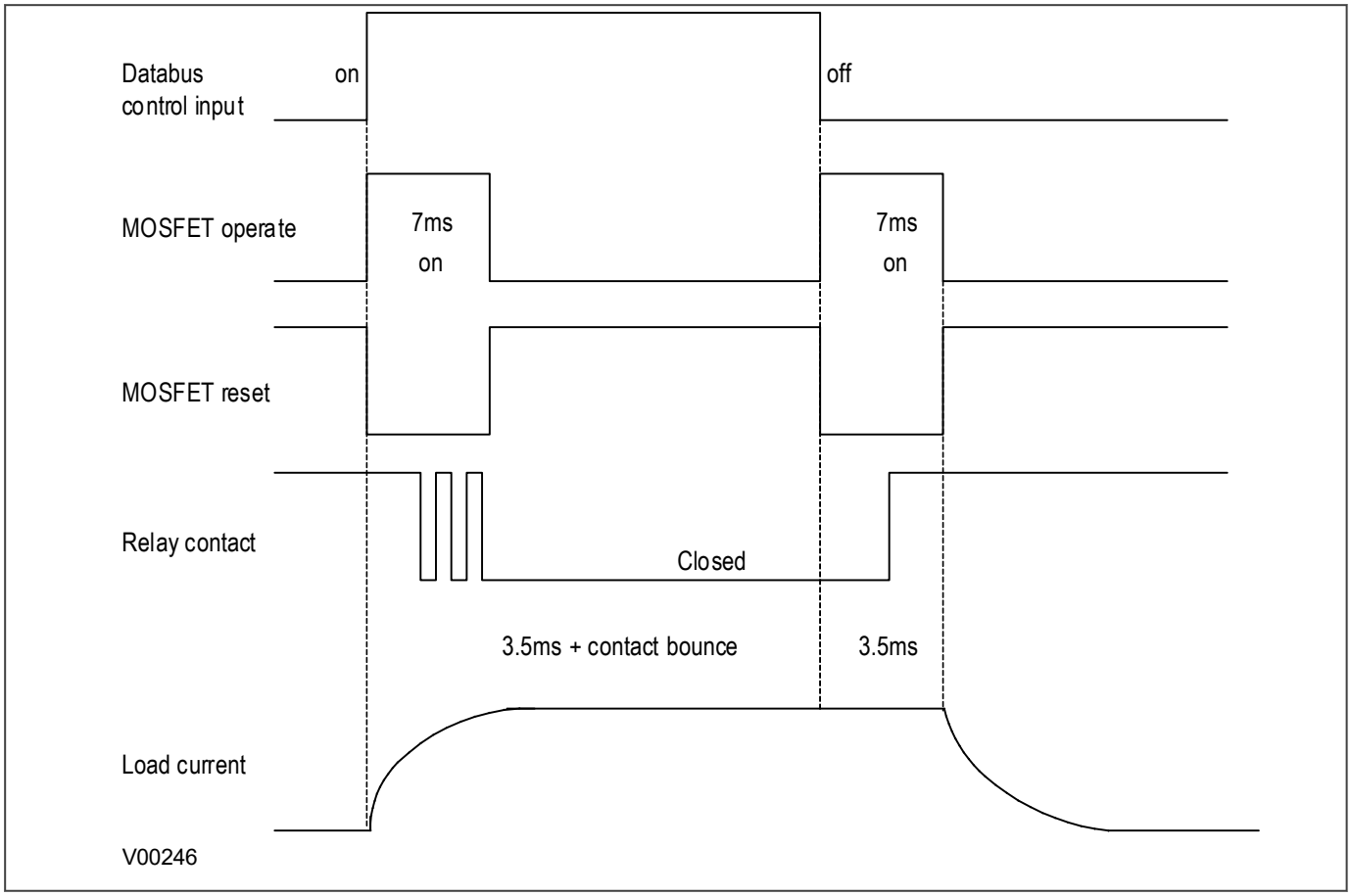


Figure 27: High break contact operation

High Break Contact Applications

- Efficient scheme engineering

  In traditional hard wired scheme designs, High Break capability could only be achieved using external electromechanical trip relays. Instead, these internal High Break contacts can be used thus reducing space requirements.

- Accessibility of CB auxiliary contacts

  It is common practise to use circuit breaker 52a (CB Closed) auxiliary contacts to break the trip coil current on breaker opening, thereby easing the duty on the protection contacts. In some cases (such as operation of disconnectors, or retrofitting), it may be that 52a contacts are either unavailable or unreliable. In such cases, High Break contacts can be used to break the trip coil current in these applications.

- Breaker fail

  In the event of failure of the local circuit breaker (stuck breaker), or defective auxiliary contacts (stuck contacts), it is incorrect to use 52a contact action. The interrupting duty at the local breaker then falls on the relay output contacts, which may not be rated to perform this duty. High Break contacts should be used in this case to avoid the risk of burning out relay contacts.

- Initiation of teleprotection

The High Break contacts also offer fast making, which results in faster tripping. In addition, fast keying of teleprotection is a benefit. Fast keying bypasses the usual contact operation time, such that permissive, blocking and intertrip commands can be routed faster.



Warning:
These relay contacts are POLARITY SENSITIVE. External wiring must comply with the polarity requirements described in the external connection diagram to ensure correct operation.

CHAPTER 4

SOFTWARE DESIGN

4.1 CHAPTER OVERVIEW

This chapter describes the software design of the IED.

This chapter contains the following sections:

Chapter Overview 59
Software Design Overview 60
System Level Software 61
Platform Software 63
Protection and Control Functions 64

4.2 SOFTWARE DESIGN OVERVIEW

The device software can be conceptually categorized into several elements as follows:

- The system level software
- The platform software
- The protection and control software

These elements are not distinguishable to the user, and the distinction is made purely for the purposes of explanation. The following figure shows the software architecture.

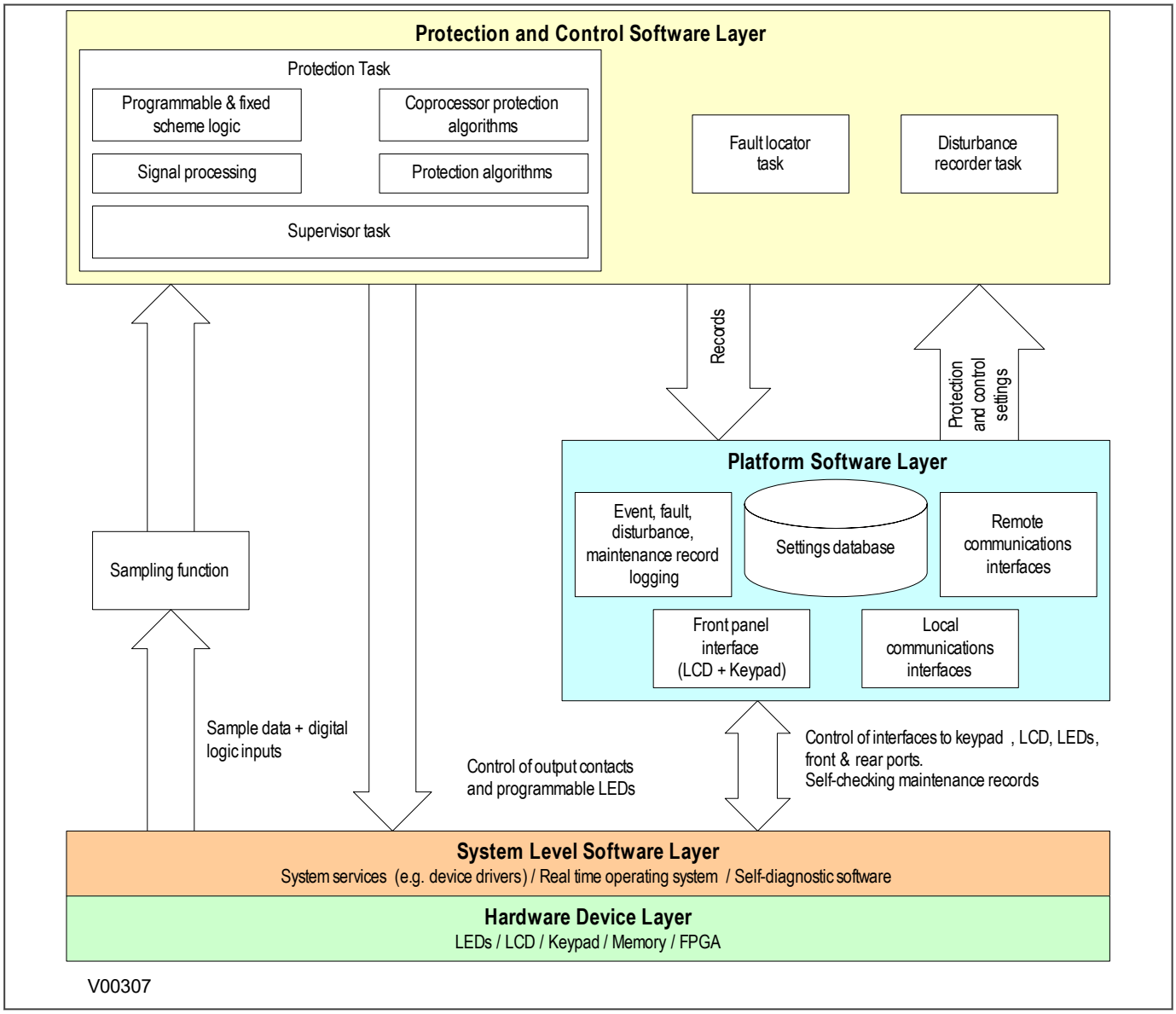


Figure 28: Software architecture

The software, which executes on the main processor, can be divided into a number of functions as illustrated above. Each function is further broken down into a number of separate tasks. These tasks are then run according to a scheduler. They are run at either a fixed rate or they are event driven. The tasks communicate with each other as and when required.

4.3 SYSTEM LEVEL SOFTWARE

4.3.1 REAL TIME OPERATING SYSTEM

The real-time operating system is used to schedule the processing of the various tasks. This ensures that they are processed in the time available and in the desired order of priority. The operating system also plays a part in controlling the communication between the software tasks, through the use of operating system messages.

4.3.2 SYSTEM SERVICES SOFTWARE

The system services software provides the layer between the hardware and the higher-level functionality of the platform software and the protection and control software. For example, the system services software provides drivers for items such as the LCD display, the keypad and the remote communication ports. It also controls things like the booting of the processor and the downloading of the processor code into DRAM at startup.

4.3.3 SELF-DIAGNOSTIC SOFTWARE

The device includes several self-monitoring functions to check the operation of its hardware and software while in service. If there is a problem with the hardware or software, it should be able to detect and report the problem, and attempt to resolve the problem by performing a reboot. In this case, the device would be out of service for a short time, during which the ‘Healthy’ LED on the front of the device is switched OFF and the watchdog contact at the rear is ON. If the restart fails to resolve the problem, the unit takes itself permanently out of service; the ‘Healthy’ LED stays OFF and watchdog contact stays ON.

If a problem is detected by the self-monitoring functions, the device attempts to store a maintenance record to allow the nature of the problem to be communicated to the user.

The self-monitoring is implemented in two stages: firstly a thorough diagnostic check which is performed on boot-up, and secondly a continuous self-checking operation, which checks the operation of the critical functions whilst it is in service.

4.3.4 STARTUP SELF-TESTING

The self-testing takes a few seconds to complete, during which time the IEDs measurement, recording, control, and protection functions are unavailable. On a successful start-up and self-test, the ‘Healthy' state LED on the front of the device is switched on. If a problem is detected during the start-up testing, the device remains out of service until it is manually restored to working order.

The operations that are performed at start-up are:

1. System boot
2. System software initialisation
3. Platform software initialisation and monitoring

4.3.4.1 SYSTEM BOOT

The integrity of the Flash memory is verified using a checksum before the program code and stored data is loaded into DRAM for execution by the processor. When the loading has been completed, the data held in DRAM is compared to that held in the Flash memory to ensure that no errors have occurred in the data transfer and that the two are the same. The entry point of the software code in DRAM is then called. This is the IED's initialisation code.

4.3.4.2 SYSTEM LEVEL SOFTWARE INITIALISATION

The initialization process initializes the processor registers and interrupts, starts the watchdog timers (used by the hardware to determine whether the software is still running), starts the real-time operating system and creates and starts the supervisor task. In the initialization process the device checks the following:

- The status of the supercapacitor to maintain the real time clock
- The operation of the LCD controller
- The watchdog operation

At the conclusion of the initialization software the supervisor task begins the process of starting the platform software.

4.3.4.3 PLATFORM SOFTWARE INITIALISATION AND MONITORING

When starting the platform software, the IED checks the following:

- The integrity of the data held in non-volatile memory (using a checksum)
- The operation of the real-time clock
- The optional IRIG-B function (if applicable)
- The presence and condition of the input board
- The analog data acquisition system (it does this by sampling the reference voltage)

At the successful conclusion of all of these tests the unit is entered into service and the application software is started up.

4.3.5 CONTINUOUS SELF-TESTING

When the IED is in service, it continually checks the operation of the critical parts of its hardware and software. The checking is carried out by the system services software and the results are reported to the platform software. The functions that are checked are as follows:

- The Flash memory containing all program code and language text is verified by a checksum.
- The code and constant data held in system memory is checked against the corresponding data in Flash memory to check for data corruption.
- The system memory containing all data other than the code and constant data is verified with a checksum.
- The integrity of the digital signal I/O data from the opto-inputs and the output relay coils is checked by the data acquisition function every time it is executed.
- The operation of the analog data acquisition system is continuously checked by the acquisition function every time it is executed. This is done by sampling the reference voltages.
- The operation of the optional Ethernet board is checked by the software on the main processor board. If the Ethernet board fails to respond an alarm is raised and the board is reset in an attempt to resolve the problem.
- The operation of the optional IRIG-B function is checked by the software that reads the time and date from the board.

In the event that one of the checks detects an error in any of the subsystems, the platform software is notified and it attempts to log a maintenance record.

If the problem is with the IRIG-B board, the device continues in operation. For problems detected in any other area, the device initiates a shutdown and re-boot, resulting in a period of up to 10 seconds when the functionality is unavailable.

A restart should clear most problems that may occur. If, however, the diagnostic self-check detects the same problem that caused the IED to restart, it is clear that the restart has not cleared the problem, and the device takes itself permanently out of service. This is indicated by the ‘’health-state’ LED on the front of the device, which switches OFF, and the watchdog contact which switches ON.

4.4 PLATFORM SOFTWARE

The platform software has three main functions:

- To control the logging of records generated by the protection software, including alarms, events, faults, and maintenance records
- To store and maintain a database of all of the settings in non-volatile memory
- To provide the internal interface between the settings database and the user interfaces, using the front panel interface and the front and rear communication ports

4.4.1 RECORD LOGGING

The logging function is used to store all alarms, events, faults and maintenance records. The records are stored in non-volatile memory to provide a log of what has happened. The IED maintains four types of log on a first in first out basis (FIFO). These are:

- Alarms
- Event records
- Fault records
- Maintenance records

The logs are maintained such that the oldest record is overwritten with the newest record. The logging function can be initiated from the protection software. The platform software is responsible for logging a maintenance record in the event of an IED failure. This includes errors that have been detected by the platform software itself or errors that are detected by either the system services or the protection software function. See the Monitoring and Control chapter for further details on record logging.

4.4.2 SETTINGS DATABASE

The settings database contains all the settings and data, which are stored in non-volatile memory. The platform software manages the settings database and ensures that only one user interface can modify the settings at any one time. This is a necessary restriction to avoid conflict between different parts of the software during a setting change. Changes to protection settings and disturbance recorder settings, are first written to a temporary location DRAM memory. This is sometimes called 'Scratchpad' memory. These settings are not written into non-volatile memory immediately. This is because a batch of such changes should not be activated one by one, but as part of a complete scheme. Once the complete scheme has been stored in DRAM, the batch of settings can be committed to the non-volatile memory where they will become active.

4.4.3 INTERFACES

The settings and measurements database must be accessible from all of the interfaces to allow read and modify operations. The platform software presents the data in the appropriate format for each of the interfaces (LCD display, keypad and all the communications interfaces).

4.5 PROTECTION AND CONTROL FUNCTIONS

The protection and control software processes all of the protection elements and measurement functions. To achieve this it has to communicate with the system services software, the platform software as well as organise its own operations.

The protection task software has the highest priority of any of the software tasks in the main processor board. This ensures the fastest possible protection response.

The protection and control software provides a supervisory task, which controls the start-up of the task and deals with the exchange of messages between the task and the platform software.

4.5.1 ACQUSITION OF POWER SYSTEM INPUT SIGNALS

A sampling function controls the acquisition of sampled input data to the various protection and control and recording functions in this device.

Following successful initialisation from the system services software, the sampling function delivers a constant stream of input data to the Protection and Control software at a rate of 48 samples per cycle of the power system frequency. This means that on a 50Hz power system the nominal sampling rate is 2,400 Hz whereas, for a 60 Hz system, sampling will be at 2,880 Hz.

The sampled input data is consumed at different rates by the various protection, control, and recording functions according to specific application requirements and, typically, Fourier filters and/or disturbance recorders may be populated at sub-multiples of the device sampling rate (for example, 24 or 8 samples per cycle).

The following section, explains that the sampling rate is synchronised to the power system frequency by a frequency tracking algorithm. This ensures that for minor excursions in the system frequency, an exact number of samples are always acquired for every cycle, ensuring protection stability. In normal operation, the outputs from the protection elements are updated 16 times per cycle.

4.5.2 FREQUENCY TRACKING OF INPUT SIGNAL ACQUISITION

This device features a frequency tracking algorithm so that, even for small changes, its power system inputs are sampled exactly 48 times every power system cycle over the full rated frequency range. If the system frequency moves out of range, the sampling rate defaults according to the applied system frequency setting, at either 2,400 Hz for 50 Hz or 2,880 Hz for 60 Hz.

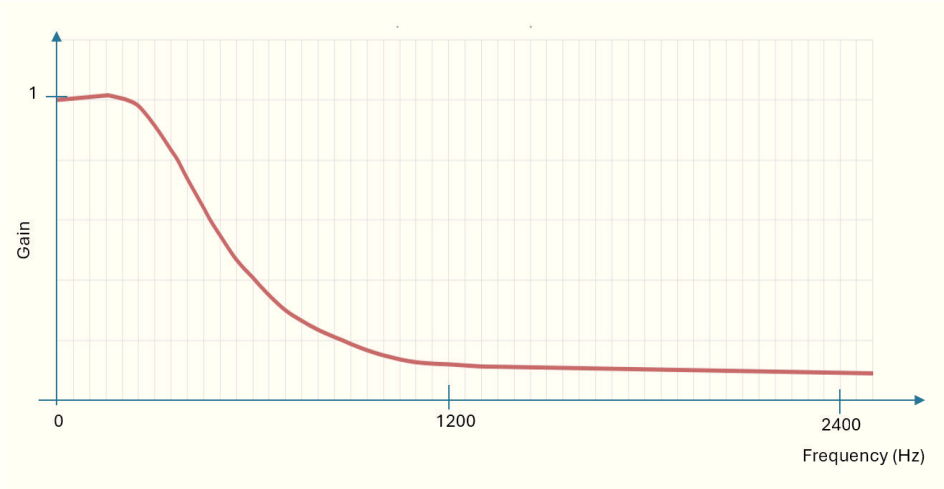
A recursive Fourier filter applied to the device's analog inputs detects phase variations. From these changes, the precise system frequency can be determined. This is used to implement frequency tracking of the input signals acquisition, as well as to inform the protection and control and recording tasks about the measured system frequency. The frequency tracking controls the acquisition by adjusting the intervals between sampling instants to ensure that the number of samples acquired per cycle exactly matches the expected constant value. To execute, the frequency tracking requires that just one of the phase input voltage or phase input current signals is available. Availability thresholds are set as 10% Vn for voltage, and 5% In for current, and the frequency tracks off any available voltage or current input signal, prioritised in the order VA, VB, VC, IA, IB, IC.

4.5.3 INPUT SIGNAL FILTERING

Most of the protection algorithms in this product apply digital filtering to the sampled data input streams to extract useful information from power system analogue signals (phase current angles, for example). Fourier filters may be employed to provide useful information about specific frequency components, whereas other bespoke filters may facilitate the calculation of quantities such as fault impedances and distance-to-fault values.

Some of the functionality provided by this product, however, is better implemented using raw data that has not been subject to digital filtering. Un-processed raw data may be required by special (potentially very fast acting) protection functions or, more typically waveform recording and the calculation of true RMS values of current, voltage and

power for metering purposes. In these cases, the fidelity is defined by the anti-aliasing filters applied to the input signals for which the characteristics are defined by the following figure.



E80069

Figure 29: Anti-alias filter response

4.5.4 FOURIER SIGNAL FILTERING

Most protection and measurement functions in this device use single-cycle Fourier digital filtering to extract power frequency components.

The software to implement the Fourier filters acts on the sampled analogue input signals and is, along with the associated protection and control software, hosted on the main processor board.

The principal use of Fourier filters in this product is to provide measurements of fundamental components for current based protection, but Fourier filters may also be applied to extract fundamental signals for other protection functions such as voltage, as well as deriving harmonic components such as the second harmonic used to restrain current differential protection.

The magnitude and angle of fundamental frequency components of input signals are calculated using one complete cycle of the most recently acquired input data. In this case, the Fourier algorithm extracts the power frequency fundamental component from the input signal, presenting it in terms of magnitude and phase angle. This can be represented in either polar format or rectangular format, as required. Values for harmonic components can be similarly determined by appropriately varying the filters' input data streams and filter coefficients.

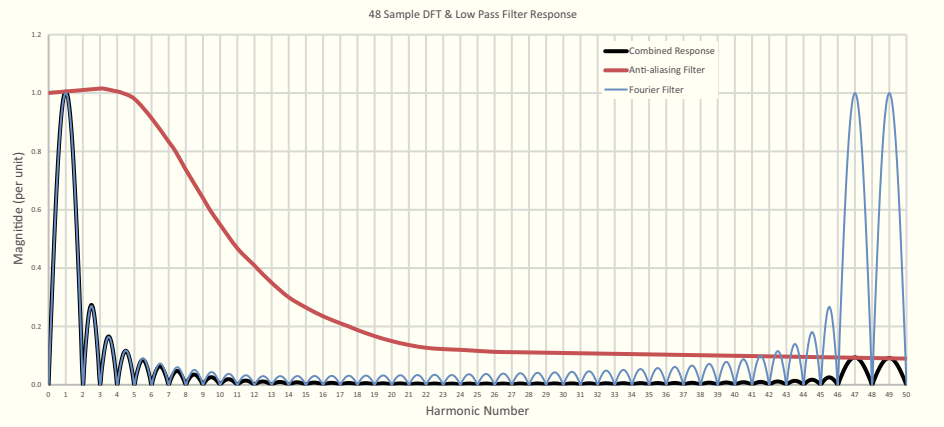
The Fourier filter acts as a function with zero gain at DC, unity gain at the fundamental, and with good harmonic rejection for all harmonic frequencies up to a value known as the Nyquist frequency (and equivalent to half the sampling frequency). Any frequency component of the input signal above this Nyquist frequency appears as an unwanted alias component causing problems. The introduction of low-pass filters to limit the input frequency spectrum to less than half that of the sampling frequency effectively prevents aliasing.

4.5.4.1 COMBINED FOURIER FILTER RESPONSE

In this product, the rate at which sampled data is made available to the protection and control software is 48 per cycle and so the required minimum cut-off frequency for the anti-aliasing filters is:

- 1200 Hz (for a 50 Hz system), or
- 1440 Hz for a 60 Hz system.

The following figure shows the frequency response of the combined anti-alias filter and 48-sample single-cycle Fourier filter implemented in this product.



E80021

Figure 30: Combined input filter response

4.5.5 FAULT LOCATOR

The fault locator uses 12 cycles of the analog input signals to calculate the fault location. The result is returned to the protection and control task, which includes it in the fault record. The pre-fault and post-fault voltages are also presented in the fault record. When the fault record is complete, including the fault location, the protection and control task sends a message to the supervisor task to log the fault record.

The Fault Locator is not available on all models.

4.5.6 DISTURBANCE RECORDER

The disturbance recorder operates as a separate task from the protection and control task and they both use the same input data. However, unlike in the protection functions where additional filters (such as Fourier) may be applied to refine the data processed, the only processing of the signals presented to the disturbance recorder (other than a calibration function) is that caused by the low-pass input filters employed to prevent aliasing. The filter effectively suppresses high-frequency components according to the anti-alias filter characteristic presented in the section on input signal filtering.

The disturbance recorder stores the waveforms of calibrated analogue channels and digital signals to a resolution of 48 samples/cycles. The recording time is user selectable. Typically, up to 100 waveforms, each up to 10.5 seconds duration can be stored. The disturbance recorder is supplied with data by the protection and control task once per cycle. The disturbance recorder collates the data that it receives into the required length disturbance record. The disturbance records can be extracted by settings application software such as S1 Agile, which can also store the data in COMTRADE format, therefore allowing the use of other packages to view the recorded data.

For more information see the Monitoring and Control chapter.

4.5.7 EVENT RECORDER INTERFACE

A change in any digital input signal or protection element output signal is used to indicate that an event has taken place. When this happens, the protection and control task sends a message to the supervisor task to indicate that an event is available to be processed and writes the event data to a fast buffer controlled by the supervisor task. A background task in the platform software then converts the data into a stored non-volatile record.

Maintenance records are a special category of event record which may be created during power-up or self-testing. Similar to other events, the supervisor task instructs the platform software to log a record when it receives a maintenance record message, but the maintenance records are stored in a separate register to simplify examination.

4.5.8 SCHEME LOGIC INTERFACE

Association of the protection and control algorithms implemented in this device with external plant relies on logical allocation of software inputs and outputs with physical inputs and outputs. The functionality which implements this is known as scheme logic. The scheme logic in this device consists of fixed components and programmable components. Fixed scheme logic components are hard-coded into the protection and control algorithm software modules. They have been designed to complement the protection and control objectives and cannot be changed by the user. User control over the operation of the devices' digital inputs and output is provided by a feature know as the programmable scheme logic (PSL). Executed in response to changes of state of inputs either from external plant, or from functional inputs from the user interfaces, or from internal logic state changes emanating from execution of the protection and control software, the scheme logic allows the user to combine factory-proven application scheme logic with versatile user-designed logic processing to control outputs and led indications.

4.5.9 PROGRAMMABLE SCHEME LOGIC

The purpose of the programmable scheme logic (PSL) is to allow you to configure your own protection schemes to suit your particular application. This is done with programmable logic gates and delay timers. To allow greater flexibility, different PSL is allowed for each of the four setting groups.

The input to the PSL is any combination of the status of the digital input signals from the opto-isolators on the input board, the outputs of the protection elements such as protection starts and trips, and the outputs of the fixed protection scheme logic (FSL). The fixed scheme logic provides the standard protection schemes. The PSL consists of software logic gates, timers, and counters. The logic gates can be programmed to perform a range of different logic functions and can accept any number of inputs. The timers are used either to create a programmable delay, and/or to condition the logic outputs, such as to create a pulse of fixed duration on the output regardless of the length of the pulse on the input. The outputs of the PSL are the LEDs on the front panel of the device and the output contacts at the rear.

The execution of the PSL logic is event driven. The logic is processed whenever any of its inputs change, for example as a result of a change in one of the digital input signals or a trip output from a protection element. Also, only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This reduces the amount of processing time that is used by the PSL. The protection & control software updates the logic delay timers and checks for a change in the PSL input signals every time it runs.

The PSL can be configured to create very complex schemes. Because of this PSL design is achieved by means of a PC support package called the PSL Editor. This is available as part of the settings application software MiCOM S1 Agile.

Note:
On this product the contents of the timers and counters included within the PSL can be directly accessed from the user interface main menu according to the attributes afforded via the PSL Editor.

4.5.10 FUNCTION KEY INTERFACE

The function keys interface directly into the PSL as digital input signals. A change of state is only recognized when a key press is executed on average for longer than 200 ms. The time to register a change of state depends on whether the function key press is executed at the start or the end of a protection task cycle, with the additional hardware and software scan time included. A function key press can provide a latched (toggled mode) or output on key press only (normal mode) depending on how it is programmed. It can be configured to individual protection scheme requirements. The latched state signal for each function key is written to non-volatile memory and read from non-volatile memory during device power up thus allowing the function key state to be reinstated after power-up, should power be inadvertently lost.

CHAPTER 5

CONFIGURATION

5.1 CHAPTER OVERVIEW

Each product has different configuration parameters according to the functions it has been designed to perform. There is, however, a common methodology used across the entire product series to set these parameters.

Some of the communications setup cannot be carried out using the settings applications software, it can only be carried out using the HMI. This chapter includes concise instructions on how to configure the device, as well as a description of the common methodology used to configure the device in general.

This chapter contains the following sections:

Chapter Overview 69

Settings Application Software 70

Using the HMI Panel 71

5.2 SETTINGS APPLICATION SOFTWARE

To configure this device, you will need to use the Settings Application Software. The settings application software used in this range of IEDs is called MiCOM S1 Agile. It is a collection of software tools, which is used for setting up and managing the IEDs.

Although you can change many settings using the front panel HMI, some of the features cannot be configured without the Settings Application Software. For example, the programmable scheme logic, or the IEC 61850 communications or the SLD.

If you do not already have a copy of the Settings Application Software, you can obtain it from the GE Vernova contact centre.

To configure your product, you will need a data model that matches your product. When you launch the Settings Application Software, you will be presented with a panel that allows you to invoke the “Data Model Manager”. This will close the other aspects of the software to allow an efficient import of the chosen data model. If you don’t have, or can’t find, the data model relating to your product, please call the GE Vernova contact centre.
When you have loaded all the data models you need, you should restart the Settings Application Software and start to create a model of your system using the “System Explorer” panel.

The software is designed to be intuitive, but help is available in an online help system and in the Settings Application Software user guide P40-M&CR-SAS-UG-EN-n, where 'Language' is a 2-letter code designating the language version of the user guide and 'n' is the latest version of the settings application software.

If using Adobe Acrobat Reader, click on the button below to open the S1 Agile User Guide.
This manual must be opened with a PDF viewer capable of opening attachments, such as Adobe Acrobat Reader or Nitro PDF. If using Nitro PDF, attachments are shown in the attachment pane. To show or hide the attachments pane, look in the sidebar and click the attachments tab.

Note:
An Open File dialogue box may open with a warning message about potential harm from programs, macros or viruses. The file supplied does not contain any harmful content, and may be safely opened.

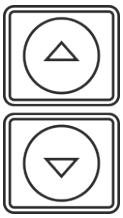
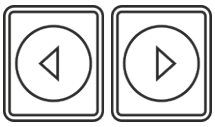
S1 Agile User Guide

5.3 USING THE HMI PANEL

Using the Graphical HMI, you can:

- Display and modify settings
- Display measurements
- Display fault records
- Display alarm lists
- Display the Single Line Diagram (SLD)
- View the digital I/O signal status
- Reset fault and alarm indications
- Issue switchgear commands

The keypad provides full access to the device functionality using a range of menu options. The information is displayed on the screen.

Keys	Description	Function
	Up and down cursor keys	To change between settings in a particular column, changing values within a cell or to select the next item on the SLD
	Left and right cursor keys	To change between settings in a particular column, change values within a cell or to select the next item on the SLD
	ENTER/OK key	For changing and executing settings. When a bottom banner Menu context key label is selected, the OK key can also be used to navigate between pages.
	Menu context keys (hot keys)	Menu context keys situated directly below the graphical HMI are used to navigate between pages.
	Cancel/Reset key	To return to the menu header from any menu cell, or to cancel a setting input.
	Read/Home key	To navigate to the default Home page from anywhere in the menu, or display latest fault record during a standing trip indication.
	Function keys (not all models)	For executing user programmable functions

Keys	Description	Function
	Control key OPEN	Control key OPEN used to open the CB/Switch. **Note:** Colour coding is selectable via labels and configuration of PSL/SLD.
	Control key CLOSE	Control key CLOSE used to close the CB/Switch. **Note:** Colour coding is selectable via labels and configuration of PSL/SLD.
	Local/Remote key	To select between local and remote operating modes.

5.3.1 NAVIGATING THE HMI PANEL

Two primary modes of navigation are provided: "hierarchical navigation" via the main menu or "horizontal navigation" via the context dependent "hot keys".

he cursor keys have an auto-repeat function if held down continuously. This can be used to speed up both setting value changes and menu navigation. For settings, the longer the key is held down, the faster the rate of change.

5.3.2 GETTING STARTED

When you first start the IED, it will go through its power up procedure. After a few seconds it will settle down into the default display. If there are alarms present, the yellow Alarms LED will be flashing and the alarm counter on the top banner will show the number of alarms that are active.

The device should be in full working order when you first start it, but an alarm could still be present. For example, if there is no network connection for a device fitted with a network board. If this is the case, you can read the alarm by selecting the Alarm counter on the top banner of the display.

For the example given, if the device is fitted with an Ethernet board, you will need to connect the device to an active Ethernet network to be able to clear the alarm.

5.3.3 DEFAULT DISPLAY

The graphical HMI default display contains shortcuts to various sections of the menu, as well as a snapshot of the current device status.

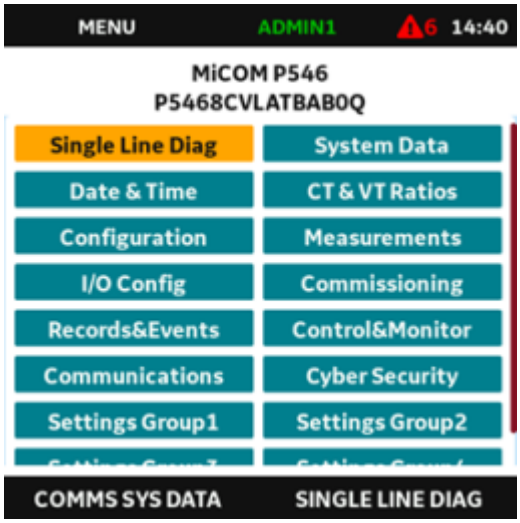


Figure 31: HMI default display

The graphical display screen consists of three main areas, which can be selected using the navigation keypad.

1. The top banner displays information left to right and includes the label for the current display, the logged in user, the number of active alarms and the time.
2. The content area displays information related to the chosen area of navigation. For example, settings, measurements or SLD.
3. The bottom banner displays labels for the two context keys, which are used for horizontal navigation.

Note:
After a period defined by the "LCD screen saver" , setting the HMI will enter rest mode. This allows the HMI to reduce power consumption and will dim the LCD backlight. The HMI may be woken from rest mode by pressing any front panel key. This mode has no effect on IED functional performance.

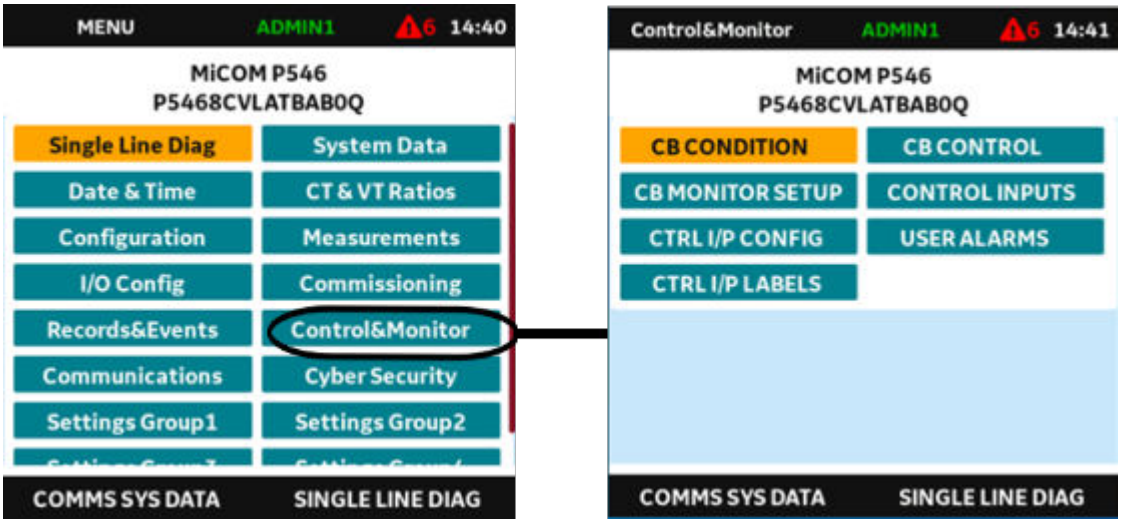
4. The default display provides quick and simple hierarchical. Use the navigation keypad to change the highlighted cell. The highlighted entry can be selected using the Enter/OK Key. When the bottom of the screen is reached, the selected area moves to the Bottom Banner. The Menu view can be directly navigated to by long pressing the "Read/Home" key.



Previous level in the navigation hierarchy may be reached by pressing the "Cancel/Reset" key.

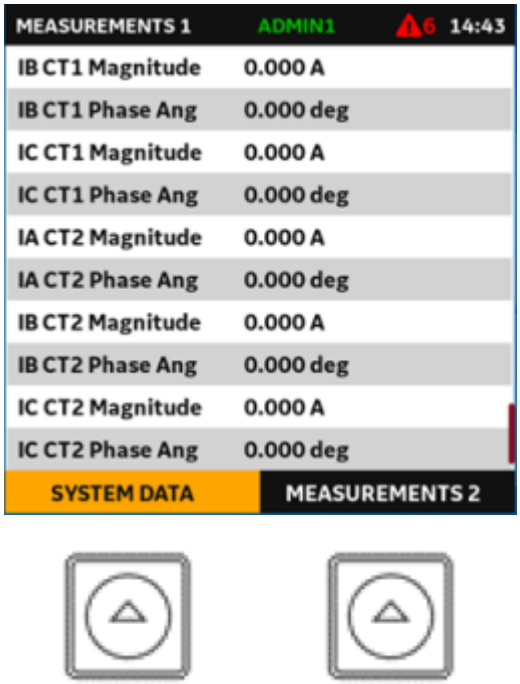


From the HMI Default Display, you can navigate to a view directly or open up a submenu using hierarchical navigation, For example, by selecting Controls & Monitor, a Submenu is opened.



As an alternative to hierarchical navigation, the views may be navigated to in sequence by using the menu context keys as “Next” and “Previous” buttons, and is referred as horizontal navigation.

For example, you can move to either ***SYSTEM DATA*** or ***MEASUREMENTS*** Views using the horizontal navigation directly from the menu view, using context hot keys situated on the lower banner.



5.3.4 PROCESSING ALARMS AND RECORDS

While there are no alarms, the Alarm Icon on the top banner is shown as:



While there are any standing alarms, the standing alarm count will be highlighted in red in the top HMI banner and the yellow alarm LED will flash.



To launch the alarm list view, select the alarm counter in the HMI top banner and press the **OK** key. The alarm view list may be scrolled to view all alarms.

New standing and fleeting alarms may be accepted by selecting the alarm and pressing the **Ack/Clear** menu context key. Rescinded alarms may also be cleared by selecting the alarm and pressing the **Ack/Clear** menu context key.

All visible alarms may be selected by pressing the **Select All** menu context key.

The "*reset indication*" command may be issued to reset latched alarms and accept the flashing led notification. A "*reset indication*" may be issued from the "*View Records*" HMI settings view or by pressing **Ack/Clear** alarm context key.

"*Ack/Clear*" and "*reset indication*" commands are available to users with ENGINEER or OPERATOR or INSTALLER roles.

To return to the launch view from the alarm view press the **Cancel** key.

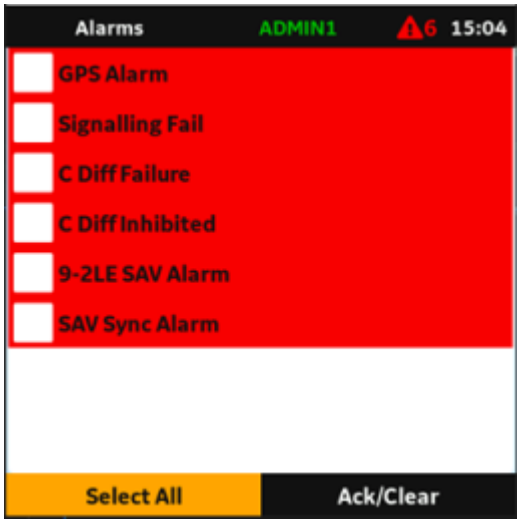


Figure 32: HMI alarms display

5.3.5 SINGLE LINE DIAGRAM (SLD) VIEWER

The SLD menu displays the saved SLD on the graphical HMI screen. You can navigate to the SLD menu using the bottom Menu context keys or by using the quick launch menu on the Home page. The SLD is configured and uploaded into the IED using the S1 Agile configuration tool. Items of plant can be selected on the SLD screen using the navigation keypad.

5.3.5.1 CIRCUIT BREAKER CONTROL (SLD VIEW ONLY)

You can OPEN and CLOSE the circuit breaker selected on the SLD using the dedicated OPEN, CLOSE and L/R buttons on the front HMI Panel.

When the ***CB Control by*** setting is selected, to option 1 *Local*, option 3 *Local+Remote*, option 5 *Opto+local*, option 7 *Opto+Rem+local* or option 8 *L/R Key* in the *CB CONTROL* column users are allowed to use the Trip and Close Key on the front panel to operate the CB.

To control an item of plant using the Open and Close and L/R buttons:

- Set ***CB control by*** setting to *L/R Key*
- Select the Local operating mode by pressing the L/R button

When the L/R button on the front panel is pressed, it will toggle the status of DDB ***L/R Key Status***. When the DDB status is TRUE, the L/R Key LED is green and the Local mode is selected. When the DDB status is FALSE, the L/R

Key LED is red and the REMOTE mode is selected. ***The L/R Key Status*** DDB status is stored in non-volatile memory, so that it's status is recovered after an IED power cycle.

- In the SLD menu, navigate to the item of plant which you require to control using the navigation keypad
- The selected plant is highlighted with an orange border
- Use the Enter key to select the item
- Press the Open or Close key to operate

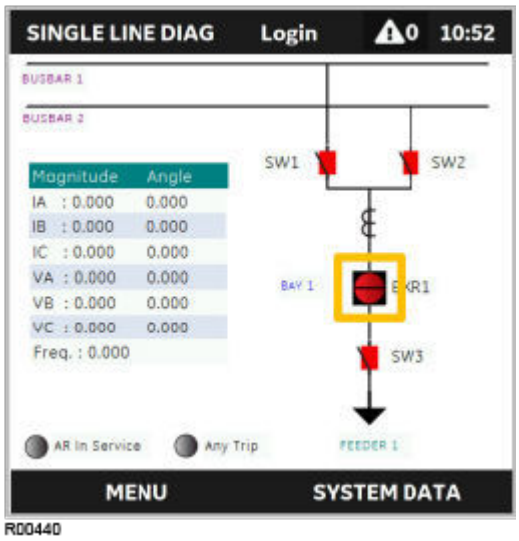


Figure 33: HMI SLD display

For the Circuit Breaker Commands from HMI, additional checks are done:

If the CB is in indeterminant state, the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked - Intermediate State".

If the associated "Control by" setting is set to "disabled" the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked due to Settings".

If the associated "Control by" setting is set to "remote" the switchgear command will not be available and HMI will raise a warning dialogue with the message "Commands blocked due to Settings".

If the associated "Control by" setting is set to "L/R key" and soft key status is set to remote, the switchgear command will not be available, and HMI will pop-up the message - "Commands blocked - In Remote Control".

If the associated local DDB is set to local, the switchgear command will not be available, and HMI will pop-up the message - "Commands blocked - Switchgear in Local".

5.3.5.2 SWITCH CONTROL (SLD VIEW ONLY)

You can OPEN and CLOSE the switches selected on the SLD using the dedicated OPEN, CLOSE and L/R buttons on the front HMI Panel.

When the Switch Control by setting is selected to option 1 *LOCAL*, option 3 `Local+Remote` or option 4 `L/R Key` in the SWITCH CONTROL column, users are allowed to use the Open and Close Key on the front panel to operate the SWITCH.

To control an item of plant using the Open and Close and L/R buttons:

- Set ***Switch Control by*** setting to `L/R Key`
- Select the Local operating mode by pressing the L/R button

When the L/R button on the front panel is pressed, it will toggle the status of DDB ***L/R Key Status***. When the DDB status is TRUE, the L/R Key LED is red and the Local mode is selected. When the DDB status is FALSE, the L/R

Key LED is green and the REMOTE mode is selected. The **L/R Key Status** DDB status is stored in non-volatile memory, so that its status is recovered after an IED power cycle.

- In the SLD menu, navigate to the item of plant you want to control using the navigation keypad
- The selected plant is highlighted with an orange border
- Use the Enter key to select the item
- Press the OPEN or CLOSE key to operate

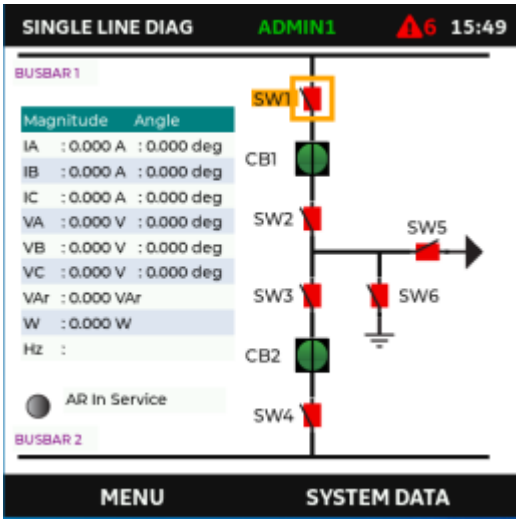


Figure 34: HMI SLD display

For the Switch Commands from HMI, these additional checks are done:

If the Switch is in indeterminant state, the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked - Intermediate State".

If the associated "***Control by***" setting is set to "disabled" the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked due to Settings".

If the associated "***Control by***" setting is set to "remote" the switchgear command will not be available and HMI will raise a warning dialogue with the message "Commands blocked due to Settings".

If the associated "***Control by***" setting is set to "L/R key" and soft key status is set to remote, the switchgear command will not be available and HMI will pop-up the message - "Commands blocked - In Remote Control."

If the associated local DDB is set to local, the switchgear command will not be available and HMI will pop-up the message - "Commands blocked - Switchgear in Local".

5.3.6 MENU STRUCTURE

Settings, commands, and measurements are stored in a real-time database inside the IED arranged as a matrix of "cells". When using the (HMI) it is convenient to consider the navigation system as a view of the underlying database. Each database cell, may be addressed by row and column. The main menu groups are allocated columns and the items within the groups are allocated rows.

You do not need to scroll through each of the columns horizontally to access a specific setting view. The Main Menu view can be used to quickly access the required column/setting view. Column contents are logically grouped, for example all of the disturbance recorder settings and records are in the same column.

There are three types of cell:

- Settings: this is for parameters that can be set to different values
- Commands: this is for issuing commands to be executed
- Data: this is for measurements and records to be viewed only

Note:
Sometimes the term "Setting" is used generically to describe all of the three types.

The table below, provides an example of the menu structure:

SYSTEM DATA (Col 00)	VIEW RECORDS (Col 01)	MEASUREMENTS 1 (Col 02)	…
Language (Row 01)	"Select Event [0...n]" (Row 01)	IA Magnitude (Row 01)	…
Password (Row 02)	Menu Cell Ref (Row 02)	IA Phase Angle (Row 02)	…
Sys Fn Links (Row 03)	Time & Date (Row 03)	IB Magnitude (Row 03)	…
…	…	…	…

It is convenient to specify all the settings in a single column, detailing the complete Courier address for each setting. The above table may therefore be represented as follows:

Setting	Column	Row	Description
SYSTEM DATA	**00**	**00**	**First Column definition**
Language (Row 01)	00	01	First setting within first column
Password (Row 02)	00	02	Second setting within first column
Sys Fn Links (Row 03)	00	03	Third setting within first column
…	…	…	
VIEW RECORDS	**01**	**00**	**Second Column definition**
Select Event [0...n]	01	01	First setting within second column
Menu Cell Ref	01	02	Second setting within second column
Time & Date	01	03	Third setting within second column
…	…	…	
MEASUREMENTS 1	**02**	**00**	**Third Column definition**
IA Magnitude	02	01	First setting within third column
IA Phase Angle	02	02	Second setting within third column
IB Magnitude	02	03	Third setting within third column
…	…	…	

The first three column headers are common throughout much of the product ranges. However, the rows within each of these column headers may differ according to the product type. Many of the column headers are the same for all products within the series. However, there is no guarantee that the addresses will be the same for a particular column header. Therefore, you should always refer to the product settings documentation and not make any assumptions.

5.3.7 MENU CONTEXT KEYS (FAST ACCESS "HOT KEYS")

A pair of keys are located directly below the LCD display. Their function is context related so they are referred to as "menu context keys". They can either facilitate horizontal menu navigation or, if appropriately qualified, provide "hot key" actions.

The hot key actions provide a short-cut facility either to switch between settings groups or to toggle the state of the device's control inputs. In conjunction with PSL, this provides for direct access to customer defined functionality.

To use the hot key functionality, it must be enabled by setting the ***Direct Access*** cell in the *CONFIGURATION* column of the menu either to `Enabled` or to `Hotkey Only`.

Note:
The `CB Ctrl Only` option is not currently supported on this product. Choosing it has the same effect as selecting Disabled).

At any time whilst the device is in a healthy energised state, the action that the menu context keys will execute is shown on the display immediately above the key (No text implies no action). In the case of the example shown below, ***Direct Access*** setting cell has been set to enable the hot keys, this allows the hot key menu to be entered by pressing the left menu context key from the main menu view.

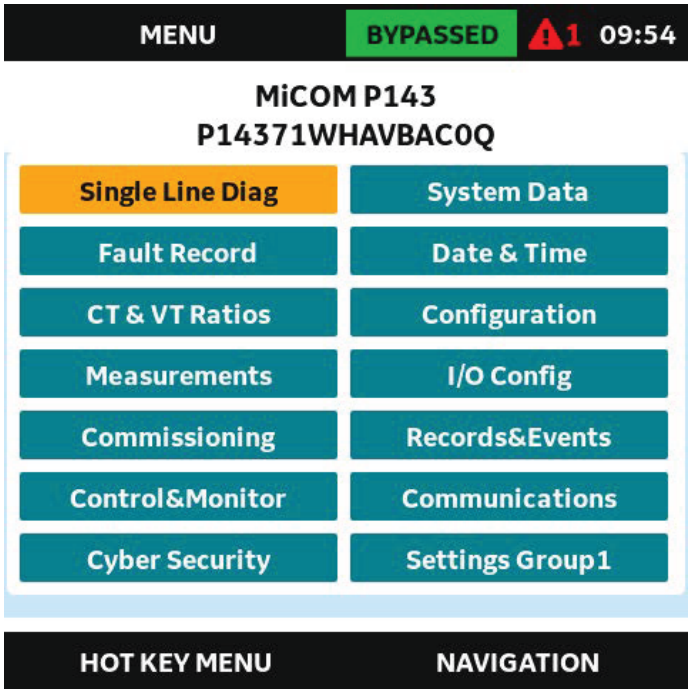


Figure 35: Main menu with Hot Key Menu access

In the example above, pressing the left-hand menu context key will invoke the hot key menu; pressing the right-hand menu context key will restore the horizontal navigation feature.

The hot key control panel will close after 30 seconds of user inactivity.

5.3.7.1 HOT KEY ACTIONS

If the hot key functionality has been enabled, the hot key menu provides the facility to either:

directly switch between settings groups

or:

directly toggle the state of the device's control inputs

Using the left-hand menu context key to select the HOT KEY MENU from the main menu will reveal the hot key menu control actions presented similarly to the following image:

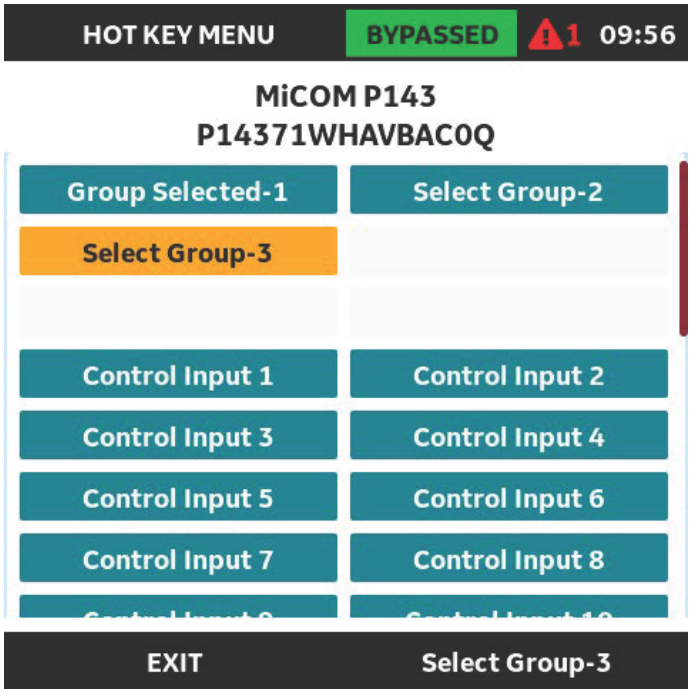


Figure 36: Hot Key menu

The cursor keys can be used to navigate to the intended target action which, when highlighted, can be selected/ toggled by pressing the right-hand hot key (or by pressing the ENTER/OK key). Choosing "EXIT" context key will close the hot key control panel.

5.3.7.2 CONTROL INPUTS

To operate control inputs, navigate to the Control Inputs settings view on the front graphical HMI screen, select the relevant control input and Set/Reset as required. RBAC is now applied to access control inputs for operation.

5.3.8 CHANGING THE SETTINGS

1. Starting at the default display, highlight the required settings column/menu
2. Use the OK key to enter the highlighted settings menu.
3. To change the value of a setting, highlight the relevant cell in the menu, then press the **Enter** key to change the cell value. A settings screen will appear next to the cell. If the currently logged in user does not have the level of access required for changing the setting, a pop-up dialog box will inform the user and prevent the settings from being changed. Acknowledge the pop-up message, then navigate to the 'user accounts' section to the top of the screen (top banner) to enter the password for the required access level to change settings.
4. To change the value on the settings screen, use the cursor keys to change the desired settings. When more settings are available than can fit on the screen, a scroll bar on the right-hand side appears. In some cases, a virtual keyboard is provided to enter complex characters. The IED maintains dependencies between various settings, and only the applicable settings are displayed for changing.
5. Press the **Enter** key to confirm the new setting value or the **Clear** key or the on-screen 'cancel' to discard it.
6. To confirm the new settings, press the **Enter** key. Navigate away from the currently active group settings or press the **Home** key. A Settings update confirmation dialogue box will appear that requires choosing of one of the following options:
   a. Save - accept all settings including the recently changed settings
   b. Abort – discard recent changes and keep existing settings
   c. Stay on page – return to the active settings page without saving recent changes

7. To return to the top of the menu, hold down the **Up** cursor key for a second or so, or press the **Clear** key once. It is possible to move across columns from anywhere in the menu by using the Menu context keys at the bottom of the display.
8. To return to the default display, press the **Home** key at any time.
9. Press the **Enter** key to accept the new settings or press the **Clear** key to discard the new settings.
10. The Date and time can be adjusted by navigating to the top banner and selecting the displayed time. Press the **Enter** key to adjust the date and time using the calendar/clock widget that pops up.

Note:
For the protection group and disturbance recorder settings, the changes are not saved unless confirmed using the Settings update confirmation prompt.

Note:
All other Control and support settings (such as Communications and Control inputs), however, are updated immediately after they are entered on the front HMI without the need to confirm using the Settings update confirmation prompt.

5.3.9 FUNCTION KEYS

Most products have a number of function keys for programming control functionality using the programmable scheme logic (PSL).

Each function key has an associated programmable tri-colour LED that can be programmed to give the desired indication on function key activation.

These function keys can be used to trigger any function that they are connected to as part of the PSL. The function key commands are in the *FUNCTION KEYS* column.

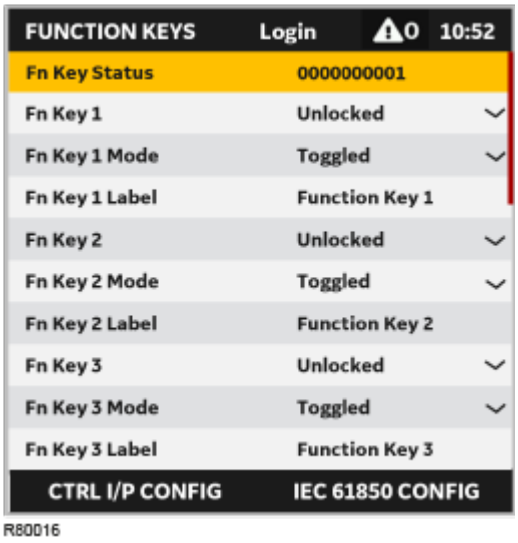


Figure 37: HMI function keys display

The first cell down in the *FUNCTION KEYS* column is the ***Fn Key Status*** cell. This contains a binary string, which represents the function key commands. Their status can be read from the binary string.

The next cell down (***Fn Key 1***) allows you to activate or disable the first function key (1). The ***Lock*** setting allows a function key to be locked. This allows function keys that are set to `Toggled` mode and their DDB signal active 'high', to be locked in their active state, preventing any further key presses from deactivating the associated function. Locking a function key that is set to the Normal mode causes the associated DDB signals to be

permanently off. This safety feature prevents any inadvertent function key presses from activating or deactivating critical functions.

The next cell down (***Fn Key 1 Mode***) allows you to set the function key to *Normal* or *Toggled*. In the Toggle mode the function key DDB signal output stays in the set state until a reset command is given, by activating the function key on the next key press. In the Normal mode, the function key DDB signal stays energised for as long as the function key is pressed then resets automatically. If required, a minimum pulse width can be programmed by adding a minimum pulse timer to the function key DDB output signal.

The next cell down (***Fn Key 1 Label***) allows you to change the label assigned to the function. The default label is *Function key 1* in this case. To change the label you need to press the enter key and then change the text on the bottom line, character by character. This text is displayed when a function key is accessed in the function key menu, or it can be displayed in the PSL.

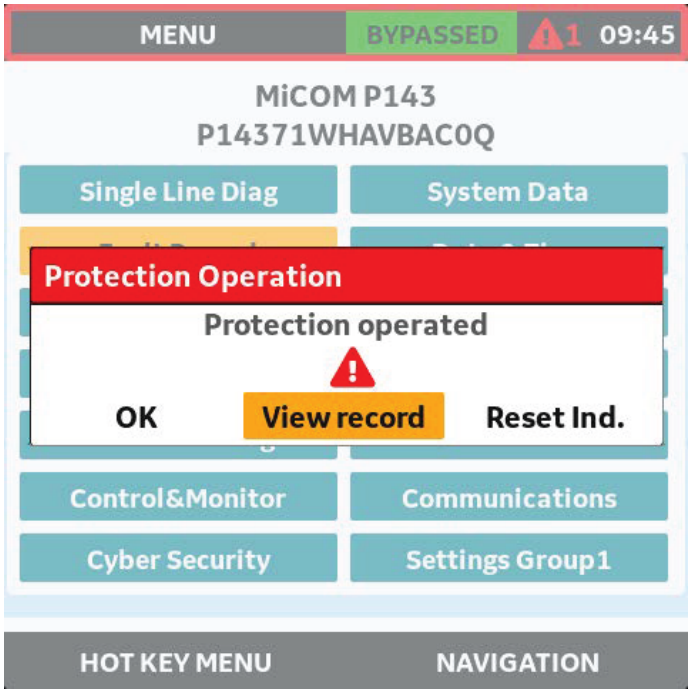
Subsequent cells allow you to carry out the same procedure as above for the other function keys.

The status of the function keys is stored in non-volatile memory. If the auxiliary supply is interrupted, the status of all the function keys is restored. The IED only recognises a single function key press at a time and a minimum key press duration of approximately 200 ms is required before the key press is recognised. This feature avoids accidental double presses.

The function keys needs operator permissions to operate. If operator permissions are not held by the present user an information dialogue is raised to inform the operation has failed.

5.3.9.1 VISUALISATION OF PROTECTION OPERATION

Where there is a protection operation/trip, in addition to the front panel LED indications, the standing trip is indicated on the LCD screen by a red trim around the top banner. Additionally, the LCD backlight becomes lit and a dialogue is presented with three options:



- "OK" - close the dialogue
- "View" - Navigate to the "record" data view and open the latest fault record
- "Reset Ind" - Attempt to reset the trip indication

5.3.9.2 FAULT RECORD VIEWER

As described in the Fault Record Events section of the Monitoring and Control chapter, asserting the ***Fault REC TRIG*** signal DDB assigned in the PSL triggers the creation of a fault record. The fault record viewer function provides ready access to view the contents of a fault record through the front panel user interface.

The information recorded in a fault record includes; the faulted phase(s), associated fault alarms, the protection elements involved, and measurements and values recorded at the time of the fault condition (fault data).

The usual trigger mechanism for the fault recorder is protection operation which also presents a dialogue on the front panel user interface similar to that shown in the following figure:

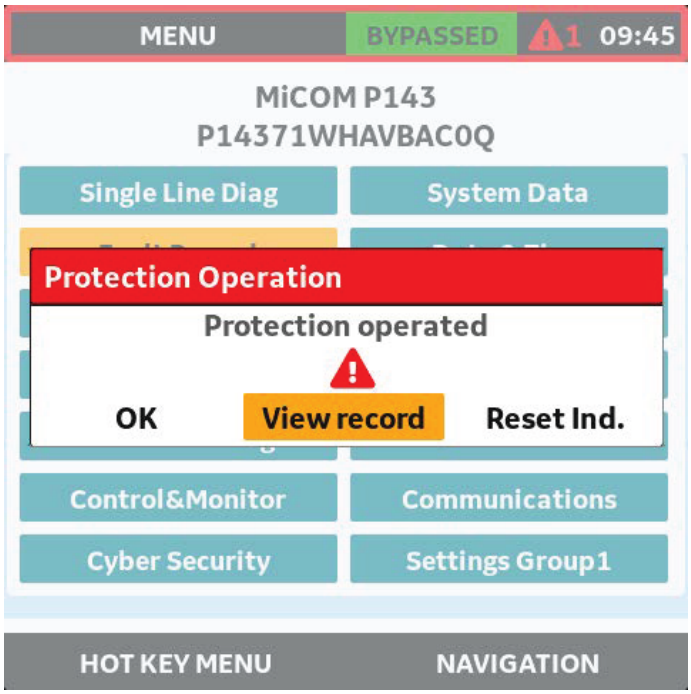


Figure 38: Protection operation indication dialogue

Selecting the "View record" option will launch the fault record viewer.

Note:
The fault data record is only completed when the condition that triggered the recorder has cleared.

To display the fault record, the screen is divided into two sections. The upper part displays the index of the selected fault record being displayed together with the associated protection operation (start and trip) conditions. The lower part is dynamically sized, scrollable, and sub-divided into four sections, to allow the display of the following record-dependent data:

- Trip Elements operated
- Start Elements operated
- Fault Alarms
- Fault data

An example of the fault record viewer display is shown in the following figure:

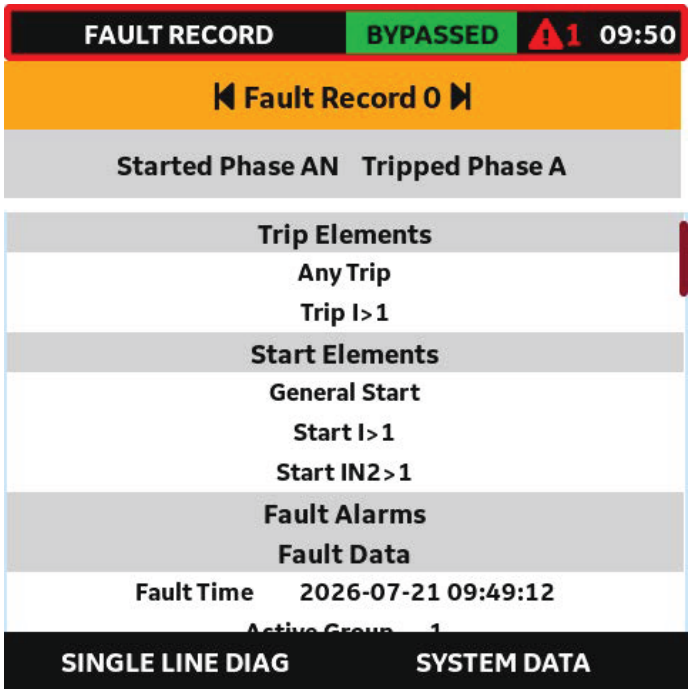


Figure 39: Fault record viewer

> *Note:*
> *While there are no fault records stored, no data will be displayed on the fault record view.*

By default, the contents of latest fault record (index 0) will be displayed. If more records are present, they can be viewed by using the menu navigation methods to select the appropriate fault record index as illustrated in the following figure:

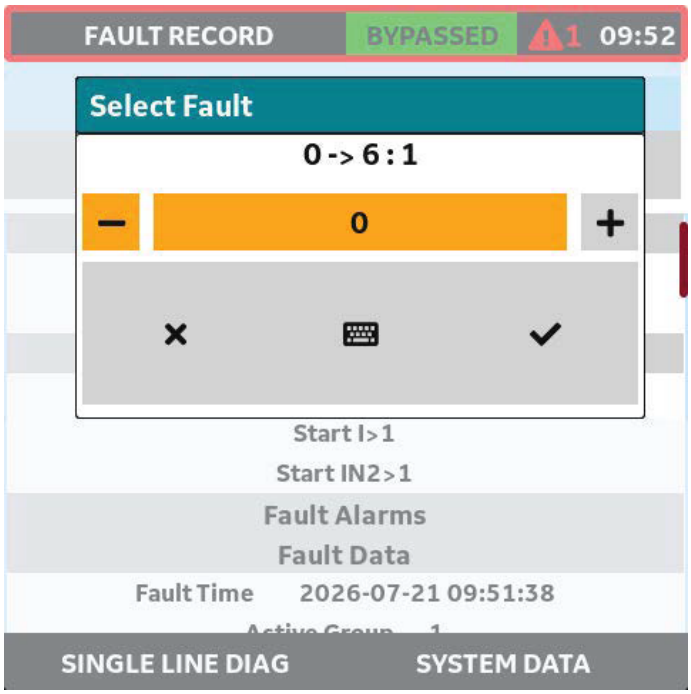


Figure 40: Fault record selection dialogue

Note:
The fault record viewer may also be accessed from the default menu page (example shown in the following figure) by navigating to the "Fault Record" option and selecting it:

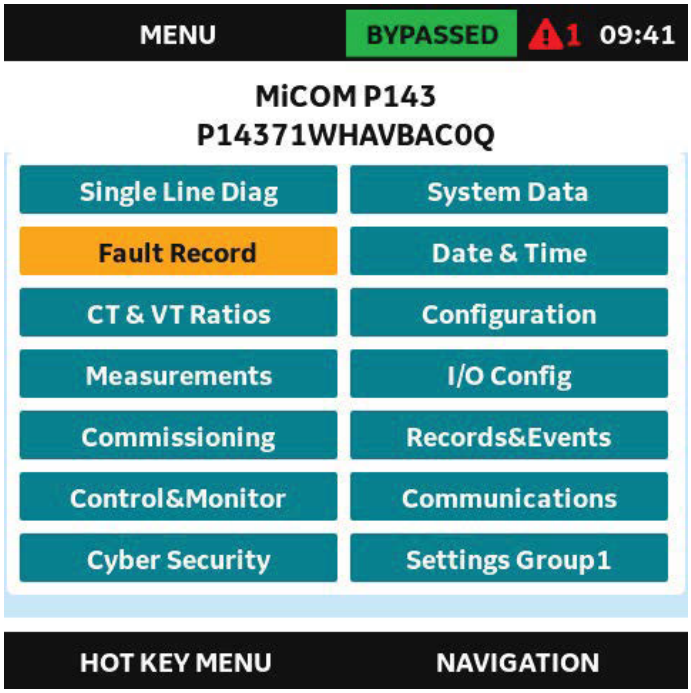


Figure 41: Fault record viewer selectable from main menu

5.3.9.3 PSL TIMERS AND COUNTERS

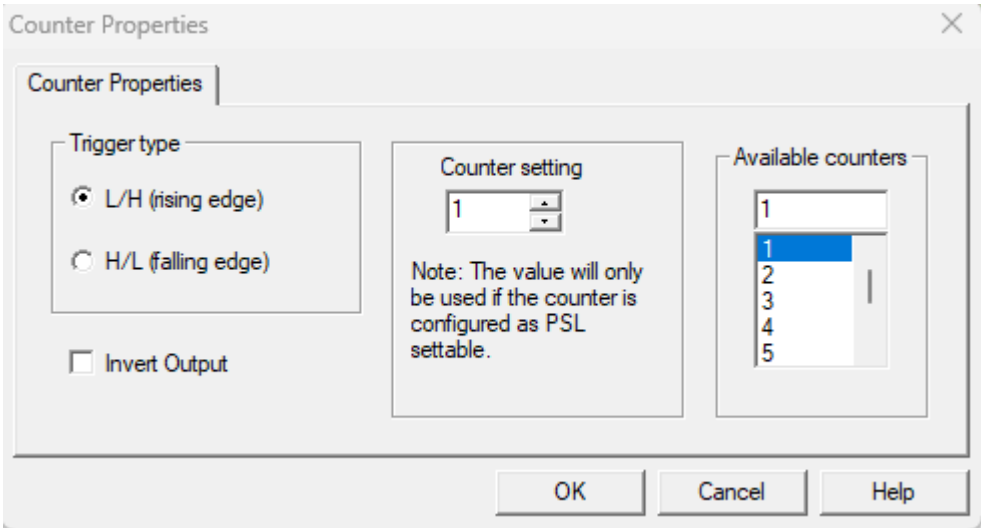
A number of configurable timers and counters are available for use within the PSL.

In this product it is possible to access the PSL timers and counters through the main menu on the HMI.

5.3.9.3.1 ACCESSING PSL COUNTERS VIA HMI

Each numbered PSL counter has inputs to either increment (+), or decrement (-) the value as well as an input to Reset (R) the count output (Q) which goes high when the count threshold value is exceeded.

As demonstrated in the following image taken from the within the PSL Editor, each of the counters can be set within the PSL to increment when triggered by either rising or falling edges. Also, from within the PSL the output can be inverted.



To set counter properties:

1. From the **Trigger Type** tick list, choose either, **Rising edge triggered** or **Falling edge triggered**.
2. Set the **Counter setting** value, if required (*).
3. Set the **Invert output** tick box, if required.
4. From the **Available counters** list, choose the counter required.

Note:
Note: The counter number will auto-increment when adding counters.

5. Click OK

Note:
** Through the main menu access routes (not from within the PSL Editor) it is possible to assign a label to the numbered counter and to set the counter value. To do this the **PSL Config** setting in the CONFIGURATION column must be set to `visible`. This reveals a set of Courier cells in the menu in the GROUP N PSL CONFIG column that can be used to monitor and control the counters.*

The applicable cells are:

- ***CounterSourcePSL***
- ***Counter n***
- ***Counter n Label***

CounterSourcePSL is a bit field that arbitrates control of the target value for each counter. If the particular bit associated with a specific counter is set to 1, then the Counter setting value used will be the one assigned from within the PSL Editor. If the particular bit is set to 0, then another setting (***Counter n***) is revealed in the *GROUP N PSL COUNTERS* sub-menu which should then be set with the required counter target. In this case, any Counter setting value applied via the PSL Editor will be ignored. Also made visible within the *GROUP N PSL COUNTERS* column are the Counter n Label fields which allow text labels to be assigned to the particular counters.

5.3.9.3.2 TIMER PROPERTIES

A number of configurable timers are available for use within the PSL.

Each timer can be selected for pick-up, drop-off, dwell, pulse or pick-up/drop-off operation.

Whilst the value for each timer can be set from within the PSL Editor, it is also possible to use the main menu access route to set the timer values. To do this the ***PSL Config*** setting in the *CONFIGURATION* column must be

set to `visible`. This reveals a set of Courier cells in the menu in the *GROUP N PSL CONFIG* column that can be used to set the timer values.

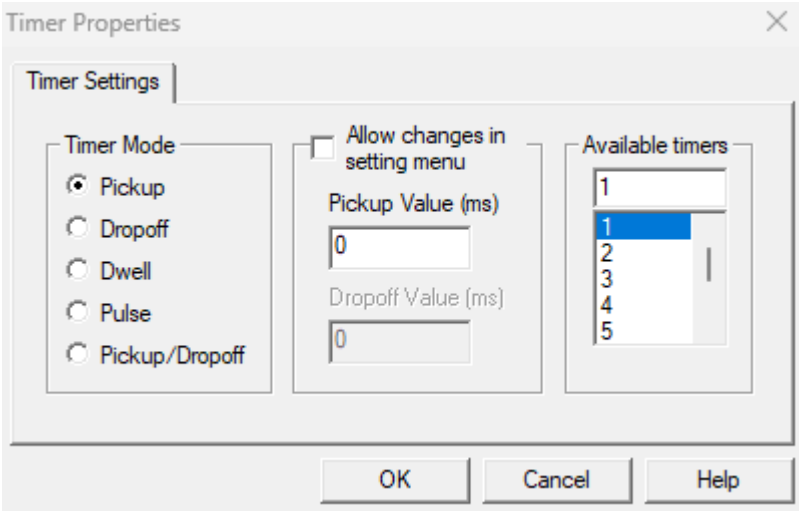
To set timer properties, within the PSL Editor:

1. From the Timer Mode tick list, choose the mode.
2. Set the Pick-up Value (in milliseconds), if required.
3. Set the Drop-off Value (in milliseconds), if required.
4. From the Available timers list, choose the timer required.

Note:
The timer number will auto-increment when adding timers.

5. To set the timer value from within the PSL Editor, the box "Allow change in setting menu" should be left unchecked. Alternatively, if the preference is to be able to set the timer value through the normal menu access, the box should be checked.
6. Click OK.
7. If the "Allow change in setting menu" box has been checked, the timer value (**Timer n (ms)**) must be set with the desired value.

The PSL Editor view of the feature is shown in the following figure:



CHAPTER 6

CURRENT PROTECTION FUNCTIONS

6.1 CHAPTER OVERVIEW

This product provides a wide range of current protection functions. This chapter describes the operation of these functions including the principles, logic diagrams and applications.

This chapter contains the following sections:

Chapter Overview 89
Using Overcurrent Protection 90
Overcurrent Protection Principles 91
Phase Overcurrent Protection 100
Voltage Dependent Overcurrent Element 107
Current Setting Threshold Selection 111
Cold Load Pickup 112
Selective Logic 115
Timer Setting Selection 117
Negative Sequence Overcurrent Protection 118
Earth Fault Protection 122
Sensitive Earth Fault Protection 132
Restricted Earth Fault Protection 141
Thermal Overload Protection 157
Broken Conductor Protection 161
Second Harmonic Blocking 165
Load Blinders 169
Neutral Admittance Protection 172
Busbar Protection 175
Transient Earth Fault Detection 185

6.2 USING OVERCURRENT PROTECTION

A suite of overcurrent protection functionality is provided in this device. It may be intended to serve as a primary protection function, or as backup to a primary protection function based on a different complimentary protection technique, such as distance or line differential. Accordingly, the conditions under which overcurrent is enabled differ from device to device. If overcurrent is the main protection, then it can be simply enabled or disabled. If it is being provided for back-up purposes, then enabling or disabling can be further qualified according to ability of the main protection to function correctly. VT fuse failure (or MCB failure) would normally prevent distance protection from working. Communications failure would normally cause line differential protection to stop working. Such conditions may be used in combination to selectively enable or disable overcurrent protection in this device according to:

- Permanently disabled
- Permanently enabled
- Enabled only in case of VT fuse/MCB failure

In addition, each stage may be inhibited/blocked by a DDB signal.

It should be noted that phase overcurrent protection is phase segregated, but the operation of any phase is mapped to 3 phase tripping in the default PSL.

The VTS element of the IED can be selected to either block the directional element or simply remove the directional control.

6.3 OVERCURRENT PROTECTION PRINCIPLES

Most electrical power system faults result in an overcurrent of one kind or another. It is the job of protection devices, formerly known as 'relays' but now known as Intelligent Electronic Devices (IEDs) to protect the power system from faults. The general principle is to isolate the faults as quickly as possible to limit the danger and prevent fault currents flowing through systems, which can cause severe damage to equipment and systems. At the same time, we wish to switch off only the parts of the power grid that are absolutely necessary, to prevent unnecessary blackouts. The protection devices that control the tripping of the power grid's circuit breakers are highly sophisticated electronic units, providing an array of functionality to cover the different fault scenarios for a multitude of applications.

The described products offer a range of overcurrent protection functions including:

- Phase Overcurrent protection
- Earth Fault Overcurrent protection
- Negative Sequence Overcurrent protection
- Sensitive Earth Fault protection

To ensure that only the necessary circuit breakers are tripped and that these are tripped with the smallest possible delay, the IEDs in the protection scheme need to co-ordinate with each other. Various methods are available to achieve correct co-ordination between IEDs in a system. These are:

- By means of time alone
- By means of current alone
- By means of a combination of both time and current.

Grading by means of current alone is only possible where there is an appreciable difference in fault level between the two locations where the devices are situated. Grading by time is used by some utilities but can often lead to excessive fault clearance times at or near source substations where the fault level is highest.

For these reasons the most commonly applied characteristic in co-ordinating overcurrent devices is the IDMT (Inverse Definite Minimum Time) type.

6.3.1 IDMT CHARACTERISTICS

There are two basic requirements to consider when designing protection schemes:

- All faults should be cleared as quickly as possible to minimise damage to equipment
- Fault clearance should result in minimum disruption to the electrical power grid.

The second requirement means that the protection scheme should be designed such that only the circuit breaker(s) in the protection zone where the fault occurs, should trip.

These two criteria are actually in conflict with one another, because to satisfy (1), we increase the risk of shutting off healthy parts of the grid, and to satisfy (2) we purposely introduce time delays, which increase the amount of time a fault current will flow. With IDMT protection applied to radial feeders, this problem is exacerbated by the nature of faults in that the protection devices nearest the source, where the fault currents are largest, actually need the longest time delay.

IDMT characteristics are described by operating curves. Traditionally, these were defined by the performance of electromechanical devices. In numerical protection, equations are used to replicate these characteristics so that they can be used to grade with older equipment.

The old electromechanical devices countered this problem somewhat due to their natural operate time v. fault current characteristic, whereby the higher the fault current, the quicker the operate time. The characteristic typical of these electromechanical devices is called Inverse Definite Minimum Time or IDMT for short.

6.3.1.1 IEC 60255 IDMT CURVES

There are four well-known variants of this characteristic:

- Standard Inverse
- Very inverse
- Extremely inverse
- UK Long Time inverse

These equations and corresponding curves governing these characteristics are very well known in the power industry.

Standard Inverse

This characteristic is commonly known as the 3/10 characteristic, i.e. at ten times setting current and TMS of 1 the device will operate in 3 seconds.

The characteristic curve can be defined by the mathematical expression:

$$t_{op} = T \frac{0.14}{\left(\frac{I}{I_s}\right)^{0.02} - 1}$$

The standard inverse time characteristic is widely applied at all system voltages – as back up protection on EHV systems and as the main protection on HV and MV distribution systems.

In general, the standard inverse characteristics are used when:

- There are no co-ordination requirements with other types of protective equipment further out on the system, e.g. Fuses, thermal characteristics of transformers, motors etc.
- The fault levels at the near and far ends of the system do not vary significantly.
- There is minimal inrush on cold load pick up. Cold load inrush is that current which occurs when a feeder is energised after a prolonged outage. In general the device cannot be set above this value but the current should decrease below the device setting before the device operates.

The Standard Inverse curve implemented in this device becomes definite time (DT) for input current values above 30 x I_s.

Very Inverse

This type of characteristic is normally used to obtain greater time selectivity when the limiting overall time factor is very low, and the fault current at any point does not vary too widely with system conditions. It is particularly suitable, if there is a substantial reduction of fault current as the distance from the power source increases. The steeper inverse curve gives longer time grading intervals. Its operating time is approximately doubled for a reduction in setting from 7 to 4 times the device current setting. This permits the same time multiplier setting for several devices in series.

The characteristic curve can be defined by the mathematical expression:

$$t_{op} = T \frac{13.5}{\left(\frac{I}{I_s}\right) - 1}$$

The Very Inverse curve implemented in this device becomes definite time (DT) for input current values above 30 x I_s.

Extremely Inverse

With this characteristic the operating time is approximately inversely proportional to the square of the current. The long operating time of the device at peak values of load current make the device particularly suitable for grading with fuses and also for protection of feeders which are subject to peak currents on switching in, such as feeders supplying refrigerators, pumps, water heaters etc., which remain connected even after a prolonged interruption of supply.

For cases where the generation is practically constant and discrimination with low tripping times is difficult to obtain, because of the low impedance per line section, an extremely inverse device can be very useful since only a small difference of current is necessary to obtain an adequate time difference.

Another application for this device is with auto reclosers in low voltage distribution circuits. As the majority of faults are of a transient nature, the device is set to operate before the normal operating time of the fuse, thus preventing perhaps unnecessary blowing of the fuse.

Upon reclosure, if the fault persists, the recloser locks itself in the closed position and allows the fuse to blow to clear the fault.

The Extremely Inverse curve implemented in this device becomes definite time (DT) for input current values above 20 x I_s.

This characteristic is also widely used for protecting plant against overheating since overheating is usually an I2t function.

This characteristic curve can be defined by the mathematical expression:

$$t_{op} = T \frac{80}{\left(\frac{I}{I_s}\right)^2 - 1}$$

UK Long Time Inverse

This type of characteristic has a long time characteristic and may be used for protection of neutral earthing resistors (which normally have a 30 second rating). The device operating time at 5 times current setting is 30 seconds at a TMS of 1.

This can be defined by:

$$t_{op} = T \frac{120}{\left(\frac{I}{I_s}\right) - 1}$$

In the above equations:

- t_{op} is the operating time
- T is the time multiplier setting
- I is the measured current
- I_s is the current threshold setting

The ratio I/I_s is sometimes defined as ‘M’ or ‘PSM’ (Plug Setting Multiplier).

The Long Time Inverse curve implemented in this device becomes definite time (DT) for input current values above 30 x I_s.

These curves are plotted as follows:

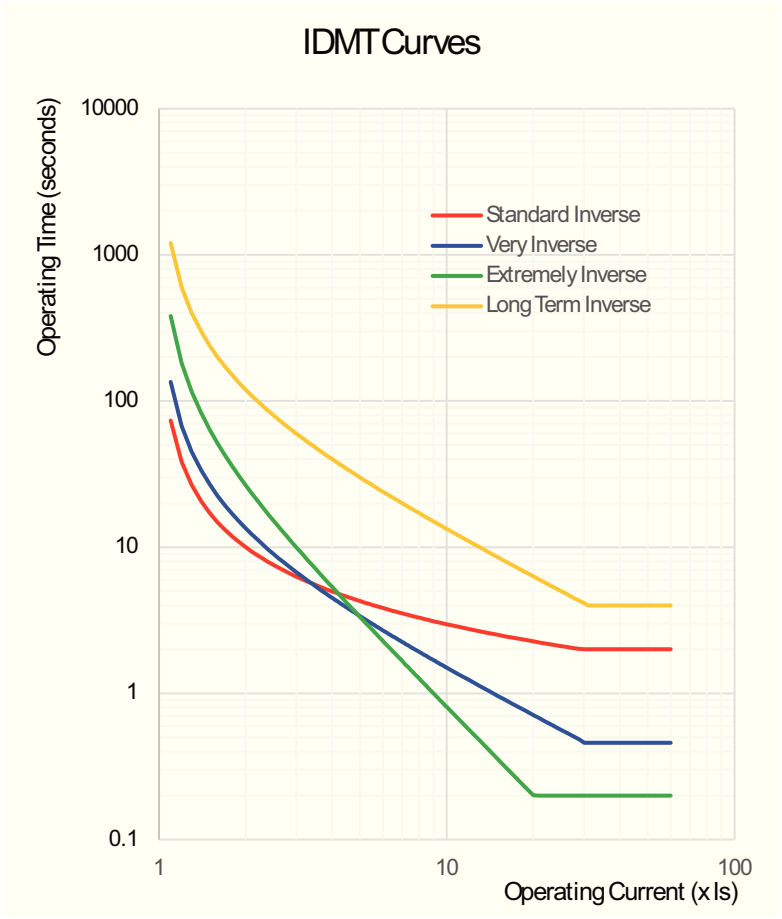


Figure 42: IEC 60255 IDMT curves

6.3.1.2 EUROPEAN STANDARDS

The IEC 60255 IDMT Operate equation is:

$$t_{op} = T\left(\frac{\beta}{M^{\alpha}-1} + L\right) + C$$

and the IEC 60255 IDMT Reset equation is:

$$t_r = T\left(\frac{\beta}{1-M^{\alpha}}\right)$$

where:

- t_{op} is the operating time
- t_r is the reset time
- T is the Time Multiplier setting
- M is the ratio of the measured current divided by the threshold current (I/Is)
- β is a constant, which can be chosen to satisfy the required curve characteristic
- α is a constant, which can be chosen to satisfy the required curve characteristic
- C is a constant for adding Definite Time (Definite Time adder)
- L is a constant (usually only used for ANSI/IEEE curves)

The constant values for the IEC IDMT curves are as follows:

Curve Description	β constant	α constant	L constant
IEC Standard Inverse Operate	0.14	0.02	0
IEC Standard Inverse Reset	8.2	6.45	0
IEC Very Inverse Operate	13.5	1	0
IEC Very Inverse Reset	50.92	2.4	0
IEC Extremely Inverse Operate	80	2	0
IEC Extremely Inverse Reset	44.1	3.03	0
UK Long Time Inverse Operate*	120	1	0

Note:
** When using UK Long Time Inverse, the DT (Definite Time) is always used for the Reset characteristic.*

6.3.1.3 NORTH AMERICAN STANDARDS

The IEEE IDMT Operate equation is:

$$t_{op} = TD\left(\frac{\beta}{M^{\alpha}-1}+L\right)+C$$

and the IEEE IDMT Reset equation is:

$$t_{r} = TD\left(\frac{\beta}{1-M^{\alpha}}\right)$$

where:

- t_{op} is the operating time
- t_r is the reset time
- TD is the Time Dial setting
- M is the ratio of the measured current divided by the threshold current (I/I_s)
- β is a constant, which can be chosen to satisfy the required curve characteristic
- α is a constant, which can be chosen to satisfy the required curve characteristic
- C is a constant for adding Definite Time (Definite Time adder)
- L is a constant (usually only used for ANSI/IEEE curves)

The constant values for the IEEE curves are as follows:

Curve Description	β constant	α constant	L constant
IEEE Moderately Inverse Operate	0.0515	0.02	0.114
IEEE Moderately Inverse Reset	4.85	2	0
IEEE Very Inverse Operate	19.61	2	0.491
IEEE Very Inverse Reset	21.6	2	0
IEEE Extremely Inverse Operate	28.2	2	0.1217
IEEE Extremely Inverse Reset	29.1	2	0
CO8 US Inverse Operate	5.95	2	0.18

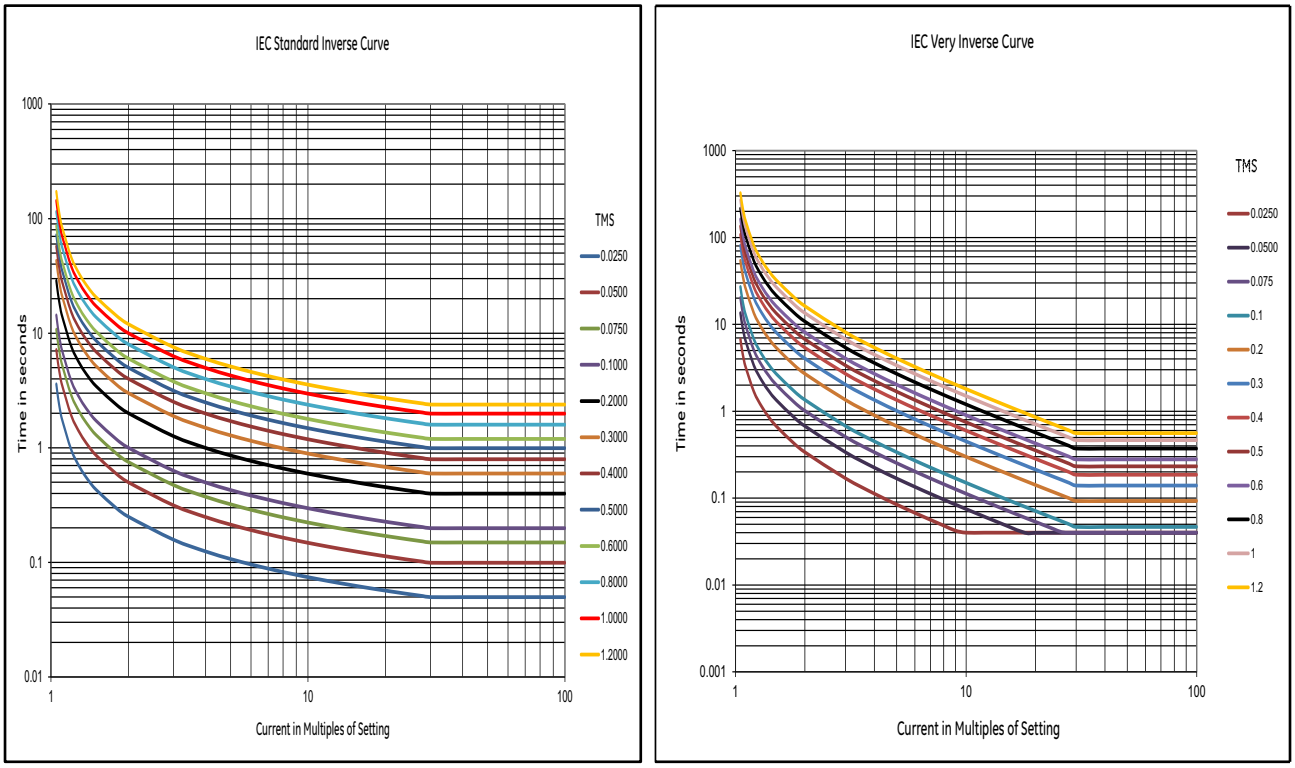
CO8 US Inverse Reset	5.95	2	0
CO2 US Short Time Inverse Operate	0.16758	0.02	0.11858
CO2 US Short Time Inverse Reset	2.261	2	0

The constant values for the ANSI curves are as follows:

Curve Description	β constant	α constant	L constant
ANSI Normally Inverse Operate	8.9341	2.0938	0.17966
ANSI Normally Inverse Reset	9	2	0
ANSI Short Time Inverse Operate	0.03393	1.2969	0.2663
ANSI Short Time Inverse Reset	0.5	2	0
ANSI Long Time Inverse Operate	2.18592	1	5.6143
ANSI Long Time Inverse Reset	15.75	2	0

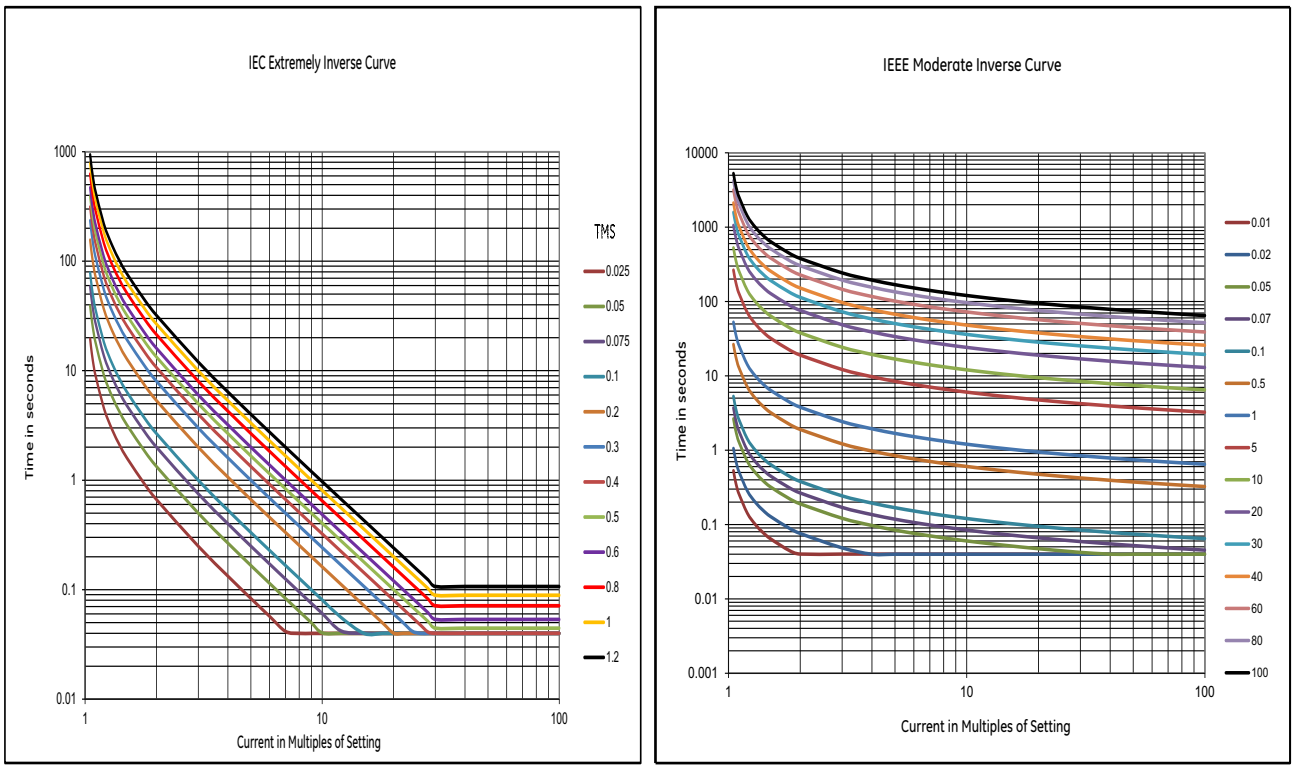
Note:
** When using UK Long Time Inverse or UK Rectifier for the Operate characteristic, DT is always used for the Reset characteristic.*

6.3.1.4 IEC AND IEEE INVERSE CURVES



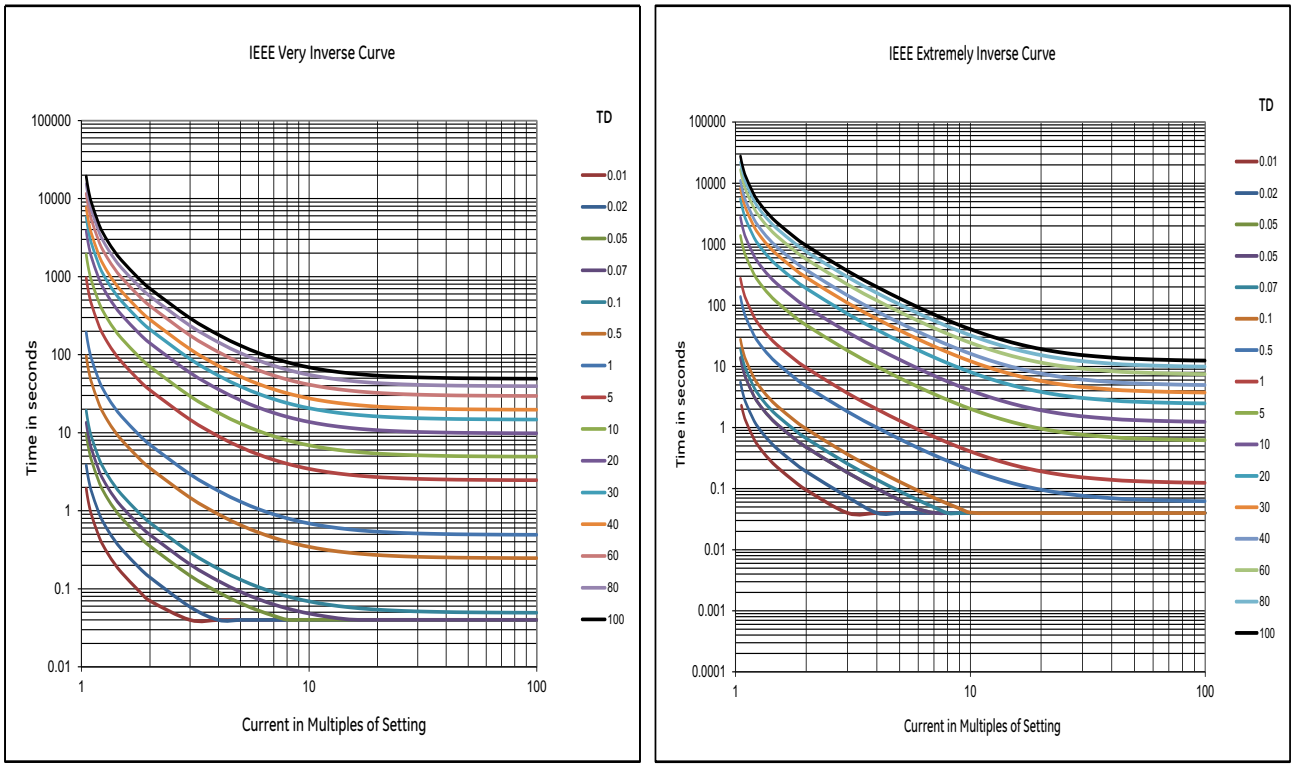
E00757

Figure 43: IEC standard and very inverse curves



E00758

Figure 44: IEC Extremely inverse and IEEE moderate inverse curves



E00759

Figure 45: IEEE very and extremely inverse curves

6.3.1.5 DIFFERENCES BETWEEN THE NORTH AMERICAN AND EUROPEAN STANDARDS

The IEEE and US curves are set differently to the IEC/UK curves, with regard to the time setting. A time multiplier setting (TMS) is used to adjust the operating time of the IEC curves, whereas a time dial setting is used for the IEEE/US curves. The menu is arranged such that if an IEC/UK curve is selected, the ***I> Time Dial*** cell is not visible and vice versa for the TMS setting. For both IEC and IEEE/US type curves, a definite time adder setting is available, which will increase the operating time of the curves by the set value.

6.3.1.6 PROGRAMMABLE CURVES

As well as the standard curves as defined by various countries and standardising bodies, it is possible to program custom curves using the User Programmable Curve Tool, described in the Settings Application Software chapter. This is a user-friendly tool by which you can create curves either by formula or by entering data points. Programmable curves help you to match more closely the withstand characteristics of the electrical equipment than standard curves.

6.3.2 PRINCIPLES OF IMPLEMENTATION

The range of protection products provides a very wide range of protection functionality. Despite the diverse range of functionality provided, there is some commonality between the way many of the protection functions are implemented. It is important to describe some of these basic principles before going deeper into the individual protection functions.

A simple representation of protection functionality is shown in the following diagram:

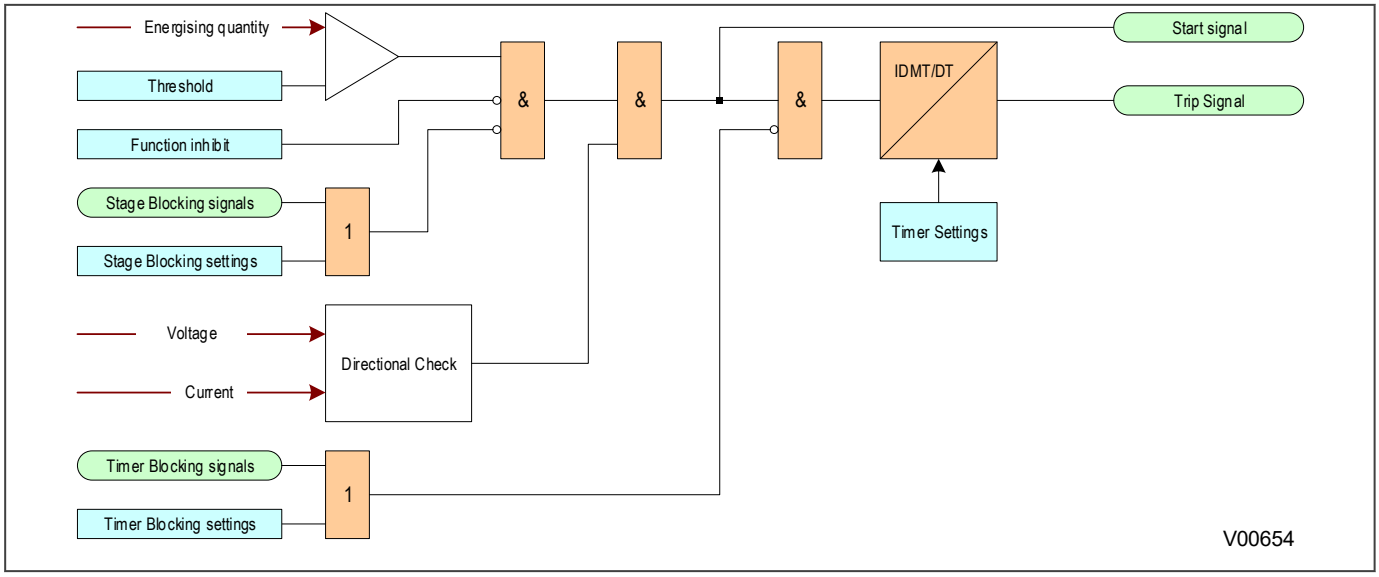


Figure 46: Principle of protection function implementation

An energising quantity is either a voltage input from a system voltage transformer, a current input from a system current transformer or another quantity derived from one or both of these. The energising quantities are extracted from the power system. The signals are converted to digital quantities where they can be processed by the IEDs internal processor.

In general, an energising quantity, be it a current, voltage, power, frequency, or phase quantity, is compared with a threshold value, which may be settable, or hard-coded depending on the function. If the quantity exceeds (for overvalues) or falls short of (for undervalues) the threshold, a signal is produced, which when gated with the various inhibit and blocking functions becomes the Start signal for that protection function. This Start signal is generally made available to Fixed Scheme Logic (FSL) and Programmable Scheme Logic (PSL) for further processing. It is also passed through a timer function to produce the Trip signal. The timer function may be an IDMT curve, or a

Definite Time delay, depending on the function. This timer may also be blocked with timer blocking signals and settings. The timer can be configured by a range of settings to define such parameters as the type of curve, The Time Multiplier Setting, the IDMT constants, the Definite Time delay etc.

In GE Vernova products, there are usually several independent stages for each of the functions, and for three-phase functions, there are usually independent stages for each of the three phases.

Typically some stages use an Inverse Definite Minimum time (IDMT) timer function, and others use a Definite Time timer (DT) function. If the DT time delay is set to '0', then the function is known to be "instantaneous". In many instances, the term 'instantaneous protection" is used loosely to describe Definite Time protection stages, even when the stage may not theoretically be instantaneous.

Many protection functions require a direction-dependent decision. Such functions can only be implemented where both current and voltage inputs are available. For such functions, a directional check is required, whose output can block the Start signal should the direction of the fault be wrong.

Note:
In the logic diagrams and descriptive text, it is usually sufficient to show only the first stage, as the design principles for subsequent stages are usually the same (or at least very similar). Where there are differences between the functionality of different stages, this is clearly indicated.

6.3.2.1 TIMER HOLD FACILITY

The Timer Hold facility is available for stages with IDMT functionality , and is controlled by the timer reset settings for the relevant stages (e.g. ***I>1 tReset***, ***I>2 tReset***). These cells are not visible for the IEEE/US curves if an inverse time reset characteristic has been selected, because in this case the reset time is determined by the time dial setting (TDS).

This feature may be useful in certain applications, such as when grading with upstream electromechanical overcurrent devices, which have inherent reset time delays. If you set the hold timer to a value other than zero, the resetting of the protection element timers will be delayed for this period. This allows the element to behave in a similar way to an electromechanical device. If you set the hold timer to zero, the overcurrent timer for that stage will reset instantaneously as soon as the current falls below a specified percentage of the current setting (typically 95%).

Another situation where the timer hold facility may be used to reduce fault clearance times is for intermittent faults. An example of this may occur in a plastic insulated cable. In this application it is possible that the fault energy melts and reseals the cable insulation, thereby extinguishing the fault. This process repeats to give a succession of fault current pulses, each of increasing duration with reducing intervals between the pulses, until the fault becomes permanent.

When the reset time is instantaneous, the device will repeatedly reset and not be able to trip until the fault becomes permanent. By using the Timer Hold facility the device will integrate the fault current pulses, thereby reducing fault clearance time.

6.4 PHASE OVERCURRENT PROTECTION

Phase current faults are faults where fault current flows between two or more phases of a power system. The fault current may be between the phase conductors only or, between two or more phase conductors and earth.

Although not as common as earth faults (single phase to earth), phase faults are typically more severe.

6.4.1 PHASE OVERCURRENT PROTECTION IMPLEMENTATION

Phase Overcurrent Protection is configured in the *OVERCURRENT* column of the relevant settings group.

Operation of each stage (n) of overcurrent protection is controlled by the ***I>(n) Status*** cell.

According to the selection made in that cell, that stage of overcurrent protection can be either:

- Permanently disabled `Disabled)`, or
- Permanently enabled `Enabled)`, or
- Enabled only in case of VT fuse/MCB failure (`Enabled VTS`)

The product provides six stages of segregated three-phase overcurrent protection, each with independent time delay characteristics. The settings are independent for each stage, but for each stage, the settings apply to all phases.

Stages 1, 2 and 3 provide a choice of operate and reset characteristics, where you can select between:

- A range of IDMT (Inverse Definite Minimum Time) curves based on IEC and IEEE standards
- A range of programmable user-defined curves
- DT (Definite Time) characteristic

For stage 1, this is achieved using the following settings:

- ***I>1 Function*** for the overcurrent operate characteristic
- ***I>1 Reset Char*** for the overcurrent reset characteristic
- ***I>1 Usr Rst Char*** for the reset characteristic for user-defined curves

The setting names for other stages follow the same principles.

The IDMT-equipped stages, (1, 2 and 3) also provide a Timer Hold facility. Stage 1 for example, is configured using the cells ***I>1 tReset***. This setting does not apply to IEEE curves.

Stages 4, 5 and 6 have definite time characteristics only.

6.4.2 NON-DIRECTIONAL OVERCURRENT LOGIC

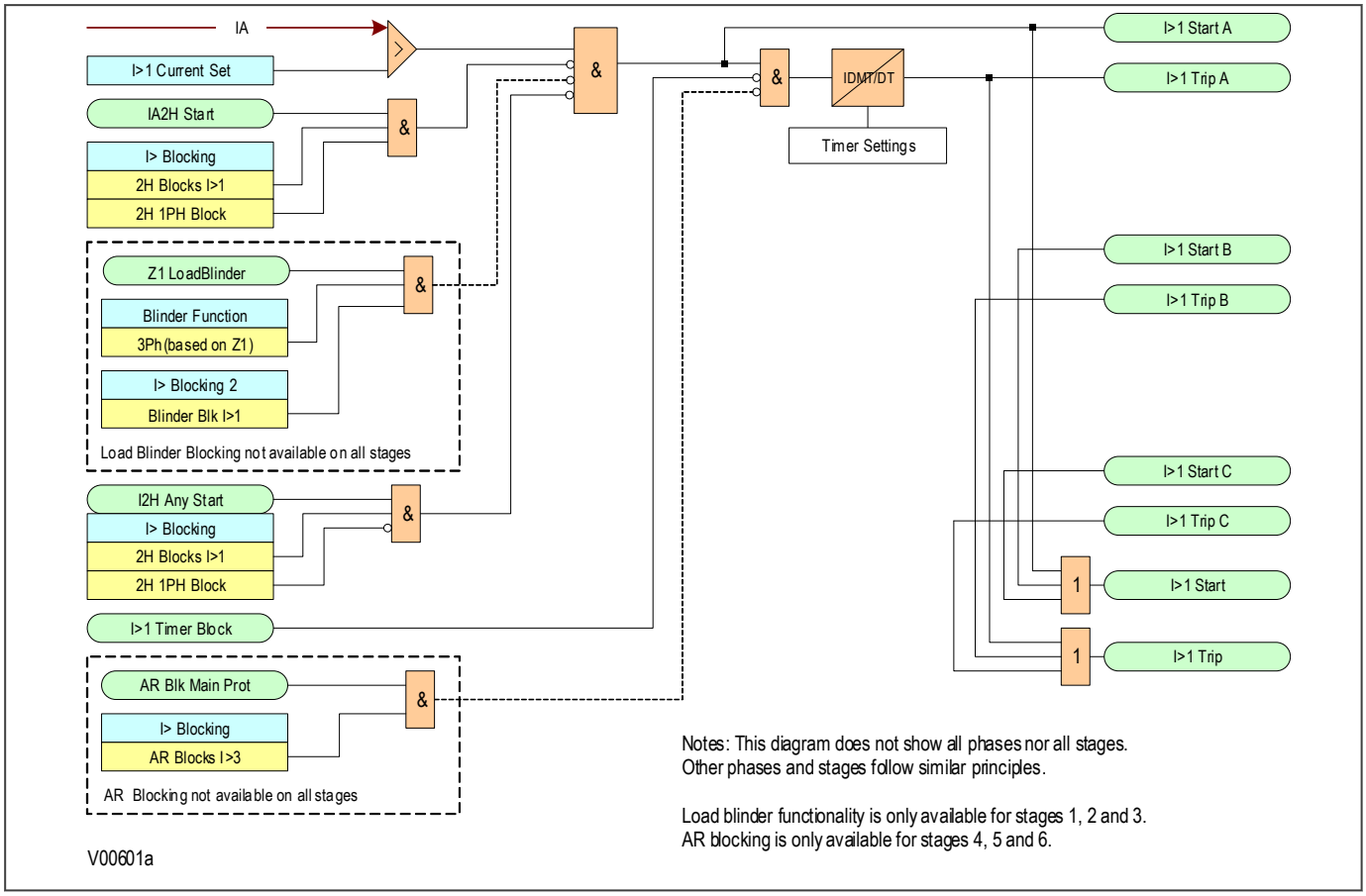


Figure 47: Non-directional overcurrent logic

Phase Overcurrent Modules are level detectors that detect when the current magnitude exceeds a set threshold. When this happens, a Start signal is generated unless it is inhibited by a blocking signal. This Start signal initiates the timer module, which can be configured as an IDMT timer or DT timer, depending on the stage number. The Start signal is also available for use in the PSL. For each stage, there are three Phase Overcurrent Modules, one for each phase. The three Start signals from each of these phases are combined to form a 3-phase Start signal.

The Start signals can be blocked by the Second Harmonic blocking function; on a per phase basis (single-phase blocking) or for all three phases at once (three-phase blocking). The relevant bits are set in the ***I> Blocking*** cell and this is combined with the relevant second harmonic blocking DDBs.

The timer can be configured with several settings depening on which type of timer is selected. Taking stage 1 as an example:

The setting ***I>1 Time Delay*** sets the DT time delay

The setting ***I>1 TMS*** sets the Time Multiplier setting for IEC IDMT curves

The setting ***I>1 Time Dial*** sets the Time Multiplier setting for IEEE/US IDMT curves

The setting ***I>1 DT Adder*** adds a fixed time delay to the IDMT operate characteristic

The setting ***I>1 tRESET*** determines the reset time for the DT characteristic

The outputs of the timer modules are the single-phase trip signals. These trip signals are combined to form a 3-phase Trip signal.

The timer modules can be blocked by a Phase Overcurrent Timer Block (for example ***I>1 Timer Block***).

For DT-only stages, the DT timer can be blocked by the Autoreclose function. An Autoreclose blocking signal is produced by the DDB signal ***AR Blk Main Prot*** and the relevant settings in the ***I> Blocking*** cell.

6.4.3 DIRECTIONAL ELEMENT

If fault current can flow in both directions through a protected location, you will need to use a directional overcurrent element to determine the direction of the fault. Once the direction has been determined the device can decide whether to allow tripping or to block tripping. To determine the direction of a phase overcurrent fault, the device must compare the phase angle of the fault current with that of a known reference quantity. The phase angle of this known reference quantity must be independent of the faulted phase. Typically this will be the line voltage between the other two phases.

The phase fault elements of the IEDs are internally polarised by the quadrature phase-phase voltages, as shown in the table below:

Phase of Protection	Operate Current	Polarising Voltage
A Phase	IA	VBC
B Phase	IB	VCA
C Phase	IC	VAB

Under system fault conditions, the fault current vector lags its nominal phase voltage by an angle depending on the system X/R ratio. The IED must therefore operate with maximum sensitivity for currents lying in this region. This is achieved by using the IED characteristic angle (RCA). This is the is the angle by which the current applied to the IED must be displaced from the voltage applied to the IED to obtain maximum sensitivity.

The device provides a setting ***I> Char Angle***, which is set globally for all overcurrent stages. It is possible to set characteristic angles anywhere in the range –95° to +95°.

A directional check is performed based on the following criteria:

Directional forward

$$-90° < (\text{angle}(I) - \text{angle}(V) - \text{RCA}) < 90°$$

Directional reverse

$$-90° > (\text{angle}(I) - \text{angle}(V) - \text{RCA}) > 90°$$

For close up three-phase faults, all three voltages will collapse to zero and no healthy phase voltages will be present. For this reason, the device includes a synchronous polarisation feature that stores the pre-fault voltage information and continues to apply this to the directional overcurrent elements for a time period of 3.2 seconds. This ensures that either instantaneous or time-delayed directional overcurrent elements will be allowed to operate, even with a three-phase voltage collapse.

6.4.3.1 DIRECTIONAL OVERCURRENT LOGIC

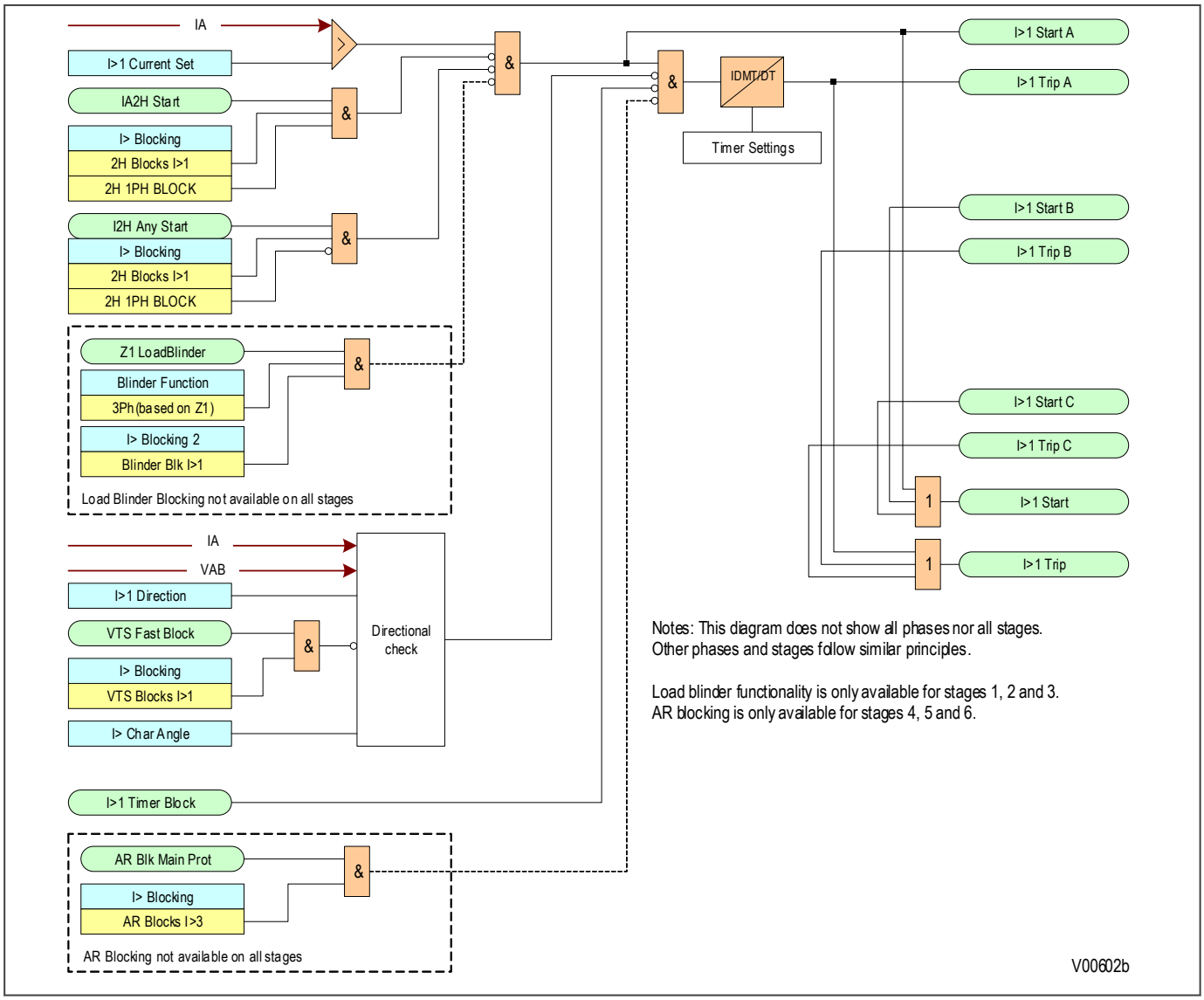


Figure 48: Directional overcurrent logic (phase A shown only)

Voltage Transformer Supervision (VTS) can be used to block operation of directional overcurrent elements.

This is achieved using the ***I>Blocking*** cell. When the relevant bit is set to 1, operation of the VTS will block the stage if directionalised. When set to 0, the stage will revert to non-directional upon operation of the VTS.

6.4.4 APPLICATION NOTES

6.4.4.1 PARALLEL FEEDERS

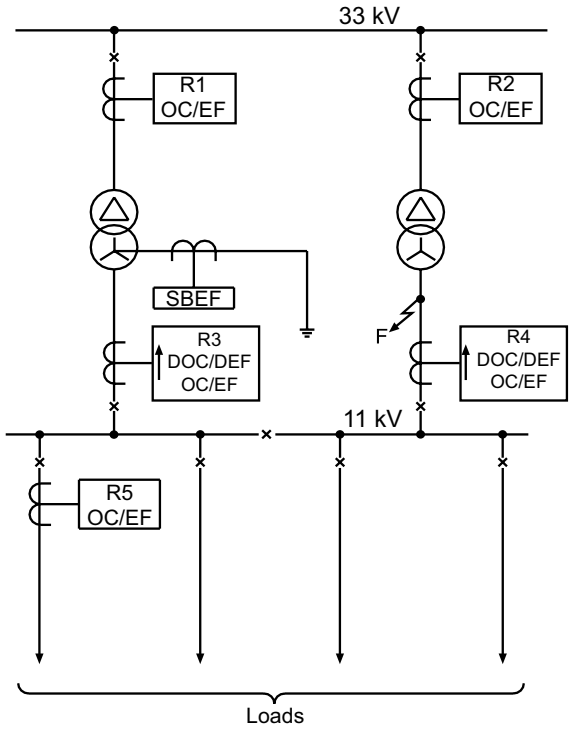


Figure 49: Typical distribution system using parallel transformers

In the application shown in the diagram, a fault at 'F' could result in the operation of both R3 and R4 resulting in the loss of supply to the 11 kV busbar. Hence, with this system configuration, it is necessary to apply directional protection devices at these locations set to 'look into' their respective transformers. These devices should co-ordinate with the non-directional devices, R1 and R2, to ensure discriminative operation during such fault conditions.

In such an application, R3 and R4 may commonly require non-directional overcurrent protection elements to provide protection to the 11 kV busbar, in addition to providing a back-up function to the overcurrent devices on the outgoing feeders (R5).

For this application, stage 1 of the R3 and R4 overcurrent protection would be set to non-directional and time graded with R5, using an appropriate time delay characteristic. Stage 2 could then be set to directional (looking back into the transformer) and also have a characteristic which provides correct co-ordination with R1 and R2. Directionality for each of the applicable overcurrent stages can be set in the directionality cells (***I>1 Direction***).

Note:
The principles outlined for the parallel transformer application are equally applicable for plain feeders that are operating in parallel.

6.4.4.2 RING MAIN ARRANGEMENTS

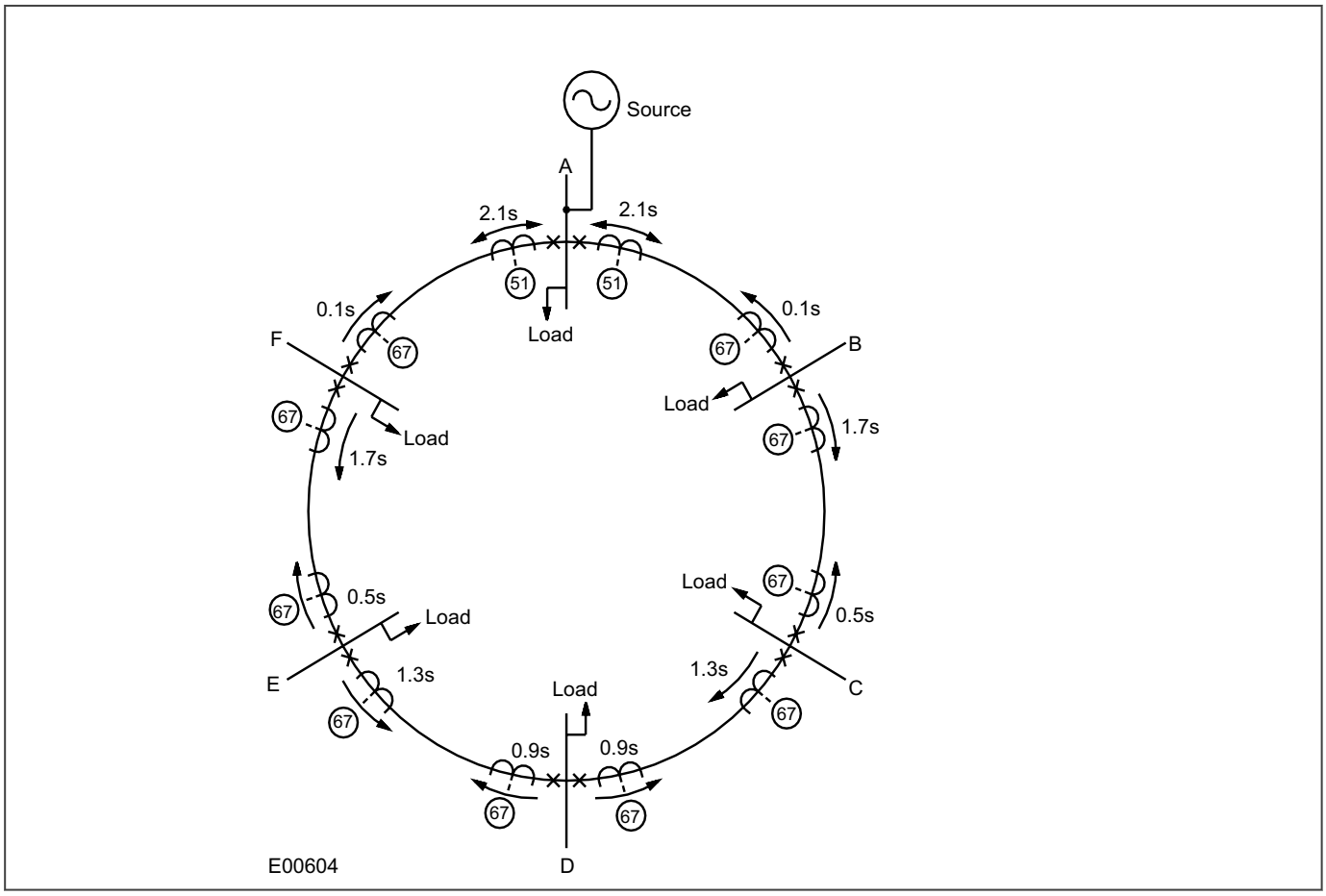


Figure 50: Typical ring main with associated overcurrent protection

In a ring main arrangement, current may flow in either direction through the various device locations, therefore directional overcurrent devices are needed to achieve correct discrimination.

The normal grading procedure for overcurrent devices protecting a ring main circuit is to consider the ring open at the supply point and to grade the devices first clockwise and then anti-clockwise. The arrows shown at the various device locations depict the direction for forward operation of the respective devices (i.e. the directional devices are set to look into the feeder that they are protecting).

The diagram shows typical time settings (assuming definite time co-ordination is used), from which it can be seen that any faults on the interconnections between stations are cleared discriminatively by the devices at each end of the feeder.

Any of the overcurrent stages may be configured to be directional and co-ordinated, but bear in mind that IDMT characteristics are not selectable on all the stages.

6.4.4.3 SETTING GUIDELINES

Standard principles should be applied in calculating the necessary current and time settings. The example detailed below shows a typical setting calculation and describes how the settings are applied.

This example is for a device feeding a LV switchboard and makes the following assumptions:

- CT Ratio = 500/1
- Full load current of circuit = 450A
- Slowest downstream protection = 100A Fuse

The current setting on the device must account for both the maximum load current and the reset ratio, therefore:

I> must be greater than: 450/drop-off = 450/0.95 = 474A.

The device allows the current settings to be applied in either primary or secondary quantities. This is done by setting the ***Setting Values*** cell of the *CONFIGURATION* column. When this cell is set to primary, all phase overcurrent setting values are scaled by the programmed CT ratio.

In this example, assuming primary currents are to be used, the ratio should be programmed as 500/1.

The required setting is therefore 0.95A in terms of secondary current or 475A in terms of primary.

A suitable time delayed characteristic will now need to be chosen. When co-ordinating with downstream fuses, the applied characteristic should be closely matched to the fuse characteristic. Therefore, assuming IDMT co-ordination is to be used, an Extremely Inverse (EI) characteristic would normally be chosen. This is found under the ***I>1 Function*** cell as *IEC E Inverse*.

Finally, a suitable time multiplier setting (TMS) must be calculated and entered in cell ***I>1 TMS*.**

6.4.4.4 SETTING GUIDELINES (DIRECTIONAL ELEMENT)

The applied current settings for directional overcurrent devices are dependent upon the application in question. In a parallel feeder arrangement, load current is always flowing in the non-operate direction. Hence, the current setting may be less than the full load rating of the circuit.

You need to observe some setting constraints when applying directional overcurrent protection at the receiving-end of parallel feeders. These minimum safe settings are designed to ensure that there is no possibility of undesired tripping during clearance of a source fault. For a linear system load, these settings are as follows:

We recommend the following settings to ensure that there is no possibility of maloperation:

- Parallel plain feeders: Set to 50% pre-fault load current
- Parallel transformer feeders: Set to 87% pre-fault load current

In a ring main application, the load current can flow in either direction. The current setting must be above the maximum load current.

The required characteristic angle settings for directional devices depend on the application. We recommend the following settings:

- Plain feeders, or applications with an earthing point behind the device location, should use a +30° RCA setting
- Transformer feeders, or applications with a zero sequence source in front of the device location, should use a +45° RCA setting

Although it is possible to set the RCA to exactly match the system fault angle, we recommend that you adhere to the above guidelines, as these settings provide satisfactory performance and stability under a wide range of system conditions.

6.5 VOLTAGE DEPENDENT OVERCURRENT ELEMENT

An overcurrent protection scheme is co-ordinated throughout a system such that cascaded operation is achieved. This means that if for some reason a downstream circuit breaker fails to trip for a fault condition, the next upstream circuit breaker should trip.

However, where long feeders are protected by overcurrent protection, the detection of remote phase-to-phase faults may prove difficult due to the fact that the current pick-up of phase overcurrent elements must be set above the maximum load current, thereby limiting the minimum sensitivity.

If the current seen by a local device for a remote fault condition is below its overcurrent setting, a voltage dependent element may be used to increase the sensitivity to such faults. As a reduction in system voltage will occur during overcurrent conditions, this may be used to enhance the sensitivity of the overcurrent protection by reducing the pick up level.

Voltage dependent overcurrent devices are often applied in generator protection applications in order to give adequate sensitivity for close up fault conditions. The fault characteristic of this protection must then co-ordinate with any of the downstream overcurrent devices that are responsive to the current decrement condition. It therefore follows that if the device is to be applied to an outgoing feeder from a generator station, the use of voltage dependent overcurrent protection in the feeder device may allow better co-ordination with the Voltage Dependent device on the generator.

6.5.1 VOLTAGE DEPENDENT OVERCURRENT PROTECTION IMPLEMENTATION

Voltage Dependent Overcurrent Protection (VDep OC) is set in the *OVERCURRENT* column of the relevant settings group, under the sub-heading *V DEPENDANT O/C*.

The function is available for stages 1, 2 and 5 of the main overcurrent element. When VDep OC is enabled, the overcurrent threshold setting is modified when the voltage falls below a set threshold.

If voltage dependant overcurrent operation is selected, the element can be set in one of two modes, voltage controlled overcurrent or voltage restrained overcurrent.

6.5.1.1 VOLTAGE CONTROLLED OVERCURRENT PROTECTION

In Voltage Controlled Operation (VCO) mode of operation, the under voltage detector is used to produce a step change in the current setting, when the voltage falls below the voltage setting ***V Dep OC V<1 Set***. The operating characteristic of the current setting when voltage controlled mode is selected is as follows:

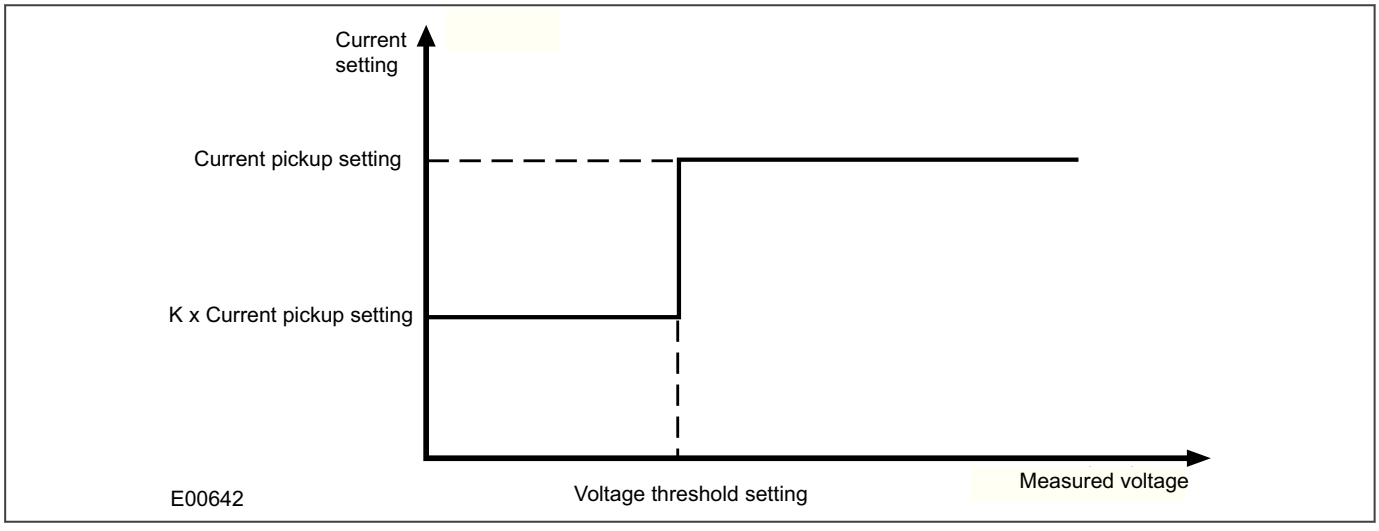


Figure 51: Modification of current pickup level for voltage controlled overcurrent protection

6.5.1.2 VOLTAGE RESTRAINED OVERCURRENT PROTECTION

In Voltage Restrained Operation (VRO) mode the effective operating current of the protection element is continuously variable as the applied voltage varies between two voltage thresholds. This protection mode is considered to be better suited to applications where the generator is connected to the system via a generator transformer.

With indirect connection of the generator, a solid phase-phase fault on the local busbar will result in only a partial phase-phase voltage collapse at the generator terminals.

The voltage-restrained current setting is related to measured voltage as follows:

- If V is greater than ***V<1***, the current setting (Is) = I>
- If V is greater than ***V<2*** but less than ***V<1***, the current setting (Is) =

$$KI> + (I> - KI)\frac{V - V<2}{V<1 - V<2}$$

- If V is less than ***V<2***, the current setting (Is) = K.I>

where:

- I> = Over current stage setting
- Is = Current setting at voltage V
- V = Voltage applied to device element
- V<1 = V Dep OC V<1 Set
- V<2 = V Dep OC V<2 Set

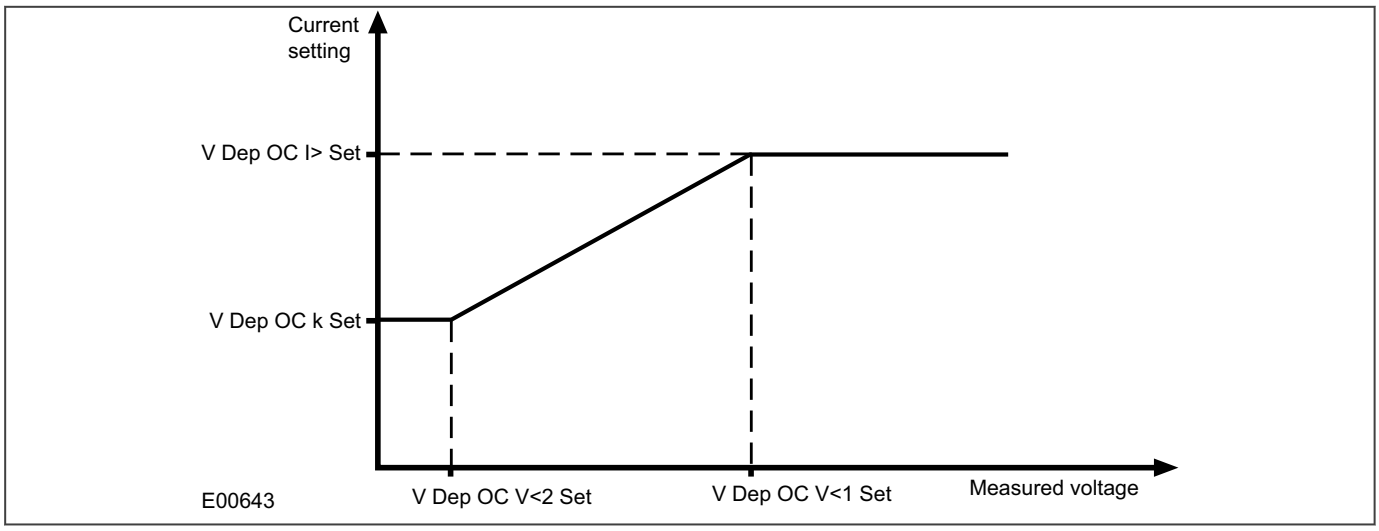


Figure 52: Modification of current pickup level for voltage restrained overcurrent protection

6.5.2 VOLTAGE DEPENDENT OVERCURRENT LOGIC

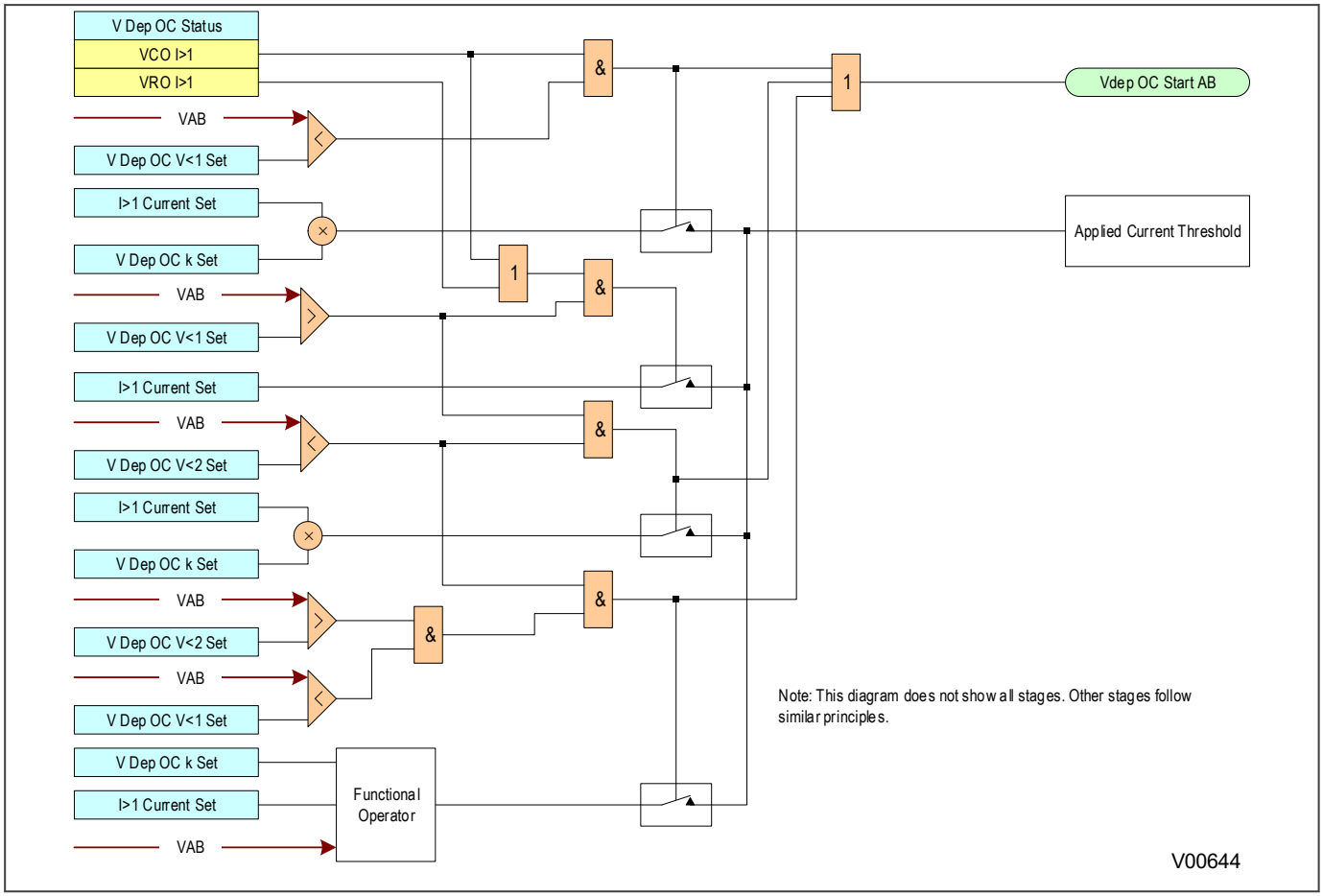


Figure 53: Voltage dependent overcurrent logic (Phase A to phase B)

The current threshold setting for the Overcurrent function is determined by the voltage.

If the voltage is greater than ***V Dep OC V<1 Set***, the normal overcurrent setting ***I>1 current set*** is used. this applies to both VCO and VRO modes.

If the voltage is less than ***V Dep OC V<1 Set*** AND it is in VCO mode, the overcurrent setting ***I>1 current set*** is multiplied by the factor set by ***V Dep OC k set***.

If the voltage is less than ***V Dep OC V<2 Set*** AND it is in VRO mode, the overcurrent setting ***I>1 current set*** is multiplied by the factor set by ***V Dep OC k set.***

If the voltage is between ***V Dep OC V<1 Set*** and ***V Dep OC V<2 Set*** AND it is in VRO mode, the overcurrent setting is multiplied by a functional operator to determine the setting.

6.5.3 APPLICATION NOTES

6.5.3.1 SETTING GUIDELINES

The ***V Dep OC k set*** setting should be set low enough to allow operation for remote phase-to-phase faults, typically:

$$k = \frac{I_F}{1.2I>}$$

where:

- I_F = Minimum fault current expected for the remote fault
- I> = Phase current setting for the element to have VCO control

Example

If the overcurrent device has a setting of 160% In, but the minimum fault current for the remote fault condition is only 80% In, then the required k factor is given by:

$$k = \frac{0.8}{1.6 \times 1.2} = 0.42$$

The voltage threshold, ***V Dep OC V<(n) Set*** setting would be set below the lowest system voltage that may occur under normal system operating conditions, whilst ensuring correct detection of the remote fault.

6.6 CURRENT SETTING THRESHOLD SELECTION

The Phase Overcurrent protection threshold setting can be influenced by the Cold Load Pickup (CLP)and the Voltage Dependent Overcurrent (V DepOC) functions, should this functionality be used.

The Overcurrent function selects the threshold setting according to the following diagram:

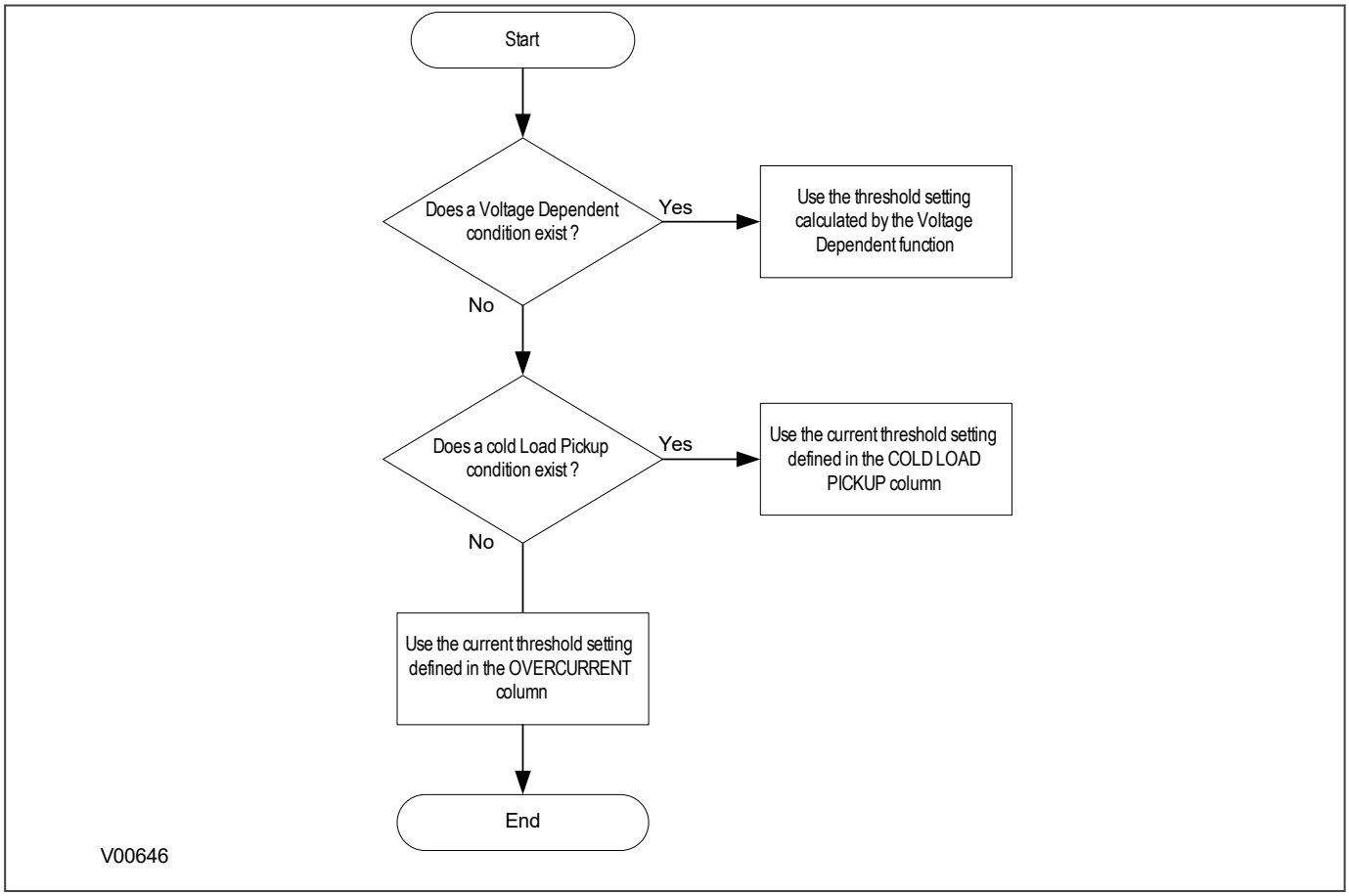


Figure 54: Selecting the current threshold setting

6.7 COLD LOAD PICKUP

When a feeder circuit breaker is closed in order to energise a load, the current levels that flow for a period of time following energisation may be far greater than the normal load levels. Consequently, overcurrent settings that have been applied to provide overcurrent protection may not be suitable during this period of energisation (cold load), as they may initiate undesired tripping of the circuit breaker. This scenario can be prevented with Cold Load Pickup (CLP) functionality.

The Cold Load Pick-Up (CLP) logic works by either:

- Blocking one or more stages of the overcurrent protection for a set duration
- Raising the overcurrent settings of selected stages, for the cold loading period.

The CLP logic therefore provides stability, whilst maintaining protection during the start-up.

6.7.1 IMPLEMENTATION

Cold Load Pickup Protection is configured in the *COLD LOAD PICKUP* column of the relevant settings group.

This function acts upon the following protection functions:

- All overcurrent stages (both non-directional and directional if applicable)
- The first stage of Earth Fault 1 (both non-directional and directional if applicable)
- The first stage of Earth Fault 2 (both non-directional and directional if applicable)

The principle of operation is identical for the 3-phase overcurrent protection and the first stages of Earth Fault overcurrent protection for both EF1 and EF2.

CLP operation occurs when the circuit breaker remains open for a time greater than ***tcold*** and is subsequently closed. CLP operation is applied after ***tcold*** and remains for a set time delay of ***tclp*** following closure of the circuit breaker. The status of the circuit breaker is provided either by means of the CB auxiliary contacts or by means of an external device via logic inputs. Whilst CLP operation is in force, the CLP settings are enabled After the time delay ***tclp*** has elapsed, the normal overcurrent settings are applied and the CLP settings are disabled.

If desired, instead of applying different current setting thresholds for the cold load time, it is also possible to completely block the overcurrrent operation during this time, for any of the overcurrent stages.

Voltage-dependent operation can also affect the overcurrent settings. If a Voltage Dependent condition arises, this takes precedence over the CLP function. If the CLP condition prevails and the Voltage Dependent function resets, the device will operate using the CLP settings. Time-delayed elements are reset to zero if they are disabled during the transitions between normal settings and CLP settings.

6.7.2 CLP LOGIC

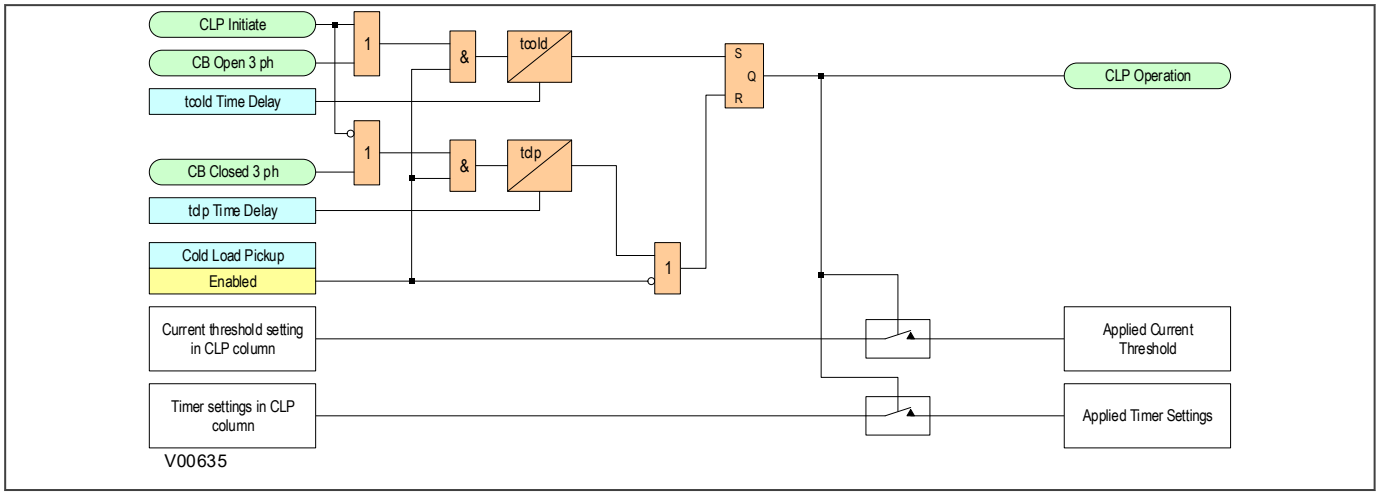


Figure 55: Cold load pickup logic

The CLP Operation signal indicates that CLP logic is in operation. This only happens when CLP is enabled AND CLP is initiated either externally or from a CB Open condition after the ***tcold*** period has elapsed. The CLP Operation indicator goes low when CLP is disabled or when the external CLP trigger is removed or when there is a CB closed condition.

tcold and ***tclp*** are initiated via the CB open and CB closed signals generated within the device. These signals are produced by connecting auxiliary contacts from the circuit breaker or starting device to the IED's opto-inputs

If dual CB contacts are not available (one for Open (52a) and for Close (52b)) you can configure the device to be driven from a single contact (either 52a or 52b). The device would then simply invert one signal to provide the other. This option is available using the ***CB status input*** cell in the *CB CONTROL* column. The setting can be set to `None`, `52a`, `52b` or `52a` and `52b`.

6.7.3 APPLICATION NOTES

6.7.3.1 CLP FOR RESISTIVE LOADS

A typical example of where CLP logic may be used is for resistive heating loads such as such as air conditioning systems. Resistive loads typically offer less resistance when cold than when warm, hence the start-up current will be higher.

To set up the CLP, you need to select `Enable` from the ***I> status*** option to enable the settings of the temporary current and time settings. These settings should be chosen in accordance with the expected load profile. Where it is not necessary to alter the setting of a particular stage, the CLP settings should be set to the same level as the standard overcurrent settings.

It may not be necessary to alter the protection settings following a short supply interruption. In this case a suitable ***tcold*** timer setting can be used.

6.7.3.2 CLP FOR MOTOR FEEDERS

In general, a dedicated motor protection device would protect feeders supplying motor loads. However, if CLP logic is available in a feeder device, this may be used to modify the overcurrent settings during start-up.

Depending on the magnitude and duration of the motor starting current, it may be sufficient to simply block operation of instantaneous elements. If the start duration is long, the time-delayed protection settings may also need to be raised. A combination of both blocking and raising of the overcurrent settings may be adopted. The CLP overcurrent settings in this case must be chosen with regard to the motor starting characteristic.

This may be useful where instantaneous earth fault protection needs to be applied to the motor. During motor start-up conditions, it is likely that incorrect operation of the earth fault element would occur due to asymmetric CT saturation. This is due to the high level of starting current causing saturation of one or more of the line CTs feeding the overcurrent/earth fault protection. The resultant transient imbalance in the secondary line current quantities is therefore detected by the residually connected earth fault element. For this reason, it is normal to either apply a nominal time delay to the element, or to use a series stabilising resistor.

The CLP logic may be used to allow reduced operating times or current settings to be applied to the earth fault element under normal running conditions. These settings could then be raised prior to motor starting, by means of the logic.

6.7.3.3 CLP FOR SWITCH ONTO FAULT CONDITIONS

In some feeder applications, fast tripping may be required if a fault is already present on the feeder when it is energised. Such faults may be due to a fault condition not having been removed from the feeder, or due to earthing clamps having been left on following maintenance. In either case, it is desirable to clear the fault condition quickly, rather than waiting for the time delay imposed by IDMT overcurrent protection.

The CLP logic can cater for this situation. Selected overcurrent/earth fault stages could be set to instantaneous operation for a defined period following circuit breaker closure (typically 200 ms). Therefore, instantaneous fault clearance would be achieved for a switch onto fault (SOTF) condition.

6.8 SELECTIVE LOGIC

With Selective Logic you can use the Start signals to control the time delays of upstream IEDs, as an alternative to simply blocking them. This provides an alternative approach to achieving non-cascading types of overcurrent scheme.

6.8.1 SELECTIVE LOGIC IMPLEMENTATION

Selective Logic is set in the *SELECTIVE LOGIC* column of the relevant settings group.

The Selective Logic function works by temporarily increasing the time delay settings of the chosen overcurrent elements. This logic is initiated by issuing signals to an upstream IED.

This function acts on the following protection functions:

- Non-Directional/Directional phase overcurrent (4th, 5th and 6th stages)
- Non-Directional/Directional earth fault - 1 (3rd and 4th stages)
- Non-Directional/Directional earth fault - 2 (3rd and 4th stages)
- Non-Directional/Directional sensitive earth fault (3rd and 4th stages)

Note:
In the event of a conflict between Selective Logic and CLP, Selective Logic takes precedence.

6.8.2 SELECTIVE LOGIC DIAGRAM

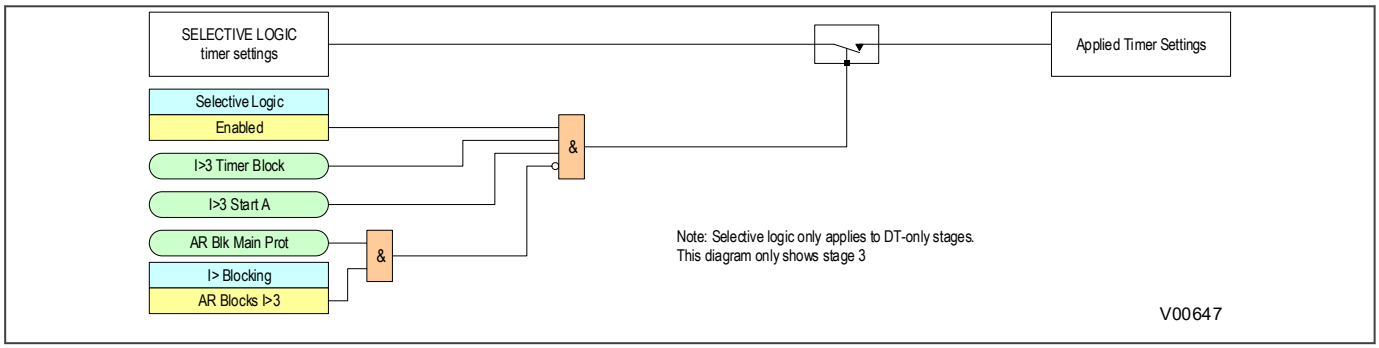


Figure 56: Selective logic

The logic diagram is shown for overcurrent phase A, but is valid for all three phases for each of the stages. The principle of operation is also identical for earth fault protection.

When the selective logic function is enabled, the action of the blocking input is as follows:

No block applied

In the event of a fault condition that continuously asserts the start output, the function will assert a trip signal after the normal time delay has elapsed.

Logic input block applied

In the event of a fault condition that continuously asserts the start output, the function will assert a trip signal after the selective logic time delay has elapsed.

Auto-reclose input block applied

In the event of a fault condition that continuously asserts the start output, when an auto-reclose block is applied the function will not trip. The auto-reclose block also overrides the logic input block and will block the selective logic timer.

> *Note:*
> *The Auto-reclose function outputs two signals that block protection, namely;* ***AR Blk Main Prot*** *and* ***AR Blk SEF Prot****.*

AR Blk Main Prot is common to Phase Overcurrent, Earth Fault 1 and Earth Fault 2, whereas ***AR Blk SEF Prot*** is used for SEF protection.

6.9 TIMER SETTING SELECTION

The timer settings used depend on whether there is a Selective Overcurrent condition or a Cold Load Pickup condition (if this functionality is used). The protection function selects the settings according to the following flow diagram:

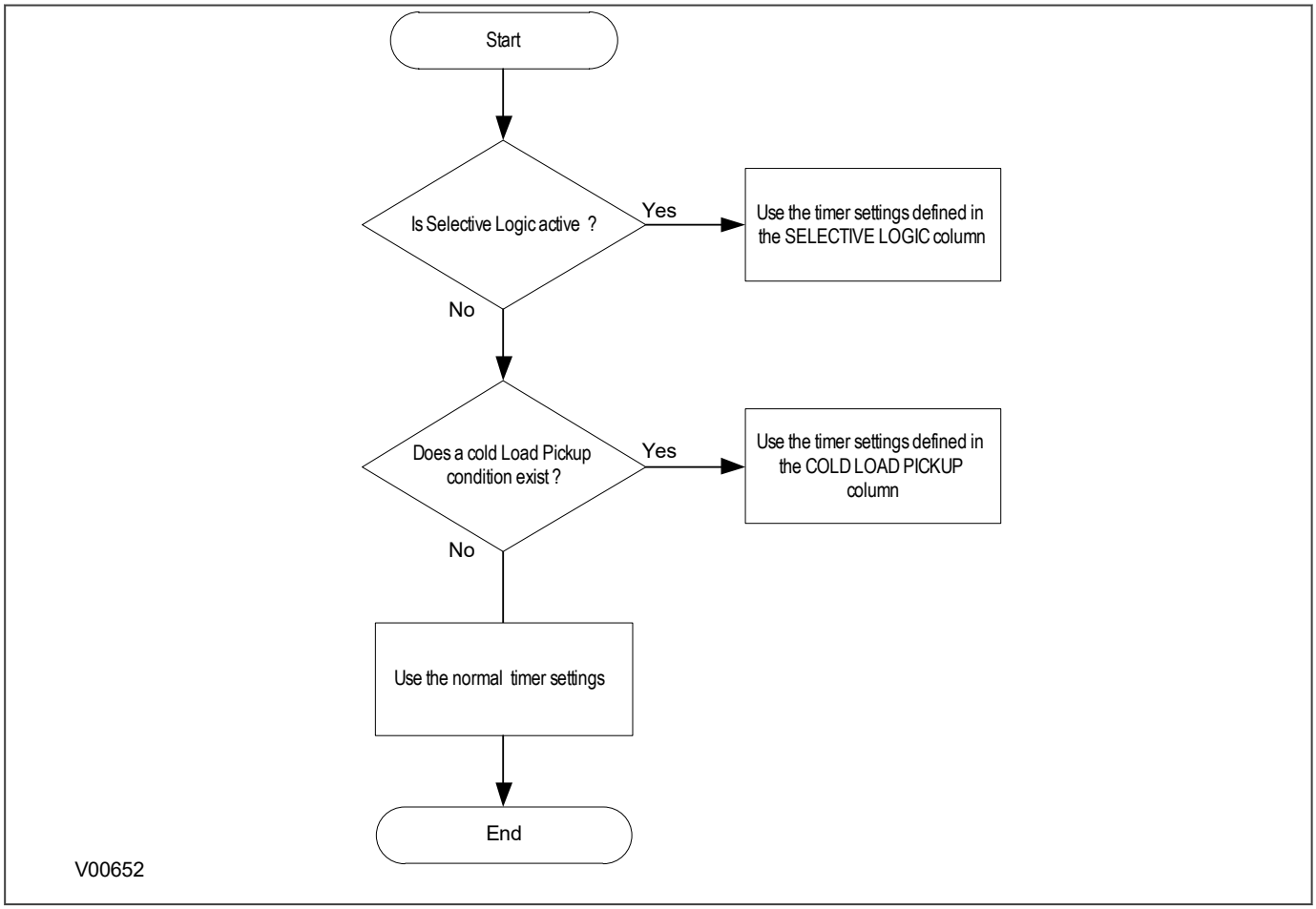


Figure 57: Selecting the timer settings

6.10 NEGATIVE SEQUENCE OVERCURRENT PROTECTION

When applying standard phase overcurrent protection, the overcurrent elements must be set significantly higher than the maximum load current. This limits the element's sensitivity. Most protection schemes also use an earth fault element operating from residual current, which improves sensitivity for earth faults. However, certain faults may arise which can remain undetected by such schemes. Negative Phase Sequence Overcurrent elements can help in such cases.

Any unbalanced fault condition will produce a negative sequence current component. Therefore, a negative phase sequence overcurrent element can be used for both phase-to-phase and phase-to-earth faults. Negative Phase Sequence Overcurrent protection offers the following advantages:

- Negative phase sequence overcurrent elements are more sensitive to resistive phase-to-phase faults, where phase overcurrent elements may not operate.
- In certain applications, residual current may not be detected by an earth fault element due to the system configuration. For example, an earth fault element applied on the delta side of a delta-star transformer is unable to detect earth faults on the star side. However, negative sequence current will be present on both sides of the transformer for any fault condition, irrespective of the transformer configuration. Therefore, a negative phase sequence overcurrent element may be used to provide time-delayed back-up protection for any uncleared asymmetrical faults downstream.

6.10.1 NEGATIVE SEQUENCE OVERCURRENT PROTECTION IMPLEMENTATION

Negative Sequence Overcurrent Protection is implemented in the *NEG SEQ O/C* column of the relevant settings group.

The product provides four stages of negative sequence overcurrent protection with independent time delay characteristics.

Stages 1, 2 provide a choice of operate and reset characteristics, where you can select between:

- A range of standard IDMT (Inverse Definite Minimum Time) curves
- A range of User-defined curves
- DT (Definite Time)

For stage 1, this is achieved using the following settings:

- ***I2>1 Function*** for the overcurrent operate characteristic
- ***I2>1 Reset Char*** for the overcurrent reset characteristic
- ***I2>1 Usr RstChar*** for the reset characteristic for user-defined curves

The setting names for other stages follow the same principles.

The IDMT-equipped stages, (1 and 2) also provide a Timer Hold facility. Stage 1, for example, is configured using the cells ***I2>1 tRESET***. This setting is not applicable for curves based on the IEEE standard.

Stages 3 and 4 have definite time characteristics only.

6.10.2 NON-DIRECTIONAL NEGATIVE SEQUENCE OVERCURRENT LOGIC

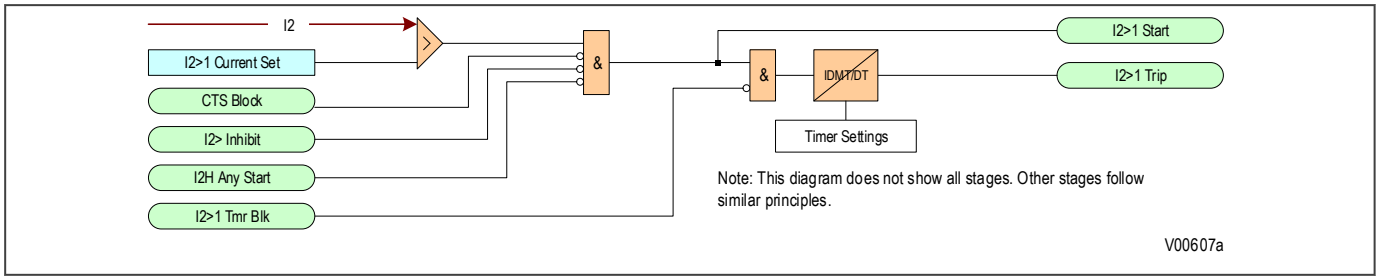


Figure 58: Negative sequence overcurrent logic - non-directional operation

For Negative Phase Sequence Overcurrent Protection, the energising quanitity ***I2>*** is compared with the threshold voltage ***I2>1 Current Set***. If the value exceeds this setting a Start signal (***I2>1 Start***) is generated, provided there are no blocks.

The function is blocked if a CTS condition is detected.

The ***I2>1 Start*** signal is fed into a timer to produce the ***I2>1 trip*** signal. The timer can be blocked by the timer block signal ***I2>1 Tmr Blk***.

This diagram and description applies to each stage.

6.10.3 DIRECTIONAL ELEMENT

Where negative phase sequence current may flow in either direction, directional control should be used.

Directionality is achieved by comparing the angle between the negative phase sequence voltage and the negative phase sequence current. A directional element is available for all of the negative sequence overcurrent stages. This is found in the ***I2> Direction*** cell for the relevant stage. It can be set to non-directional, directional forward, or directional reverse.

A suitable characteristic angle setting (***I2> Char Angle***) is chosen to provide optimum performance. This setting should be set equal to the phase angle of the negative sequence current with respect to the inverted negative sequence voltage (**–V2**), in order to be at the centre of the directional characteristic.

6.10.3.1 DIRECTIONAL NEGATIVE SEQUENCE OVERCURRENT LOGIC

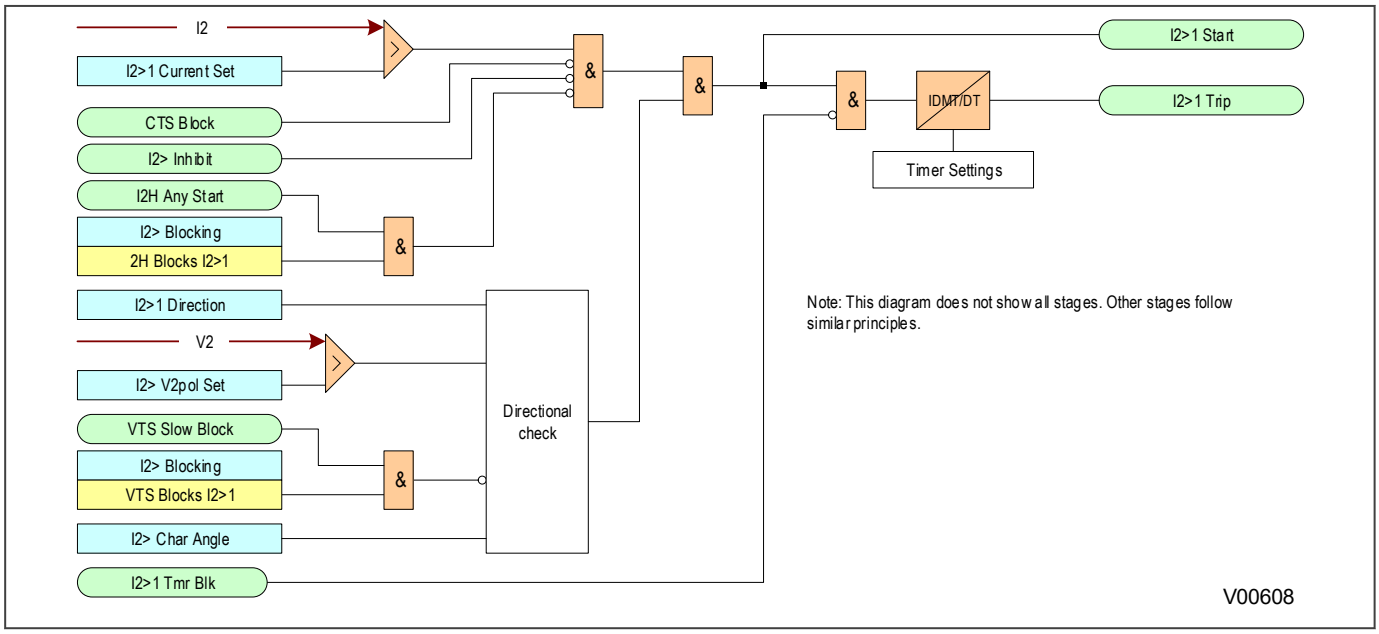


Figure 59: Negative sequence overcurrent logic - directional operation

Directionality is achieved by comparing the angle between the negative phase sequence voltage and the negative phase sequence current. The element may be selected to operate in either the forward or reverse direction. A suitable characteristic angle setting (***I2> Char Angle***) is chosen to provide optimum performance. This setting should be set equal to the phase angle of the negative sequence current with respect to the inverted negative sequence voltage (–V2), in order to be at the centre of the directional characteristic.

For the negative phase sequence directional elements to operate, the device must detect a polarising voltage above a minimum threshold, ***I2> V2pol Set***. This must be set in excess of any steady state negative phase sequence voltage. This may be determined during the commissioning stage by viewing the negative phase sequence measurements in the device.

When the element is selected as directional (directional devices only), a VTS Block option is available. When the relevant bit is set to 1, operation of the Voltage Transformer Supervision (VTS) will block the stage. When set to 0, the stage will revert to non-directional.

6.10.4 APPLICATION NOTES

6.10.4.1 SETTING GUIDELINES (CURRENT THRESHOLD)

A negative phase sequence element can be connected in the primary supply to the transformer and set as sensitively as required to protect for secondary phase-to-earth or phase-to-phase faults. This function will also provide better protection than the phase overcurrent function for internal transformer faults. The NPS overcurrent protection should be set to coordinate with the low-side phase and earth elements for phase-to-earth and phase-to-phase faults.

The current pick-up threshold must be set higher than the negative phase sequence current due to the maximum normal load imbalance. This can be set practically at the commissioning stage, making use of the measurement function to display the standing negative phase sequence current. The setting should be at least 20% above this figure.

Where the negative phase sequence element needs to operate for specific uncleared asymmetric faults, a precise threshold setting would have to be based on an individual fault analysis for that particular system due to the complexities involved. However, to ensure operation of the protection, the current pick-up setting must be set

approximately 20% below the lowest calculated negative phase sequence fault current contribution to a specific remote fault condition.

6.10.4.2 SETTING GUIDELINES (TIME DELAY)

Correct setting of the time delay for this function is vital. You should also be very aware that this element is applied primarily to provide back-up protection to other protection devices or to provide an alarm. It would therefore normally have a long time delay.

The time delay set must be greater than the operating time of any other protection device (at minimum fault level) that may respond to unbalanced faults such as phase overcurrent elements and earth fault elements.

6.10.4.3 SETTING GUIDELINES (DIRECTIONAL ELEMENT)

Where negative phase sequence current may flow in either direction through an IED location, such as parallel lines or ring main systems, directional control of the element should be employed (VT models only).

Directionality is achieved by comparing the angle between the negative phase sequence voltage and the negative phase sequence current and the element may be selected to operate in either the forward or reverse direction. A suitable relay characteristic angle setting (***I2> Char Angle***) is chosen to provide optimum performance. This setting should be set equal to the phase angle of the negative sequence current with respect to the inverted negative sequence voltage (–V2), in order to be at the centre of the directional characteristic.

The angle that occurs between V2 and I2 under fault conditions is directly dependent on the negative sequence source impedance of the system. However, typical settings for the element are as follows:

- For a transmission system the relay characteristic angle (RCA) should be set equal to –60°
- For a distribution system the relay characteristic angle (RCA) should be set equal to –45°

For the negative phase sequence directional elements to operate, the device must detect a polarising voltage above a minimum threshold, ***I2> V2pol Set***. This must be set in excess of any steady state negative phase sequence voltage. This may be determined during the commissioning stage by viewing the negative phase sequence measurements in the device.

6.11 EARTH FAULT PROTECTION

Earth faults are overcurrent faults where the fault current flows to earth. Earth faults are the most common type of fault.

Earth faults can be measured directly from the system by means of:

- A separate current Transformer (CT) located in a power system earth connection
- A separate Core Balance Current Transformer (CBCT), usually connected to the SEF transformer input
- A residual connection of the three line CTs, where the Earth faults can be derived mathematically by summing the three measured phase currents

Depending on the device model, it will provide one or more of the above means for Earth fault protection.

6.11.1 EARTH FAULT PROTECTION ELEMENTS

Earth fault protection is implemented in the columns *EARTH FAULT 1* and *EARTH FAULT 2* of the relevant settings group.

Each column contains an identical set of elements. *EARTH FAULT 1* (EF1) and *EARTH FAULT 2* (EF2) are used for earth fault current that is measured directly from the system (measured) and derived internally from summing the three-phase currents.

The product provides four stages of Earth Fault protection with independent time delay characteristics, for each *EARTH FAULT* column.

Each stage can be either:

- Permanently disabled (`Disabled`), or
- Permanently enabled (`Enabled`), or
- Enabled only in case of VT fuse/MCB failure (`Enabled VTS`)

Stages 1 and 2 provide a choice of operate and reset characteristics, where you can select between:

- A range of IDMT (Inverse Definite Minimum Time) curves
- A range of User-defined curves
- DT (Definite Time)

For the EF1 column, this is achieved using the cells:

- ***IN1>(n) Status*** to enable/disable the stage
- ***IN1>(n) Function*** for the overcurrent operate characteristics
- ***IN1>(n) Reset Char*** for the overcurrent reset characteristic
- ***IN1>(n) Usr RstChar*** for the reset characteristic for user-defined curves

For the EF2 column, this is achieved using the cells:

- ***IN2>(n) Status*** to enable/disable the stage
- ***IN2>(n) Function*** for the overcurrent operate characteristics
- ***IN2>(n) Reset Char*** for the overcurrent reset characteristic
- ***IN2>(n) Usr RstChar*** for the reset characteristic for user-defined curves

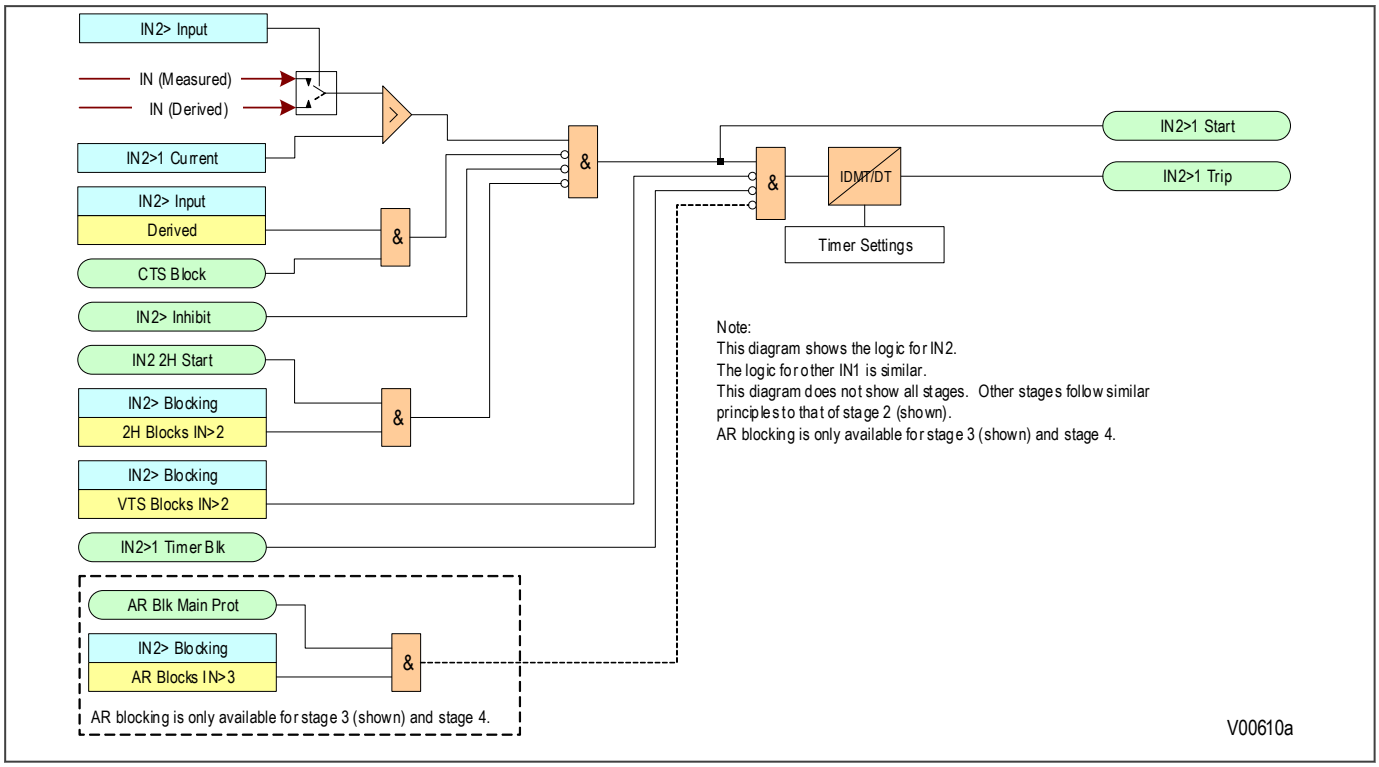
where (n) is the number of the stage.

Stages 1 and 2 provide a Timer Hold facility. This is configured using the cells ***IN1>(n) tReset*** for EF1 and ***IN2>(n) tReset*** for EF2.

Stages 3 and 4 can have definite time characteristics only.

The fact that both EF1 and EF2 elements may be enabled at the same time leads to a number of applications advantages. For example, some applications may require directional earth fault protection for upstream equipment and backup earth fault protection for downstream equipment. This can be achieved with a single IED, rather than two.

6.11.2 NON-DIRECTIONAL EARTH FAULT LOGIC



Note:
1 If a CLP condition exists, the **I>(n) Current Set threshold is taken from the COLD LOAD PICKUP column*
**2 Autoreclose blocking is only available for stages 3,4 and 6 and on selected models*
**3 The CTS blocking is not applicable for IN1, however this can be achieved using the PSL*

Figure 60: Non-directional EF logic (single stage)

The Earth Fault current is compared with a set threshold (***IN1>(n) Current***) for each stage. If it exceeds this threshold, a Start signal is triggered, providing it is not blocked. This can be blocked by the second harmonic blocking function, or an Inhibit Earth Fault DDB signal.

The autoreclose logic can be set to block the Earth Fault trip after a prescribed number of shots (set in *AUTORECLOSE* column). This is achieved using the ***AR Blk Main Prot*** setting. this can also be blocked by the relevant timer block signal ***IN1>(n)TimerBlk*** DDB signal.

Earth Fault protection can follow the same IDMT characteristics as described in the Overcurrent Protection Principles section. Please refer to that section for details of IDMT characteristics.

The diagram and description also applies to the Earth Fault 2 element (IN2).

6.11.3 IDG CURVE

The IDG curve is commonly used for time delayed earth fault protection in the Swedish market. This curve is available in stage 1 of the Earth Fault protection.

The IDG curve is represented by the following equation:

$$t_{op} = 5.8 - 1.35 log_e \left(\frac{I}{IN > Setting} \right)$$

where:

t_{op} is the operating time

I is the measured current

IN> Setting is an adjustable setting, which defines the start point of the characteristic

Note:
Although the start point of the characteristic is defined by the "IN>" setting, the actual current threshold is a different setting called "IDG Is". The "IDG Is" setting is set as a multiple of "IN>".

Note:
When using an IDG Operate characteristic, DT is always used with a value of zero for the Rest characteristic.

An additional setting "IDG Time" is also used to set the minimum operating time at high levels of fault current.

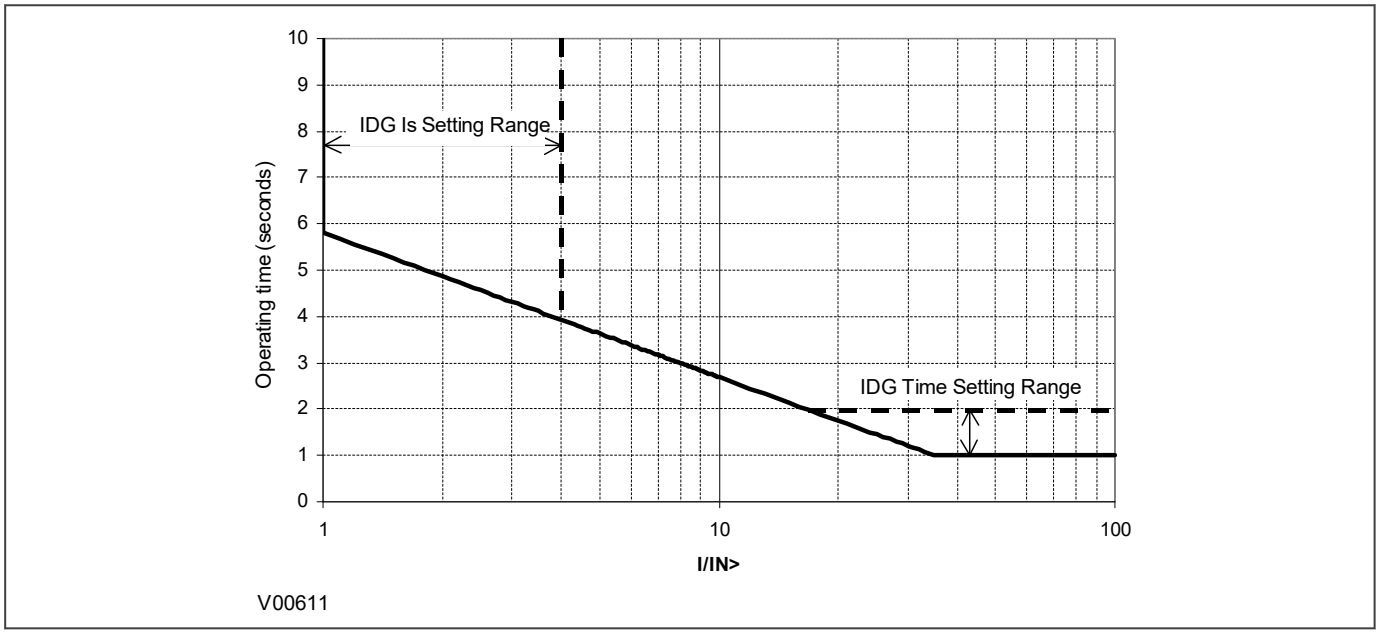


Figure 61: IDG characteristic

6.11.4 DIRECTIONAL ELEMENT

If Earth fault current can flow in both directions through a protected location, you will need to use a directional overcurrent element to determine the direction of the fault. Typical systems that require such protection are parallel feeders and ring main systems.

A directional element is available for all of the Earth Fault stages. These are found in the direction setting cells for the relevant stage. They can be set to non-directional, directional forward, or directional reverse.

Directional control can be blocked by the VTS element if required.

For standard earth fault protection, two options are available for polarisation; Residual Voltage (zero sequence) or Negative Sequence.

6.11.4.1 RESIDUAL VOLTAGE POLARISATION

With earth fault protection, the polarising signal needs to be representative of the earth fault condition. As residual voltage is generated during earth fault conditions, this quantity is commonly used to polarise directional earth fault elements. This is known as Zero Sequence Voltage polarisation, Residual Voltage polarisation or Neutral Displacement Voltage (NVD) polarisation.

Small levels of residual voltage could be present under normal system conditions due to system imbalances, VT inaccuracies, device tolerances etc. For this reason, the device includes a user settable threshold (***IN> VNPol set***), which must be exceeded in order for the DEF function to become operational. The residual voltage measurement provided in the *MEASUREMENTS 1* column of the menu may assist in determining the required threshold setting during the commissioning stage, as this will indicate the level of standing residual voltage present.

Note:
Residual voltage is nominally 180° out of phase with residual current. Consequently, the DEF elements are polarised from the "-Vres" quantity. This 180° phase shift is automatically introduced within the device.

The directional criteria with residual voltage polarisation is given below:

- Directional forward: -90° < (angle(IN) - angle(VN + 180°) - RCA) < 90°
- Directional reverse : -90° > (angle(IN) - angle(VN + 180°) - RCA) > 90°

Most of the models derive the Residual Voltage quantity internally, from the 3-phase voltage input supplied from either a 5-limb VT or three single-phase VTs.

A 5-limb VT or three single-phase VTs allow the passage of residual flux and consequently allows the device to derive the required residual voltage. The primary star point of the VT must be earthed. A three-limb VT has no path for residual flux and is therefore unsuitable to supply the device.

6.11.4.1.1 DIRECTIONAL EARTH FAULT LOGIC WITH RESIDUAL VOLTAGE POLARISATION

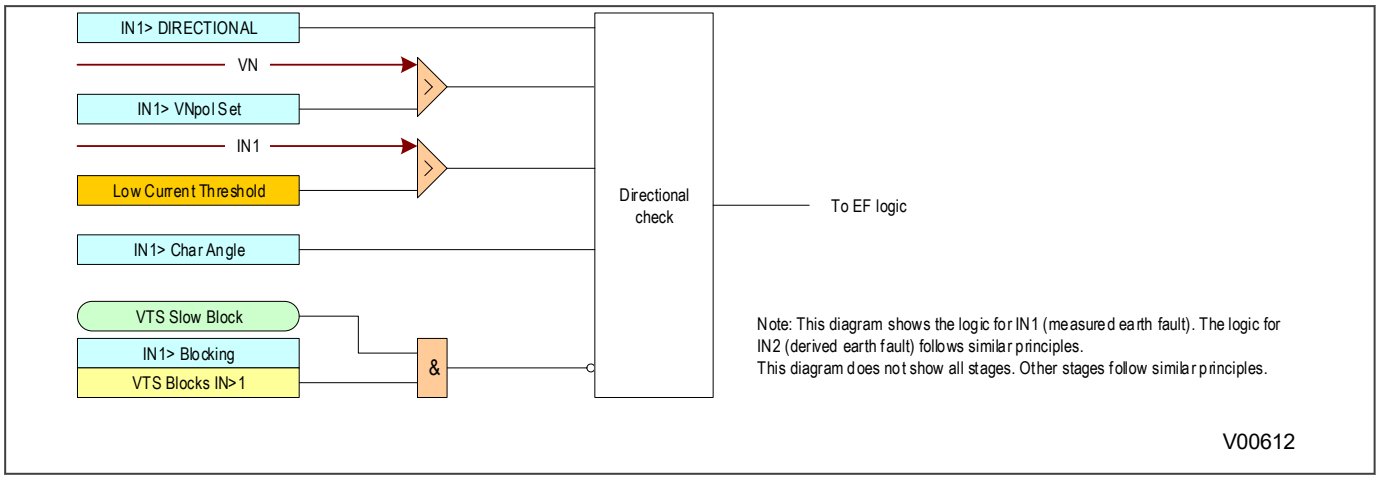


Figure 62: Directional EF logic with neutral voltage polarisation (single stage)

Voltage Transformer Supervision (VTS) selectively blocks the directional protection or causes it to revert to non-directional operation. When selected to block the directional protection, VTS blocking is applied to the directional checking which effectively blocks the Start outputs as well.

6.11.4.2 NEGATIVE SEQUENCE POLARISATION

In some applications, the use of residual voltage polarisation may not be possible to achieve or it can be problematic. For example, a suitable type of VT may be unavailable, or an HV/EHV parallel line application may present problems with zero sequence mutual coupling.

In such situations, the problem may be solved by using Negative Phase Sequence (NPS) quantities for polarisation. This method determines the fault direction by comparing the NPS voltage with the NPS current. The operating quantity, however, is still residual current.

This can be used for both the derived and measured standard earth fault elements. It requires a suitable voltage and current threshold to be set in cells ***IN> V2pol set*** and ***IN> I2pol set*** respectively.

Negative phase sequence polarising is not recommended for impedance earthed systems regardless of the type of VT feeding the device. This is due to the reduced earth fault current limiting the voltage drop across the negative sequence source impedance to negligible levels. If this voltage is less than 0.5 volts the device will stop providing directionalisation.

The directional criteria with negative sequence polarisation is given below:

- Directional forward: -90° < (angle(I2) - angle(V2 + 180°) - RCA) < 90°
- Directional reverse : -90° > (angle(I2) - angle(V2 + 180°) - RCA) > 90°

6.11.4.2.1 DIRECTIONAL EARTH FAULT LOGIC WITH NPS POLARISATION

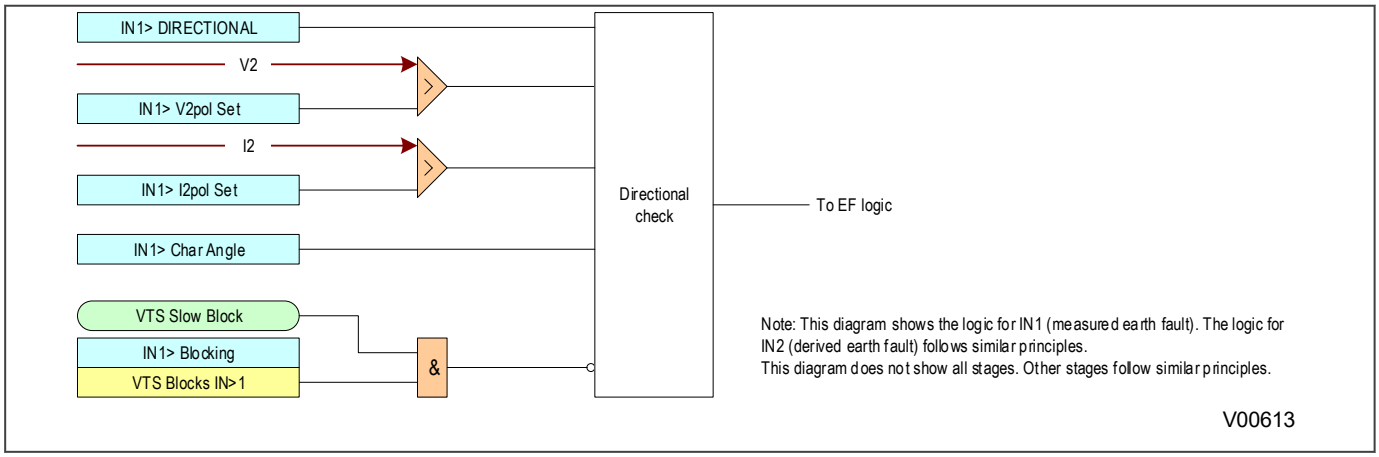


Figure 63: Directional earth fault logic with negative sequence polarisation (single stage)

Voltage Transformer Supervision (VTS) selectively blocks the directional protection or causes it to revert to non-directional operation. When selected to block the directional protection, VTS blocking is applied to the directional checking which effectively blocks the Start outputs as well.

6.11.5 APPLICATION NOTES

6.11.5.1 SETTING GUIDELINES (DIRECTIONAL ELEMENT)

With directional earth faults, the residual current under fault conditions lies at an angle lagging the polarising voltage. Hence, negative RCA settings are required for DEF applications. This is set in the cell ***I> Char Angle*** in the relevant earth fault menu.

We recommend the following RCA settings:

- Resistance earthed systems: 0°
- Distribution systems (solidly earthed): -45°
- Transmission systems (solidly earthed): -60°

6.11.5.2 PETERSEN COIL EARTHED SYSTEMS

A Petersen Coil earthing system is used in compensated earthing systems, as well as being used in cases of high impedance earthing. Petersen Coil earthed systems (also called compensated or resonant systems) are commonly found in areas where the system consists mainly of rural overhead lines. They are particularly beneficial in locations

which are subject to a high incidence of transient faults. In a Petersen Coil earthed system, the network is earthed via a reactor, whose reactance is tuned to be nominally equal to the total system capacitance to earth. Similar to insulated systems, if a single-phase to earth fault is applied to a Petersen Coil earthed system, under steady state conditions no earth fault current flows. The effectiveness of the method in reducing the current to zero is dependent on the accuracy of the tuning of the reactance value and any changes in system capacitance (for example due to system configuration changes) require changes to the coil reactance. In practice, perfect matching of the coil reactance to the system capacitance is difficult to achieve, so that a small earth fault current will flow.

In isolated and compensated earthed systems, if an earth fault current is below a certain level, then the fault will self-extinguish due to the low current magnitude. It therefore appears as a transient phenomenon. The figure below shows earth fault current levels, below which they self-extinguish on these types of system. Statistics demonstrate that around 80% of earth faults in Petersen Coil earthed systems self-extinguish. This, in part, explains their popularity.

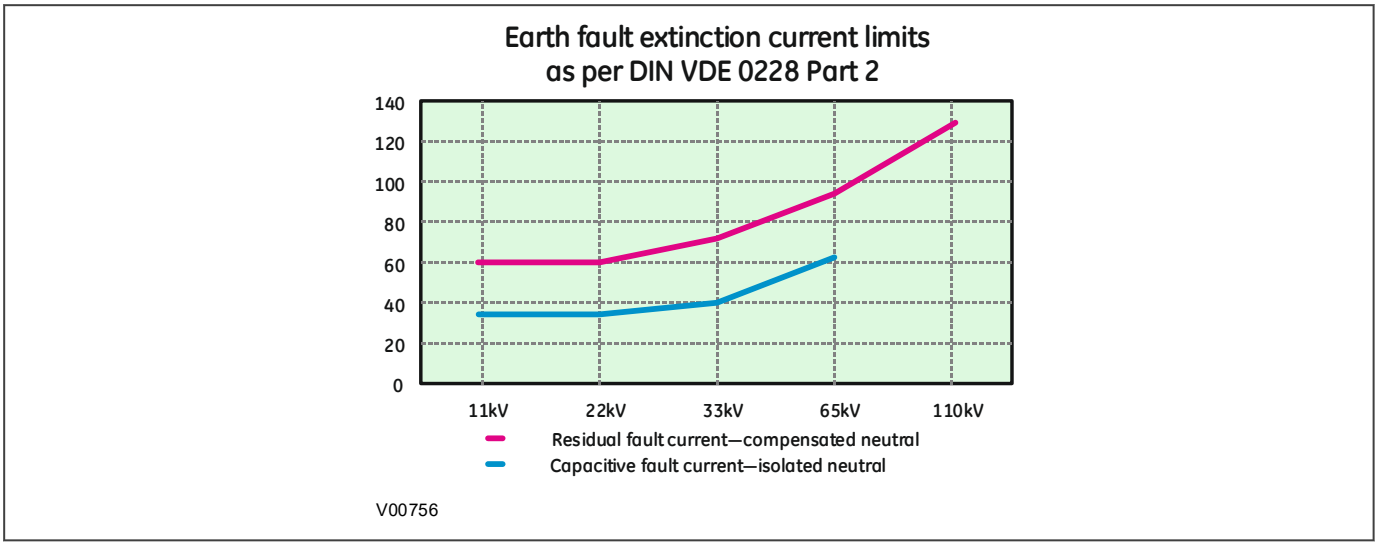


Figure 64: Current level (amps) at which transient faults are self-extinguishing

The following figure depicts a simple network earthed through a Petersen Coil reactance. It can be shown that if the reactor is correctly tuned, theoretically no earth fault current will flow.

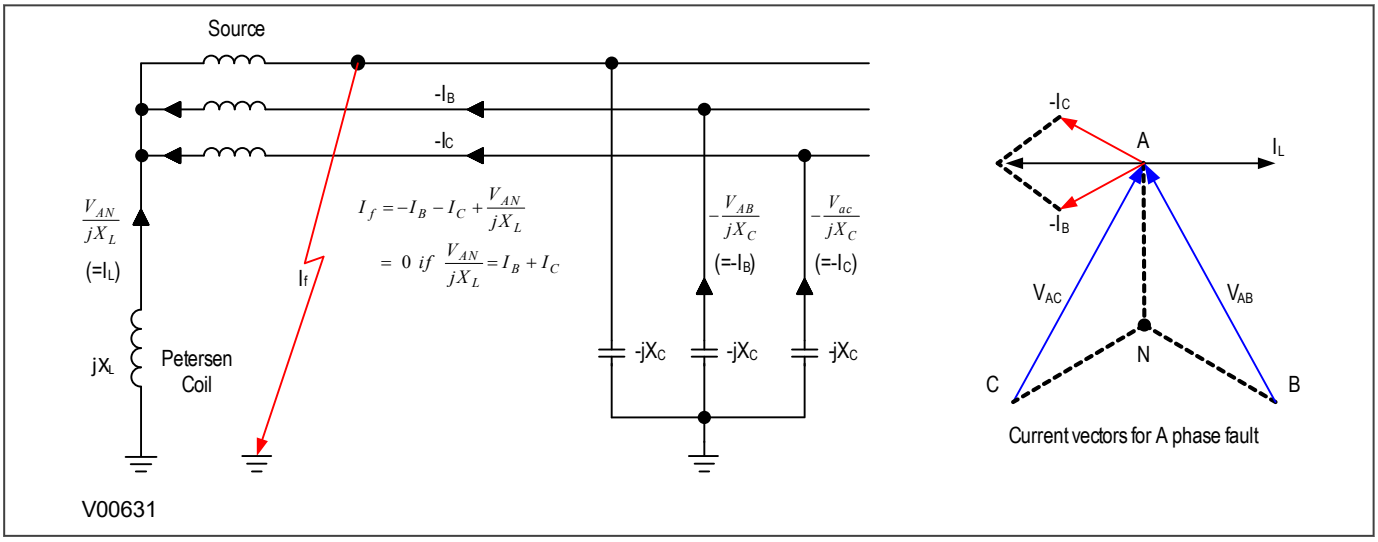


Figure 65: Earth fault in Petersen Coil earthed system

Consider a radial distribution system earthed using a Petersen Coil with a phase to earth fault on phase C, shown in the figure below:

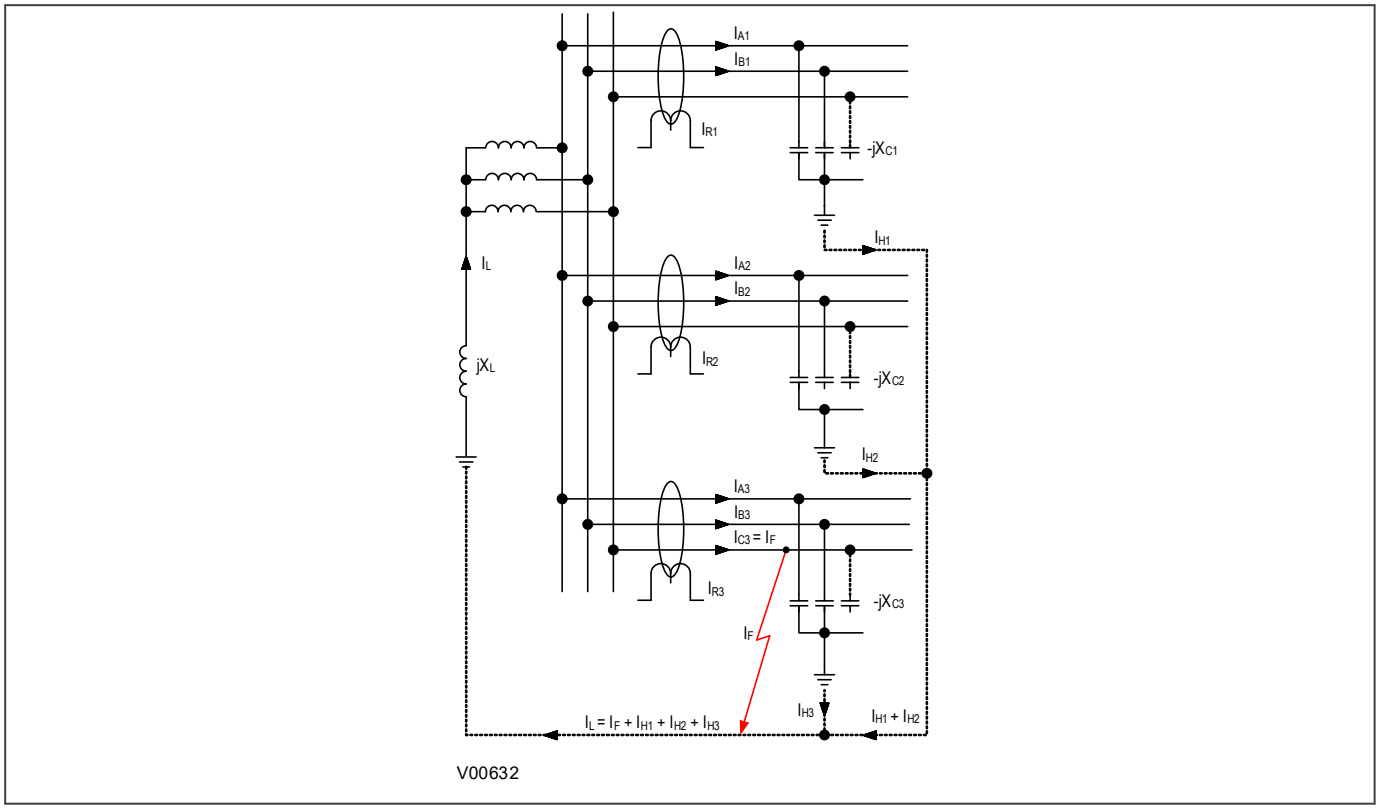


Figure 66: Distribution of currents during a phase C fault

Assuming that no resistance is present in X_L or X_C, the resulting phasor diagrams will be as shown in the figure below:

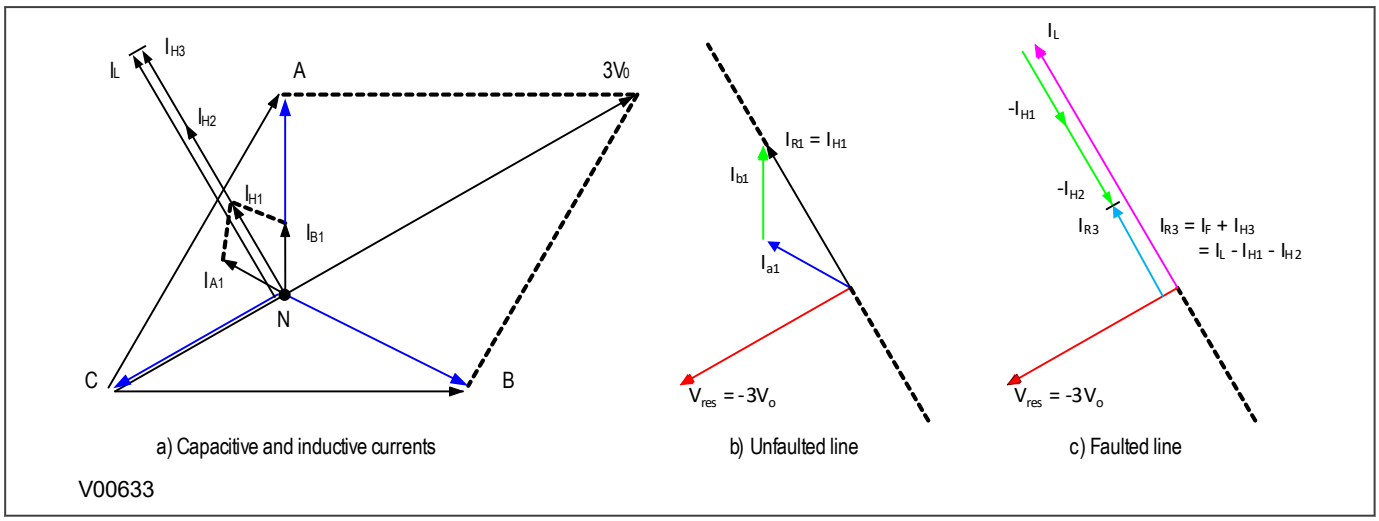


Figure 67: Phasors for a phase C earth fault in a Petersen Coil earthed system

It can be seen that:

- The voltage in the faulty phase reduces to almost 0V
- The healthy phases raise their phase to earth voltages by a factor of √3
- The triangle of voltages remains balanced
- The charging currents lead the voltages by 90°

Using a core-balance current transformer (CBCT), the current imbalances on the healthy feeders can be measured. They correspond to simple vector addition of I_{A1} and I_{B1}, I_{A2} and I_{B2}, I_{A3} and I_{B3}, and they lag the residual voltage by exactly 90º.

The magnitude of the residual current I_{R1} is equal to three times the steady-state charging current per phase. On the faulted feeder, the residual current is equal to I_L - I_{H1} - I_{H2} (C). This is shown in the zero sequence network shown in the following figure:

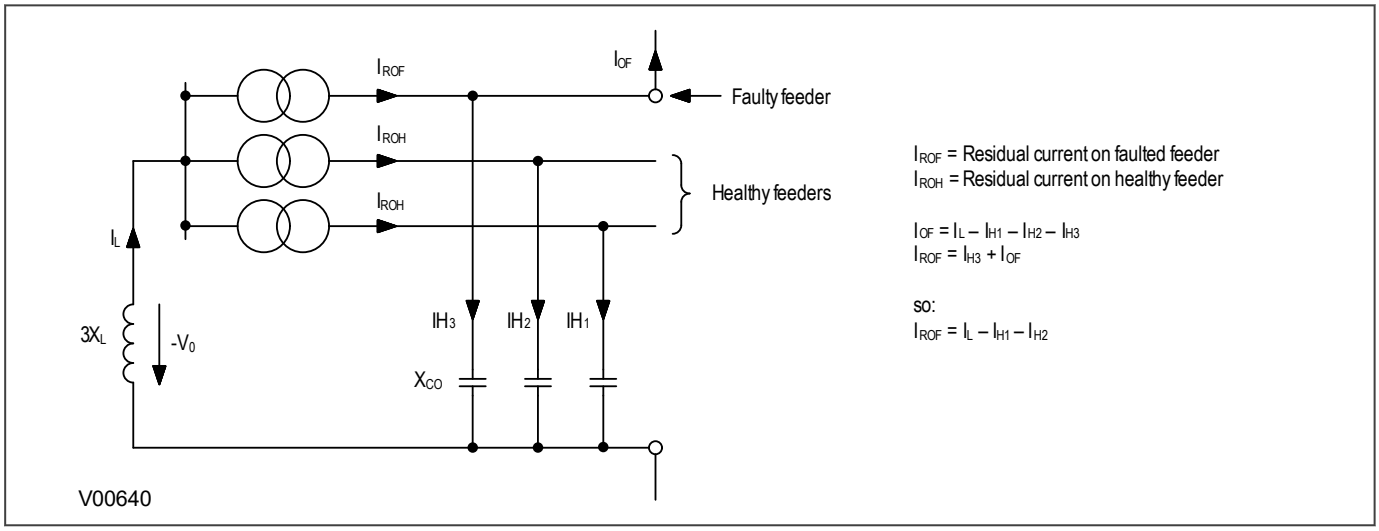


Figure 68: Zero sequence network showing residual currents

In practical cases, however, resistance is present, resulting in the following phasor diagrams:

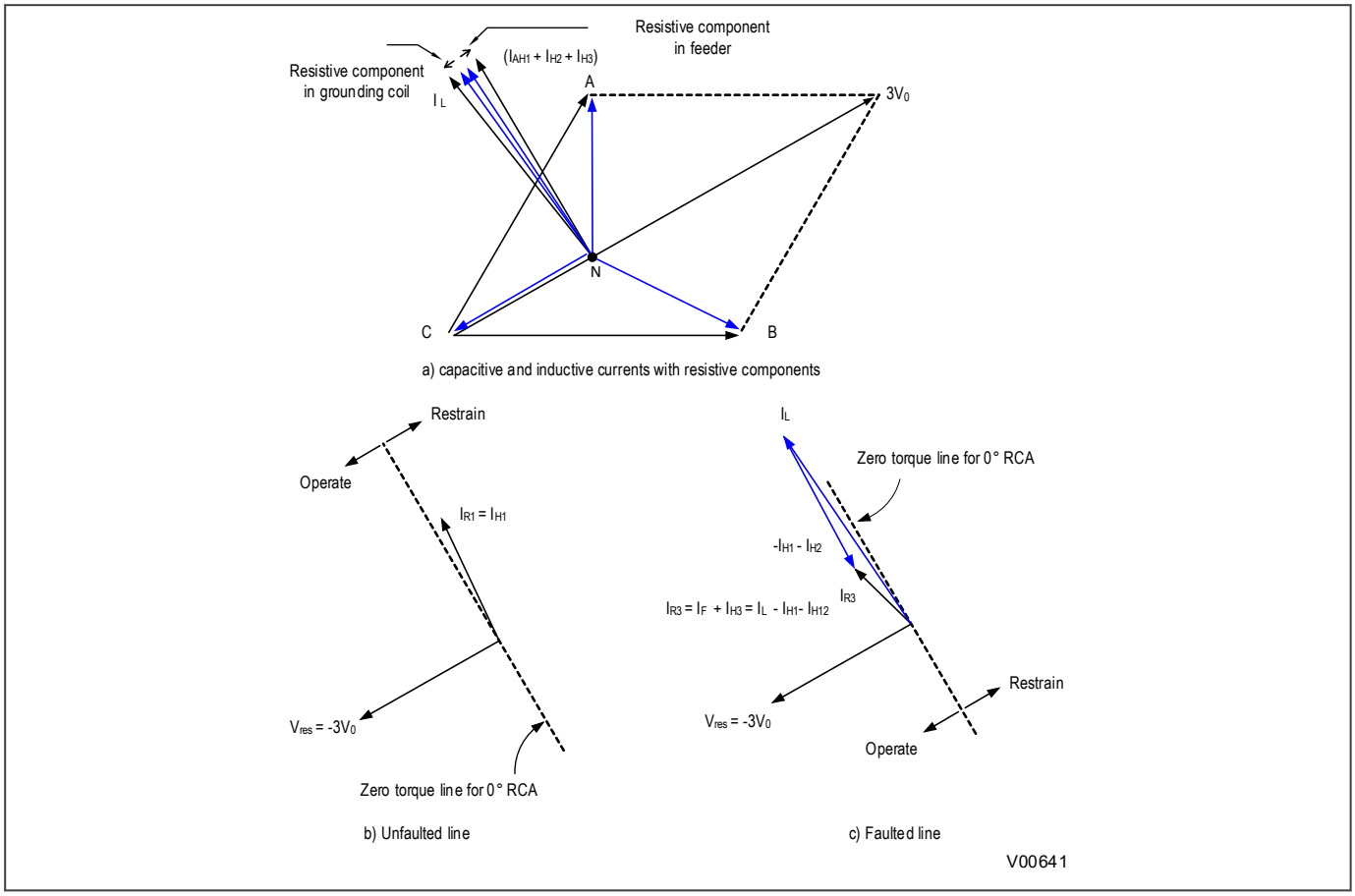


Figure 69: Phase C earth fault in Petersen Coil earthed system: practical case with resistance present

If the residual voltage is used as the polarising voltage, the residual current is phase shifted by an angle less than 90° on the faulted feeder, and greater than 90° on the healthy feeders. With an RCA of 0°, the healthy feeder residual current will fall in the 'restrain' area of the characteristic while the faulted feeder residual current falls in the 'operate' area.

Often, a resistance is deliberately inserted in parallel with the Petersen Coil to ensure a measurable earth fault current and increase the angular difference between the residual signals to reinforce the directional decision.

Directionality is usually implemented using a Wattmetric function rather than a simple directional function, since this is more sensitive.

6.11.5.3 SETTING GUIDELINES (COMPENSATED NETWORKS)

The directional setting should be such that the forward direction is looking down into the protected feeder (away from the busbar), with a 0° RCA setting.

For a fully compensated system, the residual current detected by the device on the faulted feeder is equal to the coil current minus the sum of the charging currents flowing from the rest of the system. Further, the addition of the two healthy phase charging currents on each feeder gives a total charging current which has a magnitude of three times the steady state per phase value. Therefore, for a fully compensated system, the detected unbalanced current is equal to three times the per phase charging current of the faulted circuit. A typical setting may therefore be in the order of 30% of this value, i.e. equal to the per phase charging current of the faulted circuit. In practice, the exact settings may well be determined on site, where system faults can be applied and suitable settings can be adopted based on practically obtained results.

In most situations, the system will not be fully compensated and consequently a small level of steady state fault current will be allowed to flow. The residual current seen by the protection on the faulted feeder may therefore be a

larger value, which further emphasises the fact that the protection settings should be based upon practical current levels, wherever possible.

The above also holds true for the RCA setting. As has been shown, a nominal RCA setting of 0º is required. However, fine-tuning of this setting on-site may be necessary in order to obtain the optimum setting in accordance with the levels of coil and feeder resistances present. The loading and performance of the CT will also have an effect in this regard. The effect of CT magnetising current will be to create phase lead of current. Whilst this would assist with operation of faulted feeder IEDs, it would reduce the stability margin of healthy feeder IEDs. A compromise can therefore be reached through fine adjustment of the RCA. This is adjustable in 1° steps.

6.12 SENSITIVE EARTH FAULT PROTECTION

With some earth faults, the fault current flowing to earth is limited by either intentional resistance (as is the case with some HV systems) or unintentional resistance (e.g. in very dry conditions and where the substrate is high resistance, such as sand or rock).

To provide protection in such cases, it is necessary to provide an earth fault protection system with a setting that is considerably lower than for normal line protection. Such sensitivity cannot be provided with conventional CTs, therefore the SEF input would normally be fed from a core balance current transformer (CBCT) mounted around the three phases of the feeder cable. The SEF transformer should be a special measurement class transformer.

6.12.1 SEF PROTECTION IMPLEMENTATION

The product provides four stages of SEF protection with independent time delay characteristics.

Stages 1, 2 provide a choice of operate and reset characteristics, where you can select between:

- A range of IDMT (Inverse Definite Minimum Time) curves
- A range of User-defined curves
- DT (Definite Time)

This is achieved using the cells

- ***ISEF>(n) Function*** for the overcurrent operate characteristic
- ***ISEF>(n) Reset Char*** for the overcurrent reset characteristic
- ***ISEF>(n) Usr RstChar*** for the reset characteristic for user -defined curves

where (n) is the number of the stage.

Stages 1 and 2 also provide a Timer Hold facility. This is configured using the cells ***ISEF>(n) tReset***.

Stages 3 and 4 have definite time characteristics only.

6.12.2 NON-DIRECTIONAL SEF LOGIC

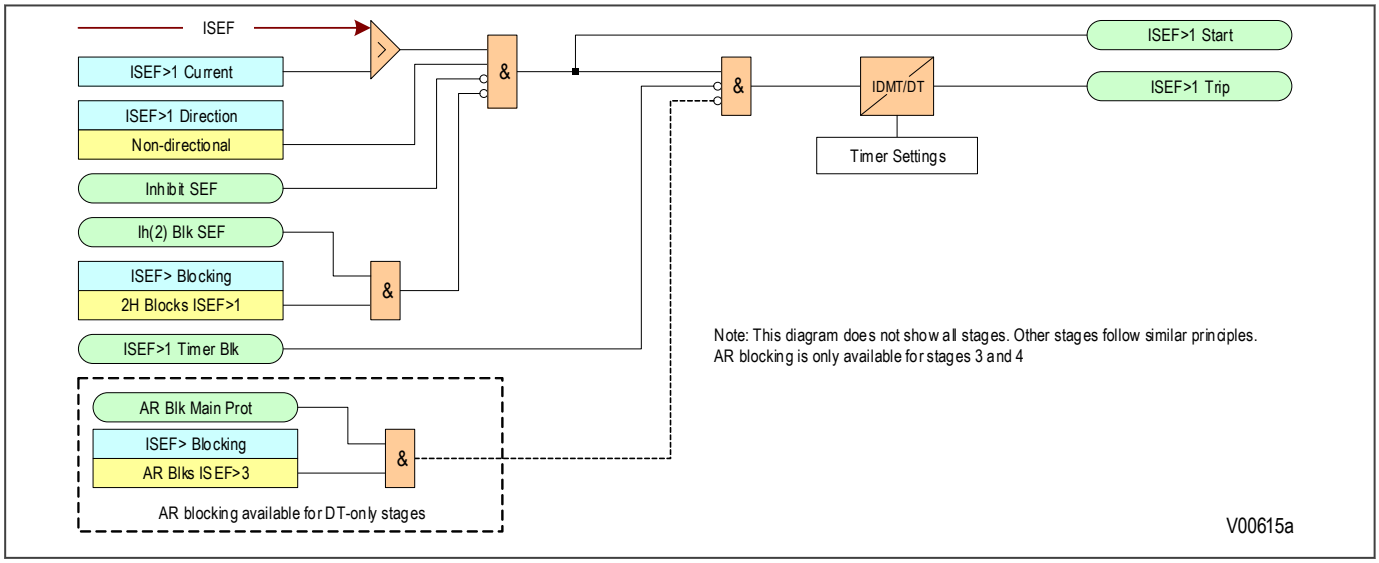


Figure 70: Non-directional SEF logic

The SEF current is compared with a set threshold (***ISEF>(n) Current***) for each stage. If it exceeds this threshold, a Start signal is triggered, providing it is not blocked. This can be blocked by the second harmonic blocking function, or an Inhibit SEF DDB signal.

The autoreclose logic can be set to block the SEF trip after a prescribed number of shots (set in *AUTORECLOSE* column). This is achieved using the ***AR Blk Main Prot*** setting. This can also be blocked by the relevant timer block signal ***ISEF>(n)TimerBlk*** DDB signal.

SEF protection can follow the same IDMT characteristics as described in the Overcurrent Protection Principles section. Please refer to this section for details of IDMT characteristics.

6.12.3 SEF ANY START LOGIC

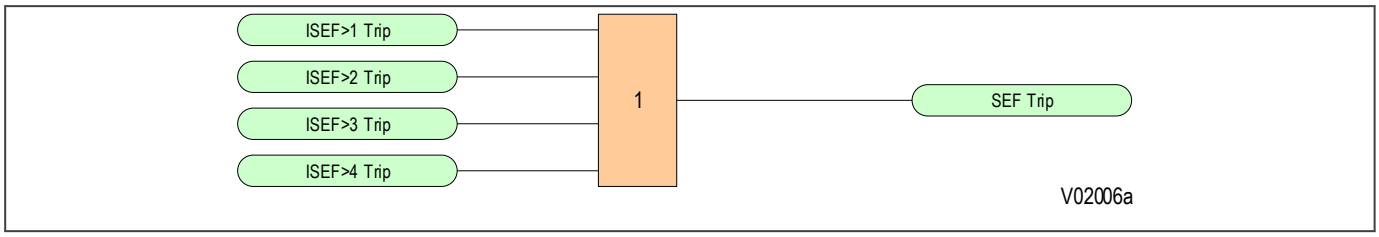


Figure 71: SEF any start logic

6.12.4 EPATR B CURVE

The EPATR B curve is commonly used for time-delayed Sensitive Earth Fault protection in certain markets. This curve is only available in the Sensitive Earth Fault protection stages 1 and 2. It is based on primary current settings, employing a SEF CT ratio of 100:1 A.

The EPATR_B curve has 3 separate segments defined in terms of the primary current. It is defined as follows:

Segment	Primary Current Range Based on 100A:1A CT Ratio	Current/Time Characteristic
1	ISEF = 0.5A to 6.0A	t = 432 x TMS/ISEF 0.655 secs
2	ISEF = 6.0A to 200A	t = 800 x TMS/ISEF secs
3	ISEF above 200A	t = 4 x TMS secs

where TMS (time multiplier setting) is 0.025 - 1.2 in steps of 0.025.

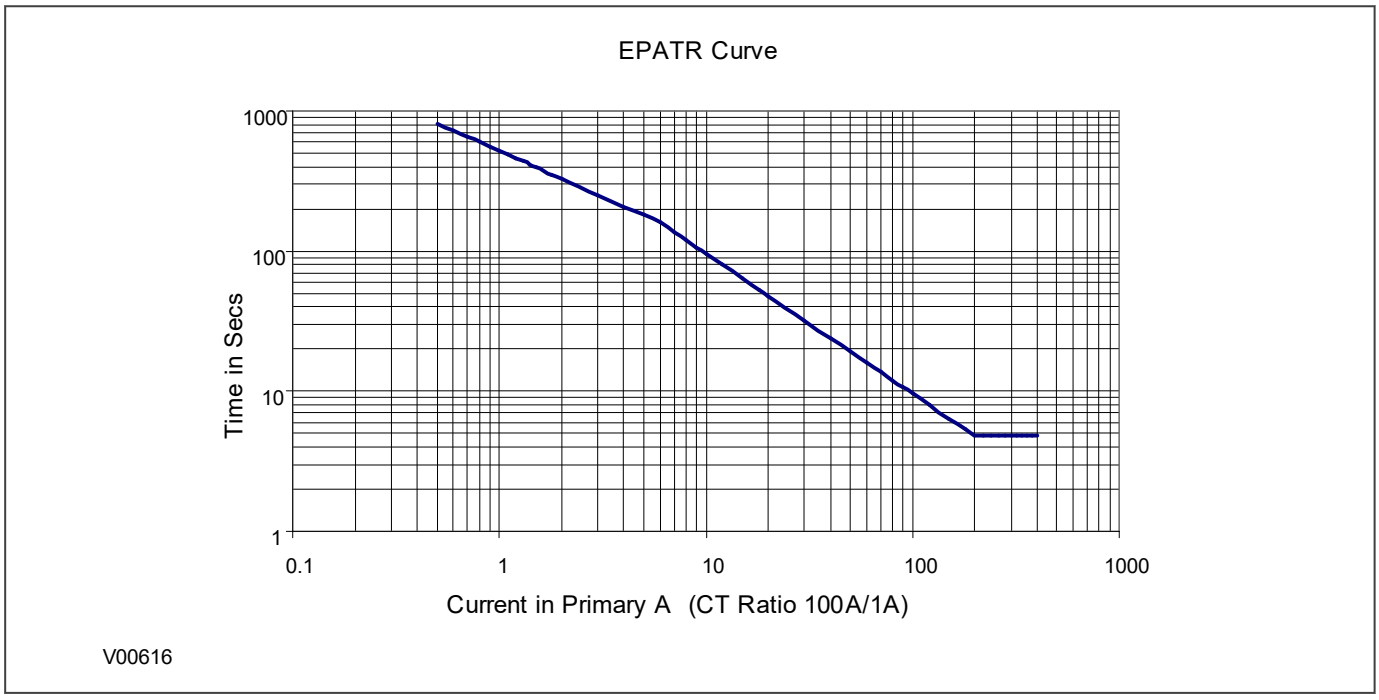


Figure 72: EPATR B characteristic shown for TMS = 1.0

6.12.5 DIRECTIONAL ELEMENT

Where current may flow in either direction, directional control should be used.

A directional element is available for all of the SEF overcurrent stages. This is found in the ***ISEF>(n) Direction*** cell for the relevant stage. It can be set to non-directional, directional forward, or directional reverse.

Directionality is achieved by using different techniques depending on the application. With reference to the figure below, you can see that directional SEF can be used for:

- Solidly earthed systems
- Unearthed systems (insulated systems)
- Compensated systems
- Resistance earthed systems

The following diagram shows which type of directional control can be used for which systems.

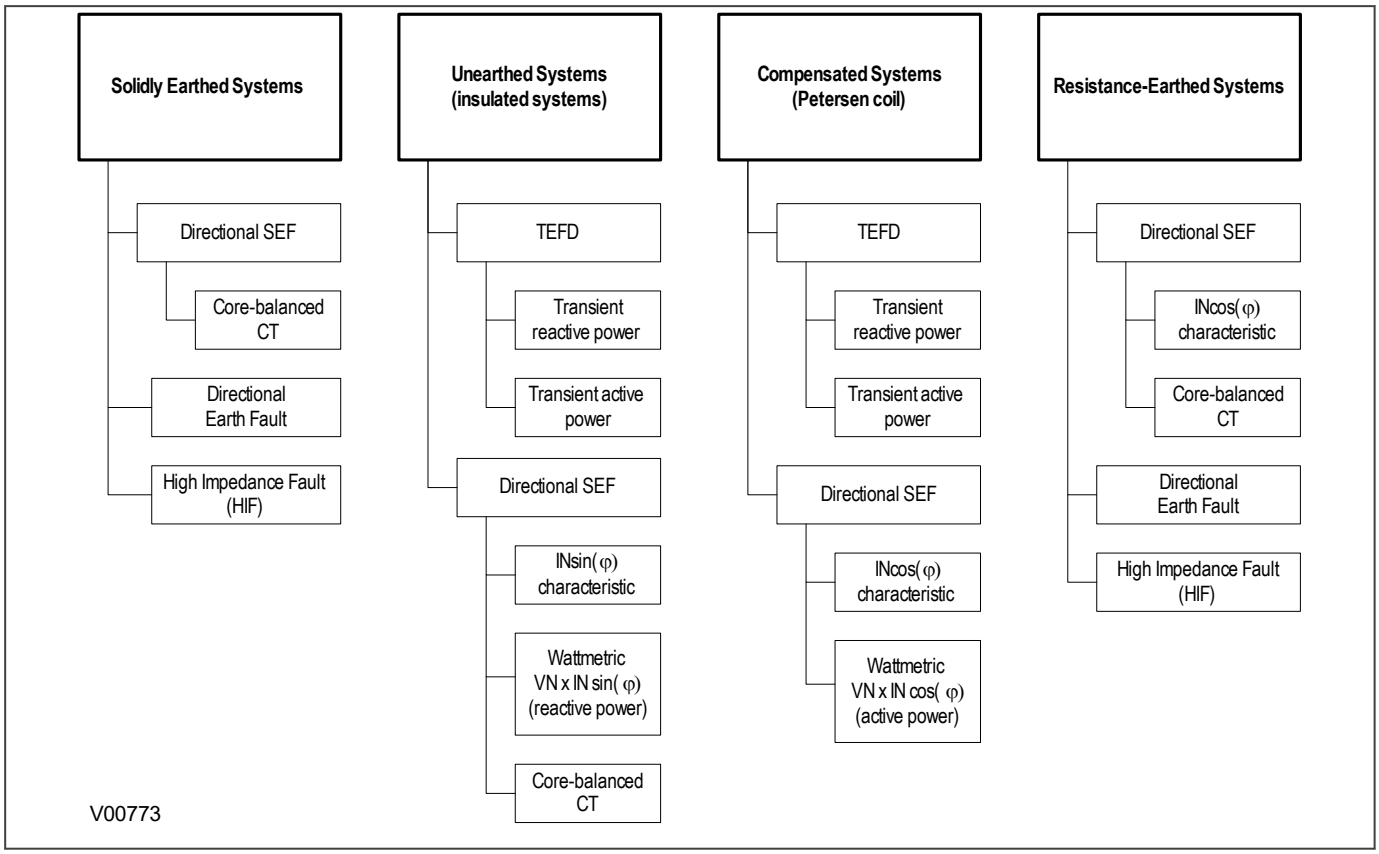


Figure 73: Types of directional control

The device supports standard core-balanced directional control as well as Isin(ϕ), Icos(ϕ) and Wattmetric characteristics.

If you are using directional SEF protection, you select the required polarisation using the ***SEF/REF Options*** setting in the *SEF/REF PROT'N* column.

6.12.5.1 WATTMETRIC CHARACTERISTIC

Analysis has shown that a small angular difference exists between the spill current on healthy and faulted feeders for earth faults on compensated networks. This angular difference gives rise to active components of current which are in anti-phase to one another.

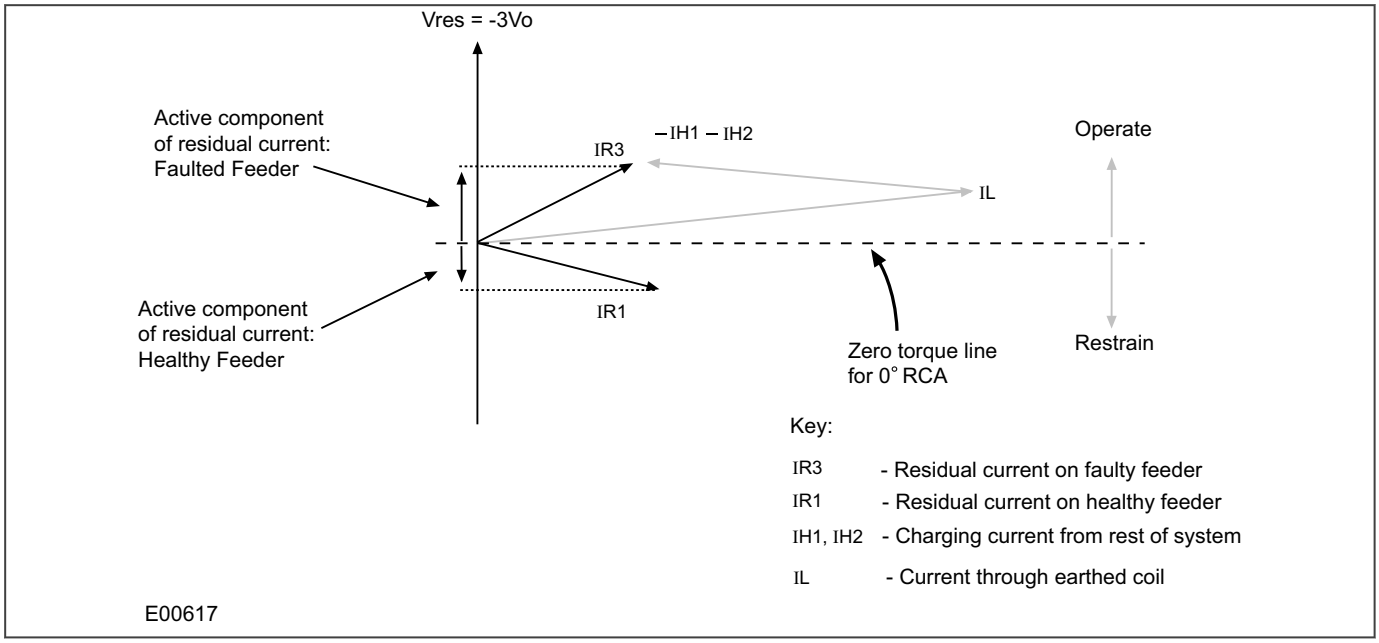


Figure 74: Resistive components of spill current

Consequently, the active components of zero sequence power will also lie in similar planes, meaning an IED capable of detecting active power can make discriminatory decisions. If the Wattmetric component of zero sequence power is detected in the forward direction, then this would indicate fault on that feeder. If power is detected in the reverse direction, then the fault must be present on an adjacent feeder or at the source.

For operation of the directional earth fault element, all three of the settable thresholds must be exceeded; namely the current ISEF>, the voltage ***ISEF>VNpol Set*** and the power ***PN> Setting***.

The power setting is called PN> and is calculated using residual quantities. The formula for operation is as follows:

The PN> setting corresponds to:

$$V_{res}I_{res}\cos(\phi - \phi_c) = 9V_oI_o\cos(\phi - \phi_c)$$

where:

- ϕ = Angle between the Polarising Voltage (**-Vres**) and the Residual Current
- ϕ_c = Relay Characteristic Angle (RCA) Setting (***ISEF> Char Angle***)
- V_{res} = Residual Voltage
- I_{res} = Residual Current
- V_o = Zero Sequence Voltage
- I_o = Zero Sequence Current

The action of setting the PN> threshold to zero would effectively disable the wattmetric function and the device would operate as a basic, sensitive directional earth fault element. However, if this is required, then the SEF option can be selected from the ***SEF/REF Options*** cell in the menu.

Note:
The residual power setting, PN>, is scaled by the programmed Transformer ratios.

A further point to note is that when a power threshold other than zero is selected, a slight alteration is made to the angular boundaries of the directional characteristic. Rather than being ±90° from the RCA, they are made slightly narrower at ±85°.

The directional check criteria is as follows:

Directional forward: -85° < (angle(IN) - angle(VN + 180°) - RCA) < 85°

Directional reverse: -85° > (angle(IN) - angle(VN + 180°) - RCA) > 85°

6.12.5.2 ICOS PHI/ISIN PHI CHARACTERISTIC

In some applications, the residual current on the healthy feeder can lie just inside the operating boundary following a fault condition. The residual current for the faulted feeder lies close to the operating boundary.

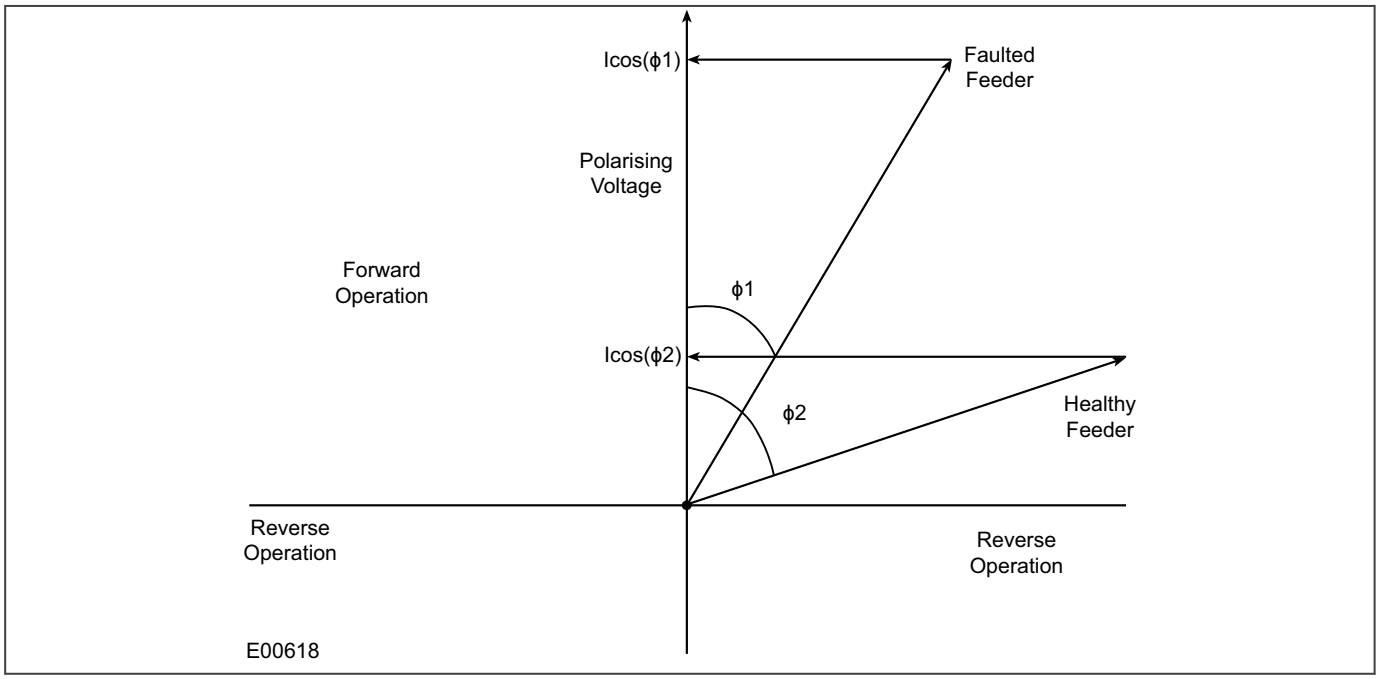


Figure 75: Operating characteristic for Icos

The diagram illustrates the method of discrimination when the real (cosϕ) component is considered. Faults close to the polarising voltage will have a higher magnitude than those close to the operating boundary. In the diagram, we assume that the current magnitude I is in both the faulted and non-faulted feeders.

- For the active component Icos, the criterion for operation is: Icosϕ > ***ISEF>(n) current***
- For the reactive component Isin, the criterion for operation is: Isinϕ > ***ISEF>(n) current***

Where ***ISEF>(n) current*** is the sensitive earth fault current setting for the stage in question

If any stage is set to non-directional, the element reverts back to normal operation based on current magnitude I with no directional decision. In this case, correct discrimination is achieved by means of an Icos characteristic as the faulted feeder will have a large active component of residual current, whilst the healthy feeder will have a small value.

For insulated earth applications, it is common to use the Isin characteristic.

All of the relevant settings can be found under the *SEF PROTECTION* column.

6.12.5.3 DIRECTIONAL SEF LOGIC

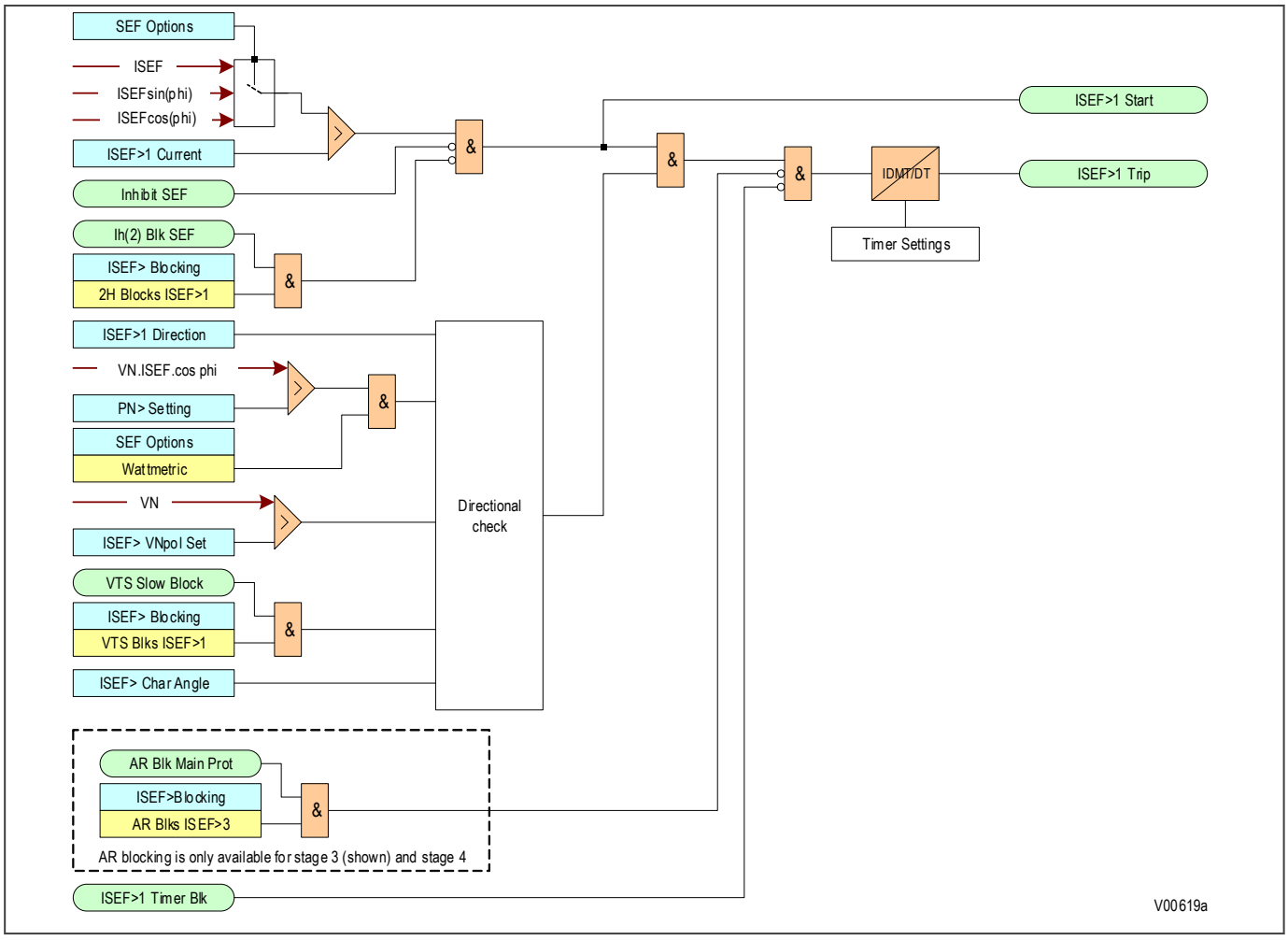


Figure 76: Directional SEF with VN polarisation (single stage)

The sensitive earth fault protection can be set IN/OUT of service using the appropriate DDB inhibit signal, which can be operated from an opto-input or control command. VT Supervision (VTS) selectively blocks the directional protection or causes it to revert to non-directional operation. When selected to block the directional protection, VTS blocking is applied to the directional checking which effectively blocks the start outputs as well.

The directional check criteria are given below for the standard directional sensitive earth fault element:

- Directional forward: -90° < (angle(IN) - angle(VN + 180°) - RCA) < 90°
- Directional reverse: -90° > (angle(IN) - angle(VN + 180°) - RCA) > 90°

Three possibilities exist for the type of protection element that you can use for sensitive earth fault detection:

- A suitably sensitive directional earth fault protection element having a characteristic angle setting (RCA) of zero degrees, with the possibility of fine adjustment about this threshold.
- A sensitive directional zero sequence wattmetric protection element having a characteristic angle setting (RCA) of zero degrees, with the possibility of fine adjustment about this threshold.
- A sensitive directional earth fault protection element having Icosϕ and Isinϕ characteristics.

All stages of the sensitive earth fault element can be set down to 0.5% of rated current.

6.12.6 APPLICATION NOTES

6.12.6.1 INSULATED SYSTEMS

When insulated systems are used, it is not possible to detect faults using standard earth fault protection. It is possible to use a residual overvoltage device to achieve this, but even with this method full discrimination is not possible. Fully discriminative earth fault protection on this type of system can only be achieved by using a SEF (Sensitive Earth Fault) element. This type of protection detects the resultant imbalance in the system charging currents that occurs under earth fault conditions. A core balanced CT must be used for this application. This eliminates the possibility of spill current that may arise from slight mismatches between residually connected line CTs. It also enables a much lower CT ratio to be applied, thereby allowing the required protection sensitivity to be more easily achieved.

The following diagram shows an insulated system with a C-phase fault.

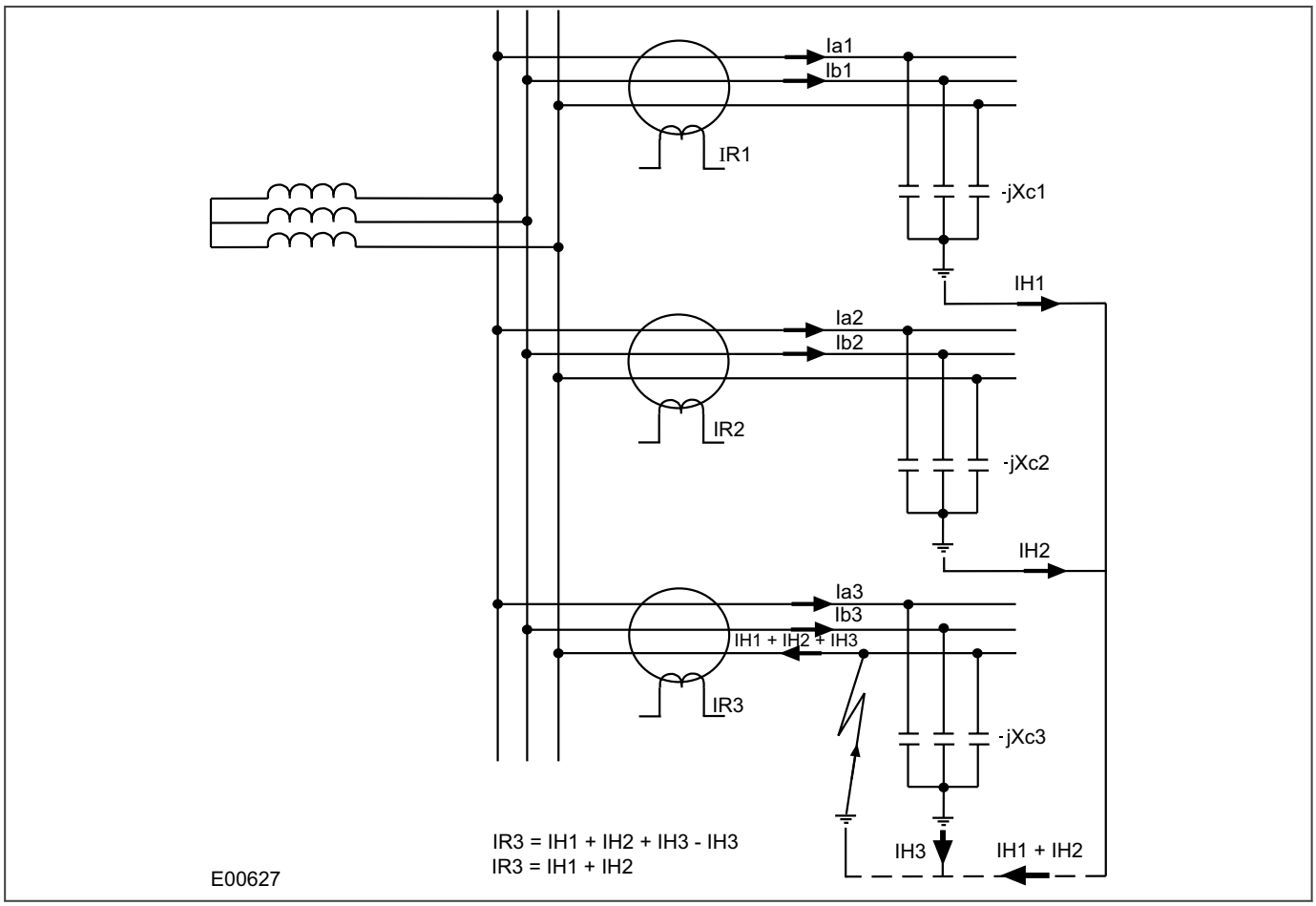


Figure 77: Current distribution in an insulated system with C phase fault

The protection elements on the healthy feeder see the charging current imbalance for their own feeder. The protection element on the faulted feeder, however, sees the charging current from the rest of the system (IH1 and IH2 in this case). Its own feeder's charging current (IH3) is cancelled out.

With reference to the associated vector diagram, it can be seen that the C-phase to earth fault causes the voltages on the healthy phases to rise by a factor of √3. The A-phase charging current (Ia1), leads the resultant A phase voltage by 90°. Likewise, the B-phase charging current leads the resultant Vb by 90°.

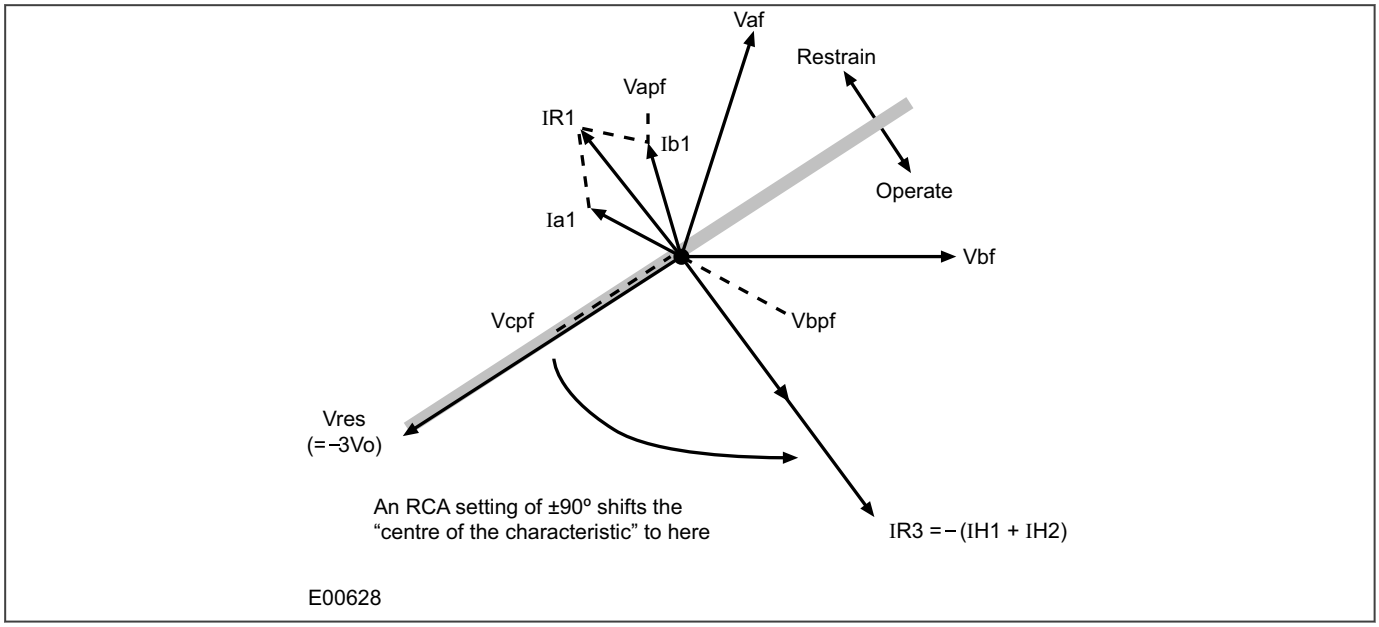


Figure 78: Phasor diagrams for insulated system with C phase fault

The current imbalance detected by a core balanced current transformer on the healthy feeders is the vector addition of Ia1 and Ib1. This gives a residual current which lags the polarising voltage (–3Vo) by 90°. As the healthy phase voltages have risen by a factor of √3, the charging currents on these phases are also √3 times larger than their steady state values. Therefore, the magnitude of the residual current IR1, is equal to 3 times the steady state per phase charging current.

The phasor diagram indicates that the residual currents on the healthy and faulted feeders (IR1 and IR3 respectively) are in anti-phase. A directional element (if available) could therefore be used to provide discriminative earth fault protection.

If the polarising is shifted through +90°, the residual current seen by the device on the faulted feeder will lie within the operate region of the directional characteristic and the current on the healthy feeders will fall within the restrain region.

The required characteristic angle setting for the SEF element when applied to insulated systems, is +90°. This is for the case when the protection is connected such that its direction of current flow for operation is from the source busbar towards the feeder. If the forward direction for operation were set such that it is from the feeder into the busbar, then a –90° RCA would be required.

Note:
Discrimination can be provided without the need for directional control. This can only be achieved, however, if it is possible to set the IED in excess of the charging current of the protected feeder and below the charging current for the rest of the system.

6.12.6.2 SETTING GUIDELINES (INSULATED SYSTEMS)

The residual current on the faulted feeder is equal to the sum of the charging currents flowing from the rest of the system. Further, the addition of the two healthy phase charging currents on each feeder gives a total charging current which has a magnitude of three times the per phase value. Therefore, the total imbalance current is equal to three times the per phase charging current of the rest of the system. A typical setting may therefore be in the order of 30% of this value, i.e. equal to the per phase charging current of the remaining system. Practically though, the required setting may well be determined on site, where suitable settings can be adopted based on practically obtained results.

When using a core-balanced transformer, care must be taken in the positioning of the CT with respect to the earthing of the cable sheath:

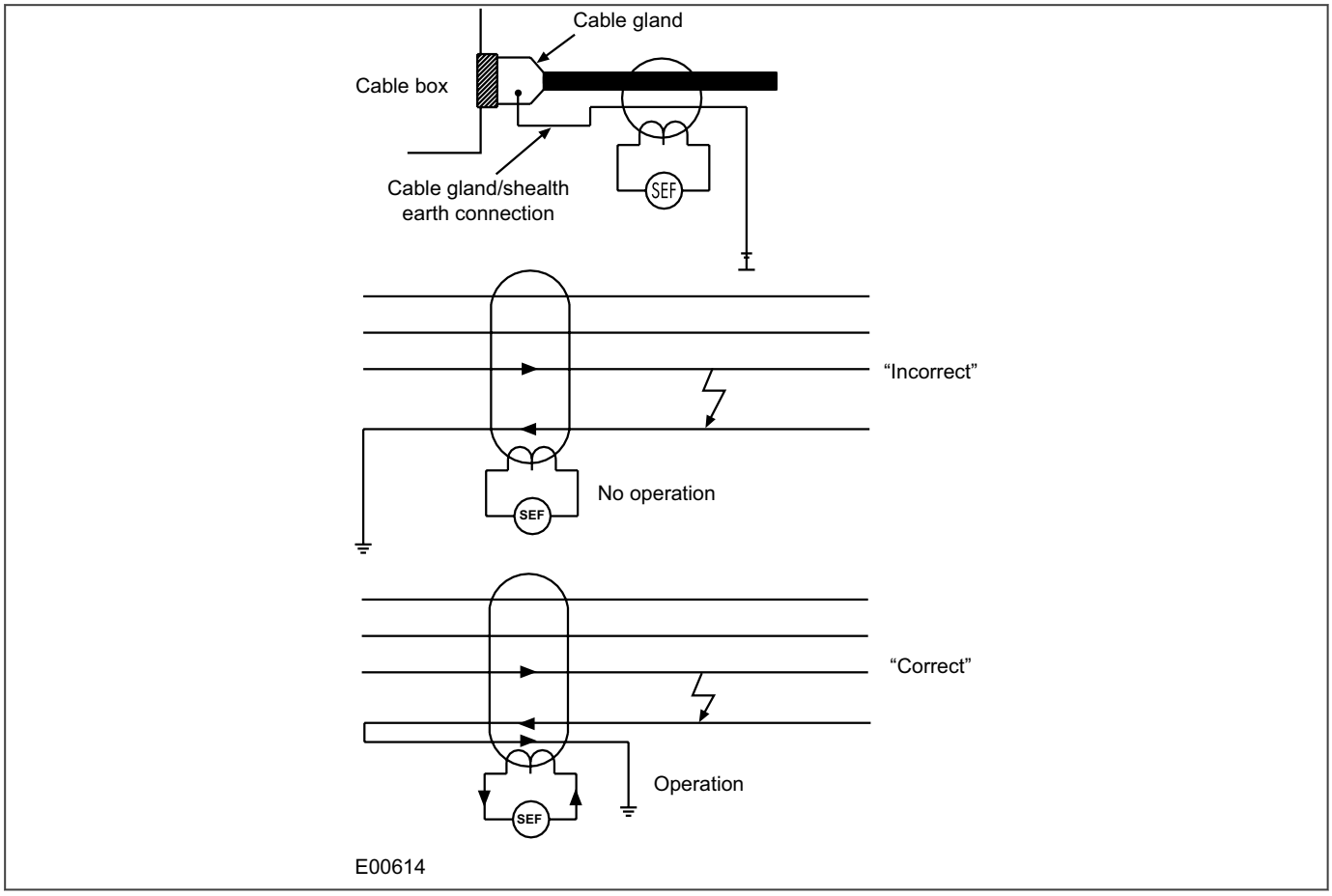


Figure 79: Positioning of core balance current transformers

If the cable sheath is terminated at the cable gland and directly earthed at that point, a cable fault (from phase to sheath) will not result in any unbalanced current in the core balance CT. Therefore, prior to earthing, the connection must be brought back through the CBCT and earthed on the feeder side. This then ensures correct device operation during earth fault conditions.

6.13 RESTRICTED EARTH FAULT PROTECTION

6.13.1 REF PROTECTION PRINCIPLES

Winding-to-core faults in a transformer can be caused by insulation breakdown. Such faults can have very low fault currents, but they still need to be picked up. If such faults are not identified, this could result in extreme damage to very expensive equipment.

Often the associated fault currents are lower than the nominal load current. Neither overcurrent nor percentage differential protection is sufficiently sensitive in this case. We therefore require a different type of protection arrangement. Not only should the protection arrangement be sensitive, but it must create a protection zone, which is limited to each transformer winding. Restricted Earth Fault protection (REF) is the protection mechanism used to protect individual transformer winding sets.

The following figure shows a REF protection arrangement for protecting the delta side of a delta-star transformer.

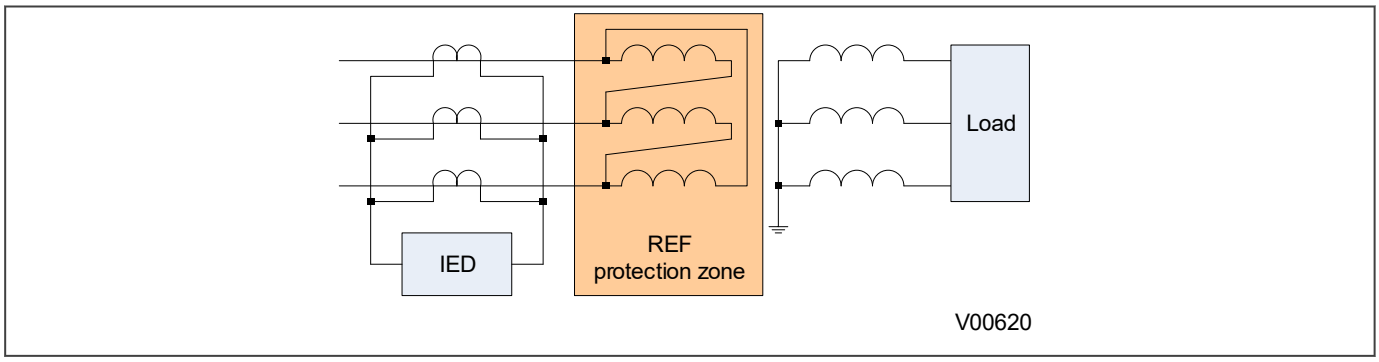


Figure 80: REF protection for delta side

The current transformers measuring the currents in each phase are connected in parallel. The currents from all three phases are summed to form a differential current, sometimes known as a spill current. Under normal operating conditions the currents of the three phases add up to zero resulting in zero spill current. A fault on the star side will also not result in a spill current, as the fault current would simply circulate in the delta windings. However, if any of the three delta windings were to develop a fault, the impedance of the faulty winding would change and that would result in a mismatch between the phase currents, resulting in a spill current. If the spill current is large enough, it will trigger a trip command.

The following figure shows a REF protection arrangement for the star side of a delta-star transformer.

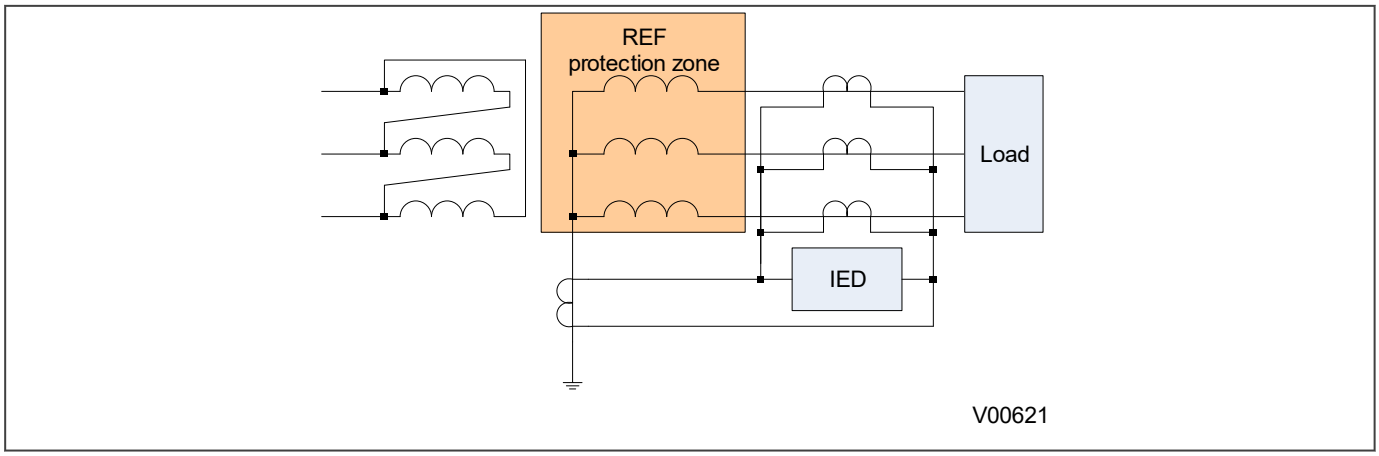


Figure 81: REF protection for star side

Here we have a similar arrangement of current transformers connected in parallel. The difference is that we need to measure the zero sequence current in the neutral line as well. An external unbalanced fault causes zero sequence

current to flow through the neutral line, resulting in uneven currents in the phases, which could cause the protection to maloperate. By measuring this zero sequence current and placing it in parallel with the other three, the currents are balanced, resulting in stable operation. Now only a fault inside the star winding can create an imbalance sufficient to cause a trip.

6.13.1.1 RESISTANCE-EARTHED STAR WINDINGS

Most distribution systems use resistance-earthed systems to limit the fault current. Consider the diagram below, which depicts an earth fault on the star winding of a resistance-earthed Dyn transformer (Dyn = Delta-Star with star-point neutral connection).

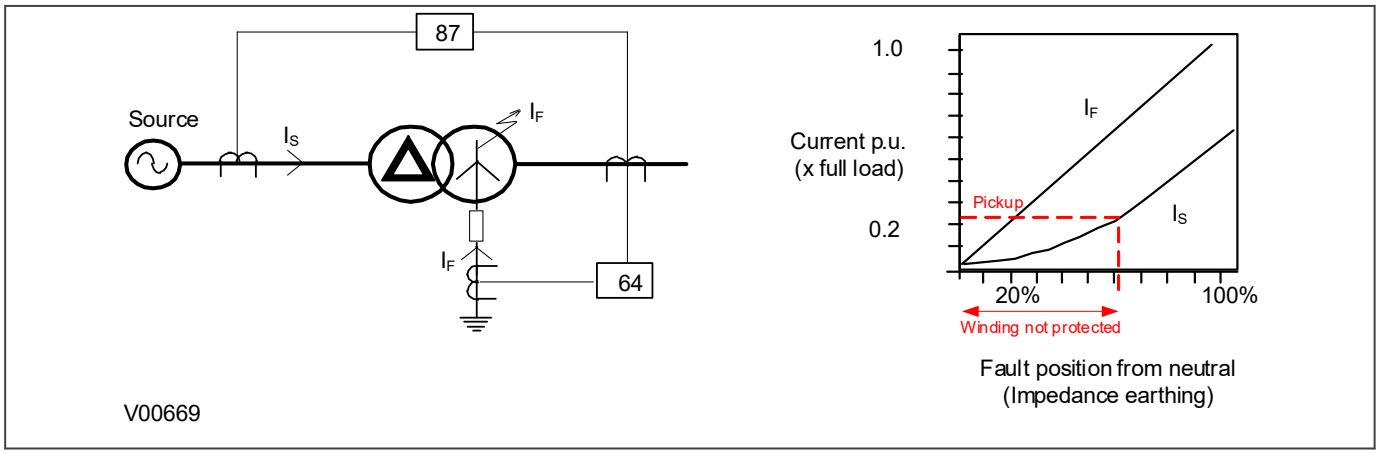


Figure 82: REF protection for resistance-earthed systems

The value of fault current (I_F) depends on two factors:

- The value of earthing resistance (which makes the fault path impedance negligible)
- The fault point voltage (which is governed by the fault location)

Because the fault current (I_F) is governed by the resistance, its value is directly proportional to the location of the fault.

A restricted earth fault element is connected to measure I_F directly. This provides very sensitive earth fault protection. The overall differential protection is less sensitive, since it only measures the HV current I_S. The value of I_S is limited by the number of faulty secondary turns in relation to the HV turns.

6.13.1.2 SOLIDLY-EARTHED STAR WINDINGS

Most transmission systems use solidly-earthed systems. Consider the diagram below, which depicts an earth fault on the star winding of a solidly-earthed Dyn transformer.

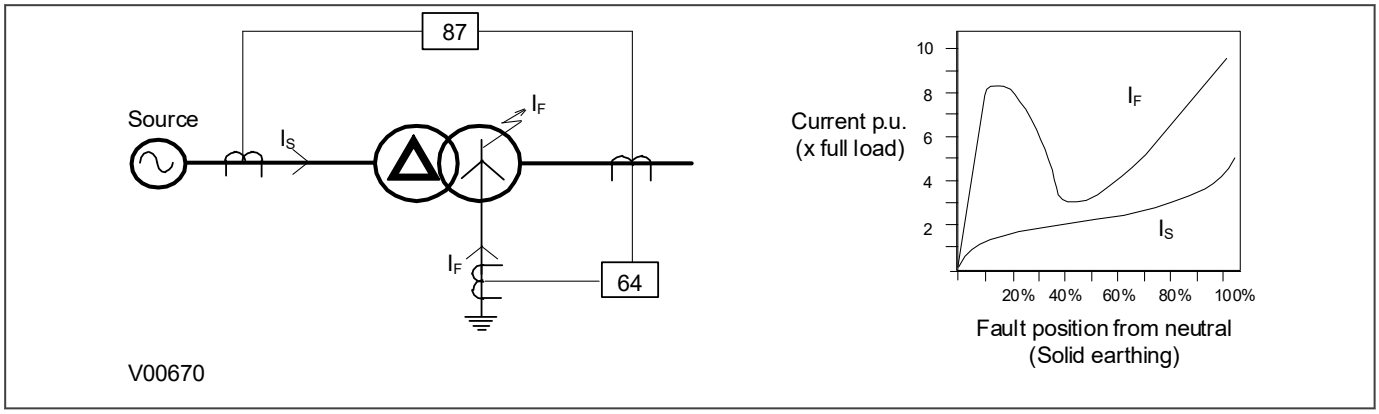


Figure 83: REF protection for solidly earthed system

In this case, the fault current I_F is dependent on:

- The leakage reactance of the winding
- The impedance in the fault path
- The fault point voltage (which is governed by the fault location)

In this case, the value of fault current (I_F) varies with the fault location in a complex manner.

A restricted earth fault element is connected to measure I_F directly. This provides very sensitive earth fault protection.

For solidly earthed systems, the operating current for the transformer differential protection is still significant for faults over most of the winding. For this reason, independent REF protection may not have been previously considered, especially where an additional device would have been needed. But with this product, it can be applied without extra cost.

6.13.1.3 THROUGH FAULT STABILITY

In an ideal world, the CTs either side of a differentially protected system would be identical with identical characteristics to avoid creating a differential current. However, in reality CTs can never be identical, therefore a certain amount of differential current is inevitable. As the through-fault current in the primary increases, the discrepancies introduced by imperfectly matched CTs is magnified, causing the differential current to build up. Eventually, the value of the differential current reaches the pickup current threshold, causing the protection element to trip. In such cases, the differential scheme is said to have lost stability. To specify a differential scheme's ability to restrain from tripping on external faults, we define a parameter called 'through-fault stability limit', which is the maximum through-fault current a system can handle without losing stability.

6.13.1.4 RESTRICTED EARTH FAULT TYPES

There are two different types of Restricted Earth Fault; Low Impedance REF (also known as Biased REF) and High Impedance REF. Each method compensates for the effect of through-fault errors in a different manner.

With Low Impedance REF, the through-fault current is measured and this is used to alter the sensitivity of the REF element accordingly by applying a bias characteristic. So the higher the through fault current, the higher the differential current must be for the device to issue a trip signal, Often a transient bias component is added to improve stability during external faults.

Low impedance protection used to be considered less secure than high impedance protection. This is no longer true as numerical IEDs apply sophisticated algorithms to match the performance of high-impedance schemes. Some advantages of using Low Impedance REF are listed below:

- There is no need for dedicated CTs. As a result CT cost is substantially reduced
- The wiring is simpler as it does not require an external resistor or Metrosil
- Common phase current inputs can be used
- It provides internal CT ratio mismatch compensation. It can match CT ratios up to 1:40 resulting flexibility in substation design and reduced cost
- Advanced algorithms make the protection secure

With High Impedance REF, there is no bias characteristic, and the trip threshold is set to a constant level. However, the High Impedance differential technique ensures that the impedance of the circuit is sufficiently high such that the differential voltage under external fault conditions is lower than the voltage needed to drive differential current through the device. This ensures stability against external fault conditions so the device will operate only for faults occurring inside the protected zone.

High Impedance REF protection responds to a voltage across the differential junction points. During external faults, even with severe saturation of some of the CTs, the voltage does not rise above certain level, because the other CTs will provide a lower-impedance path compared with the device input impedance. The principle has been used for more than half a century. Some advantages of using High Impedance REF are listed below:

- It provides a simple proven algorithm, which is fast, robust and secure
- It is less sensitive to CT saturation

6.13.1.4.1 RESTRICTED EARTH FAULT PROTECTION

The REF protection in the P14 device may be configured to operate as either a high impedance or low impedance element and the following sections describe the application of the device in each mode.

The high impedance REF element of the device shares the same CT input as the SEF protection hence, only one of these elements may be selected. However, the low impedance REF element does not use the SEF input and so may be selected at the same time.

6.13.1.4.2 BIASED DIFFERENTIAL PROTECTION

In a biased differential device, the through current is measured and used to increase the setting of the differential element. For heavy through faults, one CT in the scheme can be expected to become more saturated than the other and hence differential current can be produced. However, biasing will increase the device setting such that the resulting differential current is insufficient to cause operation of the relay.

The figures below show the operating characteristic for the P14 device applied for biased REF protection.

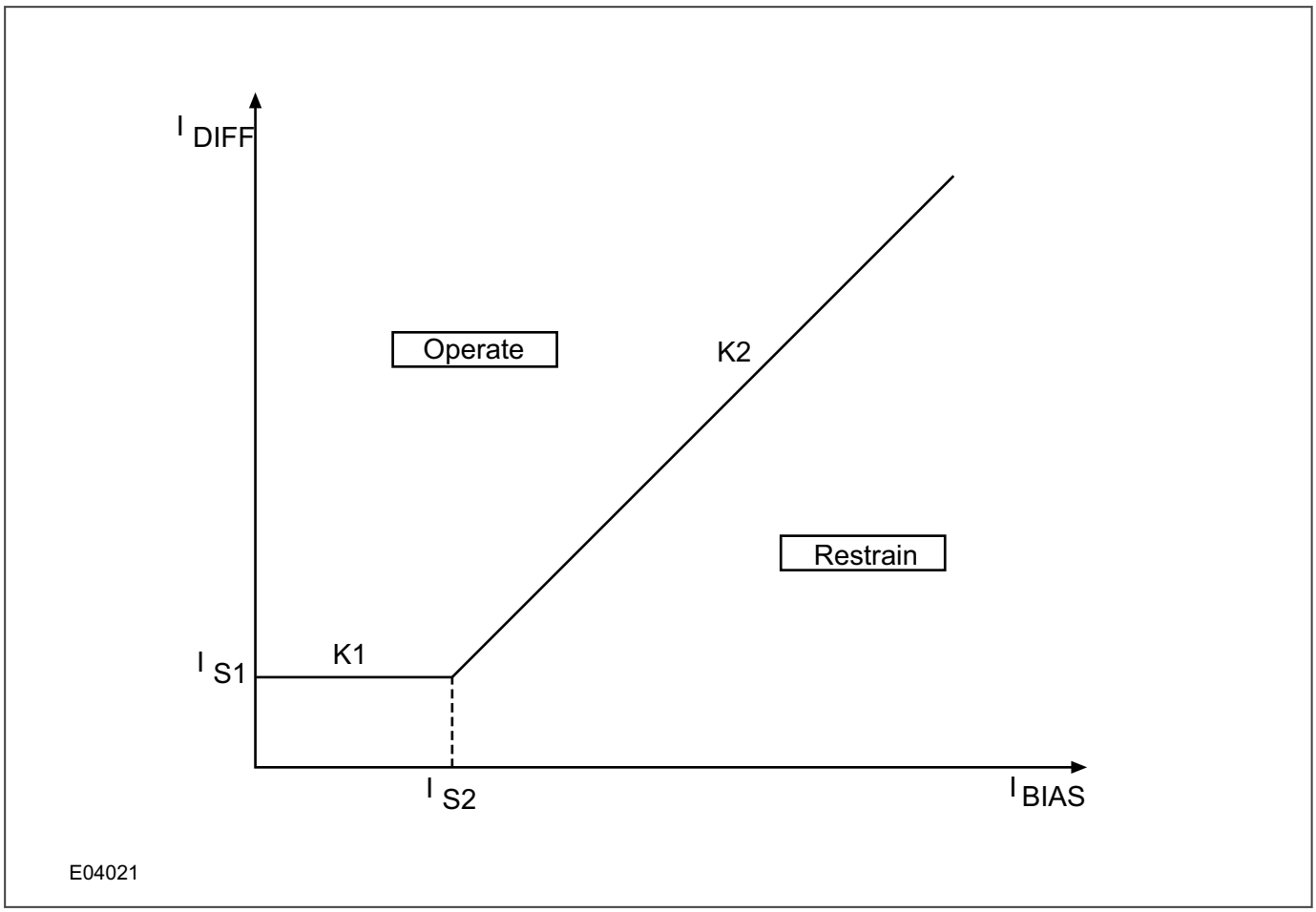


Figure 84: REF bias characteristic

The actual operating characteristic of the element is shown in the figure above.

The formulae used by the device to calculate the required bias quantity is therefore as follows:

Ibias = {(Highest of Ia, Ib or Ic) + (Ineutral x Scaling Factor)}/2

The reason for the scaling factor included on the neutral current is explained by referring to the figure above.

For IBIAS < IS2

Operate when IDIFF > IS1 + K1.IBIAS

For IBIAS = IS2

Operate when IDIFF > IS1 + K1.IS2

For IBIAS > IS2

Operate when IDIFF > IS1 + K1.IS2 + K2.(IBIAS-IS2)

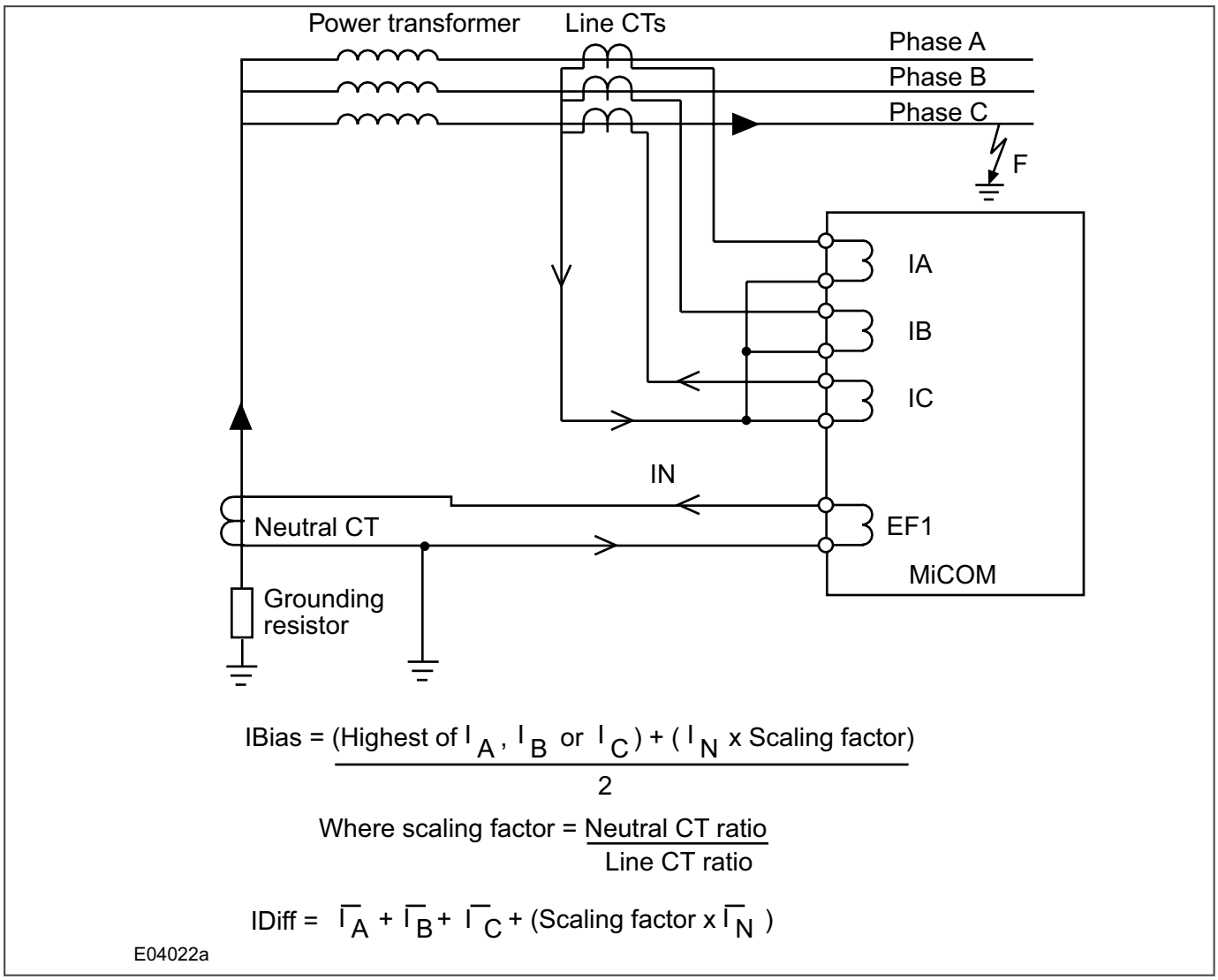


Figure 85: REF bias principle

Where it is required that the neutral CT also drives the EF1 protection element to provide standby earth fault protection, it may be a requirement that the neutral CT has a lower ratio than the line CTs in order to provide better earth fault sensitivity. If this were not accounted for in the REF protection, the neutral current value used would be incorrect. For this reason, the device automatically scales the level of neutral current used in the bias calculation by a factor equal to the ratio of the neutral to line CT primary ratings. The use of this scaling factor is shown in the figure above, where the formulae for bias and differential currents are given.

6.13.1.4.3 HIGH IMPEDANCE REF PRINCIPLE

This scheme is very sensitive and can protect against low levels of fault current, typical of winding faults.

High Impedance REF protection is based on the differential principle. It works on the circulating current principle as shown in the following diagram.

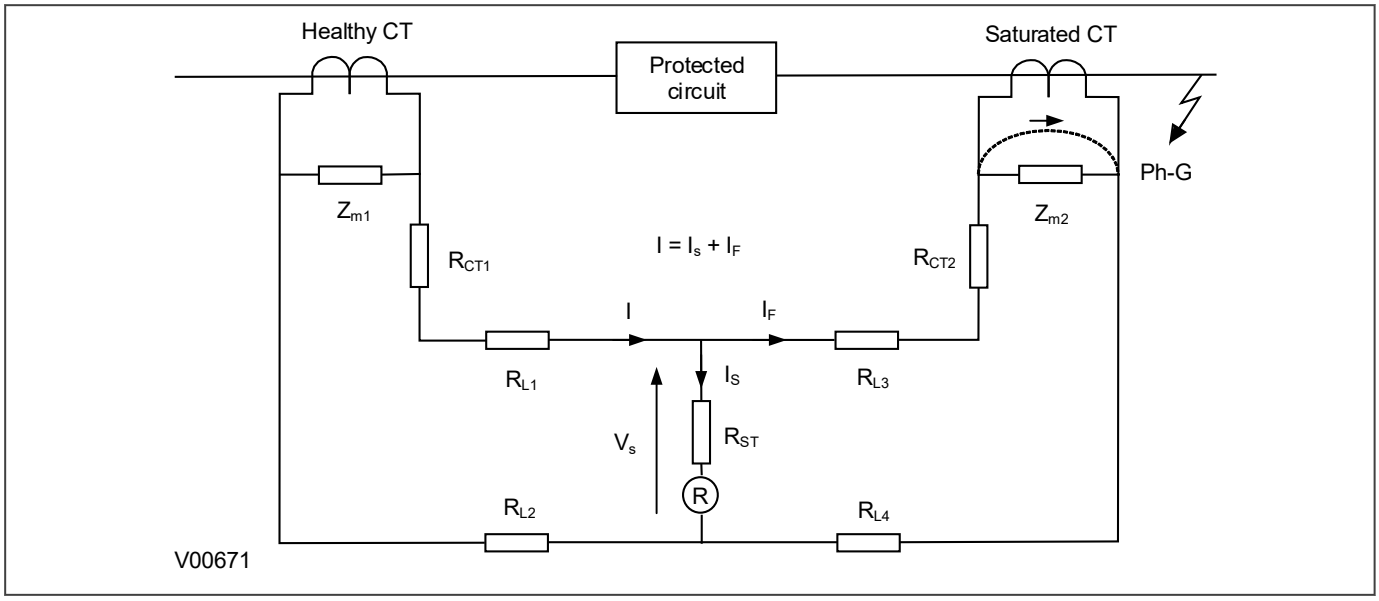


Figure 86: High impedance REF principle

When subjected to heavy through faults the line current transformer may enter saturation unevenly, resulting in imbalance. To ensure stability under these conditions a series connected external resistor is required, so that most of the unbalanced current will flow through the saturated CT. As a result, the current flowing through the device will be less than the setting, therefore maintaining stability during external faults.

Voltage across REF element $V_s = I_F (R_{CT2} + R_{L3} + R_{L4})$

Stabilising resistor $R_{ST} = V_s/I_s - R_R$

where:

- I_F = maximum secondary through fault current
- R_R = device burden
- R_{CT} = CT secondary winding resistance
- R_{L2} and R_{L3} = Resistances of leads from the device to the current transformer
- R_{ST} = Stabilising resistor

High Impedance REF can be used for either delta windings or star windings in both solidly grounded and resistance grounded systems. The connection to a modern IED are as follows:

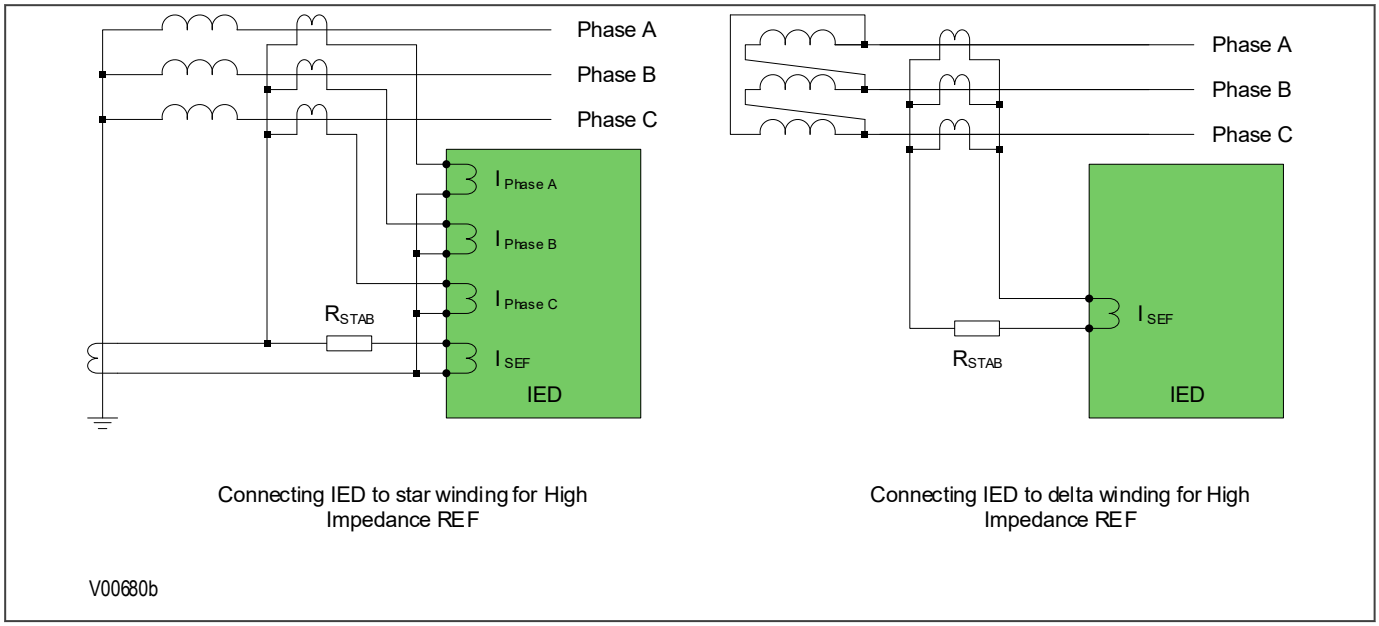


Figure 87: High impedance REF connection

6.13.2 RESTRICTED EARTH FAULT PROTECTION IMPLEMENTATION

6.13.2.1 RESTRICTED EARTH FAULT PROTECTION SETTINGS

Restricted Earth Fault Protection is implemented in the Restricted E/F column of the relevant settings group. It is here that the constants and bias currents are set.

The REF protection may be configured to operate as either a high impedance or biased element.

6.13.2.2 LOW IMPEDANCE REF

6.13.2.2.1 SETTING THE BIAS CHARACTERISTIC

Low impedance REF uses a bias charactersitic for increasing sensitivity and stabilising for through faults. The current required to trip the differential IED is called the Operate current. This Operate current is a function of the differential current and the bias current according to the bias characteristic.

The differential current is defined as follows:

$$I_{diff} = \left(\bar{I}_A + \bar{I}_B + \bar{I}_C\right) + K\bar{I}_N$$

The bias current is as follows:

$$I_{bias} = \frac{1}{2}\left\{\max\left[|I_A|,|I_B|,|I_C|\right] + K|I_N|\right\}$$

where:

- K = Neutral CT ratio / Line CT ratio
- IN = current measured by the neutral CT

The operate current is calculated according to the following characteristic:

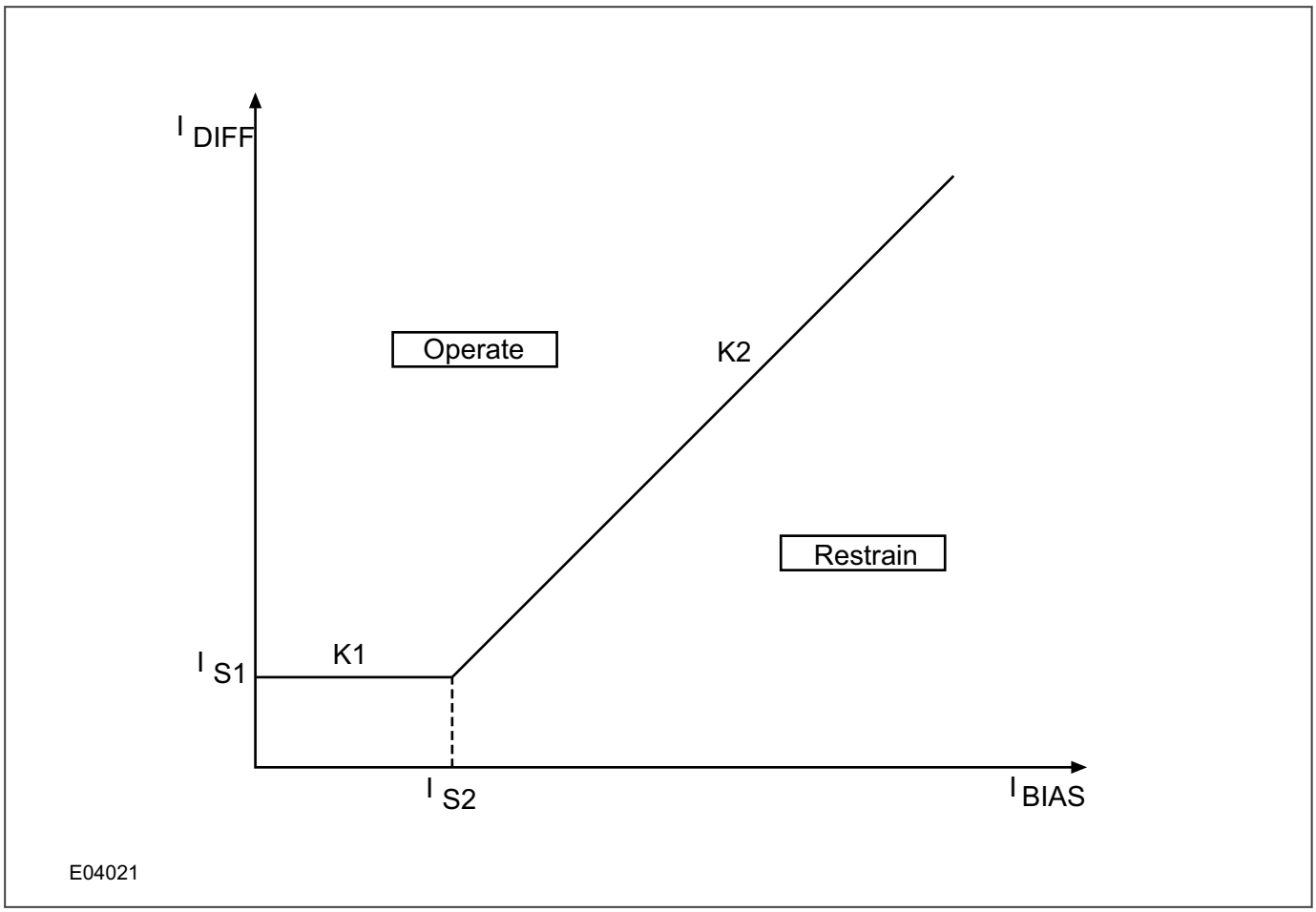


Figure 88: REF bias characteristic

The following settings are provided to define this bias characteristic:

- ***IREF> Is1***: sets the minimum trip threshold
- ***IREF> Is2***: sets the bias current kneepoint whereby the required trip current starts increasing
- ***IREF> k1***: defines the first slope (often set to 0%)
- ***IREF> k2***: defines the second slope

Note:
Is1 and Is2 are relative to the line CT, which is always the reference CT.

6.13.2.3 HIGH IMPEDANCE REF

The device provides a high impedance restricted earth fault protection function. An external resistor is required to provide stability in the presence of saturated line current transformers. Current transformer supervision signals do not block the high impedance REF protection. The appropriate logic must be configured in PSL to block the high impedance REF when any of the above signals is asserted.

6.13.2.3.1 HIGH IMPEDANCE REF CALCULATION PRINCIPLES

The primary operating current (Iop) is a function of the current transformer ratio, the device operate current (***IREF>Is***), the number of current transformers in parallel with a REF element (n) and the magnetizing current of each current transformer (Ie) at the stability voltage (Vs). This relationship can be expressed in three ways:

1. The maximum current transformer magnetizing current to achieve a specific primary operating current with a particular operating current:

$$I_e < \frac{1}{n}\left(\frac{I_{op}}{CT\ ratio} - [IREF > Is]\right)$$

2. The maximum current setting to achieve a specific primary operating current with a given current transformer magnetizing current:

$$[IREF > Is] < \left(\frac{I_{op}}{CT\ ratio} - nI_e\right)$$

3. The protection primary operating current for a particular operating current with a particular level of magnetizing current:

$$I_{op} = (CT\ ratio)([IREF > Is] + nI_e)$$

To achieve the required primary operating current with the current transformers that are used, you must select a current setting for the high impedance element, as shown in item 2 above. You can calculate the value of the stabilising resistor (R_{ST}) in the following manner.

$$R_{st} = \frac{Vs}{[IREF > Is]} = \frac{I_F\left(R_{CT} + 2R_L\right)}{[IREF > Is]}$$

where:

- R_{CT} = the resistance of the CT winding
- R_L = the resistance of the lead from the CT to the IED.

> *Note:*
> *The above formula assumes negligible relay burden.*

We recommend a stabilizing resistor, which is continuously adjustable up to its maximum declared resistance.

6.13.3 APPLICATION NOTES

6.13.3.1 STAR WINDING RESISTANCE EARTHED

Consider the following resistance earthed star winding below.

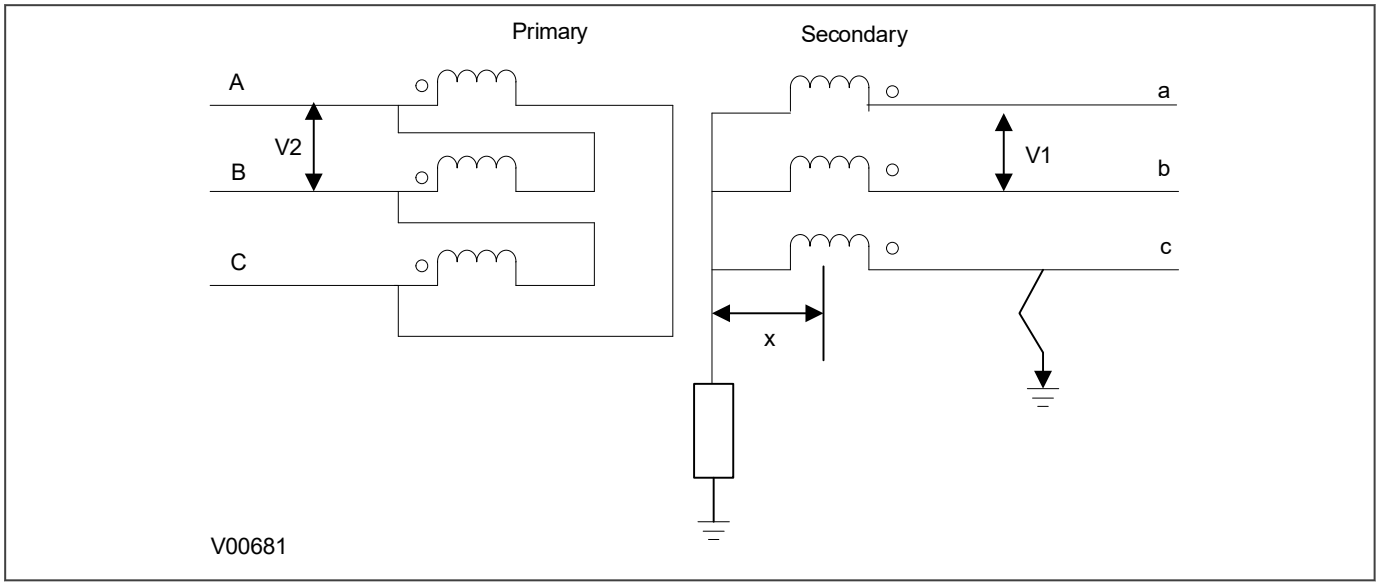


Figure 89: Star winding, resistance earthed

An earth fault on such a winding causes a current which is dependent on the value of earthing impedance. This earth fault current is proportional to the distance of the fault from the neutral point since the fault voltage is directly proportional to this distance.

The ratio of transformation between the primary winding and the short circuited turns also varies with the position of the fault. Therefore the current that flows through the transformer terminals is proportional to the square of the fraction of the winding which is short circuited.

The earthing resistor is rated to pass the full load current $I_{FLC} = V1/\sqrt{3}R$

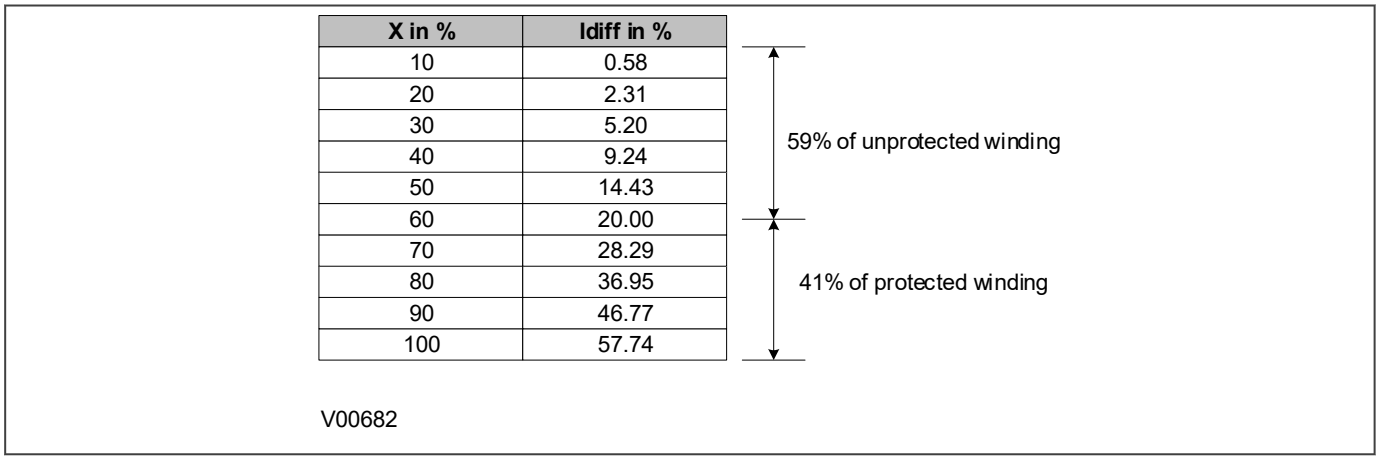
Assuming that V1 = V2 then $T2 = \sqrt{3}T1$

For a fault at x PU distance from the neutral, the fault current $If = xV1/\sqrt{3}R$

Therefore the secondary fault current referred to the primary is $I_{primary} = x^2.I_{FLC}/\sqrt{3}$

If the fault is a single end fed fault, the primary current should be greater than 0.2 pu (Is1 default setting) for the differential protection to operate. Therefore $x^2/\sqrt{3} > 20\%$

The following diagram shows that 41% of the winding is protected by the differential element.



X in %	Idiff in %
10	0.58
20	2.31
30	5.20
40	9.24
50	14.43
60	20.00
70	28.29
80	36.95
90	46.77
100	57.74

Figure 90: Percentage of winding protected

6.13.3.2 LOW IMPEDANCE REF PROTECTION APPLICATION

6.13.3.2.1 SETTING GUIDELINES FOR BIASED OPERATION

Two bias settings are provided in the REF characteristic. The K1 level of bias is applied up to through currents of Is2, which is normally set to the rated current of the transformer. K1 is normally be set to 0% to give optimum sensitivity for internal faults. However, if any CT mismatch is present under normal conditions, then K1 may be increased accordingly, to compensate. We recommend a setting of 20% in this case.

K2 bias is applied for through currents above Is2 and would typically be set to 150%.

According to ESI 48-3 1977, typical settings for the Is1 thresholds are 10-60% of the winding rated current when solidly earthed and 10-25% of the minimum earth fault current for a fault at the transformer terminals when resistance earthed.

6.13.3.2.2 LOW IMPEDANCE REF SCALING FACTOR

The three line CTs are connected to the three-phase CTs, and the neutral CT is connected to the neutral CT input. These currents are then used internally to derive both a bias and a differential current quantity for use by the low impedance REF protection. The advantage of this mode of connection is that the line and neutral CTs are not differentially connected, so the neutral CT can also be used to provide the measurement for the Standby Earth Fault Protection. Also, no external components such as stabilizing resistors or Metrosils are required.

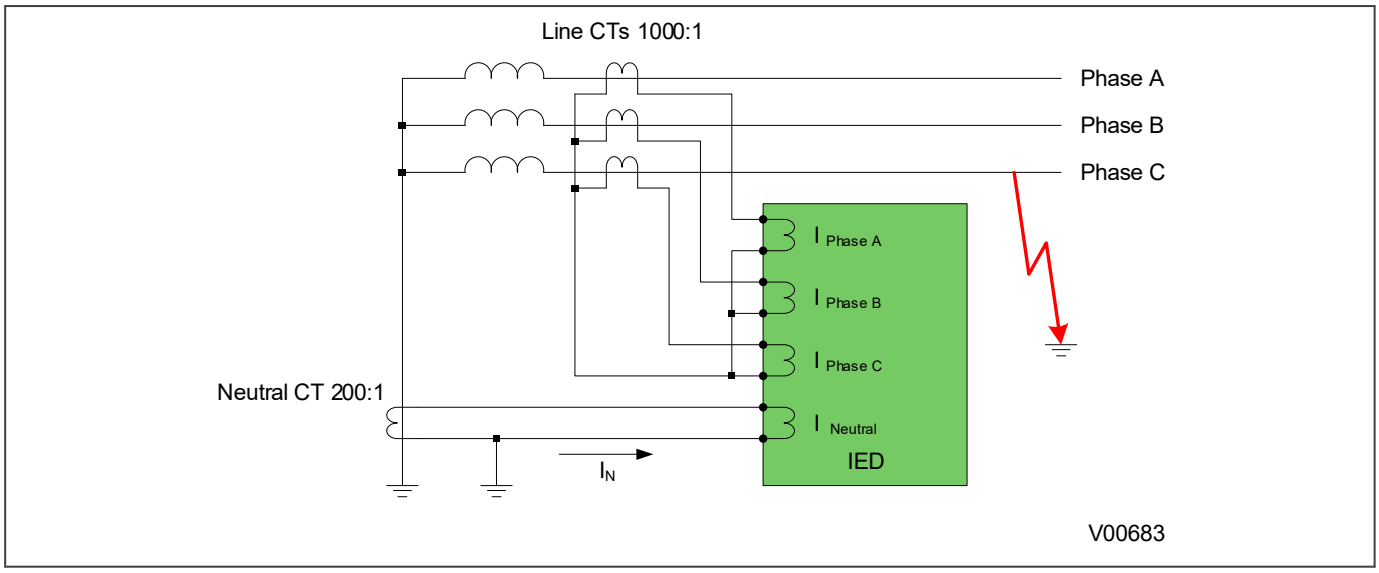


Figure 91: Low impedance REF scaling factor

Another advantage of Low Impedance REF protection is that you can use a neutral CT with a lower ratio than the line CTs in order to provide better earth fault sensitivity. In the bias calculation, the device applies a scaling factor to the neutral current. This scaling factor is as follows:

Scaling factor = K = Neutral CT ratio / Line CT ratio

This results in the following differential and bias current equations:

$$I_{diff} = \left(\bar{I}_A + \bar{I}_B + \bar{I}_C\right) + K\bar{I}_N$$

$$I_{bias} = \frac{1}{2}\left\{\max\left[|I_A|, |I_B|, |I_C|\right] + K|I_N|\right\}$$

6.13.3.2.3 PARAMETER CALCULATIONS

Consider a solidly earthed 90 MVA 132 kV transformer with a REF-protected star winding. Assume line CTS with a ratio of 400:1.

Is1 is set to 10% of the winding nominal current:

$= (0.1 \times 90 \times 10^6) / (\sqrt{3} \times 132 \times 10^3)$

= 39 Amps primary

= 39/400 = 0.0975 Amps secondary (approx 0.1 A)

Is2 is set to the rated current of the transformer:

$= 90 \times 10^6 / (\sqrt{3} \times 132 \times 10^3)$

= 390 Amps primary

= 390/400 = 0.975 Amps secondary (approx 1 A)

Set ***K1*** to 0% and ***K2*** to 150%

6.13.3.3 HIGH IMPEDANCE REF PROTECTION APPLICATION

6.13.3.3.1 HIGH IMPEDANCE REF OPERATING MODES

In the examples below, the respective Line CTS and measurement CTs must have the same CT ratios and similar magnetising characteristics.

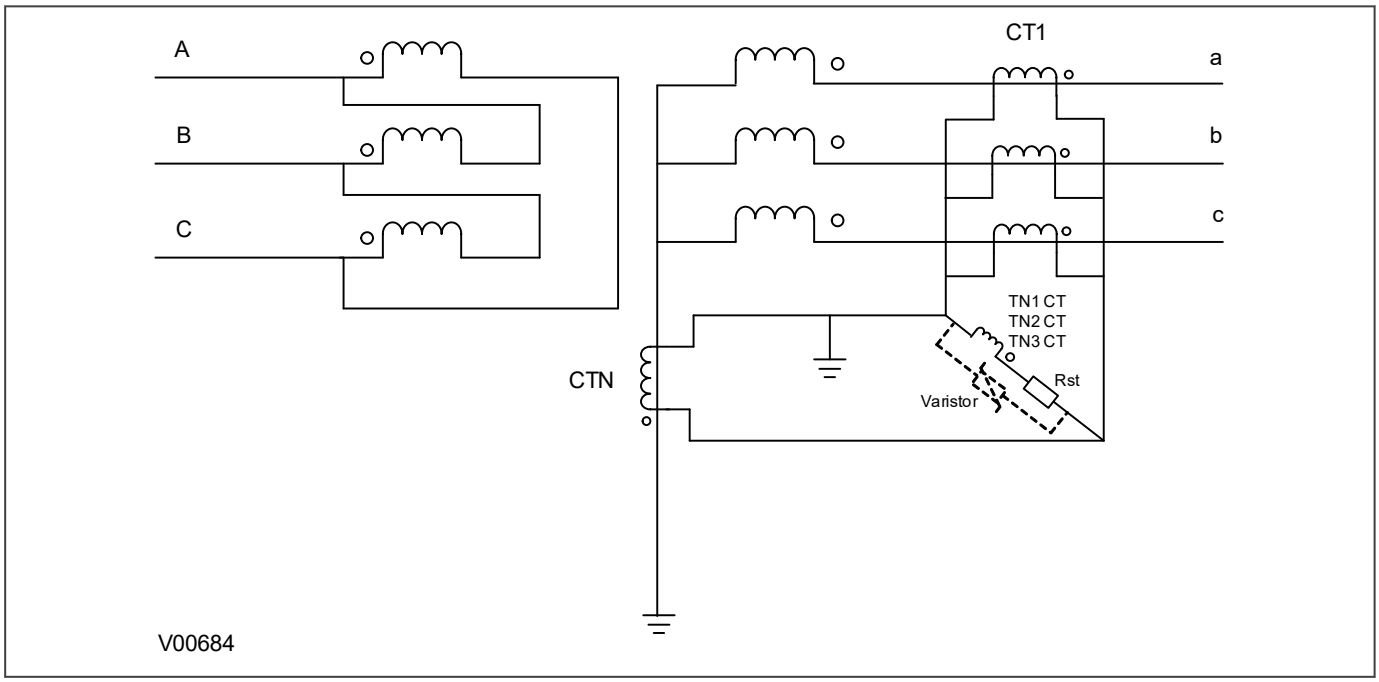


Figure 92: Hi-Z REF protection for a grounded star winding

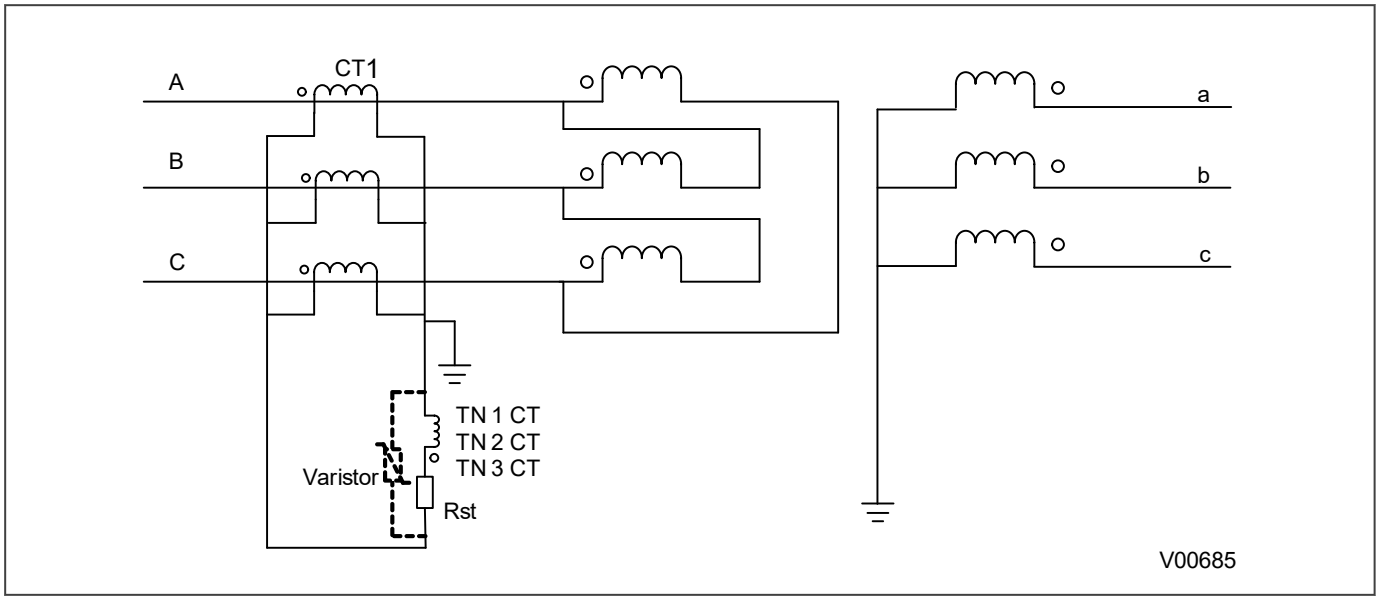


Figure 93: Hi-Z REF protection for a delta winding

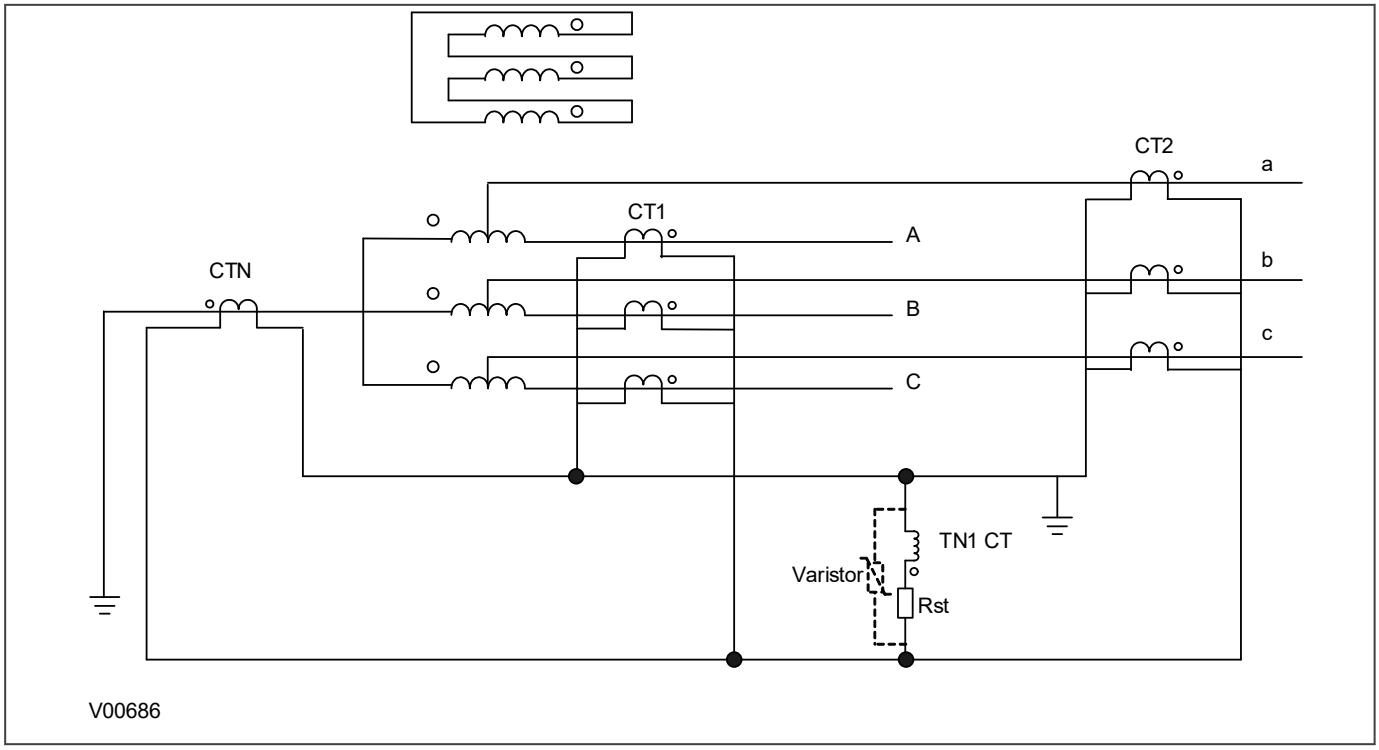


Figure 94: Hi-Z REF protection for autotransformer configuration

6.13.3.3.2 SETTING GUIDELINES FOR HIGH IMPEDANCE OPERATION

This scheme is very sensitive and can protect against low levels of fault current in resistance grounded systems. In this application, the ***IREF>Is*** settings should be chosen to provide a primary operating current less than 10-25% of the minimum earth fault level.

This scheme can also be used in a solidly grounded system. In this application, the ***IREF>Is*** settings should be chosen to provide a primary operating current between 10% and 60 % of the winding rated current.

The following diagram shows the application of a high impedance REF element to protect the LV winding of a power transformer.

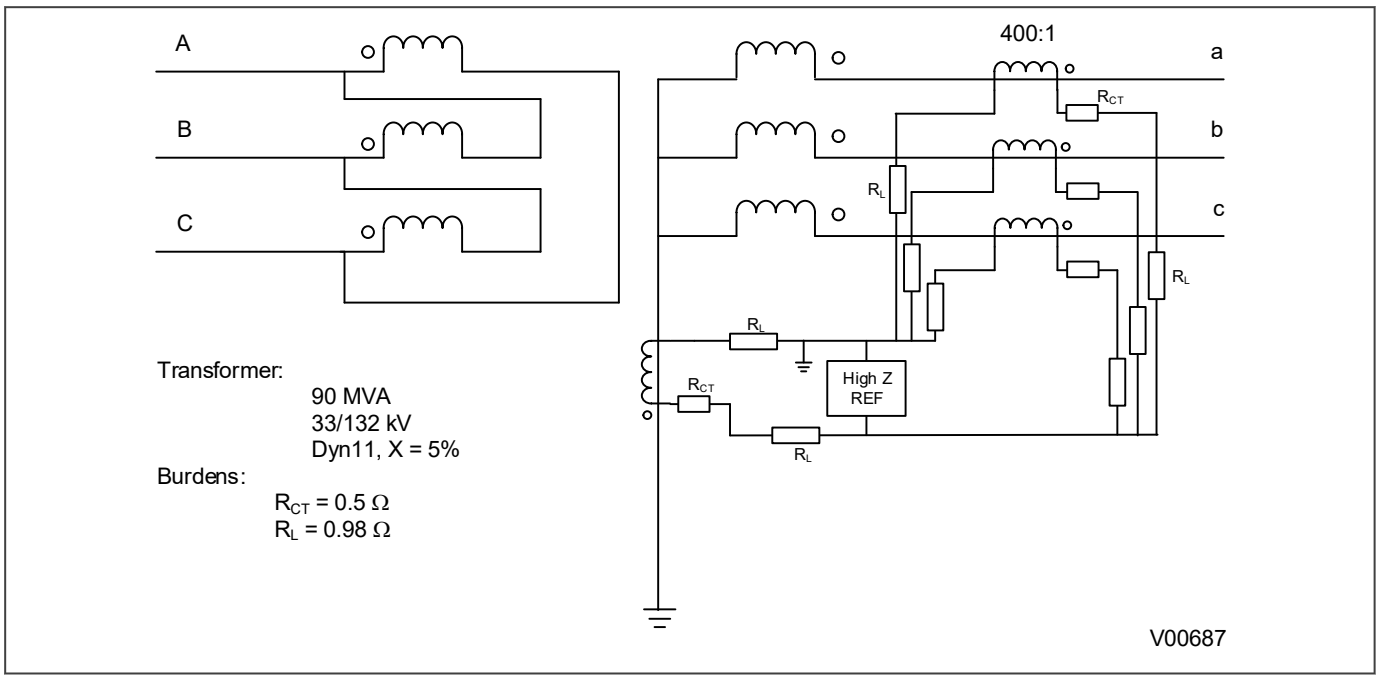


Figure 95: High impedance REF for the LV winding

6.13.3.3.2.1 STABILITY VOLTAGE CALCULATION

The transformer full load current, IFLC, is:

$$I_{FLC} = (90 \times 10^6)/32 \times 10^3 \times \sqrt{3}) = 394 \text{ A}$$

To calculate the stability voltage the maximum through fault level should be considered. The maximum through fault level, ignoring the source impedance, I_F, is:

$$I_F = I_{FLC}/_{TX} = 394/.05 = 7873 \text{ A}$$

The required stability voltage, VS, and assuming one CT saturated is:

$$V_s = KI_F(R_{CT} + 2R_L)$$

The following figure can be used to determine the K factor and the operating time. The K factor is valid when:

- 5 ≤ X/R ≤ 120

and

- 0.5In ≤ I f ≤ 40In

We recommend a value of VK/VS = 4.

With the transformer at full load current and percentage impedance voltage of 394A and 5% respectively, the prospective fault current is 7873 A and the required stability voltage Vs (assuming that one CT is saturated) is:

$$V_s = 0.9 \times 7873 \times (0.5 + 2 \times 0.98)/400 = 45.5 \text{ V}$$

The CTs knee point voltage should be at least 4 times Vs so that an average operating time of 40 ms is achieved.

6.13.3.3.2.2 PRIMARY CURRENT CALCULATION

The primary operating current should be between 10 and 60 % of the winding rated current. Assuming that the relay effective setting or primary operating current is approximately 30% of the full load current, the calculation below shows that a setting of less than 0.3 A is required.

$$\text{Effective setting} = 0.3I_{FLC} / \text{CT Ratio} = 0.3 \times 394 / 400 = \text{approximately } 0.3 \text{ A}$$

6.13.3.3.2.3 STABILISING RESISTOR CALCULATION

Assuming that a setting of 0.1A is selected the value of the stabilizing resistor, R_{ST}, required is

$$R_{ST} = V_s/(\text{IREF> Is1 (HV)}) = 45.5/0.1 = 455 \text{ ohms}$$

To achieve an average operating time of 40 ms, Vk/Vs should be 3.5.

The Kneepoint voltage is:

$$V_K = 4V_s = 4 \times 45.5 = 182 \text{ V.}$$

If the actual V_K is greater than 4 times V_s, then the K factor increases. In this case, V_s should be recalculated.

Note:
K can reach a maximum value of approximately 1.

6.13.3.3.2.4 CURRENT TRANSFORMER CALCULATION

The effective primary operating current setting is:

$$I_P = N(I_s + nI_e)$$

By re-arranging this equation, you can calculate the excitation current for each of the current transformers at the stability voltage. This turns out to be:

$$I_e = (0.3 - 0.1) / 4 = 0.05 \text{ A}$$

In summary, the current transformers used for this application must have a kneepoint voltage of 182 V or higher (note that maximum Vk/Vs that may be considered is 16 and the maximum K factor is 1), with a secondary winding resistance of 0.5 ohms or lower and a magnetizing current at 45.5 V of less than 0.05 A.

Assuming a CT kneepoint voltage of 200 V, the peak voltage can be estimated as:

$$V_P = 2\sqrt{2V_K(V_F-V_K)} = 2\sqrt{2(200)(9004-200)} = 3753 \text{ V}$$

This value is above the peak voltage of 3000 V and therefore a non-linear resistor is required.

Note:
The kneepoint voltage value used in the above formula should be the actual voltage obtained from the CT magnetizing characteristic and not a calculated value.

Note:
One stabilizing resistor, part No. ZB9016 756, and one varistor, part No. 600A/S1/S256 might be used.

6.14 THERMAL OVERLOAD PROTECTION

The heat generated within an item of plant is the resistive loss. The thermal time characteristic is therefore based on the equation I^2Rt. Over-temperature conditions occur when currents in excess of their maximum rating are allowed to flow for a period of time.

Temperature changes during heating follow exponential time constants. The device provides two characteristics for thermal overload protection; a single time constant characteristic and a dual time constant characteristic. You select these according to the application.

6.14.1 SINGLE TIME CONSTANT CHARACTERISTIC

This characteristic is used to protect cables, dry type transformers and capacitor banks.

The single constant thermal characteristic is given by the equation:

$$t = -\tau \log_e \left[\frac{I^2 - \left(KI_{FLC}\right)^2}{I^2 - I_p{}^2} \right]$$

where:

- t = time to trip, following application of the overload current I
- τ = heating and cooling time constant of the protected plant
- I = largest phase current
- I_{FLC} full load current rating (the Thermal Trip setting)
- K = a constant with the value of 1.05
- I_p = steady state pre-loading before application of the overload

6.14.2 DUAL TIME CONSTANT CHARACTERISTIC

This characteristic is used to protect equipment such as oil-filled transformers with natural air cooling. The thermal model is similar to that with the single time constant, except that two timer constants must be set.

For marginal overloading, heat will flow from the windings into the bulk of the insulating oil. Therefore, at low current, the replica curve is dominated by the long time constant for the oil. This provides protection against a general rise in oil temperature.

For severe overloading, heat accumulates in the transformer windings, with little opportunity for dissipation into the surrounding insulating oil. Therefore at high current levels, the replica curve is dominated by the short time constant for the windings. This provides protection against hot spots developing within the transformer windings.

Overall, the dual time constant characteristic serves to protect the winding insulation from ageing and to minimise gas production by overheated oil. Note however that the thermal model does not compensate for the effects of ambient temperature change.

The dual time constant thermal characteristic is given by the equation:

$$0.4e^{(-t/\tau_1)} + 0.6e^{(-t/\tau_2)} = \left[\frac{I^2 - \left(KI_{FLC}\right)^2}{I^2 - I_p{}^2} \right]$$

where:

- τ_1 = heating and cooling time constant of the transformer windings
- τ_2 = heating and cooling time constant of the insulating oil

6.14.3 THERMAL OVERLOAD PROTECTION IMPLEMENTATION

The device incorporates a current-based thermal characteristic, using RMS based load current to model heating and cooling of the protected plant. The element can be set with both alarm and trip stages.

Thermal Overload Protection is implemented in the *THERMAL OVERLOAD* column of the relevant settings group.

This column contains the settings for the characteristic type, the alarm and trip thresholds and the time constants.

6.14.4 THERMAL OVERLOAD PROTECTION LOGIC

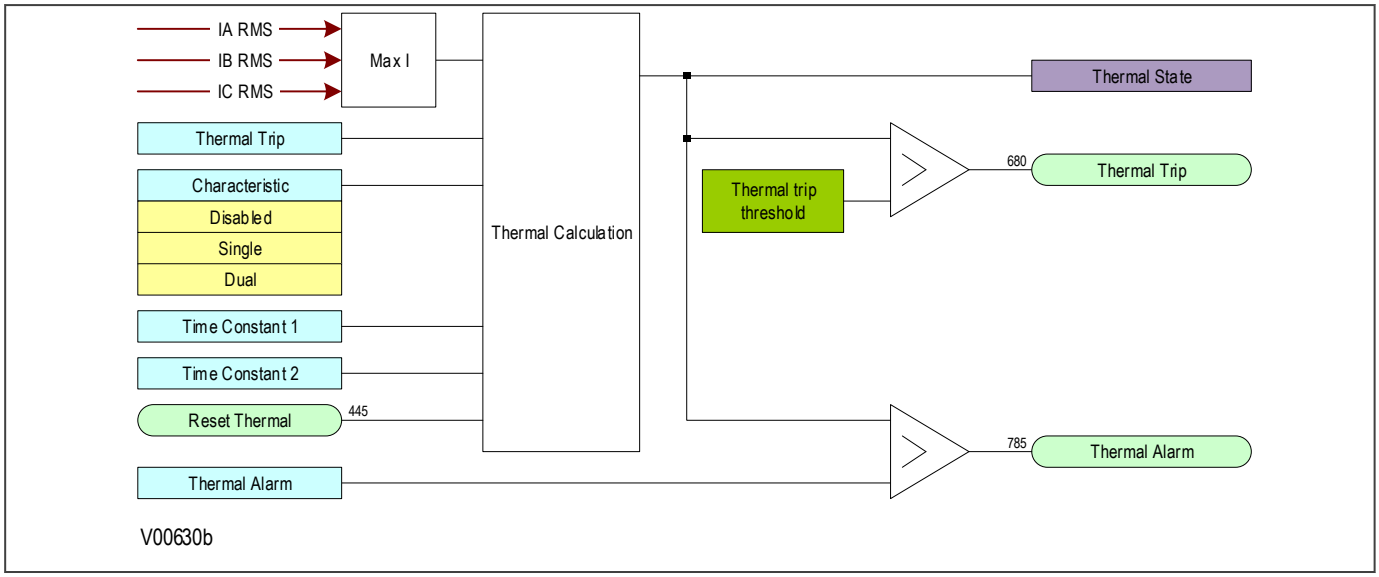


Figure 96: Thermal overload protection logic

The magnitudes of the three phase input currents are compared and the largest magnitude is taken as the input to the thermal overload function. If this current exceeds the thermal trip threshold setting a start condition is asserted.

The Start signal is applied to the chosen thermal characteristic module, which has three outputs signals; alarm trip and thermal state measurement. The thermal state measurement is made available in one of the *MEASUREMENTS* columns.

The thermal state can be reset by either a digital signal (Opto, GOOSE, InterMiCOM), if assigned to this function using programmable scheme logic or the HMI panel menu.

6.14.5 APPLICATION NOTES

6.14.5.1 SETTING GUIDELINES FOR DUAL TIME CONSTANT CHARACTERISTIC

The easiest way of solving the dual time constant thermal equation is to express the current in terms of time and to use a spreadsheet to calculate the current for a series of increasing operating times using the following equation, then plotting a graph.

$$I = \sqrt{\frac{0.4I_p^{\,2}.e^{(-t/\tau 1)} + 0.6I_p^{\,2}.e^{(-t/\tau 2)} - k^2.I_{FLC}^{\,2}}{0.4e^{(-t/\tau 1)} + 0.6e^{(-t/\tau 2)} - 1}}$$

	A	B	C	D	E	F
1						
2	**Time constant 1 =**		**300**	seconds		
3	**Time constant 2 =**		**7200**	seconds		
4	**Pre-overload current Ip =**		**0.9**	per unit		
5	**Full load current =**		**1**	Amps		
6						
7	**OP Time (t)**	**Overload current (I)**				
8	1	14.40852032				
9	1.5	11.7805774				
10	2	10.21617905				
11	2.5	9.150045407				
12	3	8.364131776				
13	3.5	7.754150044				
14	4	7.263123888				
15	4.5	6.856949012				

Figures based on equation

E00728

Figure 97: Spreadsheet calculation for dual time constant thermal characteristic

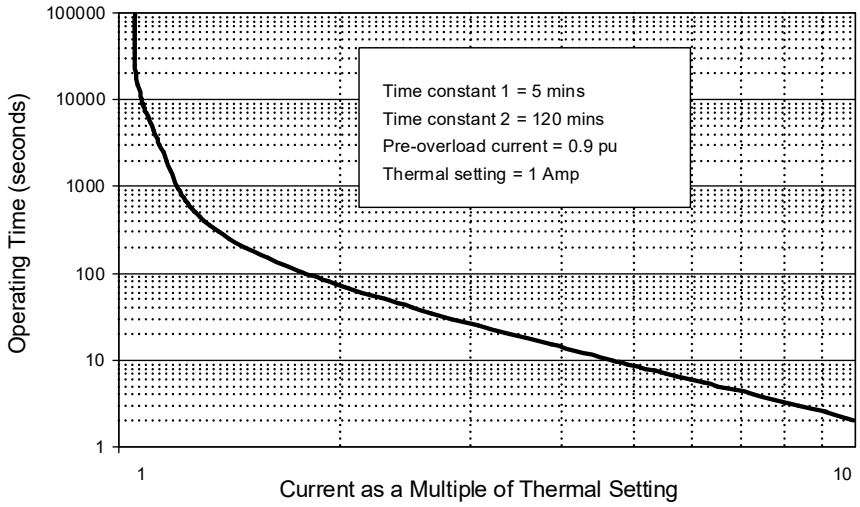


Figure 98: Dual time constant thermal characteristic

The current setting is calculated as:

Thermal Trip = Permissible continuous loading of the transformer item/CT ratio.

For an oil-filled transformer with rating 400 to 1600 kVA, the approximate time constants are:

- τ_1 = 5 minutes
- τ_2 = 120 minutes

An alarm can be raised on reaching a thermal state corresponding to a percentage of the trip threshold. A typical setting might be "Thermal Alarm" = 70% of thermal capacity.

Note:
The thermal time constants given in the above tables are typical only. Reference should always be made to the plant manufacturer for accurate information.

6.14.5.2 SETTING GUIDELINES FOR SINGLE TIME CONSTANT CHARACTERISTIC

The time to trip varies depending on the load current carried before application of the overload, i.e. whether the overload was applied from hot or cold.

The thermal time constant characteristic may be rewritten as:

$$e^{(-t/\tau)} = \left[\frac{\theta - \theta_p}{\theta - 1}\right]$$

where:

- θ = thermal state = $I^2/K^2I_{FLC}^2$
- θ_p = pre-fault thermal state = $I_p^2/K^2I_{FLC}^2$
- I_p is the pre-fault thermal state
- I_{FLC} is the full load current

Note:
A current of 105%Is (KI_{FLC}) has to be applied for several time constants to cause a thermal state measurement of 100%.

The current setting is calculated as:

Thermal Trip = Permissible continuous loading of the plant item/CT ratio.

The following tables show the approximate time constant in minutes, for different cable rated voltages with various conductor cross-sectional areas, and other plant equipment.

Area mm^2	6 - 11 kV	22 kV	33 kV	66 kV
25 - 50	10 minutes	15 minutes	40 minutes	–
70 - 120	15 minutes	25 minutes	40 minutes	60 minutes
150	25 minutes	40 minutes	40 minutes	60 minutes
185	25 minutes	40 minutes	60 minutes	60 minutes
240	40 minutes	40 minutes	60 minutes	60 minutes
300	40 minutes	60 minutes	60 minutes	90 minutes

Plant Type	Time Constant (Minutes)
Dry-type transformer <400 kVA	40
Dry-type transformers 400 – 800 kVA	60 - 90
Air-core reactors	40
Capacitor banks	10
Overhead lines with cross section > 100 mm^2	10
Overhead lines	10
Busbars	60

6.15 BROKEN CONDUCTOR PROTECTION

One type of unbalanced fault is the 'Series' or 'Open Circuit' fault. This type of fault can arise from, among other things, broken conductors. Series faults do not cause an increase in phase current and so cannot be detected by overcurrent protection. However, they do produce an imbalance, resulting in negative phase sequence current, which can be detected.

It is possible to apply a negative phase sequence overcurrent element to detect broken conductors. However, on a lightly loaded line, the negative sequence current resulting from a series fault condition may be very close to, or less than, the full load steady state imbalance arising from CT errors and load imbalances, making it very difficult to distinguish. A regular negative sequence element would therefore not work at low load levels. To overcome this, the device incorporates a special Broken Conductor protection element.

The Broken Conductor element measures the ratio of negative to positive phase sequence current (I2/I1). This ratio is approximately constant with variations in load current, therefore making it more sensitive to series faults than standard negative sequence protection.

A setting invokes different internal logic blocks to allow the broken conductor detection function to be applied to cases affecting either just a single phase, or permutations of one or two phases.

6.15.1 BROKEN CONDUCTOR PROTECTION IMPLEMENTATION

Broken Conductor protection is implemented in the *BROKEN CONDUCTOR* column of the relevant settings group.

This column contains the settings to enable the function, for the pickup threshold and the time delay.

6.15.2 BROKEN CONDUCTOR PROTECTION LOGIC

The ratio of I_2/I_1 is calculated and compared with the threshold setting. If the threshold is exceeded, the delay timer is initiated.

A BRC Detection setting invokes different logic blocks (Logic 1 or Logic 2) according to a preference. The preference can be either to operate according to just single-phase detection, or to operate upon detection of the condition affecting one or two phases.

The CTS block signal is used to block the operation of the delay timer.

The broken conductor functionality and internal logic is presented in the following two figures:

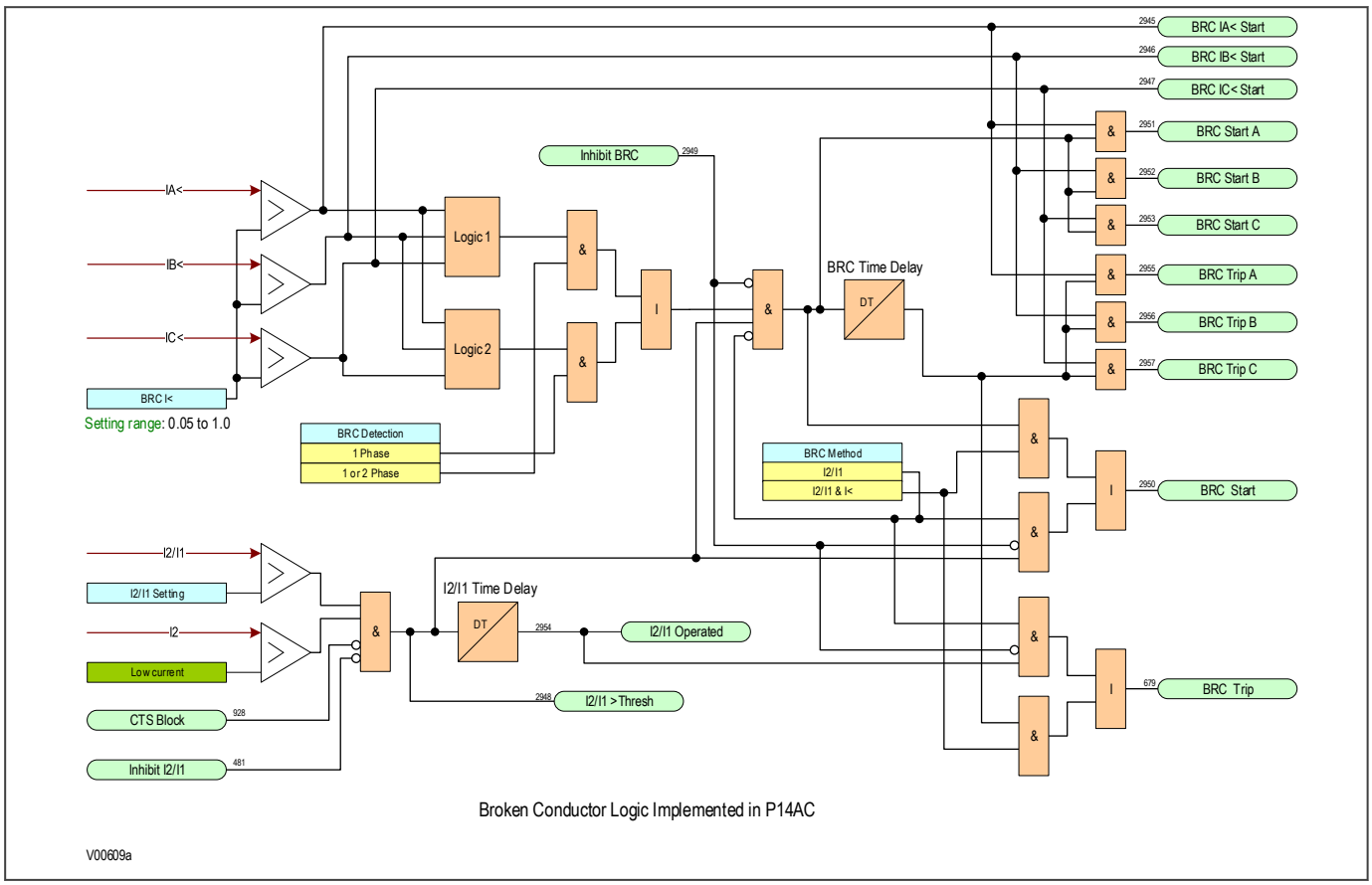


Figure 99: Broken conductor logic

Broken Conductor Internal Logic Functionality (Logic 1 and Logic 2)

Logic 1 Function - any 1 or 2 (of 3)

Logic 2 Function - only any 1 of 3

BRC IA< Start	BRC IB< Start	BRC IC< Start	Logic 1	Logic 2
0	0	0	False	False
0	0	1	True	True
0	1	0	True	True
0	1	1	True	False
1	0	0	True	True
1	0	1	True	False
1	1	0	True	False
1	1	1	False	False

V00009

Figure 100: Broken conductor internal logic functionality

6.15.3 APPLICATION NOTES

6.15.3.1 SETTING GUIDELINES

For a broken conductor affecting a single point earthed power system, there will be little zero sequence current flow and the ratio of I_2/I_1 that flows in the protected circuit will approach 100%. In the case of a multiple earthed power system (assuming equal impedance's in each sequence network), the ratio I_2/I_1 will be 50%.

In practise, the levels of standing negative phase sequence current present on the system govern this minimum setting. This can be determined from a system study, or by making use of the measurement facilities at the commissioning stage. If the latter method is adopted, it is important to take the measurements during maximum system load conditions, to ensure that all single-phase loads are accounted for.

Note:
A minimum value of 8% negative phase sequence current is required for successful operation.

Since sensitive settings have been employed, we can expect that the element will operate for any unbalanced condition occurring on the system (for example, during a single pole autoreclose cycle). For this reason, a long time delay is necessary to ensure co-ordination with other protection devices. A 60 second time delay setting may be typical.

The following example was recorded by an IED during commissioning:

$$I_{\text{full load}} = 500\text{A}$$

$$I_2 = 50\text{A}$$

therefore the quiescent I_2/I_1 ratio = 0.1

To allow for tolerances and load variations a setting of 20% of this value may be typical: Therefore set:

$$I_2/I_1 = 0.2$$

In a double circuit (parallel line) application, using a 40% setting will ensure that the broken conductor protection will operate only for the circuit that is affected. A setting of 0.4 results in no pick-up for the parallel healthy circuit.

Set I_2/I_1 Time Delay = 60 s to allow adequate time for short circuit fault clearance by time delayed protections.

6.16 SECOND HARMONIC BLOCKING

When a transformer is initially connected to a source of AC voltage, there may be a substantial surge of current through the primary winding called inrush current.

Inrush current caused by energisation is a normal phenomenon not a fault condition. The magnitude of inrush current, however, is often larger than that produced by faults occurring inside the transformer. The protection should operate in case of a fault, but we don't want it to trip just because a transformer has been energised. We need, therefore, a method to differentiate between the two conditions. Fortunately, the characteristics of inrush currents are quite different from most fault currents: An inrush current waveform is rich in harmonics (particularly the second), whereas an internal fault current generally consists only of the fundamental. We can thus develop a restraining method related to the harmonic content of the measured current. The mechanism by which this is achieved is called second harmonic blocking.

6.16.1 SECOND HARMONIC BLOCKING IMPLEMENTATION

In this device, a technique called second harmonic blocking is used to prevent false protection tripping during transformer inrush conditions. It works by detecting the second harmonic component of the measured current signals. If the feature is selected, then if the second harmonic component of the measured current signal is within certain limits, a blocking signal is issued which can block operation of the overcurrent elements. The following overcurrent protection types can be affected by second harmonic blocking:

- Phase Overcurrent protection (POC)
- Earth Fault protection (derived and measured) (EF1 and EF2)
- Sensitive Earth Fault protection (SEF)

Second harmonic blocking is configured using the associated settings located in the appropriate overcurrent column of the relevant setting group (***OVERCURRENT, EARTH FAULT, SEF/REF PROT'N)***.

The application of second harmonic blocking to the different overcurrent protection types is determined by an ***I> Blocking*** setting associated with the affected protection elements. Second harmonic blocking can be applied to all stages of each of the elements. For phase overcurrent elements, second harmonic blocking can be applied to each phase individually (phase segregated) or to all three phases at once (cross-block).

The function works by measuring and comparing the values of the second harmonic current components to the values of the fundamental component for each affected protection type. If this ratio exceeds set thresholds, then the blocking signal is generated. The thresholds are defined by the ***2ndHarm Thresh*** settings.

We only want to use second harmonic content to block the protection if the fundamental current component is within the normal range. Large values of fundamental currents are indicative of a fault, which must be protected. For this reason, there is another threshold associated with the second harmonic influence which, when exceeded, removes the 2nd harmonic blocking function.

6.16.2 SECOND HARMONIC BLOCKING LOGIC (IN OVERCURRENT)

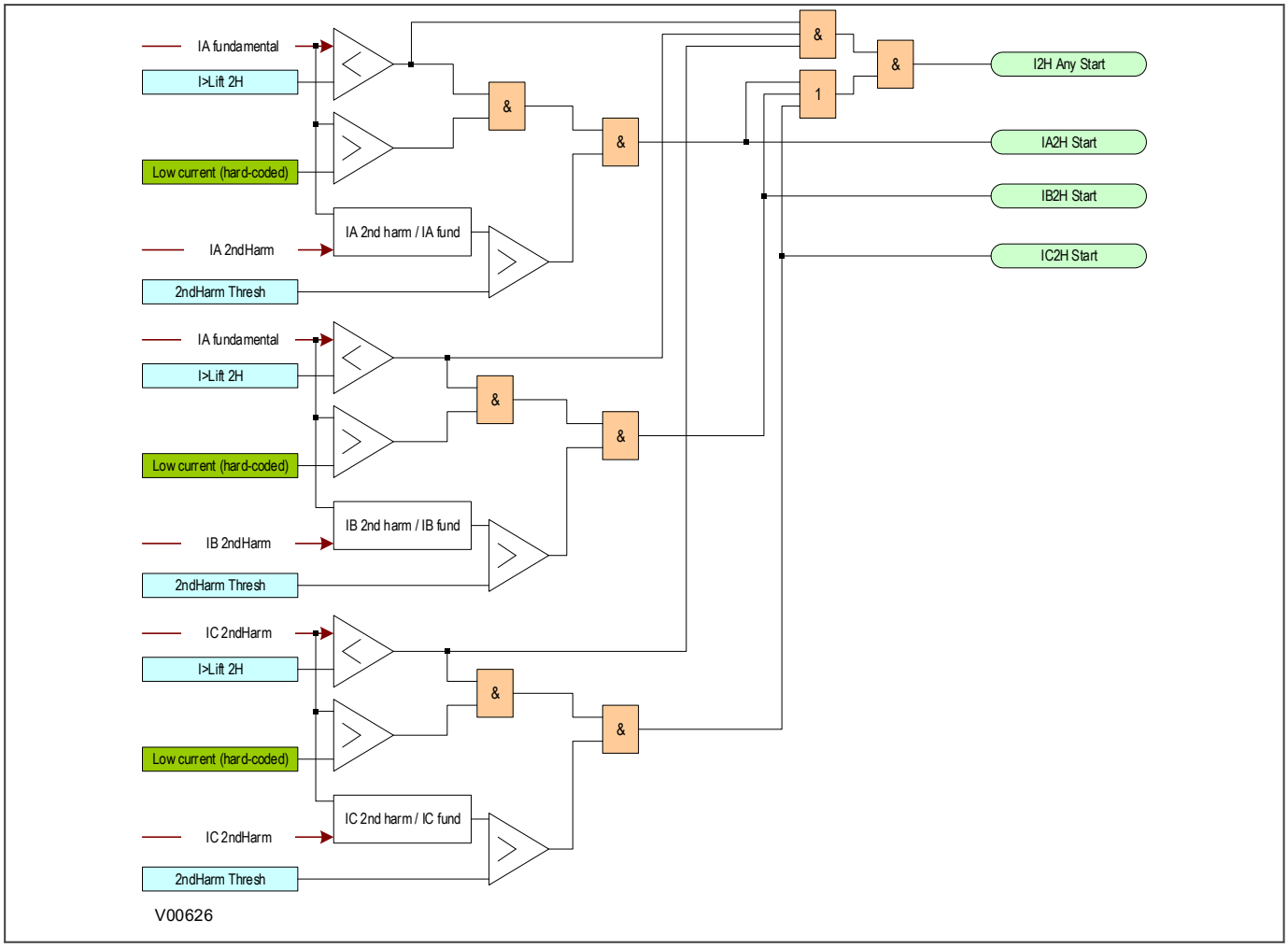


Figure 101: 2nd harmonic blocking logic (in overcurrent)

The function works by identifying and measuring the inrush currents present in the phase currents at switch on. It does this by comparing the value of the second harmonic current components to the value of the fundamental component. If this ratio exceeds the set thresholds, then the blocking signal is generated. The threshold is defined by the ***2ndHarm Thresh*** setting.

We only want the function to block the protection if the fundamental current component is within the normal range. If this exceeds the normal range, then this is indicative of a fault, which must be protected. For this reason there is another settable trigger ***I>lift 2H***, which when exceeded, stops the 2nd harmonic blocking function.

6.16.3 SECOND HARMONIC BLOCKING LOGIC (IN EARTH FAULT)

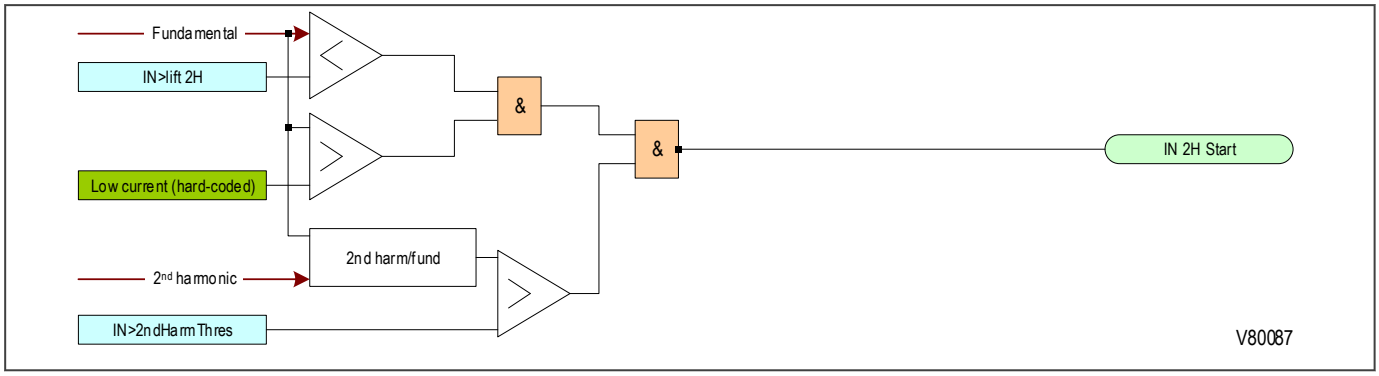


Figure 102: 2nd harmonic blocking logic (earth fault input)

There are two independent 2nd harmonic blocking modules, one for EF1 and one for EF2. Both of these can determine the ratio of the second harmonic component present in the earth fault current (measured or derived based on settings) to the fundamental. If this ratio exceeds the set threshold, then the earth fault second harmonic blocking signal is generated. The threshold is defined by the ***IN(n)>2ndHarmThres*** setting.

We only want the function to block the protection if the fundamental current component is within the normal range. If this exceeds the normal range, then this is indicative of a fault, which must be protected. For this reason there is another settable trigger ***IN(n)> lift 2H***, which when exceeded, stops the 2nd harmonic blocking function.

The minimum detection level is 50 mA rms.

6.16.4 SECOND HARMONIC BLOCKING LOGIC (IN SEF/REF PROTECTION)

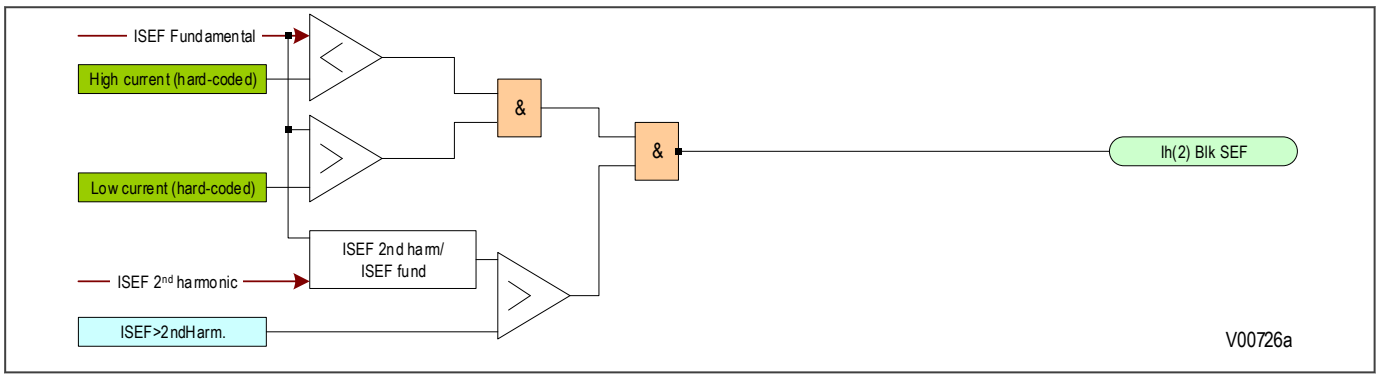


Figure 103: 2nd harmonic blocking logic (SEF input)

The function measures the current present at the sensitive earth fault current input and determines the ratio of the second harmonic component to the fundamental. If this ratio exceeds the set threshold, then the sensitive earth fault second harmonic blocking signal is generated. The threshold is defined by the ***ISEF>2nd Harm.*** setting.

For the second harmonic blocking of the SEF function, the minimum detection level is 4 mA rms. Second harmonic blocking is removed from the SEF function if the input current is determined to have risen above 1.8 A rms for any sample over the previous cycle. There is no additional delay on pick-up but there is a 1 cycle delay on drop-off.

6.16.5 APPLICATION NOTES

6.16.5.1 SETTING GUIDELINES

During the energisation period, the second harmonic component of the inrush current may be as high as 70%. The second harmonic level may be different for each phase, which is why phase segregated blocking is available.

If the setting is too low, the 2nd harmonic blocking may prevent tripping during some internal transformer faults. If the setting is too high, the blocking may not operate for low levels of inrush current which could result in undesired tripping of the overcurrent element during the energisation period. In general, a setting of 15% to 20% is suitable.

6.17 LOAD BLINDERS

Load blinding is a mechanism, where protection elements are prevented from tripping under heavy load, but healthy conditions. In the past this mechanism was mainly used for transmission systems and was rarely needed at distribution voltage levels. In the last few years, however, distribution networks have become more subject to periods of sustained heavy loads. This is due to a number of reasons, one of which is the increase of distributed generation. For this reason, it has become very desirable to equip overcurrent protection, normally targeted at distribution networks, with load blinding functionality. This device features load blinders to enhance the overcurrent protection.

Load blinders work by measuring, not only the system current levels, but also the system voltage levels and making tripping decisions based on analysis of both of these measurements. This is known as Impedance measurement.

When the measured current is higher than normal, this can be caused by one of two things; either a fault or a heavy load. If the cause is a fault, the system voltage level will reduce significantly. However, if the cause is a heavy, but healthy load, the voltage will not decrease significantly. Therefore, by measuring the both the system voltage and currents, the protection can make a decision not to trip under heavy load conditions.

The principle of a load blinder is to configure a blinder envelope, which surrounds the expected worst case load limits, and to block tripping for any impedance measured within this blinder region. Only fault impedance outside the load area is allowed to cause a trip. It is possible to set the impedance and angle setting independently for the forward and reverse regions in the Z plane.

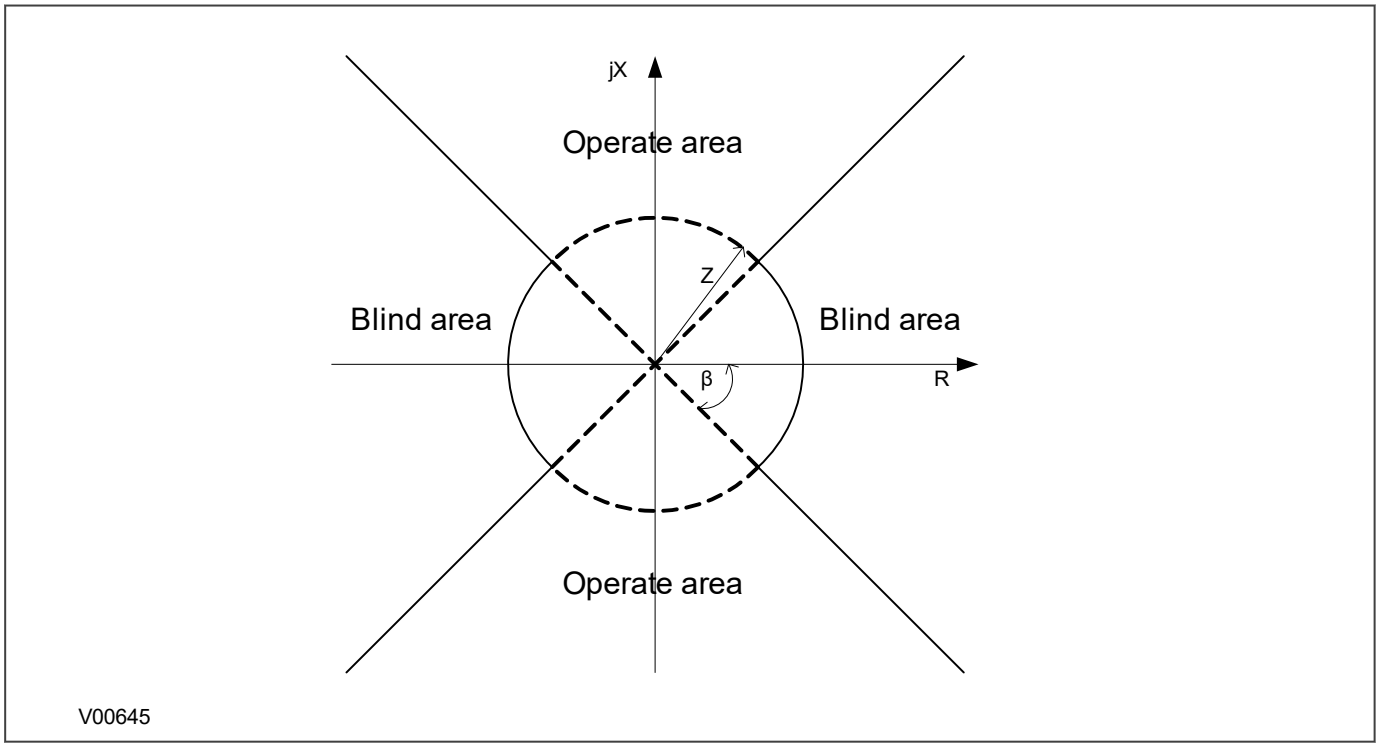


Figure 104: Load blinder and angle

6.17.1 LOAD BLINDER IMPLEMENTATION

The Load blinder function is implemented in the *OVERCURRENT* column of the relevant settings group, under the sub-heading *LOAD BLINDER*.

The settings allow you to set the impedance and angle limits for both reverse and forward directions, the undervoltage and negative sequence current thresholds for blocking the function, and the operation mode.

There are two modes of operation; single phase and three phase;

The single phase mode uses the normal impedance (Z) of each phase. When single phase mode is selected, the overcurrent blocking is phase segregated and is dependant on the individual overcurrent settings per phase. In single phase mode, only the undervoltage threshold (***Blinder V< Block***) can block the function.

The three phase mode uses positive sequence impedance (Z1). The three phase mode uses both the negative sequence overcurrent threshold (***Blinder I2>Block***) and the undervoltage threshold (***Blinder V< Block***) to block the function.

6.17.2 LOAD BLINDER LOGIC

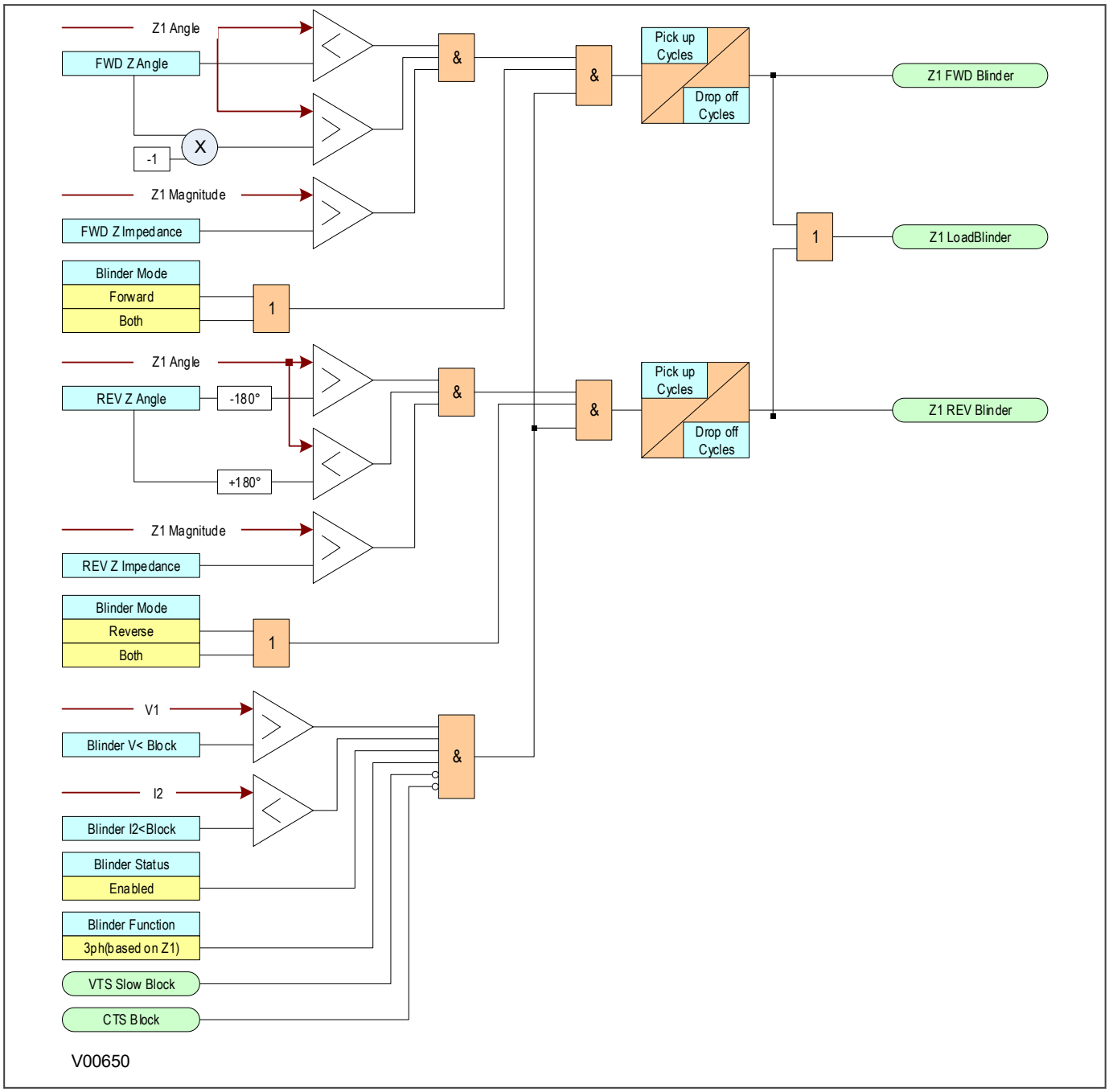


Figure 105: Load blinder logic 3phase

For the forward direction, the positive sequence impedance magnitude is compared with a set value, and the positive sequence impedance angle is compared with two values, which define the angular range. If the criteria are

satisfied and the Blinder mode is in the direction Forward or Both, the blinder signals ***Z1 FWD Blinder*** and ***Z1 LoadBlinder*** are produced.

For the reverse direction, the positive sequence impedance magnitude is compared with a set value, and the positive sequence impedance angle is compared with two values, which define the angular range. If the criteria are satisfied and the Blinder mode is in the direction Forward or Both, the blinder signals ***Z1 REV Blinder*** and ***Z1 LoadBlinder*** are produced.

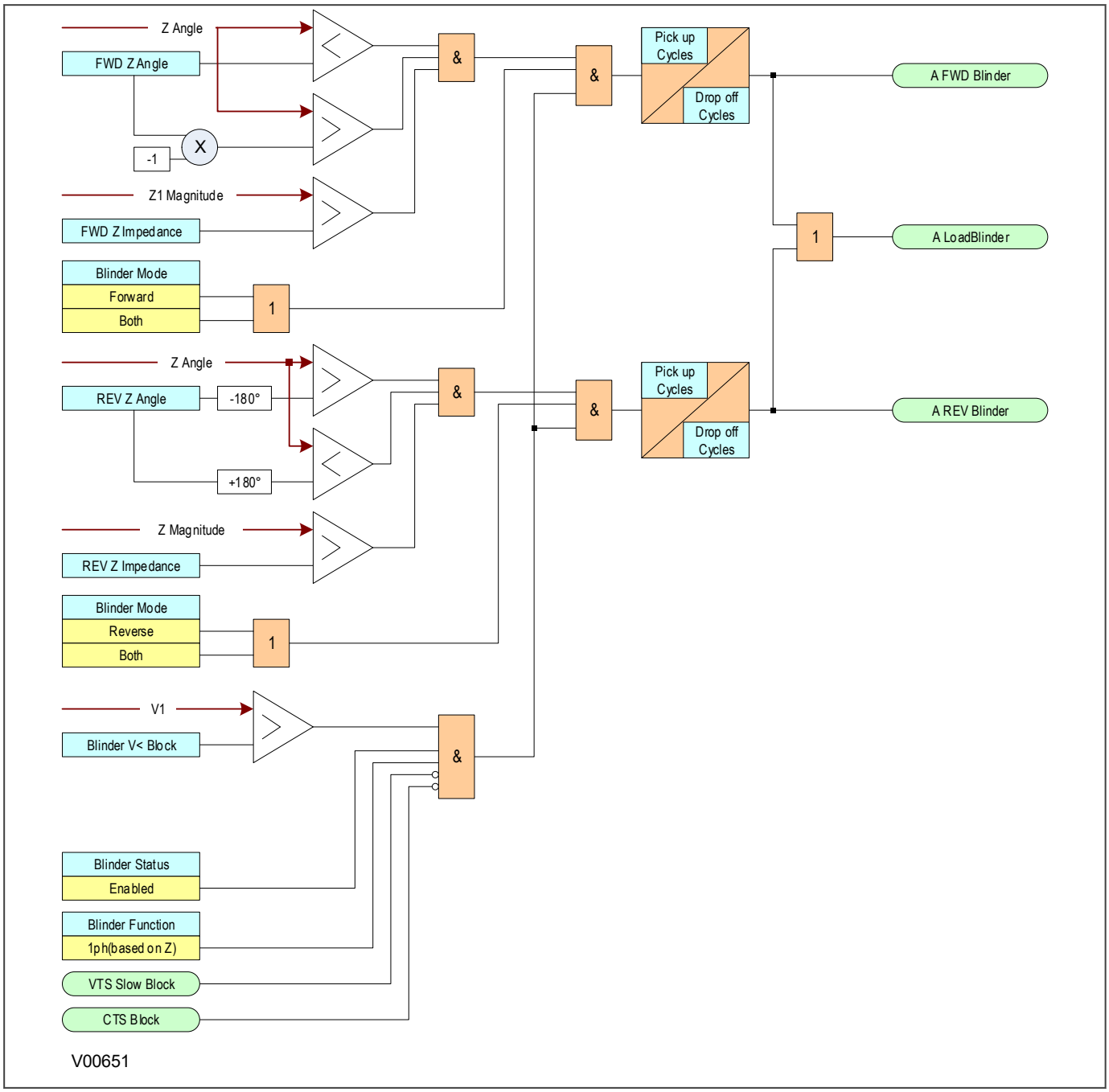


Figure 106: Load blinder logic phase A

The diagram shows the single-phase Load Blinder logic for phase A. The same principle applies to phases B and C. The single phase Load Blinder logic is very similar to the three-phase Load Blinder logic. The main differences are:

The single-phase function does not use positive sequence impedance, it uses normal impedance measurment. It also does not use negative sequence overcurrent to block the function.

6.18 NEUTRAL ADMITTANCE PROTECTION

Neutral admittance protection works by calculating the neutral admittance from the neutral input current and voltage (I_N/V_N). The neutral current input is measured with an earth fault or sensitive earth fault current transformer, and the neutral voltage is based on the internally derived quantity VN or optionally from the 4th VT if it is designated for checksynch. Three single stage elements are provided:

- Overadmittance YN>: This is non-directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input
- Overconductance GN>: This is non-directional or directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input
- Oversusceptance BN>: This is non-directional or directional, providing both start and time delayed trip outputs. The trip may be blocked by a logic input

The overadmittance elements YN>, GN> and BN> will operate providing the neutral voltage remains above the set level for the set operating time of the element. They are blocked by operation of the fast VTS block signal from the VT supervision function.

The overadmittance elements provide measurements of admittance, conductance and susceptance, while enabled, that also appear in the fault record.

The overadmittance elements are capable of initiating auto-reclose by means of YN>, GN> and BN> settings in the AUTO-RECLOSE menu column.

6.18.1 NEUTRAL ADMITTANCE OPERATION

The admittance protection is non-directional. Hence, provided the magnitude of admittance exceeds the set value ***YN>*** Set, and the magnitude of neutral voltage exceeds the set value VN Threshold, and the element is enabled, the device will operate.

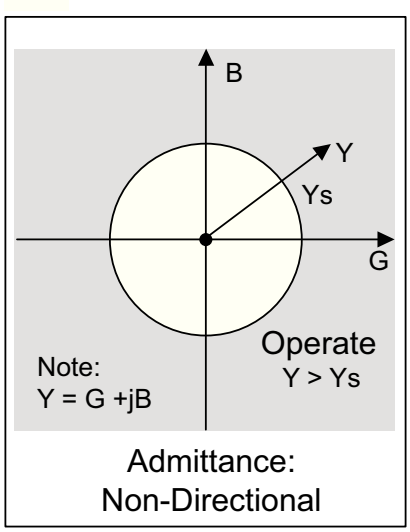


Figure 107: Admittance protection

6.18.2 CONDUCTANCE OPERATION

The conductance protection may be set non-directional, directional forward or directional reverse. Hence, provided the magnitude and the directional criteria are met for conductance, and the magnitude of neutral voltage exceeds

the set value VN Threshold, and the element is enabled, the device will operate. The correction angle causes rotation of the directional boundary for conductance through the set correction angle.

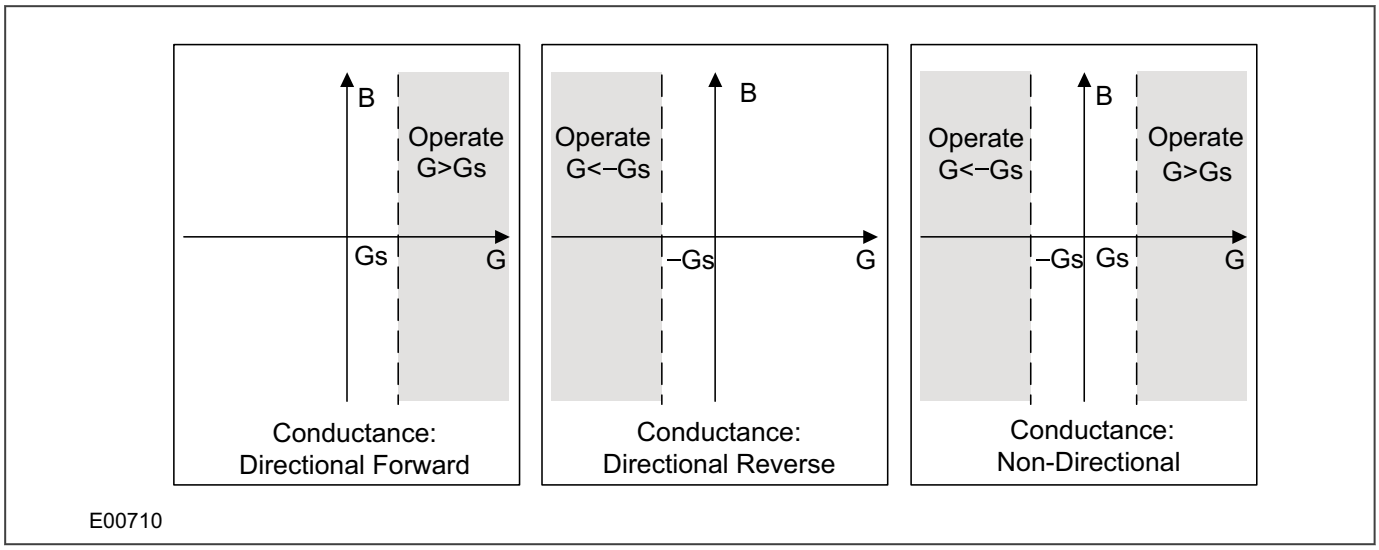


Figure 108: Conductance operation

Note:
For forward operation, the centre of characteristic occurs when IN is in phase with VN.

Note:
If the correction angle is set to +30°, this rotates the boundary from 90° - 270° to 60° - 240°. It is assumed that the direction of the G axis indicates 0°.

6.18.3 SUSCEPTANCE OPERATION

The susceptance protection may be set non-directional, directional forward or directional reverse. Hence, provided the magnitude and the directional criteria are met for susceptance, and the magnitude of neutral voltage exceeds the set value VN Threshold, and the element is enabled, the device will operate. The correction angle causes rotation of the directional boundary for susceptance through the set correction angle.

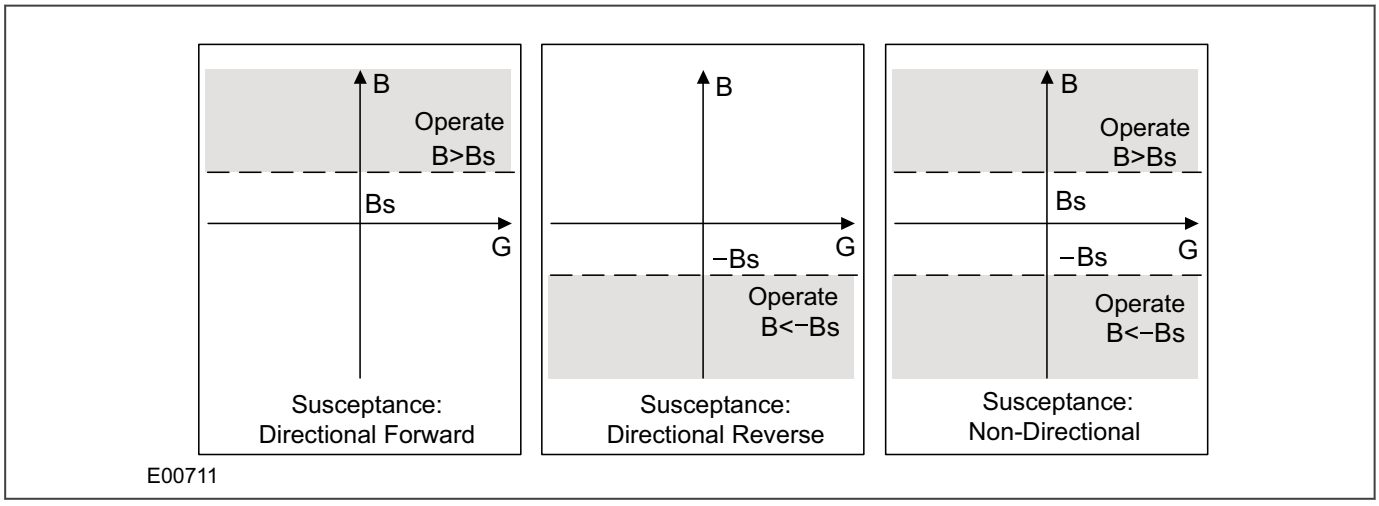


Figure 109: Susceptance operation

Note:
For forward operation, the centre of characteristic occurs when IN ieads VN by 90°.

Note:
If the correction angle is set to +30°, this rotates the boundary from 0° - 180° to 330° - 150°. It is assumed that the direction of the G axis indicates 0°.

6.19 BUSBAR PROTECTION

Busbars are the nerve centers of the power system. This is where power lines are connected together in a substation. Essentially a bus bar is a robust and highly conductive metal framework, onto which power lines are connected.

Busbars can pass current from a large number of lines, so a fault on the busbar could result in an extremely large fault current resulting in enormous damage. Faults on busbars are generally rare, but because of the extreme consequence in the event of failure, it is generally wise to provide dedicated protection for them.

Because the connections to busbars are close together, differential protection offers a convenient solution for busbar protection. Using the principle of Kirchoff's law, we need only to compare the sum of the incoming currents with the sum of the outgoing current and establish the difference. If there is a significant difference, then this indicates a fault on the busbar.

The following figure shows a simplified busbar with two input lines and three output lines.

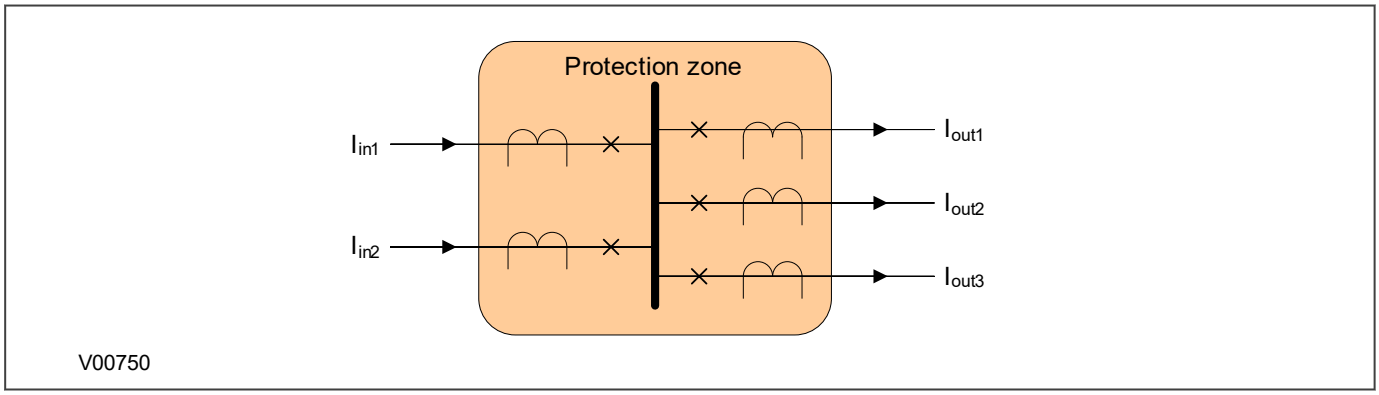


Figure 110: Simplified busbar representation

In this example, if the vector sum of Iin1, Iin2, Iout1, Iout2 and Iout3 = 0, there is no fault. If the vector sum is not equal to zero, then there is a fault.

There are various protection techniques for busbars, but the technique which is most commonly used is high impedance differential protection. A standard overcurrent protection element can be used for this purpose.

For high impedance differential protection, we need to connect the secondary windings of identical current transformers in parallel, then measure the summed current as follows:

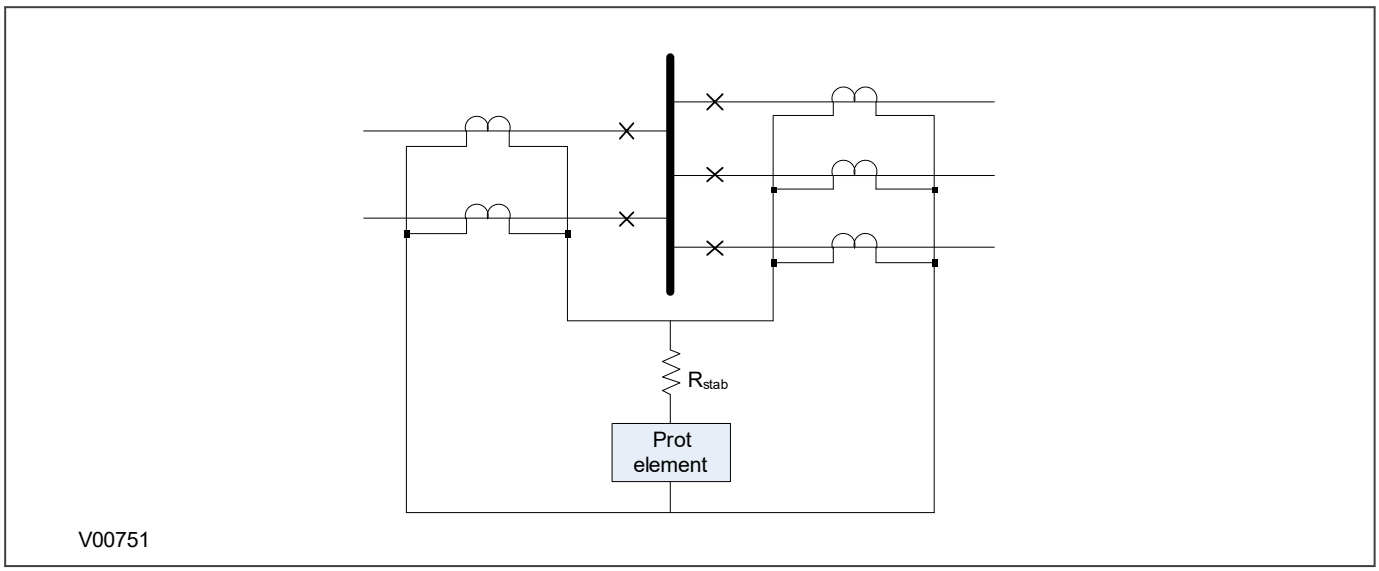


Figure 111: High impedance differential protection for busbars

The stabilising resistor R_{stab} is the reason why the protection type is high impedance. This resistor reduces the value of the spill current caused by CT discrepancies, thereby reducing the chance of maloperation caused by external faults.

6.19.1 BUSWIRE SUPERVISION

P14 feeder protection devices can use their overcurrent elements for high impedance busbar protection applications. With any high impedance busbar application, it is essential to provide a special type of CT supervision called Buswire Supervision. This is to prevent overvoltages on the CTs in case of CT open circuits and to prevent overheating of the protection devices.

This buswire supervision can be achieved using a dedicated device called an MVTP relay. But this functionality can now be achieved numerically with any P14 device from software versions 52 and 61 via the Sensitive Overvoltage Protection (SOV)function. The unique characteristic in SOV function extends the device's capability to mimic the buswire supervision function in a high impedance busbar protection scheme. It is therefore now possible to provide a single box solution for high impedance busbar protection with integrated buswire supervision. Buswire supervison uses the Sensitive Overvoltage Protection function as described in the Voltage Protection section of this manual. The Sensitive Overvoltage protection function allows the possibility of low pickup voltages (down to 2 V) making it ideal for monitoring the voltages apparent on the Busbar protection CTs. The start and trip outputs can be used for creating alarms and for short circuiting the Busbar protection CT secondary windings.

6.19.2 APPLICATION NOTES

6.19.2.1 BUSBAR PROTECTION

A typical 132kV double bus generating station is made up of two 100MVA generators and associated step-up transformers, providing power to the high voltage system, by means of four overhead transmission lines, shown below. The main and reserve busbars are sectionalised with bus section circuit breakers. The application for a high impedance circulating current scheme having 4 zones and an overall check feature, is as follows:

The switchgear rating is 3500MVA, the system voltage is 132kV solidly earthed and the maximum loop lead resistance is 2 ohms. The current transformers are of ratio 500/1 amp and have a secondary resistance of 0.7 ohms. The system has an X/R ratio of 20.

Stability voltage

The stability level of the busbar protection is governed by the maximum through fault level which is assumed to be the switchgear rating. Using the switchgear rating allows for any future system expansion.

$$= \frac{3500 \text{ x } 10^6}{\sqrt{3} \text{ x } 132 \text{ x } 10^3} = 15300\text{A}$$

Required relay stability voltage (assuming one CT is saturated)

$$= K I_f (R_{CT} + 2_{RL})$$
$$= \frac{1.2 \text{ x } 15300}{500}(0.7 + 2)$$
$$= 99\text{V}$$

Current setting

The primary operating current of busbar protection is normally set to less than 30% of the minimum fault level. It is also considered good practice by some utilities to set the minimum primary operating current in excess of the rated load. Therefore, if one of the CTs becomes open circuit the high impedance relay does not maloperate.

The primary operating current should be made less than 30% of the minimum fault current and more than the full load current of one of the incomers. Therefore, if one of the incomer CTs becomes open circuit the differential protection will not maloperate. It is assumed that 30% of the minimum fault current is more than the full load current of the largest circuit.

Full load current

$$= \frac{100 \text{ x } 10^3}{\sqrt{3} \text{ x } 132} = 438\text{A}$$

Discriminating zone

Magnetising current taken by each CT at 99V = 0.072A

Maximum number of CTs per zone = 5

Relay current setting, Ir(I>) = 400A = 0.8In

Relay primary operating current,

$$I_{op} = \text{CT ratio x } (I_r + n\ I_e)$$
$$= 500 \text{ x } (0.8 + (5 \text{ x } 0.072))$$
$$= 500 \text{ x } 1.16$$
$$= 580\text{A (132\% full load current)}$$

Check zone

Magnetising current taken by each CT at 99V = 0.072A

Maximum number of circuits = 6

Relay current setting, I_r (I>) = 0.8A

Relay primary operating current,

$$I_{op} = 500 \text{ x } (0.8 + (6 \text{ x } 0.072))$$
$$= 500 \text{ x } 1.232$$

$= 616A$ (141%- full load current)

Therefore, by setting Ir (I>) = 0.8A, the primary operating current of the busbar protection meets the requirements stated earlier.

Stabilising resistor

The required value of the stabilising resistor is:

$$R_{ST} = \frac{V_S}{I_r}$$
$$= \frac{99}{0.8}$$
$$= 124\Omega$$

Therefore the standard 220Ω variable resistor can be used.

Current transformer requirements

To ensure that internal faults are cleared in the shortest possible time the knee point voltage of the current transformers should be at least 5 times the stability voltage, Vs.

$$V_k/V_s = 4$$

$$V_k = 396V$$

Metrosil non-linear resistor requirements

If the peak voltage appearing across the relay circuit under maximum internal fault conditions exceeds 3000V peak then a suitable non-linear resistor (Metrosil), externally mounted, should be connected across the relay and stabilising resistor, in order to protect the insulation of the current transformers, relay and interconnecting leads. In the present case the peak voltage can be estimated by the formula:

$$V_P = 2\sqrt{2V_K(V_f - V_K)}$$

where VK = 396V (In practice this should be the actual current transformer kneepoint voltage, obtained from the current transformer magnetisation curve).

$$V_r = I'f(R_{CT} + 2_{RL} + R_{ST} + R_r)$$
$$= 15300 \text{ x } \frac{1}{500} \text{ x } (0.7+2+124)$$
$$= 30.6 \text{ x } 126.7$$
$$= 3877V$$

Therefore substituting these values for VK and Vf into the main formula, it can be seen that the peak voltage developed by the current transformer is:

$$V_P = 2\sqrt{2V_K(V_f - V_K)}$$
$$= 2\sqrt{2 \text{ x } 396 \text{ x } (3877 - 396)}$$
$$= 3320V$$

This value is above the maximum of 3000V peak and therefore a non-linear resistor (Metrosil) would have to be connected across the relay and the stabilising resistor. The recommended non-linear resistor type would have to be chosen in accordance with the maximum secondary internal fault current and voltage setting.

Busbar supervision

Whenever possible the supervision primary operating current should not be more than 25 amps or 10% of the smallest circuit, whichever is the greater.

The IN>1 earth fault element in the P140 with its low current settings can be used for busbar supervision.

Assuming that 25A is greater than 10% of the smallest circuit current.

$$IN>1 = 25/500 = 0.05In$$

Using the I>3 element for 3 phase busbar supervision.

$$I>3 = 0.08\ In\ (minimum\ setting)$$

The time delay setting of the I_N>1 and I>3 elements, used for busbar supervision, is 3s.

Any elements not used should be disabled.

Advanced busbar application requirements for through fault stability

The previous busbar protection example is used here to demonstrate the use of the advanced application requirements for through stability.

To ensure through fault stability with a transient offset in the fault current the required voltage setting is given by:

$$V_S = (0.005\ X/R + 0.78)\ x\ If\ (2RL + RCT)$$

To be used when X/R is less or equal to 80. The standard equation should be used for X/R ratios greater than 80.

If the calculated value is lower than that given by equation 1 (with K = 1.2) then it should be used instead.

Transient stability limit

$$V_S = 0.005\ X/R + 0.78\ x\ \frac{15300}{500}\ x\ (0.7 + 2)$$

$$V_S = 0.88\ x\ 30.6\ x\ 2.7$$

$$V_S = 73V$$

The relay current setting, Ir = 0.8In

$$R_{ST} = \frac{V_S}{I_r}$$

$$R_{ST} = \frac{73}{0.8} = 91\Omega$$

Assuming V_K = 4Vs

$$V_K = 4Vs = 292V$$

Using the advanced application method the knee point voltage requirement has been reduced to 292V compared to the conventional method where the knee point voltage was calculated to be 396V.

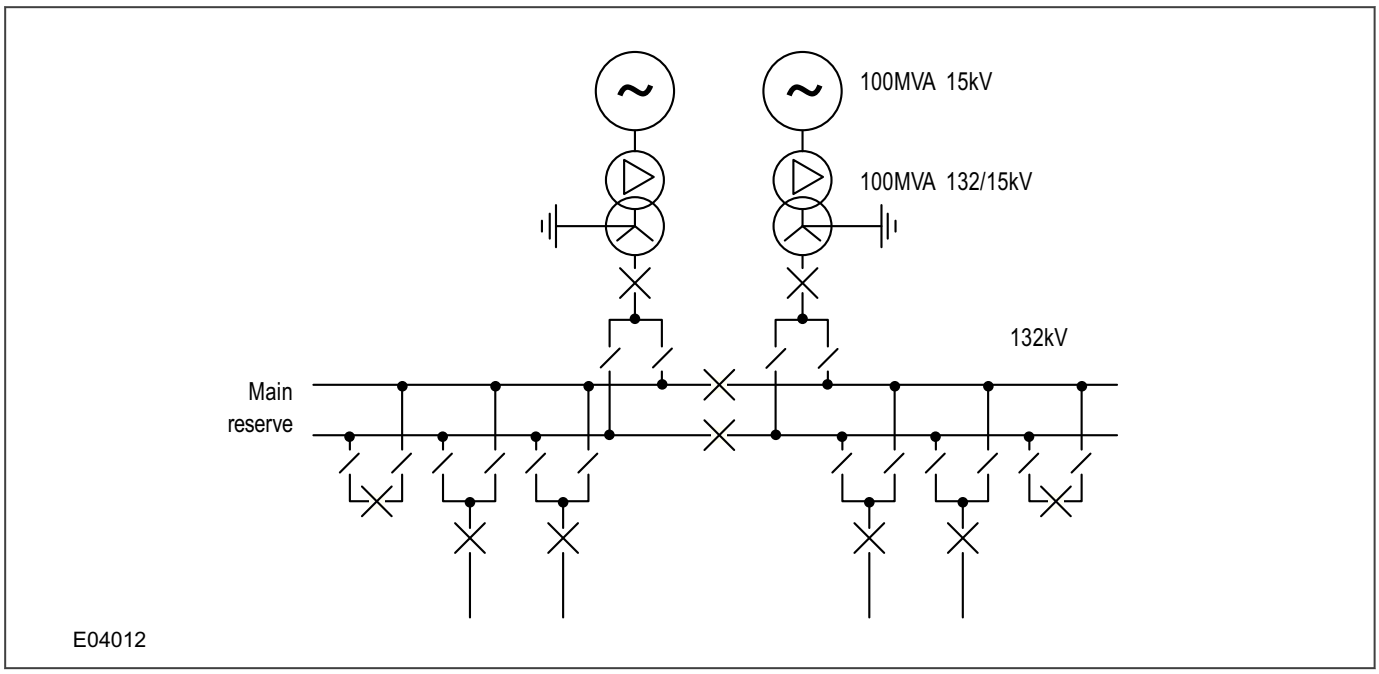


Figure 112: Double busbar generating station

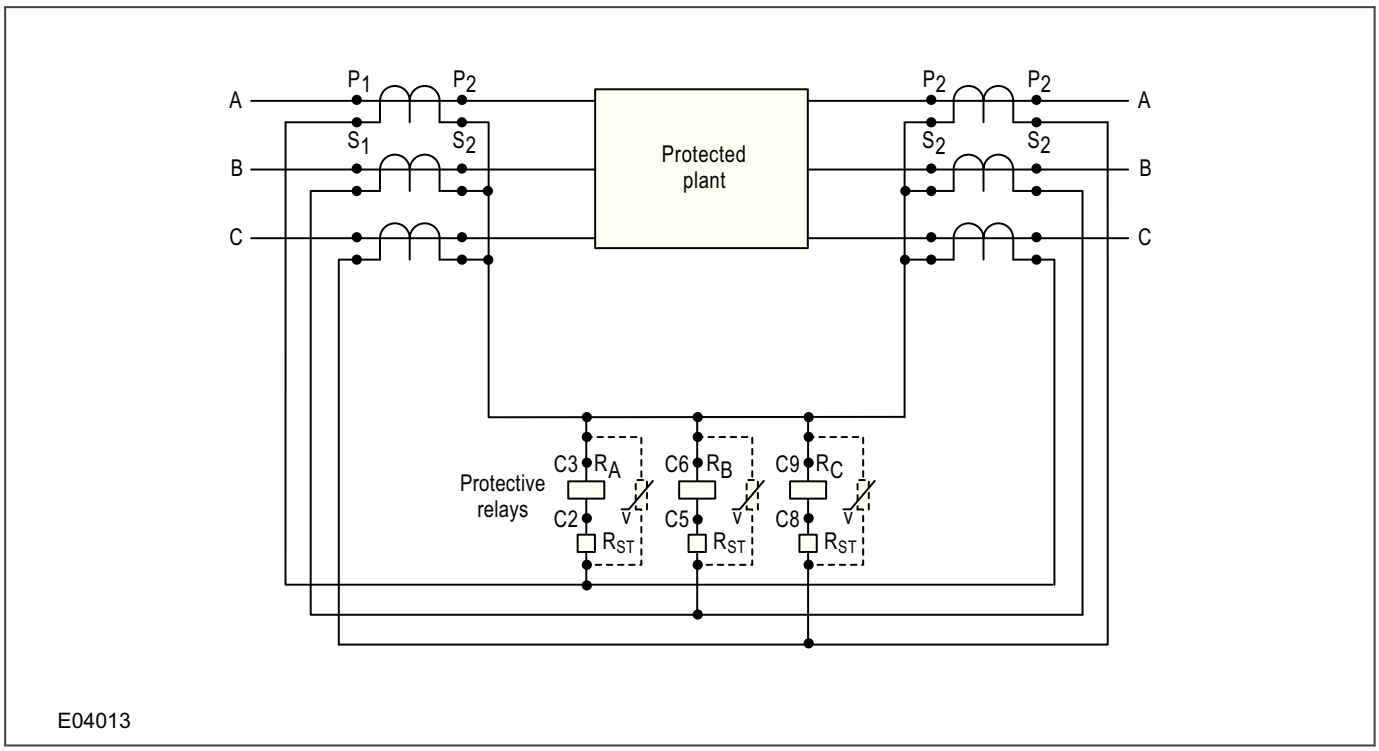


Figure 113: Phase and earth fault differential protection for generators, motors or reactors

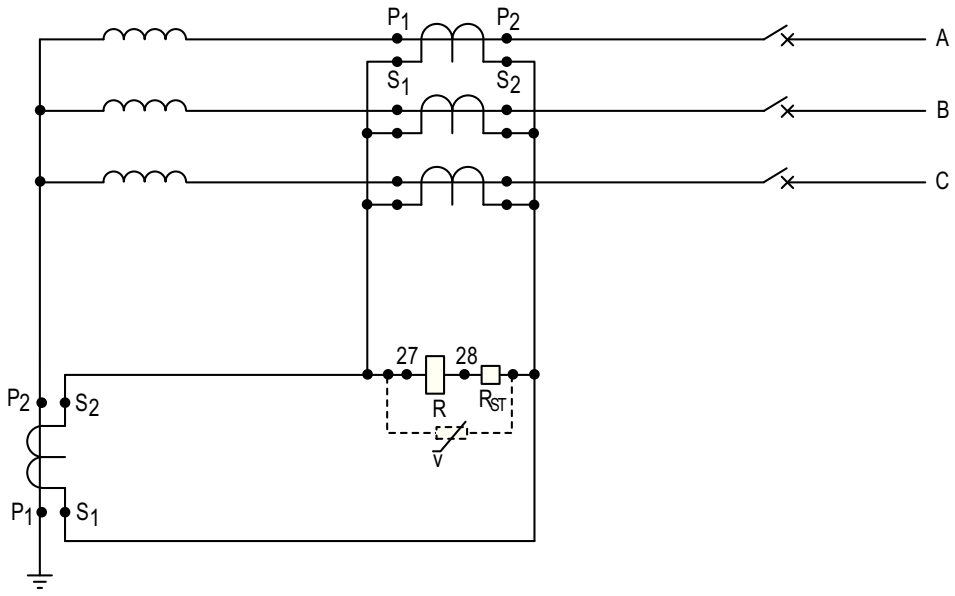


Figure 114: Restricted earth fault protection for 3 phase, 3 wire system-applicable to star connected generators or power transformer windings

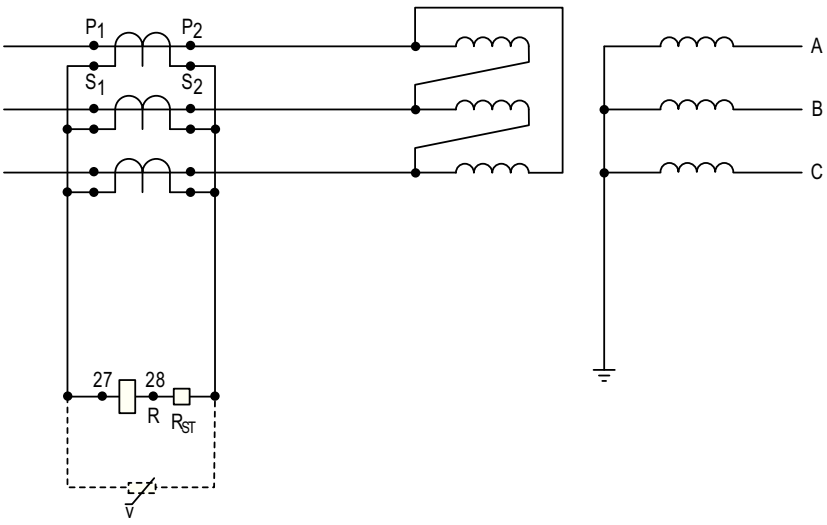
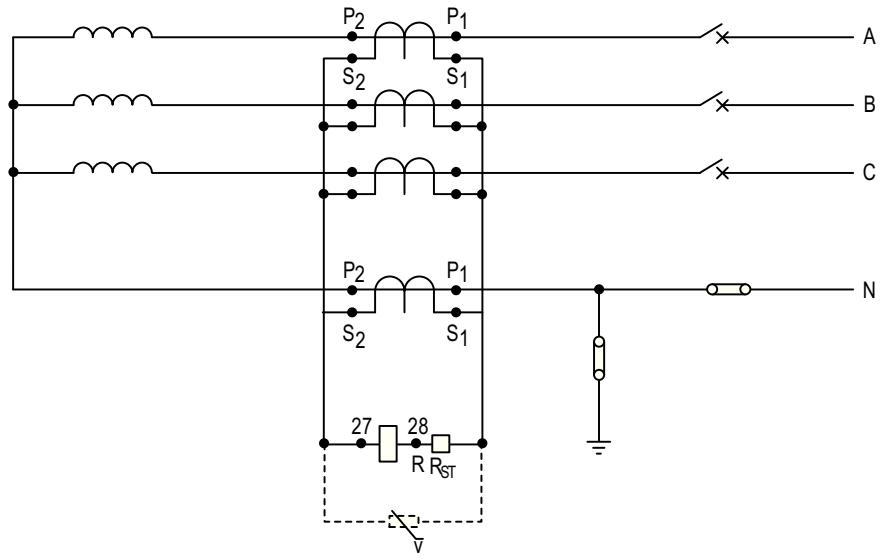
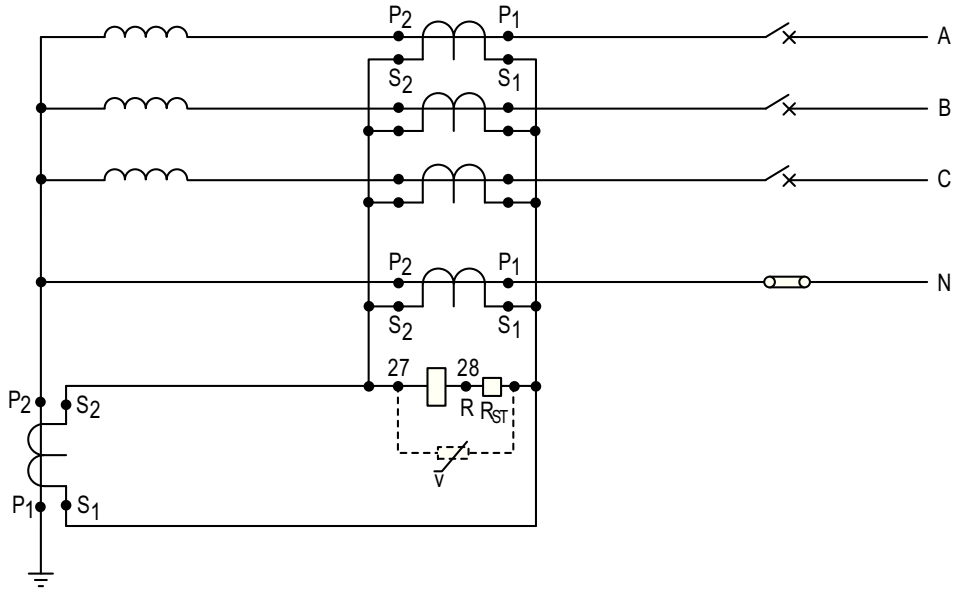


Figure 115: Balanced or restricted earth fault protection for delta winding of a power transformer with supply system earthed



E04016

Figure 116: Restricted earth fault protection for 3 phase, 4 wire system-applicable to star connected generators or power transformer windings with neutral earthed at switchgear



E04017

Figure 117: Restricted earth fault protection for 3 phase, 4 wire system-applicable to star connected generators or power transformer windings earthed directly at the star point

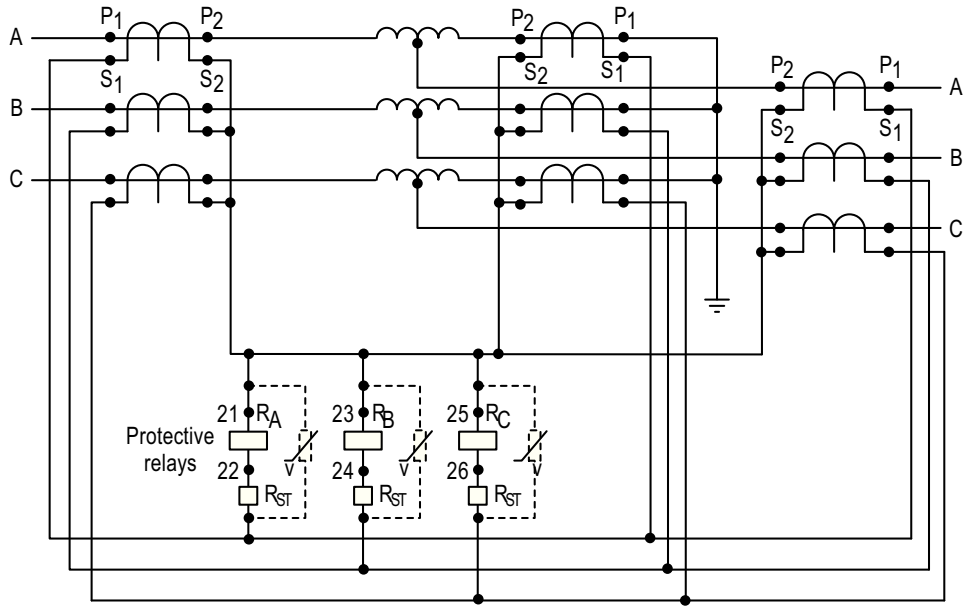


Figure 118: Phase and earth fault differential protection for an auto-transformer with CT's at the neutral star point

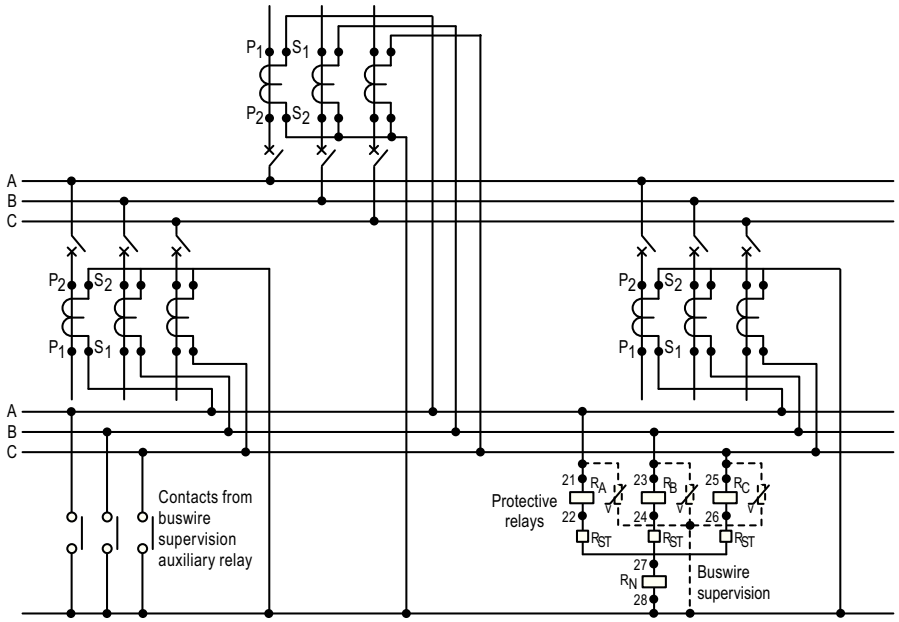


Figure 119: Busbar protection - simple single zone phase and earth fault scheme

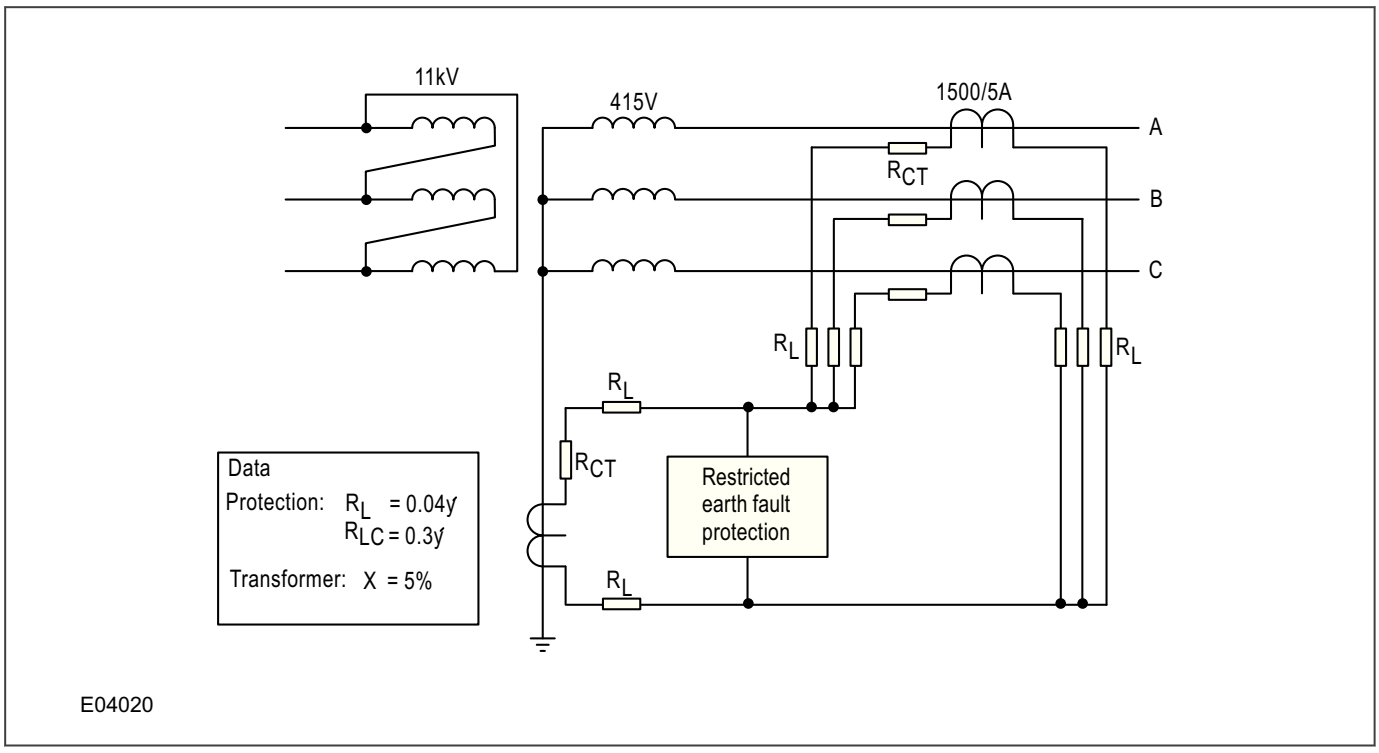


Figure 120: Restricted earth fault protection on a power transformer LV winding

6.20 TRANSIENT EARTH FAULT DETECTION

Some distribution systems run completely insulated from earth. Such systems are called unearthed systems. The advantage of an unearthed system is that a single phase to earth fault does not cause an earth fault current to flow. This means the whole system remains operational and the supply is not interrupted. The system must be designed to withstand high transient and steady state overvoltages, however, and so its use is generally restricted to low and medium voltage distribution systems.

When there is an earth fault in an unearthed 3-phase system, the voltage of the faulted phase is reduced to the earth potential. This causes the phase voltage in the other two phases to increase, which causes a significant charging current between the phase-to-earth capacitances. This can cause arcing at the fault location. Many systems use a Petersen coil to compensate for this, thus eliminating the arcing problem. Such systems are called compensated networks. The network is earthed with an inductive reactor, where its reactance is made nominally equal to the total system capacitance to earth. Under this condition, a single-phase earth fault does not result in any steady state earth fault current.

The introduction of a Petersen coil introduces major difficulties when it comes to determining the direction of the fault. This is because the faulted line current is the sum of the inductive current introduced by the Petersen coil and the capacitive current of the line, which are in anti-phase with each other. If they are equal in magnitude, the current in the faulted line is zero. If the inductive current is larger than capacitance current, the direction of the faulted line current will appear to be in the same direction as that of the healthy line.

Standard directionalizing techniques used by conventional feeder protection devices are not adequate for this scenario, therefore we need a different method for determining the direction of the fault. Two commonly used methods are the First Half Wave method and the Residual Active Power method.

First Half Wave Method

The initial transient wave, generated at the fault point travels towards the bus along the faulted line, until it reaches the healthy line. For forward faults the high frequency fault voltage and current components are in opposite directions during the first half wave, whereas for reverse faults, they are in phase. This fact can be used to determine the fault direction. This method, however, is subject to the following disadvantages:

- The time duration of the characteristic is very short, in most cases not more than 3 ms. Because of this, it requires a high sampling frequency (3000Hz or even higher)
- It requires an analogue high pass filter, necessitating special hardware
- It is affected by the fault inception angle. For example, when the fault inception angle is 0°, there are no initial travelling waves.

Residual Active Power Method

Residual Active power, which is sometimes used to detect the instance of a fault can also in some cases be used for detecting the fault direction. Although the capacitive currents can be compensated by an inductive current generated by a Petersen coil, the active (instantaneous) current can never be compensated for and this is still opposite to that of the healthy line. This fact can also be used to directionalise the fault.

For a forward directional fault, the zero-sequence active power is the power loss of Petersen's coil, which is negative. For a reverse fault, the zero-sequence active power is the power loss of the transmission line, which is positive. This method, however, is subject to the following disadvantages:

- The zero-sequence active power will be very small in magnitude for a reverse directional fault. Its value depends on the power loss of transmission line.
- The zero-sequence active power may be too small in magnitude to be detected for a forward directional fault. Its value depends on the power loss of Petersen coil.
- High resolution CTs are required

Due to the low magnitude of measured values, reliability is compromised

This product does not use the above techniques for directionalisation. This product uses an innovative patented technique called Transient Reactive Power method to determine the fault direction of an earth fault in a compensated network.

6.20.1 TRANSIENT EARTH FAULT DETECTION IMPLEMENTATION

Transient Earth Fault Detection (TEFD) in this device comprises three modules:

- Transient Earth Fault Detection module (TEF)
- Fault Type Detector (FTD)
- Direction Detector (DD)

Note:
In this product, TEFD is implemented for 50Hz only.

6.20.1.1 TRANSIENT EARTH FAULT DETECTOR

To establish if there is an earth fault on the system somewhere is straightforward. A simple residual overvoltage comparison can determine this. Therefore, a ***TEF> Start*** signal is produced by comparing the neutral voltage with a threshold voltage set by ***TEF VN> Start*** in the *TEF DETECTION* column. The difficulty comes with establishing the type of fault and its direction.

6.20.1.2 FAULT TYPE DETECTOR

The FTD uses a Fundamental analysis (FA) technique to establish whether the fault is an intermittent fault or a steady state faults. For Transient Earth Fault Detection, the detector counts the Residual Voltage bursts within a specified time window. With some clever signal processing the detector module creates pulses by comparing the bursts with a settable threshold, then counts these pulses. If the number of pulses equals or exceeds the number specified by the ***FTD> Fault Count*** setting, within the time window specified by ***FTD> Time Window***, the fault is deemed to be intermittent and the ***TEF> Intermit DDB*** signal is asserted. If there are fewer pulses than this number, this indicates either a disturbance or a permanent fault. To establish which, we need to look at the RMS value of the residual voltage.

If there are fewer pulses than specified and the RMS value does not drop below setting within the specified time window, the fault is deemed to be permanent. In this case the ***TEF> Steady*** DDB signal is asserted.

If there are fewer pulses than specified and the RMS value does drop below setting, this indicates that a disturbance has been detected but it is not a fault. In this case, the ***TEF> Steady*** DDB signal is not asserted.

The user can map the signals ***TEF>Steady***, ***TEF>Intermit***, ***TEF>DIR FWD*** or ***TEF> DIR REV*** to the TEF Alarm Logic DDB to generate a TEF Alarm.

The inputs to this module are:

- The residual voltage
- ***FTD> VN*** (defines the threshold which converts the residual voltage burst into a pulse
- ***FTD> Time Window*** (defines the time window - default is 2 seconds)
- ***FTD> Fault Count*** (defines the fault count)

The FTD outputs two signals to indicate whether the fault is steady state or intermittent.

6.20.1.3 DIRECTION DETECTOR

The Direction Detector (DD) uses a patented technique based on Transient Reactive Power (TRP) to establish the direction of the fault. Unlike traditional methods, this TRP method does not require high resolution CTs or special analogue filtering hardware and is therefore cheaper to implement.

It can be shown that the residual voltage and residual current components can be reliably used as discriminative criteria between a faulty and healthy feeder at 220Hz.

The admittance response of a healthy distributed feeder is shown below using a Pi model:

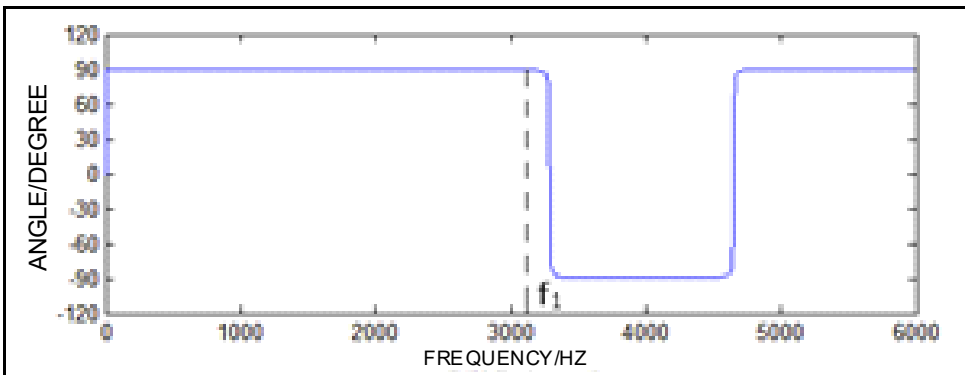


Figure 121: Healthy line response

In the above figure, the phase response of the admittance is consistent at 90o up to frequency f1 (approximately 3000Hz). For a compensated faulty feeder, the admittance response is shown below using a Pi model:

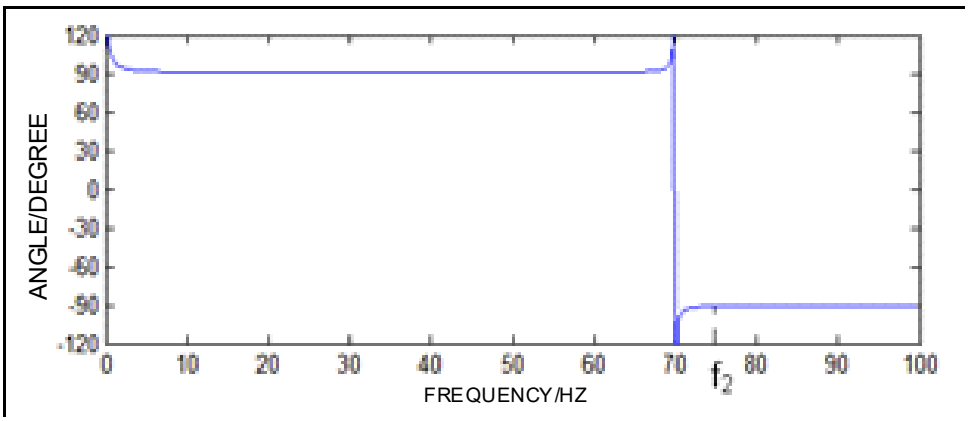


Figure 122: Faulty line response

We can observe that the phase angle (and thus, the reactive power flow) changes from 90o to -90o at frequencies higher than f2. Based on the above, we have clear direction discrimination between a healthy and faulted feeder at any frequency between f2 and f1 approximately.

> *Note:*
> *The resonant frequency in the above system is 70Hz. For a perfectly compensated system, this will be 50Hz.*

MiCOM devices use an anti-aliasing band pass filter with cut-off frequency of 150Hz. Furthermore, at 220Hz the post-filter magnitude is approximately 0.5pu, and at 330Hz, it is less than 0.2pu. To avoid any integer harmonics, and to avoid severely attenuated quantities due to the filter, we have chosen 220Hz as the most suitable frequency for direction determination.

In the forward direction, the residual voltage leads the residual current by 90°, and in the reverse direction the residual voltage lags the residual current by 90°. These criteria can be used to directionalise the fault.

The residual voltage (Vres) after passing through the bandpass filter tuned to 220 Hz, has 90° added to its phase. The residual current (Ires) is also passed through a 220 Hz bandpass filter, but no phase shift is applied. The resulting components which we shall call VH1 and IH2 are therefore in antiphase with each other for forward faults and in phase if the forward line is not faulted.

The VH1 and IH2 components are passed through a sign filter and multiplied to create a reactive power component in the range of -1 to +1. This is the transient reactive power Q_{tran}. If $Q_{tran} > 0$, then there forward line is healthy. If $Q_{tran} < 0$, then the forward line is faulty.

There are two modes of operation for the direction detector; Standard and Advanced. Standard mode is used in most cases and is described here. Advanced mode is for special applications that deviate from the standard model of two or more geographically close feeders outgoing from a power transformer. The following default settings are recommended for the majority of applications:

- ***Dir>Qn Thresh*** 100.0e-3
- ***Dir>Qr Thresh*** 40.00e-3

When ***TEF>Dir Mod*** is set to `Advance`, the following settings become visible:

- ***Dir>Qn Thresh*** 100.0e-3
- ***Dir>Qr Thresh*** 40.00e-3

Then these two settings can be configured for special applications:

It is important to note that all settings for the TGFD function, including those at 220Hz, can be set based on 50Hz nominal secondary values, This is because the gain of the 220Hz transient filter is 1.

The inputs to this module are:

- The residual voltage
- The residual current

The DD outputs two signals to indicate a forward fault and a reverse fault.

Q_{tran} Thresholds

The setting ***Dir>Qn Thresh*** is the forward direction Q_{tran} threshold calculated from the quantised Vnf and Inf values.

The setting ***Dir>Qr*** is the reverse direction Q_{trans} threshold calculated from the quantised Vnf and Inf values.

The following DDBs are also available:

Timer Block: used to inhibit the TEF function and reset all associated DDBs

Reset TEF: can be configured as user-defined manual reset alarms

TEF Alarm Output: This is the main TEF alarm that can be mapped to a relay output for a trip

6.20.2 TRANSIENT EARTH FAULT DETECTION LOGIC

6.20.2.1 TRANSIENT EARTH FAULT DETECTION LOGIC OVERVIEW

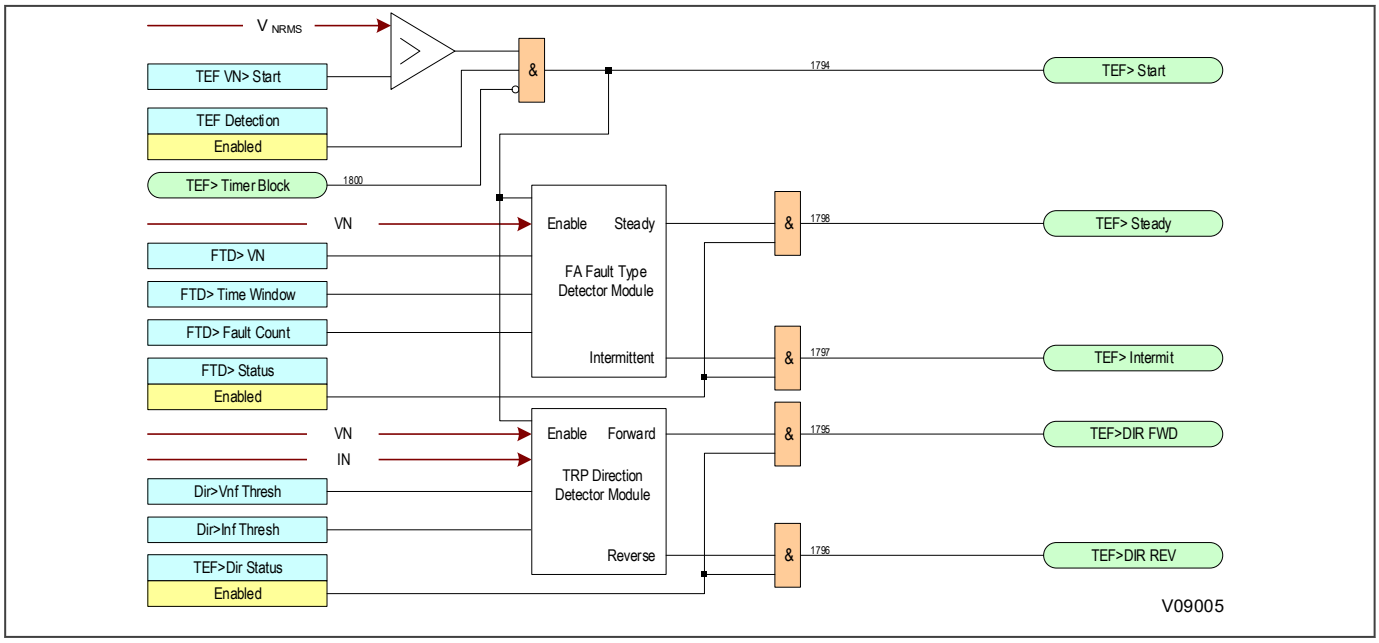


Figure 123: Transient earth fault logic overview

6.20.2.2 FAULT TYPE DETECTOR LOGIC

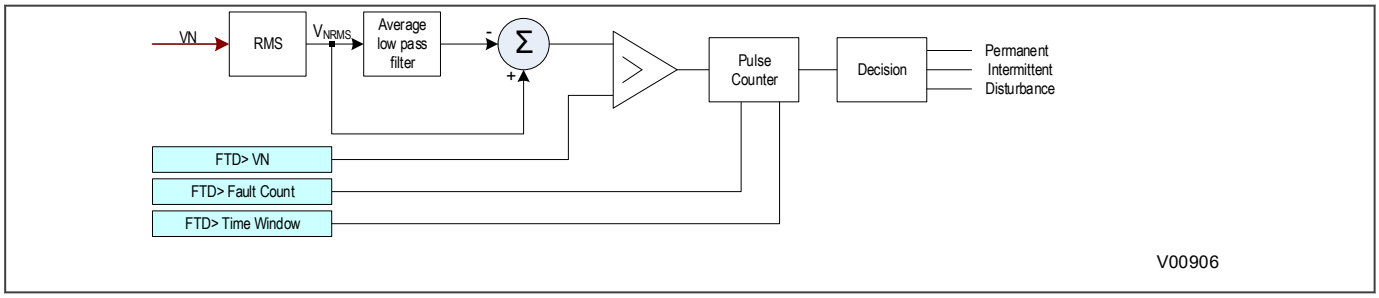


Figure 124: Fault type detector logic

6.20.2.3 DIRECTION DETECTOR LOGIC - STANDARD MODE

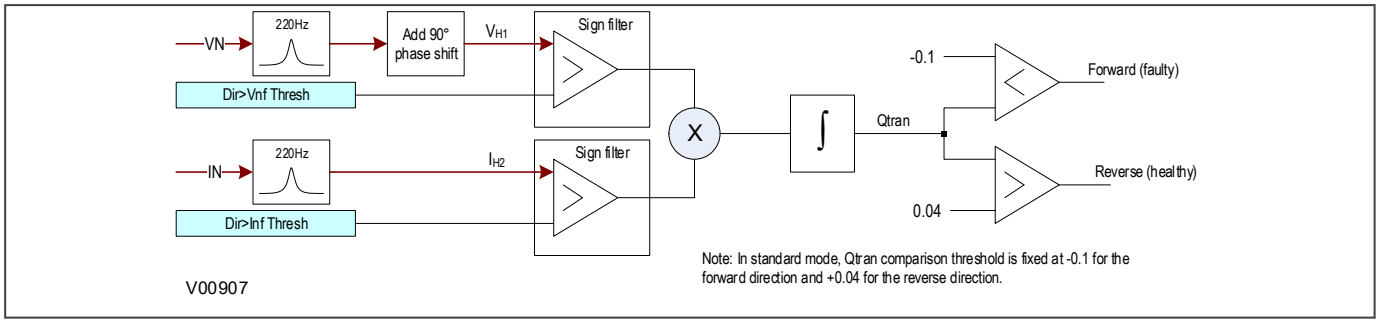


Figure 125: Direction detector logic - standard mode

6.20.2.4 TRANSIENT EARTH FAULT DETECTION OUTPUT ALARM LOGIC

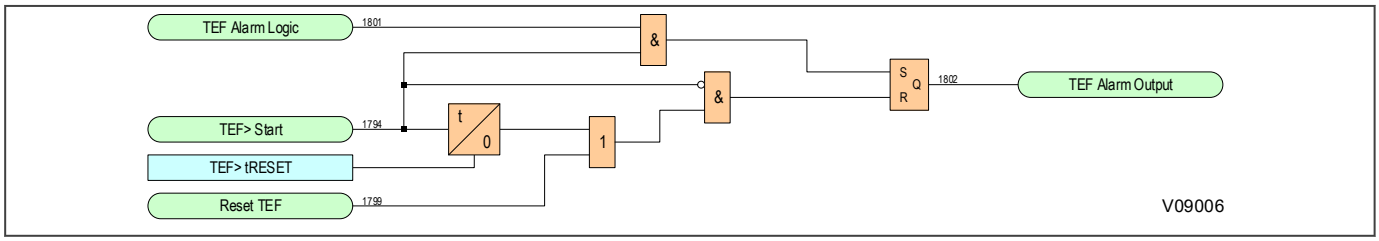


Figure 126: TEFD output alarm logic

6.20.2.5 APPLICATION NOTES

6.20.2.5.1 TRANSIENT EARTH FAULT DETECTION: ACTIVE POWER CHECK

A preventive measure should be taken in cases when devices are located at the extremities of a radial system, where the charging current component reduces the further the device is from the source, and the active component remains small but constant. In these cases, the transient active current component can be comparable to the transient reactive current during the directional check of the TEFD algorithm.

To ensure correct directionality for all fault positions and system configurations (radial, ring or meshed), the TEFD algorithm shall be supplemented with an additional element - 'Active Power Check'. This scheme ensures the correct directional decision is raised regardless of residual active power levels present in the system at the time of the fault. Sensitive Directional Earth Fault (SDEF) with Active Power Check shall be applied in parallel with the TEFD algorithm.

The combined logic for the TEFD and SDEF is shown in Figure below. A 'Forward START' (shown as a name modified User Alarm) signal is raised when either TEFD FWD or SDEF FWD signals are active. However, 'Forward START' is inhibited if the SDEF REV signal is ever active. This ensures SDEF takes priority if there is enough residual active power during a fault condition. For cases where the residual active power is low, the TEFD algorithm provides the directional decision.

An additional 100ms delay is included to delay the start conditions, thus ensuring the SDEF protection is not adversely affected by the initial fault transient. The TEFD logic is unaffected by the additional timer as its directional decision is latched for a minimum of 200ms after fault inception.

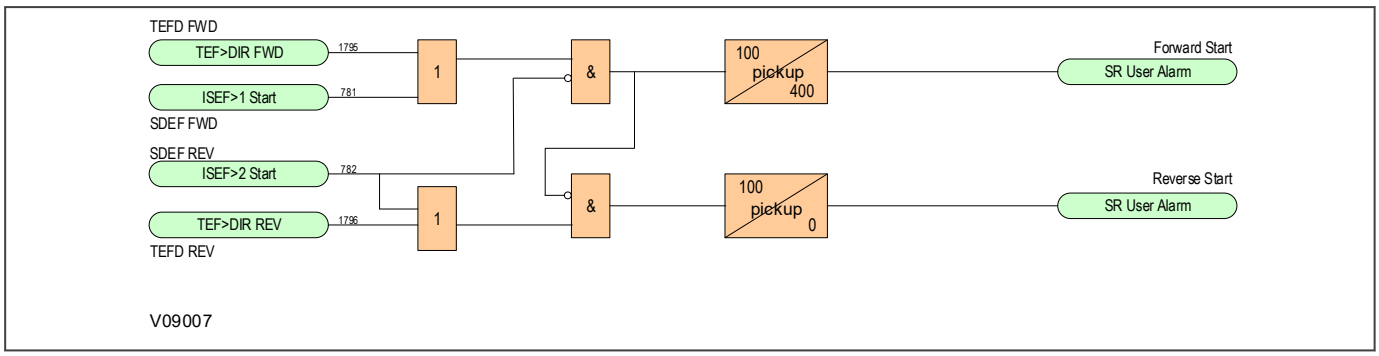


Figure 127: Combined TEFD and SDEF start PSL logic

CHAPTER 7

VOLTAGE PROTECTION FUNCTIONS

7.1 CHAPTER OVERVIEW

The device provides a wide range of voltage protection functions. This chapter describes the operation of these functions including the principles, logic diagrams and applications.

This chapter contains the following sections:

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Undervoltage Protection 193
Overvoltage Protection 196
Compensated Overvoltage 199
Residual Overvoltage Protection 201
Negative Sequence Overvoltage Protection 209
Sensitive Overvoltage Protection 211

7.2 UNDERVOLTAGE PROTECTION

Undervoltage conditions may occur on a power system for a variety of reasons, some of which are outlined below:

- Undervoltage conditions can be related to increased loads, whereby the supply voltage will decrease in magnitude. This situation would normally be rectified by voltage regulating equipment such as AVRs (Auto Voltage Regulators) or On Load Tap Changers. However, failure of this equipment to bring the system voltage back within permitted limits leaves the system with an undervoltage condition, which must be cleared.
- If the regulating equipment is unsuccessful in restoring healthy system voltage, then tripping by means of an undervoltage element is required.
- Faults occurring on the power system result in a reduction in voltage of the faulty phases. The proportion by which the voltage decreases is dependent on the type of fault, method of system earthing and its location. Consequently, co-ordination with other voltage and current-based protection devices is essential in order to achieve correct discrimination.
- Complete loss of busbar voltage. This may occur due to fault conditions present on the incomer or busbar itself, resulting in total isolation of the incoming power supply. For this condition, it may be necessary to isolate each of the outgoing circuits, such that when supply voltage is restored, the load is not connected. Therefore, the automatic tripping of a feeder on detection of complete loss of voltage may be required. This can be achieved by a three-phase undervoltage element.
- Where outgoing feeders from a busbar are supplying induction motor loads, excessive dips in the supply may cause the connected motors to stall, and should be tripped for voltage reductions that last longer than a pre-determined time.

7.2.1 UNDERVOLTAGE PROTECTION IMPLEMENTATION

Undervoltage Protection is implemented in the *VOLT PROTECTION* column of the relevant settings group. The Undervoltage parameters are contained within the sub-heading *UNDERVOLTAGE*.

The product provides two stages of Undervoltage protection with independent time delay characteristics.

Stage 1 provides a choice of operate characteristics, where you can select between:

- An IDMT characteristic
- DT (Definite Time)

You set this using the ***V<1 Function*** setting.

The IDMT characteristic is defined by the following formula:

$$t = K/(M-1)$$

where:

- K = Time multiplier setting
- t = Operating time in seconds
- M = Measured voltage / IED setting voltage (***V<(n) Voltage Set***)

The undervoltage stages can be configured either as phase-to-neutral or phase-to-phase voltages in the ***V< Measur't Mode*** cell.

There is no Timer Hold facility for Undervoltage.

Stages 2, 3 and 4 can have definite time characteristics only. This is set in the ***V<2 Status*** cell.

Outputs are available for single or three-phase conditions via the ***V< Operate Mode*** cell for each stage.

7.2.2 UNDERVOLTAGE PROTECTION LOGIC

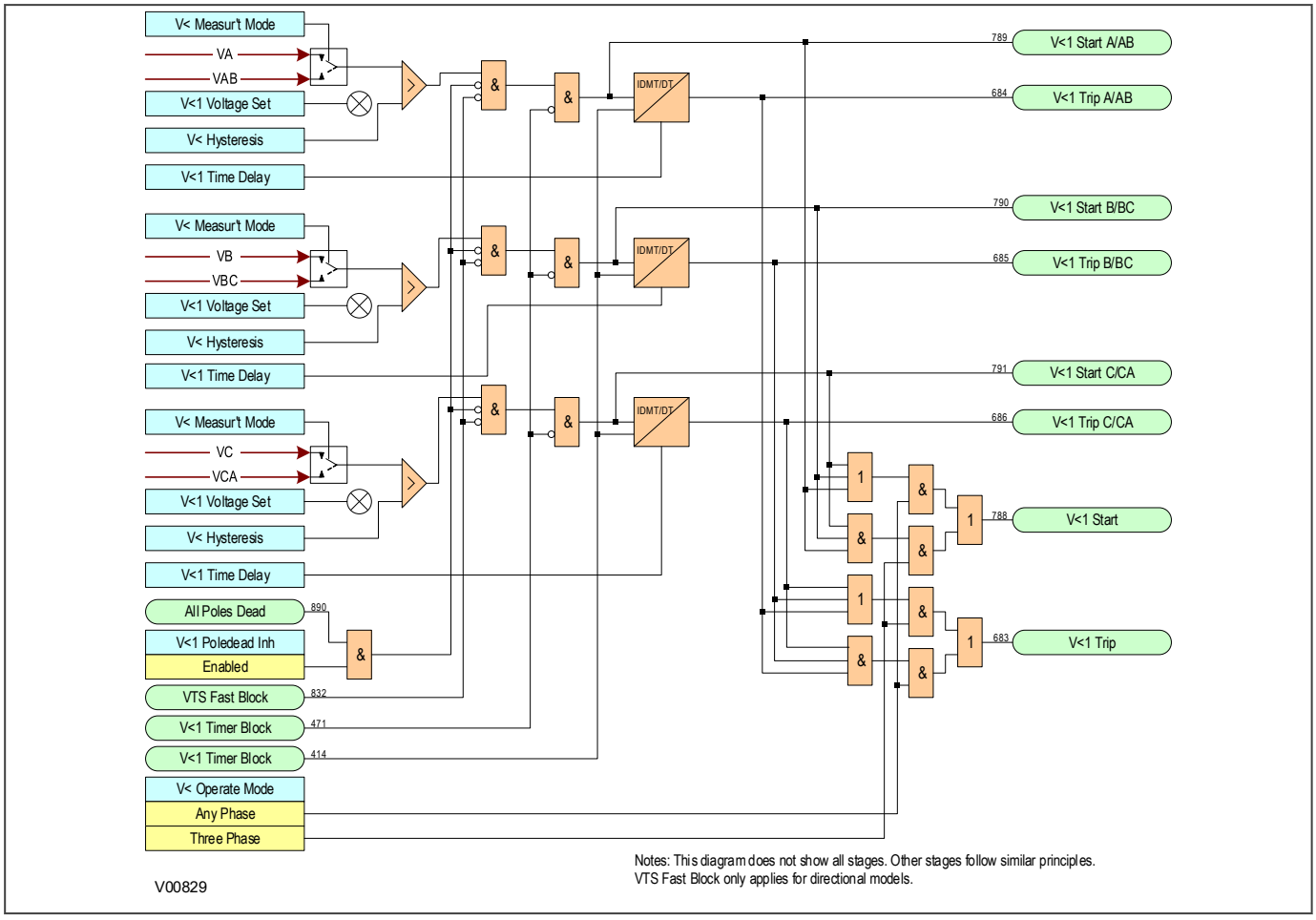


Figure 128: Undervoltage - single and three phase tripping mode (single stage)

The Undervoltage protection function detects when the voltage magnitude for a certain stage falls short of a set threshold. If this happens a ***Start*** signal, signifying the "Start of protection", is produced. This Start signal can be blocked by the ***VTS Fast Block*** signal and an ***All Poles Dead*** signal. This ***Start*** signal is applied to the timer module to produce the ***Trip*** signal, which can be blocked by the undervoltage timer block signal (***V<(n) Timer Block***). For each stage, there are three Phase undervoltage detection modules, one for each phase. The three ***Start*** signals from each of these phases are OR'd together to create a 3-phase Start signal (***V<(n) Start***), which can be be activated when any of the three phases start (Any Phase), or when all three phases start (Three Phase), depending on the chosen ***V< Operate Mode*** setting.

The outputs of the timer modules are the trip signals which are used to drive the tripping output relay. These tripping signals are also OR'd together to create a 3-phase Trip signal, which are also controlled by the ***V< Operate Mode*** setting.

If any one of the above signals is low, or goes low before the timer has counted out, the timer module is inhibited (effectively reset) until the blocking signal goes high.

In some cases, we do not want the undervoltage element to trip; for example, when the protected feeder is de-energised, or the circuit breaker is opened, an undervoltage condition would obviously be detected, but we would not want to start protection. To cater for this, an ***All Poles Dead*** signal blocks the ***Start*** signal for each phase. This is controlled by the ***V<Poledead Inh*** cell, which is included for each of the stages. If the cell is enabled, the relevant stage will be blocked by the integrated pole dead logic. This logic produces an output when it detects either an open circuit breaker via auxiliary contacts feeding the opto-inputs or it detects a combination of both undercurrent and undervoltage on any one phase.

Voltage drop-off threshold, defined as a percentage of set voltage, may be adjusted via the ***V< Hysteresis*** setting. For example, where the ***V<Hysteresis*** default setting is *2*, relay pick-up will be at set voltage and drop-off will be at 102% of set voltage.

7.2.3 APPLICATION NOTES

7.2.3.1 UNDERVOLTAGE SETTING GUIDELINES

In most applications, undervoltage protection is not required to operate during system earth fault conditions. If this is the case you should select phase-to-phase voltage measurement, as this quantity is less affected by single-phase voltage dips due to earth faults.

The voltage threshold setting for the undervoltage protection should be set at some value below the voltage excursions that may be expected under normal system operating conditions. This threshold is dependent on the system in question but typical healthy system voltage excursions may be in the order of 10% of nominal value.

The same applies to the time setting. The required time delay is dependent on the time for which the system is able to withstand a reduced voltage.

If motor loads are connected, then a typical time setting may be in the order of 0.5 seconds.

7.3 OVERVOLTAGE PROTECTION

Overvoltage conditions are generally related to loss of load conditions, whereby the supply voltage increases in magnitude. This situation would normally be rectified by voltage regulating equipment such as AVRs (Auto Voltage Regulators) or On Load Tap Changers. However, failure of this equipment to bring the system voltage back within permitted limits leaves the system with an overvoltage condition which must be cleared.

Note:
During earth fault conditions on a power system there may be an increase in the healthy phase voltages. Ideally, the system should be designed to withstand such overvoltages for a defined period of time.

7.3.1 OVERVOLTAGE PROTECTION IMPLEMENTATION

Overvoltage Protection is implemented in the *VOLT PROTECTION* column of the relevant settings group. The Overvoltage parameters are contained within the sub-heading *OVERVOLTAGE*.

The product provides two stages of overvoltage protection with independent time delay characteristics.

Stage 1 provides a choice of operate characteristics, where you can select between:

- An IDMT characteristic
- DT (Definite Time)

You set this using the ***V>1 Function*** setting.

The IDMT characteristic is defined by the following formula:

$$t = K/(M - 1)$$

where:

- K = Time multiplier setting
- t = Operating time in seconds
- M = Measured voltage setting voltage (***V>(n) Voltage Set***)

The overvoltage stages can be configured either as phase-to-neutral or phase-to-phase voltages in the ***V> Measur't Mode*** cell.

There is no Timer Hold facility for Overvoltage.

Stages 2, 3 and 4 can have definite time characteristics only. This is set in the ***V>2 Status*** cell.

Outputs are available for single or three-phase conditions via the ***V> Operate Mode*** cell for each stage.

7.3.2 OVERVOLTAGE PROTECTION LOGIC

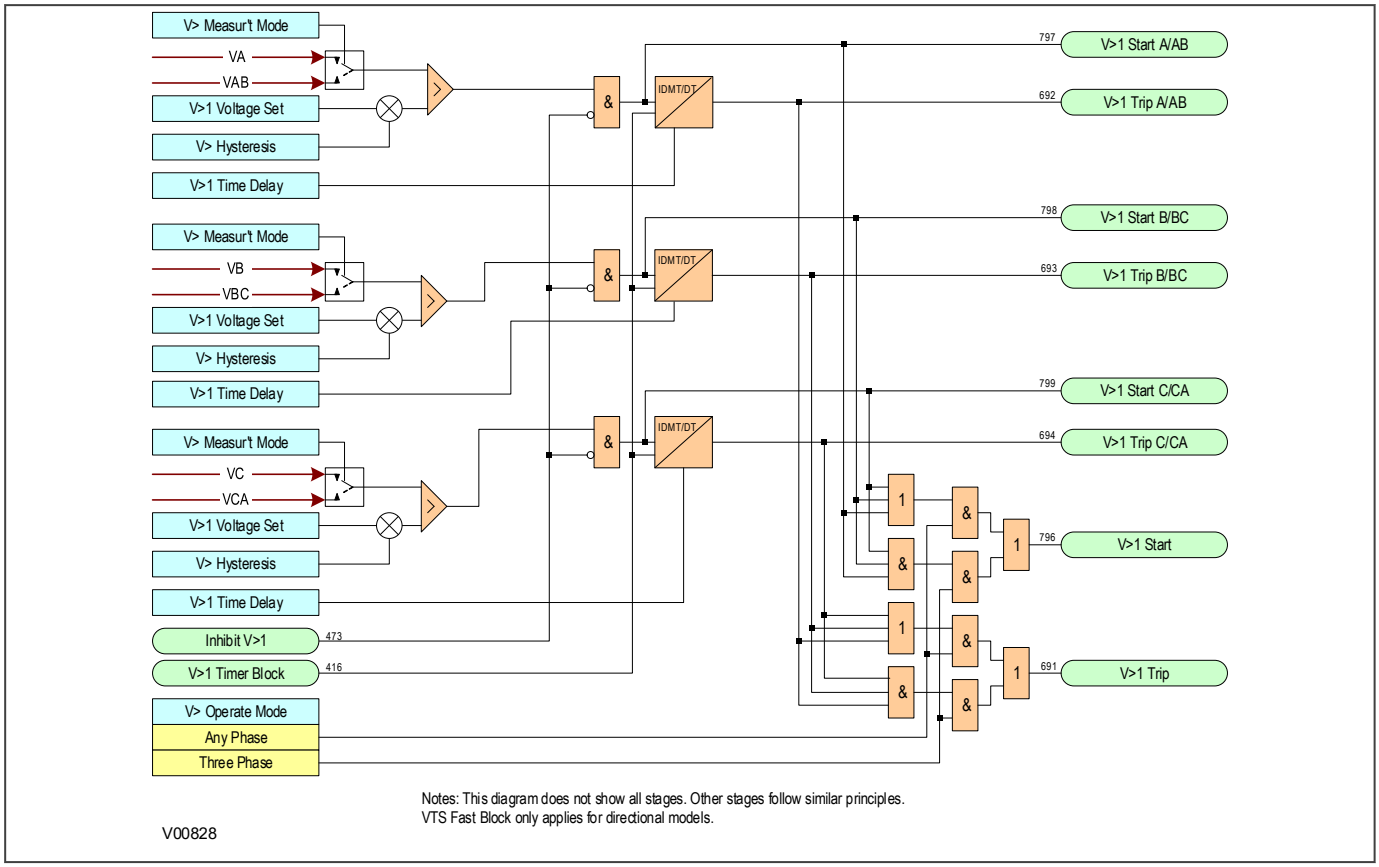


Figure 129: Overvoltage - single and three phase tripping mode (single stage)

The Overvoltage protection function detects when the voltage magnitude for a certain stage exceeds a set threshold. If this happens a ***Start*** signal, signifying the "Start of protection", is produced. This Start signal can be blocked by the ***VTS Fast Block*** signal. This start signal is applied to the timer module to produce the ***Trip*** signal, which can be blocked by the overvoltage timer block signal (***V>(n) Timer Block***). For each stage, there are three Phase overvoltage detection modules, one for each phase. The three ***Start*** signals from each of these phases are OR'd together to create a 3-phase Start signal (***V>(n) Start***), which can then be activated when any of the three phases start (Any Phase), or when all three phases start (Three Phase), depending on the chosen ***V> Operate Mode*** setting.

The outputs of the timer modules are the trip signals which are used to drive the tripping output relay. These tripping signals are also OR'd together to create a 3-phase Trip signal, which are also controlled by the ***V> Operate Mode*** setting.

If any one of the above signals is low, or goes low before the timer has counted out, the timer module is inhibited (effectively reset) until the blocking signal goes high.

Voltage drop-off threshold, defined as a percentage of set voltage, may be adjusted via the ***V> Hysteresis*** setting. For example, where the ***V>Hysteresis*** default setting is 2, relay pick-up will be at set voltage and drop-off will be at 98% of set voltage.

7.3.3 APPLICATION NOTES

7.3.3.1 OVERVOLTAGE SETTING GUIDELINES

The provision of multiple stages and their respective operating characteristics allows for a number of possible applications:

- Definite Time can be used for both stages to provide the required alarm and trip stages.
- Use of the IDMT characteristic allows grading of the time delay according to the severity of the overvoltage. As the voltage settings for both of the stages are independent, the second stage could then be set lower than the first to provide a time-delayed alarm stage.
- If only one stage of overvoltage protection is required, or if the element is required to provide an alarm only, the remaining stage may be disabled.

This type of protection must be co-ordinated with any other overvoltage devices at other locations on the system.

7.4 COMPENSATED OVERVOLTAGE

The Compensated Overvoltage function calculates the positive sequence voltage at the remote terminal using the positive sequence local current and voltage and the line impedance and susceptance. This can be used on long transmission lines where Ferranti Overvoltages can develop under remote circuit breaker open conditions.

7.4.1 COMPENSATED OVERVOLTAGE IMPLEMENTATION

The Compensated overvoltage protection function can be set in the *VOLT PROTECTION* column under the sub heading COMP OVERVOLTAGE. The remote voltage is calculated using line impedance settings and the line charging admittance in the *LINE PARAMETERS* column.

The IED uses the [A,B,C,D] transmission line equivalent model given the following parameters:

- Total Impedance Z = $z\angle\theta$ ohms
- Total Susceptance Y = $y\angle -90°$
- Line Length l

The remote voltage is calculated using the following equations:

$$\begin{bmatrix} \bar{V}r \\ \bar{I}r \end{bmatrix} = \begin{bmatrix} D & -C \\ -BA & \end{bmatrix} \times \begin{bmatrix} \bar{V}s \\ \bar{I}s \end{bmatrix}$$

where

- V_r is the voltage at the receiving end
- I_r is the current at the receiving end
- V_s is the measured voltage at the sending end
- I_s is the measured current at the sending end
- A= D = cosh(y.l)
- B = Z_c.sinh(y.l)
- C = Y_c.sinh(y.l)
- y.l = $\sqrt{}$(Z.Y)
- Z_c = 1/Y_c = $\sqrt{}$(Z/Y)
- Y = total line capacitive charging susceptance
- Z_c = characteristic impedance of the line (surge impedance)

There are two stages to provide both alarm and trip stages where required. Both stages can be set independently.

Stage 1 can be set to `IDMT`, `DT` or `Disabled`, in the ***V1>1 Cmp Funct*** cell. Stage 2 is DT only and is enabled or disabled in the ***V1>2 Cmp Status*** cell.

The IDMT characteristic on the first stage is defined by the following formula:

$$t = K/(M - 1)$$

where:

- K = Time multiplier setting
- t =Operating time in seconds
- M = Remote Calculated voltage / IED setting voltage

7.4.2 COMPENSATED OVERVOLTAGE LOGIC

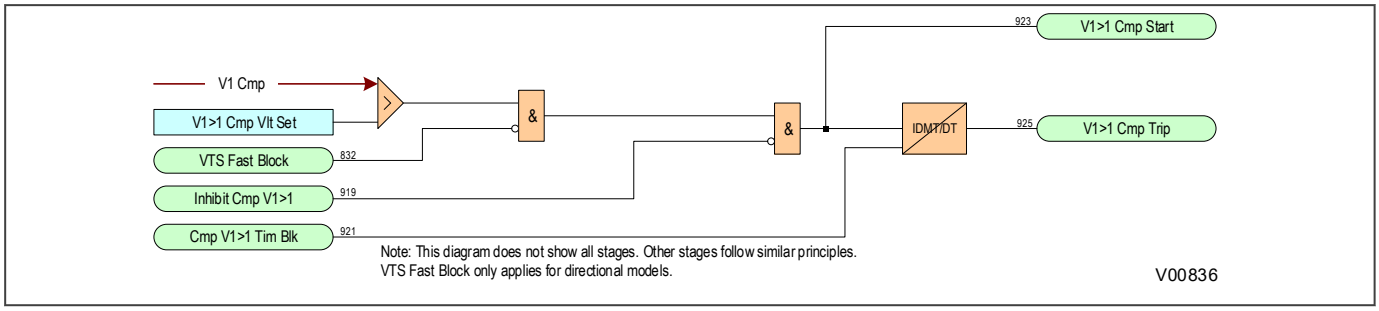


Figure 130: Compensated overvoltage logic

The Compensated Overvoltage module (***V1 Cmp***) is a level detector that detects when the voltage magnitude exceeds a set threshold, for each stage. When this happens, the comparator output produces a ***Start*** signal (***V1>(n) Cmp Start***), which signifies the "Start of protection". This can be blocked by a ***VTS Fast block*** signal. This ***Start*** signal is applied to the timer module. The output of the timer module is the ***V1> (n) Cmp Trip*** signal which is used to drive the tripping output relay.

Voltage drop-off threshold, defined as a percentage of set voltage, may be adjusted via the ***Cp V Hysteresis*** setting. For example, where the ***Cp V Hysteresis*** default setting is *2*, relay pick-up will be at set voltage and drop-off will be at 98% of set voltage.

7.4.3 APPLICATION NOTES

7.4.3.1 COMPENSATED OVERVOLTAGE SETTING GUIDELINES

The provision of multiple stages and their respective operating characteristics allows for a number of possible applications:

- Definite Time can be used for both stages to provide the required alarm and trip stages.
- Use of the IDMT characteristic allows grading of the time delay according to the severity of the overvoltage. As the voltage settings for both of the stages are independent, the second stage could then be set lower than the first to provide a time-delayed alarm stage.
- If only one stage of overvoltage protection is required, or if the element is required to provide an alarm only, the remaining stage may be disabled.

This type of protection must be co-ordinated with any other overvoltage devices at other locations on the system.

7.5 RESIDUAL OVERVOLTAGE PROTECTION

On a healthy three-phase power system, the sum of the three-phase to earth voltages is nominally zero, as it is the vector sum of three balanced vectors displaced from each other by 120°. However, when an earth fault occurs on the primary system, this balance is upset and a residual voltage is produced. This condition causes a rise in the neutral voltage with respect to earth. Consequently this type of protection is also commonly referred to as 'Neutral Voltage Displacement' or NVD for short.

This residual voltage may be derived (from the phase voltages) or measured (from a measurement class open delta VT). Derived values will normally only be used where the model does not support measured functionality (a dedicated measurement class VT). If a measurement class VT is used to produce a measured Residual Voltage, it cannot be used for other features such as Check Synchronisation.

This offers an alternative means of earth fault detection, which does not require any measurement of current. This may be particularly advantageous in high impedance earthed or insulated systems, where the provision of core balanced current transformers on each feeder may be either impractical, or uneconomic, or for providing earth fault protection for devices with no current transformers.

7.5.1 RESIDUAL OVERVOLTAGE PROTECTION IMPLEMENTATION

Residual Overvoltage Protection is implemented in the *RESIDUAL O/V NVD* column of the relevant settings group.

Some applications require more than one stage. For example an insulated system may require an alarm stage and a trip stage. It is common in such a case for the system to be designed to withstand the associated healthy phase overvoltages for a number of hours following an earth fault. In such applications, an alarm is generated soon after the condition is detected, which serves to indicate the presence of an earth fault on the system. This gives time for system operators to locate and isolate the fault. The second stage of the protection can issue a trip signal if the fault condition persists.

The product provides four stages of Residual Overvoltage protection with independent time delay characteristics.

Stage 1 provides a choice of operate characteristics, where you can select between:

- An IDMT characteristic
- DT (Definite Time)

The IDMT characteristic is defined by the following formula:

$$t = K/(M - 1)$$

where:

- K= Time multiplier setting
- t = Operating time in seconds
- M = Derived residual voltage setting voltage (***VN> Voltage Set***)

You set this using the ***VN>1 Function*** setting.

Stages 2, 3 and 4 can have definite time characteristics only. These are selected using the ***VN>2, VN>3 and VN>4 status*** cells.

The relay also has the option of using measured voltage from the relay's 4th VT if the relay Residual O/V setting ***VN Input*** is set to `Measured`, as opposed to being set to `Derived`. These types of VT design provide a path for the residual flux and consequently permit the device to derive the required residual voltage. In addition, the primary star point of the VT must be earthed. Three-limb VTs have no path for residual flux and are therefore unsuitable for this type of protection.

7.5.2 RESIDUAL OVERVOLTAGE LOGIC

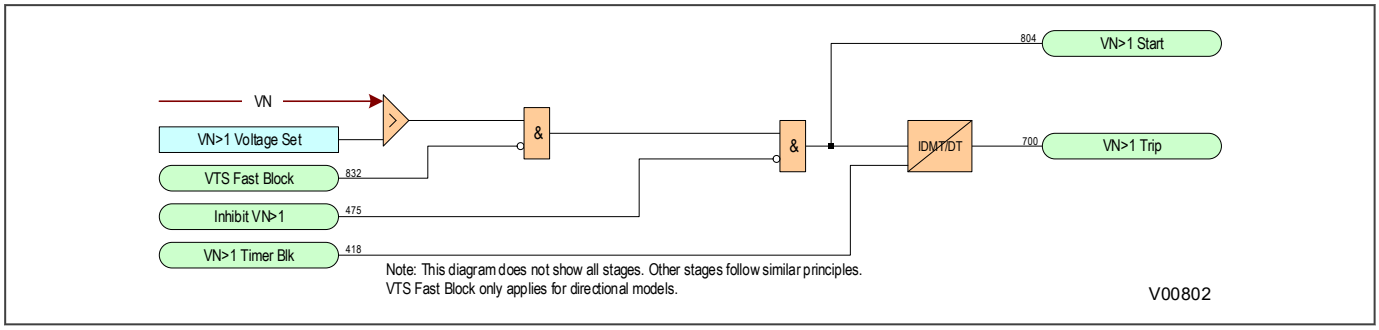


Figure 131: Residual overvoltage logic

The Residual Overvoltage module (VN>) is a level detector that detects when the voltage magnitude exceeds a set threshold, for each stage. When this happens, the comparator output produces a ***Start*** signal (***VN>(n) Start***), which signifies the "Start of protection". This can be blocked by a ***VTS Fast block*** signal. This ***Start*** signal is applied to the timer module. The output of the timer module is the ***VN> (n) Trip*** signal which is used to drive the tripping output relay.

7.5.3 APPLICATION NOTES

7.5.3.1 CALCULATION FOR SOLIDLY EARTHED SYSTEMS

Consider a Phase-A to Earth fault on a simple radial system.

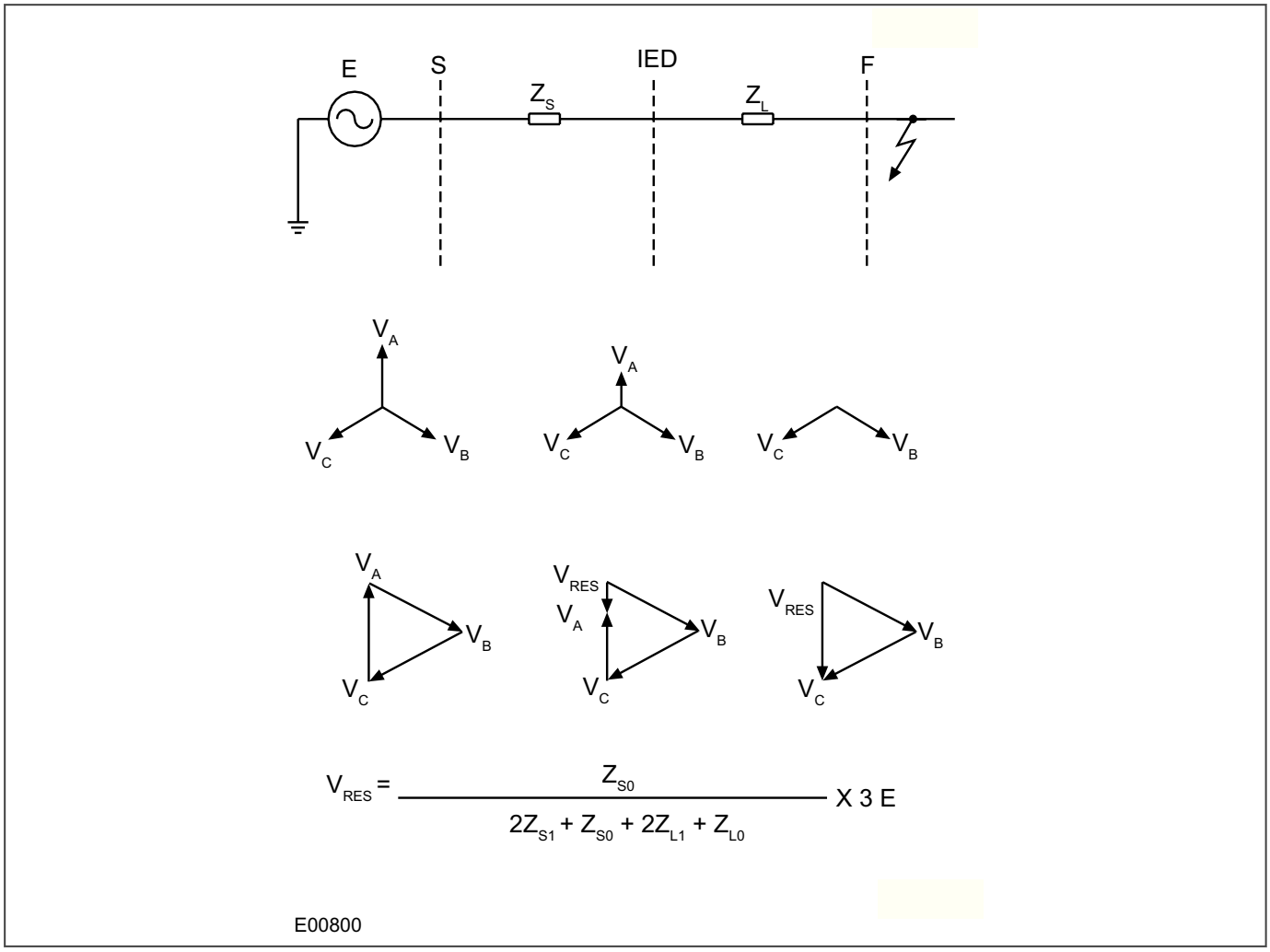


Figure 132: Residual voltage for a solidly earthed system

As can be seen from the above diagram, the residual voltage measured on a solidly earthed system is solely dependent on the ratio of source impedance behind the protection to the line impedance in front of the protection, up to the point of fault. For a remote fault far away, the Z_S/Z_L: ratio will be small, resulting in a correspondingly small residual voltage. Therefore, the protection only operates for faults up to a certain distance along the system. The maximum distance depends on the device setting.

7.5.3.2 CALCULATION FOR IMPEDANCE EARTHED SYSTEMS

Consider a Phase-A to Earth fault on a simple radial system.

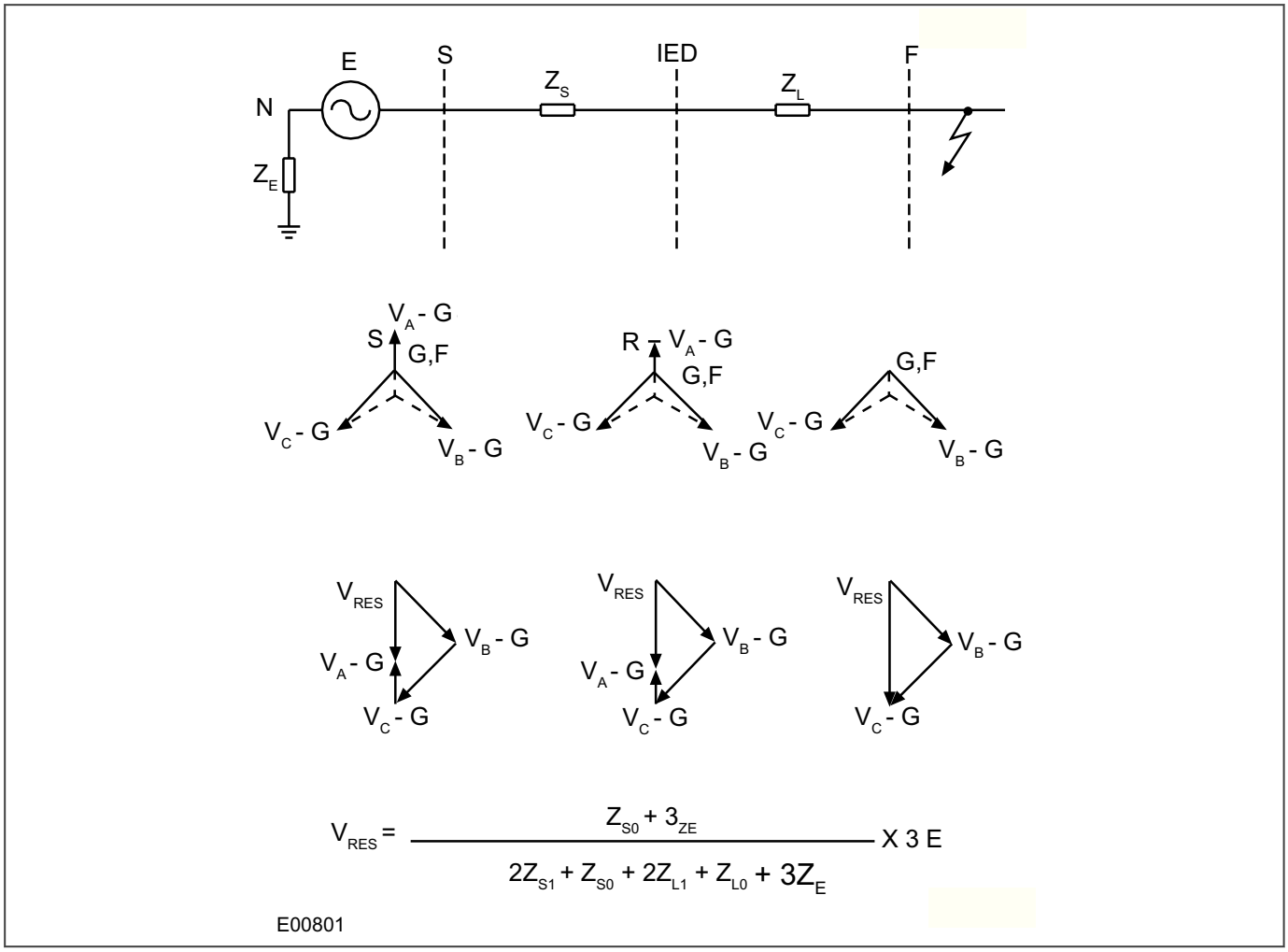


Figure 133: Residual voltage for an impedance earthed system

An impedance earthed system will always generate a relatively large degree of residual voltage, as the zero sequence source impedance now includes the earthing impedance. It follows then that the residual voltage generated by an earth fault on an insulated system will be the highest possible value (3 x phase-neutral voltage), as the zero sequence source impedance is infinite.

7.5.3.3 NEUTRAL VOLTAGE DISPLACEMENT (NVD) PROTECTION APPLIED TO CONDENSER BUSHINGS (CAPACITOR CONES)

Voltage Transformers are not fitted at distribution levels, due to their expense. Instead, capacitor cones, or condenser bushings, may be used at 11kV and 33kV substations to provide a neutral voltage displacement output to a suitable protection device.

Often, bushings are starred together, and the star point used to provide the displacement voltage to the device, as seen in the diagram, below.



Warning:
As protection method requires the device to be placed in a primary circuit location, all relevant safety measures must be in place.

Warning:
When operating in areas with restricted space, suitable protective barriers must be used where there is a risk of electric shock due to exposed terminals.

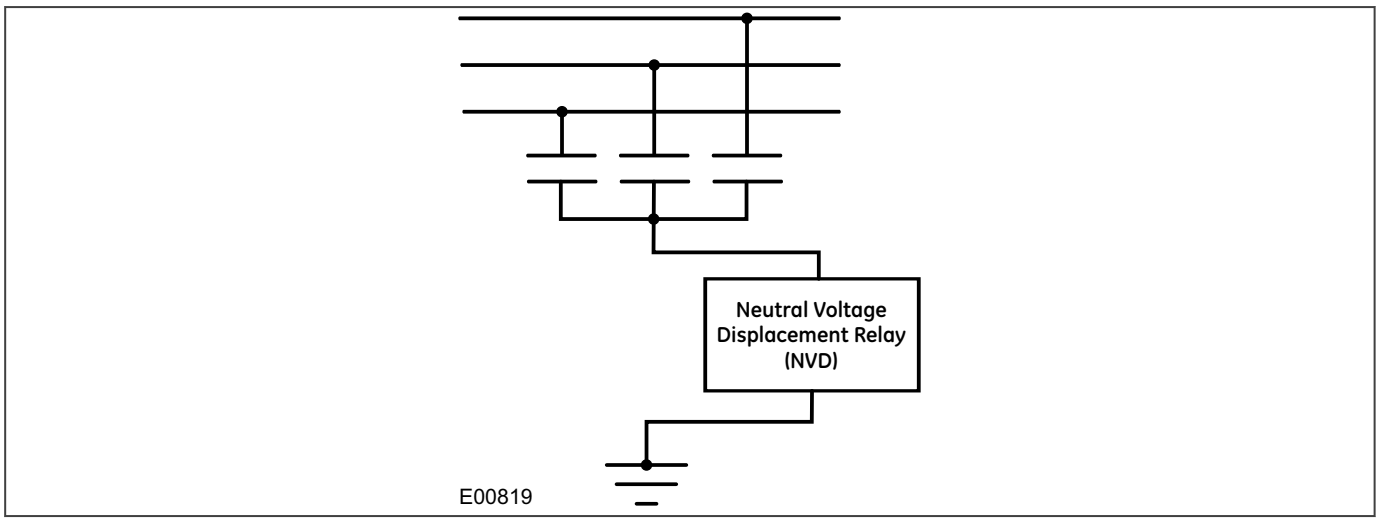


Figure 134: Star connected condenser bushings

Calculations for Condenser Bushing Systems

Consider a single-phase fault to ground on B-Phase:

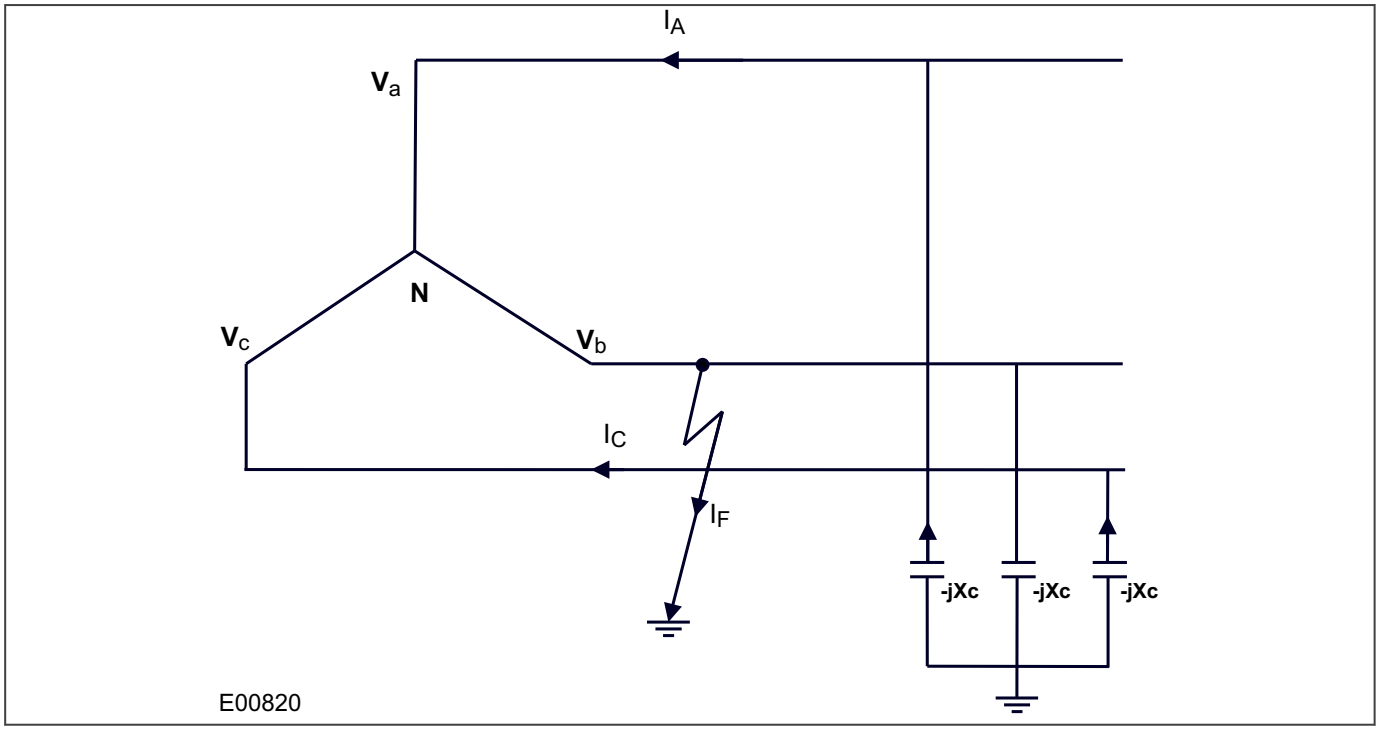


Figure 135: Theoretical earth fault in condenser bushing system

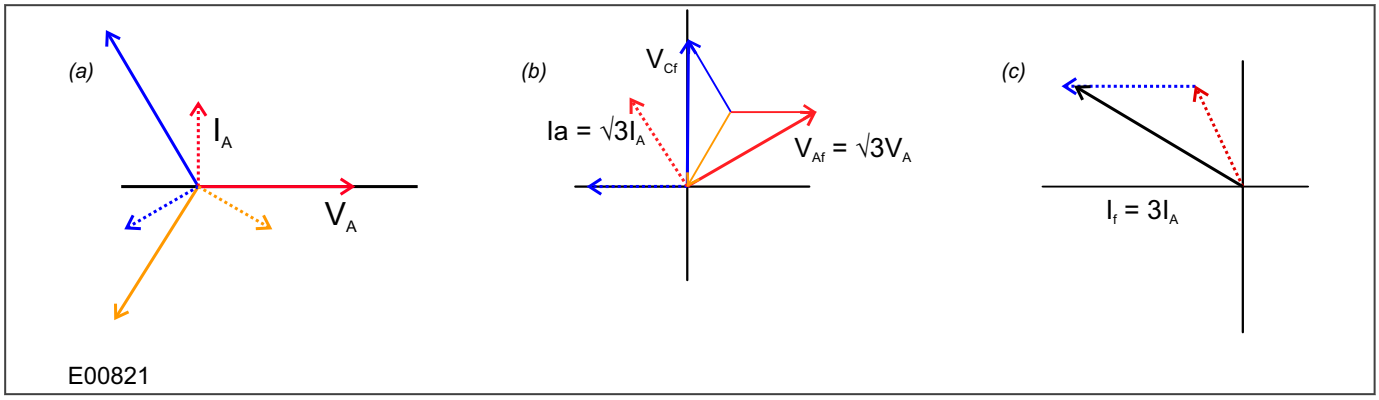


Figure 136: Condenser bushing system vectors

In the figure above:

(a) Shows three healthy voltages, three capacitor currents that lead their respective voltages by 90º and sum to zero,

(b) Shows B phase earthed, A and C voltages are √3 times their healthy magnitude & at 60º to each other, giving correspondingly altered capacitor currents Ia and Ic.

The vector sum of the A & C phase capacitor currents is:

$$I_f = \sqrt{3} \times Ia,$$

$$= \sqrt{3} \times \sqrt{3} \times I_A,$$

$$= 3 \times I_A$$

Therefore, the total fault current I_f equals three times a single capacitor healthy condition current I_A.

(c) Shows the vector sum of the fault condition I_f.

Therefore, I_f is the current which will flow in the Neutral Displacement Relay under fault conditions (neglecting the impedance of the relay itself).

For example, for a 60pF capacitor on a 33kV system, the single capacitor healthy condition current I_A is given by:

$$I_A = V_A / X_C$$

$$= V_A / (1/2\pi fC)$$

$$= \frac{33 \times 10^3}{\sqrt{3}} / (1/(2 \times \pi \times 50 \times 60 \times 10^{-12}))$$

$$= 0.359mA$$

Therefore, the total fault current which would flow in an NVD relay (neglecting the impedance of the relay itself):

$$I_f = 3 \times 0.359 = 1.08mA$$

The table below shows the total fault current I_f for a 60pF capacitor, and also I_f for a 90pF capacitor, and for a 150pF capacitor.

C (pF)	60.00	90.00	150.00
Xc (MΩ)	53.08	35.39	21.23
VA (kV)	19.00	19.00	19.00
IA (mA)	0.359	0.539	0.898
If (mA)	1.08	1.62	2.69

Where If is the total fault current which would flow in an NVD relay (neglecting the impedance of the relay itself), then knowing this current (If) and the input impedance of the relay (Rr) we can calculate the voltage produced across it (Vr) during a fault condition:

$$Vr = If \times Rr$$

Therefore, we would recommend setting the relay to less than half this voltage:

$$Vs < Vr/2$$

Practical Application

In practice, the device's input impedance varies with voltage, which will have some effect on actual settings. Therefore, we recommend the use a 23½kΩ resistor combination in parallel with this input, to fix the impedance. This value is achieved by the use of two 47kΩ resistors in parallel. Utilising two resistors in parallel also gives increased security.

The resistors used must have a continuous working voltage rating of 5kVdc minimum and a minimum power rating of 1W.



Warning:
There is the risk of high voltage developing on removal of the device or PCB from its case. Fixed resistors on the device input will prevent this, but we would also recommend use of an externally connected shorting contact.

Note:
A suitable shorting contact is available on each device. Please see diagram, below.

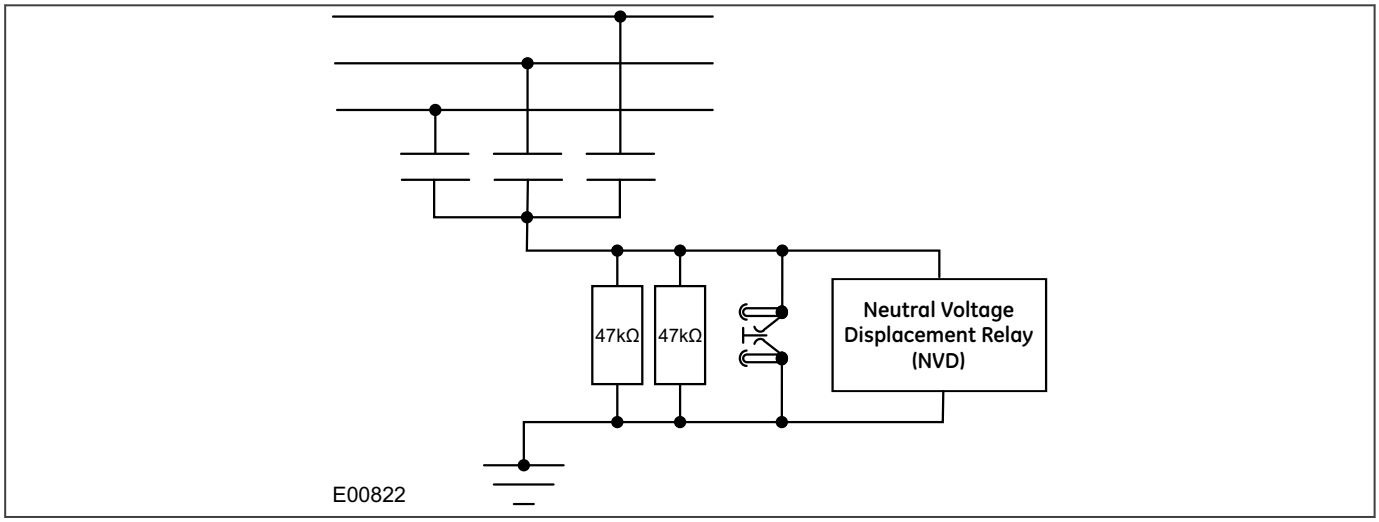


Figure 137: Device connection with resistors and shorting contact

Voltage Setting

The device has a minimum setting on the residual OV/NVD of 1V, which should provide a sensitive enough setting for most applications. The operating voltage to be applied can be calculated for various capacitor ratings, shown in calculations provided above.

For maximum settings for various capacitors (assuming 23½kΩ resistance applied in conjunction with the device), see the table below.

C (pF)	60.00	90.00	150.00
Xc (MΩ)	53.08	35.39	21.23
VA (kV)	19.00	19.00	19.00
If (mA)	1.08	1.62	2.69
Rr (kΩ)*	22.00	22.00	22.00
Vr (V)	23.63	35.44	59.06
Vs (V)	11.81	17.72	29.53

* Relay and Resistor Combination

Wiring Diagram

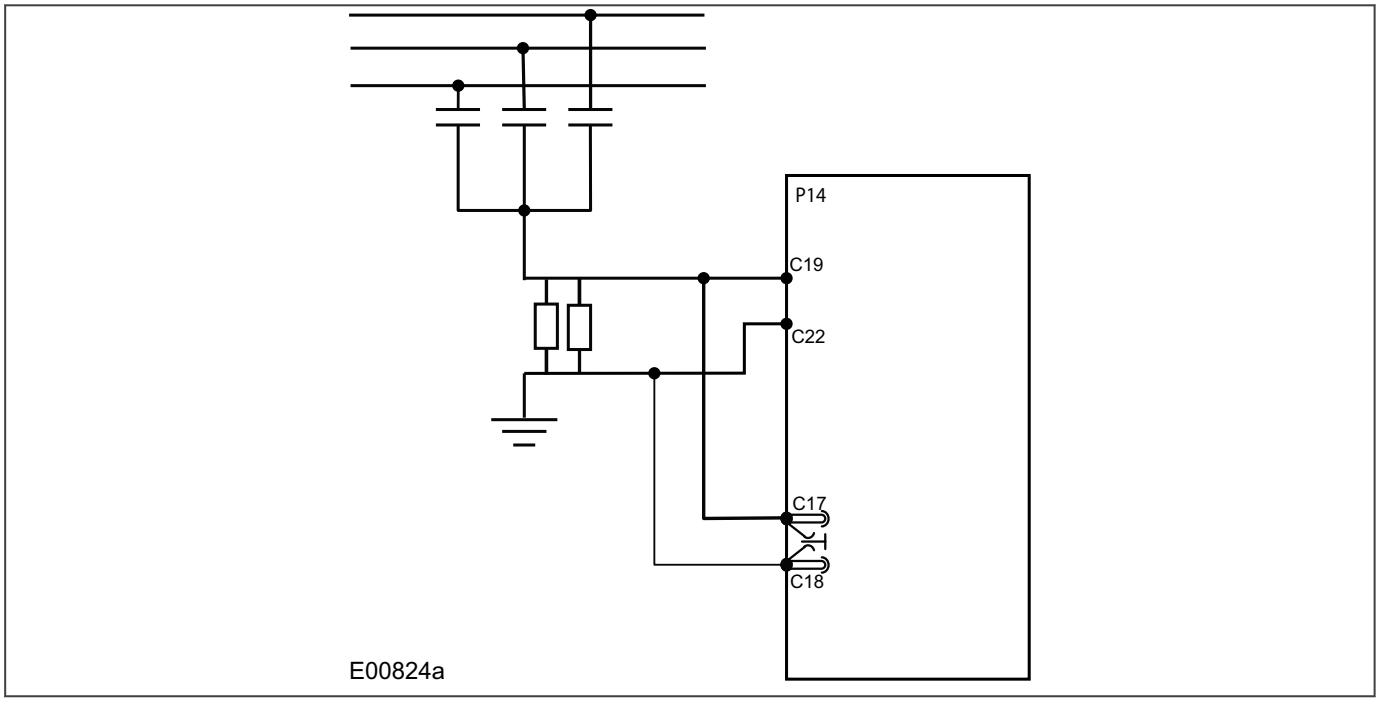


Figure 138: Device connection P14

Note:
Residual voltage measurement is derived from phase inputs, but neutral voltage may be connected into one of the phase inputs. This assumes that voltage inputs are not used for other purposes.

7.5.3.4 SETTING GUIDELINES

The voltage setting applied to the elements is dependent on the magnitude of residual voltage that is expected to occur during the earth fault condition. This in turn is dependent on the method of system earthing employed.

Also, you must ensure that the protection setting is set above any standing level of residual voltage that is present on the system.

7.6 NEGATIVE SEQUENCE OVERVOLTAGE PROTECTION

Where an incoming feeder is supplying rotating plant equipment such as an induction motor, correct phasing and balance of the supply is essential. Incorrect phase rotation will result in connected motors rotating in the wrong direction. For directionally sensitive applications, such as elevators and conveyor belts, it is unacceptable to allow this to happen.

Imbalances on the incoming supply cause negative phase sequence voltage components. In the event of incorrect phase rotation, the supply voltage would effectively consist of 100% negative phase sequence voltage only.

7.6.1 NEGATIVE SEQUENCE OVERVOLTAGE IMPLEMENTATION

Negative Sequence Overvoltage Protection is implemented in the *NEG SEQUENCE O/V* column of the relevant settings group.

The device includes one Negative Phase Sequence Overvoltage element with a single stage. Only Definite time is possible.

This element monitors the input voltage rotation and magnitude (normally from a bus connected voltage transformer) and may be interlocked with the motor contactor or circuit breaker to prevent the motor from being energised whilst incorrect phase rotation exists.

The element is enabled using the ***V2> status*** cell.

7.6.2 NEGATIVE SEQUENCE OVERVOLTAGE LOGIC

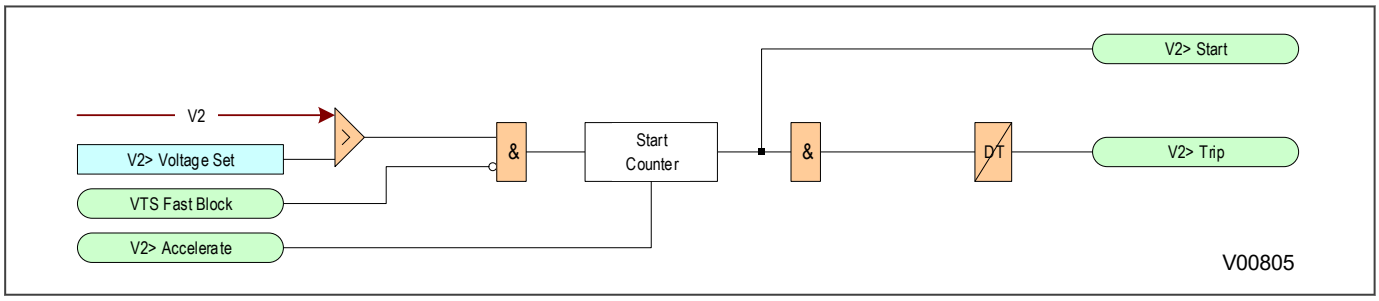


Figure 139: Negative sequence overvoltage logic

The Negative Voltage Sequence Overvoltage module (***V2>***) is a level detector that detects when the voltage magnitude exceeds a set threshold. When this happens, the comparator output Overvoltage Module produces a ***Start*** signal (***V2> Start***), which signifies the "Start of protection". This can be blocked by a ***VTS Fast block*** signal. This ***Start*** signal is applied to the DT timer module. The output of the DT timer module is the ***V2> Trip*** signal which is used to drive the tripping output relay.

The ***V2> Accelerate*** signal accelerates the operating time of the function, by reducing the number of confirmation cycles needed to start the function. At 50 Hz, this means the protection Start is reduced by 20 ms.

7.6.3 APPLICATION NOTES

7.6.3.1 SETTING GUIDELINES

The primary concern is usually the detection of incorrect phase rotation (rather than small imbalances), therefore a sensitive setting is not required. The setting must be higher than any standing NPS voltage, which may be present due to imbalances in the measuring VT, device tolerances etc.

A setting of approximately 15% of rated voltage may be typical.

Note:
Standing levels of NPS voltage (V2) are displayed in the ***V2 Magnitude*** *cell of the MEASUREMENTS 1 column.*

The operation time of the element depends on the application, but a typical setting would be in the region of 5 seconds.

7.7 SENSITIVE OVERVOLTAGE PROTECTION

The SOV function provides an extended range for the pickup setting (from 2V to 185V). The unique characteristic in SOV function extends the device's capability to mimic the buswire supervision function in a high impedance busbar protection scheme. The P14 device can detect open circuit scenarios in buswire by using the sensitive overvoltage function. This enables the P14 device to provide cost & space efficient one box solution for both high impedance busbar protection and buswire supervision.

7.7.1 SENSITIVE OVERVOLTAGE IMPLEMENTATION

The device provides two stages of Sensitive Overvoltage Supervision; SOV>1 and SOV>2. Two measurement modes are available; phase-to-phase or phase-to-neutral. You choose the measurement mode with the ***SOV Meas't Mode*** setting. Two operation modes are also available; any phase, or three-phase. You choose the operating mode with the ***SOV Operate Mode*** setting. This setting determines whether any one of the phases or all three of the phases have to satisfy the overvoltage criteria before a decision is made.

Both of these settings are global for both stages and cannot be applied individually to each stage.

Each stage can be enabled or disabled individually with the ***SOV>1 Status*** and ***SOV>2 Status*** settings. The pickup threshold voltage for each stage can be set using, ***SOV>1 Volt Set*** and ***SOV>2 Volt Set*** settings respectively. A DT time delay for each stage can also be set with the ***SOV>1 Time Delay*** and ***SOV>2 Time Delay*** settings.

7.7.1.1 SENSITIVE OVERVOLTAGE FILTER MODE

The SOV function also has ***SOV Filter Mod***. When the ***SOV Filter Mod*** is enabled, the SOV protection provides adaptive pickup responding to the frequency of the voltage input. In the ***SOV Filter Mod***, the SOV function is tuned to operate sensitively on nominal frequency, but adapt the pickup level to higher when the frequency is outside nominal range.

> *Note:*
> *The SOV function in **SOV Filter Mod** has a pickup setting range from 10V to 185V, this will respond to the relay's frequency tracking range (40Hz to 70Hz). SOV protection in **SOV Filter Mod** will be blocked if the frequency of the voltage input is outside the frequency tracking range.*

It is possible to enable a band pass frequency characteristic for this function using the ***SOV Filter Mod*** setting. If you set this to `Disabled`, the normal mode is chosen, which is no different from previous models. If you select `Enabled`, however, this allows you to set the rate of operation voltage for various proportions of the system frequency. You can set this individually from 0.8 times system frequency through to 1.2 times system frequency, with the setting cells under the *SOV OPERA CURVE* sub heading.

With the ***SOV Filter Mod*** set to `Enabled`, SOV pickup is adjusted to the U-curve according to the system frequency. However, when the voltage is <10V, the device cannot detect the system frequency. If the voltage moves quickly from 0V to above 10V, the device will take time to detect the system frequency and adjust the pickup to the U-curve, this will slow down the relay tripping response. To prevent this delay, the device will be defaulted to the nominal frequency when the frequency is not found, so that the relay SOV can pickup immediately without waiting for the system frequency. When the device detects the system frequency and adjusts the overvoltage pickup according to U-curve, if the voltage is still above the pickup (according to U-curve), the device can trip without delay. But, if the voltage is below pickup (according to U-curve), the SOV pickup will drop off.

To prevent unwanted behaviour, ***SOV Filter Mod*** `Enabled` has minimum timer of 300ms. The SOV function is also intended to be used for buswire supervision, which is normally set to 2s-10s delay. The Sensitive overvoltage characteristic for buswire supervision is shown below.

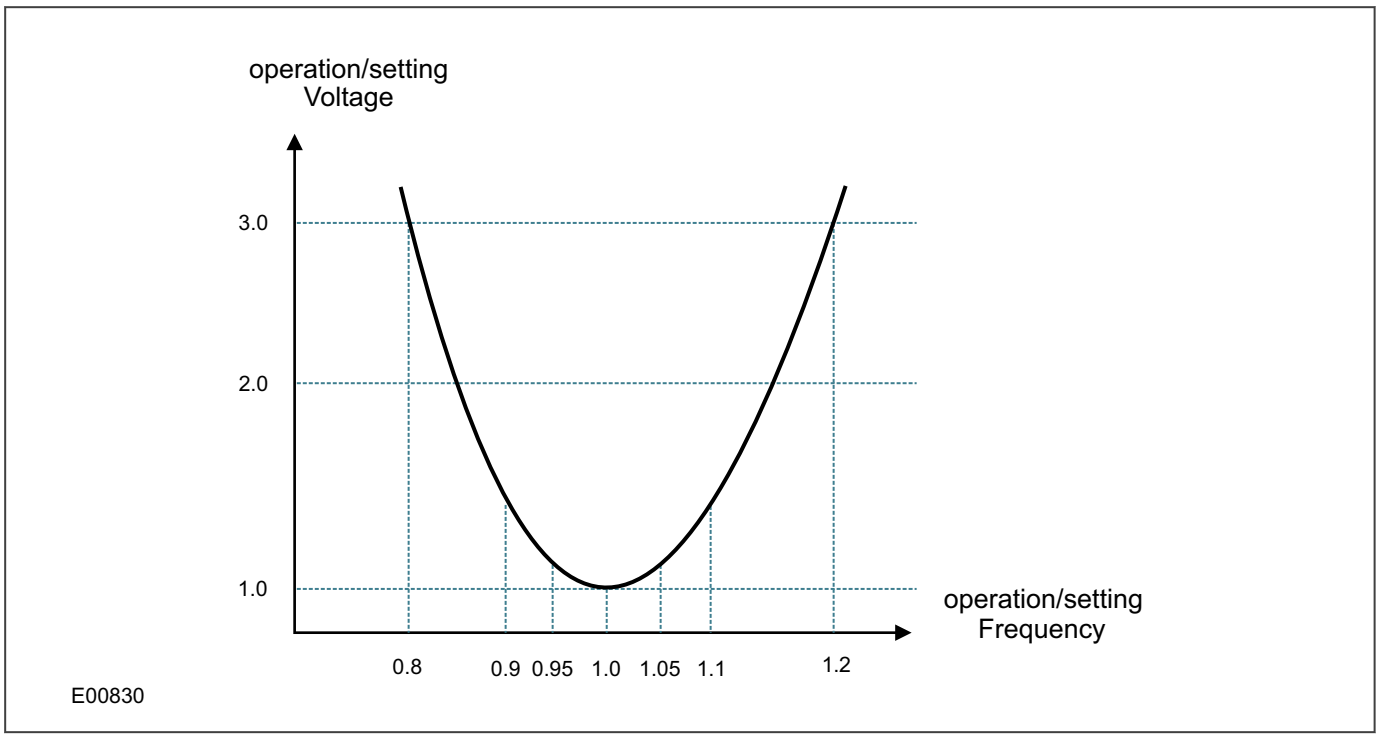


Figure 140: Sensitive overvoltage characteristic for buswire supervision

7.7.2 SENSITIVE OVERVOLTAGE LOGIC

7.7.2.1 SENSITIVE OVERVOLTAGE OPERATION LOGIC

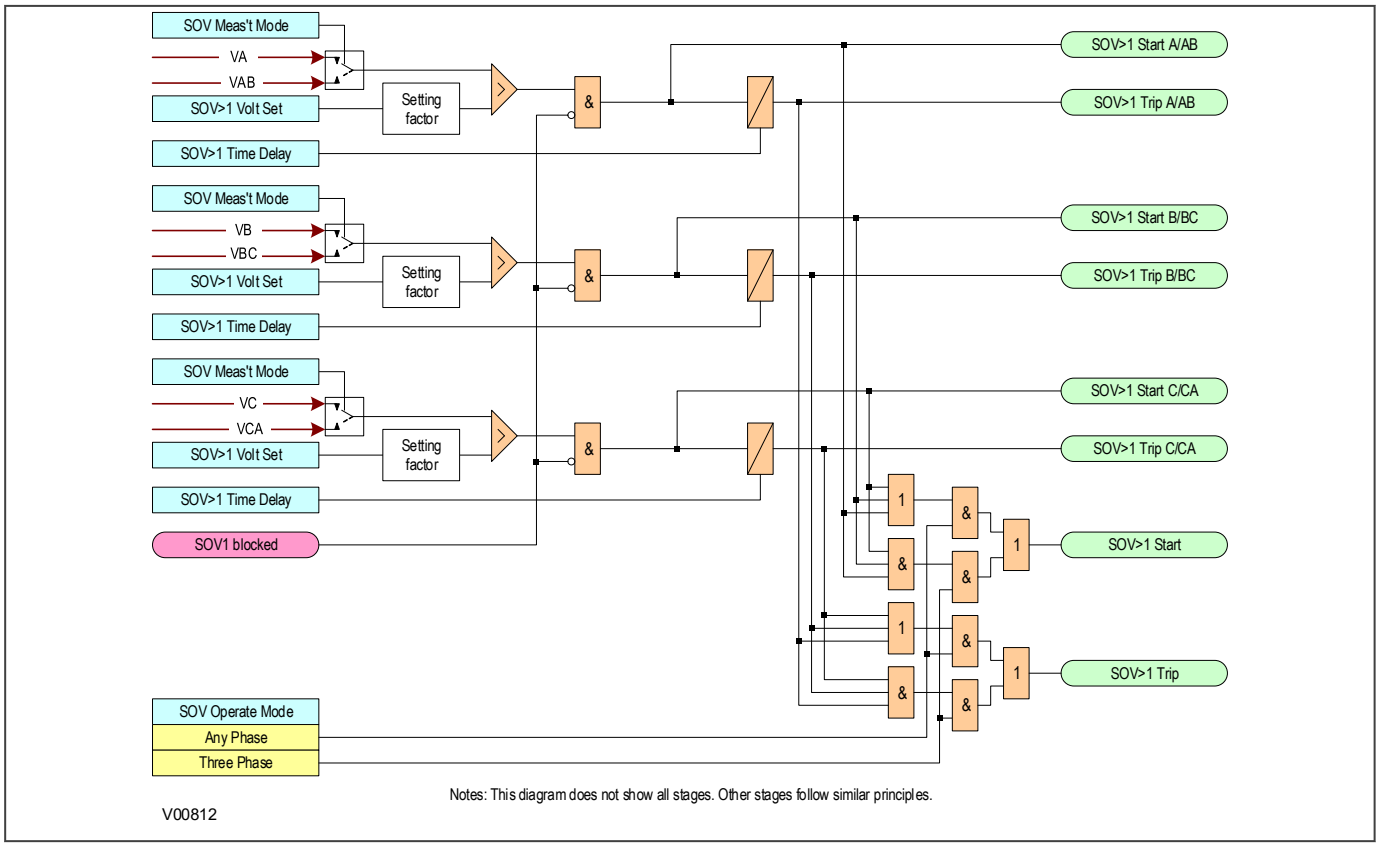


Figure 141: Sensitive overvoltage operation logic

7.7.2.2 SENSITIVE OVERVOLTAGE FILTER MODE LOGIC

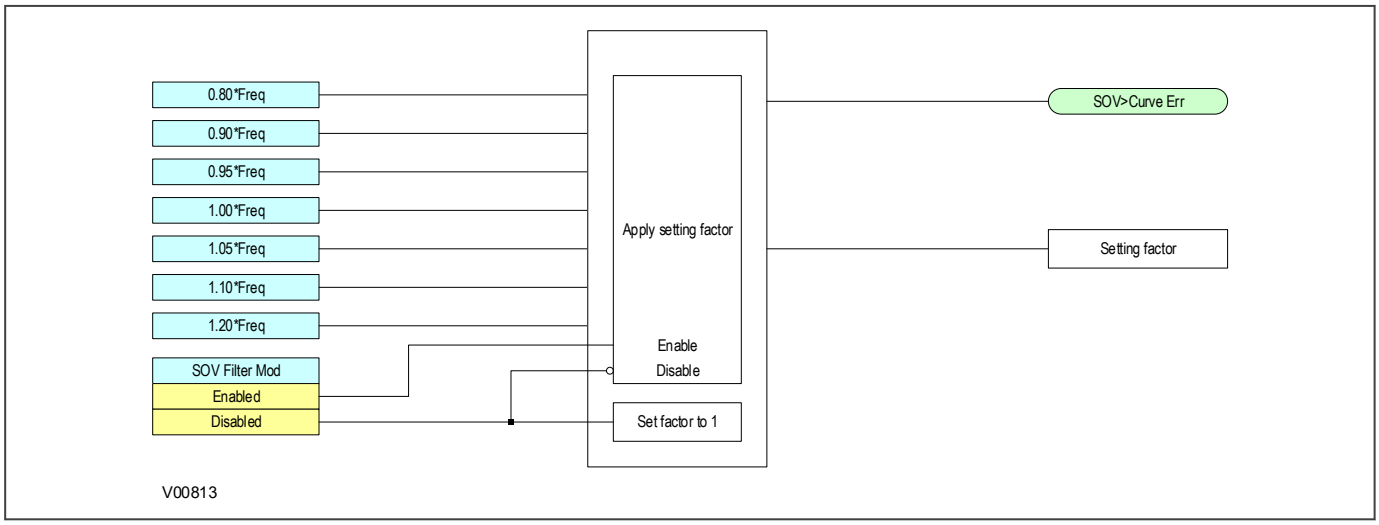


Figure 142: Sensitive overvoltage filter mode logic

7.7.2.3 SENSITIVE OVERVOLTAGE BLOCKING LOGIC

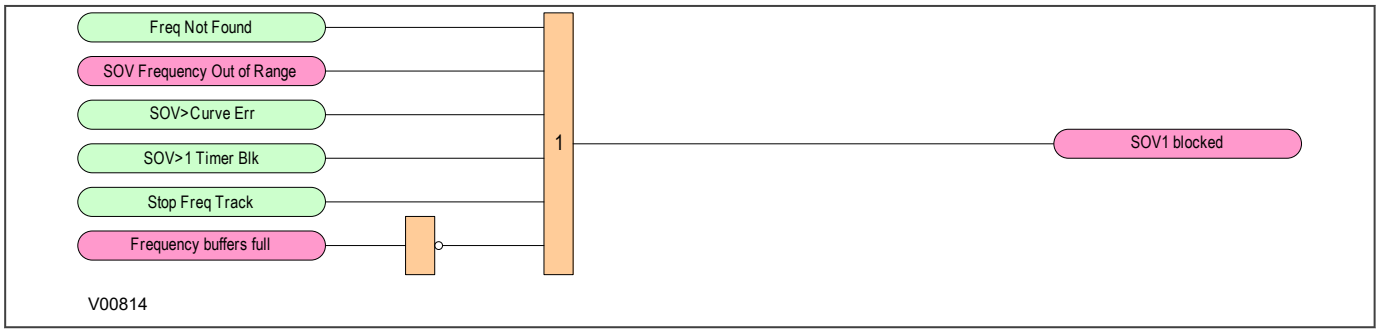


Figure 143: Sensitive overvoltage blocking logic

7.7.3 VT CONNECTIONS

7.7.3.1 APPLICATION NOTES

7.7.3.1.1 OPEN DELTA (VEE CONNECTED) VTS

The P14 can be used with vee connected VTs by connecting the VT secondaries to C19, C20 and C21 input terminals, with the C22 input left unconnected.

This type of VT arrangement cannot pass zero-sequence (residual) voltage to the device, or provide any phase to neutral voltage quantities. Therefore any protection that is dependent upon phase to neutral voltage measurements should be disabled.

The under and over voltage protection can be set as phase-to-phase measurement with vee connected VTs. The voltage dependent overcurrent use phase-phase voltages anyway, therefore the accuracy should not be affected. Directional earth fault and sensitive directional earth fault protection should be disabled as the neutral voltage will always be zero, even in the event of an earth fault. The VT dependent CT supervision should also be disabled as this is also dependent upon the measurement of zero sequence voltage.

The accuracy of single phase voltage measurements can be impaired when using vee connected VTs. The device attempts to derive the phase to neutral voltages from the phase to phase voltage vectors. If the impedance of the voltage inputs were perfectly matched the phase to neutral voltage measurements would be correct, provided the phase to phase voltage vectors were balanced. However, in practice there are small differences in the impedance of the voltage inputs, which can cause small errors in the phase to neutral voltage measurements. This may give rise to an apparent residual voltage. This problem also extends to single phase power measurements that are also dependent upon their respective single phase voltages.

The phase to neutral voltage measurement accuracy can be improved by connecting three, well matched, load resistors between the phase voltage inputs (C19, C20, C21) and neutral C22, thus creating a ‘virtual’ neutral point. The load resistor values must be chosen so that their power consumption is within the limits of the VT. It is recommended that 10kΩ ±1% (6W) resistors are used for the 110V (Vn) rated relay, assuming the VT can supply this burden.

7.7.3.1.2 VT SINGLE POINT EARTHING

The P14 will function correctly with conventional 3-phase VTs earthed at any one point on the VT secondary circuit. Typical earthing examples being neutral earthing and yellow phase earthing.

CHAPTER 8

BASIC FREQUENCY PROTECTION FUNCTIONS

8.1 CHAPTER OVERVIEW

The device provides a range of basic frequency protection functions. This chapter describes the operation of these functions including the principles, logic diagrams and applications.

This chapter contains the following sections:

Chapter Overview 216

Frequency Protection 217

Underfrequency Protection 218

Overfrequency Protection 219

8.2 FREQUENCY PROTECTION

Power generation and utilisation needs to be well balanced in any industrial, distribution or transmission network. These electrical networks are dynamic entities, with continually varying loads and supplies, which are continually affecting the system frequency. Increased loading reduces the system frequency and generation needs to be increased to maintain the frequency of the supply. Conversely decreased loading increases the system frequency and generation needs to be reduced. Sudden fluctuations in load can cause rapid changes in frequency, which need to be dealt with quickly.

Unless corrective measures are taken at the appropriate time, frequency decay can go beyond the point of no return and cause widespread network collapse, which has dire consequences.

Normally, generators are rated for a particular band of frequency. Operation outside this band can cause mechanical damage to the turbine blades. Protection against such contingencies is required when frequency does not improve even after load shedding steps have been taken. This type of protection can be used for operator alarms or turbine trips in case of severe frequency decay.

A Frequency Protection package is provided in this device to satisfy the basic needs for underfrequency and overfrequency responses.

An Advanced Frequency Protection package is also provided to satisfy more critical applications where the demand may be for more complex assessments such as those based on Rate of Change of Frequency (ROCOF) for example.

Frequency Protection is implemented in the *FREQ PROTECTION* column of the relevant settings group.

The Advanced Frequency Protection is implemented in the *ADV. FREQ PROT'N* column of the relevant settings group.

Either the basic package or the advanced package may be chosen by enabling the appropriate ***Freq Protection*** or ***Adv. Freq Prot'n*** setting in the *CONFIGURATION* column.

> *Note:*
> *1. Only one of the frequency protection packages should be used so you enable only one or the other settings - **Freq Protection** or **Adv. Freq Prot'n**.*
> *2. Since the Advanced Frequency Protection package includes all the functionality available in the basic Frequency Protection package, then unless there is a specific requirement for a minimal application, the recommended configuration is to set **Adv. Freq Prot'n** to `Enabled`, and **Freq Protection** to `Disabled`.*

This chapter applies to installations where the basic Frequency Protection package is preferred. Accordingly, it assumes that ***Freq Protection*** is set to `Enabled`, and ***Adv. Freq Prot'n*** is set to `Disabled`. This will make the settings in the *FREQ PROTECTION* column visible and hide the Advanced Frequency Protection settings.

8.3 UNDERFREQUENCY PROTECTION

A reduced system frequency implies that the net load is in excess of the available generation. Such a condition can arise, when an interconnected system splits, and the load left connected to one of the subsystems is in excess of the capacity of the generators in that particular subsystem. Industrial plants that are dependent on utilities to supply part of their loads will experience underfrequency conditions when the incoming lines are lost.

Many types of industrial loads have limited tolerances on the operating frequency and running speeds (e.g. synchronous motors). Sustained underfrequency has implications on the stability of the system, whereby any subsequent disturbance may damage equipment and even lead to blackouts. It is therefore essential to provide protection for underfrequency conditions.

8.3.1 UNDERFREQUENCY PROTECTION IMPLEMENTATION

Simple underfrequency Protection is configured in the *FREQ PROTECTION* column of the relevant settings group.

The device provides 4 stages of underfrequency protection. The function uses the following settings (shown for stage 1 only - other stages follow the same principles).

- ***F<1 Status:*** enables or disables underfrequency protection for the relevant stage
- ***F<1 Setting***: defines the frequency pickup setting
- ***F<1 Time Delay***: sets the time delay

8.3.2 UNDERFREQUENCY PROTECTION LOGIC

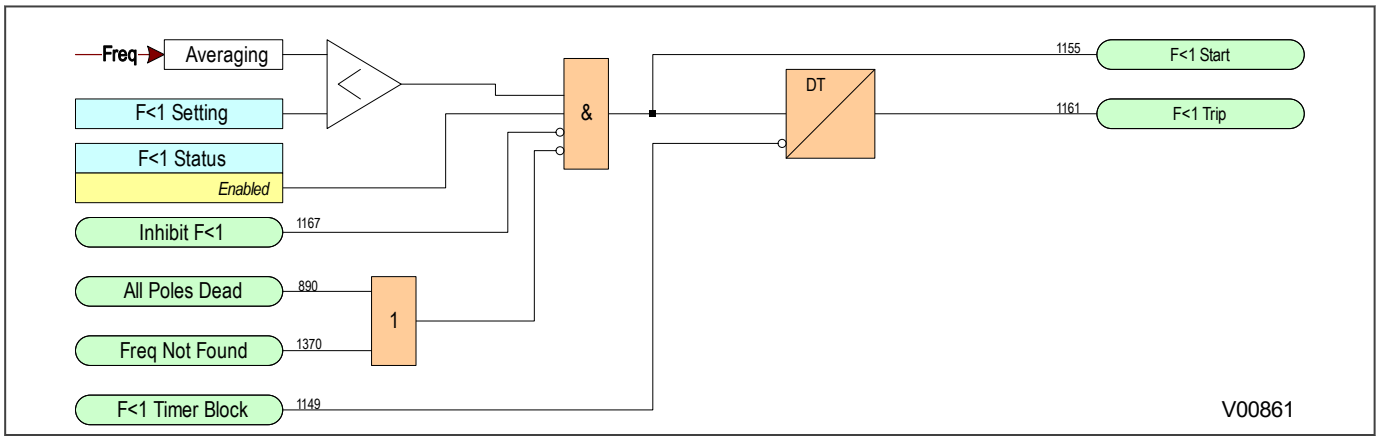


Figure 144: Underfrequency logic (single stage)

If the frequency is below the setting and not blocked the DT timer is started. If the frequency cannot be determined, the function is blocked.

8.3.3 APPLICATION NOTES

8.4 OVERFREQUENCY PROTECTION

An increased system frequency arises when the mechanical power input to a generator exceeds the electrical power output. This could happen, for instance, when there is a sudden loss of load due to tripping of an outgoing feeder from the plant to a load centre. Under such conditions, the governor would normally respond quickly to obtain a balance between the mechanical input and electrical output, thereby restoring normal frequency. Overfrequency protection is required as a backup to cater for cases where the reaction of the control equipment is too slow.

8.4.1 OVERFREQUENCY PROTECTION IMPLEMENTATION

Simple overfrequency Protection is configured in the *FREQ PROTECTION* column of the relevant settings group.

The device provides 2 stages of overfrequency protection. The function uses the following settings (shown for stage 1 only - other stages follow the same principles).

- ***F>1 Status:*** enables or disables underfrequency protection for the relevant stage
- ***F>1 Setting***: defines the frequency pickup setting
- ***F>1 Time Delay***: sets the time delay

8.4.2 OVERFREQUENCY PROTECTION LOGIC

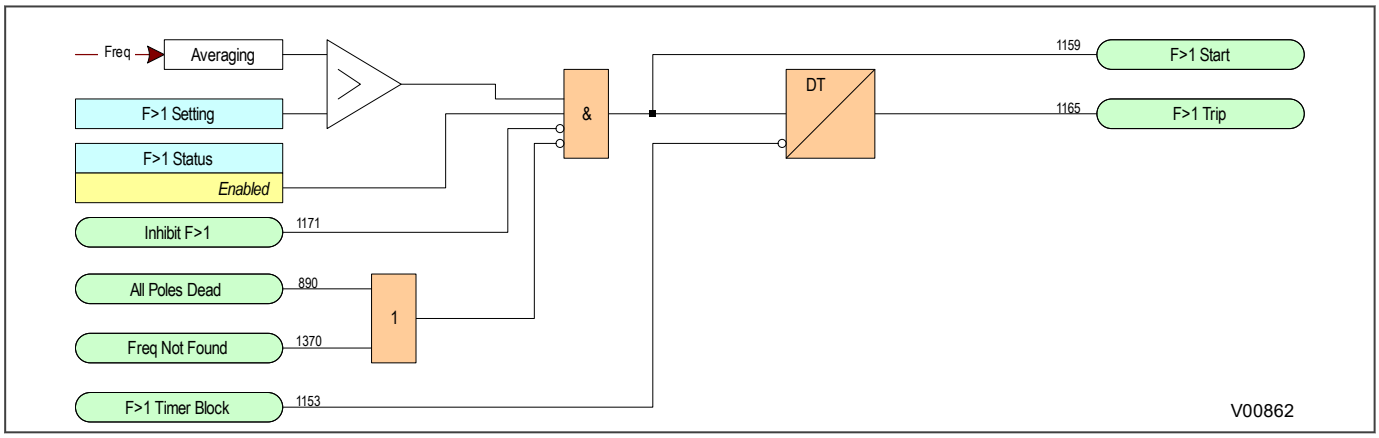


Figure 145: Overfrequency logic (single stage)

If the frequency is above the setting and not blocked, the DT timer is started and after this has timed out, the trip is produced. If the frequency cannot be determined, the function is blocked.

8.4.3 APPLICATION NOTES

8.4.3.1 SETTING GUIDELINES

Following changes on the network caused by faults or other operational requirements, it is possible that various subsystems will be formed within the power network. It is likely that these subsystems will suffer from a generation/ load imbalance. The "islands" where generation exceeds the existing load will be subject to overfrequency conditions. Severe over frequency conditions may be unacceptable to many industrial loads, since running speeds of motors will be affected. The overfrequency element can be suitably set to sense this contingency.

CHAPTER 9

ADVANCED FREQUENCY PROTECTION FUNCTIONS

9.1 CHAPTER OVERVIEW

The device provides a range of advanced frequency protection functions. This chapter describes the operation of these functions including the principles, logic diagrams and applications.

This chapter contains the following sections:

Chapter Overview 221
Frequency Protection 222
Underfrequency Protection 224
Overfrequency Protection 226
Independent R.O.C.O.F Protection 228
Frequency-supervised R.O.C.O.F Protection 230
Average Rate of Change of Frequency Protection 233
Load Shedding and Restoration 236

9.2 FREQUENCY PROTECTION

Power generation and utilisation needs to be well balanced in any industrial, distribution or transmission network. These electrical networks are dynamic entities, with continually varying loads and supplies, which are continually affecting the system frequency. Increased loading reduces the system frequency and generation needs to be increased to maintain the frequency of the supply. Conversely decreased loading increases the system frequency and generation needs to be reduced. Sudden fluctuations in load can cause rapid changes in frequency, which need to be dealt with quickly.

Unless corrective measures are taken at the appropriate time, frequency decay can go beyond the point of no return and cause widespread network collapse, which has dire consequences.

Normally, generators are rated for a particular band of frequency. Operation outside this band can cause mechanical damage to the turbine blades. Protection against such contingencies is required when frequency does not improve even after load shedding steps have been taken. This type of protection can be used for operator alarms or turbine trips in case of severe frequency decay.

A Frequency Protection package is provided in this device to satisfy the basic needs for underfrequency and overfrequency responses.

An Advanced Frequency Protection package is also provided to satisfy more critical applications where the demand may be for more complex assessments such as those based on Rate of Change of Frequency (ROCOF) for example.

Frequency Protection is implemented in the *FREQ PROTECTION* column of the relevant settings group.

The Advanced Frequency Protection is implemented in the *ADV. FREQ PROT'N* column of the relevant settings group.

Either the basic package or the advanced package may be chosen by enabling the appropriate ***Freq Protection*** or ***Adv. Freq Prot'n*** setting in the *CONFIGURATION* column.

Note:
*1. Only one of the frequency protection packages should be used so you enable only one or the other settings - **Freq Protection** or **Adv. Freq Prot'n**.*
*2. Since the Advanced Frequency Protection package includes all the functionality available in the basic Frequency Protection package, then unless there is a specific requirement for a minimal application, the recommended configuration is to set **Adv. Freq Prot'n** to `Enabled`, and **Freq Protection** to `Disabled`.*

This chapter applies to installations where the Advanced Frequency Protection package is preferred. Accordingly, it assumes that ***Adv, Freq Prot'n*** is set to `Enabled`, and ***Freq Protection*** is set to `Disabled`. This will make the settings in the *FREQ PROTECTION* column visible, and hide the Advanced Frequency Protection settings.

9.2.1 ADVANCED FREQUENCY PROTECTION IMPLEMENTATION

The Advanced Frequency Protection supports 9 stages, each element of which provides the following functions:

- Underfrequency Protection: abbreviated to f+t<
- Overfrequency Protection: abbreviated to f+t>
- Independent Rate of Change of Frequency Protection: abbreviated to Independent R.O.C.O.F, or df/dt+t.
- Frequency-supervised Rate of Change of Frequency Protection: abbreviated to Frequency-supervised R.O.C.O.F, or f+df/dt.
- Average Rate of Change of Frequency Protection: abbreviated to Average R.O.C.O.F, or f+Df/Dt (note the uppercase 'D').
- Load Shedding and Restoration

The advanced version of frequency protection is implemented in the *ADV. FREQ PROT'N* column of the relevant settings group.

If you require only four stages of underfrequency protection and two stages of overfrequency protection, you could use the basic version of frequency protection instead. For flexibility however, we propose using the advanced version in all cases.

To use advanced frequency protection you must enable it, as well as disabling the equivalent basic frequency protection. You do this in the *CONFIGURATION* column by setting the e ***Adv. Freq Prot'n*** setting to `Enabled` and the ***Freq Protection*** setting to `Disabled`.

Within the advanced frequency protection, you can enable or disable all frequency protections for each stage with the ***Stage (n)*** setting. The ***Stage (n)*** settings provide a choice, allowing undervoltage blocking to be applied to that stage.

9.3 UNDERFREQUENCY PROTECTION

A reduced system frequency implies that the net load is in excess of the available generation. Such a condition can arise, when an interconnected system splits, and the load left connected to one of the subsystems is in excess of the capacity of the generators in that particular subsystem. Industrial plants that are dependent on utilities to supply part of their loads will experience underfrequency conditions when the incoming lines are lost.

Many types of industrial loads have limited tolerances on the operating frequency and running speeds (e.g. synchronous motors). Sustained underfrequency has implications on the stability of the system, whereby any subsequent disturbance may damage equipment and even lead to blackouts. It is therefore essential to provide protection for underfrequency conditions.

9.3.1 UNDERFREQUENCY PROTECTION IMPLEMENTATION

The following settings are relevant for underfrequency elements in the advanced frequency protection:

- ***Stg (n) f+t Status***: determines whether the stage is underfrequency, overfrequency, or disabled.
- ***Stg (n) f+t Freq***: defines the frequency pickup setting
- ***Stg (n) f+t Time***: sets the time delay

Note:
This section refers to advanced frequency protection. The basic frequency protection works in a similar manner, but the setting names and DDB signal names are different.

9.3.2 UNDERFREQUENCY PROTECTION LOGIC

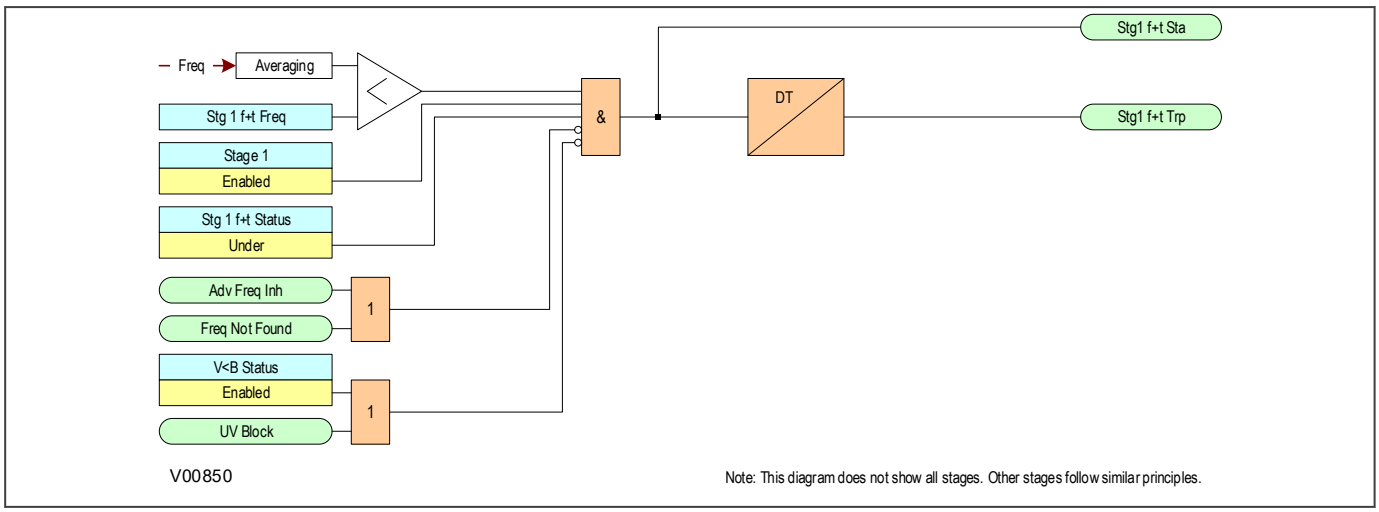


Figure 146: Underfrequency logic (single stage)

If the frequency is below the setting and not blocked the DT timer is started. If the frequency cannot be determined, the function is blocked.

Note:
This section refers to advanced frequency protection. The basic frequency protection works in a similar manner, but the setting names and DDB signal names are different.

9.3.3 APPLICATION NOTES

9.3.3.1 SETTING GUIDELINES

In order to minimise the effects of underfrequency, a multi-stage load shedding scheme may be used with the plant loads prioritised and grouped. During an underfrequency condition, the load groups are disconnected sequentially, with the highest priority group being the last one to be disconnected.

The effectiveness of each load shedding stage depends on the proportion of power deficiency it represents. If the load shedding stage is too small compared with the prevailing generation deficiency, then there may be no improvement in the frequency. This should be taken into account when forming the load groups.

Time delays should be sufficient to override any transient dips in frequency, as well as to provide time for the frequency controls in the system to respond. These should not be excessive as this could jeopardize system stability. Time delay settings of 5 - 20 s are typical.

An example of a four-stage load shedding scheme for 50 Hz systems is shown below:

Stage	Element	Frequency Setting (Hz)	Time Setting (Sec)
1	Stage 1(f+t)	49.0	20 s
2	Stage 2(f+t)	48.6	20 s
3	Stage 3(f+t)	48.2	10 s
4	Stage 4(f+t)	47.8	10 s

The relatively long time delays are intended to provide sufficient time for the system controls to respond. This will work well in a situation where the decline of system frequency is slow. For situations where rapid decline of frequency is expected, this load shedding scheme should be supplemented by rate of change of frequency protection elements.

Note:
This section refers to advanced frequency protection. The basic frequency protection works in a similar manner, but the setting names and DDB signal names are different.

9.4 OVERFREQUENCY PROTECTION

An increased system frequency arises when the mechanical power input to a generator exceeds the electrical power output. This could happen, for instance, when there is a sudden loss of load due to tripping of an outgoing feeder from the plant to a load centre. Under such conditions, the governor would normally respond quickly to obtain a balance between the mechanical input and electrical output, thereby restoring normal frequency. Overfrequency protection is required as a backup to cater for cases where the reaction of the control equipment is too slow.

9.4.1 OVERFREQUENCY PROTECTION IMPLEMENTATION

The following settings are relevant for overfrequency:

- ***Stg (n) f+t Status***: determines whether the stage is underfrequency, overfrequency, or disabled
- ***Stg (n) f+t Freq***: defines the frequency pickup setting
- ***Stg (n) f+t Time***: sets the time delay

9.4.2 OVERFREQUENCY PROTECTION LOGIC

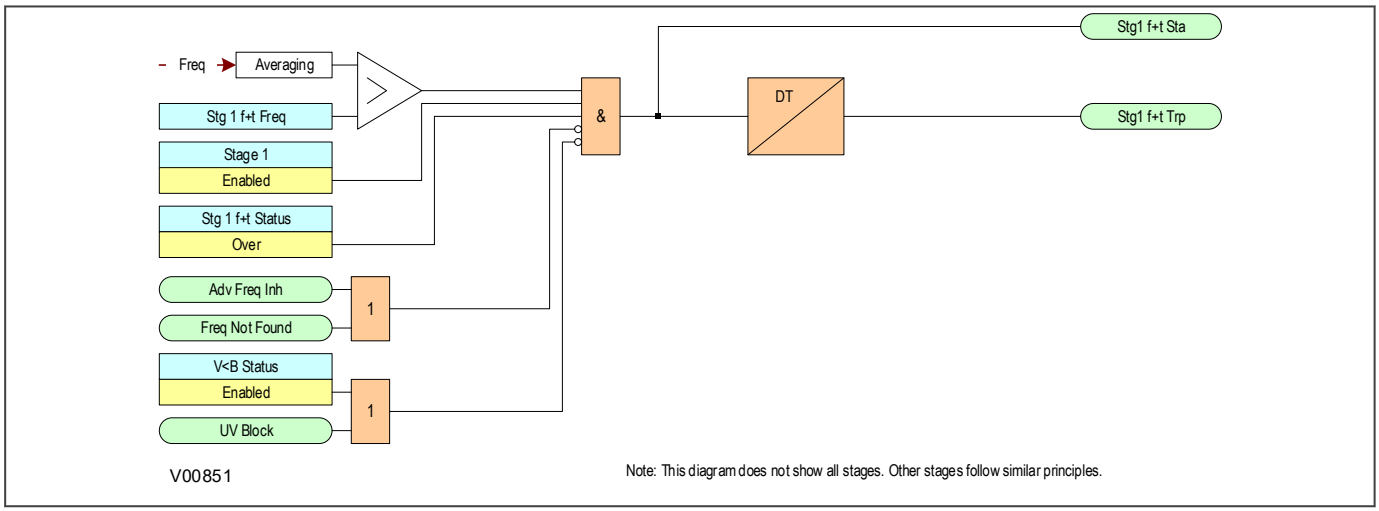


Figure 147: Overfrequency logic (single stage)

If the frequency is above the setting and not blocked, the DT timer is started and after this has timed out, the trip is produced. If the frequency cannot be determined, the function is blocked.

Note:
This section refers to advanced frequency protection. The basic frequency protection works in a similar manner, but the setting names and DDB signal names are different.

9.4.3 APPLICATION NOTES

9.4.3.1 SETTING GUIDELINES

Following changes on the network caused by faults or other operational requirements, it is possible that various subsystems will be formed within the power network. It is likely that these subsystems will suffer from a generation/ load imbalance. The "islands" where generation exceeds the existing load will be subject to overfrequency conditions. Severe over frequency conditions may be unacceptable to many industrial loads, since running speeds of motors will be affected. The overfrequency element can be suitably set to sense this contingency.

An example of two-stage overfrequency protection is shown below using stages 5 and 6 of the f+t elements. However, settings for a real system will depend on the maximum frequency that equipment can tolerate for a given period of time.

Stage	Element	Frequency Setting (Hz)	Time Setting (Sec.)
1	Stage 5(f+t)	50.5	30
2	Stage 6(f+t)	51.0	20

The relatively long time delays are intended to provide time for the system controls to respond and will work well in a situation where the increase of system frequency is slow.

For situations where rapid increase of frequency is expected, the protection scheme above could be supplemented by rate of change of frequency protection elements.

In the system shown below, the generation in the MV bus is sized according to the loads on that bus, whereas the generators linked to the HV bus produce energy for export to utility. If the links to the grid are lost, the generation will cause the system frequency to rise. This rate of rise could be used to isolate the MV bus from the HV system.

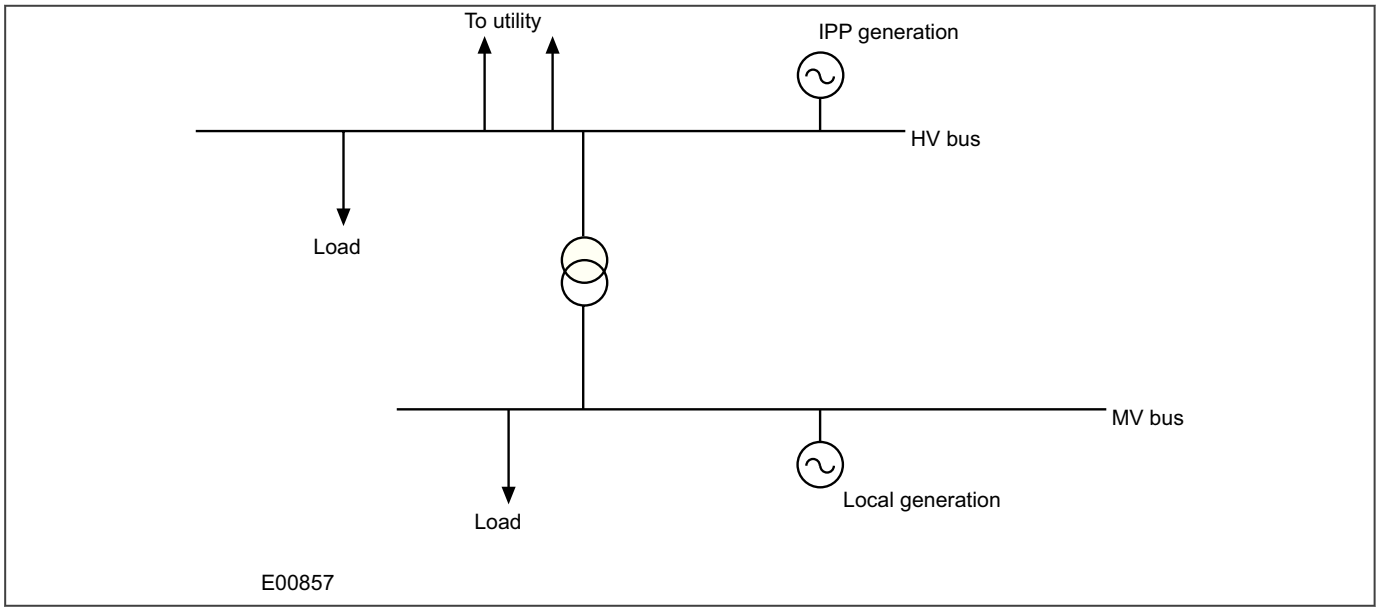


Figure 148: Power system segregation based upon frequency measurements

Note:
This section refers to advanced frequency protection. The basic frequency protection works in a similar manner, but the setting names and DDB signal names are different.

9.5 INDEPENDENT R.O.C.O.F PROTECTION

Where there are very large loads, imbalances may occur that result in rapid decline in system frequency. The situation could be so bad that shedding one or two stages of load is unlikely to stop this rapid frequency decline. In such a situation, standard underfrequency protection will normally have to be supplemented with protection that responds to the rate of change of frequency. An element is therefore required which identifies the high rate of decline of frequency, and adapts the load shedding scheme accordingly.

Such protection can identify frequency variations occurring close to nominal frequency thereby providing early warning of a developing frequency problem. The element can also be used as an alarm to warn operators of unusually high system frequency variations.

9.5.1 INDEPENENT R.O.C.O.F PROTECTION IMPLEMENTATION

The device provides nine independent stages of protection. Each stage can respond to either rising or falling frequency conditions. This depends on whether the frequency threshold is set above or below the system nominal frequency. For example, if the frequency threshold is set above nominal frequency, the rate of change of frequency setting is considered as positive and the element will operate for rising frequency conditions. If the frequency threshold is set below nominal frequency, the setting is considered as negative and the element will operate for falling frequency conditions.

The following settings are relevant for df/dt+t protection:

- ***df/dt+t (n) Status***: determines whether the stage is for falling or rising frequency conditions
- ***df/dt+t (n) Set***: defines the rate of change of frequency pickup setting
- ***df/dt+t (n) Time***: sets the time delay

9.5.2 INDEPENDENT R.O.C.O.F PROTECTION LOGIC

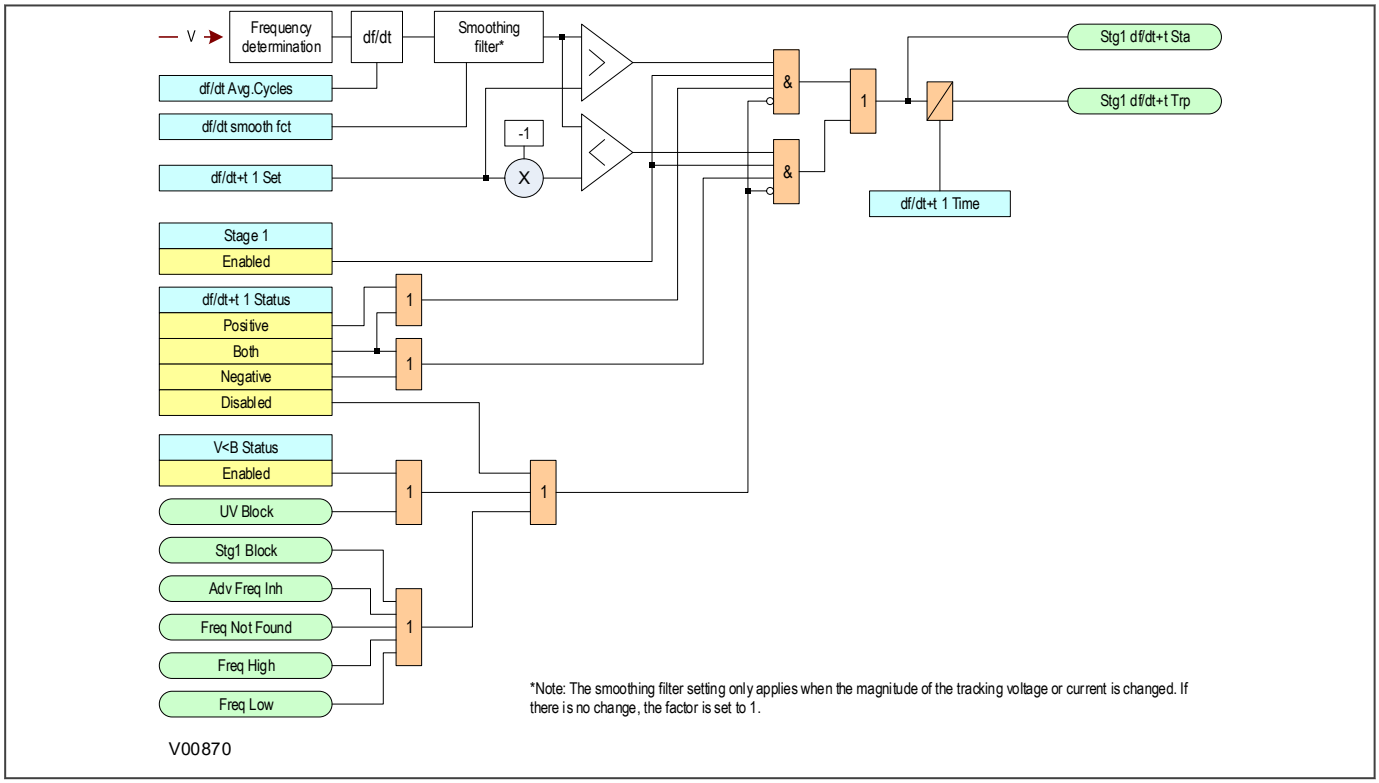


Figure 149: Independent rate of change of frequency logic (single stage)

9.5.3 APPLICATION NOTES

9.5.3.1 SETTING GUIDELINES

Considerable care should be taken when setting this element because it is not supervised by a frequency setting. Setting of the time delay or increasing the number of df/dt averaging cycles will improve stability but this is traded against reduced tripping times.

It is likely that this element would be used in conjunction with other frequency based protection elements to provide a scheme that accounts for severe frequency fluctuations. An example scheme is shown below:

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/Sec.)
1	49	20	49.2	1.0
2	48.6	20	48.8	1.0
3	48.2	10	48.4	1.0
4	47.8	10	48.0	1.0
5	-	-	-	-

Stage	Rate of Change of Frequency "df/dt+t [81R]" Elements	
	Rate of Change of Frequency Setting (Hz/Sec.)	Time Setting (Sec.)
1	-	-
2	-	-
3	-3.0	0.5
4	-3.0	0.5
5	-3.0	0.1

In this scheme, tripping of the last two stages is accelerated by using the independent rate of change of frequency element. If the frequency starts falling at a high rate (> 3 Hz/s in this example), then stages 3 & 4 are shed at around 48.5 Hz, with the objective of improving system stability. Stage 5 serves as an alarm and gives operators advance warning that the situation is critical.

9.6 FREQUENCY-SUPERVISED R.O.C.O.F PROTECTION

Frequency-supervised Rate of Change of Frequency protection works in a similar way to Independent Rate of change of Frequency Protection. The only difference is that with frequency supervision, the actual frequency itself is monitored and the protection operates when both the rate of change of frequency AND the frequency itself go outside the set limits.

Frequency-supervised Rate of Change of Frequency protection is also known as f+df/dt protection.

9.6.1 FREQUENCY-SUPERVISED R.O.C.O.F IMPLEMENTATION

The device provides nine independent stages of protection. Each stage can respond to either rising or falling frequency conditions. This depends on whether the frequency threshold is set above or below the system nominal frequency. For example, if the frequency threshold is set above nominal frequency, the rate of change of frequency setting is considered as positive and the element will operate for rising frequency conditions. If the frequency threshold is set below nominal frequency, the setting is considered as negative and the element will operate for falling frequency conditions.

The following settings are relevant for f+ df/dt protection:

- ***f+df/dt 1 Status***: determines whether the stage is for falling or rising frequency conditions
- ***f+df/dt 1 freq***: defines the frequency pickup setting
- ***f+df/dt 1 df/dt***: defines the rate of change of frequency pickup setting

The device will also indicate when an incorrect setting has been applied if the frequency threshold is set to the nominal system frequency. There is no intentional time delay associated with this element, but time delays could be applied using the PSL if required.

9.6.2 FREQUENCY-SUPERVISED R.O.C.O.F LOGIC

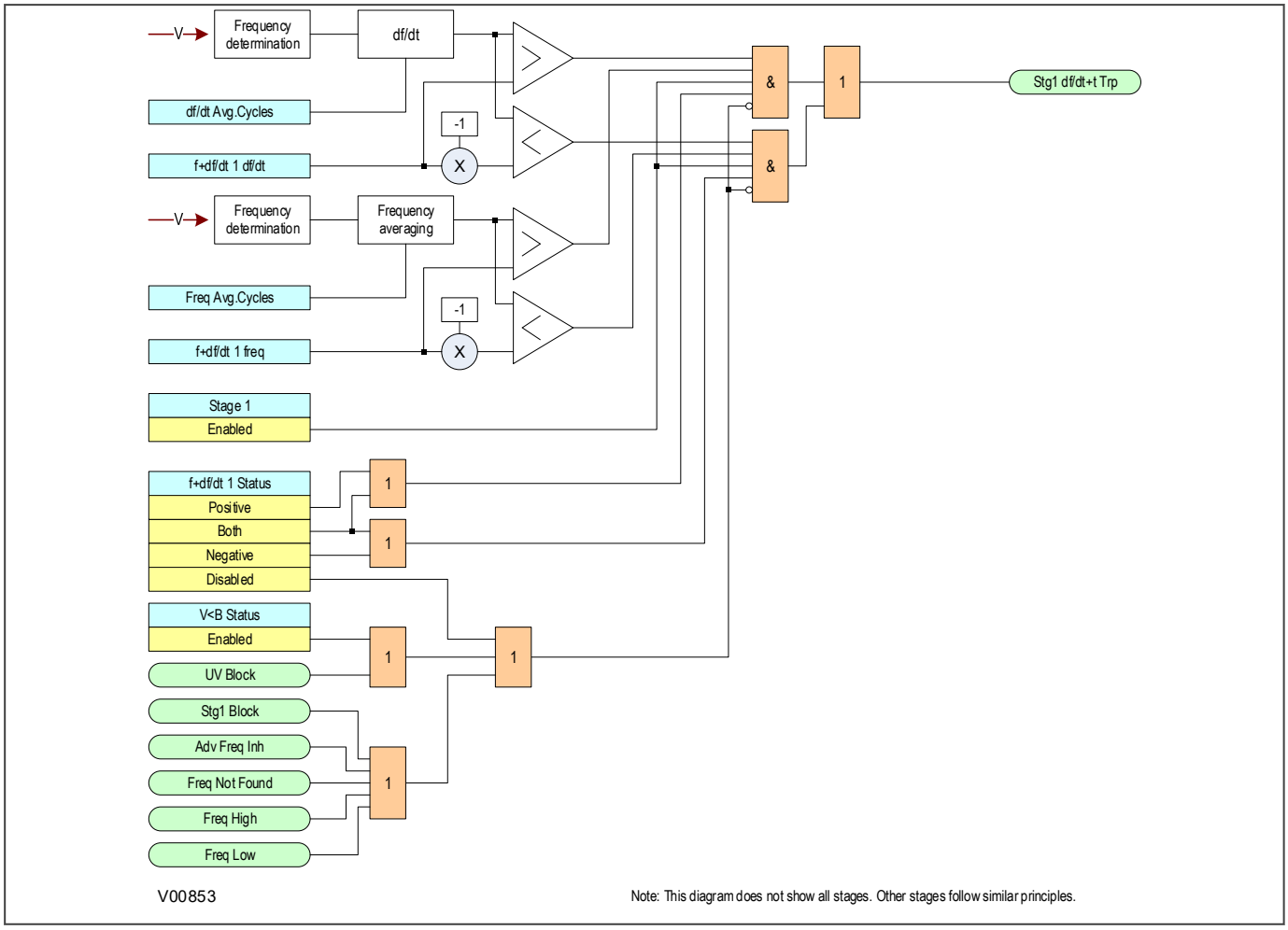


Figure 150: Frequency-supervised rate of change of frequency logic (single stage)

9.6.3 APPLICATION NOTES

9.6.3.1 FREQUENCY-SUPERVISED R.O.C.O.F EXAMPLE

In the load shedding scheme below, we assume that for falling frequency conditions, the system can be stabilised at frequency f2 by shedding a stage of load. For slow rates of decay, this can be achieved using the underfrequency protection element set at frequency f1 with a suitable time delay. However, if the generation deficit is substantial, the frequency will rapidly decrease and it is possible that the time delay imposed by the underfrequency protection will not allow for frequency stabilisation. In this case, the chance of system recovery will be enhanced by disconnecting the load stage based on a measurement of rate of change of frequency and bypassing the time delay.

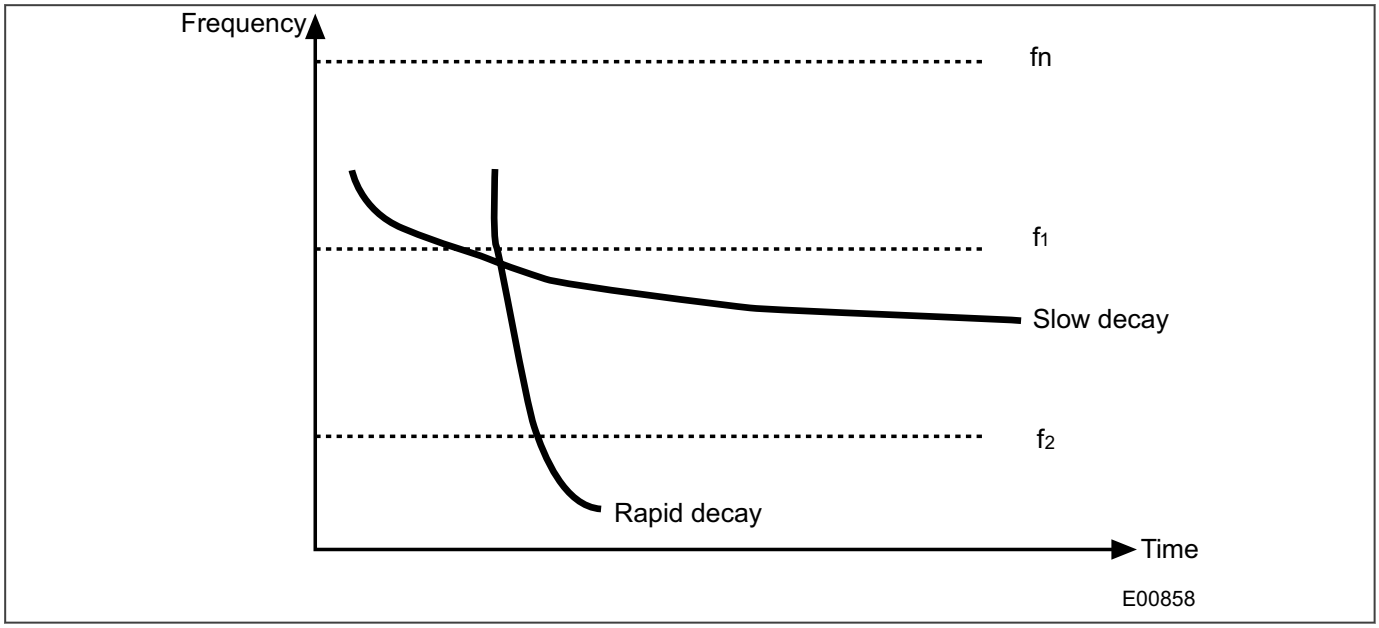


Figure 151: Frequency supervised rate of change of frequency protection

9.6.3.2 SETTING GUIDELINES

We recommend that the frequency supervised rate of change of frequency protection (f+df/dt) element be used in conjunction with the time delayed frequency protection (f+t) elements.

A four stage high speed load shedding scheme may be configured as indicated below, noting that in each stage, both the "f+t" and the "f+df/dt" elements are enabled.

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/sec.)
1	49	20	49	1.0
2	48.6	20	48.6	1.0
3	48.2	10	48.2	1.0
4	47.8	10	47.8	1.0

It may be possible to further improve the speed of load shedding by changing the frequency setting on the f+df/dt element. In the settings outlined below, the frequency settings for this element have been set slightly higher than the frequency settings for the f+t element. This difference will allow for the measuring time, and will result in the tripping of the two elements at approximately the same frequency value. Therefore, the slow frequency decline and fast frequency decline scenarios are independently monitored and optimised without sacrificing system security.

Stage	Frequency "f+t [81U/81O]" Elements		Frequency Supervised Rate of Change of Frequency "f+df/dt [81RF]" Elements	
	Frequency Setting (Hz)	Time Setting (Sec.)	Frequency Setting (Hz)	Rate of Change of Frequency Setting (Hz/sec.)
1	49	20	49.2	1.0
2	48.6	20	48.8	1.0
3	48.2	10	48.4	1.0
4	47.8	10	48.0	1.0

9.7 AVERAGE RATE OF CHANGE OF FREQUENCY PROTECTION

Owing to the complex dynamics of power systems, variations in frequency during times of generation-to-load imbalance are highly non-linear. Oscillations will occur as the system seeks to address the imbalance, resulting in frequency oscillations typically in the order of 0.1 Hz to 1 Hz, in addition to the basic change in frequency.

The independent and frequency-supervised rate of change of frequency elements use an instantaneous measurement of the rate of change of frequency, based on a 3-cycle, filtered, rolling average technique. Due to the oscillatory nature of frequency excursions, this instantaneous value can sometimes be misleading, either causing unexpected operation or excessive instability. For this reason, the device also provides an element for monitoring the longer term frequency trend, thereby reducing the effects of non-linearity in the system.

Average Rate of Change of Frequency protection is also known as f+Df/Dt protection (note the upper-case "D").

9.7.1 AVERAGE R.O.C.O.F PROTECTION IMPLEMENTATION

The device provides nine independent stages of average rate of change of frequency protection. Each stage can respond to either rising or falling frequency conditions. This depends on whether the frequency threshold is set above or below the system nominal frequency. For example, if the frequency threshold is set above nominal frequency, the rate of change of frequency setting is considered as positive and the element will operate for rising frequency conditions. If the frequency threshold is set below nominal frequency, the setting is considered as negative and the element will operate for falling frequency conditions.

When the measured frequency crosses the supervising frequency threshold, a timer is initiated. At the end of this time period, the frequency difference is evaluated and if this exceeds the setting, a trip output is given.

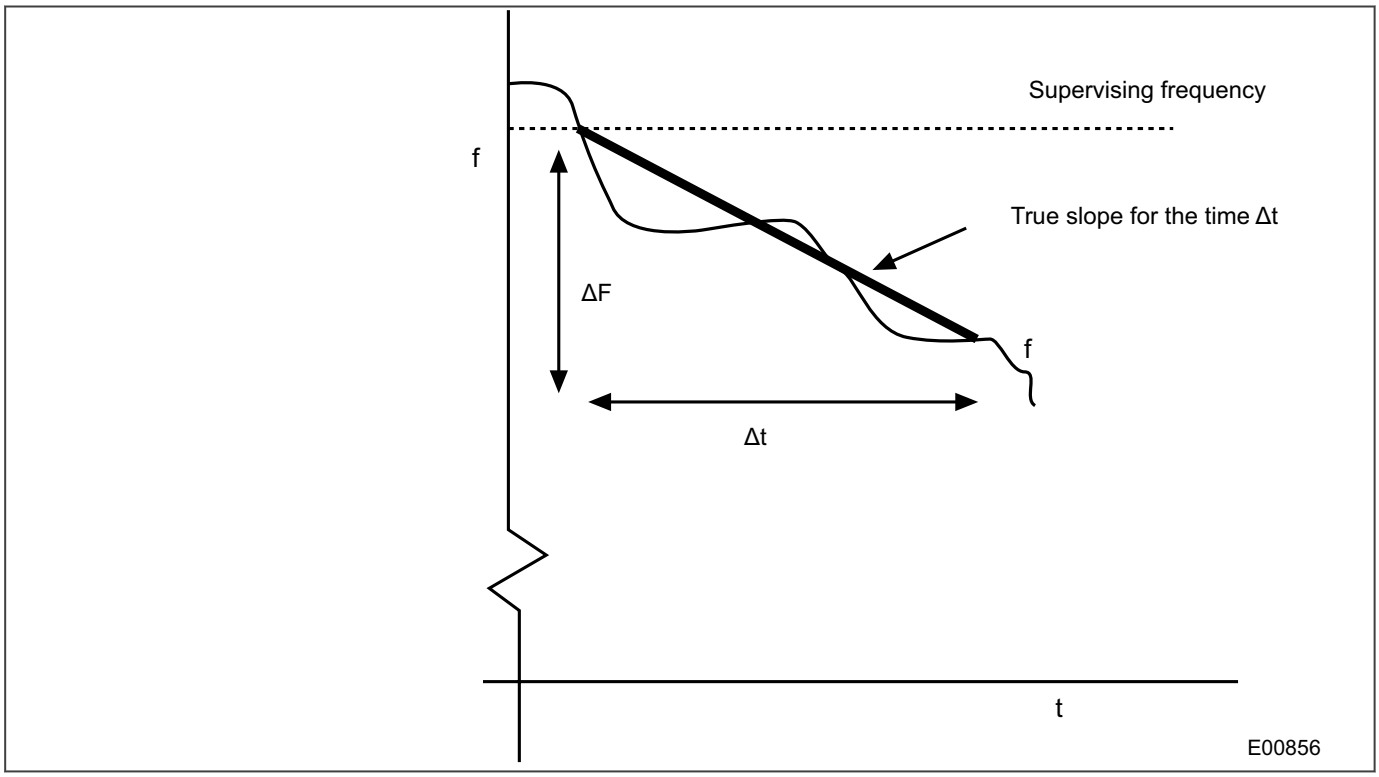


Figure 152: Average rate of change of frequency characteristic

After time Δt, the element is blocked from further operation until the frequency recovers to a value above the supervising frequency threshold. If the element has operated, the trip DDB signal will be ON until the frequency recovers to a value above the supervising frequency threshold.

The average rate of change of frequency is then measured based on the frequency difference, Δf over the settable time period, Δt.

The following settings are relevant for Df/Dt protection:

- ***f+Df/Dt (n) Status***: determines whether the stage is for falling or rising frequency conditions
- ***f+Df/Dt (n) Freq***: defines the frequency pickup setting
- ***f+Df/Dt (n) Dfreq***: defines the change in frequency that must be measured in a set time period
- ***f+Df/Dt (n) Dtime***: sets the time period over which the frequency is monitored

9.7.2 AVERAGE R.O.C.O.F LOGIC

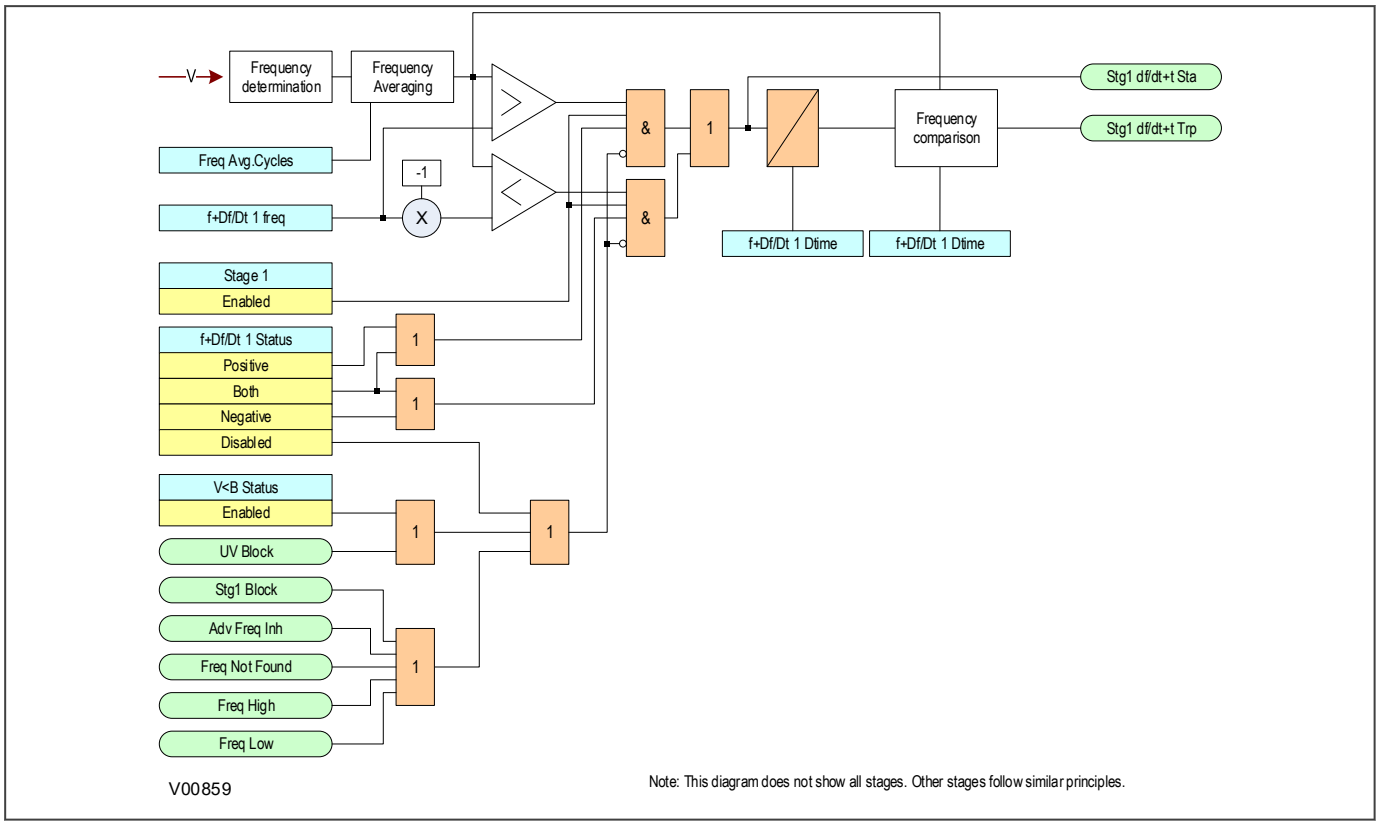


Figure 153: Average rate of change of frequency logic (single stage)

9.7.3 APPLICATION NOTES

9.7.3.1 SETTING GUIDELINES

The average rate of change of frequency element can be set to measure the rate of change over a short period as low as 20 ms (1 cycle @ 50 Hz) or a relatively long period up to 2 s (100 cycles @ 50 Hz). With a time setting, Dt, towards the lower end of this range, the element becomes similar to the frequency supervised rate of change function, "f+df/dt". With high Dt settings, the element acts as a frequency trend monitor.

Although the element has a wide range of setting possibilities we recommend that the Dt setting is set greater than 100 ms to ensure the accuracy of the element.

A possible four stage load shedding scheme using the average rate of change frequency element is shown in the following table:

	Frequency "f+t [81U/81O]" Elements		Average Rate of Change of Frequency "f+Df/Dt [81RAV]" Elements		
Stage	**(f+t) f Frequency Setting (Hz)**	**(f+t) t Time Setting (Sec.)**	**(f+Df/Dt) f Frequency Setting (Hz)**	**(f+Df/Dt) Df Frequency Diff Setting, (Hz)**	**(f+Df/Dt) Dt Time Period, (Sec.)**
1	49	20	49	0.5	0.5
2	48.6	20	48.6	0.5	0.5
3	48.2	10	48.2	0.5	0.5
4	47.8	10	47.8	0.5	0.5

In the above scheme, the faster load shed decisions are made by monitoring the frequency change over 500 ms. Therefore tripping takes place more slowly than in schemes employing frequency-supervised df/dt, but the difference is not very much at this setting. If the delay jeopardises system stability, then the scheme can be improved by increasing the independent "f" setting. Depending on how much this value is increased, the frequency at which the "f+Df/Dt" element will trip also increases and so reduces the time delay under more severe frequency fluctuations. For example, with the settings shown below, the first stage of load shedding would be tripped approximately 300 msecs after 49.0 Hz is reached and at a frequency of approximately 48.7 Hz.

	Frequency "f+t [81U/81O]" Elements		Average Rate of Change of Frequency "f+Df/Dt [81RAV]" Elements		
Stage	**(f+t) f Frequency Setting (Hz)**	**(f+t) t Time Setting (Sec)**	**(f+Df/Dt) f Frequency Setting (Hz)**	**(f+Df/Dt) Df Frequency Diff Setting (Hz)**	**(f+Df/Dt) Dt Time Period, (Sec.)**
1	49	20	49.2	0.5	0.5 s
2	48.6	20	48.8	0.5	0.5 s
3	48.2	10	48.4	0.5	0.5 s
4	47.8	10	48.0	0.5	0.5 s

9.8 LOAD SHEDDING AND RESTORATION

The goal of load shedding is to stabilise a falling system frequency. As the system stabilises and the generation capability improves, the system frequency will recover to near normal levels and after some time delay it is possible to consider the restoration of load onto the healthy system. However, load restoration needs to be performed carefully and systematically so that system stability is not jeopardized again.

In the case of industrial plants with captive generation, load restoration should be linked to the available generation since connecting additional load when the generation is still inadequate, will only result in declining frequency and more load shedding. If the in-plant generation is insufficient to meet the load requirements, then load restoration should be interlocked with recovery of the utility supply.

Whilst load shedding leads to an improvement in the system frequency, the disconnected loads need to be reconnected after the system is stable again. Loads should only be restored if the frequency remains stable for some period of time (minor frequency excursions can be ignored during this time period). The number of load restoration steps is normally less than the load shedding steps to reduce repeated disturbances while restoring load.

9.8.1 LOAD RESTORATION IMPLEMENTATION

The device uses the measurement of system frequency as the main criteria for load restoration. For each stage of load restoration, it is necessary that the same stage of load shedding has occurred previously and that no elements within that stage are configured for overfrequency or rising frequency conditions. If load shedding has not previously occurred, the load restoration for that stage is inactive.

The device provides nine independent stages of Load Restoration. It is implemented in the *FREQ PROTECTION* column of the relevant settings group. The following settings are relevant for Load Restoration:

- ***Restore(n) Status***: determines whether the stage is disabled or enabled
- ***Restore(n) Freq***: defines the frequency pickup setting
- ***Restore(n) Time***: Timer period for which the measured frequency must be higher than the stage restoration.
- ***Holding Timer***: Sets the holding timer value

9.8.2 HOLDING BAND

Load restoration for a given stage begins when the system frequency rises above the ***Restore(n) Freq*** setting for that stage and the stage restoration timer ***Restore(n) Time*** is initiated. If the system frequency remains above the frequency setting for the set time delay, load restoration of that stage will be triggered.

Unfortunately, frequency recovery profiles are highly non-linear and it would be reasonably common for the system frequency to fall transiently below the restoration frequency threshold. If the restoration timer immediately reset whenever a frequency dip occurred, it is likely that load restoration would never be successful. For this reason, the protection has a "holding band". This holding band is a region defined by the restoration frequency and the highest frequency setting used in the load shedding elements for that stage. The difference between these two settings must always be greater than 0.02 Hz, otherwise a ***Wrong Setting*** alarm will be generated. Whenever the system frequency dips into the holding band, operation of the stage restoration timer is suspended until the frequency rises above the restoration frequency setting, at which point timing will continue. If the system frequency dip is sufficiently large to cause any frequency element to start or trip in this stage, i.e. if the frequency falls below the lower limit of the holding band, the restoration timer will immediately be reset. This is demonstrated below.

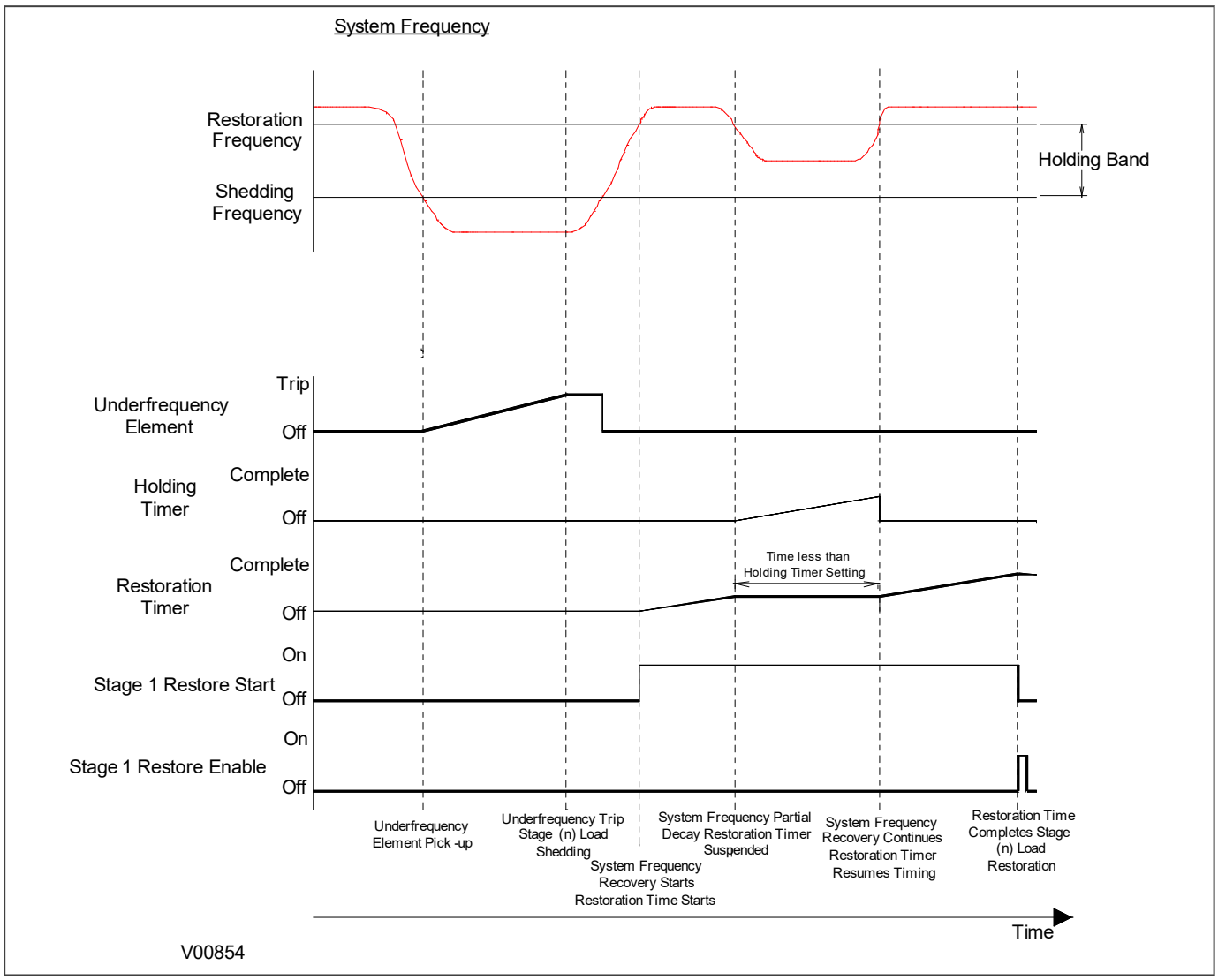


Figure 154: Load restoration with short deviation into holding band

If the system frequency remains in the holding band for too long it is likely that other system frequency problems are occurring and it would be prudent to reset the restoration timer for that stage. For this reason, as soon as the system frequency is measured to be within the holding band, the "Holding Timer" is initiated. If the system frequency doesn't leave the holding band before the holding timer setting has been exceeded, the load restoration time delay for that stage is immediately reset.

Note:
The holding timer has a common setting for all stages of load restoration.

An example of the case when the time in the holding band is excessive is shown below.

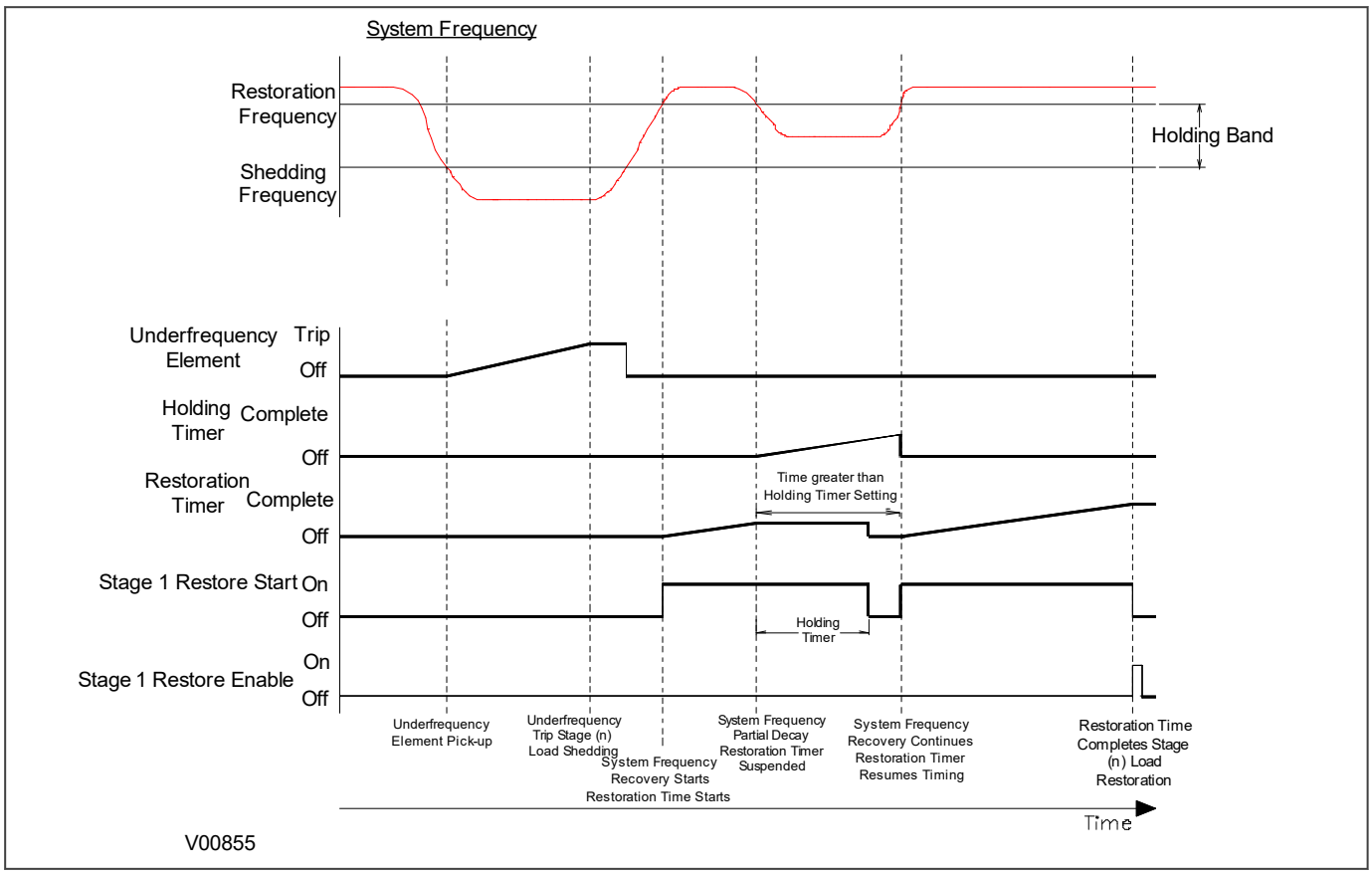


Figure 155: Load restoration with long deviation into holding band

9.8.3 LOAD RESTORATION LOGIC

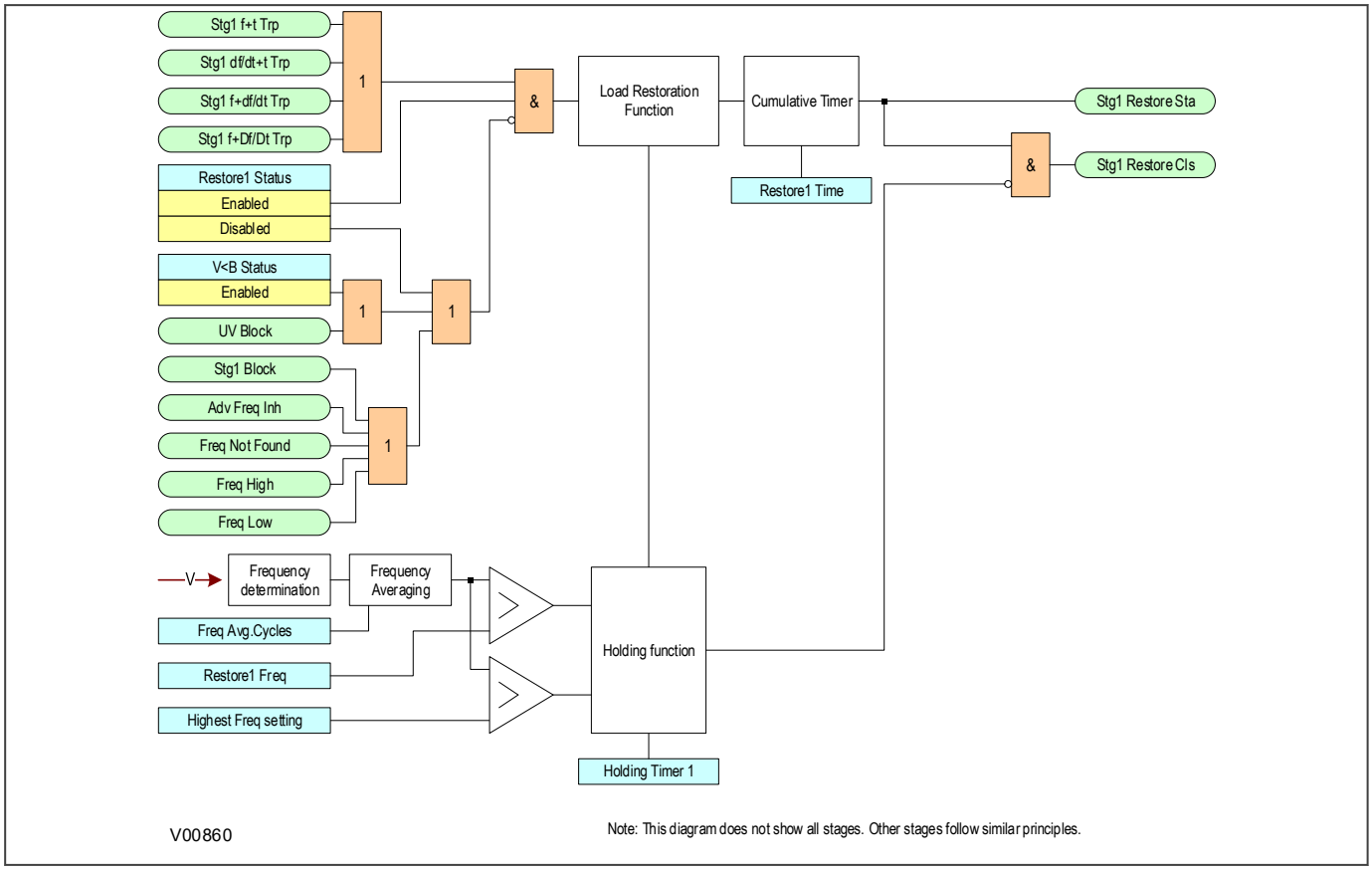


Figure 156: Load restoration logic

9.8.4 APPLICATION NOTES

9.8.4.1 SETTING GUIDELINES

A four stage, single frequency load restoration scheme is shown below. The frequency setting has been chosen such that there is sufficient separation between the highest load shed frequency and the restoration frequency to prevent any possible hunting. A restoration frequency setting closer to nominal frequency may be chosen if an operating frequency of 49.3 Hz is unacceptable.

Stage	Restoration Frequency Setting (Hz)	Restoration Time Delay (secs)	Holding Time Delay (secs)
1	49.3 Hz	240 sec	20 sec
2	49.3 Hz	180 sec	20 sec
3	49.3 Hz	120 sec	20 sec
4	49.3 Hz	60 sec	20 sec

In this scheme, the time delays ensure that the most critical loads are reconnected (assuming that the higher stages refer to more important loads). By restoring the load sequentially, system stability should normally be maintained. These time settings are system dependent; higher or lower settings may be required depending on the particular application.

It is possible to set up restoration schemes involving multiple frequencies. This allows faster restoration of loads, but there is the possibility of continuous system operation at frequencies far removed from the nominal. A typical scheme using two frequencies is illustrated below:

Stage	Restore Freq. Restoration Frequency Setting (Hz)	Restore DelayRestoration Time Delay (S)	Holding Time Delay (S)
1	49.5 Hz	120 sec	20 sec
2	49.5 Hz	60 sec	20 sec
3	49.0 Hz	120 sec	20 sec
4	49.0 Hz	60 sec	20 sec

Staggered time settings may be used in this scheme as well, but the time separation among the restoration of stages will be a function of the frequency recovery pattern. Time coordinated restoration can only be guaranteed for those stages with a common restoration frequency setting.

CHAPTER 10

POWER PROTECTION FUNCTIONS

10.1 CHAPTER OVERVIEW

Power protection is used for protecting generators. Although the main function of this device is for feeder applications, it can also be used as a cost effective alternative for protecting small distributed generators, typically less than 2 MW.

This chapter contains the following sections:

Chapter Overview 242

Overpower Protection 243

Underpower Protection 246

Sensitive Power Protection 250

10.2 OVERPOWER PROTECTION

With Overpower, we should consider two distinct conditions: Forward Overpower and Reverse Overpower.

A forward overpower condition occurs when the system load becomes excessive. A generator is rated to supply a certain amount of power and if it attempts to supply power to the system greater than its rated capacity, it could be damaged. Therefore overpower protection in the forward direction can be used as an overload indication. It can also be used as back-up protection for failure of governor and control equipment. Generally the Overpower protection element would be set above the maximum power rating of the machine.

A reverse overpower condition occurs if the generator prime mover fails. When this happens, the power system may supply power to the generator, causing it to motor. This reversal of power flow due to loss of prime mover can be very damaging and it is important to be able to detect this with a Reverse Overpower element.

10.2.1 OVERPOWER PROTECTION IMPLEMENTATION

Overpower Protection is implemented in the *POWER PROTECTION* column of the relevant settings group.

The Power Protection elements provide 4 stages of directional power for both active and reactive power, any of which can be configured as Overpower by selecting the `Over` value in the ***Power1 Function*** (or other stage) setting. The directional element can be configured as forward or reverse and for single-phase or three-phase operation.

The elements use three-phase power and single phase power measurements (based on A, B and/or C phases) as the energising quantities. A Start condition occurs when two consecutive measurements exceed the setting threshold. A trip condition occurs if the Start condition is present for the set time delay. This can be inhibited by the VTS Slow Block and Pole Dead logic if desired.

The Start and Trip timer resets if the power falls below the drop-off level or if an inhibit condition occurs. The reset mechanism is similar to the overcurrent reset functionality, where the percentage of elapsed time for the operate timer is memorised for a set reset time delay. If the Start condition returns before the reset timer has timed out, the operate time initialises from the memorised travel value. Otherwise the memorised value is reset to zero after the reset time times out.

10.2.2 OVERPOWER LOGIC

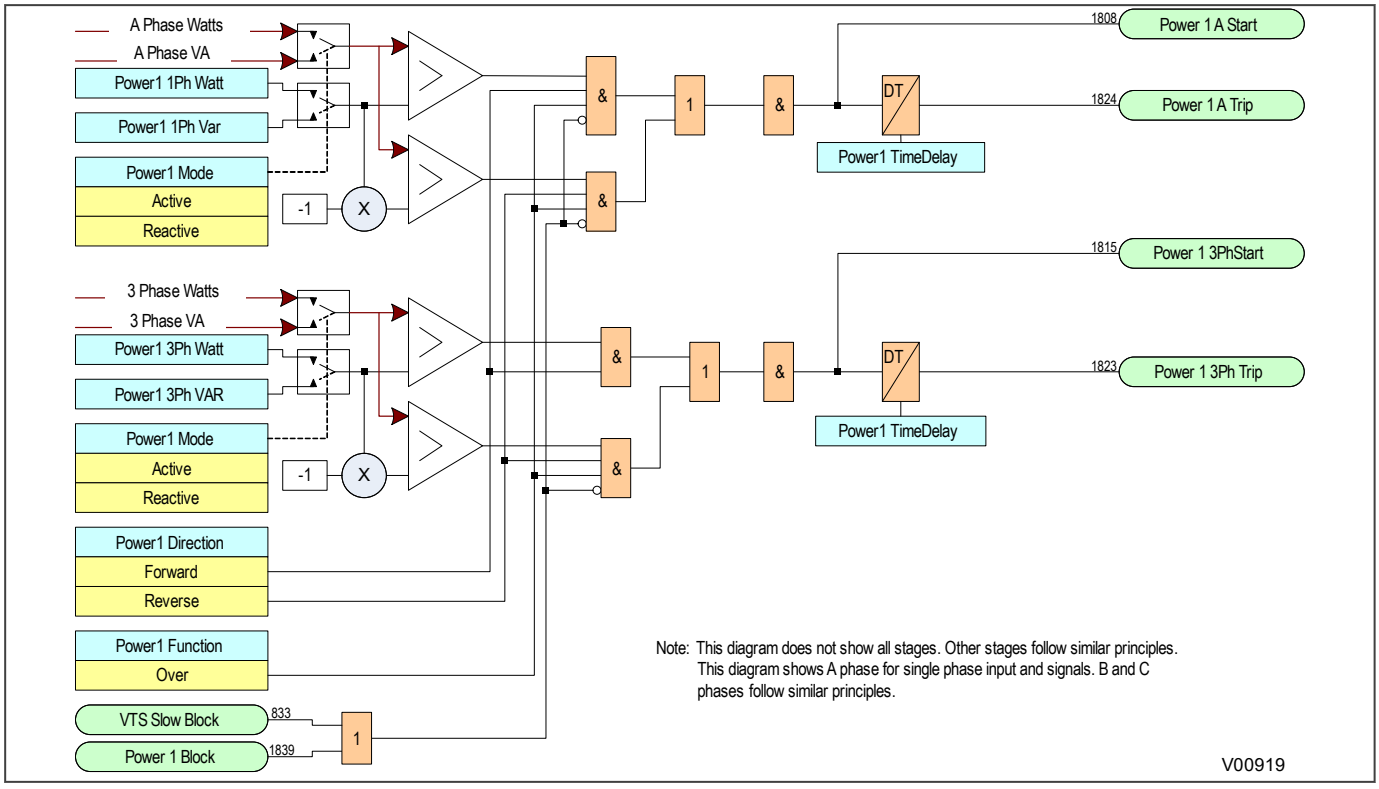


Figure 157: Overpower logic

10.2.3 APPLICATION NOTES

10.2.3.1 FORWARD OVERPOWER SETTING GUIDELINES

The relevant power threshold settings should be set greater than the full load rated power.

The operating mode should be set to Forward.

A time delay setting, ***Power1 TimeDelay*** (or other stage) should be applied. This setting is dependant on the application. The delay on the reset timer, ***Power1 tRESET*** (or other stage) setting, would normally be set to zero.

10.2.3.2 REVERSE POWER CONSIDERATIONS

A generator is expected to supply power to the connected system in normal operation. If the generator prime mover fails, it will begin to take motoring power from the power system (if the power system to which it is connected has other generating sources). The consequences of this reversal of power and the level of power drawn from the power system will be dependent on the type of prime mover.

Prime Mover	Motoring Power	Possible Damage (Percentage Rating)
Diesel Engine	5% - 25%	Risk of fire or explosion from unburned fuel
Motoring level depends on compression ratio and cylinder bore stiffness. Rapid disconnection is required to limit power loss and risk of damage.		
Gas Turbine	10% - 15% (Split-shaft) >50% (Single-shaft)	With some gear-driven sets, damage may arise due to reverse torque on gear teeth.
Compressor load on single shaft machines leads to a high motoring power compared to split-shaft machines. Rapid disconnection is required to limit power loss or damage.		
Hydraulic Turbines	0.2 - >2% (Blades out of water) >2.0% (Blades in water)	Blade and runner damage may occur with a long period of motoring
Power is low when blades are above tail-race water level. Hydraulic flow detection devices are often the main means of detecting loss of drive. Automatic disconnection is recommended for unattended operation.		
Steam Turbines	0.5% - 3% (Condensing sets) 3% - 6% (Non-condensing sets)	Thermal stress damage may be inflicted on low-pressure turbine blades when steam flow is not available to dissipate losses due to air resistance.
Damage may occur rapidly with non-condensing sets or when vacuum is lost with condensing sets. Reverse power protection may be used as a secondary method of detection and might only be used to raise an alarm.		

In some applications, the level of reverse power in the case of prime mover failure may fluctuate. This may be the case for a failed diesel engine. To prevent cyclic initiation and reset of the main trip timer, an adjustable reset time delay is provided. You will need to set this time delay longer than the period for which the reverse power could fall below the power setting. This setting needs to be taken into account when setting the main trip time delay.

Note:
A delay in excess of half the period of any system power swings could result in operation of the reverse power protection during swings.

10.2.3.3 REVERSE OVERPOWER SETTING GUIDELINES

Each stage of power protection can be selected to operate as a reverse power stage by setting the ***Power1 Direction*** (or other stage) cell to `Reverse`.

The relevant power threshold settings should be set to less than 50% of the motoring power.

The operating mode should be set to Reverse.

The reverse power protection function should be time-delayed to prevent false trips or alarms being given during power system disturbances or following synchronisation.

A time delay setting, of approximately 5 s would be typically applied.

The delay on the reset timer, ***Power1 tRESET*** (or other stage), would normally be set to zero.

When settings of greater than zero are used for the reset time delay, the pick-up time delay setting may need to be increased to ensure that false tripping does not result in the event of a stable power swinging event.

Reverse overpower protection can also be used for loss of mains applications. If the distributed generator is connected to the grid but not allowed to export power to the grid, it is possible to use reverse power detection to switch off the generator. In this case, the threshold setting should be set to a sensitive value, typically less than 2% of the rated power. It should also be time-delayed to prevent false trips or alarms being given during power system disturbances, or following synchronisation. A typical time delay is 5 seconds.

10.3 UNDERPOWER PROTECTION

Although the Underpower protection is directional and can be configured as forward or reverse, the most common application is for Low Forward Power protection.

When a machine is generating and the circuit breaker connecting the generator to the system is tripped, the electrical load on the generator is cut off. This could lead to overspeeding of the generator if the mechanical input power is not reduced quickly. Large turbo-alternators, with low-inertia rotor designs, do not have a high over speed tolerance. Trapped steam in a turbine, downstream of a valve that has just closed, can rapidly lead to over speed. To reduce the risk of over speed damage, it may be desirable to interlock tripping of the circuit breaker and the mechanical input with a low forward power check. This ensures that the generator circuit breaker is opened only after the mechanical input to the prime mover has been removed, and the output power has reduced enough such that overspeeding is unlikely. This delay in tripping the circuit breaker may be acceptable for non-urgent protection trips (e.g. stator earth fault protection for a high impedance earthed generator). For urgent trips however (e.g. stator current differential protection), this Low Forward Power interlock should not be used.

10.3.1 UNDERPOWER PROTECTION IMPLEMENTATION

Underpower Protection is implemented in the *POWER PROTECTION* column of the relevant settings group..

The Power Protection element provides 4 stages of directional power for both active and reactive power, any of which can be configured as Underpower by selecting the `Under` value in the ***Power1 Function*** (or other stage) setting. The directional element can be configured as forward or reverse and for single-phase or three-phase operation.

The elements use three-phase power or single phase power measurements (based on A, B or/and or C phases) as the energising quantity. A start condition occurs when two consecutive measurements fall below the setting threshold. A trip condition occurs if the start condition is present for the set trip time. This can be inhibited by the VTS slow block and pole dead logic if desired.

The Start and Trip timer resets if the power exceeds the drop-off level or if an inhibit condition occurs. The reset mechanism is similar to the overcurrent reset functionality, where the percentage of elapsed time for the operate timer is memorised for a set reset time delay. If the Start condition returns before the reset timer has timed out, the operate time initialises from the memorised travel value. Otherwise the memorised value is reset to zero after the reset time times out.

10.3.2 UNDERPOWER LOGIC

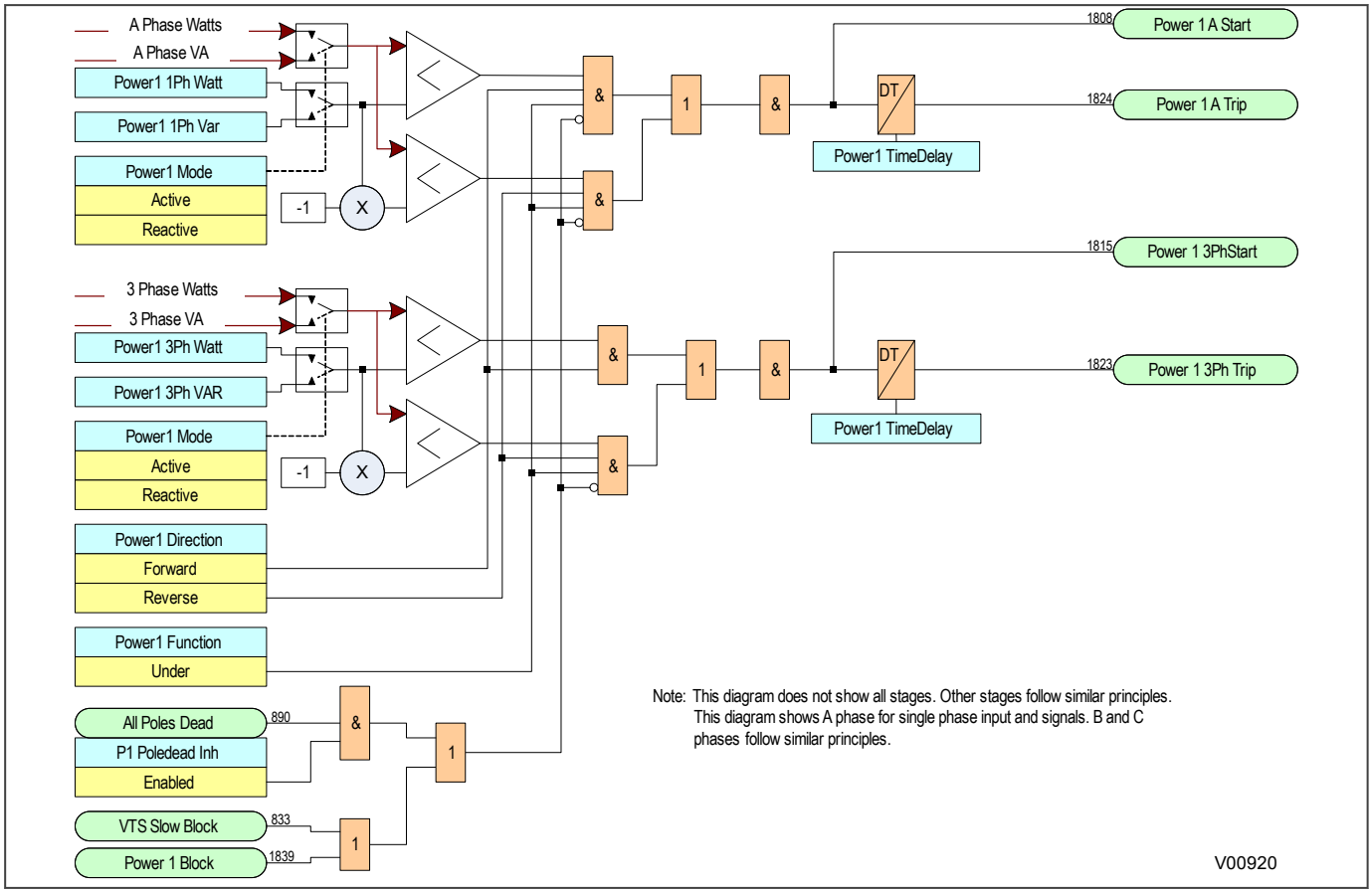


Figure 158: Underpower logic

10.3.3 APPLICATION NOTES

10.3.3.1 LOW FORWARD POWER CONSIDERATIONS

The Low Forward Power protection can be arranged to interlock 'non-urgent' protection tripping using the Flexlogic Equation Editor. It can also be arranged to provide a contact for external interlocking of manual tripping. To prevent unwanted alarms and flags, a Low Forward Power protection element can be disabled when the circuit breaker is opened via Pole Dead logic.

The Low Forward Power protection can also be used to provide loss of load protection when a machine is motoring. It can be used for example to protect a machine which is pumping from becoming unprimed, or to stop a motor in the event of a failure in the mechanical transmission.

A typical application would be for pump storage generators operating in the motoring mode, where there is a need to prevent the machine becoming unprimed which can cause blade and runner damage. During motoring conditions, it is typical for the protection to switch to another setting group with the low forward power enabled and correctly set and the protection operating mode set to `Reverse`.

A low forward power element may also be used to detect a loss of mains or loss of grid condition for applications where the distributed generator is not allowed to export power to the system.

10.3.3.2 LOW FORWARD POWER SETTING GUIDELINES

Each stage of power protection can be selected to operate as a forward power stage by setting the ***Power1 Direction*** (or other stage) cell to `Forward`.

When required for interlocking of non-urgent tripping applications, the threshold setting of the low forward power protection function should be less than 50% of the power level that could result in a dangerous overspeed condition on loss of electrical loading.

When required for loss of load applications, the threshold setting of the low forward power protection function, is system dependent, however, it is typically set to 10 - 20% below the minimum load. The operating mode should be set to operate for the direction of the load current, which would typically be reverse for a pump storage machine application where *Forward* is the Generating direction and *Reverse* is the motoring direction.

For interlocking non-urgent trip applications the time delay associated with the low forward power protection function could be set to zero. However, some delay is desirable so that permission for a non-urgent electrical trip is not given in the event of power fluctuations arising from sudden steam valve/throttle closure. A typical time delay is 2 seconds.

For loss of load applications the pick-up time delay is application dependent but is normally set in excess of the time between motor starting and the load being established. Where rated power cannot be reached during starting (for example where the motor is started with no load connected) and the required protection operating time is less than the time for load to be established then it will be necessary to inhibit the power protection during this period. This can be done in the PSL using AND logic and a pulse timer triggered from the motor starting to block the power protection for the required time.

When required for loss of mains or loss of grid applications where the distributed generator is not allowed to export power to the system, the threshold setting of the reverse power protection function, should be set to a sensitive value, typically <2% of the rated power.

The low forward power protection function should be time-delayed to prevent false trips or alarms being given during power system disturbances or following synchronisation. A time delay setting, of 5 s should be applied typically.

The delay on the reset timers would normally be set to zero.

To prevent unwanted alarms and flags, the protection element can be disabled when the circuit breaker is open via Pole Dead logic.

10.3.3.3 REACTIVE POWER PROTECTION

Some applications provide underexcitation protection using negative reactive power elements. This is popular for synchronous motors and small generators.

A reverse reactive power element may also be used to detect a loss of mains or loss of grid condition for applications where the distributed generator is not allowed to export power to the system.

Setting guidelines

Each stage of power protection can be selected to operate as a reverse reactive power stage by selecting the ***Power1 Function*** (or other stage) cell to *Over* and the ***Power1 Direction*** (or other stage) cell to *Reverse*.

The power threshold setting of the negative reactance power protection, ***Power1 3Ph VAr*** or ***Power1 1Ph VAr*** (or other stage) should be set to supervise the steady state and dynamic stability limits for under excitation protection. The following figure shows an example of the typical settings, Q1 and Q2.

The disadvantage of this method is that the measurement is not very sensitive during low voltage operation of the generator. The reactive power elements can be blocked in the PSL from an undervoltage start signal if this is a problem. This method is less secure than the impedance method and so is often used just to alarm.

If the static limit characteristic Q1 is exceeded, the voltage regulator must first have the opportunity of increasing the excitation. For this reason, a time delayed trip of typically 5-10s is used ***Power1 TimeDelay*** (or other stage). A shorter delay of 0.5s can be used for Q2.

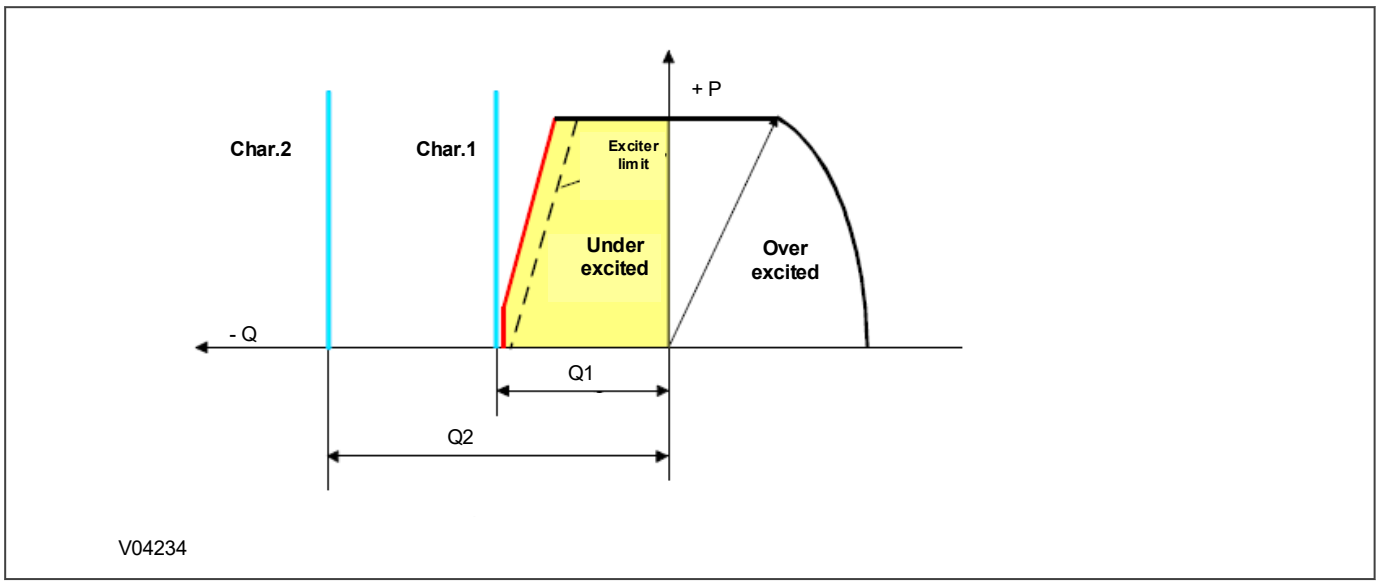


Figure 159: Reactive power protection for underexcitation protection

$Q1 = VN^2/Xd$

$Q2 >= 2\ VN^2/Xd$

Where:

VN = Machine nominal voltage

Xd = Generator direct-axis synchronous reactance in ohms

When required for loss of mains or loss of grid applications where the distributed generator is not allowed to export power to the system, the threshold setting of the reverse reactive power protection function, ***Power1 3Ph VAr*** or ***Power1 1Ph VAr*** (or other stage), should be set to a suitable value, typically <2% of the rated reactive power. The reverse reactive power protection function should be time-delayed, to prevent false trips or alarms being given during power system disturbances or following synchronisation, a typical time delay is 5 s.

10.4 SENSITIVE POWER PROTECTION

In some applications, it is necessary to have very high accuracy when applying power protection. For such applications it is possible to use metering class CTs and separate Sensitive Power elements.

The Sensitive Power protection is a single-phase power element using phase A current and voltage. It provides two independent stages of Low Forward Power, Reverse Power and Over Power protection with timer and pole-dead blocking.

Note:
Sensitive Power Protection is only available for models equipped with a SEF transformer.

10.4.1 SENSITIVE POWER PROTECTION IMPLEMENTATION

Sensitive Power Protection is a single-phase power element using the A-phase voltage and sensitive current ISEF. Its settings are found in the ***POWER PROTECTION*** column of the menu.

There are two stages of Sensitive Power protection, which can be independently selected as Low Forward Power, Reverse Power and Overpower.

If the SEF input is fitted and sensitive power protection is needed, a metering class CT monitoring the phase A current should be connected to the SEF input and ***Aph Sens Power*** should be enabled.

Note:
When the sensitive power function is used, the SEF CT must be connected to Phase A current, so that the phase A sensitive power measurement reflects the single-phase quantity derived from current in the SEF input x VA.
To measure sensitive power, the SEF input is dedicated to providing phase A current measurements. This compromises the other SEF input-dependent features. When measuring sensitive power with this element, therefore, all SEF related functionality must be disabled. Specifically, by appropriate application of settings:
** SEF protection should not be enabled,*
** Hi Z REF protection should not be enabled,*
** Admittance may only be used if the protection if the 4th CT is available to be assigned to IN. Otherwise, admittance should not be enabled.*

10.4.2 SENSITIVE POWER MEASUREMENTS

Three sensitive power related measurements are added to the Measurements column, the visibility of which will depend on the protection configuration.

- A-Phase Sensitive Active Power in Watts (***APh Sen Watts***)
- A-Phase Sensitive Re-active Power in VArs (***APh Sen VARs***)
- A-Phase Sensitive Power Angle (***APh Power Angle***)

10.4.3 SENSITIVE POWER LOGIC

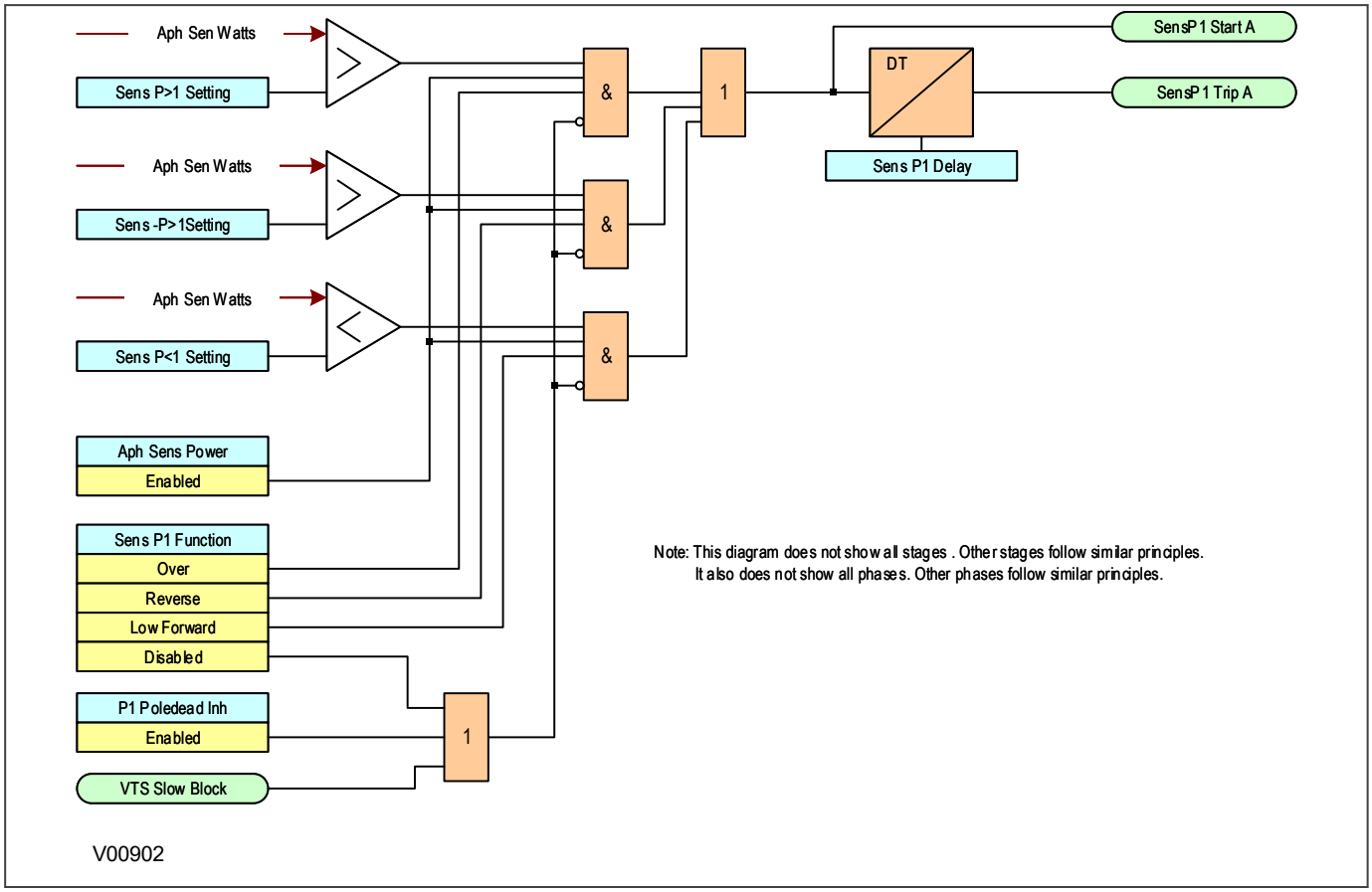


Figure 160: Sensitive power logic

10.4.4 APPLICATION NOTES

10.4.4.1 SENSITIVE POWER CALCULATION

Input Quantities

Sensitive power is calculated from the A-phase-neutral voltage and the A-phase sensitive current input.

The calculation for active power with the correction angle is:

$$P_A = I_{AS} V_A \cos(\varphi - \theta_C)$$

where:

- P_A = sensitive power
- V_A = A-phase voltage
- I_{AS} = A-phase sensitive current
- Φ= the angle of I_{AS} with respect to V_A
- θ_C = the CT correction angle

Calculations within the device are based upon quadrature components obtained from the Fourier analysis of the input signals. The quadrature values for V_A and I_{AS} are used for the sensitive power calculation as shown:

$$\bar{V}_A = V_{Ar} + jV_{Ai}$$

$$\bar{I}_{AS} = I_{ASr} + jI_{ASi}$$

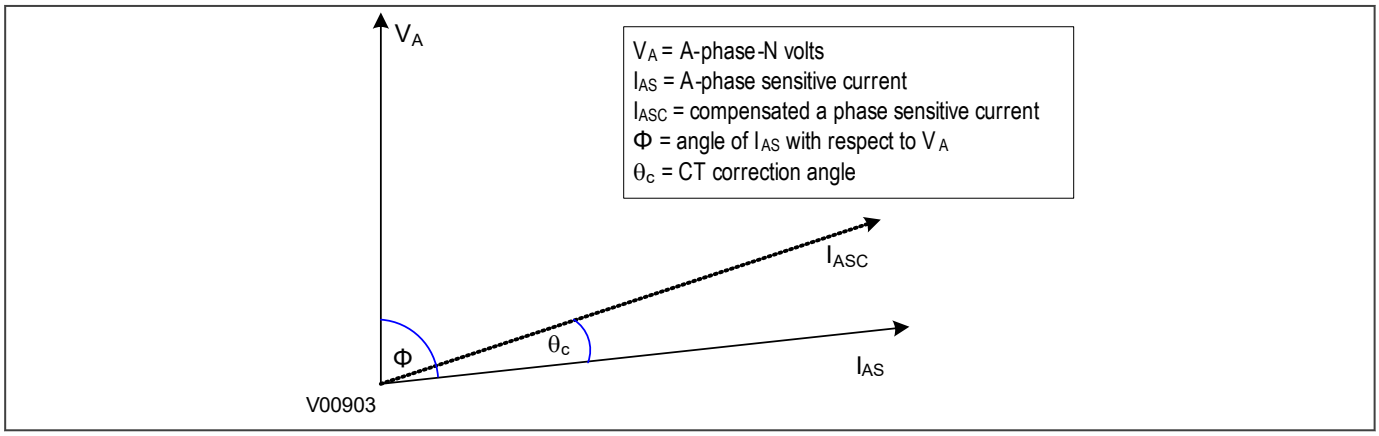


Figure 161: Sensitive power input vectors

CT Compensation

The CT correction rotates the I_{AS} vector by the correction angle. This correction is performed before the power calculation and can be achieved with the use of a rotation matrix:

$$\begin{bmatrix} \cos\theta_C & -\sin\theta_C \\ \sin\theta_C & \cos\theta_C \end{bmatrix}$$

The corrected phase-A sensitive current I_{ASC} is therefore:

$$\bar{I}_{ASC} = \begin{bmatrix} I_{ASCr} \\ I_{ASCi} \end{bmatrix} = \bar{I}_{AS} = \begin{bmatrix} I_{ASr} \\ I_{ASi} \end{bmatrix} \begin{bmatrix} \cos\theta_C & -\sin\theta_C \\ \sin\theta_C & \cos\theta_C \end{bmatrix} = \begin{bmatrix} I_{ASr}\cos\theta_C - I_{ASi}\sin\theta_C \\ I_{ASr}\sin\theta_C + I_{ASi}\cos\theta_C \end{bmatrix}$$

therefore:

$$I_{ASCr} = I_{ASr}\cos\theta_C - I_{ASi}\sin\theta_C$$

and

$$I_{ASCi} = I_{ASr}\sin\theta_C + I_{ASi}\cos\theta_C$$

Active Power Calculation

The compensated A-phase sensitive current vector is used to calculate the sensitive A-Phase active power P_{AS}.

Using the equation:

$$P_{AS} = Re\,\bar{V}_A \bar{I}^*_{ASC}$$

we can derive:

$$P_{AS} = Re\left(V_{Ar} + jV_{Ai}\right)\left(I_{ASCr} + jI_{ASCi}\right)$$

$$= Re\left(V_{Ar} + jV_{Ai}\right)\left(I_{ASCr} - jI_{ASCi}\right) = Re\left(V_{Ar}I_{ASCr} + V_{Ai}I_{ASCi}\right) + j\left(V_{Ai}I_{ASCr} - V_{Ar}I_{ASCi}\right)$$

$$= V_{Ar} I_{ASCr} + V_{Ai} I_{ASCi}$$

10.4.4.2 SENSITIVE POWER SETTING GUIDELINES

For reverse and low forward power protection, if settings greater than 3% Pn are used, the phase angle errors of suitable protection class current transformers will not result in any risk of maloperation. If settings of less than 3% are used, however, we recommend that the current input is driven by a correctly loaded metering class current transformer.

The sensitive power protection has a minimum setting accuracy of 0.5% Pn. It uses the In sensitive CT to calculate single-phase active power. It also provides phase compensation to remove errors introduced by the primary input transformers.

CHAPTER 11

CURRENT TRANSFORMER REQUIREMENTS

11.1 CHAPTER OVERVIEW

This chapter contains the following sections:

Chapter Overview 255
CT requirements 256

11.2 CT REQUIREMENTS

The current transformer requirements are based on a maximum fault current of 50 times the rated current (In) with the device having an instantaneous overcurrent setting of 25 times the rated current. The current transformer requirements are designed to provide operation of all protection elements.

Where the criteria for a specific application are in excess of this, or the lead resistance exceeds the limiting lead resistance shown in the following table, the CT requirements may need to be modified according to the formulae in the subsequent sections:

Nominal Rating	Nominal Output	Accuracy Class	Accuracy Limited Factor	Limiting Lead Resistance
1A	2.5 VA	10P	20	1.3 ohms
5A	7.5 VA	10P	20	0.11 ohms

The formula subscripts used in the subsequent sections are as follows:

K = A constant affected by the dynamic response of the relay

I_{cn} = Maximum prospective secondary earth fault current or 30 times I> setting (whichever is lower) (amps)

I_{cp} = Maximum prospective secondary phase fault current or 30 times I> setting (whichever is lower) (amps)

I_f = Maximum through-fault current level (amps)

I_{fn} = Maximum prospective secondary earth fault current (amps)

I_{fp} = Maximum prospective secondary phase fault current (amps)

I_n = Rated secondary current (amps)

I_s = Current setting of REF elements (amps)

I_{sn} = Stage 3 & 4 earth fault setting (amps)

I_{sp} = Stage 3, 4, 5 and 6 setting (amps)

I_{st} = Motor start up current referred to CT secondary side (amps)

R_{CT} = Resistance of current transformer secondary winding (ohms)

R_L = Resistance of a single lead from relay to current transformer (ohms)

R_n = Impedance of the neutral current input at 30In (ohms)

R_p = Impedance of the phase current input at 30In (ohms)

R_{st} = Value of stabilising resistor for REF applications (ohms)

V_K = Required CT knee-point voltage (volts)

V_S = Required stability voltage

11.2.1 PHASE OVERCURRENT PROTECTION

11.2.1.1 DIRECTIONAL ELEMENTS

Time-delayed phase overcurrent elements

$$V_K = \frac{I_{cp}}{2}(R_{CT} + R_L + R_p)$$

Instantaneous phase overcurrent elements

$$V_K = \frac{I_{fp}}{2}(R_{CT} + R_L + R_p)$$

11.2.1.2 NON-DIRECTIONAL ELEMENTS

Time-delayed phase overcurrent elements

$$V_K = \frac{I_{cp}}{2}(R_{CT} + R_L + R_p)$$

Instantaneous phase overcurrent elements

$$V_K = I_{sp}(R_{CT} + R_L + R_p)$$

11.2.2 EARTH FAULT PROTECTION

11.2.2.1 DIRECTIONAL ELEMENTS

Instantaneous earth fault overcurrent elements

$$V_K = \frac{I_{fn}}{2}(R_{CT} + 2R_L + R_p + Rn)$$

11.2.2.2 NON-DIRECTIONAL ELEMENTS

Time-delayed earth fault overcurrent elements

$$V_K = \frac{I_{cn}}{2}(R_{CT} + 2R_L + R_p + R_n)$$

Instantaneous earth fault overcurrent elements

$$V_K = I_{sn}(R_{CT} + 2R_L + R_p + R_n)$$

11.2.3 SEF PROTECTION (RESIDUALLY CONNECTED)

11.2.3.1 DIRECTIONAL ELEMENTS

Time delayed SEF protection

$$V_K \geq \frac{I_{cn}}{2}(R_{CT} + 2R_L + R_p + Rn)$$

Instantaneous SEF protection

$$V_K \geq \frac{I_{fn}}{2}(R_{CT} + 2R_L + R_p + Rn)$$

11.2.3.2 NON-DIRECTIONAL ELEMENTS

Time delayed SEF protection

$$V_K \geq \frac{I_{cn}}{2}(R_{CT} + 2R_L + R_p + Rn)$$

Instantaneous SEF protection

$$V_K \geq \frac{I_{sn}}{2}(R_{CT} + 2R_L + R_p + Rn)$$

11.2.4 SEF PROTECTION (CORE-BALANCED CT)

11.2.4.1 DIRECTIONAL ELEMENTS

Instantaneous element

$$V_K \geq \frac{I_{fn}}{2}(R_{CT} + 2R_L + Rn)$$

Note:
Ensure that the phase error of the applied core balance current transformer is less than 90 minutes at 10% of rated current and less than 150 minutes at 1% of rated current.

11.2.4.2 NON-DIRECTIONAL ELEMENTS

Time delayed element

$$V_K \geq \frac{I_{cn}}{2}(R_{CT} + 2R_L + Rn)$$

Instantaneous element

$$V_K \geq I_{sn}(R_{CT} + 2R_L + Rn)$$

Note:
Ensure that the phase error of the applied core balance current transformer is less than 90 minutes at 10% of rated current and less than 150 minutes at 1% of rated current.

11.2.5 HIGH IMPEDANCE REF PROTECTION

The high impedance REF element will maintain stability for through-faults and operate in less than 40ms for internal faults, provided the following equations are met:

$$R_{st} = \frac{I_f(R_{CT} + 2R_L)}{I_s}$$

$$V_K \geq 4I_s R_{st}$$

Note:
Class x CTs should be used for high impedance REF applications.

11.2.6 USE OF METROSIL NON-LINEAR RESISTORS

Current transformers can develop high peak voltages under internal fault conditions. Metrosils are used to limit these peak voltages to a value below the maximum withstand voltage (usually 3 kV).

You can use the following formulae to estimate the peak transient voltage that could be produced for an internal fault. The peak voltage produced during an internal fault is a function of the current transformer kneepoint voltage and the prospective voltage that would be produced for an internal fault if current transformer saturation did not occur.

$$Vp = 2\sqrt{(2VK(V_F - V_K))}$$

$$Vf = I'f(R_{CT} + 2_{RL} + R_{ST})$$

where:

- Vp = Peak voltage developed by the CT under internal fault conditions
- Vk = Current transformer kneepoint voltage
- Vf = Maximum voltage that would be produced if CT saturation did not occur
- I'f = Maximum internal secondary fault current
- R_{CT} = Current transformer secondary winding resistance
- R_L = Maximum lead burden from current transformer to relay
- R_{ST} = Relay stabilising resistor

You should always use Metrosils when the calculated values are greater than 3000 V. Metrosils are connected across the circuit to shunt the secondary current output of the current transformer from the device to prevent very high secondary voltages.

Metrosils are externally mounted and take the form of annular discs. Their operating characteristics follow the expression:

$$V = CI^{0.25}$$

where:

- V = Instantaneous voltage applied to the Metrosil
- C = Constant of the Metrosil
- I = Instantaneous current through the Metrosil

With a sinusoidal voltage applied across the Metrosil, the RMS current would be approximately 0.52 x the peak current. This current value can be calculated as follows:

$$I_{RMS} = 0.52\left(\frac{\sqrt{2}V_{S(RMS)}}{C}\right)^4$$

where:

- $V_{S(RMS)}$ = RMS value of the sinusoidal voltage applied across the metrosil.

This is due to the fact that the current waveform through the Metrosil is not sinusoidal but appreciably distorted.

The Metrosil characteristic should be such that it complies with the following requirements:

- The Metrosil current should be as low as possible, and no greater than 30 mA RMS for 1 A current transformers or 100 mA RMS for 5 A current transformers.
- At the maximum secondary current, the Metrosil should limit the voltage to 1500 V RMS or 2120 V peak for 0.25 second. At higher device voltages it is not always possible to limit the fault voltage to 1500 V rms, so higher fault voltages may have to be tolerated.

The following tables show the typical Metrosil types that will be required, depending on relay current rating, REF voltage setting etc.

Metrosils for devices with a 1 Amp CT

The Metrosil units with 1 Amp CTs have been designed to comply with the following restrictions:

- The Metrosil current should be less than 30 mA rms.
- At the maximum secondary internal fault current the Metrosil should limit the voltage to 1500 V rms if possible.

The Metrosil units normally recommended for use with 1Amp CTs are as shown in the following table:

	Nominal Characteristic		Recommended Metrosil Type	
Device Voltage Setting	**C**	**β**	**Single Pole Relay**	**Triple Pole Relay**
Up to 125 V RMS	450	0.25	600A/S1/S256	600A/S3/1/S802
125 to 300 V RMS	900	0.25	600A/S1/S1088	600A/S3/1/S1195

Note:
Single pole Metrosil units are normally supplied without mounting brackets unless otherwise specified by the customer.

Metrosils for devices with a 5 Amp CT

These Metrosil units have been designed to comply with the following requirements:

- The Metrosil current should be less than 100 mA rms (the actual maximum currents passed by the devices shown below their type description.
- At the maximum secondary internal fault current the Metrosil should limit the voltage to 1500 V rms for 0.25secs. At the higher relay settings, it is not possible to limit the fault voltage to 1500 V rms so higher fault voltages have to be tolerated.

The Metrosil units normally recommended for use with 5 Amp CTs and single pole relays are as shown in the following table:

Secondary Internal Fault Current	Recommended Metrosil Types for Various Voltage Settings			
Amps RMS	Up to 200 V RMS	250 V RMS	275 V RMS	300 V RMS
50A	600A/S1/S1213 C = 540/640 35 mA RMS	600A/S1/S1214 C = 670/800 40 mA RMS	600A/S1/S1214 C =670/800 50 mA RMS	600A/S1/S1223 C = 740/870 50 mA RMS
100A	600A/S2/P/S1217 C = 470/540 70 mA RMS	600A/S2/P/S1215 C = 570/670 75 mA RMS	600A/S2/P/S1215 C =570/670 100 mA RMS	600A/S2/P/S1196 C =620/740 100 mA RMS
150A	600A/S3/P/S1219 C = 430/500 100 mA RMS	600A/S3/P/S1220 C = 520/620 100 mA RMS	600A/S3/P/S1221 C = 570/670 100 mA RMS	600A/S3/P/S1222 C =620/740 100 mA RMS

In some situations single disc assemblies may be acceptable, contact GE Vernova for detailed applications.

Note:
The Metrosils recommended for use with 5 Amp CTs can also be used with triple pole devices and consist of three single pole units mounted on the same central stud but electrically insulated from each other. To order these units please specify "Triple pole Metrosil type", followed by the single pole type reference. Metrosil for higher voltage settings and fault currents are available if required.

11.2.7 USE OF ANSI C-CLASS CTS

Where American/IEEE standards are used to specify CTs, the C class voltage rating can be used to determine the equivalent knee point voltage according to IEC. The equivalence formula is:

$$V_K = 1.05(C\ rating\ in\ volts) + 100R_{CT}$$

CHAPTER 12

AUTORECLOSE

12.1 CHAPTER OVERVIEW

Selected models of this product provide sophisticated Autoreclose (AR) functionality. The purpose of this chapter is to describe the operation of this functionality including the principles, logic diagrams and applications.

This chapter contains the following sections:

Chapter Overview 263
Introduction to 3-phase Autoreclose 264
Implementation 265
Autoreclose Function Inputs 266
Autoreclose Function Outputs 269
Autoreclose Function Alarms 271
Autoreclose Operation 272
Setting Guidelines 289

12.2 INTRODUCTION TO 3-PHASE AUTORECLOSE

It is known that approximately 80 - 90% of faults are transient in nature. This means that most faults do not last long and are self-clearing. A common example of a transient fault is an insulator flashover, which may be caused for example by lightning, clashing conductors or wind-blown debris.

A transient fault, such as an insulator flashover, is a self-clearing ‘non-damage’ fault. The flashover will cause one or more circuit breakers to trip, but it may also have the effect of clearing the fault. If the fault clears itself, the fault does not recur when the line is re-energised.

The remaining 10 – 20% of faults are either semi-permanent or permanent. A small tree branch falling on the line could cause a semi-permanent fault. Here the cause of the fault would not be removed by the immediate tripping of the circuit, but could be burnt away during a time-delayed trip. Permanent faults could be broken conductors, transformer faults, cable faults or machine faults, which must be located and repaired before the supply can be restored.

In the majority of fault incidents, if the faulty line is immediately tripped out, and time is allowed for the fault arc to deionise, reclosure of the circuit breakers will result in the line being successfully re-energised.

Autoreclose schemes are used to automatically reclose a circuit breaker a set time after it has been opened due to operation of a protection element.

On HV/MV distribution networks, autoreclosing is applied mainly to radial feeders, where system stability problems do not generally arise. The main advantages of using Autoreclose are:

- Minimal interruption in supply to the consumer
- Reduction of operating costs - fewer man hours in repairing fault damage and the possibility of running unattended substations
- With Autoreclose, instantaneous protection can be used which means shorter fault durations. This in turn means less fault damage and fewer permanent faults

Autoreclosing provides an important benefit on circuits using time-graded protection, in that it allows the use of instantaneous protection to provide a high speed first trip. With fast tripping, the duration of the power arc resulting from an overhead line fault is reduced to a minimum. This lessens the chance of damage to the line, which might otherwise cause a transient fault to develop into a permanent fault. Using instantaneous protection also prevents blowing of fuses in teed feeders, as well as reducing circuit breaker maintenance by eliminating pre-arc heating.

When instantaneous protection is used with autoreclosing, the scheme is normally arranged to block the instantaneous protection after the first trip. Therefore, if the fault persists after re-closure, the time-graded protection will provide discriminative tripping resulting in the isolation of the faulted section. However, for certain applications, where the majority of the faults are likely to be transient, it is common practise to allow more than one instantaneous trip before the instantaneous protection is blocked.

Some schemes allow a number of re-closures and time-graded trips after the first instantaneous trip, which may result in the burning out and clearance of semi-permanent faults. Such a scheme may also be used to allow fuses to operate in teed feeders where the fault current is low.

When considering feeders that are partly overhead line and partly underground cable, any decision to install auto-reclosing should be subject to analysis of the data (knowledge of the frequency of transient faults). This is because this type of arrangement probably has a greater proportion of semi-permanent and permanent faults than for purely overhead feeders. In this case, the advantages of autoreclosing are small. It can even be disadvantageous because re-closing on to a faulty cable is likely to exacerbate the damage.

12.3 IMPLEMENTATION

Autoreclose functionality is a software option, which is selected when ordering the device, so this description only applies to models with this option.

Autoreclose works for phase overcurrent (POC) earth fault (EF) and sensitive earth fault (SEF) protection. It is implemented in the *AUTORECLOSE* column of the relevant settings group. In addition to the settings contained in this column, you will also need to make some settings in the blocking cells of the relevant protection columns.

The Autoreclose function can be set to perform a single-shot, two-shot, three-shot or four-shot cycle. You select this by the ***Number of Shots*** cell in the *AUTORECLOSE* column. You can also initiate a separate Autoreclose cycle for the SEF protection, with a different number of shots, selected by the ***Number SEF Shots*** cell. Dead times for all shots can be adjusted independently.

An Autoreclose cycle can be initiated internally by operation of a protection element, or externally by a separate protection device. The dead time starts in one of two cases; when the circuit breaker has tripped, or when the protection has reset. You select this using the ***Start Dead t On*** cell.

At the end of the relevant dead time, a ***CB Closed 3 ph*** signal is given, providing it is safe for the circuit breaker to close. This is determined by checking that certain system conditions are met as specified by the **System *Checks*** functionality.

It is safe to close the circuit breaker providing that:

- only one side of the circuit breaker is live (either dead line / live bus, or live line / dead bus), or
- if both bus and line sides of the circuit breaker are live, the system voltages are synchronised.

In addition, the energy source powering the circuit breaker (for example the closing spring) must be fully charged. This is indicated from the ***CB Healthy*** DDB input.

When the CB has closed, the reclaim time starts. If the circuit breaker does not trip again, the Autoreclose function resets at the end of the set reclaim time. If the protection operates during the reclaim time the device either advances to the next shot in the Autoreclose cycle, or if all reclose attempts have been made, goes to lockout.

CB Status signals must also be available, so the default setting for ***CB Status Input*** should be modified according to the application. The default PSL requires 52A, 52B and CB Healthy logic inputs, so a setting of both **52A and 52B** would be required for the ***CB Status Input*** if used with the default PSL.

12.4 AUTORECLOSE FUNCTION INPUTS

The Autoreclose function has several logic inputs, which can be mapped to any of the opto-inputs or to one or more of the DDB output signals generated by the PSL. The functions of these inputs are described below.

12.4.1 CB HEALTHY

It is necessary to establish if there is sufficient energy in the circuit breaker (spring charged, gas pressure healthy, etc.) before the CB can be closed. This ***CB Healthy*** input is used to ensure this before initiating a ***CB closed 3ph*** command. If on completion of the dead time, the ***CB Healthy*** input is low, and remains low for a period given by the ***CB Healthy Time*** timer, lockout will result and the circuit breaker will remain open.

The majority of circuit breakers are only capable of providing a single trip-close-trip cycle, in which case the ***CB Healthy*** signal would stay low after one Autoreclose shot, resulting in lockout.

This check can be disabled by not allocating an opto-input for the ***CB Healthy*** signal, whereby the signal defaults to a High state.

12.4.2 BLOCK AR

The ***Block AR*** input blocks the Autoreclose function and causes a lockout. It can be used when protection operation without Autoreclose is required. A typical example is on a transformer feeder, where Autoreclose may be initiated by the feeder protection but blocked by the transformer protection.

12.4.3 RESET LOCKOUT

The ***Reset Lockout*** input can be used to reset the Autoreclose function following lockout. It also resets any Autoreclose alarms, provided that the signals that initiated the lockout have been removed.

12.4.4 AR AUTO MODE

The ***AR Auto Mode*** input is used to select the Auto operating mode. In this mode, the Autoreclose function is in service.

12.4.5 AUTO MODE

The ***Auto Mode*** input is used to select the Auto operating mode. In this mode, the Autoreclose function is in service.

12.4.6 LIVELINE MODE

The ***Live Line Mode*** input is used to select the Live Line operating mode when Autoreclose is out of service and all blocking of instantaneous protection by Autoreclose is disabled. This operating mode takes precedence over all other operating modes for safety reasons, as it indicates that utility personnel are working near live equipment.

12.4.7 TELECONTROL MODE

The ***Telecontrol*** input is used to select the Telecontrol operating mode so that the Auto and Non-auto modes of operation can be selected remotely.

12.4.8 CIRCUITS OK

The ***Circuits OK*** signal is a signal indicating the status of the Live Line / Dead Bus or Live Bus / Dead Line system conditions (High = OK, Low = Not OK). The logic required can be derived in the PSL from the Live Line, Dead Line, Live Bus and Dead Bus signals in the System Check logic (if applicable), or it can come from an external source depending on the application.

12.4.9 AR SYS CHECKS OK

The ***AR Sys Checks OK*** signal can be mapped from the system checks output ***SysChksInactive***, to enable autoreclosing without any system checks, providing the ***System Checks*** setting in the *CONFIGURATION* column is disabled. This mapping is not essential, because the ***No System Checks*** setting in the *AUTORECLOSE* column can be enabled to achieve the same effect.

This signal can also be mapped to an opto-input, to allow the IED to receive a signal from an external system monitoring device, indicating that the system conditions are suitable for CB closing. This should not normally be necessary, since the IED has comprehensive built in system check functionality.

12.4.10 EXT AR PROT TRIP (EXTERNAL AR PROTECTION TRIP)

The ***Ext AR Prot Trip*** signal allows Autoreclose initiation by a Trip from a separate protection device.

12.4.11 EXT AR PROT START (EXTERNAL AR PROTECTION START)

The ***Ext AR Prot Strt*** signal allows Autoreclose initiation by a Start from a separate protection device.

12.4.12 DAR COMPLETE (DELAYED AUTORECLOSE COMPLETE)

Some utilities require Delayed Autoreclose (DAR) functionality.

The ***DAR Complete*** signal can, if required, be mapped in PSL to provide a short pulse when a CB Close command is given at the end of the dead time. If ***DAR Complete*** is activated during an Autoreclose cycle, the output signal ***DAR in Progress*** resets, even though the reclaim time may still be running, and ***AR 3pole in Prog*** remains set until the end of the reclaim time.

For most applications, ***DAR complete*** can be ignored (not mapped in PSL). In such cases, **DAR in *Progress*** operates and resets in parallel with ***AR 3pole in Prog***.

12.4.13 CB IN SERVICE (CIRCUIT BREAKER IN SERVICE)

The ***CB In Service*** signal must remain asserted when protection operates if autoreclose is to be initiated. For most applications, it can be mapped to ***CB Closed 3ph***. More complex PSL mapping can be programmed if required, for example where it is necessary to confirm not only that the CB is closed but also that the line and/or bus VT is actually live up to the instant of protection operation.

12.4.14 AR RESTART

In some applications, it is sometimes necessary to initiate an Autoreclose cycle by means of connecting an external signal to an opto-input. This would be when the normal interlock conditions are not all satisfied, i.e. when the CB is open and the associated feeder is dead. If the ***AR Restart*** input is mapped to an opto-input, activation of that opto-input will initiate an Autoreclose cycle irrespective of the status of the ***CB in Service*** input, provided the other interlock conditions, are still satisfied.

12.4.15 DT OK TO START (DEAD TIME OK TO START)

This is an optional extra interlock in the dead time initiation logic. In addition to the CB being open and the protection reset, ***DT OK To Start*** has to be set high to allow the dead time function to be primed after an AR cycle has started. Once the dead time function is primed, this signal has no further affect – the dead time function stays primed even if the signal subsequently goes low. A typical PSL mapping for this input is from the ***Dead Line*** signal from the System Check logic. This would enable dead time priming only when the feeder has gone dead after CB tripping. If this extra dead time priming interlock is not required, ***DT OK To Start*** can be left unmapped, and it will default to a high state.

12.4.16 DEADTIME ENABLED

This is an optional interlock in the dead time logic. This signal has to be high to allow the dead time to run. If this signal goes low, the dead time stops and resets, but stays primed, and will restart from zero when it goes high again. A typical PSL mapping is from the ***CB Healthy*** input or from selected signals from the System Check logic. It could also be mapped to an opto-input to provide a 'hold off' function for the follower CB in a 'master/follower' application with 2 CBs. If this optional interlock is not required, ***DeadTime Enabled*** can be left unmapped, and it will default to a high state.

12.4.17 AR INIT TRIPTEST (INITIATE TRIP TEST)

If ***AR Init TripTest*** is mapped to an opto-input, and that input is activated momentarily, the IED generates a CB trip output via ***AR Trip Test***. The default PSL then maps this to output to the trip output relay and initiates an Autoreclose cycle.

12.4.18 AR SKIP SHOT 1

If **A*R Skip Shot 1*** is mapped to an opto-input, and that input is activated momentarily, the IED logic will cause the Autoreclose sequence counter to increment by 1. This will decrease the available number of reclose shots and will lockout the re-closer.

12.4.19 INH RECLAIM TIME (INHIBIT RECLAIM TIME)

If ***Inh Reclaim Time*** is mapped to an opto-input, and that input is active at the start of the reclaim time, the IED logic will cause the reclaim timers to be blocked.

12.5 AUTORECLOSE FUNCTION OUTPUTS

The Autoreclose function has several logic outputs, which can be assigned to output relay contacts, monitor bits in the *COMMISSION TESTS* column, or the PSL. The functions of these outputs are described below.

12.5.1 AR 3POLE IN PROG

This signal is present during the complete re-close cycle from the start of protection to the end of the reclaim time or lockout.

12.5.2 AR IN PROGRESS 1 (DAR IN PROGRESS)

This operates together with the ***AR 3pole in Prog*** signal at the start of Autoreclose. If ***DAR Complete*** does not operate, ***DAR in Progress*** remains operated until ***AR 3pole in Prog*** resets at the end of the cycle. If ***DAR Complete*** goes high during the Autoreclose cycle, ***AR in Progress 1*** resets.

12.5.3 SEQUENCE COUNTER STATUS DDB SIGNALS

During each Autoreclose cycle a sequence Counter increments by 1 after each fault trip and resets to zero at the end of the cycle.

- ***Seq Counter = 0*** is set when the counter is at zero
- ***Seq Counter = 1*** is set when the counter is at 1
- ***Seq Counter = 2*** is set when the counter is at 2
- ***Seq Counter = 3*** is set when the counter is at 3
- ***Seq Counter = 4*** is set when the counter is at 4

12.5.4 SUCC.CLOSE 3P AR

The ***Succ.Close 3P AR*** output indicates that an Autoreclose cycle has been successfully completed. A successful Autoreclose signal is given after the protection has tripped the CB and it has reclosed successfully. The successful Autoreclose output is reset at the next CB trip or from one of the reset lockout methods.

12.5.5 AR IN SERVICE

The ***AR In Service*** output indicates whether the Autoreclose is in or out of service. Autoreclose is In Service when the device is in ***Auto*** mode and Out of Service when in the ***Non Auto*** and ***Live Line*** modes.

12.5.6 BLOCK MAIN PROT (BLOCK MAIN PROTECTION)

The ***Block Main Prot*** signal blocks the DT-only stages (instantaneous stages) of the main current protection elements. These are ***I>4, I>5, I>6, IN1>3, IN1>4, IN2>3,*** and ***IN2>4***. You block the instantaneous stages for each trip of the Autoreclose cycle using the Overcurrent and Earth Fault 1 and 2 settings, ***I> Blocking, IN1> Blocking, IN2> Blocking*** and the ***Trip 1/2/3/4/5 Main*** settings.

12.5.7 BLOCK SEF PROT (BLOCK SEF PROTECTION)

The ***Block SEF Prot*** signal blocks the DT-only stages (instantaneous stages) of the SEF protection elements. These are ***ISEF>3***, and ***ISEF>4***. You block the instantaneous SEF stages for each trip of the Autoreclose cycle using the *SEF PROTECTION* setting ***ISEF> Blocking***, and the ***Trip 1/2/3/4/5 SEF*** settings.

12.5.8 RECLOSE CHECKS

The ***Reclose Checks*** output indicates that the AR System Checks are in progress.

12.5.9 DEADT IN PROG (DEAD TIME IN PROGRESS)

The ***Dead T in Prog*** output indicates that the dead time is in progress. This signal is set when ***Reclose Checks*** is set AND input ***Dead TimeEnabled*** is high. This may be useful during commissioning to check the operation of the Autoreclose cycle.

12.5.10 DT COMPLETE (DEAD TIME COMPLETE)

DT *Complete* (Dead time complete) operates at the end of the set dead time, and remains operated until either the scheme resets at the end of the reclaim time or a further protection operation or Autoreclose initiation occurs. It can be applied purely as an indication, or included in PSL mapping to logic input ***DAR Complete***.

12.5.11 AR SYNC CHECK (AR SYNCHRONISATION CHECK)

AR Sync Check indicates that the Autoreclose Synchronism checks are satisfactory. This is when either of the synchronisation check modules (CS1 or CS2), confirms an In-Synchronism condition.

12.5.12 AR SYSCHECKS OK (AR SYSTEM CHECKS OK)

AR SysChecks OK indicates that the Autoreclose System checks are satisfactory. This is when any selected system check condition (synchronism check, live bus/dead line etc.) is confirmed.

This DDB signal ihas the number 463 and is an output from the Autoreclose function (i.e. a PSL input). It should not be confused with DDB signal 403, which is an input to the Autoreclose function (i.e. a PSL output).

12.5.13 AUTO CLOSE

The ***Auto Close*** output indicates that the Autoreclose logic has issued a `Close` signal to the CB. This output feeds a signal to the control close pulse timer and remains on until the CB has closed. This signal may be useful during commissioning to check the operation of the Autoreclose cycle.

12.5.14 PROTECTION LOCKT (PROTECTION LOCKOUT)

Protection Lockt (Protection Lockout) operates if ***AR lockout*** is triggered by protection operation either during the inhibit period following a manual CB close or when the device is in ***Non-auto*** or ***Live Line*** mode.

12.5.15 RESET LCKOUT ALM (RESET LOCKOUT ALARM)

Reset Lckout Alm operates when the device is in ***Non-auto mode***, if the ***Reset Lockout*** setting is set to `Select Non Auto`.

12.5.16 RECLAIM IN PROG

Reclaim in Prog output indicates that a reclaim timer is in progress and will drop-off once the reclaim timer resets.

12.5.17 RECLAIM COMPLETE

Reclaim Complete operates at the end of the set reclaim time and is a fast reset. To maintain the output indication a dwell timer has to be implemented in PSL.

12.6 AUTORECLOSE FUNCTION ALARMS

The following DDB signals will produce an alarm. These are described below.

12.6.1 AR NO SYS CHECK

The ***AR No Sys Check*** alarm indicates that the system voltages are not suitable for autoreclosing at the end of the system check time (setting ***Sys Check Time***), leading to a lockout condition. This alarm is latched and must be reset manually.

12.6.2 AR CB UNHEALTHY

The ***AR CB Unhealthy*** alarm indicates that the **CB *Healthy*** input was not energised at the end of the *CB Healthy Time*, leading to a lockout condition. This alarm is latched and must be reset manually.

12.6.3 AR LOCKOUT

The ***AR Lockout*** alarm indicates that the device is in a lockout status and that further re-close attempts will not be made. This alarm can configured to reset automatically (self-reset) or manually as determined by the setting ***Reset Lockout by*** in the *CB CONTRO*L column.

12.7 AUTORECLOSE OPERATION

The Autoreclose function is a complex function consisting of several modules interacting with one another. This is described in terms of separate logic diagrams, which link together by means of Internal signals (depicted by the pink-coloured boxes. To help you with the analysis of the various Autoreclose modules, the following table describes how these internal signals link up in the various logic diagrams. Each internal signal is allocated with an ID, and the diagrams on which they appear are also identified.

Internal signal ID	Input to AR function	Appearing in diagrams	Output from AR function	Appearing in diagrams
1	Autoreclose Disabled	V00505, V00507	Autoreclose Disabled	V00501
2	Live Line Mode	V00505, V00507, V00514	Live Line Mode	V00501
3	Non Auto Mode	V00505, V00507, V00514	Non Auto Mode	V00501
4	Auto Mode (int)	V00505, V00507, V00512	Auto Mode (int)	V00501
5	Main Protection Start	V00504, V00505, V00507, V00511, V00512	Main Protection Start	V00502
6	SEF Protection Start	V00504, V00505, V00511, V00512	SEF Protection Start	V00502
7	Main Protection Trip	V00505, V00513, V00514	Main Protection Trip	V00503
8	SEF Protection Trip	V00505, V00507, V00513, V00514	SEF Protection Trip	V00503
9	Block Autoreclose	V00513	Block Autoreclose	V00515
10	SC Count >= Main Shots	V00504	SC Count >= Main Shots	V00505
11	SC Count >= SEF Shots	V00504	SC Count >= SEF Shots	V00505
12	Main High Shots	V00505, V00513	Main High Shots	V00504
13	SEF High Shots	V00505, V00513	SEF High Shots	V00504
14	Autoreclose Inhibit	V00505, V00507, V00514	Autoreclose Inhibit	V00512
15	Autoreclose Start	V00508, V00509, V00511, V00513	Autoreclose Start	V00505
16	Autoreclose Initiate	V00508, V00513	Autoreclose Initiate	V00505
17	SC Count > 4	V00506	SC Count > 4	V00505
18	Block Main Prot Trips	V00507	Block Main Prot Trips	V00506
19	Block SEF Prot Trips	V00507	Block SEF Prot Trips	V00506
20	Hold Reclaim Output	V00511	Hold Reclaim Output	V00509

12.7.1 OPERATING MODES

The Autoreclose function has three operating modes:

- Auto Mode: Autoreclose is in service
- Non-auto Mode: Autoreclose is out of service AND the chosen protection functions are blocked if setting ***AR Deselected*** = `Block Inst Prot.`
- Live Line Mode: Autoreclose is out of service, but protection functions are NOT blocked, even if setting ***AR Deselected*** = `Block Inst Prot.`

> *Note:*
> *Live Line Mode provides extra security for live line working on the protected feeder.*

The Autoreclose function must first be enabled in the *CONFIGURATION* column. You can then select the operating mode according to application requirements. The basic method of mode selection is determined by the setting ***AR Mode Select*** in the *AUTORECLOSE* column, as summarised in the following table:

AR Mode Select Setting	Description
Command Mode	Auto or Non-auto mode selection is determined by the command cell ***Autoreclose Mode*** in the *CB CONTROL* column.
Opto Set Mode	Auto or Non-auto mode selection is determined by an opto-input mapped to ***AR Auto Mode*** If the ***AR Auto Mode*** input is high, Auto operating mode is selected. If the ***AR Auto Mode*** input is low, Non-Auto operating mode is selected.
User Set Mode	Auto or Non-auto mode selection is controlled by the ***Telecontrol Mode*** input. If the ***Telecontrol Mode*** input is high, the setting ***Autoreclose Mode*** in the *CB CONTROL* column is used to select Auto or Non Auto operating mode. If the ***Telecontrol Mode*** input is low, it behaves as for the `Opto Set Mode` setting.
Pulse Set Mode	Auto or Non-auto mode selection is determined by the falling edge of ***AR Auto Mode*** signal. If the Telecontrol input is high, the operating mode is toggled between Auto and Non Auto Mode on the falling edge of the ***AR Auto Mode*** signal as it goes low. The Auto Mode pulses are produced by the SCADA system. If the Telecontrol input is low, it behaves as for the ***Opto Set Mode*** setting.

The Live Line Mode is controlled by ***AR LiveLine Mode***. If this is high, the scheme is forced into Live Line Mode irrespective of the other signals.

12.7.1.1 FOUR-POSITION SELECTOR SWITCH IMPLEMENTATION

It is quite common for some utilities to apply a four position selector switch to control the mode of operation. This application can be implemented using the DDB signals ***AR LiveLine Mode***, ***AR Auto Mode*** and ***Telecontrol Mode***. This is demonstrated in the following diagram.

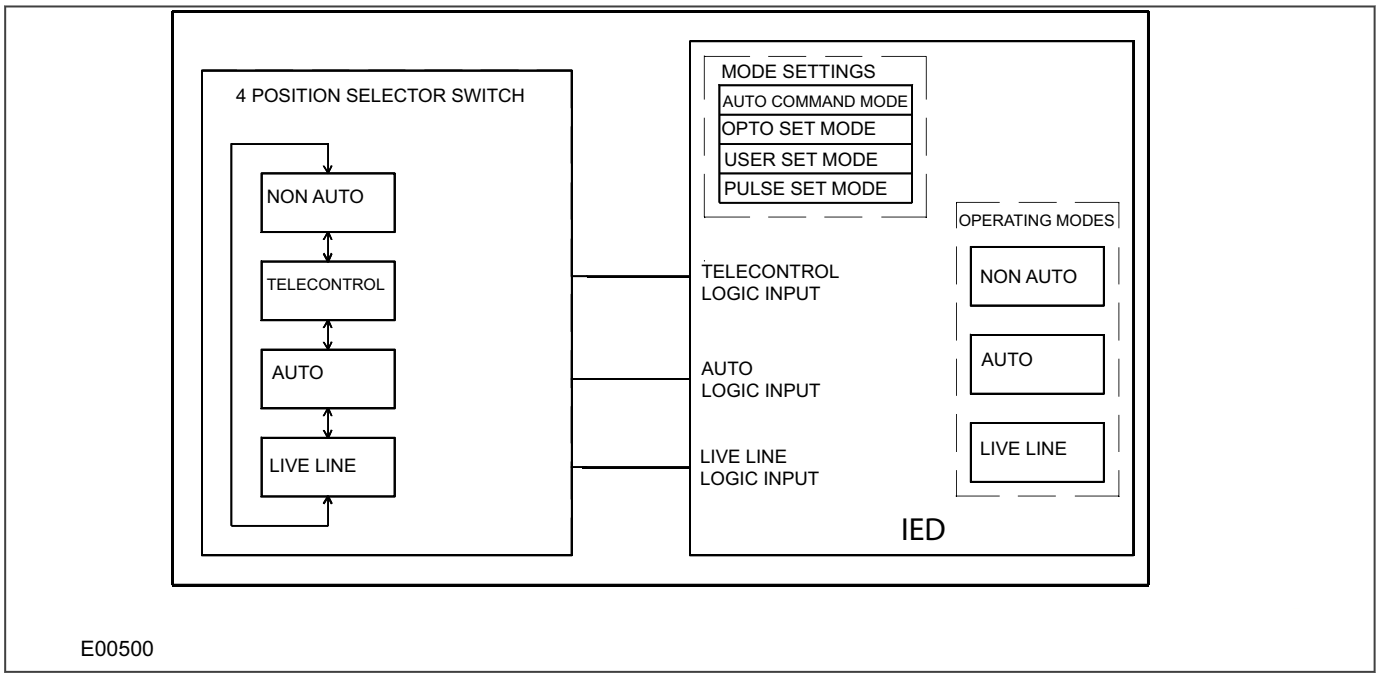


Figure 162: Four-position selector switch implementation

The required logic truth table for this arrangement is as follows:

Switch position	AR Auto Mode	Telecontrol Mode	AR Live Line Mode
Non-auto	0	0	0
Telecontrol	0 or SCADA pulse	1	0
Auto	1	0	0
Live Line	0	0	1

12.7.1.2 OPERATING MODE SELECTION LOGIC

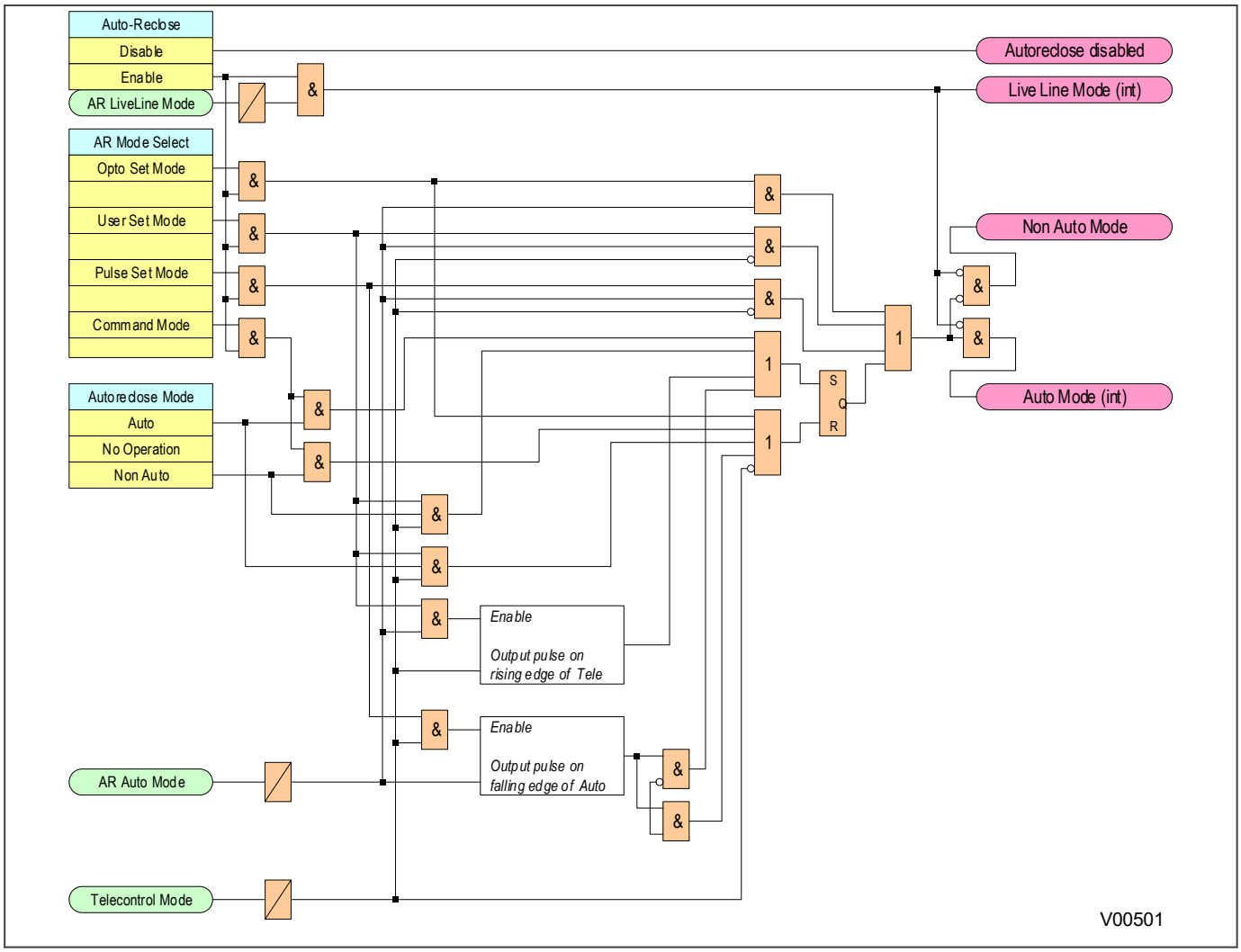


Figure 163: Autoreclose mode select logic

The mode selection logic includes a 100 ms delay for ***Auto Mode***, ***Telecontrol*** and ***Live Line*** logic inputs, to ensure a predictable change of operating modes. This is of particular importance for the case when the four position switch does not have 'make-before-break' contacts. The logic also ensures that when the switch is moved from Auto or Non-Auto position to Telecontrol, the scheme remains in the previously selected mode (Auto or Non-Auto) until a different mode is selected by remote control.

For applications where live line operating mode and remote selection of Auto/Non-auto modes are not required, a simple two position switch can be arranged to activate ***Auto Mode*** input. In this case, the ***Live Line*** and ***Telecontrol*** inputs would be unused.

12.7.2 AUTORECLOSE INITIATION

Autoreclose is usually initiated from the IED's internal protection function. Different stages of phase overcurrent and earth fault protection can be programmed to initiate or block the main Autoreclose function. The stages of sensitive earth fault protection can also be programmed to initiate or block both the Main Autoreclose function or the SEF Autoreclose function.

The associated settings are found in the *AUTORECLOSE* column under the sub-heading *AR INITIATION*.

For example:

If ***I>1 AR*** is set to `Initiate Main AR`, operation of the ***I>1*** protection stage will initiate Autoreclose

If ***ISEF>1 AR*** is set to `No Action`, operation of the ***ISEF>1*** protection stage will lead to a CB trip but no reclose. Otherwise it can be used to initiate Main autoreclose or SEF autoreclose.

Note:
A selection must be made for each protection stage that is enabled.

A separate protection device may also initiate Autoreclose. The Autoreclose can be initiated from a protection Trip, or when sequence coordination is required from a protection Start. If external triggering of Autoreclose is required, the following DDB signals should be mapped to opto-inputs:

- ***Ext AR Prot Trip***
- ***Ext AR Prot Strt*** (if applicable)

In addition, the setting ***Ext Prot*** should be set to `Initiate Main AR`.

Although a protection start and a protection trip can initiate an AR cycle, several checks still have to be performed before the initialisation signal is given. Some of the checks are listed below:

- ***Auto Mode*** has been selected
- ***Live line mode*** is disabled
- The number of main protection and SEF shots have not been reached
- Sequence co-ordination is enabled (for protection start to initiate AR. This is not necessary if a protection trip is doing the initiating)
- The ***CB Ops Lockout*** DDB signal is not set
- The ***CB in Service*** DDB signal is high

Note:
*The relevant protection trip must be mapped to the **Trip Command In** DDB.*

12.7.2.1 START SIGNAL LOGIC

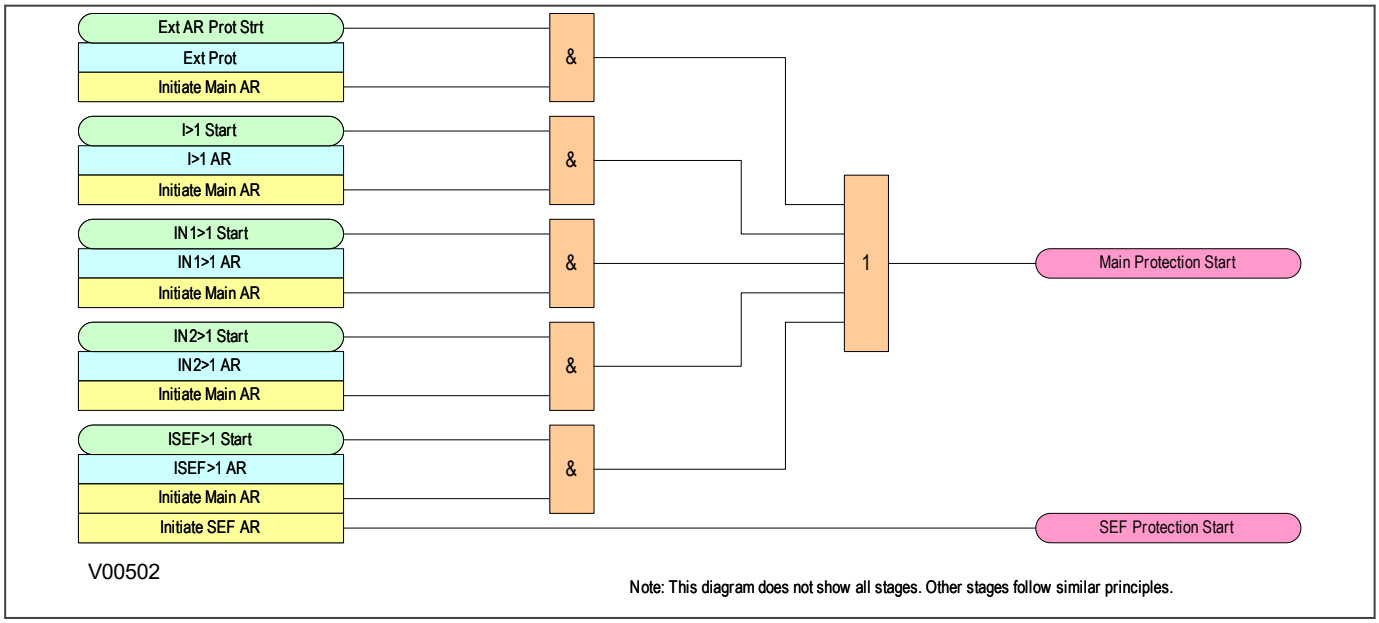


Figure 164: Start signal logic

12.7.2.2 TRIP SIGNAL LOGIC

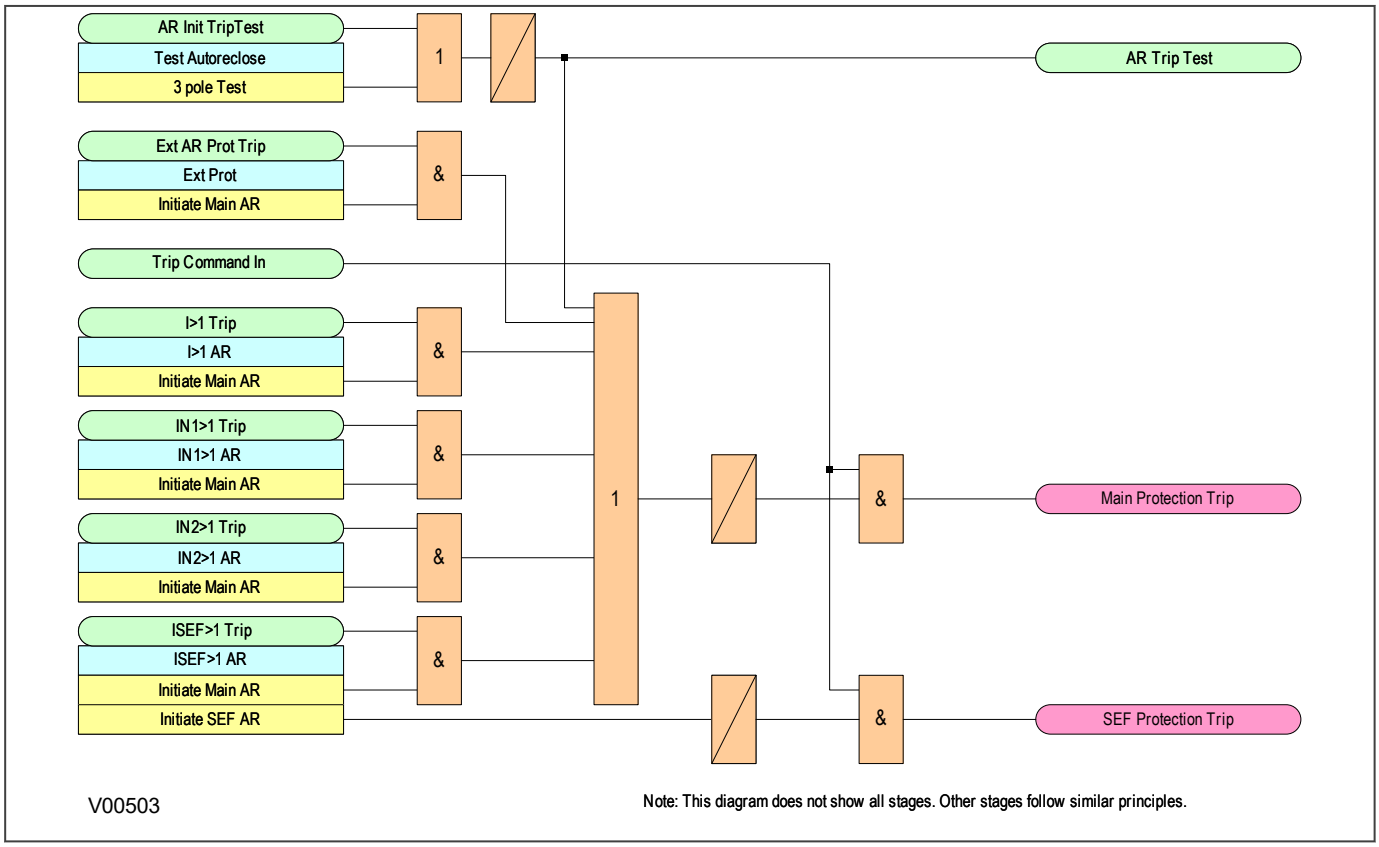


Figure 165: Trip signal logic

12.7.2.3 BLOCKING SIGNAL LOGIC

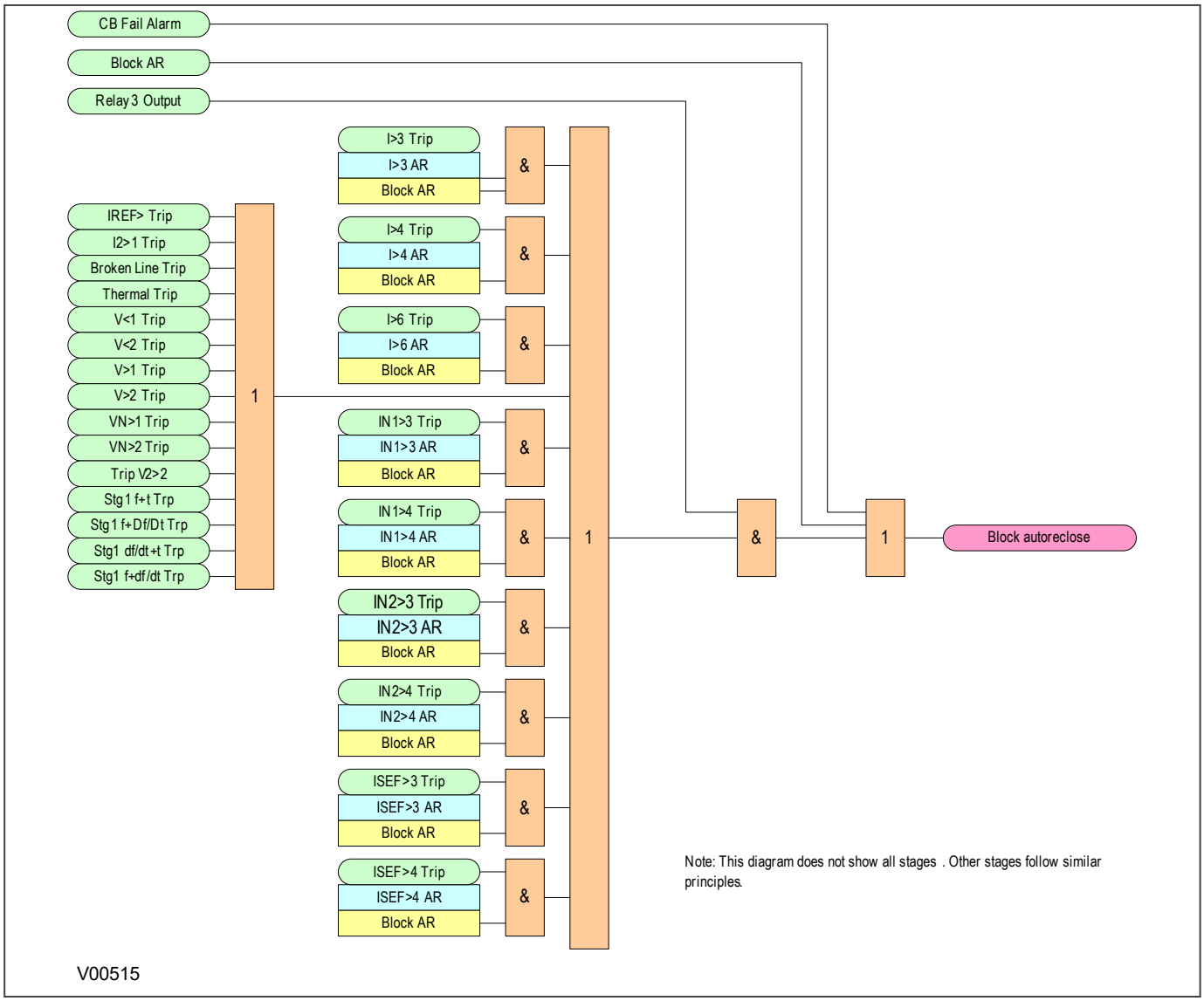


Figure 166: Blocking signal logic

12.7.2.4 SHOTS EXCEEDED LOGIC

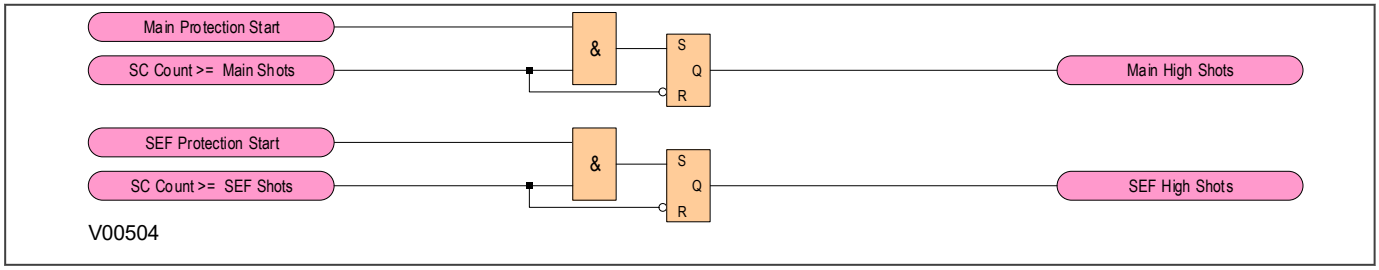


Figure 167: Shots exceeded logic

12.7.2.5 AR INITIATION LOGIC

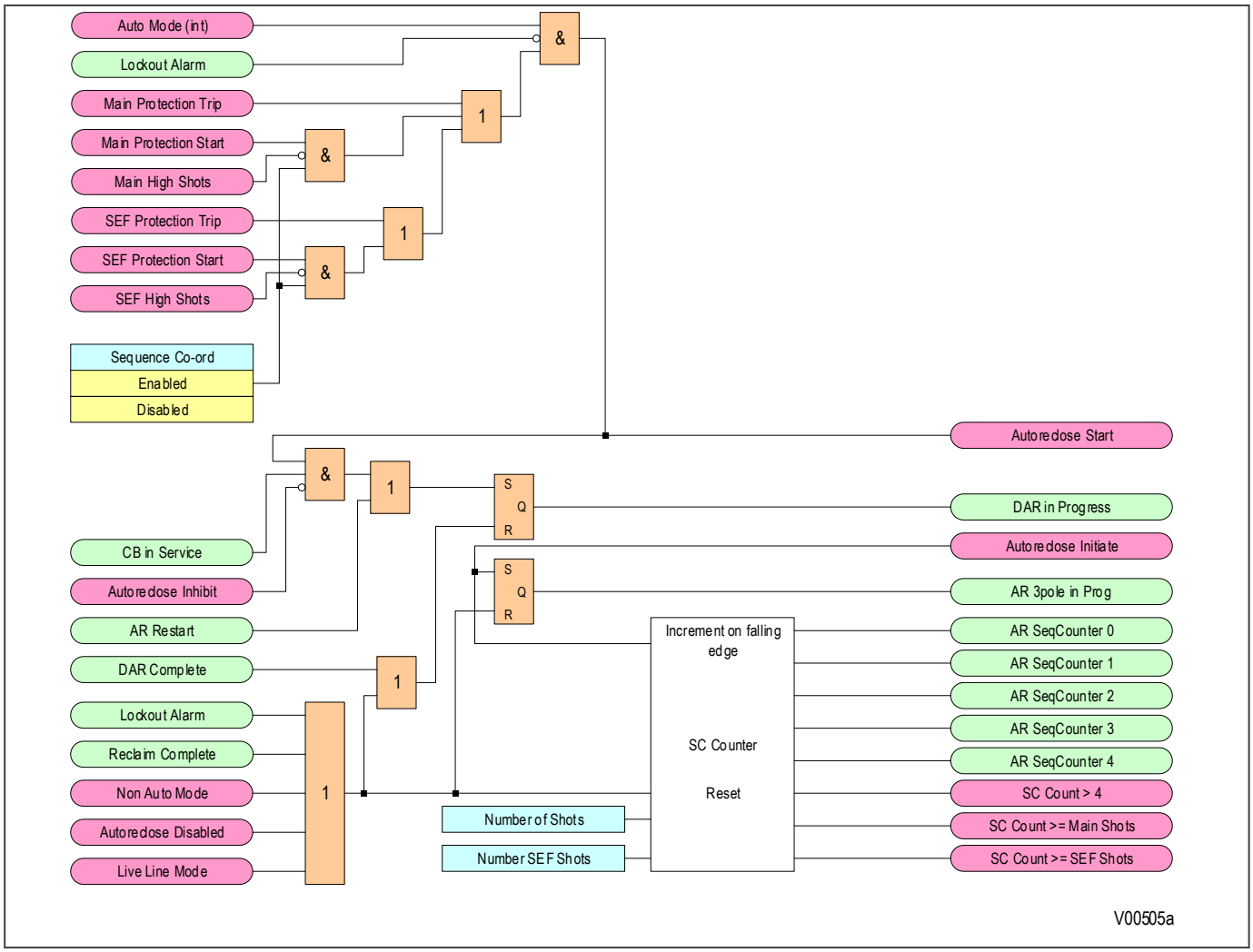


Figure 168: AR initiation logic

12.7.3 BLOCKING INSTANTANEOUS PROTECTION FOR SELECTED TRIPS

Instantaneous protection may be blocked or not blocked for each trip in an Autoreclose cycle. This is selected using the ***Trip (n) Main*** and ***Trip (n) SEF*** settings, where n is the number of the trip in the autoreclose cycle. These allow the instantaneous elements of phase, earth fault and SEF protection to be selectively blocked for a CB trip sequence. For example, if ***Trip 1 Main*** is set to `No Block` and ***Trip 2 Main*** is set to `Block Inst Prot`, the instantaneous elements of the phase and earth fault protection will be available for the first trip but blocked afterwards for the second trip during the Autoreclose cycle. The logic for this is shown below.

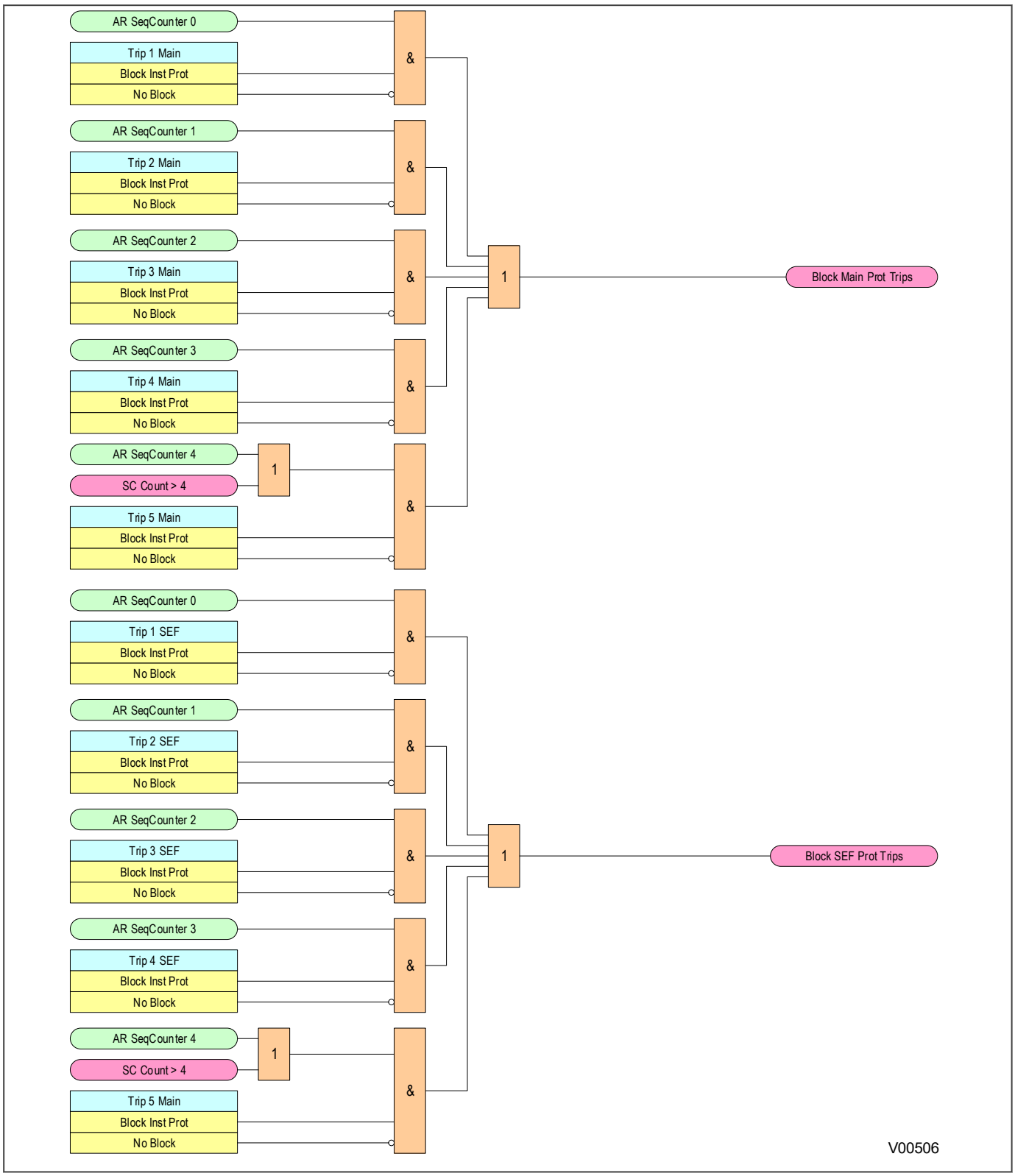


Figure 169: Blocking instantaneous protection for selected trips

12.7.4 BLOCKING INSTANTANEOUS PROTECTION FOR LOCKOUTS

Instantaneous protection can also be blocked for certain lockout conditions:

It is blocked when the CB maintenance lockout counter or excessive fault frequency lockout has reached its penultimate value.

For example, if the setting ***No. CB Ops Lock*** in the *CB MONITOR SETUP* column is set to 100 and the ***No. CB Ops Maint*** = '99', the instantaneous protection can be blocked to ensure that the last CB trip before lockout will be due to discriminative protection operation. This is controlled using the ***EFF Maint Lock*** setting (Excessive Fault Frequency maintenance lockout). If this is set to `Block Inst Prot`, the instantaneous protection will be blocked for the last CB Trip before lockout occurs.

Instantaneous protection can also be blocked when the IED is locked out, using the ***AR Lockout*** setting. It can also be blocked after a manual close using the ***Manual Close*** setting. When the IED is in the Non-auto mode it can be blocked by using the ***AR Deselected*** setting. The logic for these features is shown below.

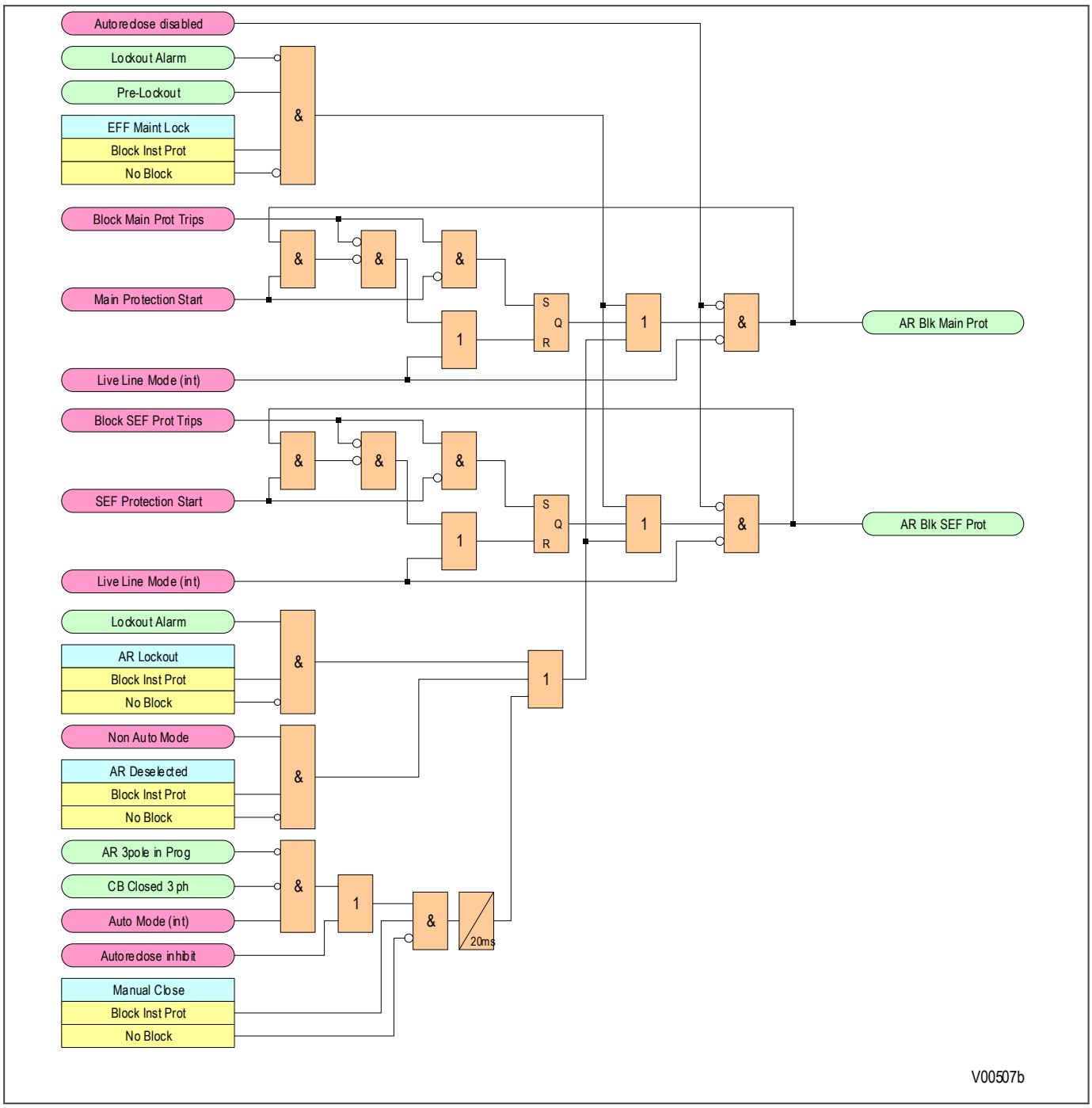


Figure 170: Blocking instantaneous protection for lockouts

12.7.5 DEAD TIME CONTROL

When the setting ***CS AR Immediate*** is enabled, immediate re-closure of the circuit breaker is allowed providing that both sides of the circuit breaker are live and in synchronism at any time after the dead time has started. This allows for quicker load restoration, as it is not necessary to wait for the full dead time to expire.

If ***CS AR Immediate*** is disabled, or neither Line nor Bus are live, the dead timer will continue to run, if the ***DeadTime Enabled*** signal is high. The ***DeadTime Enabled*** function could be mapped to an opto-input to indicate that the circuit breaker is healthy. Mapping the ***DeadTime Enabled*** function in PSL increases the flexibility by allowing it to be triggered by other conditions such as Live Line/Dead Bus. If ***DeadTime Enabled*** is not mapped in PSL, it defaults to high, so the dead time can run.

The dead time control logic is shown below.

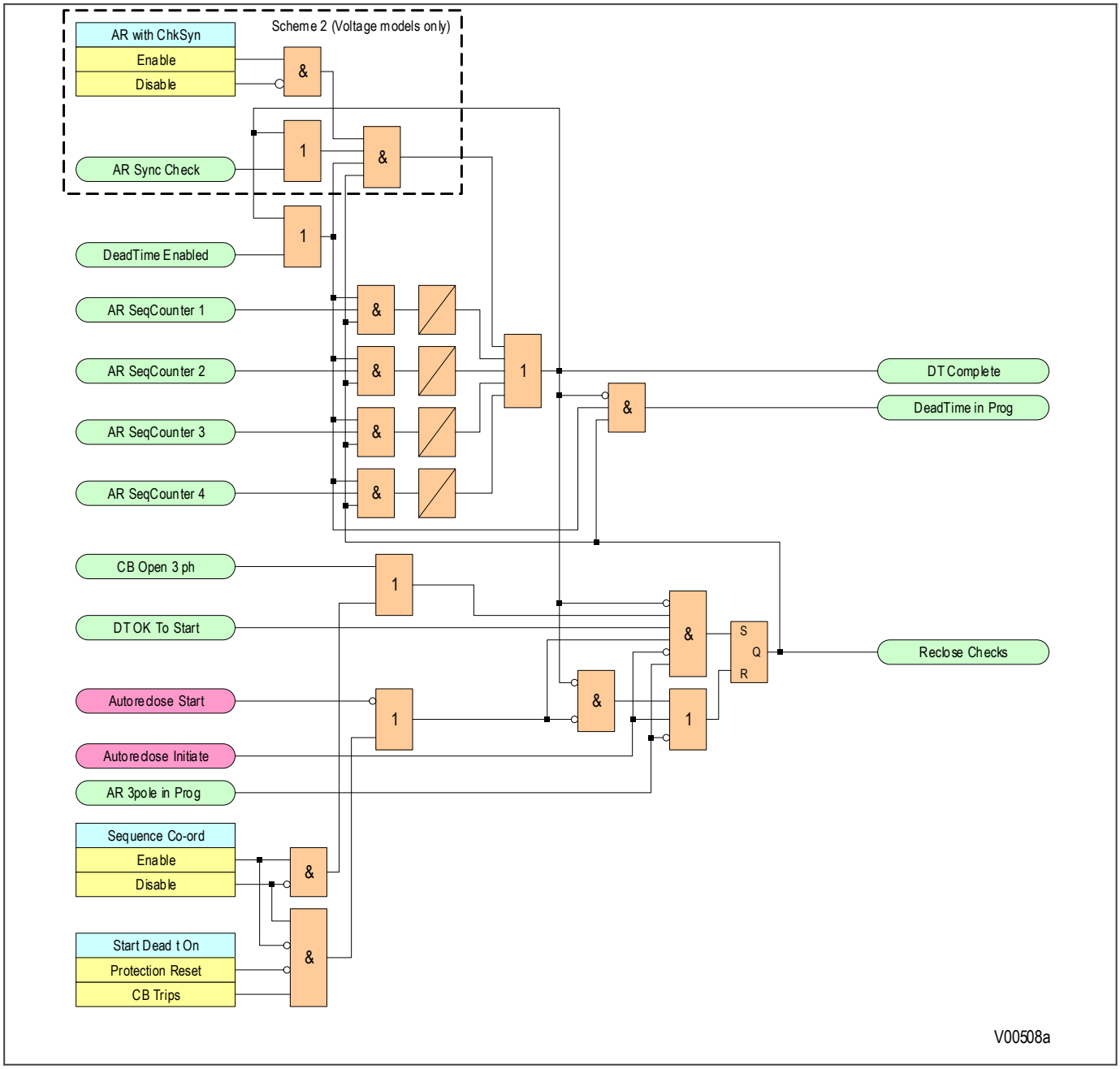


Figure 171: Dead time control logic

12.7.5.1 AR CB CLOSE CONTROL

Once the dead time is completed or a synchronism check is confirmed, the ***Auto Close*** signal is given, provided both the ***CB Healthy*** and the ***System Checks*** are satisfied. The ***Auto Close*** signal triggers a CB Close command via the CB Control functionality.

The AR CB Close Control Logic is as follows:

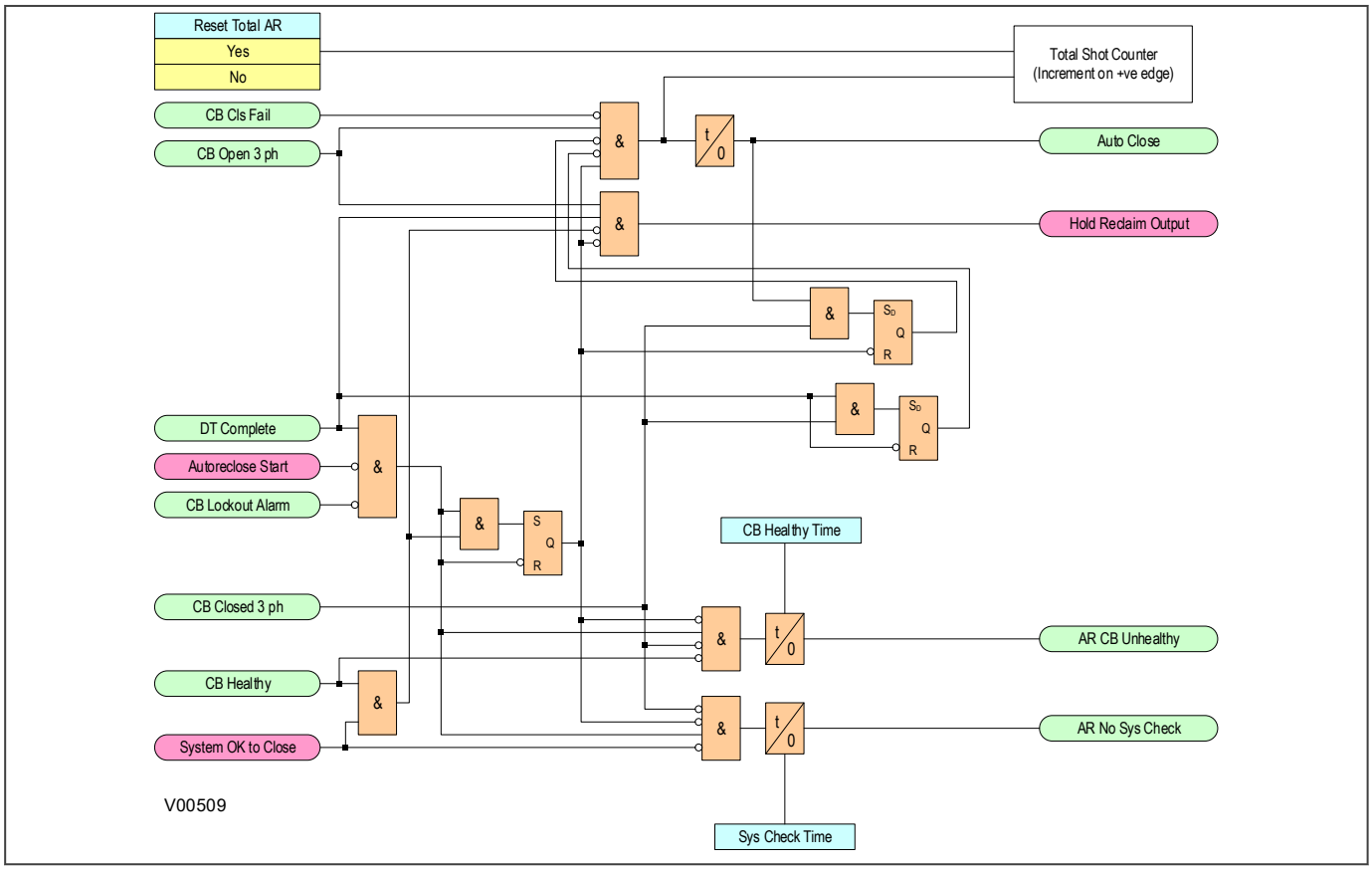


Figure 172: AR CB close control logic

12.7.6 AR SYSTEM CHECKS

The permission to initiate an Autoreclose depends on the following AR system check settings. These are found in the *AUTORECLOSE* column under the *AR SYSTEM CHECKS* sub-heading and are not to be confused with the main system check settings in the *SYSTEM CHECKS* column.

The *AR SYSTEM CHECKS* are as follows:

- ***Live/Dead Ccts***: When enabled this setting will give an ***AR Check OK*** signal when the ***LiveDead Ccts OK*** signal is high. This logic input DDB would normally be mapped in PSL to appropriate combinations of Line Live, Line Dead, Bus Live and Bus Dead DDB signals.
- ***No System Checks***: When enabled this setting completely disables system checks thus allowing Autoreclose initiation under any system conditions.
- ***SysChk on Shot 1***: Can be used to disable system checks on the first AR shot.
- ***AR with ChkSyn***: Only allows Autoreclose when the system satisfies the Check Sync Stage 1 (CS1) settings in the main *SYSTEM CHECKS* menu.
- ***AR with SysSyn***: Only allows Autoreclose when the system satisfies the Check Sync Stage 2 (CS2) settings in the main *SYSTEM CHECKS* menu.

The AR System Check logic is as follows:

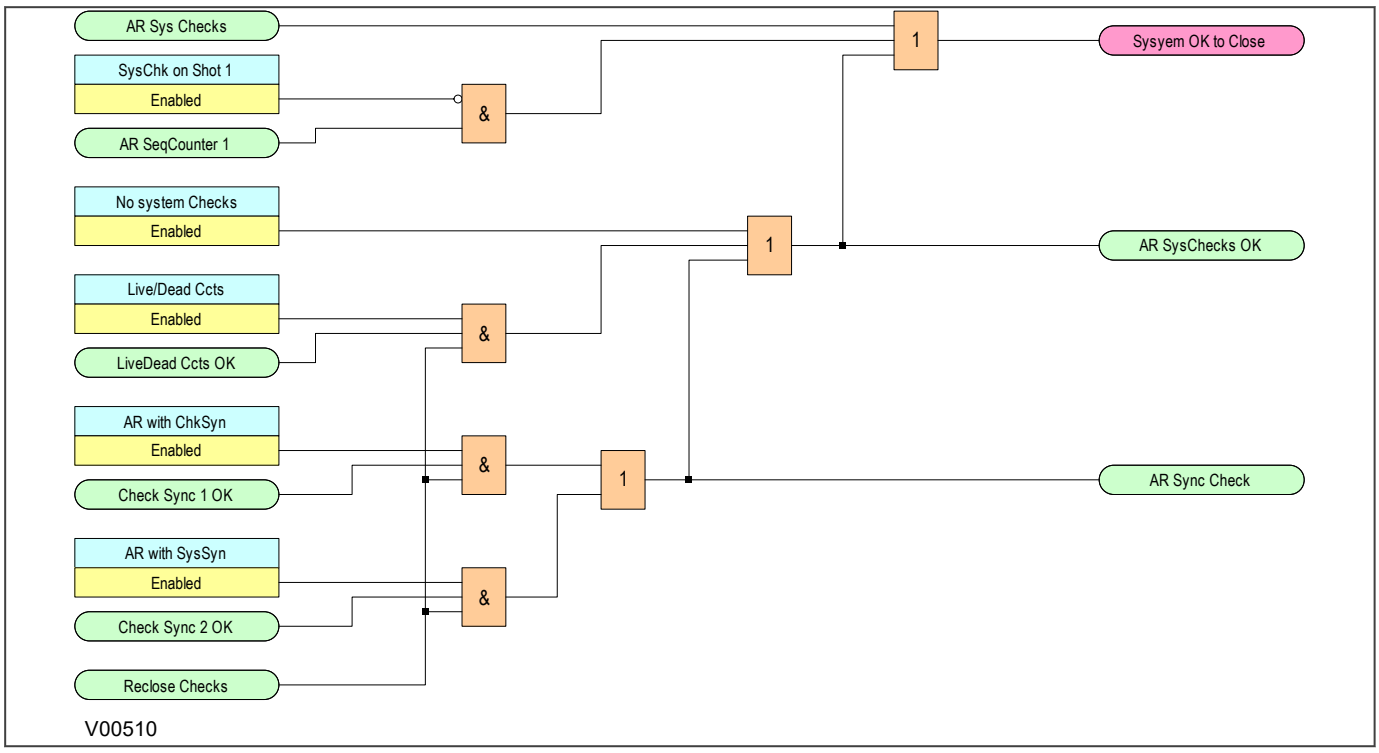


Figure 173: AR system check logic

12.7.7 RECLAIM TIMER INITIATION

The ***tReclaim Extend*** setting allows you to control whether the timer is suspended from the protection start contacts or not. When a setting of `No Operation` is used, the reclaim timer operates from the instant the CB is closed and will continue until the timer expires. The ***Reclaim Time*** must therefore be set in excess of the time-delayed protection operating time, to ensure that the protection can operate before the Autoreclose function is reset.

For certain applications it is advantageous to set ***tReclaim Extend*** to `On Prot Start`. This facility allows the operation of the reclaim timer to be suspended after CB re-closure by a signal from the main protection start or SEF protection start signals. This feature ensures that the reclaim time cannot time out and reset the Autoreclose before the time delayed protection has operated.

Since the reclaim timer will be suspended, it is unnecessary to use a timer setting in excess of the protection operating time, therefore a short reclaim time can be used. Short reclaim time settings can help to prevent unnecessary lockout for a succession of transient faults in a short period, for example during a thunderstorm.

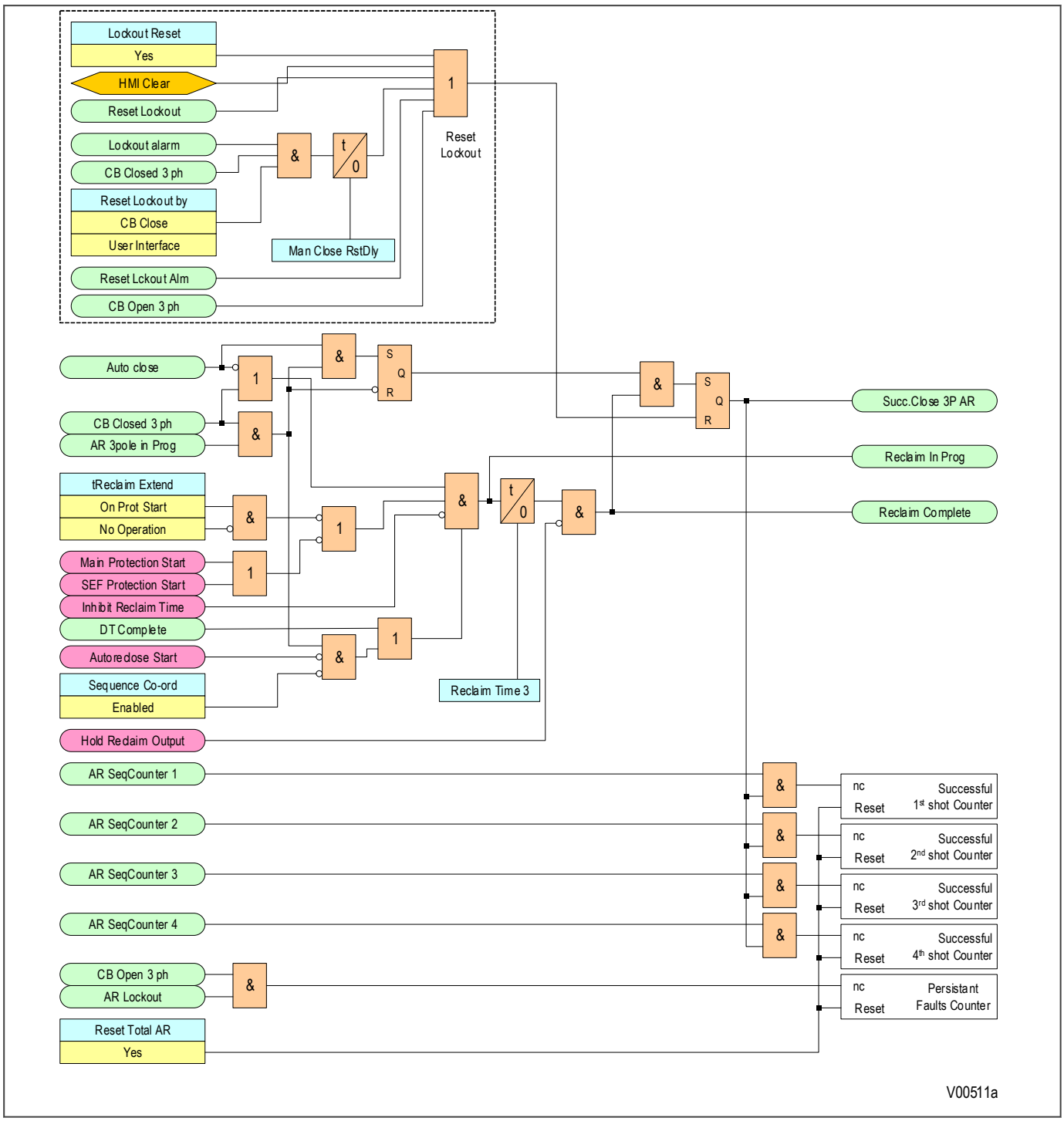


Figure 174: Reclaim time logic

12.7.8 AUTORECLOSE INHIBIT

To ensure that autoreclosing is not initiated for a manual CB closure on to a pre-existing fault (switch on to fault), the ***AR on Man Close*** setting can be set to Inhibited. With this setting, Autoreclose initiation is inhibited for a period equal to setting ***AR Inhibit Time*** following a manual CB closure. The logic for AR Inhibit is as follows:

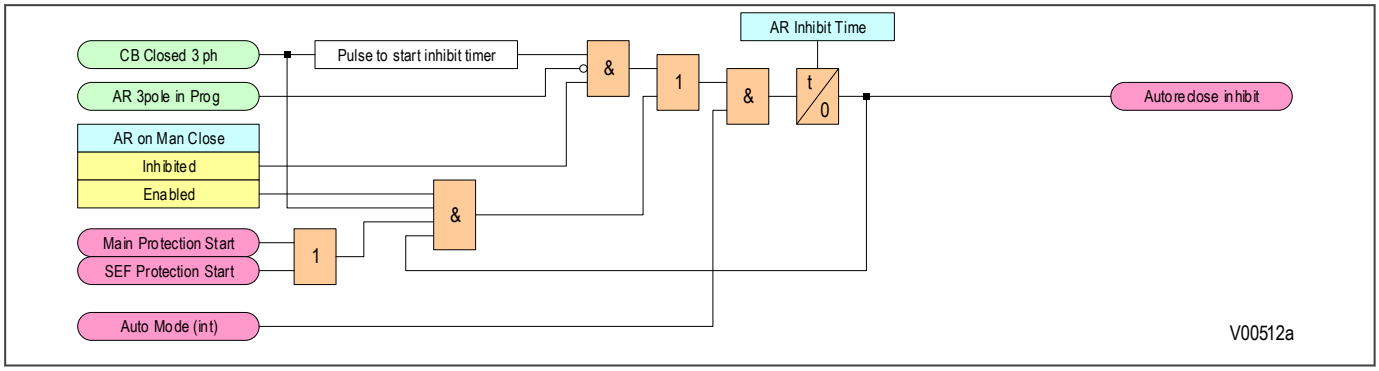


Figure 175: AR initiation inhibit

If a protection operation occurs during the inhibit period, Autoreclose is not initiated. A further option is provided by setting ***Man Close on Flt***. If this is set to `Lockout`, Autoreclose is locked out (***AR Lockout***) for a fault during the inhibit period following manual CB closure. If ***Man Close on Flt*** is set to `No Lockout`, the CB trips without reclosure, but Autoreclose is not locked out.

You may need to block selected fast non-discriminating protection in order to obtain fully discriminative tripping during the AR initiation inhibit period following CB manual close. You can do this by setting ***Manual Close*** to `Block Inst Prot`. A `No Block` setting will enable all protection elements immediately on CB closure.

If setting ***AR on Man Close*** is set to `Enabled`, Autoreclose can be initiated immediately on CB closure, and settings ***AR Inhibit Time***, ***Man Close on Flt*** and ***Manual Close*** are irrelevant.

12.7.9 AUTORECLOSE LOCKOUT

If protection operates during the reclaim time following the final reclose attempt, the IED is driven to lockout and the Autoreclose function is disabled until the lockout condition is reset. This produces the alarm, ***AR Lockout***. The ***Block AR*** input blocks Autoreclose and causes a lockout if Autoreclose is in progress.

Autoreclose lockout can also be caused by the CB failing to close due to an unhealthy circuit breaker (CB springs not charged or low gas pressure) or if there is no synchronisation between the system voltages. These two conditions are indicated by the alarms ***CB Unhealthy*** and ***AR No Sys Check*** This is shown in the AR Lockout logic diagram as follows:

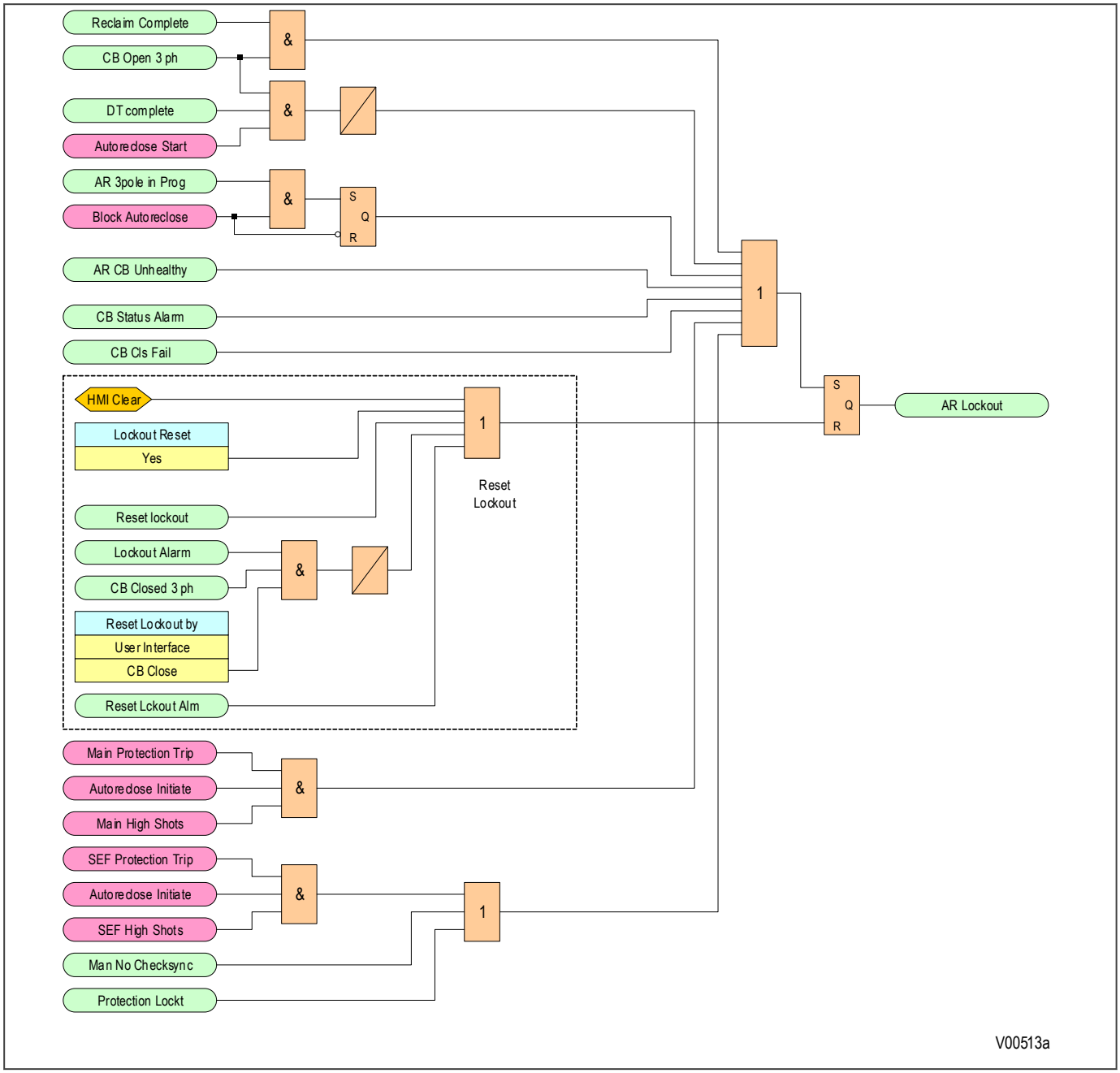


Figure 176: Overall lockout logic

AR lockout may also be due to a protection operation when the IED is in the Live Line or Non-auto modes when the setting ***Trip AR Inactive*** is set to `Lockout`. Autoreclose lockout can also be caused by a protection operation after manual closing during the ***AR Inhibit Time*** when the ***Man Close on Flt*** setting is set to `Lockout`. This is shown as follows:

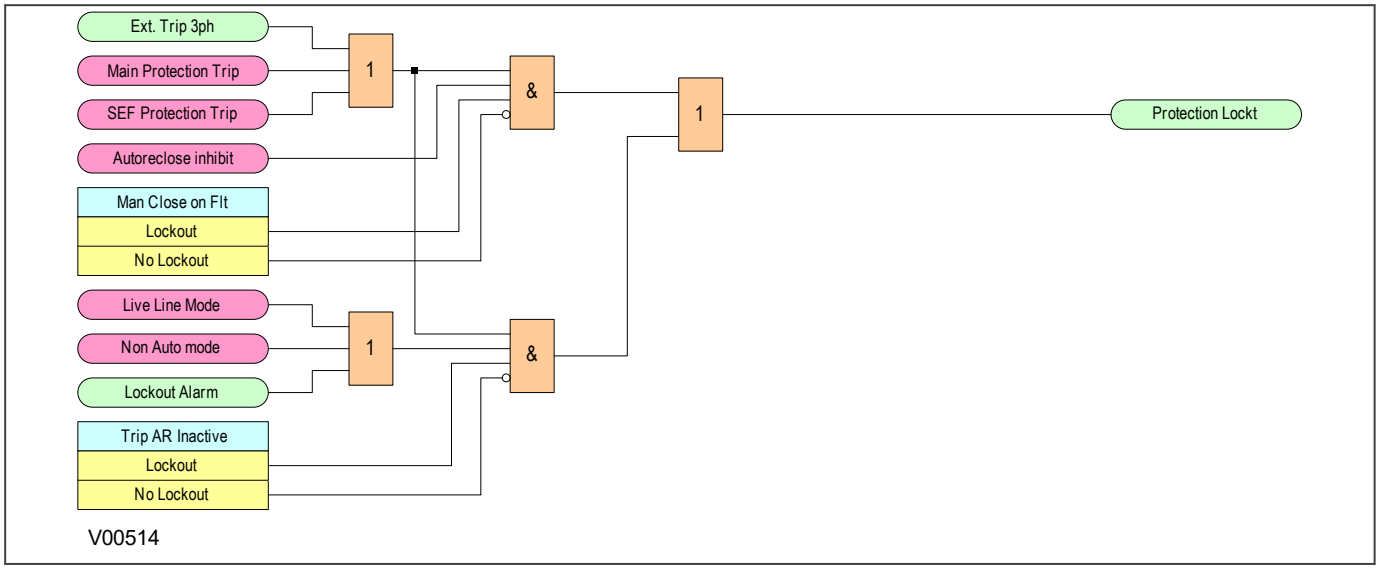


Figure 177: Lockout for protection trip when AR is not available

Note:
Lockout can also be caused by the CB condition monitoring functions in the CB MONITOR SETUP column.

The ***Reset Lockout*** input can be used to reset the Autoreclose function following lockout and reset any Autoreclose alarms, provided that the signals that initiated the lockout have been removed. Lockout can also be reset from the clear key or the command ***Lockout Reset*** from the *CB CONTROL* column.

There are two different ***Reset Lockout by*** settings. One in the *CB CONTROL* column and one in the *AUTORECLOSE* column.

The ***Reset Lockout by*** setting in the *CB CONTROL* column is used to enable or disable reset of lockout automatically from a manual close after the manual close time ***Man Close RstDly***.

The ***Reset Lockout by*** setting in the *AUTORECLOSE* column is used to enable/disable the resetting of lockout when the IED is in the Non-auto operating mode. The reset lockout methods are summarised in the following table:

Reset Lockout Method	When Available?
User Interface via the Clear key. Note: This will also reset all other protection flags	Always
User interface via *CB CONTROL* command Lockout Reset	Always
Opto-input Reset lockout	Always
Following a successful manual close if *CB CONTROL* setting Reset Lockout by is set to `CB Close`	Only when set
By selecting Non-Auto mode, provided *AUTORECLOSE* setting Reset Lockout by is set to `Select NonAuto`	Only when set

12.7.10 SEQUENCE CO-ORDINATION

The ***Sequence Co-ord*** setting in the *AUTORECLOSE* menu allows sequence co-ordination with other protection devices, such as downstream pole-mounted reclosers.

The main protection start or SEF protection start signals indicate when fault current is present, advance the sequence count by one and start the dead time, whether the CB is open or closed. When the dead time is complete and the protection start inputs are low, the reclaim timer is initiated.

You should program both the upstream and downstream Autoreclose IEDs with the same number of shots to lockout and number of instantaneous trips before instantaneous protection is blocked. This will ensure that for a

persistent downstream fault, both Autoreclose IEDs will be on the same sequence count and will block instantaneous protection at the same time. When sequence co-ordination is disabled, the circuit breaker has to be tripped to start the dead time, and the sequence count is advanced by one.

When using sequence co-ordination for some applications such as downstream pole-mounted reclosers, it may be desirable to re-enable instantaneous protection when the recloser has locked out. When the downstream recloser has locked out there is no need for discrimination. This allows you to have instantaneous, then IDMT, then instantaneous trips again during an Autoreclose cycle. Instantaneous protection may be blocked or not blocked for each trip in an Autoreclose cycle using the ***Trip (n) Main*** and ***Trip (n) SEF*** settings, where n is the number of the trip in the autoreclose cycle.

12.7.11 SYSTEM CHECKS FOR FIRST RECLOSE

The ***SysChk on Shot 1*** setting in the *SYSTEM CHECKS* sub menu of the *AUTORECLOSE* column is used to enable or disable system checks for the first reclose attempt in an Autoreclose cycle. This may be preferred when high speed Autoreclose is applied, to avoid the extra time for a synchronism check. Subsequent reclose attempts in a multi-shot cycle will, however, still require a synchronism check.

12.8 SETTING GUIDELINES

12.8.1 NUMBER OF SHOTS

There are no clear cut rules for defining the number of shots for a particular application. Generally medium voltage systems use only two or three shot Autoreclose schemes. However, in certain countries, for specific applications, a four-shot scheme is used. A four-shot scheme has the advantage that the final dead time can be set sufficiently long to allow any thunderstorms to pass before reclosing for the final time. This arrangement prevents unnecessary lockout for consecutive transient faults.

Typically, the first trip, and sometimes the second, will result from instantaneous protection. Since most faults are transient, the subsequent trips will be time delayed, all with increasing dead times to clear semi-permanent faults.

An important consideration is the ability of the circuit breaker to perform several trip-close operations in quick succession and the affect of these operations on the circuit maintenance period.

On EHV transmission circuits with high fault levels, only one re-closure is normally applied, because of the damage that could be caused by multiple re-closures.

12.8.2 DEAD TIMER SETTING

The choice of dead time is dependent on the system. The main factors that can influence the choice of dead time are:

- Stability and synchronism requirements
- Operational convenience
- Load
- The type of circuit breaker
- Fault de-ionising time
- The protection reset time

12.8.2.1 STABILITY AND SYNCHRONISM REQUIREMENTS

It may be that the power transfer level on a specific feeder is such that the systems at either end of the feeder could quickly fall out of synchronism if the feeder is opened. If this is the case, it is usually necessary to reclose the feeder as quickly as possible to prevent loss of synchronism. This is called high speed autoreclosing (HSAR). In this situation, the dead time setting should be adjusted to the minimum time necessary. This time setting should comply with the minimum dead time limitations imposed by the circuit breaker and associated protection, which should be enough to allow complete deionisation of the fault path and restoration of the full voltage withstand level. Typical HSAR dead time values are between 0.3 and 0.5 seconds.

On a closely interconnected transmission system, where alternative power transfer paths usually hold the overall system in synchronism even when a specific feeder opens, or on a radial supply system where there are no stability implications, it is often preferred to leave a feeder open for a few seconds after fault clearance. This allows the system to stabilise, and reduces the shock to the system on re-closure. This is called slow or delayed auto-reclosing (DAR). The dead time setting for DAR is usually selected for operational convenience.

12.8.2.2 OPERATIONAL CONVENIENCE

When HSAR is not required, the dead time chosen for the first re-closure following a fault trip is not critical. It should be long enough to allow any resulting transients resulting to decay, but not so long as to cause major inconvenience to consumers who are affected by the loss of the feeder. The setting chosen often depends on service experience with the specific feeder.

Typical first shot dead time settings on 11 kV distribution systems are 5 to 10 seconds. In situations where two parallel circuits from one substation are carried on the same towers, it is often arranged for the dead times on the

two circuits to be staggered, e.g. one at 5 seconds and the other at 10 seconds, so that the two circuit breakers do not reclose simultaneously following a fault affecting both circuits.

For multi-shot Autoreclose cycles, the second shot and subsequent shot dead times are usually longer than the first shot, to allow time for semi-permanent faults to burn clear, and for the CB to recharge. Typical second and third shot dead time settings are 30 seconds and 60 seconds respectively.

12.8.2.3 LOAD REQUIREMENTS

Some types of electrical load might have specific requirements for minimum and/or maximum dead time, to prevent damage and minimise disruption. For example, synchronous motors are only capable of tolerating extremely short supply interruptions without losing synchronism. In practise it is desirable to disconnect the motor from the supply in the event of a fault; the dead time would normally be sufficient to allow a controlled shutdown. Induction motors, on the other hand, can withstand supply interruptions up to typically 0.5 seconds and re-accelerate successfully.

12.8.2.4 CIRCUIT BREAKER

For HSAR, the minimum dead time of the power system will depend on the minimum time delays imposed by the circuit breaker during a tripping and reclose operation.

After tripping, time must be allowed for the mechanism to reset before applying a closing pulse, otherwise the circuit breaker might fail to close correctly. This resetting time will vary depending on the circuit breaker, but is typically 0.1 seconds.

Once the mechanism has reset, a CB Close signal can be applied. The time interval between energising the closing mechanism and making the contacts is called the closing time. A solenoid closing mechanism may take up to 0.3 seconds. A spring-operated breaker, on the other hand, can close in less than 0.1 seconds.

Where HSAR is required, for the majority of medium voltage applications, the circuit breaker mechanism reset time itself dictates the minimum dead time. This would be the mechanism reset time plus the CB closing time. A solenoid mechanism is not suitable for high speed Autoreclose as the closing time is generally too long.

For most circuit breakers, after one reclosure, it is necessary to recharge the closing mechanism energy source before a further reclosure can take place. Therefore the dead time for second and subsequent shots in a multi-shot sequence must be set longer than the spring or gas pressure recharge time.

12.8.2.5 FAULT DE-IONISATION TIME

For HSAR, the fault deionising time may be the most important factor when considering the dead time. This is the time required for ionised air to disperse around the fault position so that the insulation level of the air is restored. You cannot accurately predict this, but you can obtain an approximation from the following formula:

Deionising time = (10.5 + ((system voltage in kV)/34.5))/frequency

Examples:

At 66 kV 50 Hz, the deionising time is approximately 0.25 s

At 132 kV 60 Hz, the deionising time is approximately 0.29 s

12.8.2.6 PROTECTION RESET TIME

It is essential that any time-graded protection fully resets during the dead time, so that correct time discrimination will be maintained after reclosing on to a fault. For HSAR, instantaneous reset of protection is required. However at distribution level, where the protection is predominantly made up of overcurrent and earth fault devices, the protection reset time may not be instantaneous. In the event that the circuit breaker recloses on to a fault and the protection has not fully reset, discrimination may be lost with the downstream protection. To avoid this condition the dead time must be set in excess of the slowest reset time of either the local device or any downstream protection.

Typical 11/33 kV dead time settings are as follows:

1st dead time = 5 - 10 seconds

2nd dead time = 30 seconds

3rd dead time = 60 - 180 seconds

4th dead time = 1 - 30 minutes

12.8.3 RECLAIM TIMER SETTING

A number of factors influence the choice of the reclaim timer:

- Supply continuity: Large reclaim times can result in unnecessary lockout for transient faults.
- Fault incidence/Past experience: Small reclaim times may be required where there is a high incidence of lightning strikes to prevent unnecessary lockout for transient faults.
- Spring charging time: For HSAR the reclaim time may be set longer than the spring charging time to ensure there is sufficient energy in the circuit breaker to perform a trip-close-trip cycle. For delayed Autoreclose there is no need as the dead time can be extended by an extra CB healthy check window time if there is insufficient energy in the CB. If there is insufficient energy after the check window time the IED will lockout.
- Switchgear maintenance: Excessive operation resulting from short reclaim times can mean shorter maintenance periods. A minimum reclaim time of more than 5 seconds may be needed to allow the circuit breaker time to recover after a trip and close before it can perform another trip-close-trip cycle. This time will depend on the circuit breaker's duty rating.

The reclaim time must be long enough to allow any time-delayed protection initiating Autoreclose to operate. Failure to do so would result in premature resetting of the Autoreclose scheme and re-enabling of instantaneous protection. If this condition arose, a permanent fault would effectively look like a number of transient faults, resulting in continuous autoreclosing, unless additional measures are taken such as excessive fault frequency lockout protection.

Sensitive earth fault protection is applied to detect high resistance earth faults and usually has a long time delay, typically 10 - 15 seconds. This longer time may have to be taken into consideration, if autoreclosing from SEF protection. High resistance earth faults are rarely transient and may be a danger to the public. It is therefore common practise to block Autoreclose by operation of sensitive earth fault protection and lockout the circuit breaker.

A typical 11/33 kV reclaim time is 5 - 10 seconds. This prevents unnecessary lockout during thunderstorms. However, reclaim times of up to 60 - 180 seconds may be used elsewhere in the world.

CHAPTER 13

MONITORING AND CONTROL

13.1 EVENT RECORDS

GE Vernova devices record events in an event log. This allows you to establish the sequence of events that led up to a particular situation. For example, a change in a digital input signal or protection element output signal would cause an event record to be created and stored in the event log. This could be used to analyse how a particular power system condition was caused. These events are stored in the IED's non-volatile memory. Each event is time tagged.

The event records can be displayed on an IED's front panel but it is easier to view them through the settings application software. This can extract the events log from the device and store it as a single .evt file for analysis on a PC.

The event records are detailed in the *VIEW RECORDS* column. The first event (0) is always the latest event. After selecting the required event, you can scroll through the menus to obtain further details.

If viewing the event with the settings application software, simply open the extracted event file. All the events are displayed chronologically. Each event is summarised with a time stamp obtained from the ***Time & Date*** cell) and a short description relating to the event obtained from the ***Event Text*** cell). You can expand the details of the event by clicking on the **+** icon to the left of the time stamp.

The following table shows the correlation between the fields in the setting application software's event viewer and the cells in the menu database.

Field in Event Viewer	Equivalent cell in menu DB	Cell reference	User settable?
Left hand column header	VIEW RECORDS → Time & Date	01 03	No
Right hand column header	VIEW RECORDS → Event Text	01 04	No
Description	SYSTEM DATA → Description	00 04	Yes
Plant reference	SYSTEM DATA → Plant Reference	00 05	Yes
Model number	SYSTEM DATA → Model Number	00 06	No
Address	Displays the Courier address relating to the event	N/A	No
Event type	VIEW RECORDS → Menu Cell Ref	01 02	No
Event Value	VIEW RECORDS → Event Value	01 05	No
Evt Unique Id	VIEW RECORDS → Evt Unique ID	01 FE	No

The device is capable of storing up to 5000 time tagged event records.

In addition to the event log, there are two logs which contain duplicates of the last 10 maintenance records and the last 100 fault records. The purpose of this is to provide convenient access to the most recent fault and maintenance events.

13.1.1 EVENT TYPES

There are several different types of event:

- Opto-input events (Change of state of opto-input)
- Contact events (Change of state of output relay contact)
- Alarm events
- Fault record events
- Standard events
- Security events

Standard events are further sub-categorised internally to include different pieces of information. These are:

- Protection events (starts and trips)
- Maintenance record events
- Platform events

Note:
The first event in the list (event 0) is the most recent event to have occurred.

13.1.1.1 OPTO-INPUT EVENTS

If one or more of the opto-inputs has changed state since the last time the protection algorithm ran (which runs at several times per cycle), a new event is created, which logs the logic states of all opto-inputs. You can tell which opto-input has changed state by comparing the new event with the previous one.

The description of this event type, as shown in the ***Event Text*** cell is always `Logic Inputs #` where # is the batch number of the opto-inputs. This is '1', for the first batch of opto-inputs and '2' for the second batch of opto-inputs (if applicable).

The event value shown in the ***Event Value*** cell for this type of event is a binary string. This shows the logical states of the opto-inputs, where the Least Significant Bit (LSB), on the right corresponds to the first opto-input `Input L1`.

The same information is also shown in the ***Opto I/P Status*** cell in the *SYSTEM DATA* column. This information is updated continuously, whereas the information in the event log is a snapshot at the time when the event was created.

13.1.1.2 CONTACT EVENTS

If one or more of the output relays (also known as output contacts) has changed state since the last time the protection algorithm ran (which runs at several times per cycle), a new event is created, which logs the logic states of all output relays. You can tell which output relay has changed state by comparing the new event with the previous one.

The description of this event type, as shown in the ***Event Text*** cell is always `Output Contacts #` where # is the batch number of the output relay contacts. This is '1', for the first batch of output contacts and '2' for the second batch of output contacts (if applicable).

The event value shown in the ***Event Value*** cell for this type of event is a binary string. This shows the logical states of the output relays, where the LSB (on the right) corresponds to the first output contact `Output R1`.

The same information is also shown in the ***Relay O/P Status*** cell in the *SYSTEM DATA* column. This information is updated continuously, whereas the information in the event log is a snapshot at the time when the event was created.

13.1.1.3 ALARM EVENTS

The IED monitors itself on power up and continually thereafter. If it notices any problems, it will register an alarm event.

The description of this event type, as shown in the ***Event Text*** cell is cell dependent on the type of alarm and will be one of those shown in the following tables, followed by `OFF` or `ON`.

The event value shown in the ***Event Value*** cell for this type of event is a 32 bit binary string. There are one or more banks 32 bit registers, depending on the device model. These contain all the alarm types and their logic states (`ON` or `OFF`).

The same information is also shown in the ***Alarm Status (n)*** cells in the *SYSTEM DATA* column. This information is updated continuously, whereas the information in the event log is a snapshot at the time when the event was created.

13.1.1.4 FAULT RECORD EVENTS

An event record is created for every fault the IED detects. This is also known as a fault record.

The event type description shown in the ***Event Text*** cell for this type of event is always `Fault Recorded`.

The IED contains a separate register containing the latest fault records. This provides a convenient way of viewing the latest fault records and saves searching through the event log. You access these fault records using the ***Select Fault*** setting, where fault number 0 is the latest fault.

A fault record is triggered by the ***Fault REC TRIG*** signal DDB, which is assigned in the PSL. The fault recorder records the values of all parameters associated with the fault for the duration of the fault. These parameters are stored in separate Courier cells, which become visible depending on the type of fault.

The fault recorder stops recording only when:

The Start signal is reset AND the undercurrent is ON OR the Trip signal is reset, as shown below:

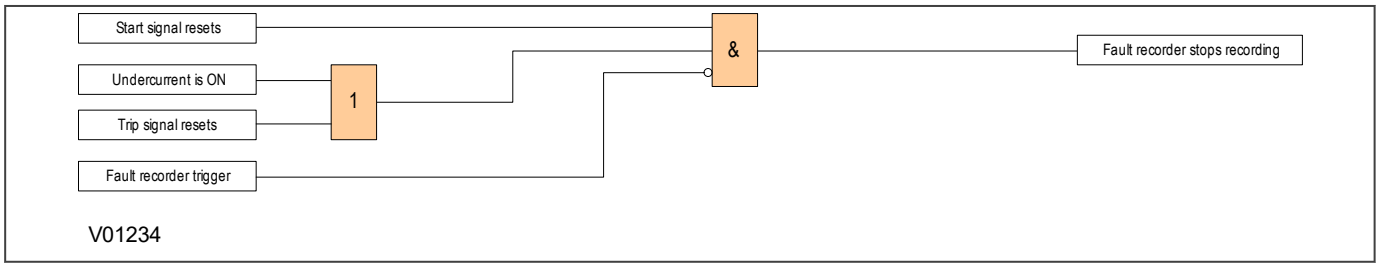


Figure 178: Fault recorder stop conditions

The event is logged as soon as the fault recorder stops. The time stamp assigned to the fault corresponds to the start of the fault. The timestamp assigned to the fault record event corresponds to the time when the fault recorder stops.

> *Note:*
> *We recommend that you do not set the triggering contact to latching. This is because if you use a latching contact, the fault record would not be generated until the contact has been fully reset.*

13.1.1.5 MAINTENANCE EVENTS

Internal failures detected by the self-test procedures are logged as maintenance records. Maintenance records are special types of standard events.

The event type description shown in the ***Event Text*** cell for this type of event is always `Maint Recorded`.

The ***Event Value*** cell also provides a unique binary code.

The IED contains a separate register containing the latest maintenance records. This provides a convenient way of viewing the latest maintenance records and saves searching through the event log. You access these fault records using the ***Select Maint*** setting.

The maintenance record has a number of extra menu cells relating to the maintenance event. These parameters are ***Maint Text***, ***Maint Type*** and ***Maint Data***. They contain details about the maintenance event selected with the ***Select Maint*** cell.

13.1.1.6 PROTECTION EVENTS

The IED logs protection starts and trips as individual events. Protection events are special types of standard events.

The event type description shown in the ***Event Text*** cell for this type of event is dependent on the protection event that occurred. Each time a protection event occurs, a DDB signal changes state. It is the name of this DDB signal followed by 'ON' or 'OFF' that appears in the ***Event Text*** cell.

The ***Event Value*** cell for this type of event is a 32 bit binary string representing the state of the relevant DDB signals. These binary strings can also be viewed in the *COMMISSION TESTS* column in the relevant DDB batch cells.

Not all DDB signals can generate an event. Those that can are listed in the *RECORD CONTROL* column. In this column, you can set which DDBs generate events.

13.1.1.7 SECURITY EVENTS

An event record is generated each time a setting that requires an access level is executed.

The event type description shown in the ***Event Text*** cell displays the type of change.

13.1.1.8 PLATFORM EVENTS

Platform events are special types of standard events.

The event type description shown in the ***Event Text*** cell displays the type of change.

13.2 DISTURBANCE RECORDER

The disturbance recorder feature allows you to record selected current and voltage inputs to the protection elements, together with selected digital signals. The digital signals may be inputs, outputs, or internal DDB signals. The disturbance records can be extracted using the disturbance record viewer in the settings application software. The disturbance record file can also be stored in the COMTRADE format. This allows the use of other packages to view the recorded data.

The integral disturbance recorder has an area of memory specifically set aside for storing disturbance records. The number of records that can be stored is dependent on the recording duration. The minimum duration is 0.1 s and the maximum duration is 10.5 s.

When the available memory is exhausted, the oldest records are overwritten by the newest ones.

Each disturbance record consists of a number of analogue data channels and digital data channels. The relevant CT and VT ratios for the analogue channels are also extracted to enable scaling to primary quantities.

The fault recording times are set by a combination of the ***Duration*** and ***Trigger Position*** cells. The ***Duration*** cell sets the overall recording time and the ***Trigger Position*** cell sets the trigger point as a percentage of the duration. For example, the default settings show that the overall recording time is set to 1.5 s with the trigger point being at 33.3% of this, giving 0.5 s pre-fault and 1 s post fault recording times.

With the ***Trigger Mode*** set to *Single*, if further triggers occurs whilst a recording is taking place, the recorder will ignore the trigger. However, with the ***Trigger Mode*** set to *Extended*, the post trigger timer will be reset to zero, extending the recording time.

You can select any of the IED's analogue inputs as analogue channels to be recorded. You can also map any of the opto-inputs output contacts to the digital channels. In addition, you may also map a number of DDB signals such as Starts and LEDs to digital channels.

You may choose any of the digital channels to trigger the disturbance recorder on either a low to high or a high to low transition, via the ***Input Trigger*** cell. The default settings are such that any dedicated trip output contacts will trigger the recorder.

It is not possible to view the disturbance records locally via the front panel LCD. You must extract these using suitable setting application software such as MiCOM S1 Agile.

13.3 MEASUREMENTS

13.3.1 MEASURED QUANTITIES

The device measures directly and calculates a number of system quantities, which are updated every second. You can view these values in the relevant MEASUREMENT columns or with the Measurement Viewer in the settings application software. Depending on the model, the device may measure and display some or more of the following quantities:

- Measured and calculated analogue current and voltage values
- Power and energy quantities
- Peak, fixed and rolling demand values
- Frequency measurements
- Thermal measurements
- Teleprotection channel measurements

13.3.2 MEASUREMENT SETUP

You can define the way measurements are set up and displayed using the *MEASURE'T SETUP* column and the measurements are shown in the relevant MEASUREMENTS tables.

13.3.3 FAULT LOCATOR

Some models provide fault location functionality. It is possible to identify the fault location by measuring the fault voltage and current magnitude and phases and presenting this information to a Fault Locator function. The fault locator is triggered whenever a fault record is generated, and the subsequent fault location data is included as part of the fault record. This information is also displayed in the ***Fault Location*** cell in the *VIEW RECORDS* column. This cell will display the fault location in metres, miles ohms or percentage, depending on the chosen units in the ***Fault Location*** cell of the *MEASURE'T SETUP* column.

The Fault Locator uses pre-fault and post-fault analogue input signals to calculate the fault location. The result is included it in the fault record. The pre-fault and post-fault voltages are also presented in the fault record.

When applied to parallel circuits, mutual flux coupling can alter the impedance seen by the fault locator. The coupling contains positive, negative and zero sequence components. In practise the positive and negative sequence coupling is insignificant. The effect on the fault locator of the zero sequence mutual coupling can be eliminated using the mutual compensation feature provided.

13.3.3.1 FAULT LOCATOR OPERATION

The fault locator uses an algorithmic method to provide a distance to fault location feature with metering capabilities. The data input to the algorithm is filtered using established digital signal processing techniques.

The data processed by the algorithm is first acquired by performing analogue to digital conversion on signals provided by the device's internal analogue bus and then performing the necessary calculations.

The metering values are continuously calculated, regularly updated and passed to the relays processor when requested.

Acquired data is written to a buffer until a fault condition is notified by the processor. This input buffer data is held pending the fault calculation and input data is redirected to an alternative buffer.

The fault calculation is initiated by a signal from the relay main processor. When the fault calculation is complete the output information is stored in non-volatile memory and made available to the processor for display on the relay front panel.

Where parallel circuits are hung on opposite sides of a route of towers, mutual flux coupling alters the impedance seen by the fault locator. In practice the positive and negative sequence coupling is insignificant and the effect on

the fault locator of the zero sequence mutual coupling can be eliminated by using the mutual compensation feature provided.

It should be noted that in devices fitted with both a ***DEF*** element and a fault locator, the mutual compensation current input terminals are shared with the ***DEF*** zero sequence current polarising input. And so, ***DEF*** zero sequence current polarising cannot be used at the same time as fault locator mutual compensation.

The fault locator is optional on the underground cable version of the device, where it is recommended that it is used for metering purposes only (see the Metering section, below) as fault location accuracy cannot be relied upon for this application.

13.3.3.2 EARTH FAULT BASIC THEORY

A two-machine equivalent circuit of a faulted power system is shown in the figure below:

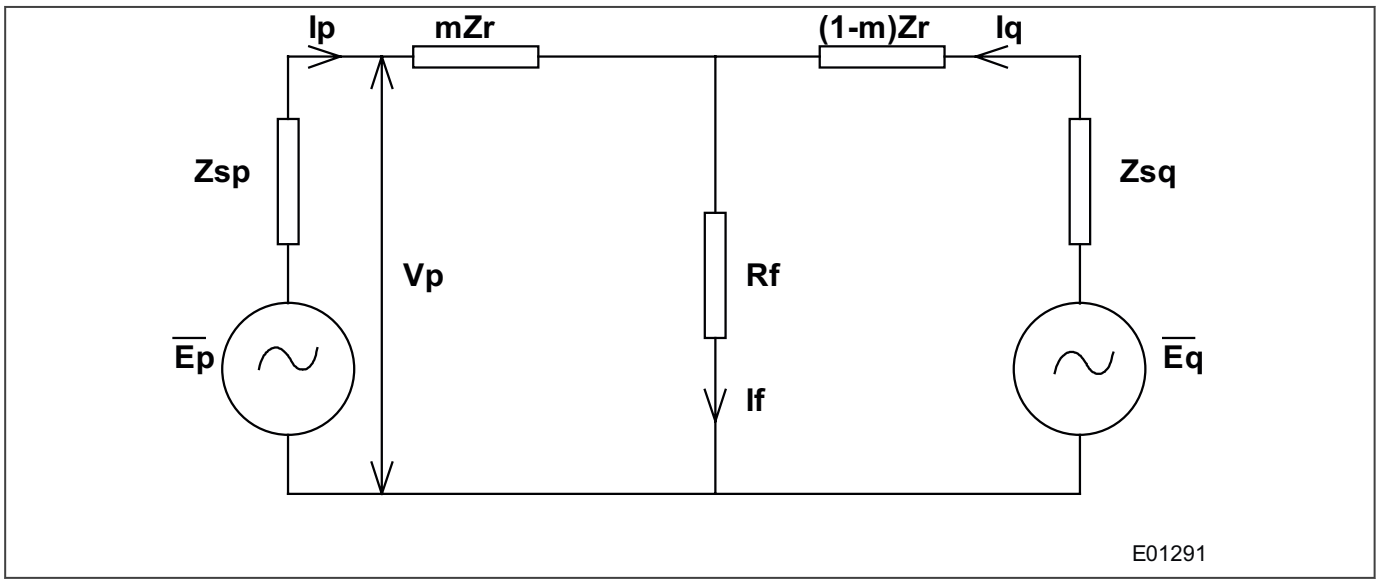


Figure 179: Two machine equivalent circuit

From the above figure:

$$Vp = mIpZr + IfRf$$

This equation shows that the calculation of m, the distance to fault, based on measurements of Vp and Ip at the local relay terminals is distorted by the IfRf term. This term is related to the current infeed from the remote terminal and cannot be readily measured. However its effect can be minimised as follows:

The real and imaginary components of these vectors (with respect to an arbitrary vector reference) vary with time as:

$$|Vp|[\cos(\omega t + s) + j\sin(\omega t + s)] = m|Zr|\,|Ip|\,[\cos(\omega t + e) + j\sin(\omega tt + e)] + Rf\,|If|\,[\cos(\omega t + d) + j\sin(\omega t + d)].$$

where:

d is the angle of the fault current.

s is the angle of Vp.

e is the angle of IpZr.

By evaluating equation *Vp = mIpZr + IfRf* at the instant in time when the fault current passes through zero and considering only the real components, then the Rf |If| term becomes zero i.e. t = ((π/2)-d)/ ω and the equation simplifies to:

$$|Vp|\cos(((\pi/2)-d) + s) = m\,|Zr|\,|Ip|\,\cos(((\pi/2)-d) + e)$$

Therefore, the fault location m can be calculated if the angle of the fault current d is known.

Estimating d the phase of the fault current If:

The fault vector If is obtained from an algorithm which uses superimposed currents, that is, the change of currents following the instant of fault.

Superimposed currents are indicated with an apostrophe (').

The sequence diagram for superimposed currents for an A-G fault is shown in the figure below:

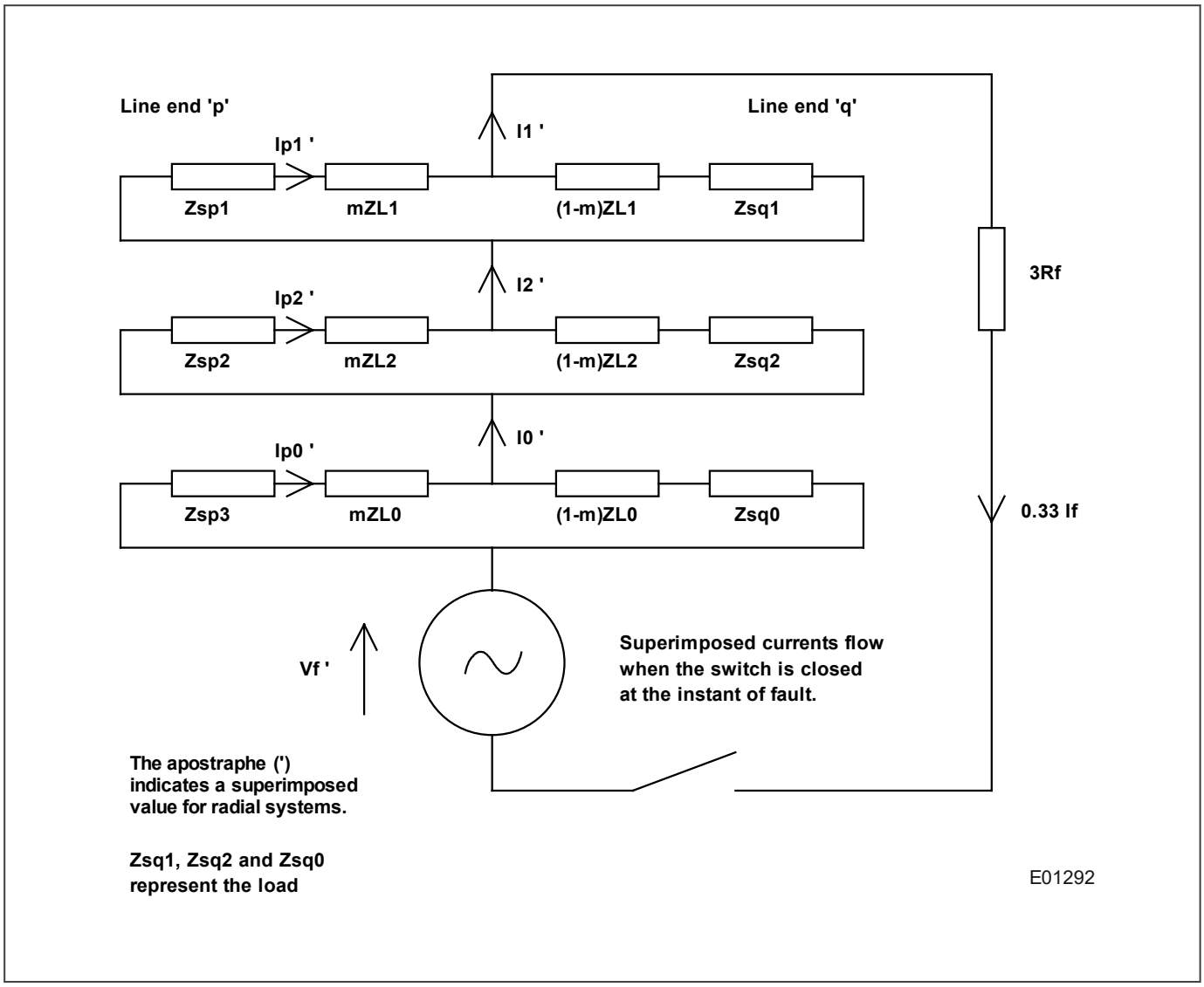


Figure 180: Superimposed symmetrical component sequence for A - N fault

For an A phase to earth fault:

$$0.33If = I1' = I2' = I0'$$

from which:

$$0.66If = I1' + I2'$$

$$= Ip1'D1 + Ip2'D2$$

where:

$$D1 = I1' / Ip1' \text{ and } D2 = I2' / Ip2'$$

and:

D2 approximately = D1 (assuming that the power system source and line positive and negative sequence impedances are approximately equal)

therefore:

$$0.66If = D1(Ip1' + Ip2')$$

also:

$$Ip' = Ip1' + Ip2' + Ip0'$$

therefore:

$$Ip1' + Ip2' = Ip' - Ip0'$$

from the equations above:

$$0.66If = D1\ (Ip' - Ip0')$$

Hence:

$$\text{angle If} = \text{angle D1} + \text{angle}\ (Ip' - Ip0')$$

where:

D1 = A SCALAR factor - assuming that the power system is homogeneous
= (Zsp1 + Zl1 + Zsq1) / ((1-m)Zl1 + Zsq1)

The angle of D1 depends upon the fault position but for the purposes of this algorithm this angle is assumed to be zero.

Thus:

$$\text{angle If} = d = \text{angle}\ (Ip' - Ip0')$$

The equation above, shows that the phase angle of the fault current d can be estimated from the superimposed phase and neutral currents measured at the relay terminals.

therefore for an earth fault:

$$|If|(\cos(d) + j\sin(d))$$
$$= kD1(Ip'-Ip0')$$
$$= kD1[(Ia(fault) - Ia(prefault))$$
$$- 0.33(In(fault) - In(prefault))]$$

where:

k is a scalar factor and d is the required phase angle of If at the instant of time that the faulted vectors are calculated.

similarly, for a phase to phase fault:

$$|If|\ (\cos(d) + j\sin(d)) = kD1[(Ia(fault) - Ia(prefault))- (Ib(fault) - Ib(prefault))]$$

Thus, using the calculated pre-fault and faulted vectors the fault locator is able to calculate the angle of the fault current vector d at the instant of time that the faulted vectors are calculated.

13.3.3.3 DATA ACQUISITION AND BUFFER PROCESSING

The fault locator stores the sampled data within a 12 cycle cyclic buffer at a resolution of 48 samples per cycle. When the fault recorder is triggered the data in the buffer is frozen such that the buffer contains 6 cycles of pre-trigger data and 6 cycles of post-trigger data. Fault calculation commences shortly after this trigger point.

The trigger for the fault recorder is user selectable via the programmable scheme logic.

The fault locator can store data for up to four faults. This ensures that fault location can be calculated for all shots on a typical multiple reclose sequence.

13.3.3.4 FAULTED PHASE SELECTION

Phase selection is derived from the superimposed current phase selector.

Phase selection and fault location calculations can only be made if the current change exceeds 5% In.

13.3.3.5 FAULTED PHASE CALCULATION

The fault location calculation works by:

1. First obtaining the vectors
2. Selecting the faulted phase(s)
3. Estimating the phase of the fault current If for the faulted phase(s)
4. Solving the below equation for the fault location m at the instant of time where f = 0

$$Vp = mIpZr + IfRf$$

13.3.3.6 DISTANCE TO FAULT CALCULATION

Replica impedance Zr

The fault location calculation needs vectors derived from the line voltage (Vp) and from the relay's "replica impedance" voltage (IpZr) under fault conditions. The replica impedance is derived from the relay settings and is effectively set to the same value as the total line impedance. i.e.

$$Zr = Zline / \theta\ line + Zresidual / / \theta\ residual$$

This "replica impedance" is modified using the mutual compensation factor when the mutual compensation feature is used. i.e.

$$Zr = Zline / \theta\ line + Zresidual / / \theta\ residual + Zmutual / / \theta\ mutual$$

Where :

$$Zresidual = kZN*Zline$$
$$Zmutual = kZm*Zline$$

The fault location calculation

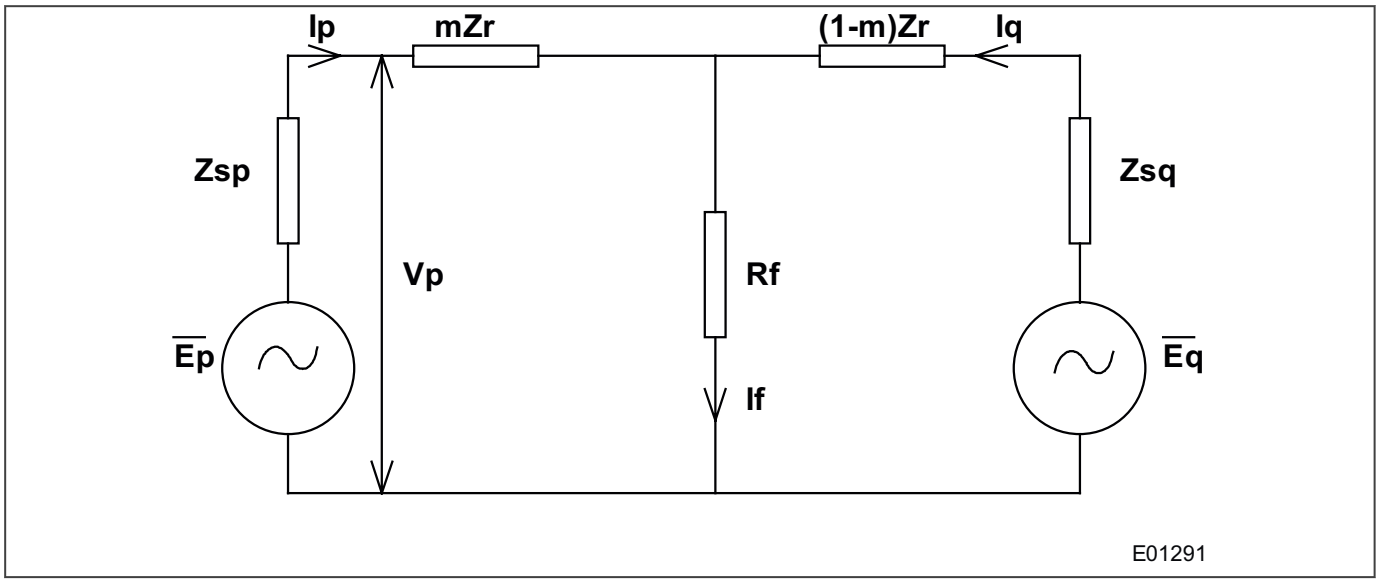


Figure 181: Two machine equivalent circuit

Fault location equation:

$$Vp = mIpZr + IfRf$$

Referring to the figure and equation, above.

The fault location calculation works by:

1. First obtaining the vectors to satisfy the above equation for the fault type specified by the phase selector.
2. Then estimating the phase of the fault current If.
3. Finally solving the above equation for the fault location m at the instant of time where If = 0.

Obtaining the vectors

Different sets of vectors are chosen depending on the type of fault identified by the phase selection algorithm. The calculation using fault location equation, above is applied for either a phase to earth fault or a phase to phase fault.

Thus, for a A phase to earth fault:

$$IpZr = Ia\ (Zline / \theta\ line) + In\ (Zresidual / / \theta\ residual)$$

and

$$Vp = VA$$

And for a A phase to B phase fault:

$$IpZr = Ia\ (\ Zline / \theta\ line\ ) - Ib\ (Zline / \theta\ line)$$

and

$$Vp = VA - VB$$

The calculation for an earth fault (A phase to earth fault equation, above) is modified when mutual compensation is used :

$$IpZr = Ia\ (Zline / \theta\ line) + In(Zresidual / / \theta\ residual\ ) + Im(Zmutual / / \theta\ mutual)$$

Solving the equation for the fault location

As the sine wave of If passes through zero, the instantaneous values of the sine waves Vp and □p can be used to solve the below equation for the fault location m. (The term IfRf being zero).

$$Vp = mIpZr + IfRf$$

This is determined by shifting the calculated vectors of Vp and IpZr by the angle (90° - angle of fault current) and then dividing the real component of Vp by the real component of IpZr. (See figure, below).

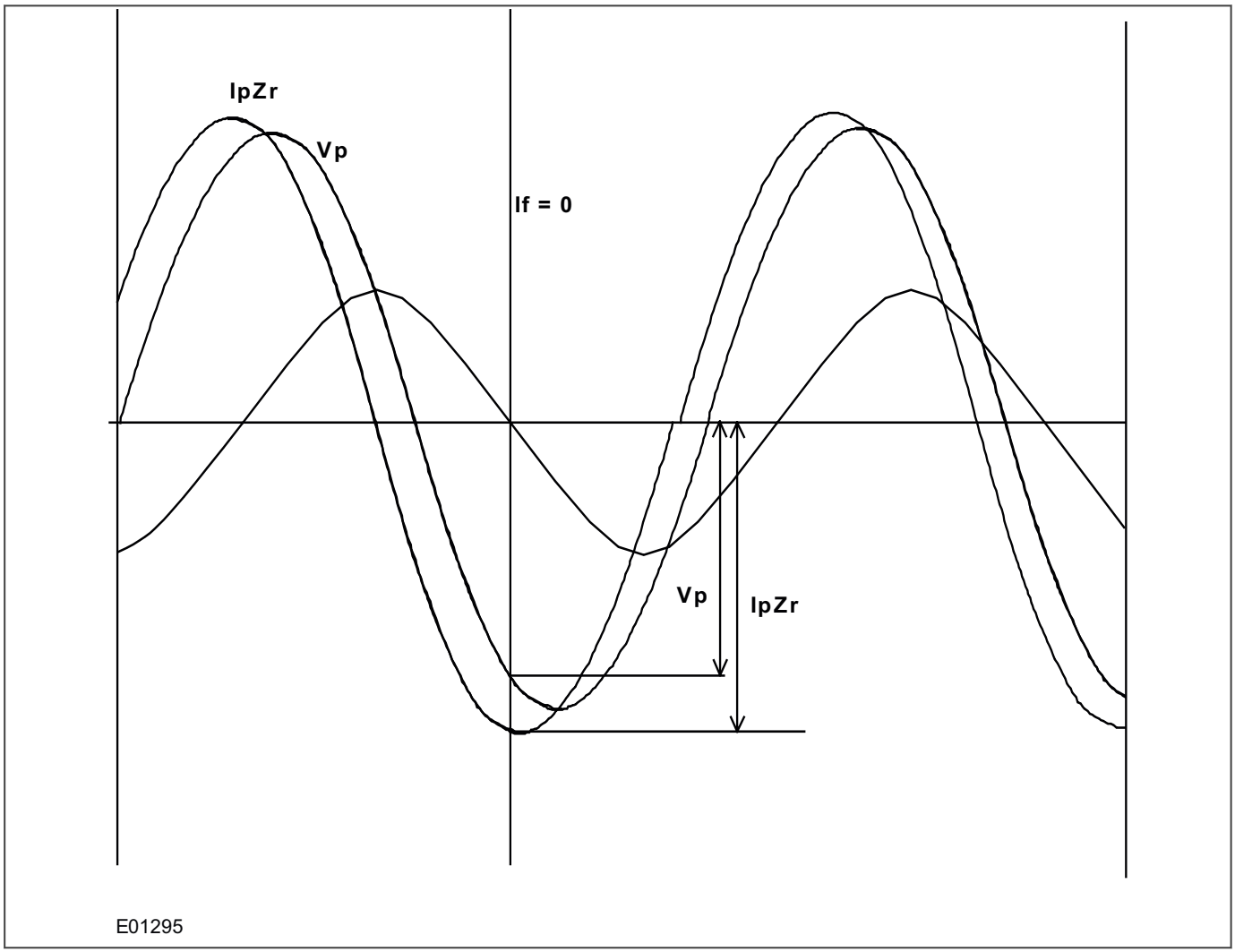


Figure 182: Fault locator selection of fault current zero

i.e.:

Phase advanced vector Vp

$$= |Vp| [\cos(s) + j\sin(s)] * [\sin(d) + j\cos(d)]$$

$$= |Vp| [-\sin(s-d) + j\cos(s-d)]$$

Phase advanced vector IpZr

$$= ||pZr| [\cos (e) + j\sin (e)] * [\sin (d) + j\cos (d)]$$

$$= ||pZr| [-\sin(e-d) + j\cos(e-d)]$$

Therefore, from equation 1:

$$m = Vp \div (Ip * Zr) \text{ at } If = 0$$

$$= Vp \sin(s-d)/(IpZr * \sin(e-d))$$

Where:

d = Angle of fault current If

s = Angle of Vp

e = Angle of IpZr

Thus, the relay evaluates m which is the fault location as a percentage of the fault locator line impedance setting and then calculates the output fault location by multiplying this by the line length setting. When calculated the fault location can be found in the fault record under the *VIEW RECORDS* column in the ***Fault Location*** cells. Distance to fault is available in kilometers, miles, impedance or percentage of line length.

13.3.3.7 MUTUAL COMPENSATION

Analysis of a ground fault on one circuit of a parallel over-head line shows that a fault locator positioned at one end of the faulty line will tend to over-reach while that at the other end will tend to under-reach. In cases of long lines with high mutual inductance, mutual zero sequence compensation can be used to improve the fault locator accuracy. The compensation is achieved by taking an input to the relay from the residual circuit of the current transformers in the parallel line.

Mutual compensation is available as needed by some protection functions as well as by the fault locator.

13.3.3.8 METERING

The metering calculations are continuously performed using the same fourier technique used by the fault locator. The results of these calculations are continuously updated and can be viewed using the relay user interface.

13.3.4 OPTO-INPUT TIME STAMPING

Each opto-input sample is time stamped within a tolerance of +/- 1 ms with respect to the Real Time Clock. These time stamps are used for the opto event logs and for the disturbance recording. The device needs to be synchronised accurately to an external clock source such as an IRIG-B signal or a master clock signal provided in the relevant data protocol.

For both the filtered and unfiltered opto-inputs, the time stamp of an opto-input change event is the sampling time at which the change of state occurred. If multiple opto-inputs change state at the same sampling interval, these state changes are reported as a single event.

13.4 CB CONDITION MONITORING

The device records various statistics related to each circuit breaker trip operation, allowing an accurate assessment of the circuit breaker condition to be determined. These statistics are available in the *CB CONDITION* column. The menu cells are register values only and cannot be set directly. They may be reset, however, during maintenance. The statistics monitored are:

- Total Current Broken: A register stores the total amount of current that the CB has broken is stored in an accumulator, giving at any time a measure of the total amount of current that the CB has broken since the value was last reset.
- Number of CB operations: A counter registers the number of CB trips that have been performed for each phase, giving at any time the total number of trips that the CB has performed since the value was last reset.
- CB Operate Time: A register stores the total amount of time the CB has transitioned from closed to open is stored in an accumulator, giving at any time a measure of the total time that the CB has spent tripping since the values was last reset.
- Excessive Fault Frequency: A counter registers the number of CB trips that have been performed for all phases, giving at any time the total number of trips performed since the value was last reset.

These statistics are available in the *CB CONDITION* column. The menu cells are register values only and cannot be set directly. They may be reset, however, during maintenance.

> *Note:*
> *When in Commissioning test mode the CB condition monitoring registers are not updated.*

Circuit breaker lockout, can be caused by the following circuit breaker condition monitoring functions:

- Maintenance lockout
- Excessive fault frequency lockout
- Broken current lockout

If the circuit breaker is locked out, the logic generates a lockout alarm

13.4.1 BROKEN CURRENT ACCUMULATOR

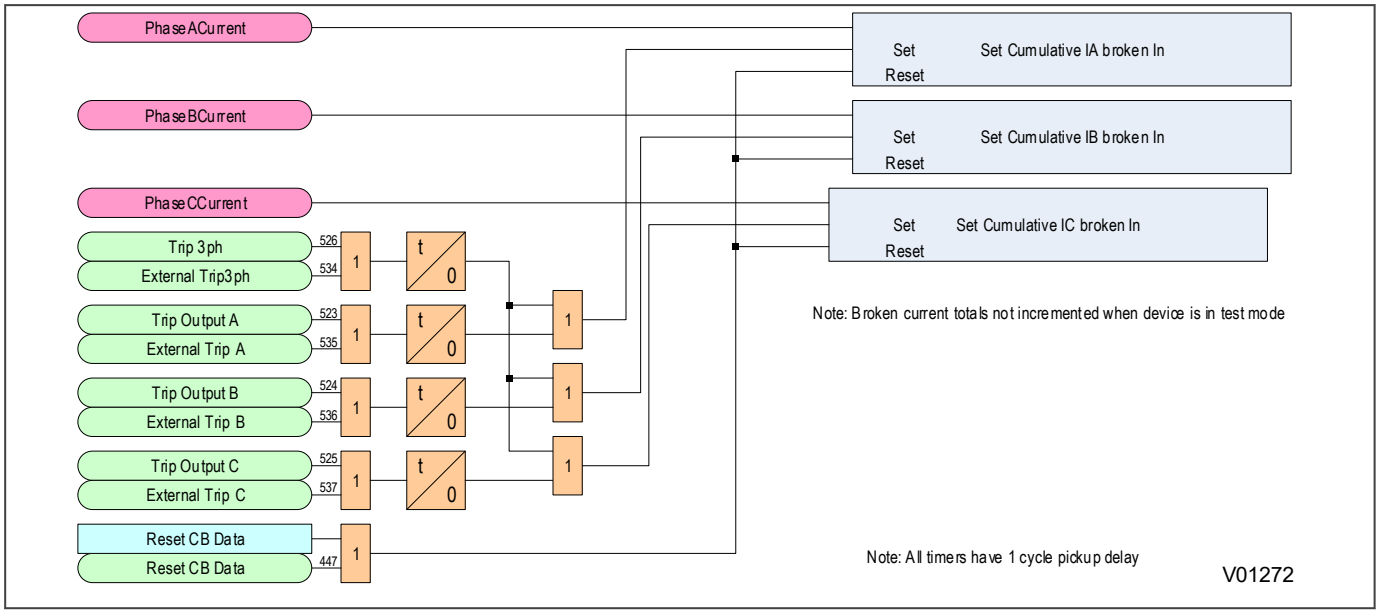


Figure 183: Broken current accumulator logic

13.4.2 CB TRIP COUNTER

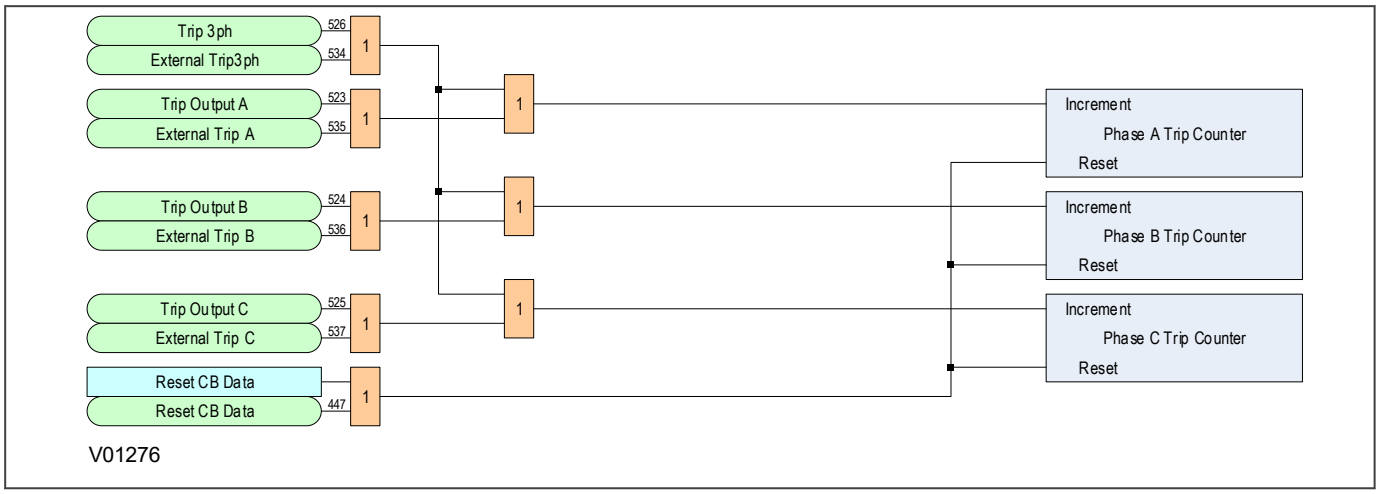


Figure 184: CB trip counter logic

13.4.3 CB OPERATING TIME ACCUMULATOR

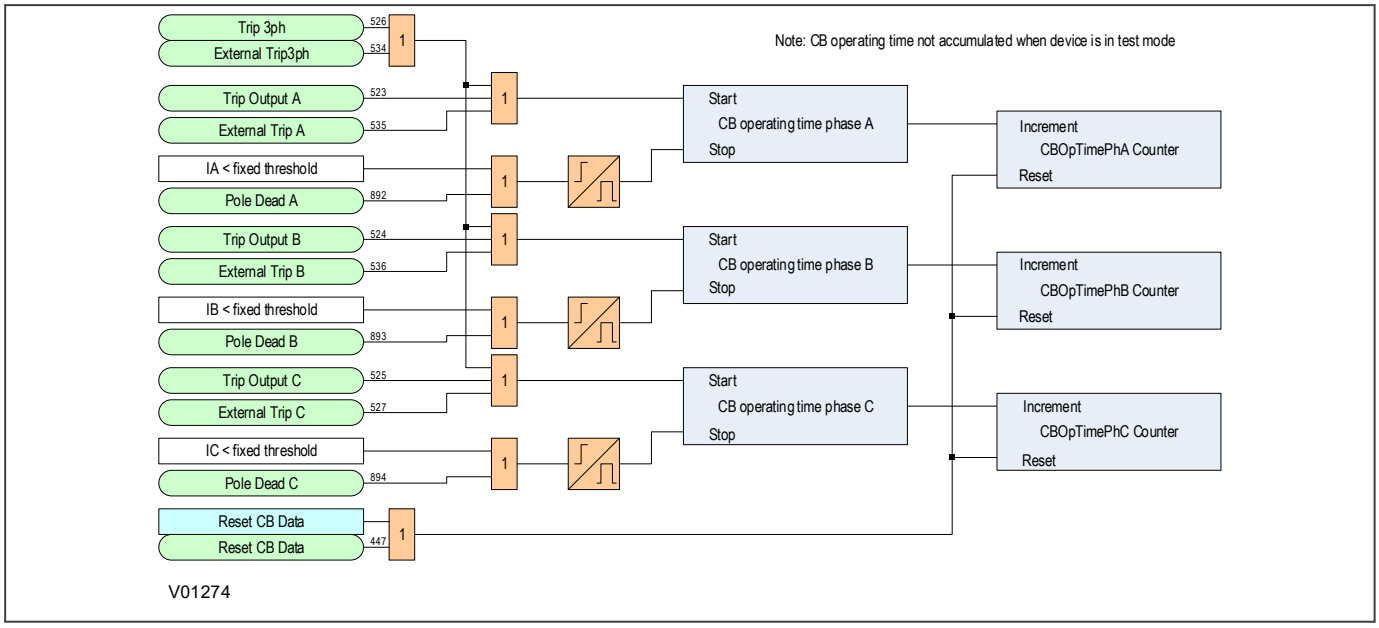


Figure 185: Operating time accumulator

13.4.4 EXCESSIVE FAULT FREQUENCY COUNTER

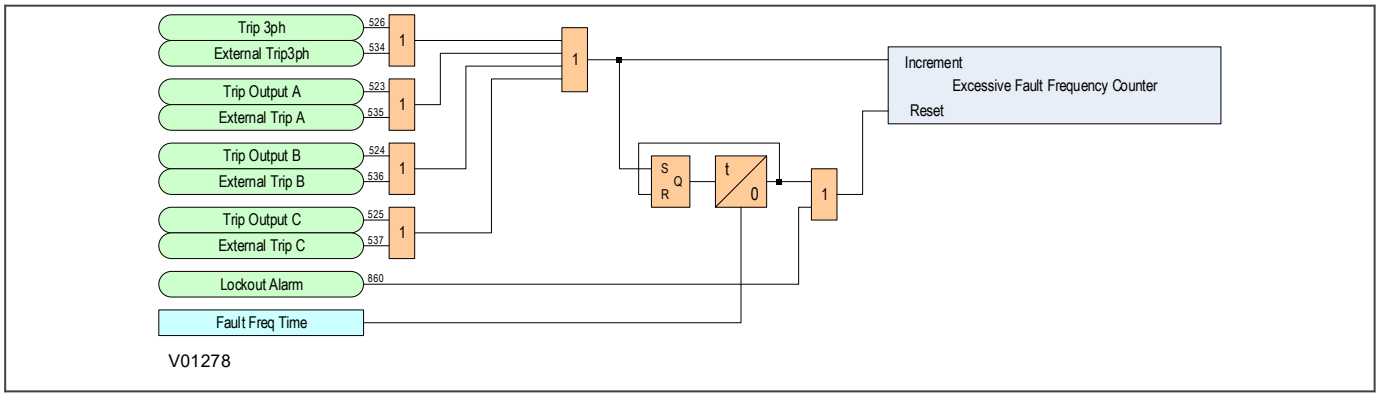


Figure 186: Excessive fault frequency logic

13.4.5 RESET LOCKOUT ALARM

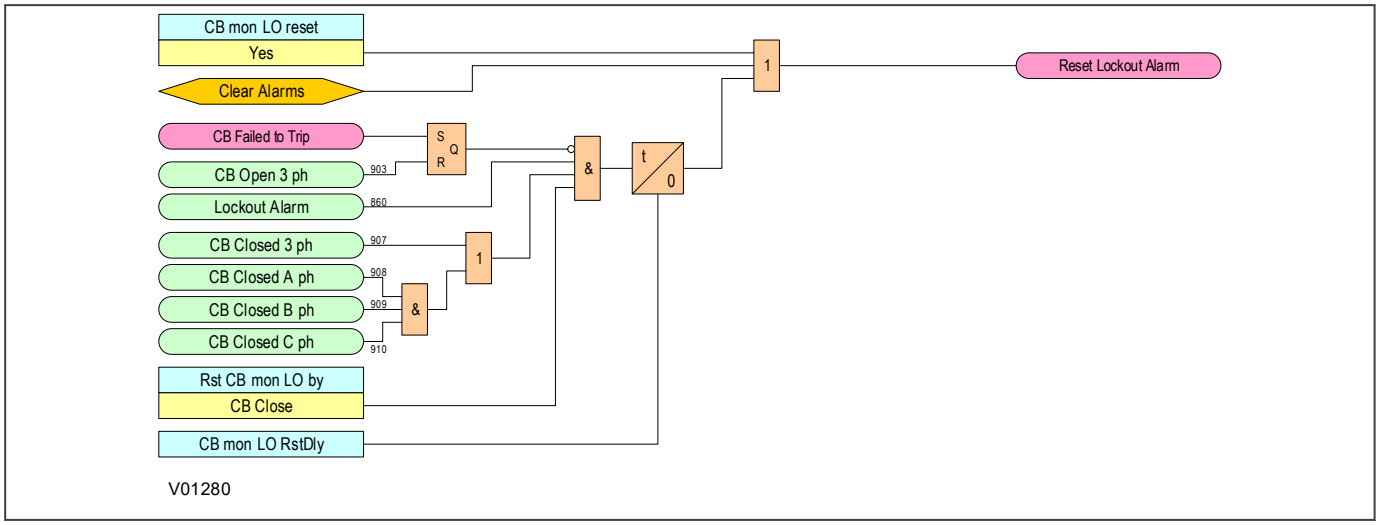


Figure 187: Reset lockout alarm logic

13.4.6 CB CONDITION MONITORING LOGIC

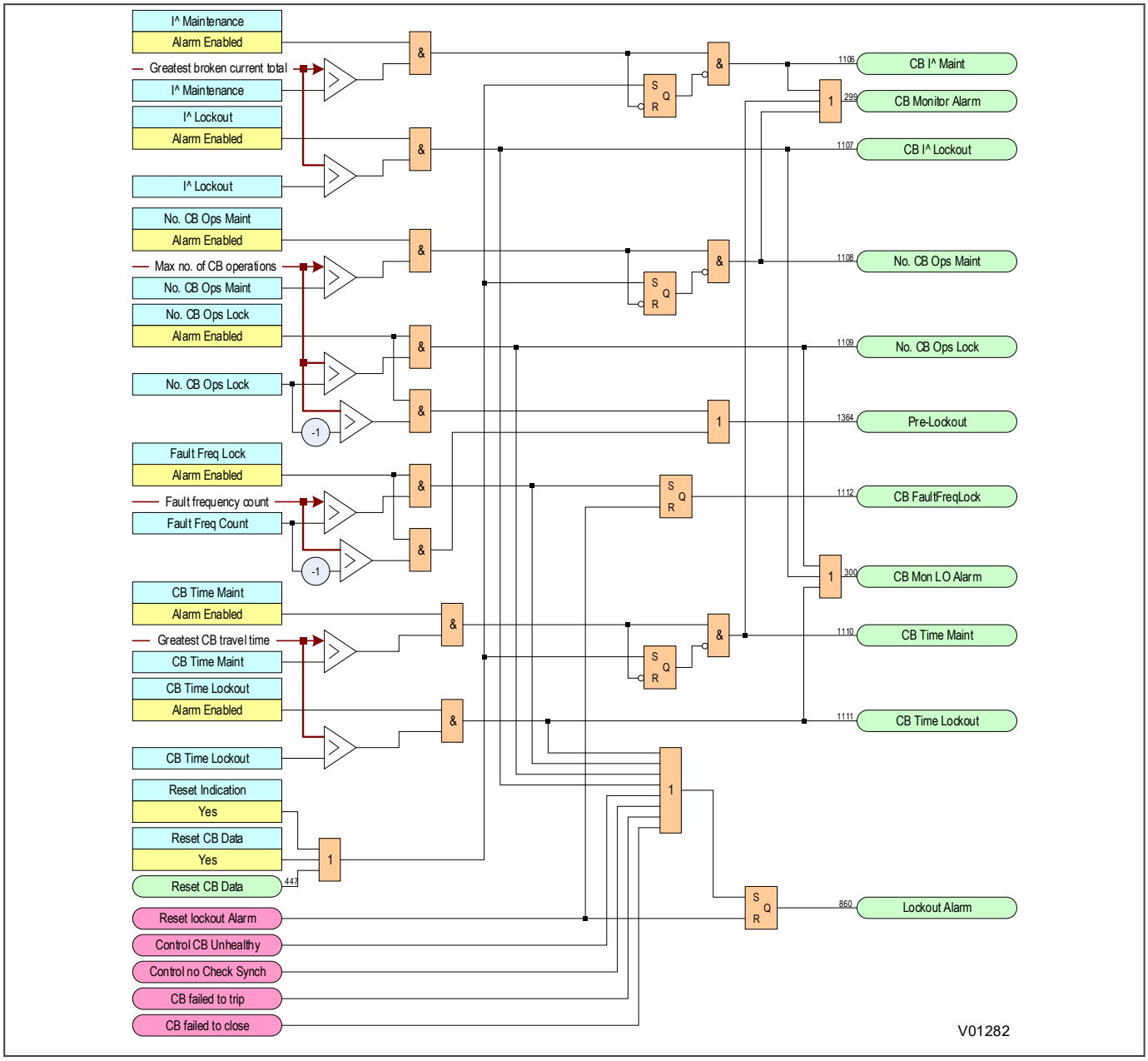


Figure 188: CB condition monitoring logic

13.4.7 CB CONDITION MONITORING LOGIC

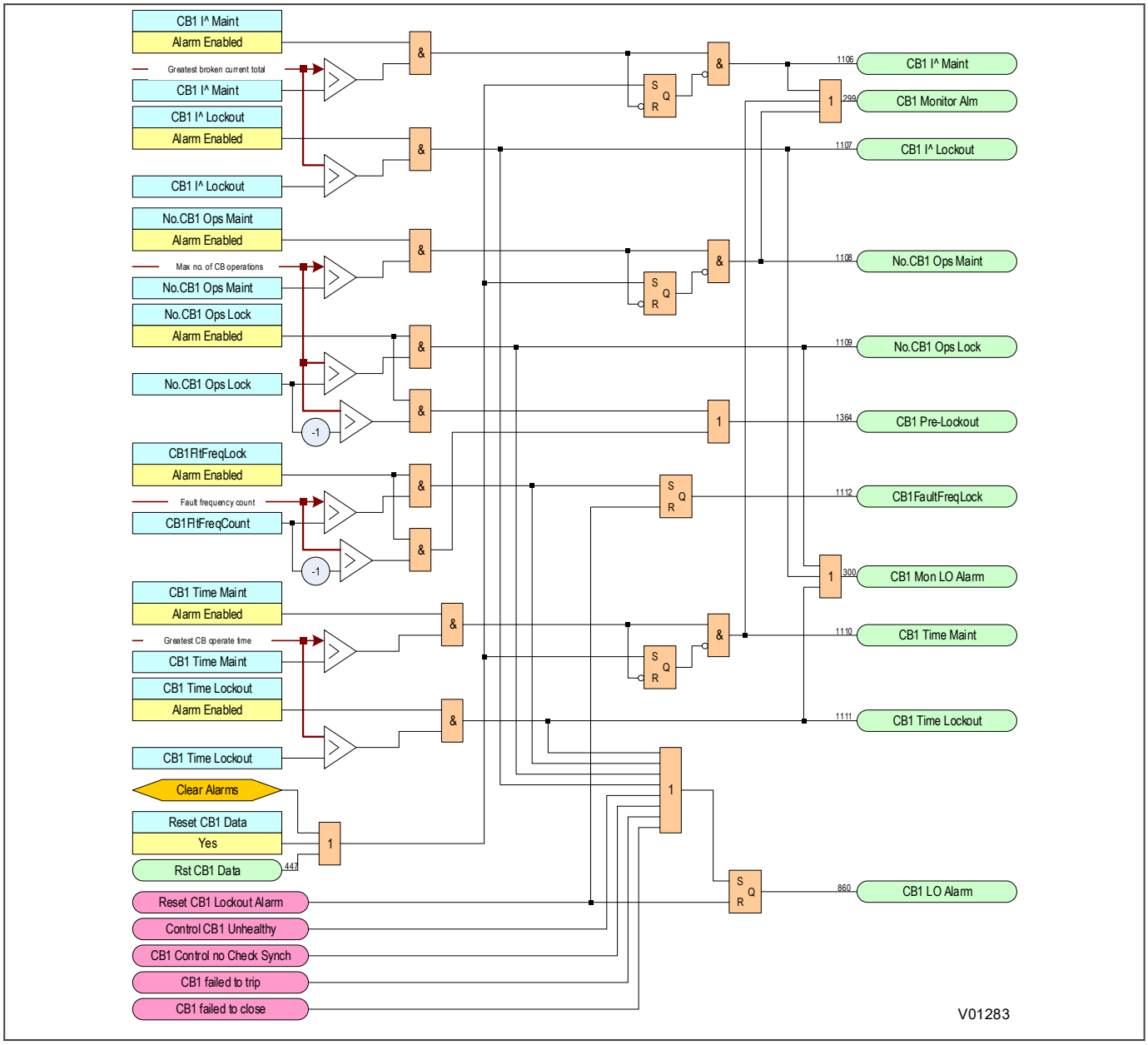


Figure 189: CB1 condition monitoring logic

13.4.8 RESET CIRCUIT BREAKER LOCKOUT

Lockout conditions caused by the circuit breaker condition monitoring functions can be reset according to the condition of the ***Rst CB mon LO*** by setting found in the *CB CONTROL* column. There are two options; `CB Close` and `User interface`.

If set to `CB Close`, a timer setting, ***CB mon LO RstDly***, becomes visible. When the circuit breaker closes, the ***CB mon LO RstDly*** time starts. The lockout is reset when the timer expires.

If set to `User Interface` then a command, ***CB mon LO reset***, becomes visible. This command can be used to reset the lockout from a user interface.

An Autoreclose lockout generates an Autoreclose lockout alarm. Autoreclose lockout conditions can be reset by various commands and setting options found under the *CB CONTROL* column.

If ***Res LO by CB IS*** is set to *Enabled*, a lockout is reset if the circuit breaker is successfully closed manually. For this, the circuit breaker must remain closed long enough so that it enters the “In Service” state.

If ***Res LO by UI*** is set to *Enabled*, the circuit breaker lockout can be reset from a user interface using the reset circuit breaker lockout command in the *CB CONTROL* column.

If ***Res LO by NoAR*** is set to *Enabled*, the circuit breaker lockout can be reset by temporarily generating an ***AR disabled*** signal.

If ***Res LO by TDelay*** is set to *Enabled*, the circuit breaker lockout is automatically reset after a time delay set in the ***LO Reset Time*** setting.

If ***Res LO by ExtDDB*** is *Enabled*, the circuit breaker lockout can be reset by activation of an external input mapped in the PSL to the relevant reset lockout DDB signal.

13.4.8.1 RESET CB LOCKOUT LOGIC DIAGRAM

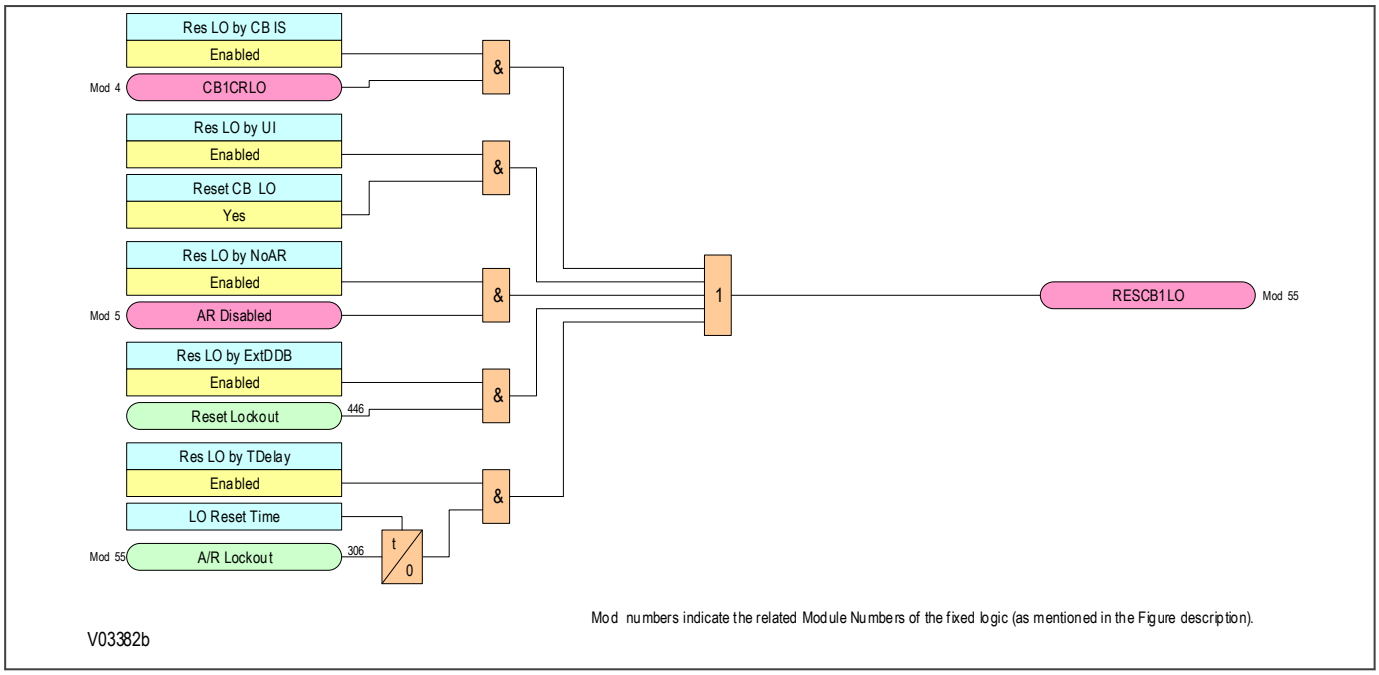


Figure 190: Reset circuit breaker lockout logic (Module 57)

13.4.9 APPLICATION NOTES

13.4.9.1 SETTING THE THRESHOLDS FOR THE TOTAL BROKEN CURRENT

Where power lines use oil circuit breakers (OCBs), changing of the oil accounts for a significant proportion of the switchgear maintenance costs. Often, oil changes are performed after a fixed number of CB fault operations. However, this may result in premature maintenance where fault currents tend to be low, because oil degradation may be slower than would normally be expected. The Total Current Accumulator (I^ counter) cumulatively stores the total value of the current broken by the circuit breaker providing a more accurate assessment of the circuit breaker condition.

The dielectric withstand of the oil generally decreases as a function of I^2t, where ‘I’ is the broken fault current and ‘t’ is the arcing time within the interrupter tank. The arcing time cannot be determined accurately, but is generally dependent on the type of circuit breaker being used. Instead, you set a factor (***Broken I^***) with a value between 1 and 2, depending on the circuit breaker.

Most circuit breakers would have this value set to '2', but for some types of circuit breaker, especially those operating on higher voltage systems, a value of 2 may be too high. In such applications ***Broken I^*** may be set lower, typically 1.4 or 1.5.

The setting range for ***Broken I^*** is variable between 1.0 and 2.0 in 0.1 steps.

Note:
Any maintenance program must be fully compliant with the switchgear manufacturer's instructions.

13.4.9.2 SETTING THE THRESHOLDS FOR THE NUMBER OF OPERATIONS

Every circuit breaker operation results in some degree of wear for its components. Therefore routine maintenance, such as oiling of mechanisms, may be based on the number of operations. Suitable setting of the maintenance threshold will allow an alarm to be raised, indicating when preventative maintenance is due. Should maintenance not be carried out, the device can be set to lockout the autoreclose function on reaching a second operations threshold (***No. CB ops Lock***). This prevents further reclosure when the circuit breaker has not been maintained to the standard demanded by the switchgear manufacturer's maintenance instructions.

Some circuit breakers, such as oil circuit breakers (OCBs) can only perform a certain number of fault interruptions before requiring maintenance attention. This is because each fault interruption causes carbonising of the oil, degrading its dielectric properties. The maintenance alarm threshold (setting ***No. CB Ops Maint***) may be set to indicate the requirement for oil dielectric testing, or for more comprehensive maintenance. Again, the lockout threshold ***No. CB Ops Lock*** may be set to disable autoreclosure when repeated further fault interruptions could not be guaranteed. This minimises the risk of oil fires or explosion.

13.4.9.3 SETTING THE THRESHOLDS FOR THE OPERATING TIME

Slow CB operation indicates the need for mechanism maintenance. Alarm and lockout thresholds (***CB Time Maint*** and ***CB Time Lockout***) are provided to enforce this. They can be set in the range of 5 to 500 ms. This time relates to the interrupting time of the circuit breaker.

13.4.9.4 SETTING THE THRESHOLDS FOR EXCESSSIVE FAULT FREQUENCY

Persistent faults will generally cause autoreclose lockout, with subsequent maintenance attention. Intermittent faults such as clashing vegetation may repeat outside of any reclaim time, and the common cause might never be investigated. For this reason it is possible to set a frequent operations counter, which allows the number of operations ***Fault Freq Count*** over a set time period ***Fault Freq Time*** to be monitored. A separate alarm and lockout threshold can be set.

13.5 CB STATE MONITORING

CB State monitoring is used to verify the open or closed state of a circuit breaker. Most circuit breakers have auxiliary contacts through which they transmit their status (open or closed) to control equipment such as IEDs. These auxiliary contacts are known as:

- 52A for contacts that follow the state of the CB
- 52B for contacts that are in opposition to the state of the CB

This device can be set to monitor both of these types of circuit breaker state indication. If the state is unknown for some reason, an alarm can be raised.

Some CBs provide both sets of contacts. If this is the case, these contacts will normally be in opposite states. Should both sets of contacts be open, this would indicate one of the following conditions:

- Auxiliary contacts/wiring defective
- Circuit Breaker (CB) is defective
- CB is in isolated position

Should both sets of contacts be closed, only one of the following two conditions would apply:

- Auxiliary contacts/wiring defective
- Circuit Breaker (CB) is defective

If any of the above conditions exist, an alarm will be issued after a 5 s ***CB Status Time*** time delay. An output contact can be assigned to this function via the programmable scheme logic (PSL). The time delay is set to avoid unwanted operation during normal switching duties.

In the CB CONTROL column there is a setting called ***CB Status Input***. This cell can be set at one of the following four options:

- None
- 52A
- 52B
- Both 52A and 52B

Where `None` is selected no CB status is available. Where only 52A is used on its own then the device will assume a 52B signal opposite to the 52A signal. Circuit breaker status information will be available in this case but no discrepancy alarm will be available. The above is also true where only a 52B is used. If both 52A and 52B are used then status information will be available and in addition a discrepancy alarm will be possible, according to the following table:

Auxiliary Contact Position		CB State Detected	Action
52A	52B		
Open	Closed	Breaker open	Circuit breaker healthy
Closed	Open	Breaker closed	Circuit breaker healthy
Closed	Closed	CB failure	Alarm raised if the condition persists for greater than 5 s
Open	Open	State unknown	Alarm raised if the condition persists for greater than 5 s. ***CB State Detected*** becomes ***CB Failure***.

In the internal logic of the P40, the breaker position used in the algorithm is considered to be open when the **CB State Detected is Breaker Open**. In all other cases, the breaker position is considered to be closed. Therefore, during operation of the circuit breaker, if the condition '52A=52B=0' or '52A=52B=1' is encountered, the circuit breaker is considered to be closed.

The Circuit Breaker status can be monitored in the serial and Ethernet data protocols. For example, IEC 60870-5-103, DNP 3.0 and IEC 61850.

IEC 60870-5-103 protocol: The CB status can be monitored from individual private information numbers.

DNP 3.0 protocol: The CB status can be monitored from individual Binary Inputs.

IEC 61850 protocol: The CB status can be monitored in 'XCBR' Logical Node(s).

13.5.1 CB STATE MONITOR LOGIC DIAGRAM

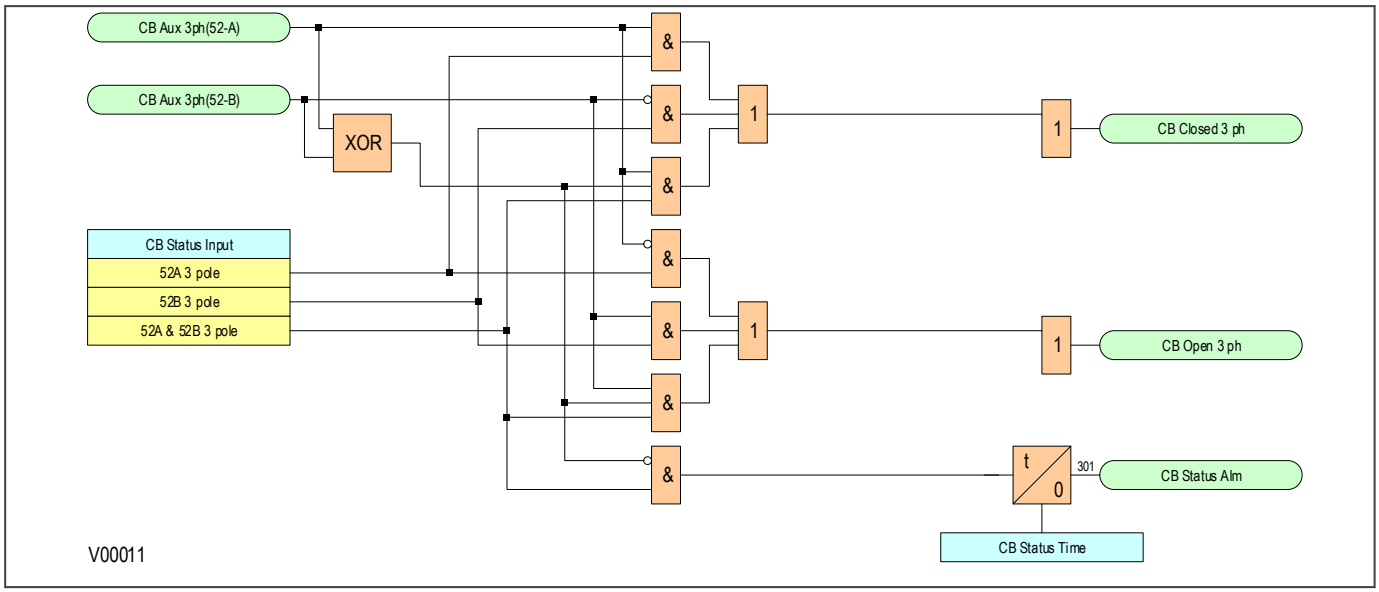


Figure 191: CB state monitor logic (Module 1)

13.6 CIRCUIT BREAKER CONTROL

Although some circuit breakers do not provide auxiliary contacts, most provide auxiliary contacts to reflect the state of the circuit breaker. These are:

- CBs with 52A contacts (where the auxiliary contact follows the state of the CB)
- CBs with 52B contacts (where the auxiliary contact is in the opposite state from the state of the CB)
- CBs with both 52A and 52B contacts

Circuit Breaker control is only possible if the circuit breaker in question provides auxiliary contacts. The ***CB Status Input*** cell in the *CB CONTROL* column must be set to the type of circuit breaker. If no CB auxiliary contacts are available then this cell should be set to `None`, and no CB control will be possible.

The ***CB control by*** cell is used to enable or disable local control options, remote control options, and combinations of both.

The output contact can be set to operate following a time delay defined by the setting ***Man Close Delay***. One reason for this delay is to give personnel time to safely move away from the circuit breaker following a CB close command.

The control close cycle can be cancelled at any time before the output contact operates by any appropriate trip signal, or by activating the ***Reset Close Dly*** DDB signal.

The length of the trip and close control pulses can be set via the ***Trip Pulse Time*** and **Close Pulse Time** settings respectively. These should be set long enough to ensure the breaker has completed its open or close cycle before the pulse has elapsed.

If an attempt to close the breaker is being made, and a protection trip signal is generated, the protection trip command overrides the close command.

The ***Reset Lockout by*** setting is used to enable or disable the resetting of lockout automatically from a manual close after the time set by ***Man Close RstDly***.

If the CB fails to respond to the control command (indicated by no change in the state of CB Status inputs) an alarm is generated after the relevant trip or close pulses have expired. These alarms can be viewed on the LCD display, remotely, or can be assigned to output contacts using the programmable scheme logic (PSL).

Note:
*The **CB Healthy Time** and **Sys Check time** set under this menu section are applicable to manual circuit breaker operations only. These settings are duplicated in the AUTORECLOSE menu for autoreclose applications.*

The ***Lockout Reset*** and ***Reset Lockout by*** settings are applicable to CB Lockouts associated with manual circuit breaker closure, CB Condition monitoring (Number of circuit breaker operations, for example) and autoreclose lockouts.

The device includes the following options for control of a single circuit breaker:

- The IED menu (local control)
- The CB Open/Close keys and the SLD on the graphical HMI
- The opto-inputs (local control)
- SCADA communication (remote control)

13.6.1 CB CONTROL USING THE IED MENU

You can control manual trips and closes with the ***CB Trip/Close*** command in the *SYSTEM DATA* column. This can be set to `No Operation`, `Trip`, or `Close` accordingly.

For this to work you have to set the ***CB control by*** cell to option 1 `Local`, option 3 `Local + Remote`, option 5 `Opto+Local`, option 7 `Opto+Local+Remote` or option 8 `L&R Key` in the *CB CONTROL* column.

13.6.2 SINGLE LINE DIAGRAM (SLD) VIEWER

The SLD menu displays the saved SLD on the graphical HMI screen. You can navigate to the SLD menu using the bottom Menu context keys or by using the quick launch menu on the Home page. The SLD is configured and uploaded into the IED using the S1 Agile configuration tool. Items of plant can be selected on the SLD screen using the navigation keypad.

13.6.2.1 CIRCUIT BREAKER CONTROL (SLD VIEW ONLY)

You can OPEN and CLOSE the circuit breaker selected on the SLD using the dedicated OPEN, CLOSE and L/R buttons on the front HMI Panel.

When the ***CB Control by*** setting is selected, to option 1 `Local`, option 3 `Local+Remote`, option 5 `Opto+local`, option 7 `Opto+Rem+local` or option 8 `L/R Key` in the *CB CONTROL* column users are allowed to use the Trip and Close Key on the front panel to operate the CB.

To control an item of plant using the Open and Close and L/R buttons:

- Set ***CB control by*** setting to `L/R Key`
- Select the Local operating mode by pressing the L/R button

When the L/R button on the front panel is pressed, it will toggle the status of DDB ***L/R Key Status***. When the DDB status is TRUE, the L/R Key LED is green and the Local mode is selected. When the DDB status is FALSE, the L/R Key LED is red and the REMOTE mode is selected. ***The L/R Key Status*** DDB status is stored in non-volatile memory, so that it's status is recovered after an IED power cycle.

- In the SLD menu, navigate to the item of plant which you require to control using the navigation keypad
- The selected plant is highlighted with an orange border
- Use the Enter key to select the item
- Press the Open or Close key to operate

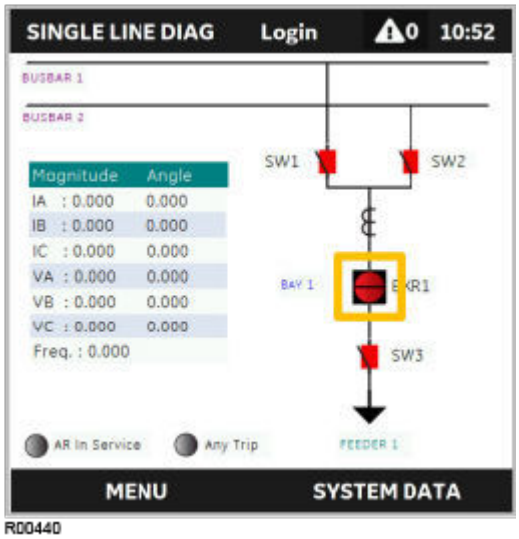


Figure 192: HMI SLD display

For the Circuit Breaker Commands from HMI, additional checks are done:

If the CB is in indeterminant state, the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked - Intermediate State".

If the associated "Control by" setting is set to "disabled" the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked due to Settings".

If the associated "Control by" setting is set to "remote" the switchgear command will not be available and HMI will raise a warning dialogue with the message "Commands blocked due to Settings".

If the associated "Control by" setting is set to "L/R key" and soft key status is set to remote, the switchgear command will not be available, and HMI will pop-up the message - "Commands blocked - In Remote Control".

If the associated local DDB is set to local, the switchgear command will not be available, and HMI will pop-up the message - "Commands blocked - Switchgear in Local".

13.6.3 CB CONTROL USING THE OPTO-INPUTS

Certain applications may require the use of push buttons or other external signals to control the various CB control operations. It is possible to connect such push buttons and signals to opto-inputs and map these to the relevant DDB signals.

For this to work, you have to set the ***CB control by*** cell to option 4 *opto*, option 5 *Opto+Local*, option 6 *Opto +Remote*, or option 7 *Opto+Local+Remote* in the *CB CONTROL* column.

13.6.4 REMOTE CB CONTROL

Remote CB control can be achieved from some of the serial and Ethernet data protocols, or by using the MiCOM S1 Agile settings application software.

For this to work, you have to set the ***CB control by*** cell to option 2 *Remote*, option 3 *Local+Remote*, option 6 *Opto+remote*, option 7 *Opto+Rem+local* or option 8 *L/R Key* in the *CB CONTROL* column.

We recommend that you allocate separate relay output contacts for remote CB control and protection tripping. This allows you to select the control outputs using a simple local/remote selector switch as shown below. Where this feature is not required the same output contact(s) can be used for both protection and remote tripping.

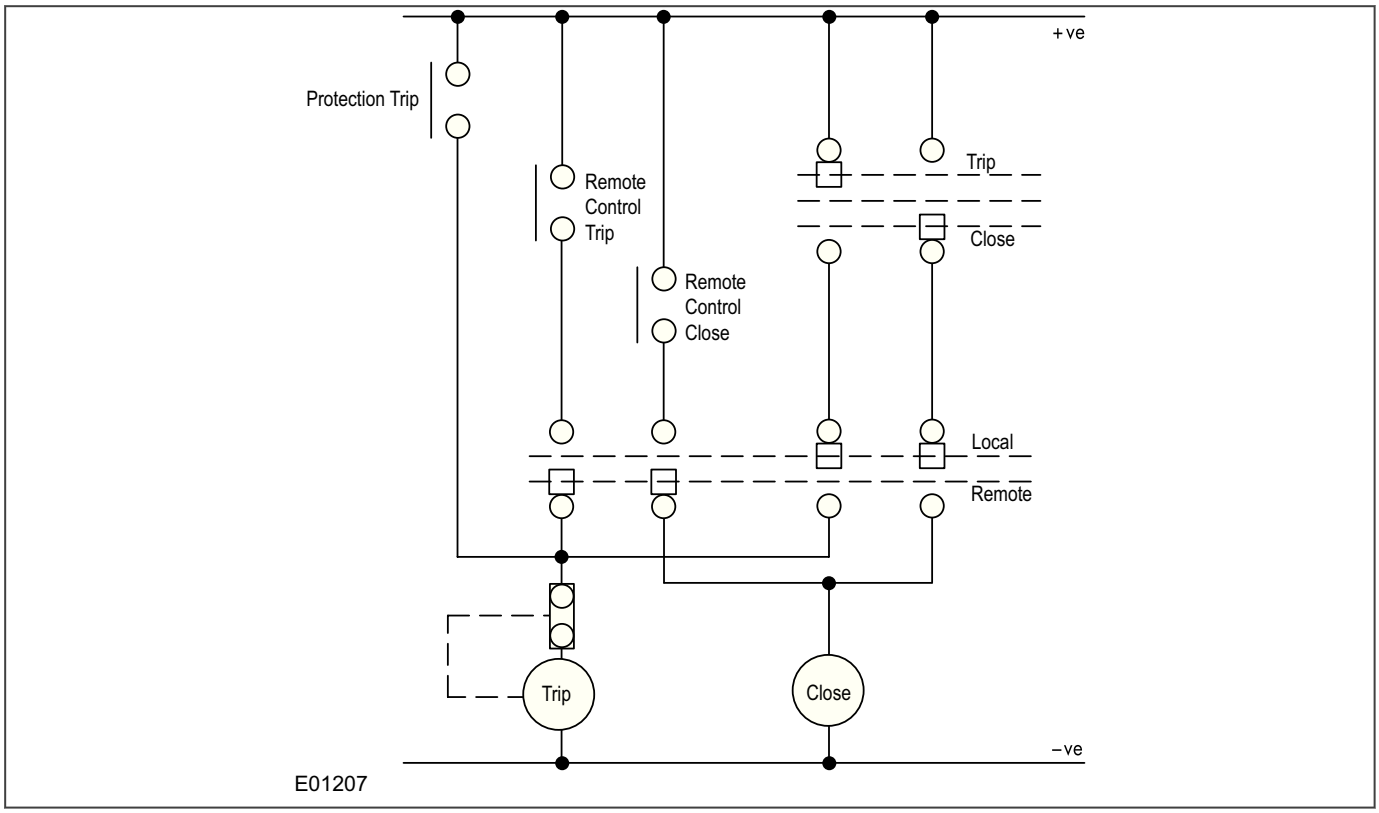


Figure 193: Remote control of circuit breaker

DNP 3.0 protocol: The CB and switch positions can be controlled from Binary Outputs/Control Relay Output Blocks.

IEC 61850 protocol: The CB and switch positions can be controlled in the ‘CSWI’ Logical Node that is linked to the ‘XCBR’ Circuit Breaker Logical Node and 'XSWI' switch Logical Nodes. For Control Authority as per IEC 61850, it is necessary to select ***CB Control by*** cell as option 8 *L/R Key*.

13.6.5 CB HEALTHY CHECK

A CB Healthy check is available if required. This facility accepts an input to one of the opto-inputs to indicate that the breaker is capable of closing (e.g. that it is fully charged). A time delay can be set with the setting ***CB Healthy Time***. If the CB does not indicate a healthy condition within the time period following a Close command, the device will lockout and alarm.

13.6.6 SYNCHRONISATION CHECK

Where the check synchronism function is set, this can be enabled to supervise manual circuit breaker Close commands. A circuit breaker Close command will only be issued if the Check Synchronisation criteria are satisfied. A time delay can be set with the setting ***Sys Check time.*** If the Check Synchronisation criteria are not satisfied within the time period following a Close command the device will lockout and alarm.

13.6.7 CB CONTROL AR IMPLICATIONS

An ***Auto Close CB*** signal from the Auto-close logic bypasses the ***Man Close Delay*** time, and the ***CB Close*** output operates immediately to close the circuit breaker.

If Autoreclose is used it may be desirable to block its operation when performing a manual close. In general, the majority of faults following a manual closure are permanent faults and it is undesirable to allow automatic reclosure.

To ensure that Autoreclose is not initiated for a manual circuit breaker closure on to a pre-existing fault, the ***CB IS Time*** (circuit breaker in service time) setting in the *AUTORECLOSE* menu should be set for the desired time window. This setting ensures that Autoreclose initiation is inhibited for a period equal to setting ***CB IS Time*** following a manual circuit breaker closure. If a protection operation occurs during the inhibit period, Autoreclose is not initiated.

Following manual circuit breaker closure, if either a single phase or a three phase fault occur, the circuit breaker is tripped three phase, but Autoreclose is not locked out for this condition.

13.6.8 CB CONTROL LOGIC DIAGRAM

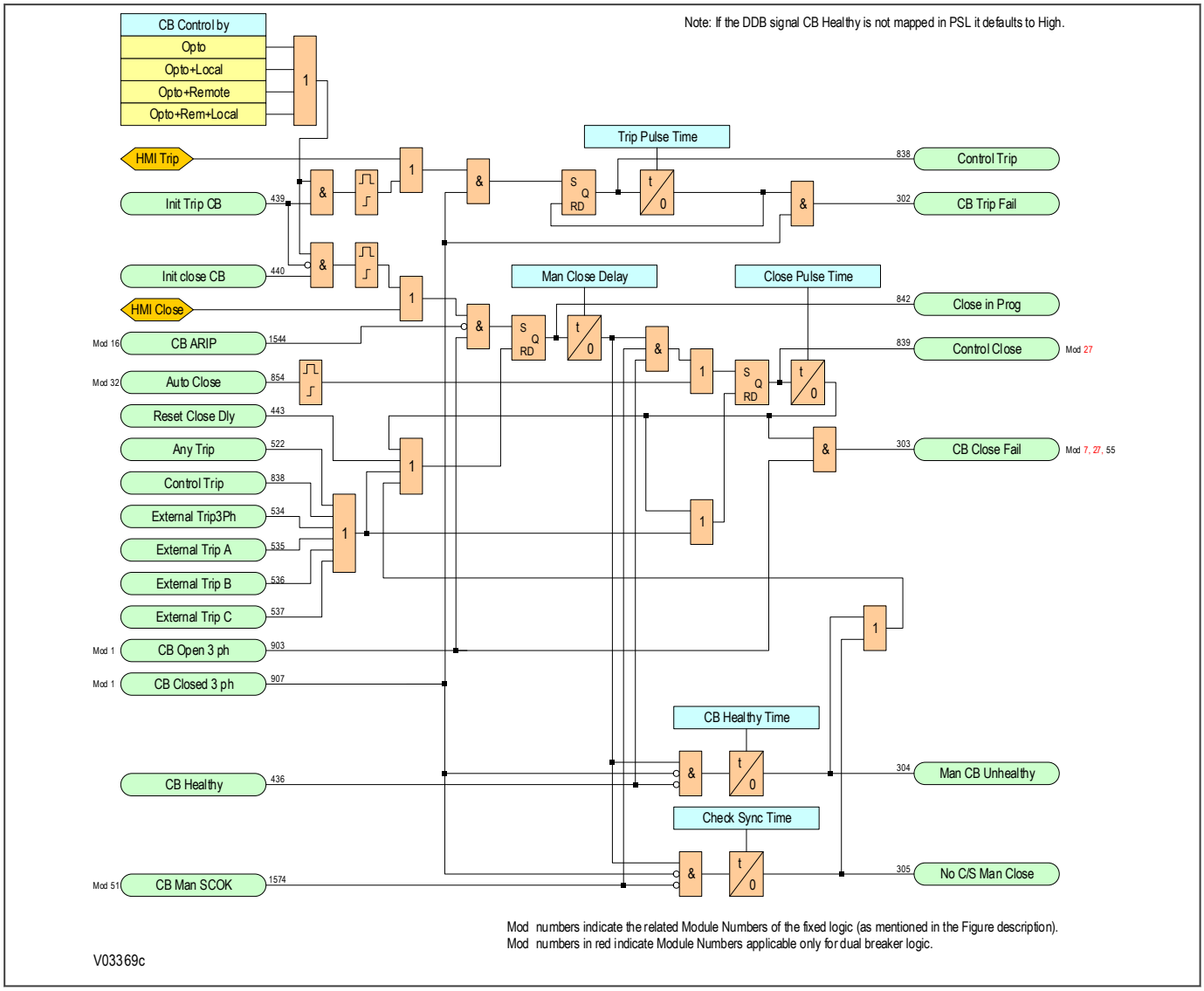


Figure 194: CB control logic (Module 43)

13.7 POLE DEAD FUNCTION

The Pole Dead Logic is used to determine and indicate that one or more phases of the line are not energised. A Pole Dead condition is determined either by measuring:

- the line currents and/or voltages, or
- by monitoring the status of the circuit breaker auxiliary contacts, as shown by dedicated DDB signals.

It can also be used to block operation of underfrequency and undervoltage elements where applicable.

13.7.1 POLE DEAD LOGIC

If both the line current and voltage values fall below a certain threshold, or a CB Open condition is asserted from the state control logic, the device initiates a Pole Dead condition. The current and voltage thresholds can be set with the ***I< Current Set*** and the ***V< settings*** respectively, in the *CBFAIL&P.DEAD* column.

If one or more poles are dead, the device indicates which phase is dead and asserts the ***Any Pole Dead*** DDB signal. If all phases are dead the ***Any Pole Dead*** signal is accompanied by the ***All Poles Dead*** signal.

If the VT fails, a ***VTS Slow Block*** signal is taken from the VTS logic to block the Pole Dead indications that would be generated by the undervoltage and undercurrent thresholds.

Note:
If the VT is connected at the busbar side, auxiliary contacts (52a or 52b) must be connected to the IED for a correct pole dead indication.

13.7.2 POLE DEAD LOGIC

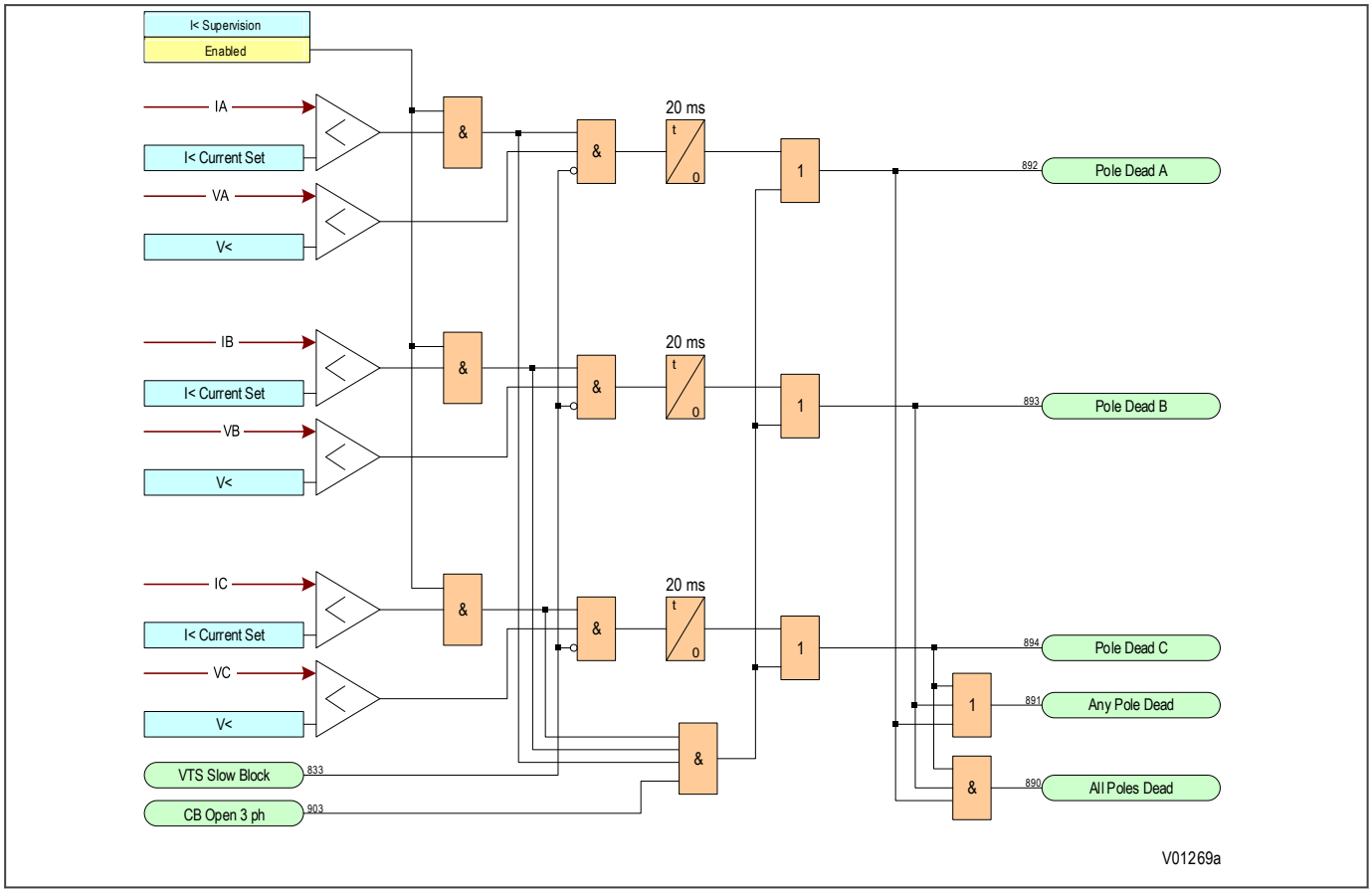


Figure 195: Pole dead logic

If both the line current and voltage values fall below a certain threshold, or a CB Open condition is asserted from the state control logic, the device initiates a Pole Dead condition. The current and voltage thresholds can be set with the ***I< Current Set*** and the ***V< settings*** respectively, in the *CBFAIL&P.DEAD* column.

If one or more poles are dead, the device indicates which phase is dead and asserts the ***Any Pole Dead*** DDB signal. If all phases are dead the ***Any Pole Dead*** signal is accompanied by the ***All Poles Dead*** signal.

If the VT fails, a ***VTS Slow Block*** signal is taken from the VTS logic to block the Pole Dead indications that would be generated by the undervoltage and undercurrent thresholds.

Note:
If the VT is connected at the busbar side, auxiliary contacts (52a or 52b) must be connected to the IED for a correct pole dead indication.

13.8 SYSTEM CHECKS

In some situations it is possible for both "bus" and "line" sides of a circuit breaker to be live when a circuit breaker is open - for example at the ends of a feeder that has a power source at each end. Therefore, it is normally necessary to check that the network conditions on both sides are suitable, before closing the circuit breaker. This applies to both manual circuit breaker closing and autoreclosing. If a circuit breaker is closed when the line and bus voltages are both live, with a large phase angle, frequency or magnitude difference between them, the system could be subjected to an unacceptable shock, resulting in loss of stability, and possible damage to connected machines.

The System Checks functionality involves monitoring the voltages on both sides of a circuit breaker, and if both sides are live, performing a synchronisation check to determine whether any differences in voltage magnitude, phase angle or frequency are within permitted limits.

The pre-closing system conditions for a given circuit breaker depend on the system configuration, and for autoreclosing, on the selected autoreclose program. For example, on a feeder with delayed autoreclosing, the circuit breakers at the two line ends are normally arranged to close at different times. The first line end to close usually has a live bus and a dead line immediately before reclosing. The second line end circuit breaker now sees a live bus and a live line.

If there is a parallel connection between the ends of the tripped feeder the frequencies will be the same, but any increased impedance could cause the phase angle between the two voltages to increase. Therefore just before closing the second circuit breaker, it may be necessary to perform a synchronisation check, to ensure that the phase angle between the two voltages has not increased to a level that would cause unacceptable shock to the system when the circuit breaker closes.

If there are no parallel interconnections between the ends of the tripped feeder, the two systems could lose synchronism altogether and the frequency at one end could "slip" relative to the other end. In this situation, the second line end would require a synchronism check comprising both phase angle and slip frequency checks.

If the second line-end busbar has no power source other than the feeder that has tripped; the circuit breaker will see a live line and dead bus assuming the first circuit breaker has re-closed. When the second line end circuit breaker closes the bus will charge from the live line (dead bus charge).

13.8.1 SYSTEM CHECKS IMPLEMENTATION

The System Checks function provides *Live/Dead Voltage Monitoring*, two stages of *Check Synchronisation* and *System Split* indication.

The System Checks function is enabled or disabled by the ***System Checks*** setting in the *CONFIGURATION* column. If ***System Checks*** is disabled, the *SYSTEM CHECKS* menu becomes invisible, and a ***SysChks Inactive*** DDB signal is set.

The System Checks functionality can also be enabled or disabled by the ***System Checks*** setting in the *SYSTEM CHECKS* column. For the Systems Checks functionality to be enabled, both the ***System Checks*** setting in the *CONFIGURATION* column AND the ***System Checks*** setting in the *SYSTEM CHECKS* column must be enabled. For the System Checks functionality to be disabled, either the ***System Checks*** setting in the *CONFIGURATION* column OR the ***System Checks*** setting in the *SYSTEM CHECKS* column must be enabled. In the latter case, the ***SysChks Inactive*** DDB signal is set.

13.8.1.1 VT CONNECTIONS

The device provides inputs for a three-phase "Main VT" and at least one single-phase VT for check synchronisation. Depending on the primary system arrangement, the Main VT may be located on either the line-side of the busbar-side of the circuit breaker, with the Check Sync VT on the other. Normally, the Main VT is located on the line-side (as per the default setting), but this is not always the case. For this reason, a setting is provided where you can define this. This is the ***Main VT Location*** setting, which is found in the *CT AND VT RATIOS* column.

The Check Sync VT may be connected to one of the phase-to-phase voltages or phase-to-neutral voltages. This needs to be defined using the ***CS Input*** setting in the *CT AND VT RATIOS* column. Options are, A-B, B-C, C-A, A-N, B-N, or C-N.

13.8.1.2 VOLTAGE MONITORING

The settings in the *VOLTAGE MONITORS* sub-heading in the *SYSTEM CHECKS* column allow you to define the threshold at which a voltage is considered live, and a threshold at which the voltage is considered dead. These thresholds apply to both line and bus sides. If the measured voltage falls below the ***Dead Voltage*** setting, a DDB signal is generated (***Dead Bus***, or ***Dead Line***, depending on which side is being measured). If the measured voltage exceeds the ***Live Voltage*** setting, a DDB signal is generated (***Live Bus***, or ***Live Line***, depending on which side is being measured).

13.8.1.3 CHECK SYNCHRONISATION

The device provides two stages of Check Synchronisation. The first stage (CS1) is intended for use in synchronous systems. This means, where the frequencies and phase angles of both sides are compared and if the difference is within set limits, the circuit breaker is allowed to close. The second stage (CS2) is similar to stage, but has an additional adaptive setting. The second stage CS2 is intended for use in asynchronous systems, i.e. where the two sides are out of synchronism and one frequency is slipping continuously with respect to another. If the closing time of the circuit breaker is known, the CB Close command can be issued at a definite point in the cycle such that the CB closes at the point when both sides are in phase.

In situations where it is possible for the voltages on either side of a circuit breaker to be either synchronous or asynchronous, both CS1 and CS2 can be enabled to provide a CB Close signal if either set of permitted closing conditions is satisfied.

Each stage can also be set to inhibit circuit breaker closing if selected blocking conditions such as overvoltage, undervoltage or excessive voltage magnitude difference are detected. CS2 requires the phase angle difference to be decreasing in magnitude before permitting the circuit breaker to close. CS2 has an optional “Adaptive” closing feature, which issues the permissive close signal when the predicted phase angle difference immediately prior to the instant of circuit breaker main contacts closing (i.e. after CB Close time) is as close as practicable to zero.

Slip frequency is the rate of change of phase between each side of the circuit breaker, which is measured by the difference between the voltage signals on either side of the circuit breaker.

Having two system synchronism check stages available allows the circuit breaker closing to be enabled under different system conditions (for example, low slip / moderate phase angle, or moderate slip / small phase angle).

The settings specific to Check Synchronisation are found under the sub-heading *CHECK SYNC* in the *SYSTEM CHECKS* column. The only difference between the CS1 settings and the CS2 settings is that CS2 has a ***CS2 Adaptive*** setting for predictive closure of CB.

13.8.1.4 CHECK SYNCRONISATION VECTOR DIAGRAM

The following vector diagram represents the conditions for the System Check functionality. The Dead Volts setting is represented as a circle around the origin whose radius is equal to the maximum voltage magnitude, whereby the voltage can be considered dead. The nominal line voltage magnitude is represented by a circle around the origin whose radius is equal to the nominal line voltage magnitude. The minimum voltage magnitude at which the system can be considered as Live, is the magnitude difference between the bus and line voltages.

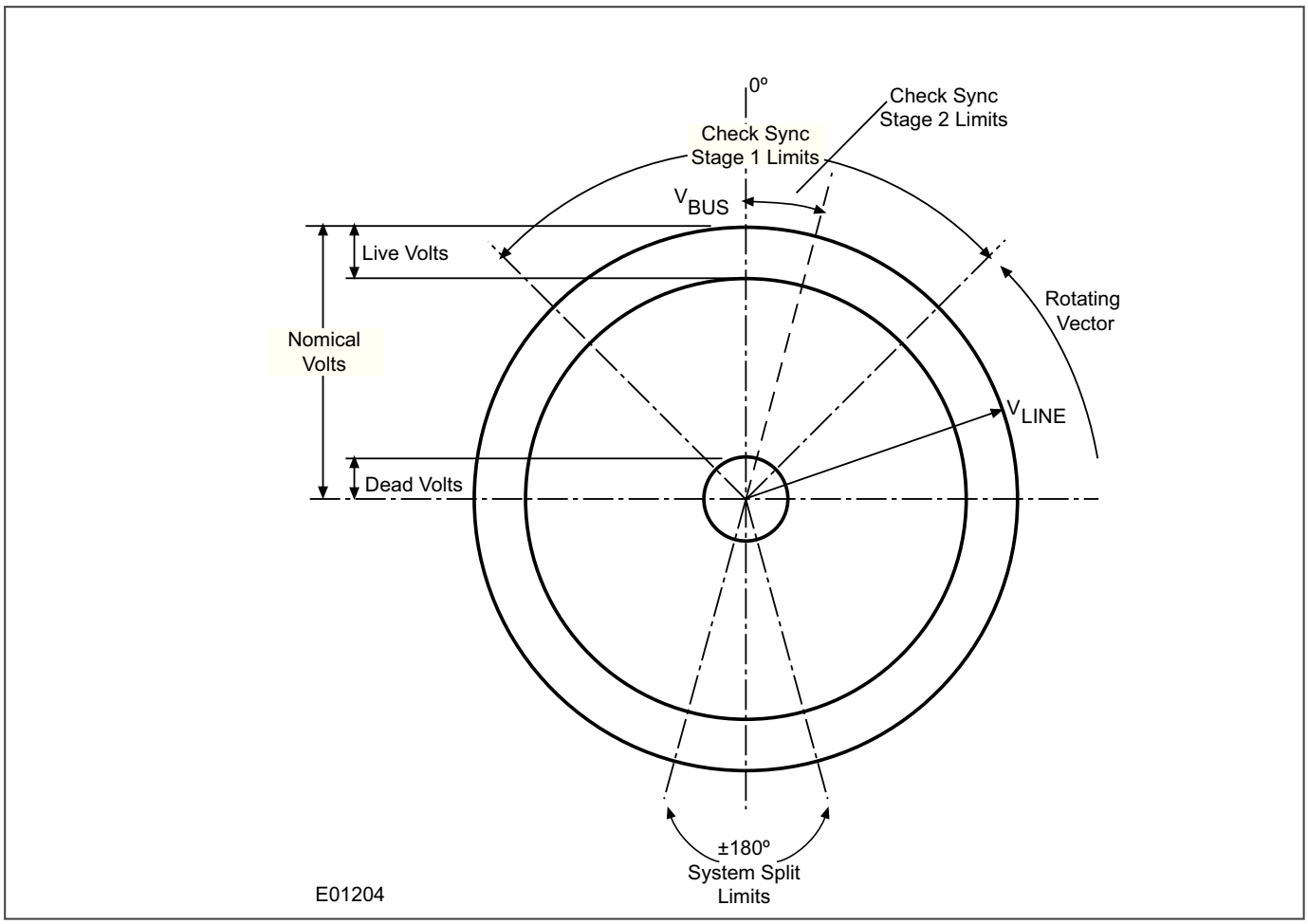


Figure 196: Check synchronisation vector

13.8.1.5 SYSTEM SPLIT

If the line side and bus side are of the same frequency (i.e. in synchronism) but have a large phase angle between them (180° +/- the set limits), the system is said to be 'Split'. If this is the case, the device will detect this and issue an alarm signal indicating this.

The settings specific to System Split functionality are found under the sub-heading *SYSTEM SPLIT* in the *SYSTEM CHECKS* column.

13.8.2 VOLTAGE MONITOR FOR CB CLOSURE

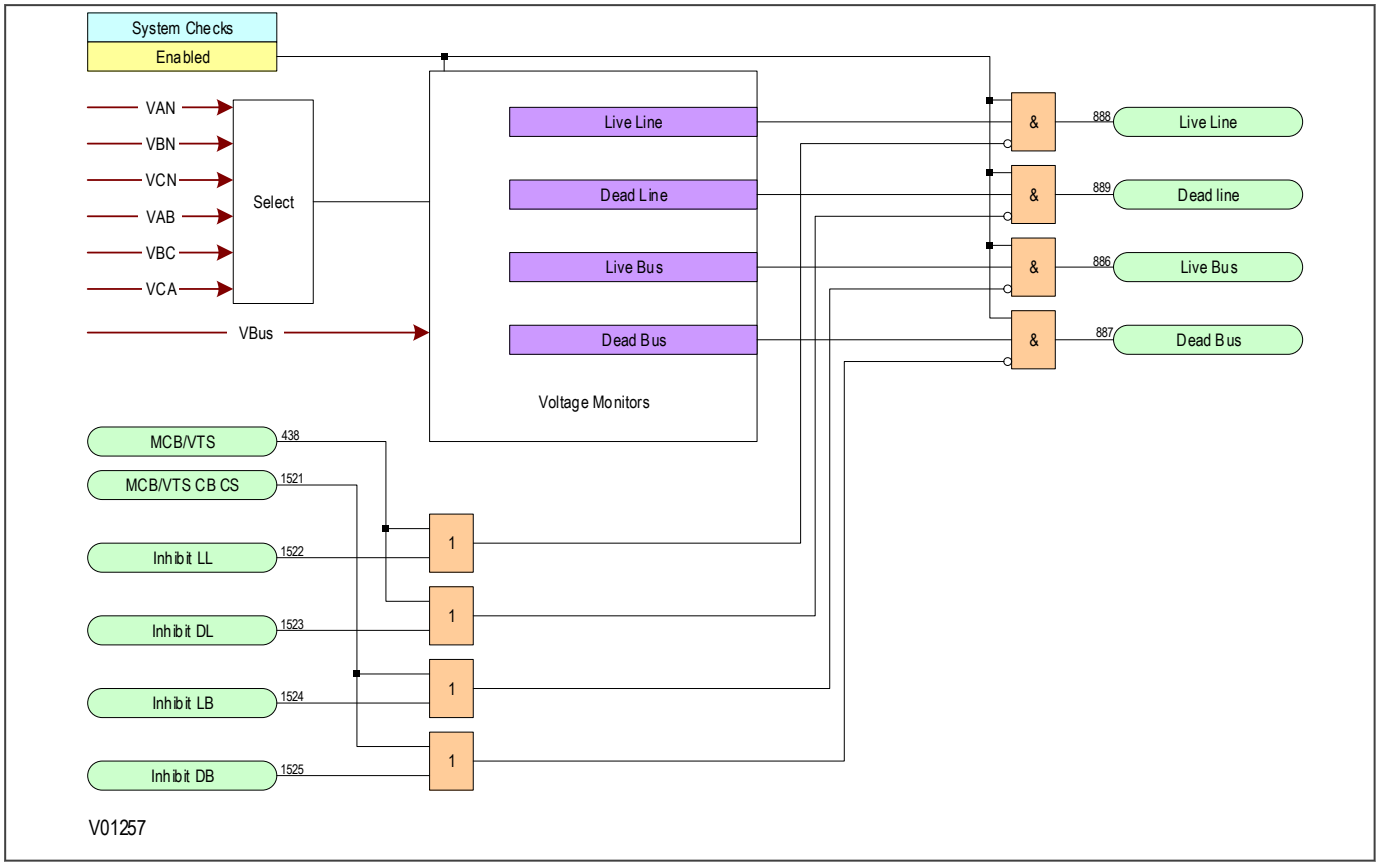


Figure 197: Voltage monitor for CB closure (Module 59)

13.8.3 CHECK SYNCHRONISATION MONITOR FOR CB CLOSURE

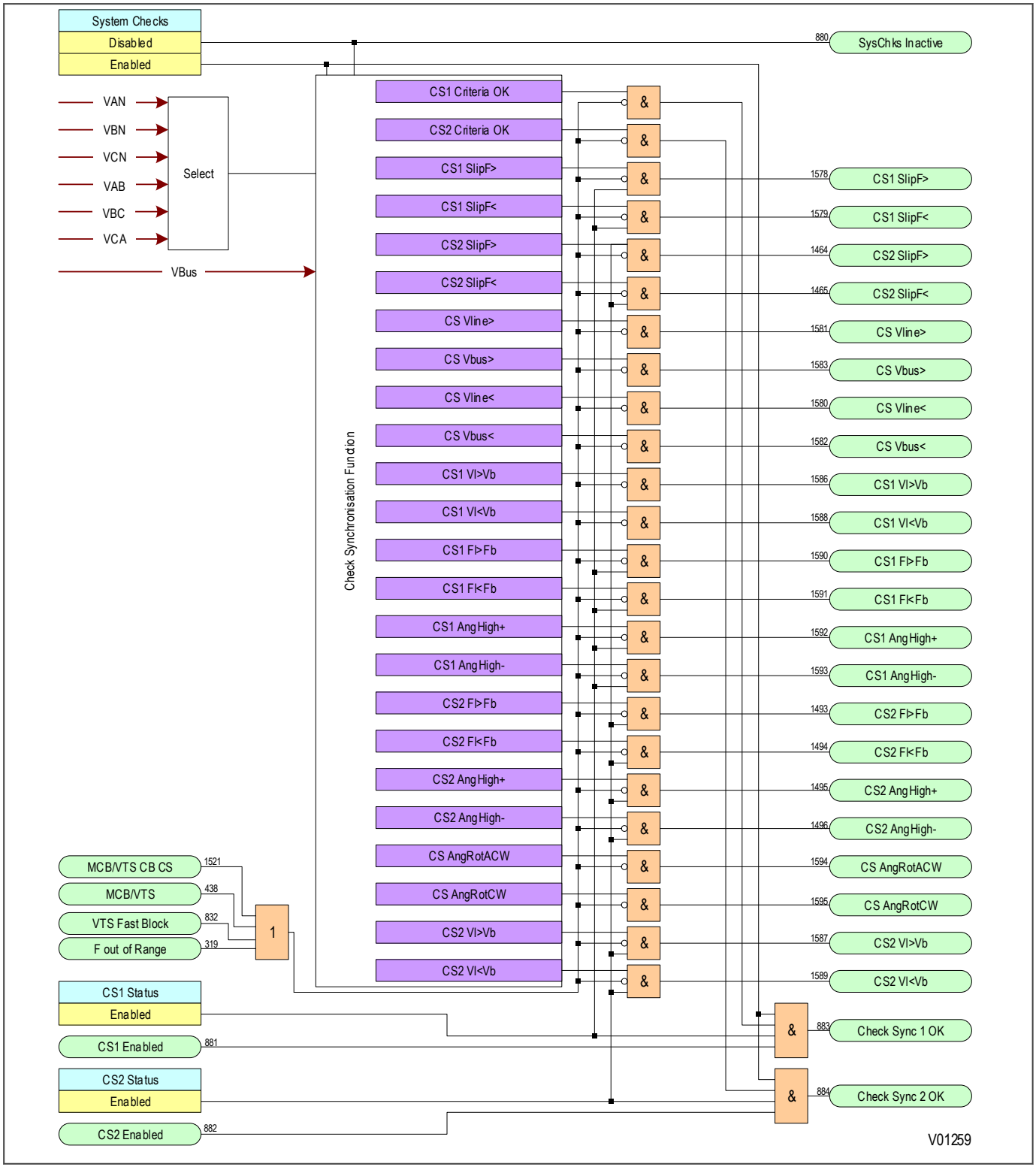


Figure 198: Check synchronisation monitor for CB closure (Module 60)

13.8.4 SYSTEM CHECK LOGIC

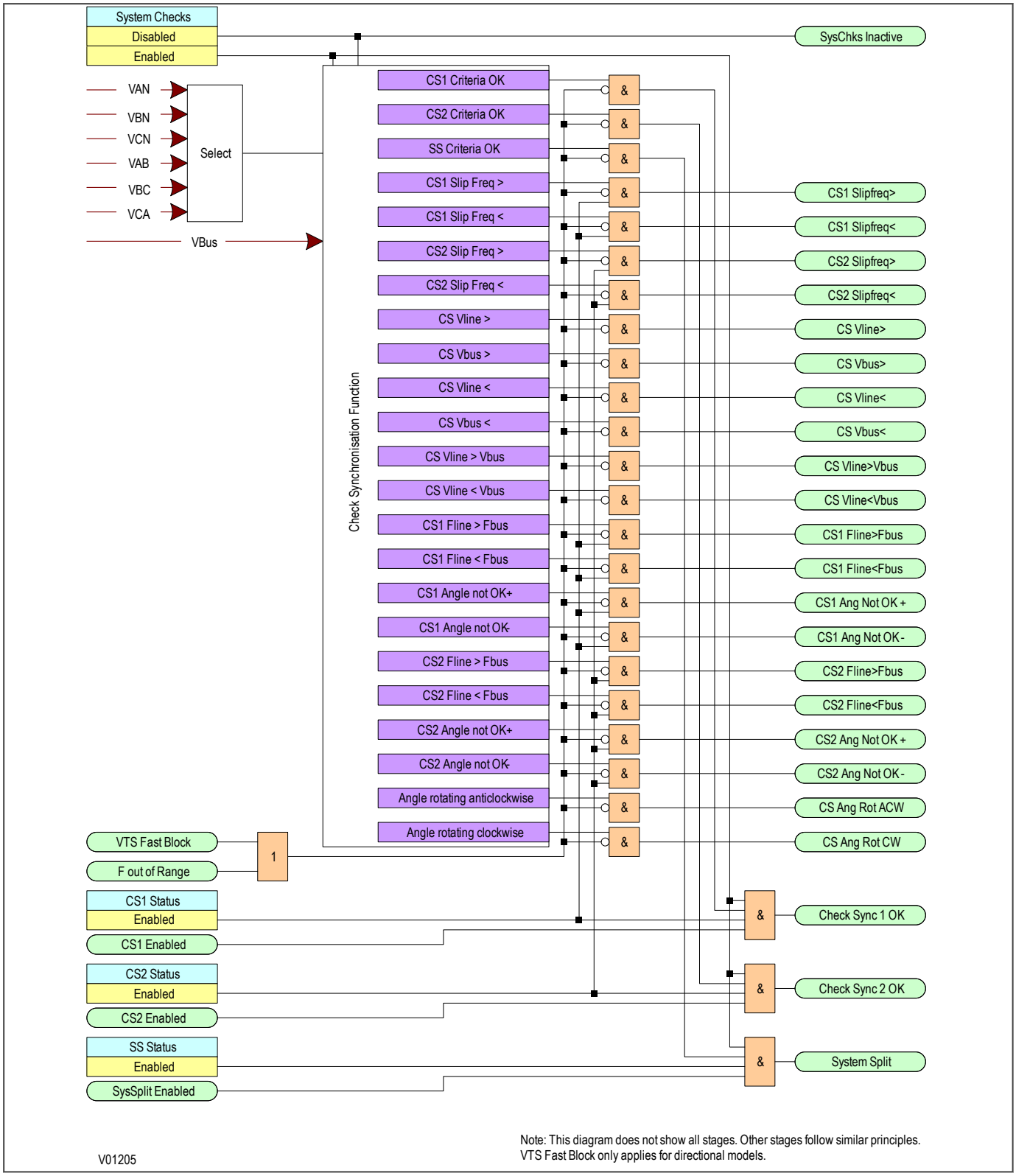


Figure 199: System check logic

13.8.5 SYSTEM CHECK PSL

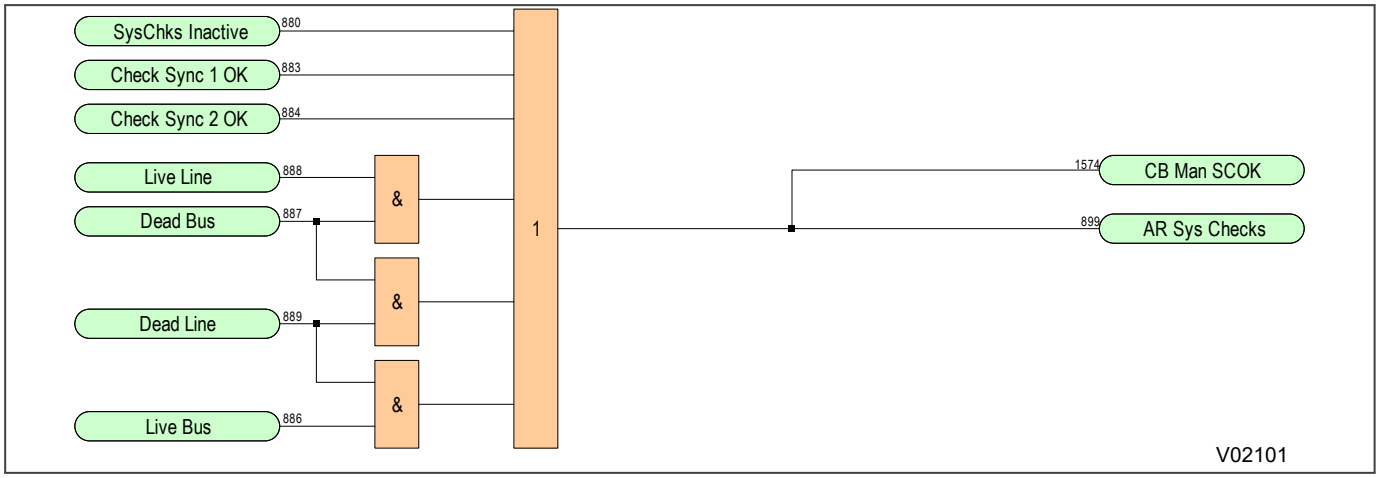


Figure 200: System check PSL

13.8.6 APPLICATION NOTES

13.8.6.1 USE OF CHECK SYNC 2 AND SYSTEM SPLIT

Check Sync 2 (CS2) and System Split functions are included for situations where the maximum permitted slip frequency and phase angle for synchronism checks can change due to adverse system conditions. A typical application is on a closely interconnected system, where synchronism is normally retained when a feeder is tripped. But under some circumstances, with parallel interconnections out of service, the feeder ends can drift out of synchronism when the feeder is tripped. Depending on the system and machine characteristics, the conditions for safe circuit breaker closing could be, for example:

Condition 1: For synchronised systems, with zero or very small slip:

- Slip <50 mHz; phase angle <30°

Condition 2: For unsynchronised systems, with significant slip:

- Slip < 250 mHz; phase angle <10° and decreasing

By enabling both CS1 and CS2, the device can be configured to allow CB closure if either of the two conditions is detected.

For manual circuit breaker closing with synchronism check, some utilities might prefer to arrange the logic to check initially for condition 1 only. However, if a System Split is detected before the condition 1 parameters are satisfied, the device will switch to checking for condition 2 parameters instead, based on the assumption that a significant degree of slip must be present when system split conditions are detected. This can be arranged by suitable PSL logic, using the System Check DDB signals.

13.8.6.2 PREDICTIVE CLOSURE OF CIRCUIT BREAKER

The ***CS2 Adaptive*** setting compensates for the time taken to close the CB. When set to provide CB Close Time compensation, a predictive approach is used to close the circuit breaker ensuring that closing occurs at close to 0º therefore minimising the impact to the power system. The actual closing angle is subject to the constraints of the existing product architecture, i.e. the protection task runs twice per power system cycle, based on frequency tracking over the frequency range of 40 Hz to 65 Hz.

13.8.6.3 PREDICTIVE CLOSURE OF CIRCUIT BREAKERS

The ***CB1 CS2 Adaptive*** and ***CB1 CS2 Adaptive*** settings compensate for the time taken to close the CB. When set to provide CB Close Time compensation, a predictive approach is used to close the circuit breaker ensuring that closing occurs at close to 0º therefore minimising the impact to the power system. The actual closing angle is subject to the constraints of the existing product architecture, i.e. the protection task runs twice per power system cycle, based on frequency tracking over the frequency range of 40 Hz to 65 Hz.

13.8.6.4 VOLTAGE AND PHASE ANGLE CORRECTION

For the Check Synchronisation function, the device needs to convert measured secondary voltages into primary voltages. In some applications, VTs either side of the circuit breaker may have different VT Ratios. In such cases, a magnitude correction factor is required.

There are some applications where the main VT is on the HV side of a transformer and the Check Sync VT is on the LV side, or vice-versa. If the vector group of the transformer is not "0", the voltages are not in phase, so phase correction is also necessary.

The correction factors are as follows and are located in the *CT AND VT RATIOS* column:

- C/S V kSM, where kSM is the voltage correction factor.
- C/S Phase kSA, where kSA is the angle correction factor.

Assuming C/S input setting is A-N, then:

The line and bus voltage magnitudes are matched if $V_{a\ sec} = V_{cs\ sec}$ x C/S V kSA

The line and bus voltage angles are matched if $\angle V_{a\ sec} = \angle V_{cs\ sec}$ + C/S Phase kSA

The following application scenarios show where the voltage and angular correction factors are applied to match different VT ratios:

Scenario	Physical Ratios (ph-N Values)				Setting Ratios				CS Correction Factors	
	Main VT Ratio		CS VT Ratio		Main VT Ratio (ph-ph) Always		CS VT Ratio		kSM	kSA
	Pri (kV)	Sec (V)	Pri (kV)	Sec (V)	Pri (kV)	Sec (V)	Pri (kV)	Sec (V)		
1	220/√3	110/√3	132/√3	100/√3	220	110	132	100	1.1	30º
2	220/√3	110/√3	220/√3	110	220	110	127	110	0.577	0º
3	220/√3	110/√3	220/√3	110/3	220	110	381	110	1.732	0º

13.9 SWITCH STATUS AND CONTROL

All P14 products support Switch Status and Control for up to 8 switchgear elements. This is available for IEC60870-5-103 and IEC61850 protocols. The device is able to monitor the status of and control up to eight switches. The types of switch that can be controlled are:

- Load Break switch
- Disconnector
- Earthing SwitchP14
- High Speed Earthing Switch

Consider the following feeder bay:

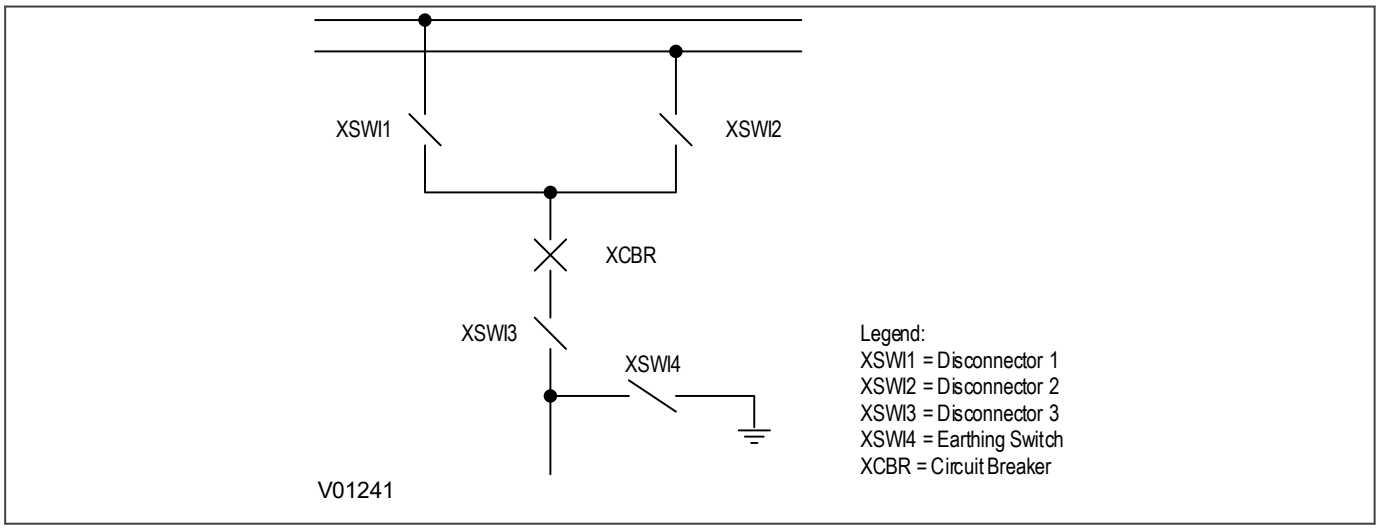


Figure 201: Representation of typical feeder bay

This bay shows four switches of the type LN XSWI and one circuit breaker of type LN XCBR. In this example, the switches XSWI1 – XSWI3 are disconnectors and XCSWI4 is an earthing switch.

For the device to be able to control the switches, the switches must provide auxiliary contacts to indicate the switch status. For convenience, the device settings refer to the auxiliary contacts as 52A and 52B, even though they are not circuit breakers.

There are eight sets of settings in the *SWITCH CONTROL* column, which allow you to set up the Switch control, one set for each switch. These settings are as follows:

SWITCH1 Type

This setting defines the type of switch. It can be a load breaking switch, a disconnector, an earthing switch or a high speed earthing switch.

SWI1 Status Inpt

This setting defines the type of auxiliary contacts that will be used for the control logic. For convenience, the device settings refer to the auxiliary contacts as 52A and 52B, even though they are not circuit breakers. "A" contacts match the status of the primary contacts, whilst "B" contacts are of the opposite polarity.

SWI1 Control by

This setting determines how the switch is to be controlled. This can be Local (using the device directly) remote (using a communications link), or both.

SWI1Trip/Close

This is a command t o directly trip or close the switch.

SWI1 Trp Puls T and ***SWI1 Cls Puls T***

These settings allow you to control the width of the open and close pulses.

SWI1 Sta Alrm T

This setting allows you to define the duration of wait timer before the device raises a status alarm.

SWI1 Trp Fail T and ***SWI1 Cls Fail T***

These settings allow you to control the delay of the open and close alarms when the final switch status is not in line with expected status.

SWI1 Operations

This is a data cell, which displays the number of switch operations that have taken place. It is an accumulator, which you can reset using the ***Reset SWI1 Data*** setting

Reset SWI1 Data

This setting resets the switch monitoring data.

Note:
Settings for switch 1 are shown, but settings for all other switch elements are the same.

IEC 61850 protocol: The Switch position can be controlled in the 'CSWI' Logical Node that is linked to the 'XSWI' Switch Logical Node. For Control Authority as per IEC 61850, it is necessary to select ***SWx Control by*** cell as option 4 L/R Key.

13.9.1 SINGLE LINE DIAGRAM (SLD) VIEWER

The SLD menu displays the saved SLD on the graphical HMI screen. You can navigate to the SLD menu using the bottom Menu context keys or by using the quick launch menu on the Home page. The SLD is configured and uploaded into the IED using the S1 Agile configuration tool. Items of plant can be selected on the SLD screen using the navigation keypad.

13.9.2 SWITCH CONTROL (SLD VIEW ONLY)

You can OPEN and CLOSE the switches selected on the SLD using the dedicated OPEN, CLOSE and L/R buttons on the front HMI Panel.

When the Switch Control by setting is selected to option 1 *LOCAL*, option 3 `Local+Remote` or option 4 `L/R Key` in the SWITCH CONTROL column, users are allowed to use the Open and Close Key on the front panel to operate the SWITCH.

To control an item of plant using the Open and Close and L/R buttons:

- Set ***Switch Control by*** setting to `L/R Key`
- Select the Local operating mode by pressing the L/R button

When the L/R button on the front panel is pressed, it will toggle the status of DDB ***L/R Key Status***. When the DDB status is TRUE, the L/R Key LED is red and the Local mode is selected. When the DDB status is FALSE, the L/R Key LED is green and the REMOTE mode is selected. The **L/R Key Status** DDB status is stored in non-volatile memory, so that its status is recovered after an IED power cycle.

- In the SLD menu, navigate to the item of plant you want to control using the navigation keypad
- The selected plant is highlighted with an orange border
- Use the Enter key to select the item
- Press the OPEN or CLOSE key to operate

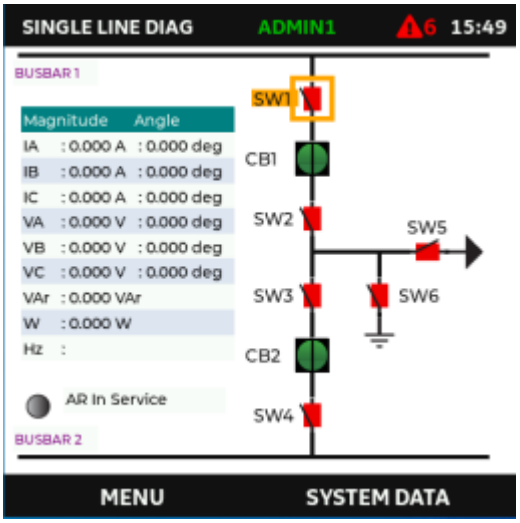


Figure 202: HMI SLD display

For the Switch Commands from HMI, these additional checks are done:

If the Switch is in indeterminant state, the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked - Intermediate State".

If the associated "***Control by***" setting is set to "disabled" the switchgear command will not be available and HMI will raise a warning dialogue with the message - "Commands blocked due to Settings".

If the associated "***Control by***" setting is set to "remote" the switchgear command will not be available and HMI will raise a warning dialogue with the message "Commands blocked due to Settings".

If the associated "***Control by***" setting is set to "L/R key" and soft key status is set to remote, the switchgear command will not be available and HMI will pop-up the message - "Commands blocked - In Remote Control."

If the associated local DDB is set to local, the switchgear command will not be available and HMI will pop-up the message - "Commands blocked - Switchgear in Local".

13.9.3 SWITCH CONTROL LOGIC

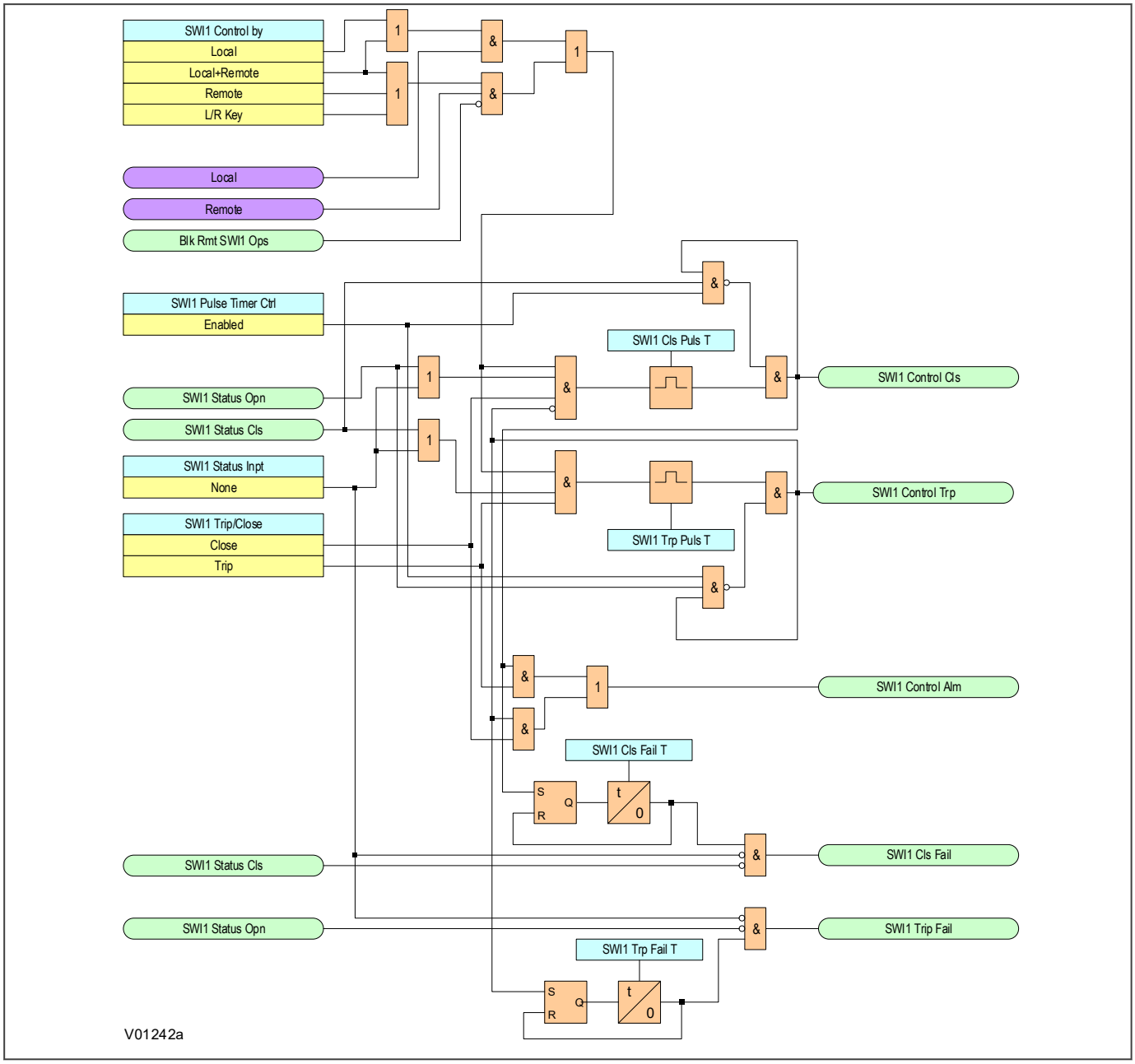


Figure 203: Switch control logic

13.9.4 SWITCH STATUS LOGIC

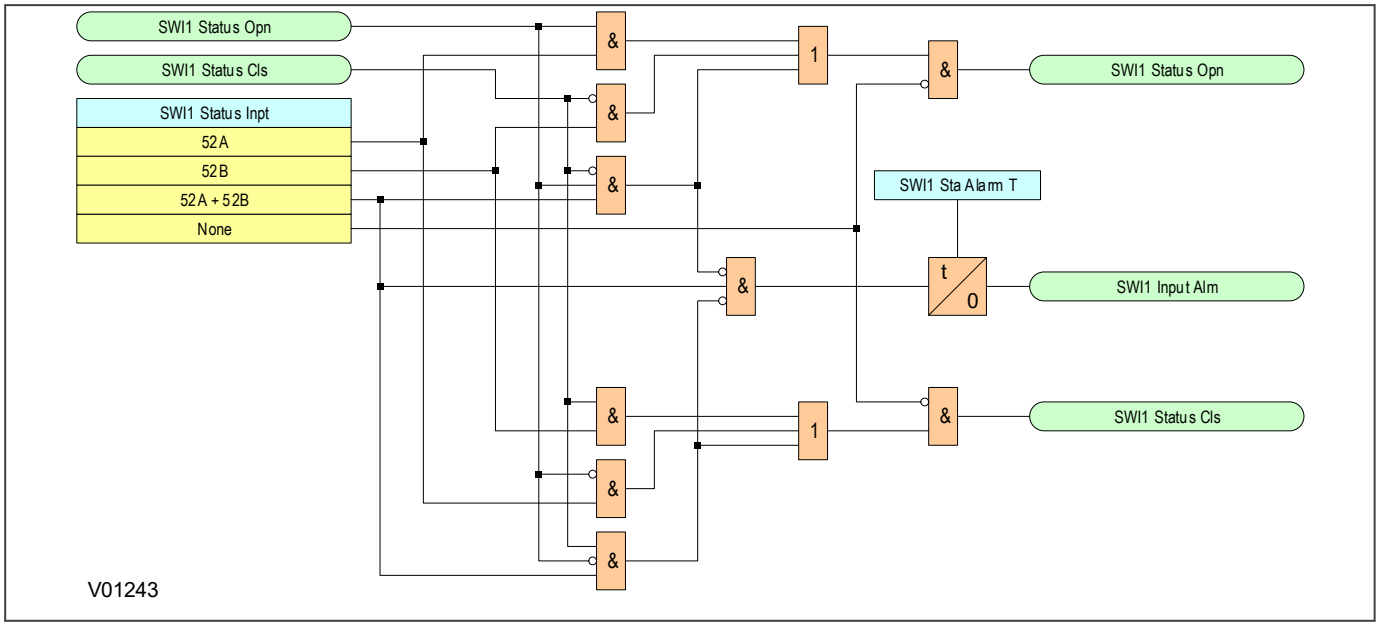


Figure 204: Switch status logic

13.10 TEST MODE

The behaviour of the IED is dependant on if it is in normal operation or in one of the Test Modes. This is reflected in some of the data that can be monitored and affects the allowed control operations, particularly using the IEC 61850 protocol.

The mode of operation is set using the ***IED Test Mode*** cell under the *COMMISSION TESTS* column. See the Commissioning Instructions chapter for more information.

When the IED is in either ***Test*** or ***Contacts Blocked*** mode, IEC 61850 status and measurement data will be transmitted with its quality parameter set to ***test***, so that the receiver understands that they have been issued by a device under test and can respond accordingly.

When the IED is in either ***Test*** or ***Contacts Blocked***' mode, the IED only responds to IEC 61850 MMS controls from the client with the 'test' flag set (with the exception of controls on System/LLN0.Mod).

You can select the mode of operation of the P40 IED by:

- Using the front panel HMI, with the setting ***IED Test Mode*** under the *COMMISSION TESTS* column
- Using an IEC 61850 MMS control service to ***System/LLN0.Mod***
- Using an opto-input via PSL with the signal ***Block Contacts***

The following table summarises the P40 IED behaviour under the different modes:

IED Test Mode Setting	IEC 61850 Mod	Result
Disabled	on	• Normal IED behaviour • IED only responds to incoming GOOSE and SV messages with quality q.test = false
Test	test	• Protection remains enabled • IED responds to incoming GOOSE and SV messages with both quality q.test = true and q.test = false • Relay output contacts are still active • IEC 61850 message outputs have 'quality' q.test = true • IED responds to incoming IEC 61850 MMS messages with only quality q.test = true
Contacts Blocked	test/blocked	• Protection remains enabled • IED responds to incoming GOOSE and SV messages with both quality q.test = true and q.test = false • Relay output contacts are disabled • IEC 61850 message outputs have quality q.test = true • IED responds to incoming IEC 61850 MMS messages with only quality q.test = true

Setting the Test or Contacts Blocked mode puts the whole IED into test mode. The IEC 61850 data object ***Beh*** in all Logical Nodes (except LPHD and any protection Logical Nodes that have Beh = 5 (off) due to the function being disabled) will be set to 3 (test) or 4 (test/blocked) as applicable.

13.11 IEC 61850 CONTROL AUTHORITY

Within the substation, control commands to the primary equipment, such as the breaker or disconnect/earth switches can be originated from one of four levels: Device, Bay, Station or Remote.

Device: Controls are issued manually at the device in the yard/GIS. Any commands from remote locations are not accepted. For this to happen the XCBR/XSWI.Loc object should be True. For P40 devices, the XCBR/XSWI.Loc is mapped to these DDBs, where applicable:

DDB No.	DDB Name	Description
2186	LocKey Local	This DDB signal indicates that the IED is in local status
2187	SW1 Local	This DDB signal indicates that the switch 1 is in local status
2188	SW2 Local	This DDB signal indicates that the switch 2 is in local status
2189	SW3 Local	This DDB signal indicates that the switch 3 is in local status
2190	SW4 Local	This DDB signal indicates that the switch 4 is in local status
2191	SW5 Local	This DDB signal indicates that the switch 5 is in local status
2192	SW6 Local	This DDB signal indicates that the switch 6 is in local status
2193	SW7 Local	This DDB signal indicates that the switch 7 is in local status
2194	SW8 Local	This DDB signal indicates that the switch 8 is in local status
2195	CB1 Local	This DDB signal indicates that the CB1 is in local status
2196	CB2 Local	This DDB signal indicates that the CB2 is in local status
2197	CB3 Local	This DDB signal indicates that the CB3 is in local status
2198	CB4 Local	This DDB signal indicates that the CB4 is in local status
2199	CB5 Local	This DDB signal indicates that the CB4 is in local status

If the DDBs associated are not connected, the default is False which facilitates remote operations.

Bay: The commands are issued from the HMI of the P40. The P40 has a dedicated L/R Button for selection in the front face.

Key	Description	Function
	Local/Remote key	To select between local and remote operating modes.

When the L/R button on the front panel is pressed, it will toggle the status of DDB ***L/R Key Status***. When the DDB status is TRUE, the L/R Key LED is Red and the Local mode is selected. When the DDB status is FALSE, the L/R Key LED is Green and the REMOTE mode is selected. The ***L/R Key Status*** DDB status is stored in non-volatile memory, so that its status is recovered after an IED power cycle.

Bay Level controls are possible from the HMI if the ***L/R Key Status*** is in Local. When L/R Key is in Local the IEC 61850 Signal, System\LLN0.Loc is set as True. When L/R Key is in Remote, and a control action is attempted, the User will be advised with a pop-up message of "Command Unavailable - in remote".

To facilitate integration of the IED into a wired Local/Remote control switch in a panel, an additional DDB L/R Key has been provided.

This is modelled into IEC 61850 System\LLN0.LocKey. The data object LocKey represents the status of a physical key switch and allows taking over the control authority, if the DDB is wired. If the DDB is used, and is set to 1, the IED Local/Remote (System\LLN0.Loc) automatically changes to Local. At this stage, it is not possible to change the

IED L/R Key to remote. If the DDB is set to 0, the IED L/R does not automatically change to Remote. If necessary, a user action is required to change the control authority to Remote.

Station/Remote: Station level commands are those originating from either the substation gateway or from the station HMI. Remote commands are from the remote Network Control Center (NCC).

The data object LocSta modelled in System\LLN0 shows the control authority at station level. If LocSta=True, control authority is at station level and control from remote is disabled. If LocSta=False, control commands are allowed from remote, e.g. network control center (NCC).

P40 devices also support the concept of Multiple Level Control authority. This is done via a dedicated datapoint in System\LLN0 known as MltLev. If true, authority control from multiple levels is allowed, otherwise no other control level is allowed.

Under certain operational conditions, such as during maintenance, it is necessary to block commands from one or more of these levels. The local/remote control feature (described in IEC 61850 7-4: Annex B) allows users to enable or disable control authority from one or more of the three levels, as illustrated in the tables below:

IEC 61850 commands originating from the various levels are differentiated using the Origin.OrCat attribute value in the IEC 61850 command.

If the control command is rejected by the P40 IED due to control authority check, the AddCause - Blocked-by-switching-hierarchy will be shown in the IEC 61850 Client.

Control Authority for Other Controllable Objects								
Device	**Switch**	**Bay Control**			**Manual Control at Front Panel**	**Command From**		
		Mode of Switching Authority for Local Control	**Local Control Behaviour**	**Control Authority at Station Level**		**OrCat**		
LLN0.Loc Key	**XCBR.Loc XWI.Loc**	**LLN0.Mlt Lev**	**CSWI.Loc**	**CSWI.Loc Sta**		**Bay**	**Station**	**Remote**
T	n.a.	F	n.a.	n.a.	AA	NA	NA	NA
F	T	F	T	n.a.	AA	NA	NA	NA
F	T	F	F	n.a.	NA	NA	NA	NA
F	F	F	T	n.a.	AA	NA	NA	NA
F	F	F	F	T	NA	NA	AA	NA
F	F	F	F	F	NA	NA	NA	AA
T	n.a.	T	n.a.	n.a.	AA	NA	NA	NA
F	T	T	T	n.a.	AA	NA	NA	NA
F	T	T	F	n.a.	NA	NA	NA	NA
F	F	T	T	n.a.	AA	NA	NA	NA
F	F	T	F	T	NA	AA	AA	NA
F	F	T	F	F	NA	AA	AA	AA

n.a. - Not Applicable
AA - Always Allowed
NA - Not Allowed

In addition to the CB/Switches, P40 devices follow the concept of Control Authority for other commands executed via IEC 61850. These include:

- Control Inputs
- Reset of Trip LED
- Enable/Disable of Protection, Check Sync and Auto Recloser
- Reset of demands and thermal measurements

Control Authority for Other Controllable Objects							
Device	Bay Control			Manual Control at Front Panel	Command From		
	Mode of Switching Authority for Local Control	Local Control Behaviour	Control Authority at Station Level		OrCat		
LLN0.Loc Key	LLN0.Mlt Lev	LLN0.Loc	LLN0.Loc Sta		Bay	Station	Remote
T	F	n.a.	n.a.	AA	NA	NA	NA
F	F	T	n.a.	AA	NA	NA	NA
F	F	F	T	AA	NA	AA	NA
F	F	F	F	AA	NA	NA	AA
T	T	n.a.	n.a.	AA	NA	NA	NA
F	T	T	n.a.	AA	NA	NA	NA
F	T	F	T	AA	AA	AA	NA
F	T	F	F	AA	AA	AA	AA
n.a. - Not Applicable AA - Always Allowed NA - Not Allowed							

IEC 61850 based control authority can be visualized from the P40 HMI.

This is under the COMMISSION TESTS Menu, under IEC 61850 Control Sub Menu:

Menu Text	Description	Min	Max	Default	Controllable
Multiple Level	Used to enable/disable the 'multi level control authority' feature for breaker/switch and other controls	Disabled	Enabled	Disabled	Yes
Station Level	Used to get control command of station authority from IEC 61850 Client	Disabled	Enabled	Disabled	No
Device Level	Used to show the IED local/remote status	Local	Remote	Local	No

Multiple Level Control Authority can be selected either via an IEC 61850 MMS Command or via selection from the menu item shown above.

Note:
The Control Authority only works if the Protocol is IEC 61850. For Legacy Protocols, the existing control mechanism remains.

Note:
For Control Authority for CB/Switches, it is mandatory to select the option of L/R for CB/Switches if IEC 61850 is used.

CHAPTER 14

SUPERVISION

14.1 CHAPTER OVERVIEW

This chapter describes the supervison functions.

This chapter contains the following sections:

Chapter Overview 342
Voltage Transformer Supervision 343
Current Transformer Supervision 347
Trip Circuit Supervision 349

14.2 VOLTAGE TRANSFORMER SUPERVISION

The Voltage Transformer Supervision (VTS) function is used to detect failure of the AC voltage inputs to the protection. This may be caused by voltage transformer faults, overloading, or faults on the wiring, which usually results in one or more of the voltage transformer fuses blowing.

If there is a failure of the AC voltage input, the IED could misinterpret this as a failure of the actual phase voltages on the power system, which could result in unnecessary tripping of a circuit breaker.

The VTS logic is designed to prevent such a situation by detecting voltage input failures, which are NOT caused by power system phase voltage failure, and automatically blocking associated voltage dependent protection elements. A time-delayed alarm output is available to warn of a VTS condition.

The following scenarios are possible with respect to the failure of the VT inputs.

- Loss of one or two-phase voltages
- Loss of all three-phase voltages under load conditions
- Absence of three-phase voltages upon line energisation

14.2.1 LOSS OF ONE OR TWO PHASE VOLTAGES

If the power system voltages are healthy, no Negative Phase Sequence (NPS) current will be present. If however, one or two of the AC voltage inputs are missing, there will be Negative Phase Sequence voltage present, even if the actual power system phase voltages are healthy. VTS works by detecting Negative Phase Sequence (NPS) voltage without the presence of Negative Phase Sequence current. So if there is NPS voltage present, but no NPS current, it is certain that there is a problem with the voltage transformers and a VTS block should be applied to voltage dependent protection functions to prevent maloperation. The use of negative sequence quantities ensures correct operation even where three-limb or V-connected VTs are used.

The Negative Sequence VTS Element is blocked by the ***Any Pole Dead*** DDB signal during ***SP AR Dead Time***. The resetting of the blocking signal is delayed by 240 ms after an ***Any Pole Dead*** condition disappears.

14.2.2 LOSS OF ALL THREE PHASE VOLTAGES

If all three voltage inputs are lost, there will be no Negative Phase Sequence quantities present, but the device will see that there is no voltage input. If this is caused by a power system failure, there will be a step change in the phase currents. However, if this is not caused by a power system failure, there will be no change in any of the phase currents. So if there is no measured voltage on any of the three phases and there is no change in any of the phase currents, this indicates that there is a problem with the voltage transformers and a VTS block should be applied to voltage dependent protection functions to prevent maloperation.

To avoid blocking VTS due to changing load condition, the superimposed current signal can only prevent operation of the VTS during the time window of 40 ms following the voltage collapse.

14.2.3 ABSENCE OF ALL THREE PHASE VOLTAGES ON LINE ENERGISATION

On line energisation there should be a change in the phase currents as a result of loading or line charging current. Under this condition we need an alternative method of detecting three-phase VT failure.

If there is no measured voltage on all three phases during line energisation, two conditions might apply:

- A three-phase VT failure
- A three-phase fault.

The first condition would require VTS to block the voltage-dependent functions.

In the second condition, voltage dependent functions should not be blocked, as tripping is required.

To differentiate between these two conditions an overcurrent level detector is used (***VTS I> Inhibit***). This prevents a VTS block from being issued in case of a genuine fault. This overcurrent level detector is only enabled for 240 ms following line energization (based on an ***All Poles Dead*** signal drop off). It must still be set below any three-phase fault along the line.

If the line is closed where a three-phase VT failure is present, the overcurrent detector will not operate and a VTS block will be applied. Closing onto a three-phase fault will result in operation of the overcurrent detector and prevent a VTS block being applied.

14.2.4 VTS IMPLEMENTATION

VTS is implemented in the *SUPERVISION* column of the relevant settings group.

The following settings are relevant for VT Supervision:

- ***VTS Mode***: determines the mode of operation (Measured + MCB, Measured Only, MCB Only)
- ***VTS Status***: determines whether the VTS Operate output will be a blocking output or an alarm indication only
- ***VTS Reset Mode***: determines whether the Reset is to be manual or automatic
- ***VTS Time Delay***: determines the operating time delay
- ***VTS I> Inhibit***: inhibits VTS operation in the case of a phase overcurrent fault
- ***VTS I2> Inhibit***: inhibits VTS operation in the case of a negative sequence overcurrent fault

For faults with I2 less than the setting ***VTS I2 Inhibit***, VTS will be active and block the associated functions if sufficient V2 is measured. VTS is only enabled during a live line condition (as indicated by the pole dead logic) to prevent operation under dead system conditions.

Thresholds

The negative sequence thresholds used by the element are:

- V2 = 10 V (fixed)
- I2 = 0.05 to 0.5 In settable (default 0.05 In).

The phase voltage level detectors are:

- Drop off = 10 V (fixed)
- Pickup = 30 V (fixed)

The sensitivity of the superimposed current elements is fixed at 0.1 In.

Fuse Fail

The device includes a setting (***VT Connected***) in the *CT AND VT RATIOS* column, which determines whether there are voltage transformers connected to it. If set to `No`, this setting has no effect.

If set to `No` it causes the VTS logic to set the ***VTS Slow Block*** and ***VTS Fast Block*** DDBs, but not raise any alarms. It also disables the VTS function. This prevents the pole dead logic working incorrectly if there is no voltage or current. It also blocks the distance, under voltage and other voltage-dependant functions. However, it does not affect the CB open part of the logic.

A VTS condition can be raised by a mini circuit breaker (MCB) status input, by internal logic using IED measurement, or both. The setting ***VTS Mode*** is used to select the method of indicating VT failure.

14.2.5 VTS LOGIC

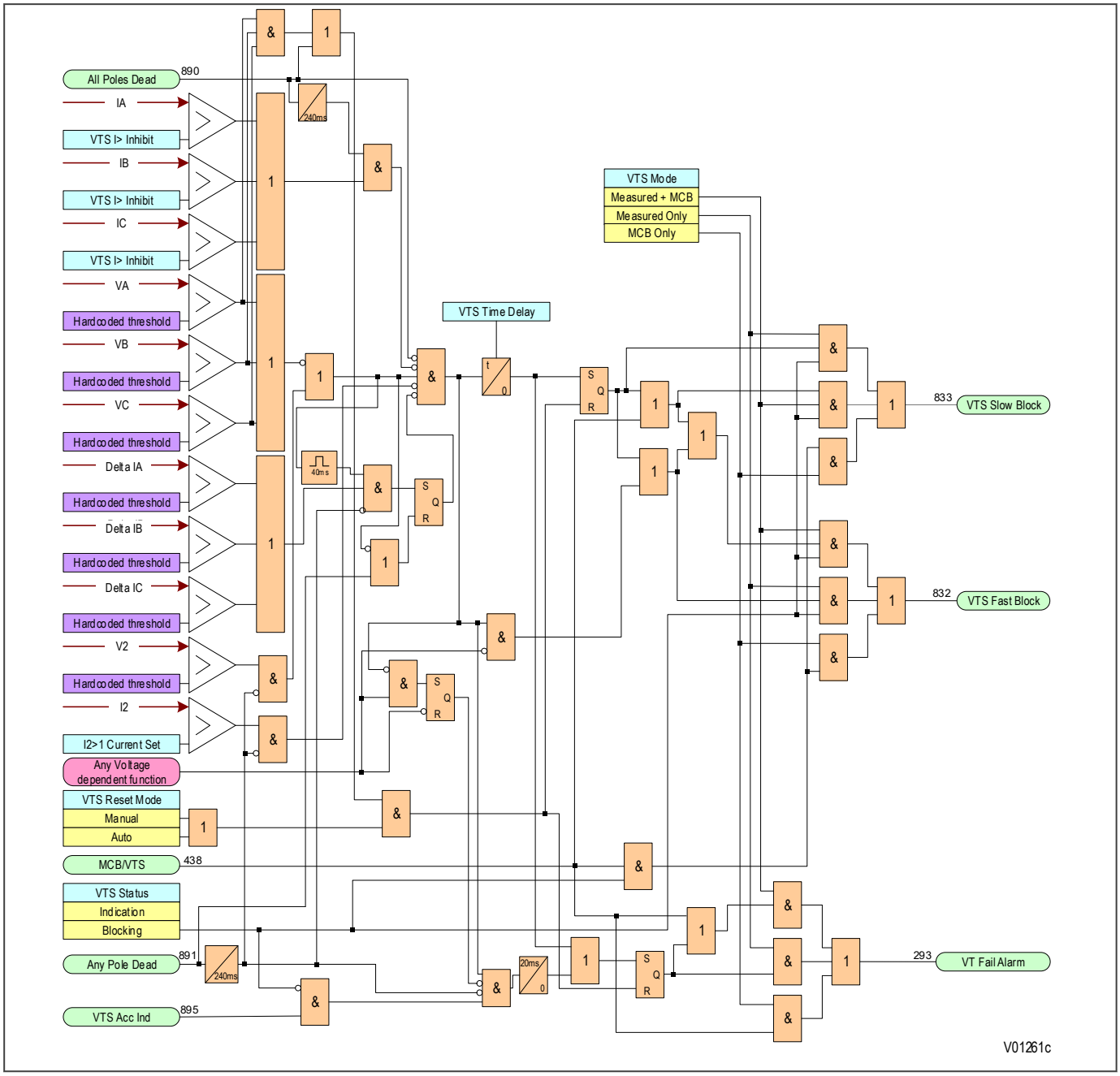


Figure 205: VTS logic

The IED may respond as follows, on operation of any VTS element:

- VTS set to provide alarm indication only
- Optional blocking of voltage-dependent protection elements
- Optional conversion of directional overcurrent elements to non-directional protection (by setting the relevant current protection status cells to `Enabled VTS`. In this case, the directional setting cells are automatically set to `non-directional`.)

The ***VTS I> Inhibit*** or ***VTS I2> Inhibit*** elements are used to override a VTS block if a fault occurs that could trigger the VTS logic. However, once the VTS block is set, subsequent system faults must not override the block. Therefore the VTS block is latched after a settable time delay (***VTS Time Delay***). Once the signal has latched, there are two

methods of resetting. The first is manually using the front panel HMI, or remote communications (if the VTS condition has been removed). The second is in Auto mode, by restoring the 3 phase voltages above the phase level detector settings mentioned previously.

VTS Status can be set to `Disabled`, `Blocking` or `Indication`. If ***VTS Status*** is set to `Blocking`, a VTS condition will block operation of the relevant protection elements. In this case, a VTS indication is given after the ***VTS Time Delay*** has expired. If it is set to `Indication`, their is a risk of maloperation because protection elements are not blocked. In this case the VTS indication is given before the ***VTS Time Delay*** expires, if a trip signal is given (in this case a signal from the VTS acceleration logic is used as an input).

This scheme also operates correctly under very low load or even no load conditions. To achieve this, it uses a combination of time delayed signals derived from the DDB signals ***VTS Fast Block*** and ***All Poles Dead***, to generate the distance blocking DDB signal called ***VTS Blk Distance.***

Note:
*All non-distance voltage-dependent elements are blocked by the **VTS Fast Block** DDB.*

If a miniature circuit breaker (MCB) is used to protect the voltage transformer output circuits, MCB auxiliary contacts can be used to indicate a three-phase output disconnection. It is possible for the VTS logic to operate correctly without this input, but this facility has been provided to maintain compatibility with some practises. Energising an opto-isolated input assigned to the ***MCB/VTS*** provides the necessary block.

The VTS function is inhibited if:

- An ***All Poles Dead*** DDB signal is present
- Any phase overcurrent condition exists
- A Negative Phase Sequence current exists
- If the phase current changes over the period of 1 cycle

14.3 CURRENT TRANSFORMER SUPERVISION

The Current Transformer Supervision function (CTS) is used to detect failure of the AC current inputs to the protection. This may be caused by internal current transformer faults, overloading, or faults on the wiring. If there is a failure of the AC current input, the protection could misinterpret this as a failure of the actual phase currents on the power system, which could result in maloperation. Also, an open circuit in the AC current circuits can cause dangerous CT secondary voltages to be generated.

14.3.1 CTS IMPLEMENTATION

If the power system currents are healthy, no zero sequence voltage are derived. However, if one or more of the AC current inputs are missing, a zero sequence current would be derived, even if the actual power system phase currents are healthy. Standard CTS works by detecting a derived zero sequence current where there is no corresponding derived zero sequence voltage.

The voltage transformer connection used must be able to refer zero sequence voltages from the primary to the secondary side. Therefore, this element should only be enabled where the VT is of a five-limb construction, or comprises three single-phase units with the primary star point earthed.

The CTS function is implemented in the *SUPERVISION* column of the relevant settings group, under the sub-heading *CT SUPERVISION*.

The following settings are relevant for CT Supervision:

- ***CTS Status***: to disable or enable CTS
- ***CTS VN< Inhibit***: inhibits CTS if the zero sequence voltage exceeds this setting
- ***CTS IN> Set***: determines the level of zero sequence current
- ***CTS Time Delay***: determines the operating time delay

14.3.2 STANDARD CTS LOGIC

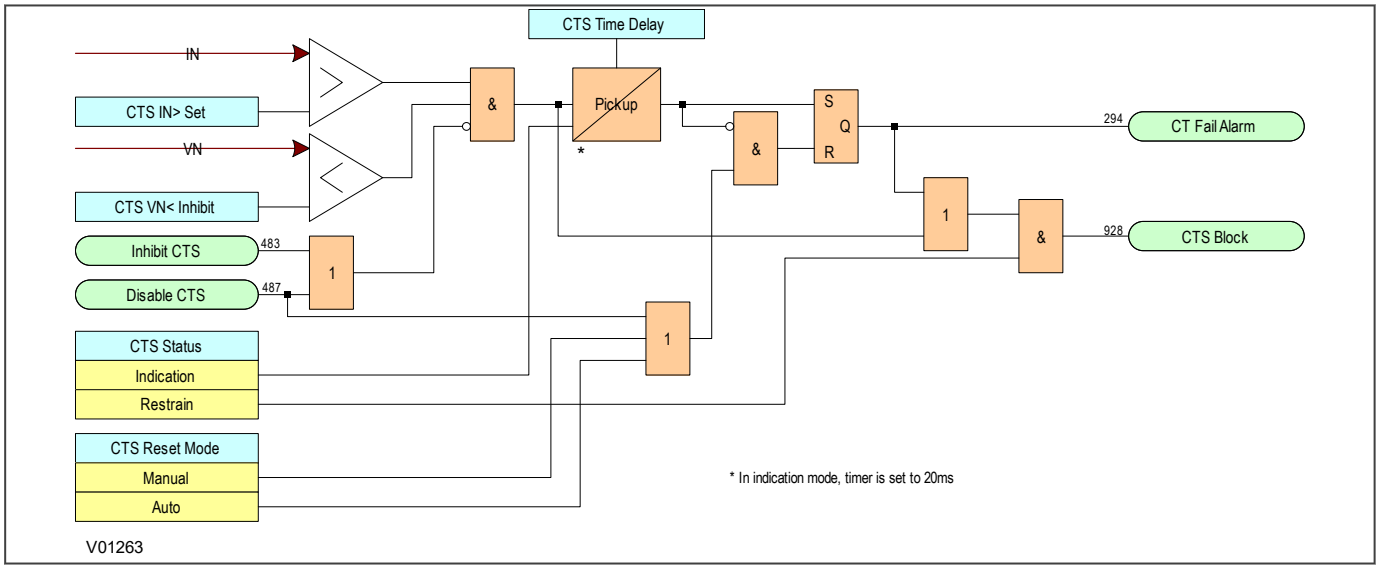


Figure 206: Standard CTS

14.3.3 CTS BLOCKING

Both the standard and differential CTS methods block protection elements operating from derived quantities, such as Broken conductor, derived earth fault and negative sequence overcurrent. Measured quantities such as DEF can be selectively blocked by designing an appropriate PSL scheme.

Differential CTS can be used to restrain the differential protection if required.

14.3.4 APPLICATION NOTES

14.3.4.1 SETTING GUIDELINES

The residual voltage setting, ***CTS VN< Inhibit*** and the residual current setting, ***CTS IN> Set***, should be set to avoid unwanted operation during healthy system conditions. For example:

- ***CTS VN< Inhibit*** should be set to 120% of the maximum steady state residual voltage.
- ***CTS IN> Set*** will typically be set below minimum load current.
- ***CTS Time Delay*** is generally set to 5 seconds.

Where the magnitude of residual voltage during an earth fault is unpredictable, the element can be disabled to prevent protection elements being blocked during fault conditions.

14.4 TRIP CIRCUIT SUPERVISION

In most protection schemes, the trip circuit extends beyond the IED enclosure and passes through components such as links, relay contacts, auxiliary switches and other terminal boards. Such complex arrangements may require dedicated schemes for their supervision.

There are two distinctly separate parts to the trip circuit; the trip path, and the trip coil. The trip path is the path between the IED enclosure and the CB cubicle. This path contains ancillary components such as cables, fuses and connectors. A break in this path is possible, so it is desirable to supervise this trip path and to raise an alarm if a break should appear in this path.

The trip coil itself is also part of the overall trip circuit, and it is also possible for the trip coil to develop an open-circuit fault.

This product supports a number of trip circuit supervision (TCS) schemes.

14.4.1 TRIP CIRCUIT SUPERVISION SCHEME 1

This scheme provides supervision of the trip coil with the CB open or closed, however, it does not provide supervision of the trip path whilst the breaker is open. The CB status can be monitored when a self-reset trip contact is used. However, this scheme is incompatible with latched trip contacts, as a latched contact will short out the opto-input for a time exceeding the recommended Delayed Drop-off (DDO) timer setting of 400 ms, and therefore does not support CB status monitoring. If you require CB status monitoring, further opto-inputs must be used.

Note:
A 52a CB auxiliary contact follows the CB position. A 52b auxiliary contact is the opposite.

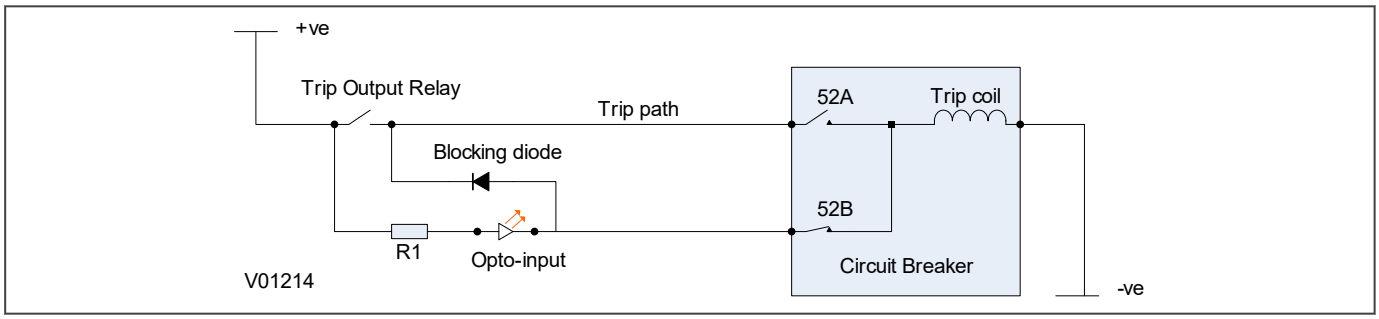


Figure 207: TCS scheme 1

When the CB is closed, supervision current passes through the opto-input, blocking diode and trip coil. When the CB is open, supervision current flows through the opto-input and into the trip coil via the 52b auxiliary contact. This means that *Trip Coil* supervision is provided when the CB is either closed or open, however *Trip Path* supervision is only provided when the CB is closed. No supervision of the trip path is provided whilst the CB is open (pre-closing supervision). Any fault in the trip path will only be detected on CB closing, after a 400 ms delay.

14.4.1.1 RESISTOR VALUES

The supervision current is a lot less than the current required by the trip coil to trip a CB. The opto-input limits this supervision current to less than 10 mA. If the opto-input were to be short-circuited however, it could be possible for the supervision current to reach a level that could trip the CB. For this reason, a resistor R1 is often used to limit the current in the event of a short-circuited opto-input. This limits the current to less than 60mA. The table below shows the appropriate resistor value and voltage setting for this scheme.

Trip Circuit Voltage	Opto Voltage Setting with R1 Fitted	Resistor R1 (ohms)
48/54	24/27	1.2k
110/125	48/54	2.7k
220/250	110/125	5.2k

Warning:
This Scheme is not compatible with Trip Circuit voltages of less than 48 V.

14.4.1.2 PSL FOR TCS SCHEME 1

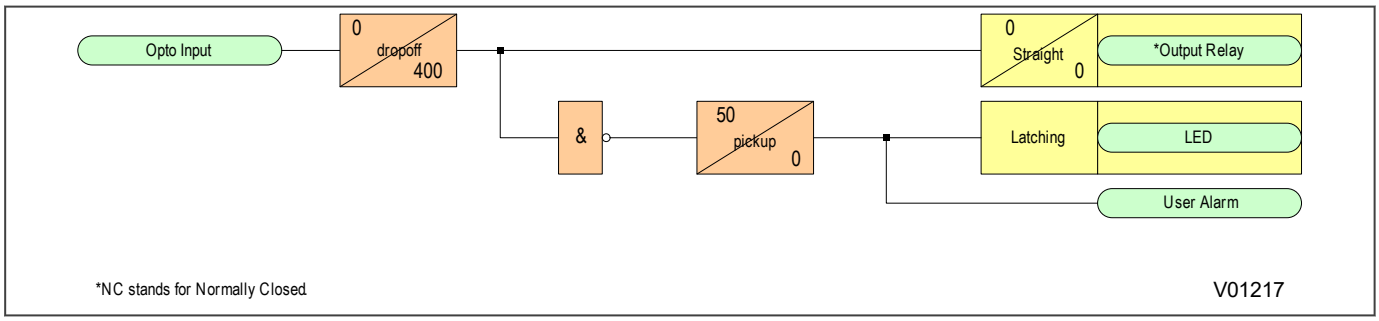


Figure 208: PSL for TCS scheme 1

The opto-input can be used to drive a Normally Closed Output Relay, which in turn can be used to drive alarm equipment. The signal can also be inverted to drive a latching programmable LED and a user alarm DDB signal.

The DDO timer operates as soon as the opto-input is energised, but will take 400 ms to drop off/reset in the event of a trip circuit failure. The 400 ms delay prevents a false alarm due to voltage dips caused by faults in other circuits or during normal tripping operation when the opto-input is shorted by a self-reset trip contact. When the timer is operated the NC (normally closed) output relay opens and the LED and user alarms are reset.

The 50 ms delay on pick-up timer prevents false LED and user alarm indications during the power up time, following a voltage supply interruption.

14.4.2 TRIP CIRCUIT SUPERVISION SCHEME 2

This scheme provides supervision of the trip coil with the breaker open or closed but does not provide pre-closing supervision of the trip path. However, using two opto-inputs allows the IED to correctly monitor the circuit breaker status since they are connected in series with the CB auxiliary contacts. This is achieved by assigning one opto-input to the 52a contact and another opto-input to the 52b contact. Provided the ***CB Status*** setting in the *CB CONTROL* column is set to `Both 52A and 52B`, the IED will correctly monitor the status of the breaker. This scheme is also fully compatible with latched contacts as the supervision current will be maintained through the 52b contact when the trip contact is closed.

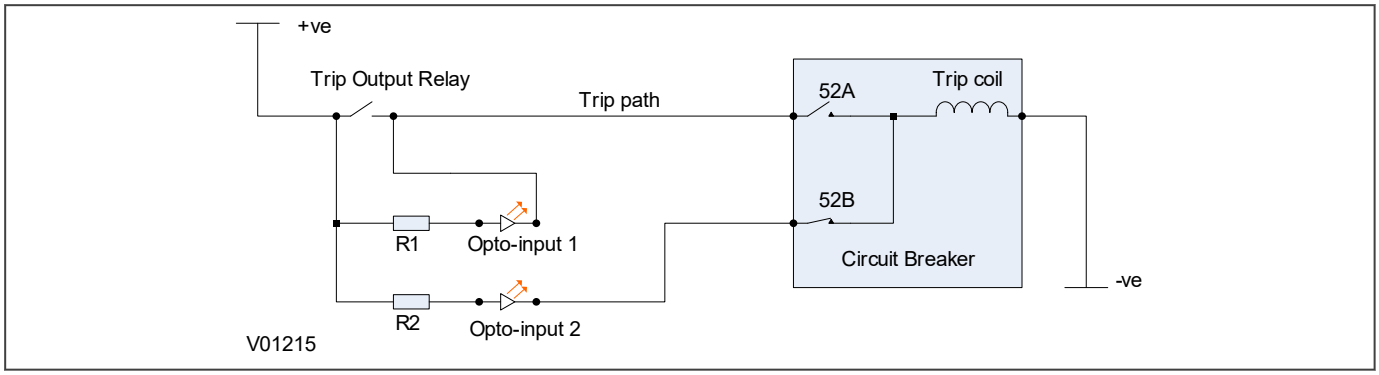


Figure 209: TCS scheme 2

When the breaker is closed, supervision current passes through opto input 1 and the trip coil. When the breaker is open current flows through opto input 2 and the trip coil. No supervision of the trip path is provided whilst the breaker is open. Any fault in the trip path will only be detected on CB closing, after a 400 ms delay.

14.4.2.1 RESISTOR VALUES

Optional resistors R1 and R2 can be added to prevent tripping of the CB if either opto-input is shorted. The table below shows the appropriate resistor value and voltage setting for this scheme.

Trip Circuit Voltage	Opto Voltage Setting with R1 Fitted	Resistor R1 and R2 (ohms)
48/54	24/27	1.2k
110/125	48/54	2.7k
220/250	110/125	5.2k

Warning:
This Scheme is not compatible with Trip Circuit voltages of less than 48 V.

14.4.2.2 PSL FOR TCS SCHEME 2

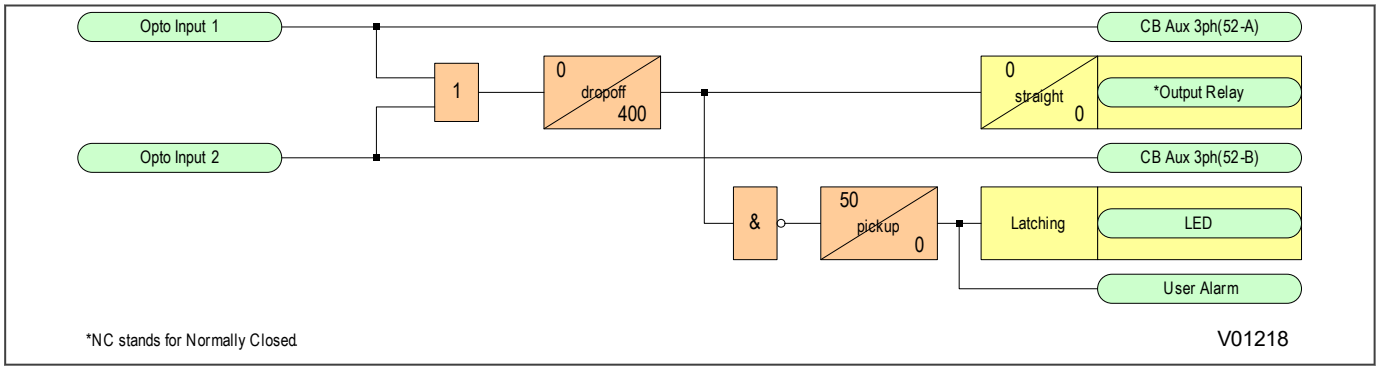


Figure 210: PSL for TCS scheme 2

In TCS scheme 2, both opto-inputs must be low before a trip circuit fail alarm is given.

14.4.3 TRIP CIRCUIT SUPERVISION SCHEME 3

TCS Scheme 3 is designed to provide supervision of the trip coil with the breaker open or closed. It provides pre-closing supervision of the trip path. Since only one opto-input is used, this scheme is not compatible with latched trip contacts. If you require CB status monitoring, further opto-inputs must be used.

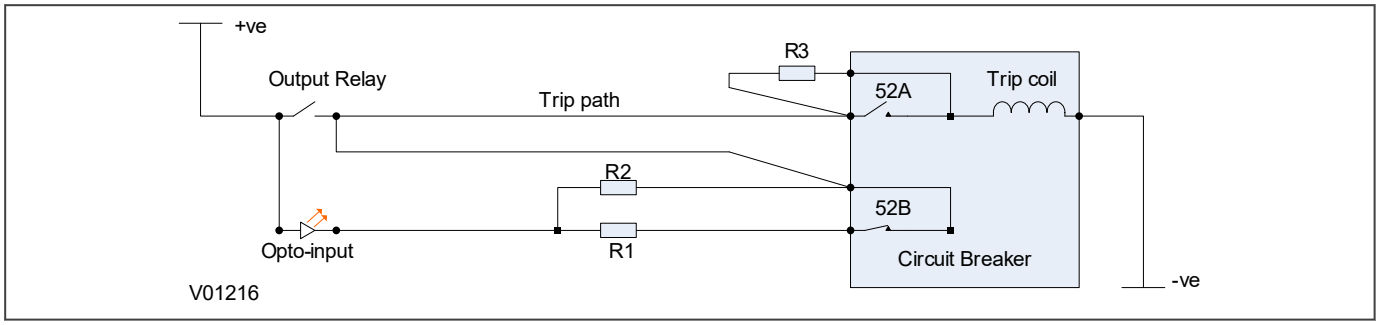


Figure 211: TCS scheme 3

When the CB is closed, supervision current passes through the opto-input, resistor R2 and the trip coil. When the CB is open, current flows through the opto-input, resistors R1 and R2 (in parallel), resistor R3 and the trip coil. The supervision current is maintained through the trip path with the breaker in either state, therefore providing pre-closing supervision.

14.4.3.1 RESISTOR VALUES

Resistors R1 and R2 are used to prevent false tripping, if the opto-input is accidentally shorted. However, unlike the other two schemes. This scheme is dependent upon the position and value of these resistors. Removing them would result in incomplete trip circuit monitoring. The table below shows the resistor values and voltage settings required for satisfactory operation.

Trip Circuit Voltage	Opto Voltage Setting with R1 Fitted	Resistor R1 & R2 (ohms)	Resistor R3 (ohms)
48/54	24/27	1.2k	600
110/250	48/54	2.7k	1.2k
220/250	110/125	5.0k	2.5k



Warning:
This Scheme is not compatible with Trip Circuit voltages of less than 48 V.

14.4.3.2 PSL FOR TCS SCHEME 3

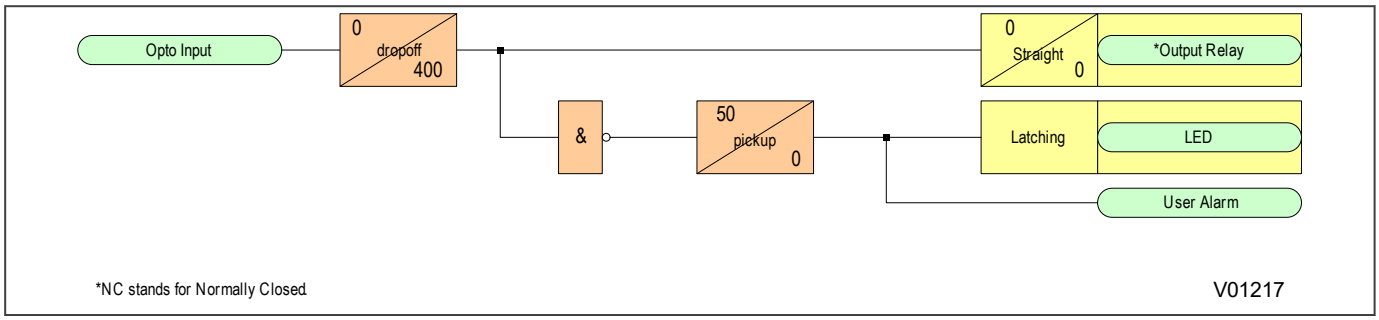


Figure 212: PSL for TCS scheme 3

CHAPTER 15

CB FAIL PROTECTION

15.1 CHAPTER OVERVIEW

The device provides a Circuit Breaker Fail Protection function. This chapter describes the operation of this function including the principles, logic diagrams and applications.

This chapter contains the following sections:

Chapter Overview 354
Circuit Breaker Fail Protection 355
Circuit Breaker Fail Implementation 356
Circuit Breaker Fail Logic 358
Application Notes 362

15.2 CIRCUIT BREAKER FAIL PROTECTION

When a fault occurs, one or more protection devices will operate and issue a trip command to the relevant circuit breakers. Operation of the circuit breaker is essential to isolate the fault and prevent, or at least limit, damage to the power system. For transmission and sub-transmission systems, slow fault clearance can also threaten system stability.

For these reasons, it is common practice to install Circuit Breaker Failure protection (CBF). CBF protection monitors the circuit breaker and establishes whether it has opened within a reasonable time. If the fault current has not been interrupted following a set time delay from circuit breaker trip initiation, the CBF protection will operate, whereby the upstream circuit breakers are back-tripped to ensure that the fault is isolated.

CBF operation can also reset all start output contacts, ensuring that any blocks asserted on upstream protection are removed.

15.3 CIRCUIT BREAKER FAIL IMPLEMENTATION

Circuit Breaker Failure Protection is implemented in the *CB FAIL & P.DEAD* column of the relevant settings group. Independent CB Fail settings are provided for CB1.

15.3.1 CIRCUIT BREAKER FAIL TIMERS

The circuit breaker failure protection incorporates two timers, ***CB Fail 1 Timer*** and ***CB Fail 2 Timer***, allowing configuration for the following scenarios:

- Simple CBF, where only ***CB Fail 1 Timer*** is enabled. For any protection trip, the **CB Fail 1** ***Timer*** is started, and normally reset when the circuit breaker opens to isolate the fault. If breaker opening is not detected, the CB Fail 1 Timer times out and closes an output contact assigned to breaker fail (using the programmable scheme logic). This contact is used to back-trip upstream switchgear, generally tripping all infeeds connected to the same busbar section.
- A retripping scheme, plus delayed back-tripping. Here, ***CB Fail 1 Timer*** is used to issue a trip command to a second trip circuit of the same circuit breaker. This requires the circuit breaker to have duplicate circuit breaker trip coils. This mechanism is known as retripping. If retripping fails to open the circuit breaker, a back-trip may be issued following an additional time delay. The back-trip uses ***CB Fail 2 Timer***, which was also started at the instant of the initial protection element trip.

You can configure the CBF elements ***CB Fail 1 Timer*** and ***CBF Fail 2 Timer*** to operate for trips triggered by protection elements within the device. Alternatively you can use an external protection trip by allocating one of the opto-inputs to the ***External Trip*** DDB signal in the PSL.

You can reset the CBF from a breaker open indication (from the pole dead logic) or from a protection reset. In these cases resetting is only allowed if the undercurrent elements have also been reset. The resetting mechanism is determined by the settings ***NonIProt Rst*** and ***Ext Prot Rst***.

The resetting options are summarised in the following table:

Initiation (Menu Selectable)	CB Fail Timer Reset Mechanism
Current based protection (e.g.50/51/46/21/87)	IA< operates AND IB< operates AND IC< operates AND IN< operates or through Ext Rst DDB in PSL
Sensitive Earth Fault element	ISEF< Operates or Ext Rst SEF DDB
Non-current based protection (e.g. 27/59/81/32L)	Five options are available: • All I< and IN< elements operate or Ext Rst CBF DDB • Protection element reset AND (all I< and IN< elements operate or Ext Rst DDB • CB open (all 3 poles) AND all I< and IN< elements operate
External protection	Five options are available. • All I< and IN< elements operate • External trip reset AND all I< and IN< elements operate • CB open (all 3 poles) AND all I< and IN< elements operate • Prot Reset OR I<: External trip reset OR all I< and IN< elements operate • Rst or CBOp & I<: External trip reset OR Pole Dead AND all I< and IN< elements operate

15.3.2 CIRCUIT BREAKER FAIL INITIATION

If ***ExtTrip Only Ini*** setting is `Disabled`, the CBF protection can be initiated when any internal protection function issues a trip or if an external protection trip occurs. If ***ExtTrip Only Ini*** setting is `Enabled`, then only external protection is allowed to initiate the CBF function. An external protection and internal current-based protections (except SEF protection) initiate the CB Fail function on per-phase basis, while non-current-based protections and SEF initiate CB Fail for all three phases simultaneously.

15.3.3 ZERO CROSSING DETECTION

When there is a fault and the circuit breaker interrupts the CT primary current, the flux in the CT core decays to a residual level. This decaying flux introduces a decaying DC current in the CT secondary circuit known as subsidence current. The closer the CT is to its saturation point, the higher the subsidence current.

The time constant of this subsidence current depends on the CT secondary circuit time constant and it is generally long. If the protection clears the fault, the CB Fail function should reset fast to avoid maloperation due to the subsidence current. To compensate for this the device includes a zero-crossing detection algorithm, which ensures that the CB Fail re-trip and back-trip signals are not asserted while subsidence current is flowing. If all the samples within half a cycle are greater than or smaller than 0 A (10 mS for a 50 Hz system), then zero crossing detection is asserted, thereby blocking the operation of the CB Fail function. The zero-crossing detection algorithm is used after the circuit breaker in the primary system has opened ensuring that the only current flowing in the AC secondary circuit is the subsidence current.

15.4 CIRCUIT BREAKER FAIL LOGIC

15.4.1 CIRCUIT BREAKER FAIL LOGIC - PART 1

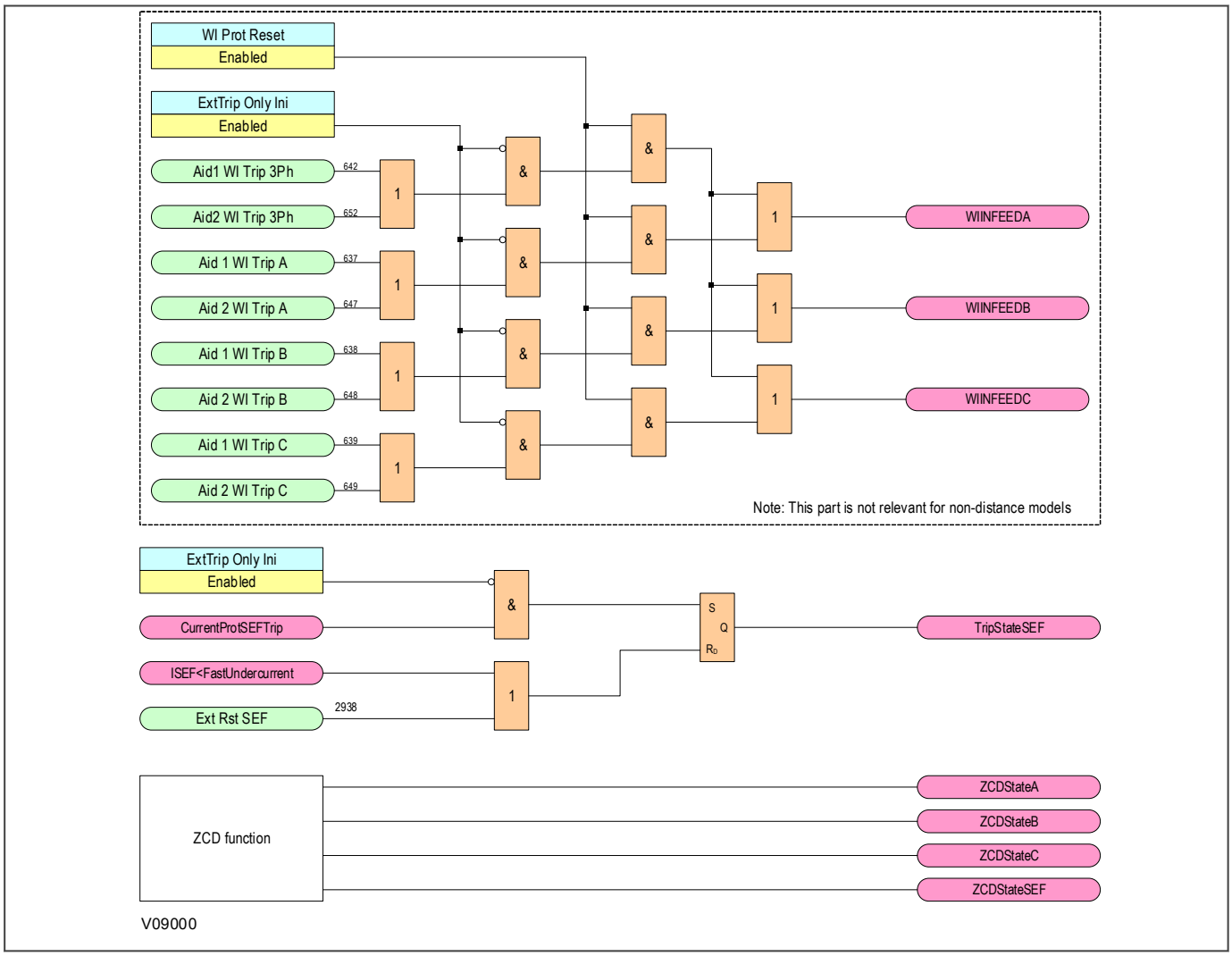


Figure 213: Circuit breaker fail logic - part 1

15.4.2 CIRCUIT BREAKER FAIL LOGIC - PART 2

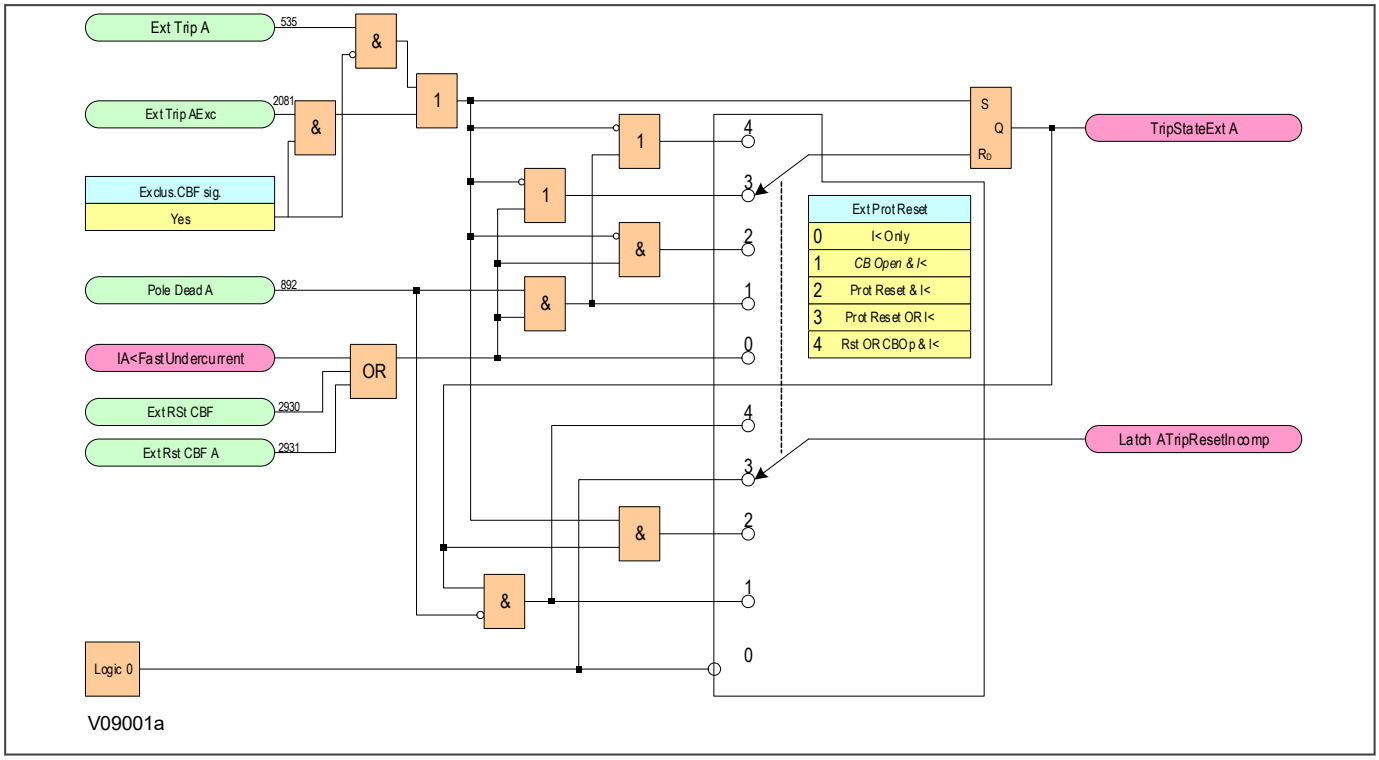


Figure 214: Circuit breaker fail logic - part 2

15.4.3 CIRCUIT BREAKER FAIL LOGIC - PART 3

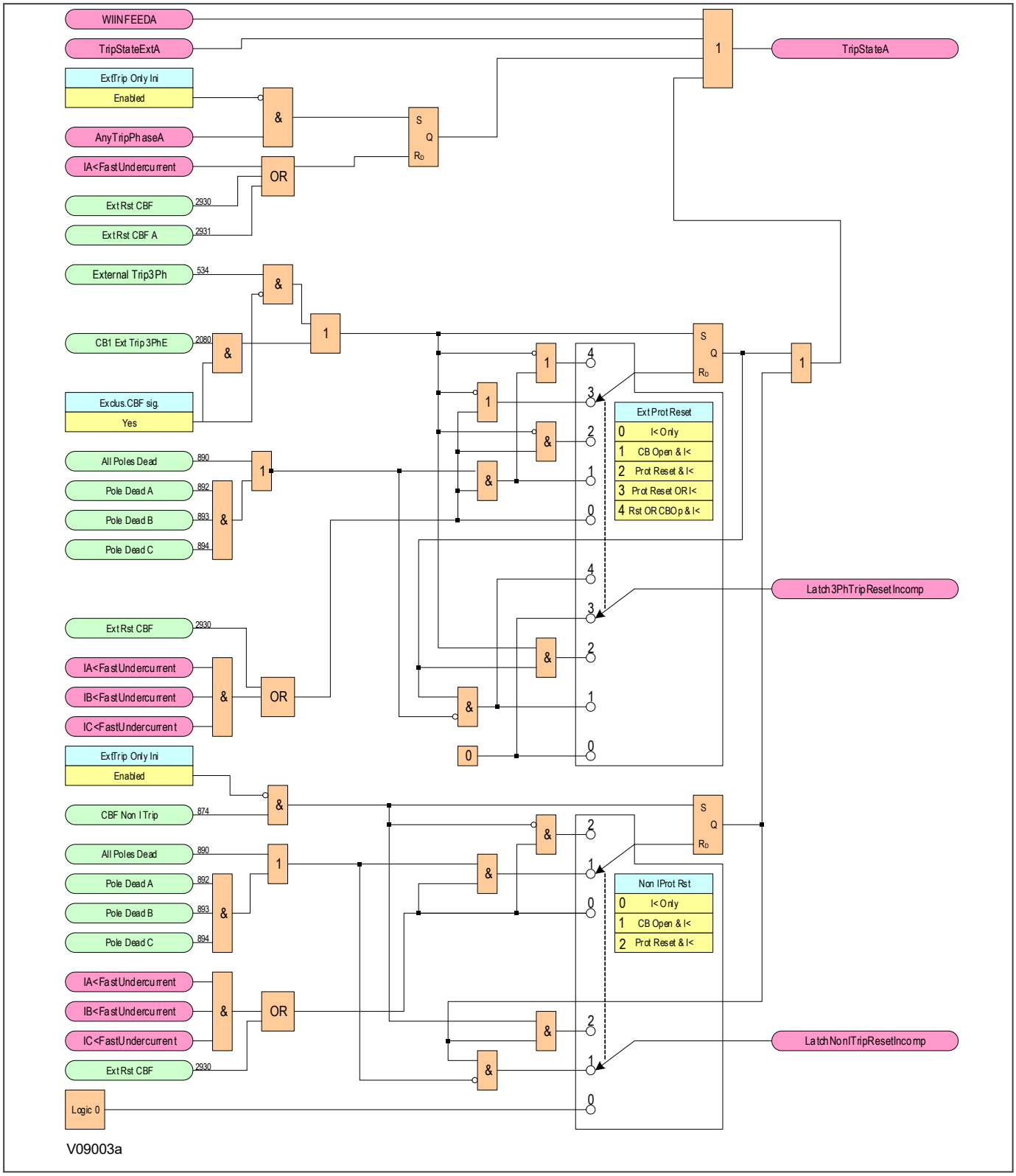


Figure 215: Circuit breaker fail logic - part 3

15.4.4 CIRCUIT BREAKER FAIL LOGIC - PART 4

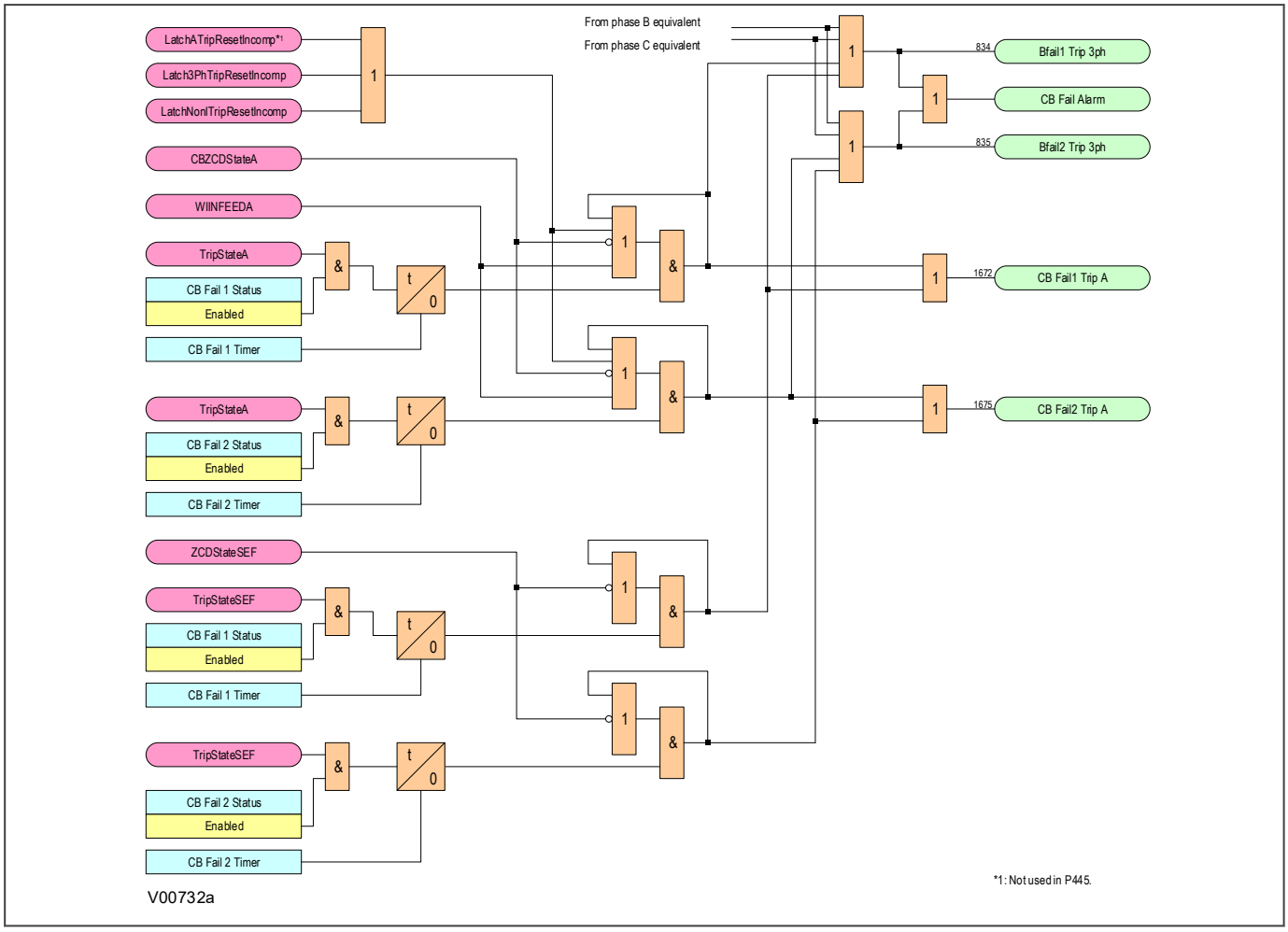


Figure 216: Circuit breaker fail logic - part 4

Note:
This diagram shows only phase-A for a single-CB device. The diagrams for phases B and C follow the same principle and are not repeated here.

15.5 APPLICATION NOTES

15.5.1 RESET MECHANISMS FOR CB FAIL TIMERS

It is common practise to use low set undercurrent elements to indicate that circuit breaker poles have interrupted the fault or load current. This covers the following situations:

- Where circuit breaker auxiliary contacts are defective, or cannot be relied on to definitely indicate that the breaker has tripped.
- Where a circuit breaker has started to open but has become jammed. This may result in continued arcing at the primary contacts, with an additional arcing resistance in the fault current path. Should this resistance severely limit fault current, the initiating protection element may reset. Therefore, reset of the element may not give a reliable indication that the circuit breaker has opened fully.

For any protection function requiring current to operate, the device uses operation of undercurrent elements to detect that the necessary circuit breaker poles have tripped and reset the CB fail timers. However, the undercurrent elements may not be reliable methods of resetting CBF in all applications. For example:

- Where non-current operated protection, such as under/overvoltage or under/overfrequency, derives measurements from a line connected voltage transformer. Here, I< only gives a reliable reset method if the protected circuit would always have load current flowing. In this case, detecting drop-off of the initiating protection element might be a more reliable method.
- Where distance schemes include Weak Infeed trip logic. The reset of the Weak infeed trip condition should be used in addition to the undercurrent check. ***WI Prot Reset*** should be set to `enabled`.
- Where non-current operated protection, such as under/overvoltage or under/overfrequency, derives measurements from a busbar connected voltage transformer. Again using I< would rely on the feeder normally being loaded. Also, tripping the circuit breaker may not remove the initiating condition from the busbar, and so drop-off of the protection element may not occur. In such cases, the position of the circuit breaker auxiliary contacts may give the best reset method.

You can reset the CBF from a breaker open indication (from the pole dead logic) or from a protection reset. In these cases resetting is only allowed if the undercurrent elements have also been reset. The resetting mechanism is determined by the settings ***Non I Prot Reset*** and ***Ext Prot Reset***.

If the CBF protection is initiated by an external protection trip, then two resetting options ***Prot Reset OR I<*** and ***Rst or CBOp & I<*** are provided. These settings don't necessarily require undercurrent element (I<) operation, as shown in the table below. These options are useful if re-tripping is not implemented, as they allow avoiding back-tripping due to spurious short-time energisation of External Trip opto-inputs.

Warning:
If you are using *Prot Reset OR I<* or *Rst or CBOp & I<*, do not connect the *External Trip* inputs to the Trip Conversion logic inputs in the PSL.

15.5.2 SETTING GUIDELINES (CB FAIL TIMER)

The following timing chart shows the CB Fail timing during normal and CB Fail operation. The maximum clearing time should be less than the critical clearing time which is determined by a stability study. The CB Fail back-up trip time delay considers the maximum CB clearing time, the CB Fail reset time plus a safety margin. Typical CB clearing times are 1.5 or 3 cycles. The CB Fail reset time should be short enough to avoid CB Fail back-trip during normal operation. Phase and ground undercurrent elements must be asserted for the CB Fail to reset. The assertion of the undercurrent elements might be delayed due to the subsidence current that might be flowing through the secondary AC circuit.

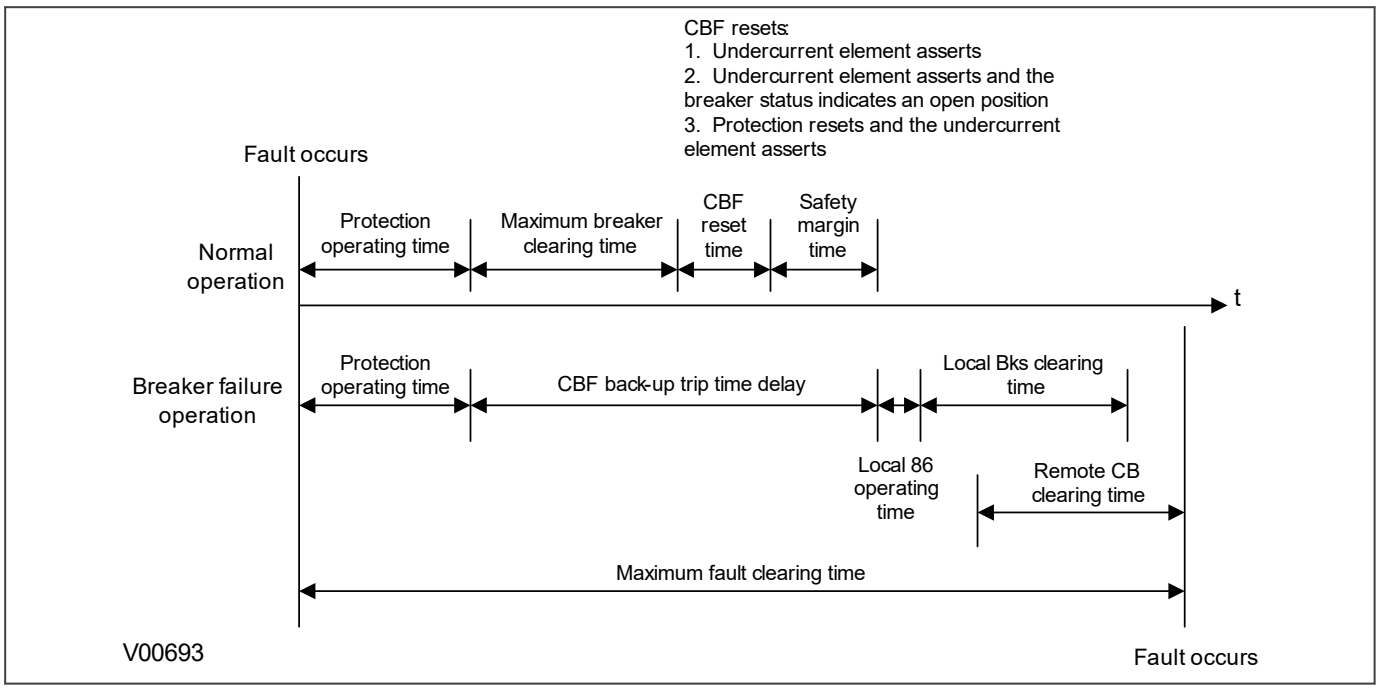


Figure 217: CB fail timing

The following examples consider direct tripping of a 2-cycle circuit breaker. Typical timer settings to use are as follows:

CB Fail Reset Mechanism	tBF Time Delay	Typical Delay For 2 Cycle Circuit Breaker
Initiating element reset	CB interrupting time + element reset time (max.) + error in tBF timer + safety margin	50 + 50 + 10 + 50 = 160 ms
CB open	CB auxiliary contacts opening/ closing time (max.) + error in tBF timer + safety margin	50 + 10 + 50 = 110 ms
Undercurrent elements	CB interrupting time + undercurrent element (max.) + safety margin operating time	50 + 25 + 50 = 125 ms

Note:
All CB Fail resetting involves the operation of the undercurrent elements. Where element resetting or CB open resetting is used, the undercurrent time setting should still be used if this proves to be the worst case.
Where auxiliary tripping relays are used, an additional 10-15 ms must be added to allow for trip relay operation.

15.5.3 SETTING GUIDELINES (UNDERCURRENT)

The phase undercurrent settings (I<) must be set less than load current to ensure that I< operation correctly indicates that the circuit breaker pole is open. A typical setting for overhead line or cable circuits is 20%In. Settings of 5% of In are common for generator CB Fail.

The earth fault undercurrent elements must be set less than the respective trip. For example:

$$IN< = (IN> \text{ trip})/2$$

CHAPTER 16

DIGITAL I/O AND PSL CONFIGURATION

16.1 CHAPTER OVERVIEW

This chapter introduces the PSL (Programmable Scheme Logic) Editor, and describes the configuration of the digital inputs and outputs. It provides an outline of scheme logic concepts and the PSL Editor. This is followed by details about allocation of the digital inputs and outputs, which require the use of the PSL Editor. A separate "Settings Application Software" document is available that gives a comprehensive description of the PSL, but enough information is provided in this chapter to allow you to allocate the principal digital inputs and outputs.

This chapter contains the following sections:

Chapter Overview 365
Configuring Digital Inputs and Outputs 366
Scheme Logic 367
Configuring the Opto-Inputs 369
Assigning the Output Relays 370
Fixed Function LEDs 371
Configuring Programmable LEDs 372
Function Keys 374
Control Inputs 375
User Alarms 376

16.2 CONFIGURING DIGITAL INPUTS AND OUTPUTS

Configuration of the digital inputs and outputs in this product is very flexible. You can use a combination of settings and programmable logic to customise them to your application. You can access some of the settings using the keypad on the front panel, but you will need a computer running the settings application software to fully interrogate and configure the properties of the digital inputs and outputs.

The settings application software includes an application called the PSL Editor (Programmable Scheme Logic Editor). The PSL Editor lets you allocate inputs and outputs according to your specific application. It also allows you to apply attributes to some of the signals such as a drop-off delay for an output contact.

In this product, digital inputs and outputs that are configurable are:

- Optically isolated digital inputs (opto-inputs). These can be used to monitor the status of associated plant.
- Output relays. These can be used for purposes such as initiating the tripping of circuit breakers, providing alarm signals, etc..
- Programmable LEDs. The number and colour of the programmable LEDs varies according to the particular product being applied.
- Function keys and associated LED indications. These are not provided on all products, but where they are, each function key has an associated tri-colour LED.
- IEC 61850 GOOSE inputs and outputs. These are only provided on products that have been specified for connection to an IEC61850 system, and the details of the GOOSE are presented in the documentation on IEC61850.

16.3 SCHEME LOGIC

The product is supplied with pre-loaded Fixed Scheme Logic (FSL) and Programmable Scheme Logic (PSL).

The Scheme Logic is a functional module within the IED, through which all mapping of inputs to outputs is handled. The scheme logic can be split into two parts; the Fixed Scheme Logic (FSL) and the Programmable Scheme Logic (PSL). It is built around a concept called the digital data bus (DDB). The DDB encompasses all of the digital signals (DDBs) which are used in the FSL and PSL. The DDBs included digital inputs, outputs, and internal signals.

The FSL is logic that has been hard-coded in the product. It is fundamental to correct interaction between various protection and/or control elements. It is fixed and cannot be changed.

The PSL gives you a facility to develop custom schemes to suit your application if the factory-programmed default PSL schemes do not meet your needs. Default PSL schemes are programmed before the product leaves the factory. These default PSL schemes have been designed to suit typical applications and if these schemes suit your requirements, you do not need to take any action. However, if you want to change the input-output mappings, or to implement custom scheme logic, you can change these, or create new PSL schemes using the PSL editor.

The PSL consists of components such as logic gates and timers, which combine and condition DDB signals.

The logic gates can be programmed to perform a range of different logic functions. The number of inputs to a logic gate are not limited. The timers can be used either to create a programmable delay or to condition the logic outputs. Output contacts and programmable LEDs have dedicated conditioners.

The PSL logic is event driven. Only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This minimises the amount of processing time used by the PSL ensuring industry leading performance.

The following diagram shows how the scheme logic interacts with the rest of the IED.

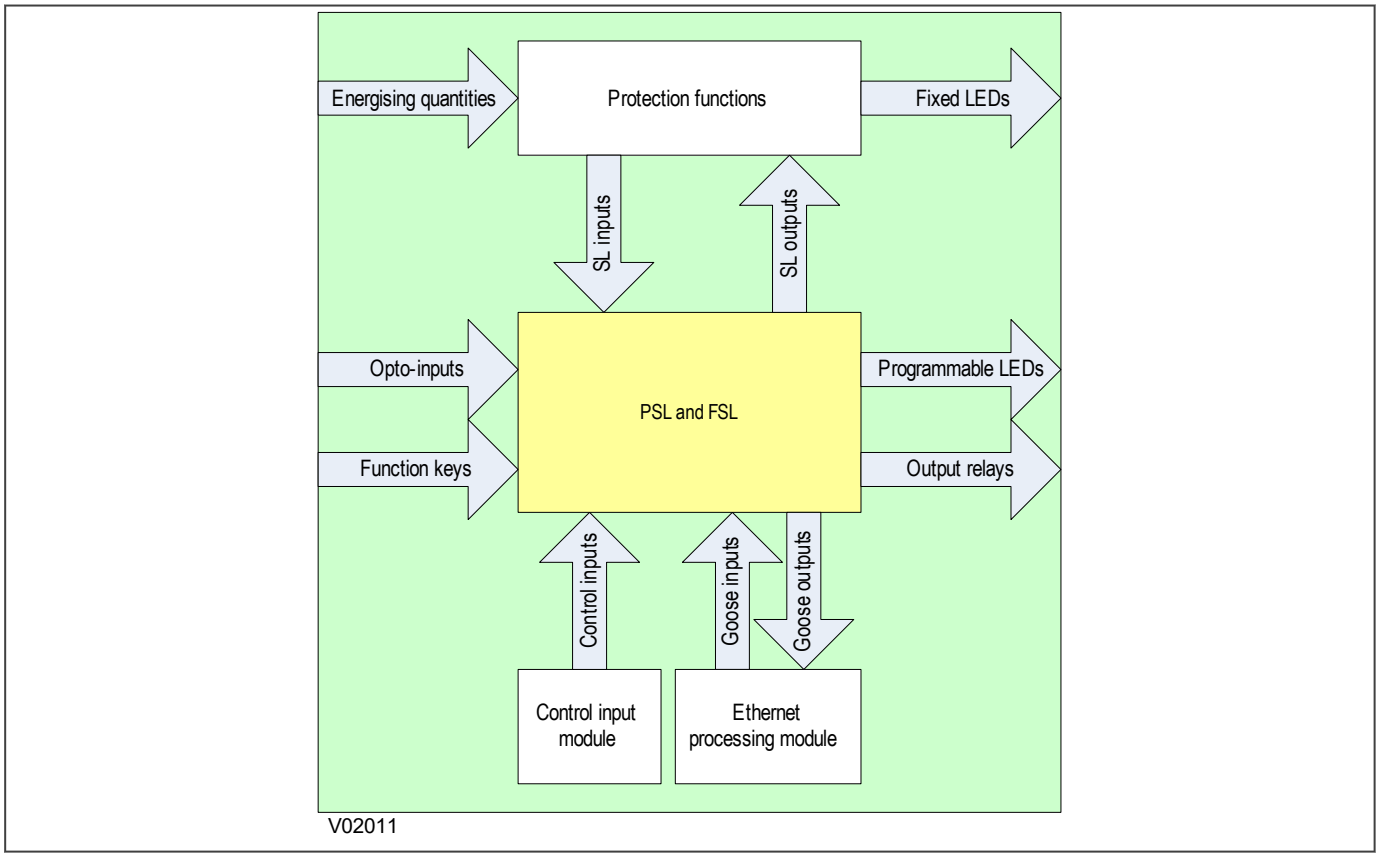


Figure 218: Scheme logic interfaces

16.3.1 PSL EDITOR

The Programmable Scheme Logic (PSL) is a module of programmable logic gates and timers in the IED, which can be used to create customised logic to qualify how the product manages its response to system conditions. The IED's digital inputs are combined with internally generated digital signals using logic gates, timers, and conditioners. The resultant signals are then mapped to digital outputs signals including output relays and LEDs.

The PSL Editor is a tool in the settings application software that allows you to create and edit scheme logic diagrams. You can use the default scheme logic which has been designed to suit most applications, but if it does not suit your application you can change it. If you create a different scheme logic with the software, you need to upload it to the device to apply it.

16.3.2 PSL SCHEMES

Your product is shipped with default scheme files. These can be used without modification for most applications, or you can choose to use them as a starting point to design your own scheme. You can also create a new scheme from scratch. To create a new scheme, or to modify an existing scheme, you will need to launch the settings application software. You then need to open an existing PSL file, or create a new one, for the particular product that you are using, and then open a PSL file. If you want to create a new PSL file, you should select **File** then **New** then **Blank scheme...** This action opens a default file appropriate for the device in question, but deletes the diagram components from the default file to leave an empty diagram with configuration information loaded. To open an existing file, or a default file, simply double-click on it.

16.3.3 PSL SCHEME VERSION CONTROL

To help you keep track of the PSL loaded into products, a version control feature is included. The user interface contains a *PSL DATA* column, which can be used to track PSL modifications. A total of 12 cells are contained in the *PSL DATA* column; 3 for each setting group.

Grp(n) PSL Ref: When downloading a PSL scheme to an IED, you will be prompted to enter the relevant group number and a reference identifier. The first 32 characters of the reference identifier are displayed in this cell. The horizontal cursor keys can scroll through the 32 characters as the LCD display only displays 16 characters.

Example:

```
Grp(n) PSL Ref
```

Date/time: This cell displays the date and time when the PSL scheme was downloaded to the IED.

Example:

```
18 Nov 2002
08:59:32.047
```

Grp(n) PSL ID: This cell displays a unique ID number for the downloaded PSL scheme.

Example:

```
Grp(n) PSL ID
ID - 2062813232
```

16.4 CONFIGURING THE OPTO-INPUTS

The number of optically isolated status inputs (opto-inputs) depends on the specific model supplied. The use of the inputs will depend on the application, and their allocation is defined in the programmable scheme logic (PSL). In addition to the PSL assignment, you also need to specify the expected input voltage. Generally, all opto-inputs will share the same input voltage range, but if different voltage ranges are being used, this device can accommodate them.

In the *OPTO CONFIG* column there is a global nominal voltage setting. If all opto-inputs are going to be energised from the same voltage range, you select the appropriate value in the setting. If you select `Custom` in the setting, then the cells ***Opto Input 1***, ***Opto Input 2***, etc. become visible. You use these cells to set the voltage ranges for each individual opto-input.

Within the *OPTO CONFIG* column there are also settings to control the filtering applied to the inputs, as well as the pick-up/drop-off characteristic.

The filter control setting provides a bit string with a bit associated with all opto-inputs. Setting the bit to '1' means that a half-cycle filter is applied to the inputs. This helps to prevent incorrect operation in the event of power system frequency interference on the wiring. Setting the field to '0' removes the filter and provides for faster operation.

The ***Characteristic*** setting is a single setting that applies to all the opto-inputs. It is used to set the pick-up/drop-off ratios of the input signals. As standard it is set to 80% pick-up and 60% drop-off, but you can change it to other available thresholds if that suits your operational requirements.

16.5 ASSIGNING THE OUTPUT RELAYS

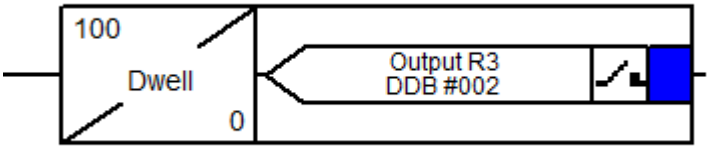
Relay contact action is controlled using the PSL. DDB signals are mapped in the PSL and drive the output relays. The driving of an output relay is controlled by means of a relay output conditioner. Several choices are available for how output relay contacts are conditioned. For example, you can choose whether operation of an output relay contact is latched, has delay on pick-up, or has a delay on drop-off. You make this choice in the **Contact Properties** window associated with the output relay conditioner.

To map an output relay in the PSL you should use the Contact Conditioner button in the toolbar to import it. You then condition it according to your needs. The output of the conditioner respects the attributes you have assigned.

The toolbar button for a Contact Conditioner looks like this:



The PSL contribution that it delivers looks like this:



Note:
Contact Conditioners are only available if they have not all been used. In some default PSL schemes, all Contact Conditioners might have been used. If that is the case, and you want to use them for something else, you will need to re-assign them.

On the toolbar there is another button associated with the relay outputs. The button looks like this:



This is the "Contact Signal" button. It allows you to put replica instances of a conditioned output relay into the PSL, preventing you having to make cross-page connections which might detract from the clarity of the scheme.

16.6 FIXED FUNCTION LEDS

Four fixed-function LEDs on the left-hand side of the front panel indicate the following conditions.

- Trip (Red) switches ON when the IED issues a trip signal. It is reset when the associated fault record is cleared from the front display. Also the trip LED can be configured as self-resetting.
- Alarm (Yellow) flashes when the IED registers an alarm. This may be triggered by a fault, event or maintenance record. The LED flashes until the alarms have been accepted (read), then changes to constantly ON. When the alarms are cleared, the LED switches OFF.
- Out of service (Yellow) is ON when the IED's functions are unavailable.
- Healthy (Green) is ON when the IED is in correct working order, and should be ON at all times. It goes OFF if the unit's self-tests show there is an error in the hardware or software. The state of the healthy LED is reflected by the watchdog contacts at the back of the unit.

16.6.1 TRIP LED LOGIC

When a trip occurs, the trip LED is illuminated. It is possible to reset this with a number of ways:

- Directly with a reset command (by pressing the Clear Key)
- With a reset logic input
- With self-resetting logic

You enable the automatic self-resetting with the ***Sys Fn Links*** cell in the *SYSTEM DATA* column. A '0' disables self resetting and a '1' enables self resetting.

The reset occurs when the circuit is reclosed and the ***Any Pole Dead*** signal has been reset for three seconds providing the ***Any Start*** signal is inactive. The reset is prevented if the ***Any Start*** signal is active after the breaker closes.

The Trip LED logic is as follows:

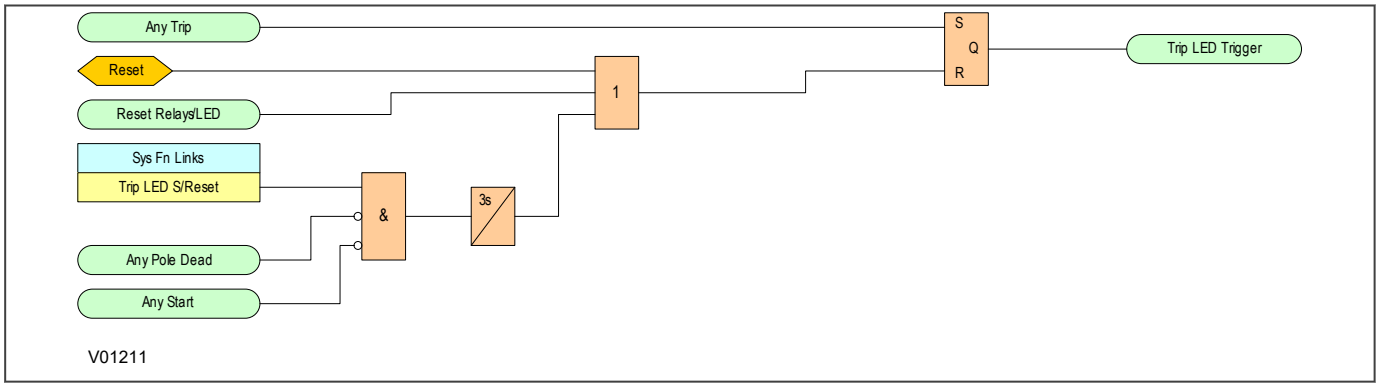


Figure 219: Trip LED logic

16.7 CONFIGURING PROGRAMMABLE LEDS

There are three types of programmable LED signals which vary according to the model being used. These are:

- Single-colour programmable LED. These are red when illuminated.
- Tri-colour programmable LED. These can be illuminated red, green, or amber.
- Tri-colour programmable LED associated with a Function Key. These can be illuminated red, green, or amber.

DDB signals are mapped in the PSL and used to illuminate the LEDs. For single-coloured programmable LEDs there is one DDB signal per LED. For tri-coloured LEDs there are two DDB signals associated with the LED. Asserting ***LED # Grn*** will illuminate the LED green. Asserting ***LED # Red*** will illuminate the LED red. Asserting both DDB signals will illuminate the LED amber.

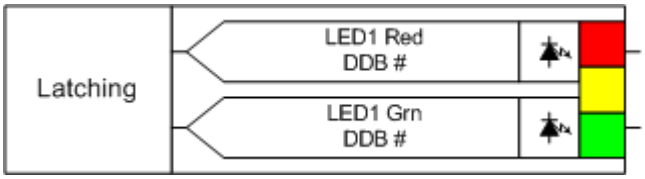
The illumination of an LED is controlled by means of a conditioner. Using the conditioner, you can decide whether the LEDs reflect the real-time state of the DDB signals, or whether illumination is latched pending user intervention.

To map an LED in the PSL you should use the LED Conditioner button in the toolbar to import it. You then condition it according to your needs. The output(s) of the conditioner respect the attribute you have assigned.

The toolbar button for a tri-colour LED looks like this:



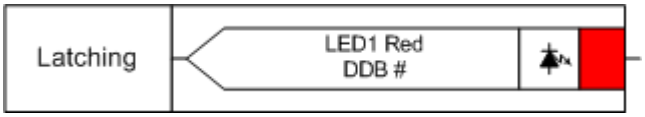
The PSL contribution that it delivers looks like this:



The toolbar button for a single-colour LED looks like this:



The PSL contribution that it delivers looks like this.



Note:
LED Conditioners are only available if they have not all been used up, and in some default PSL schemes they might be. If that is the case and you want to use them for something else, you will need to re-assign them.

On the toolbar there is another button associated with the LEDs. For a tri-coloured LED the button looks like this:



For a single-colour LED it looks like this: 

It is the "LED Signal" button. It allows you to put replica instances of a conditioned LED into the PSL, preventing you having to make cross-page connections which might detract from the clarity of the scheme.

Note:
All LED DDB signals are always shown in the PSL Editor. However, the actual number of LEDs depends on the device hardware. For example, if a small 20TE device has only 4 programmable LEDs, LEDs 5-8 will not take effect even if they are mapped in the PSL.

16.8 FUNCTION KEYS

For most models, a number of programmable function keys are available. This allows you to assign function keys to control functionality via the programmable scheme logic (PSL). Each function key is associated with a programmable tri-colour LED, which you can program to give the desired indication on activation of the function key.

These function keys can be used to trigger any function that they are connected to as part of the PSL. The function key commands are found in the *FUNCTION KEYS* column.

Each function key is associated with a DDB signal as shown in the DDB table. You can map these DDB signals to any function available in the PSL.

The ***Fn Key Status*** cell displays the status (energised or de-energised) of the function keys by means of a binary string, where each bit represents a function key starting with bit 0 for function key 1.

Each function key has three settings associated with it, as shown:

- ***Fn Key (n)***, which enables or disables the function key
- ***Fn Key (n) Mode***, which allows you to configure the key as toggled or normal
- ***Fn Key (n) label***, which allows you to define the function key text that is displayed

The ***Fn Key (n)*** cell is used to enable (unlock) or disable (unlock) the function key signals in PSL. The Lock setting has been provided to prevent further activation on subsequent key presses. This allows function keys that are set to `Toggled` mode and their DDB signal active 'high', to be locked in their active state therefore preventing any further key presses from deactivating the associated function. Locking a function key that is set to the "Normal" mode causes the associated DDB signals to be permanently off. This safety feature prevents any inadvertent function key presses from activating or deactivating critical functions.

When the ***Fn Key (n) Mode*** cell is set to `Toggle`, the function key DDB signal output will remain in the set state until a reset command is given. In the `Normal` mode, the function key DDB signal will remain energised for as long as the function key is pressed and will then reset automatically. In this mode, a minimum pulse duration can be programmed by adding a minimum pulse timer to the function key DDB output signal.

The ***Fn Key Label*** cell makes it possible to change the text associated with each individual function key. This text will be displayed when a function key is accessed in the function key menu, or it can be displayed in the PSL.

The status of all function keys are recorded in non-volatile memory. In case of auxiliary supply interruption their status will be maintained.

> *Note:*
> *All function key DDB signals are always shown in the PSL Editor. However, the actual number of function keys depends on the device hardware. For example, if a small 20TE device has no function keys, the function key DDBs mapped in the PSL will not take effect.*

16.9 CONTROL INPUTS

The control inputs are software switches, which can be set or reset locally or remotely. These inputs can be used to trigger any PSL function to which they are connected. There are three setting columns associated with the control inputs: *CONTROL INPUTS*, *CTRL I/P CONFIG* and *CTRL I/P LABELS*. These are listed in the Settings and Records appendix at the end of this manual.

16.10 USER ALARMS

User Alarms can be operated from an opto input or a control input using the PSL. They are useful for giving an alarm led and message on the LCD display, and an alarm indication via the communications of an external condition - for example: trip circuit supervision alarm, and temperature alarm etc. In the ***USER ALARMS*** menu, the ***Manual Reset*** 32 bit binary string (0 self-reset, 1 manual reset) can be used to set the operating mode of the user alarms to self or manual reset. The ***User Alarm 1-32*** labels in the ***USER ALARMS*** menu column are used to individually label each user alarm. The text is restricted to 16 characters.

CHAPTER 17

ELECTRICAL TELEPROTECTION

17.1 CHAPTER OVERVIEW

This chapter contains the following sections:

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Teleprotection Scheme Principles 380
Implementation 381
Configuration 382
Connecting to Electrical InterMiCOM 384
Application Notes 385

17.2 INTRODUCTION

Electrical Teleprotection is an optional feature that uses communications links to create protection schemes. It can be used to replace hard wiring between dedicated relay output contacts and digital input circuits. Two products equipped with electrical teleprotection can connect and exchange commands using a communication link. It is typically used to implement teleprotection schemes.

Using full duplex communications, eight binary command signals can be sent in each direction between connected products. The communication connection complies with the EIA(RS)232 standard. Ports may be connected directly, or using modems. Alternatively EIA(RS)232 converters can be used for connecting to other media such as optical fibres.

Communications statistics and diagnostics enable you to monitor the integrity of the communications link, and a loopback feature is available to help with testing.

17.3 TELEPROTECTION SCHEME PRINCIPLES

Teleprotection schemes use signalling to convey a trip command to remote circuit breakers to isolate circuits. Three types of teleprotection commands are commonly encountered:

- Direct Tripping
- Permissive Tripping
- Blocking Scheme

17.3.1 DIRECT TRIPPING

In direct tripping applications (often described by the generic term: “intertripping”), teleprotection signals are sent directly to a master trip device. Receipt of a command causes circuit breaker operation without any further qualification. Communication must be reliable and secure because any signal detected at the receiving end causes a trip of the circuit at that end. The communications system must be designed so that interference on the communication circuit does not cause spurious trips. If a spurious trip occurs, the primary system might be unnecessarily isolated.

17.3.2 PERMISSIVE TRIPPING

Permissive trip commands are monitored by a protection device. The circuit breaker is tripped when receipt of the command coincides with a ‘start’ condition being detected by the protection at the receiving. Requirements for the communications channel are less onerous than for direct tripping schemes, since receipt of an incorrect signal must coincide with a ‘start’ of the receiving end protection for a trip operation to take place. Permissive tripping is used to speed up tripping for faults occurring within a protected zone.

17.4 IMPLEMENTATION

Electrical InterMiCOM is configured using a combination of settings in the *INTERMICOM COMMS* column, settings in the *INTERMICOM CONF* column, and the programmable scheme logic (PSL).

The eight command signals are mapped to DDB signals within the product using the PSL.

Signals being sent to a remote terminal are referenced in the PSL as ***IM Output 1*** - ***IM Output 8***. Signals received from the remote terminal are referenced as ***IM Input 1*** - ***IM Input 8***.

Note:
As well as the optional Modem InterMiCOM, some products are available with a feature called InterMiCOM64 (IM64). The functionality and assignment of commands in InterMiCOM and InterMiCOM64 are similar, but they act independently and are configured independently.

17.5 CONFIGURATION

Electrical Teleprotection is compliant with IEC 60834-1:1999. For your application, you can customise individual command signals to the differing requirements of security, speed, and dependability as defined in this standard.

You customise the command signals using the ***IM# Cmd Type*** cell in the *INTERMICOM CONF* column.

Any command signal can be configured for:

- Direct intertripping by selecting 'Direct'. (this is the most secure signalling but incurs a time delay to deliver the security).
- Blocking applications by selecting 'Blocking'. (this is the fastest signalling)
- Permissive intertripping applications by selecting 'Permissive. (this is dependable signalling that balances speed and security)

You can also select to 'Disable' the command.

> *Note:*
> *When used in the context of a setting, '#' specifies which command signal (1-8) bit is being configured.*

To ensure that command signals are processed only by their intended recipient, the command signals are packaged into a message (sometimes referred to as a telegram) which contains an address field. A sending device sets a pattern in this field. A receiving device must be set to match this pattern in the address field before the commands will be acted upon. 10 patterns have been carefully chosen for maximum security. You need to choose which ones to use, and set them using the ***Source Address*** and ***Receive Address*** cells in the *INTERMICOM COMMS* column.

The value set in the ***Source Address*** of the transmitting device should match that set in the ***Receive Address*** of the receiving device. For example set ***Source Address*** to `1` at a local terminal and set ***Receive Address*** to `1` at the remote terminal.

The Source Address and Receive Address settings in the device should be set to different values to avoid false operation under inadvertent loopback conditions.

Where more than one pair of devices is likely to share a communication link, you should set each pair to use a different pair of address values.

Electrical InterMiCOM has been designed to be resilient to noise on communications links, but during severe noise conditions, the communication may fail. If this is the case, an alarm is raised and you can choose how the input signals are managed using the ***IM# FallBackMode*** cell in the *INTERMICOM CONF* column:

• If you choose `Latched`, the last valid command to be received can be maintained until a new valid message is received.

• If you choose `Default`, the signal will revert to a default value after the period defined in the ***IM# FrameSyncTim*** setting has expired. You choose the default value using the ***IM# DefaultValue*** setting.

Subsequent receipt of a full valid message will reset the alarm, and the new command signals will be used.

As well as the settings described above, you will need to assign input and output signals in the Programmable Scheme Logic (PSL). Use the 'Integral Tripping' buttons to create the logic you want to apply. A typical example is shown below.

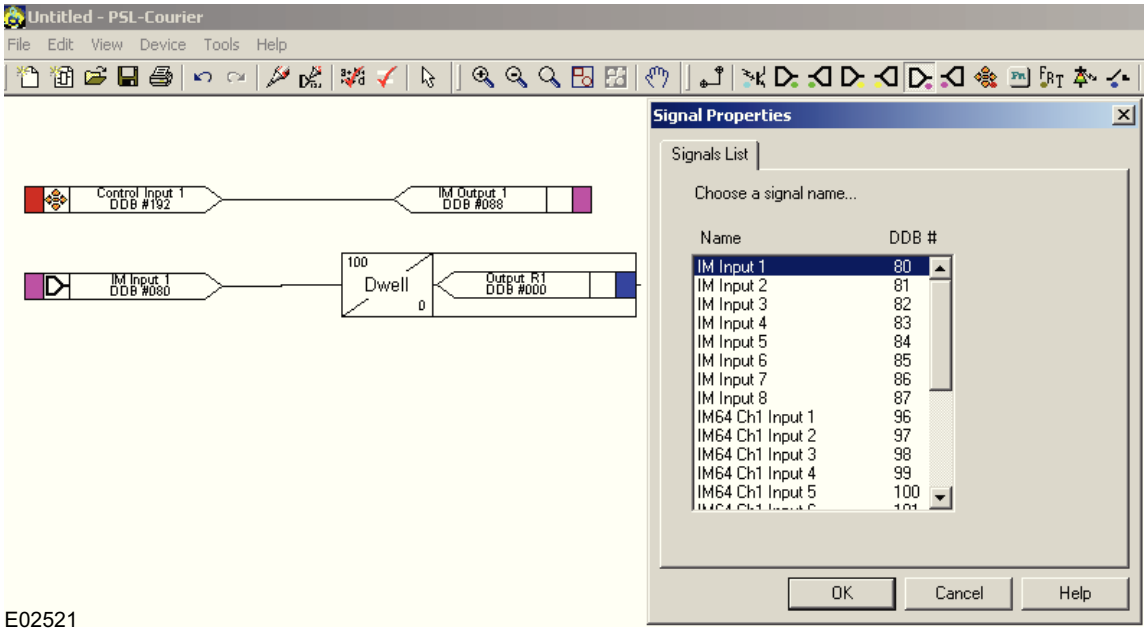


Figure 220: Example assignment of InterMiCOM signals within the PSL

Note:
When an Electrical InterMiCOM signal is sent from a local terminal, only the remote terminal will react to the command. The local terminal will only react to commands initiated at the remote terminal.

17.6 CONNECTING TO ELECTRICAL INTERMICOM

Electrical InterMiCOM uses EIA(RS)232 communication presented on a 9-pin 'D' type connector. The connector is labelled SK5 and is located at the bottom of the 2nd Rear communication board. The port is configured as standard DTE (Data Terminating Equipment).

17.6.1 SHORT DISTANCE

EIA(RS)232 is suitable for short distance connections only - less than 15m. Where this limitation is not a problem, direct connection between devices is possible. For this case, inter-device connections should be made as shown below the figure below.

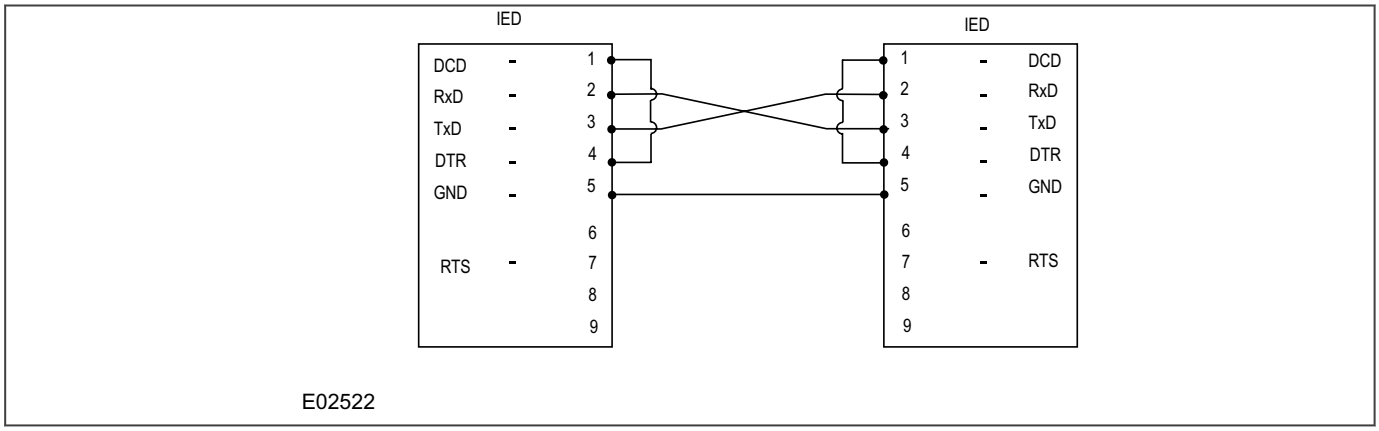


Figure 221: Direct connection

For direct connection, the maximum baud rate can generally be used.

17.6.2 LONG DISTANCE

EIA(RS)232 is suitable for short distance connections only - less than 15m. Where this limitation is a problem, direct connection between devices is not possible. For this case, inter-device connections should be made as shown below the figure below.

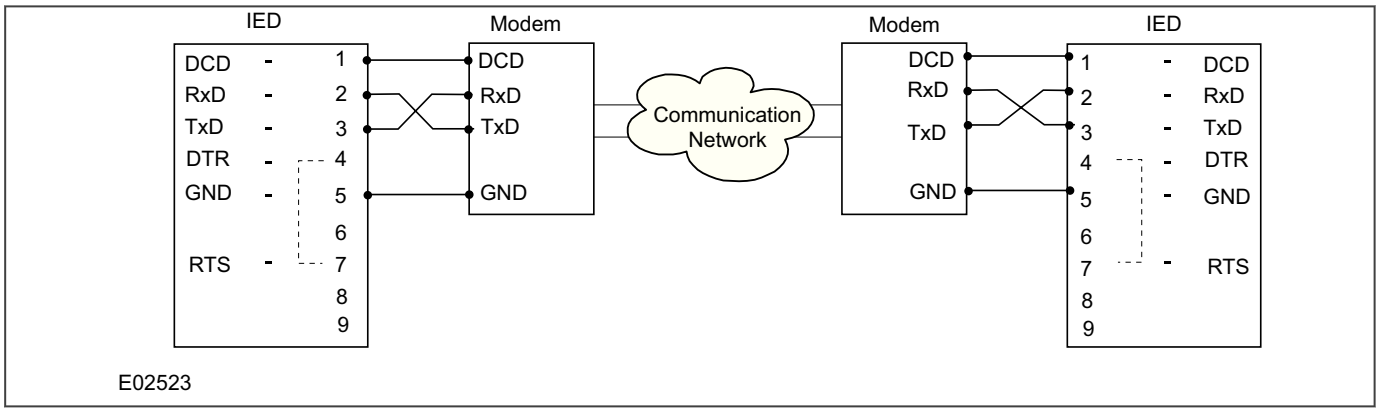


Figure 222: Indirect connection using modems

This type of connection should be used when connecting to devices that have the ability to control the DCD line. The baud rate should be chosen to be suitable for the communications network. If the Modem does not support the DCD function, the DCD terminal on the IED should be connected to the DTR terminal.

17.7 APPLICATION NOTES

Electrical InterMiCOM settings are contained within two columns; *INTERMICOM COMMS* and *INTERMICOM CONF*. The *INTERMICOM COMMS* column contains all the settings needed to configure the communications, as well as the channel statistics and diagnostic facilities. The *INTERMICOM CONF* column sets the mode of each command signal and defines how they operate in case of signalling failure.

Short metallic direct connections and connections using fire-optic converters will generally be set to have the highest signalling speed of 19200b/s. Due to this high signalling rate, the difference in operating time between the direct, permissive, and blocking type signals is small. This means you can select the most secure signalling command type ('Direct' intertrip) for all commands. You do this with the ***IM# Cmd Type*** settings. For these applications you should set the ***IM# Fallback Mode*** to `Default`. You should also set a minimal intentional delay by setting ***IM# FrameSyncTim*** to 10 msecs. This ensures that whenever two consecutive corrupt messages are received, the command will immediately revert to the default value until a new valid message is received.

For applications that use Modem and/or multiplexed connections, the trade-off between speed, security, and dependability is more critical. Choosing the fastest baud rate (data rate) to achieve maximum speed may appear attractive, but this is likely to increase the cost of the telecommunications equipment. Also, telecommunication services operating at high data rates are more prone to interference and suffer from longer re-synchronisation times following periods of disruption. Taking into account these factors we recommend a maximum baud rate setting of 9600 bps. As baud rates decrease, communications become more robust with fewer interruptions, but overall signalling times increase.

At slower baud rates, the choice of signalling mode becomes significant. You should also consider what happens during periods of noise when message structure and content can be lost.

- In 'Blocking' mode, the likelihood of receiving a command in a noisy environment is high. In this case, we recommend you set ***IM# Fallback Mode*** to `Default`, with a reasonably long ***IM# FrameSyncTim*** setting. Set ***IM# DefaultValue*** to '1'. This provides a substitute for a received blocking signal, applying a failsafe for blocking schemes.
- In 'Direct' mode, the likelihood of receiving commands in a noisy environment is small. In this case, we recommend you set ***IM# Fallback Mode*** to `Default` with a short ***IM# FrameSyncTim*** setting. Set ***IM# DefaultValue*** to '0'. This means that if a corrupt message is received, InterMiCOM will use the default value. This provides a substitute for the intertrip signal not being received, applying a failsafe for direct intertripping schemes.
- In 'Permissive' mode, the likelihood of receiving a valid command under noisy communications conditions is somwhere between that of the 'Blocking' mode and the 'Direct' intertrip mode. In this case, we recommended you set ***IM# Fallback Mode*** to `Latched`.

The table below presents recommended ***IM# FrameSyncTim*** settings for the different signalling modes and baud rates:

	Minimum Recommended "IM# FrameSyncTim" Setting			
Baud Rate	**Direct Intertrip Mode**	**Blocking Mode**	**Minimum Setting (ms)**	**Maximum Setting (ms)**
600	100	250	100	1500
1200	50	130	50	1500
2400	30	70	30	1500
4800	20	40	20	1500
9600	10	20	10	1500
19200	10	10	10	1500

Note:
As we have recommended Latched operation, the table does not contain recommendations for 'Permissive' mode. However, if you do select 'Default' mode, you should set ***IM# FrameSyncTim*** *greater than those listed above. If you set* ***IM# FrameSyncTim*** *lower than the minimum setting listed above, the device could interpret a valid change in a message as a corrupted message.*

We recommend a setting of 25% for the communications failure alarm.

CHAPTER 18

COMMUNICATIONS

18.1 CHAPTER OVERVIEW

This product supports Substation Automation System (SAS), and Supervisory Control and Data Acquisition (SCADA) communication through multiple interfaces and a choice of data protocols.

All products support rugged serial communications for SCADA and SAS applications. Optionally, any product can support Ethernet communications for IEC 61850, cyber security and remote access, either through a single port or industry-standard redundant ports.

This chapter contains the following sections:

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Serial Communication 390
Ethernet Communication 393
Ethernet Board Versions 394
Board Connections 395
Ethernet Configuration 397
Redundancy Protocols 399
Secure Shell (SSH) Communication 404
Simple Network Management Protocol (SNMP) 406
Data Protocols 412
Time Synchronisation 441

18.2 COMMUNICATION INTERFACES

The products have a number of standard and optional communication interfaces. The standard and optional hardware and protocols are summarised below:

Port	Availability	Physical Interface	Use	Data Protocols
Front	Standard	USB Type B	Local settings	Courier
Rear Port 1 (RP1 copper)	Standard	RS232/RS485/K-Bus	SCADA Remote settings	Courier, IEC 60870-5-103, DNP3.0
Rear Port 1 (RP1 fibre)	Optional	Fibre	SCADA Remote settings	Courier, IEC 60870-5-103, DNP3.0
Rear Port 2 (RP2)	Optional	RS232/RS485/K-Bus	SCADA Remote settings	SK4: Courier only SK5: InterMiCOM only
Ethernet	Optional	Ethernet	IEC 61850 Time sync Remote access	IEC 61850, Courier Tunnel, RADIUS, Syslog, SNMP, PTP, SNTP

Note:
Optional communications boards are always fitted into slot A. It is only possible to fit one optional communications board, therefore RP2 and Ethernet communications are mutually exclusive, except for ZN0098005, where both Ethernet and serial protocols are supported.
On RP1, any one of the data protocols can be selected at one time, from the COMMUNICATIONS Menu (it is no longer necessary to select one as a product order option).

18.3 SERIAL COMMUNICATION

The physical layer standards that are used for serial communications for SCADA purposes are:

- EIA(RS)485 (often abbreviated to RS485)
- K-Bus (a proprietary customization of RS485)

USB is used for local communication with the IED (for transferring settings and downloading firmware updates).

RS485 is similar to RS232 but for longer distances and it allows daisy-chaining and multi-dropping of IEDs.

K-Bus is a proprietary protocol quite similar to RS485, but it cannot be mixed on the same link as RS485. Unlike RS485, K-Bus signals applied across two terminals are not polarised.

It is important to note that these are not data protocols. They only describe the physical characteristics required for two devices to communicate with each other.

For a description of the K-Bus standard see K-Bus and GE Vernova's K-Bus interface guide reference R6509.

A full description of the RS485 is available in the published standard.

18.3.1 USB FRONT PORT

The USB interface uses the proprietary Courier protocol for local communication with the MiCOM S1 Agile settings application software.

This is intended for temporary local connection and is not suitable for permanent connection. This interface uses a fixed baud rate of 19200 bps, 11-bit frame (8 data bits, 1 start bit, 1 stop bit, even parity bit), and a fixed device address of '1'.

The USB interface is a Type B connector. Normally a Type A to Type B USB cable will be required to communicate between MiCOM S1 Agile and the IED.

18.3.2 EIA(RS485 BUS

The RS485 two-wire connection provides a half-duplex, fully isolated serial connection to the IED. The connection is polarised but there is no agreed definition of which terminal is which. If the master is unable to communicate with the product, and the communication parameters match, then it is possible that the two-wire connection is reversed.

The RS485 bus must be terminated at each end with 120 Ω 0.5 W terminating resistors between the signal wires.

The RS485 standard requires that each device be directly connected to the actual bus. Stubs and tees are forbidden. Loop bus and Star topologies are not part of the RS485 standard and are also forbidden.

Two-core screened twisted pair cable should be used. The final cable specification is dependent on the application, although a multi-strand 0.5 mm^2 per core is normally adequate. The total cable length must not exceed 1000 m. It is important to avoid circulating currents, which can cause noise and interference, especially when the cable runs between buildings. For this reason, the screen should be continuous and connected to ground at one end only, normally at the master connection point.

The RS485 signal is a differential signal and there is no signal ground connection. If a signal ground connection is present in the bus cable, then it must be ignored. At no stage should this be connected to the cable's screen or to the product’s chassis. This is for both safety and noise reasons.

It may be necessary to bias the signal wires to prevent jabber. Jabber occurs when the signal level has an indeterminate state because the bus is not being actively driven. This can occur when all the slaves are in receive mode and the master is slow to turn from receive mode to transmit mode. This may be because the master is waiting in receive mode, in a high impedance state, until it has something to transmit. Jabber causes the receiving device(s) to miss the first bits of the first character in the packet, which results in the slave rejecting the message and consequently not responding. Symptoms of this are poor response times (due to retries), increasing message error counts, erratic communications, and in the worst case, complete failure to communicate.

18.3.2.1 EIA(RS)485 BIASING REQUIREMENTS

Biasing requires that the signal lines be weakly pulled to a defined voltage level of about 1 V. There should only be one bias point on the bus, which is best situated at the master connection point. The DC source used for the bias must be clean to prevent noise being injected.

Note:
Some devices may be able to provide the bus bias, in which case external components would not be required.

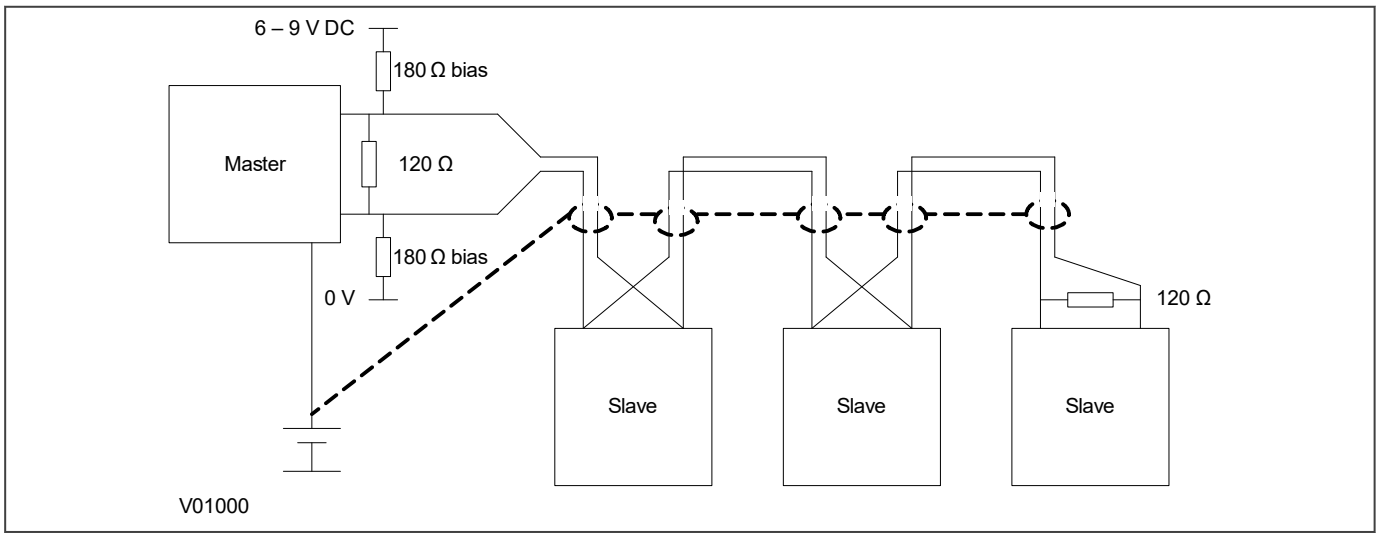


Figure 223: RS485 biasing circuit

Warning:
It is extremely important that the 120 Ω termination resistors are fitted. Otherwise the bias voltage may be excessive and may damage the devices connected to the bus.

18.3.3 K-BUS

K-Bus is a robust signalling method based on RS485 voltage levels. K-Bus incorporates message framing, based on a 64 kbps synchronous HDLC protocol with FM0 modulation to increase speed and security.

The rear interface is used to provide a permanent connection for K-Bus, which allows multi-drop connection.

A K-Bus spur consists of up to 32 IEDs connected together in a multi-drop arrangement using twisted pair wiring. The K-Bus twisted pair connection is non-polarised.

It is not possible to use a standard EIA(RS)232 to EIA(RS)485 converter to convert IEC 60870-5 FT1.2 frames to K-Bus. A protocol converter, namely the KITZ101 or KITZ102, must be used for this purpose. Please consult GE Vernova for information regarding the specification and supply of KITZ devices. The following figure demonstrates a typical K-Bus connection.

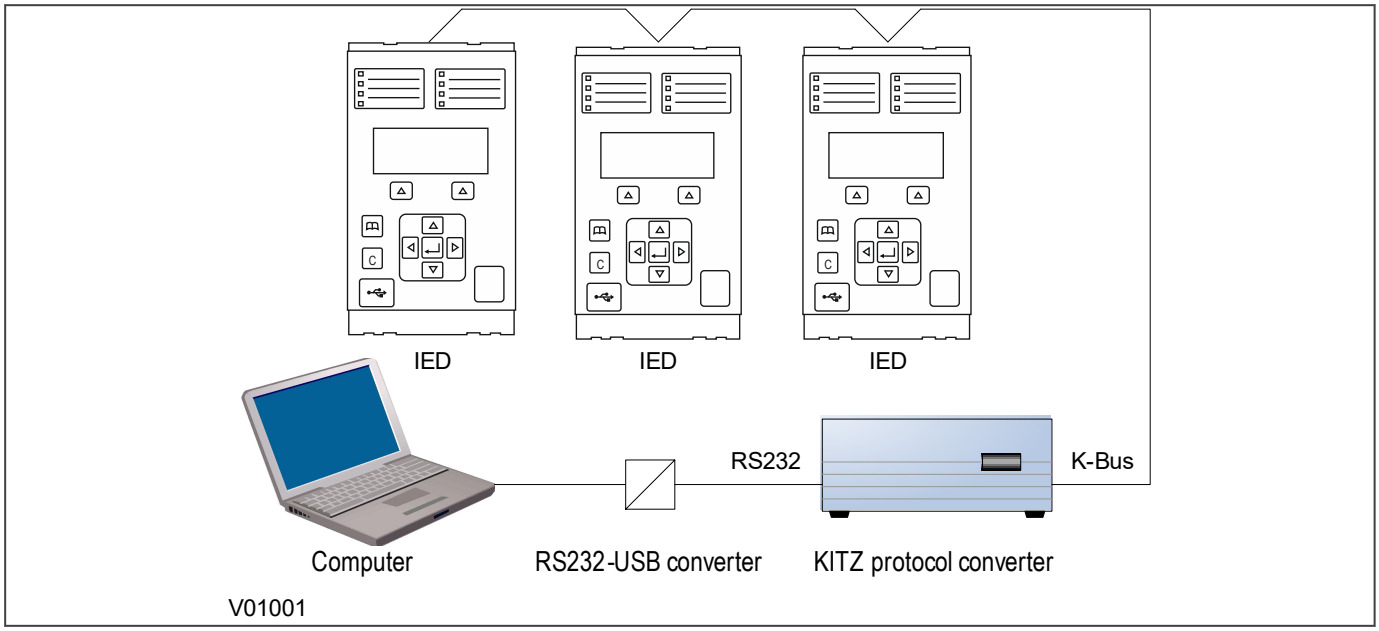


Figure 224: Remote communication using K-Bus

Note:
An RS232-USB converter is only needed if the local computer does not provide an RS232 port.

Further information about K-Bus is available in the publication R6509: K-Bus Interface Guide, which is available on request.

18.4 ETHERNET COMMUNICATION

The Ethernet interface is required for IEC 61850, and provides other Ethernet protocols including PTP, SNTP, SNMP, RADIUS authentication and syslog services, plus a universal IRIG-B time synchronisation input. It also offers communication with the settings application software for remote configuration and record extraction.

The type of Ethernet board depends on the chosen CORTEC Hardware Option. The available boards and their features are described in the Hardware Design chapter of this manual.

Fibre optic connection is recommended for use in permanent connections in a substation environment, as it offers advantages in terms of noise rejection. The fibre optic port provides 100 Mbps communication. Fibres should be suitable for 1300 nm transmission and be multimode 50/125 µm or 62.5/125 µm.

Connection can also be made to a 10Base-T or a 100Base-TX Ethernet switch using the RJ45 port.

Some P40 IEDs with later 9x software versions can support the newer Hardware Option U/W/Y Ethernet boards, in addition to the Hardware Option R/S/T Ethernet boards. Further details are provided in the Retrofit section in the Hardware Design chapter.

18.5 ETHERNET BOARD VERSIONS

Each board combines Ethernet communications, with universal IRIG-B timing functionality. There is a choice of embedded protocols for Ethernet communications, and one option that also includes support for serial protocols.

Board variants

Board	Part No.	Compatible With
One LC duplex Ethernet port with universal IRIG-B and IEEE1588 and one RJ45 Maintenance/Engineering Port	ZN0098 001	Ethernet network, no native redundancy.
Two RJ45 duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two copper pairs), with on-board universal IRIG-B and IEEE 1588 and one RJ45 Maintenance/engineering port	ZN0098 002	Any PRP, HSR, RSTP or standard Ethernet network
Two LC duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two fibre pairs), with on-board universal IRIG-B and IEEE 1588 and one RJ45 Maintenance/engineering port	ZN0098 003	Any PRP, HSR, RSTP or standard Ethernet network
Two LC duplex redundant Ethernet ports running RSTP + PRP + HSR + Failover (two fibre pairs), with serial fibre ST ports with on-board universal IRIG-B and IEEE 1588 and one RJ45 Maintenance/ engineering port	ZN0098 005	Any PRP, HSR, RSTP or standard Ethernet network. On the serial interface Courier, IEC 60870-5-103, DNP3

When using any of the redundant Ethernet boards on an IED, the final product will have two MAC addresses and will require two IP addresses, one for the maintenance port (NP1) for management purposes, and one for the IED station bus communications (NP2). Both of these are set using the IED Configurator tool of MiCOM S1 Agile release 3.1 or later.

All Ethernet connections are made with 1300 nm multi-mode 100BaseFx fiber optic Ethernet ports (LC connector). The boards support IEC 61850 over Ethernet.

18.6 BOARD CONNECTIONS

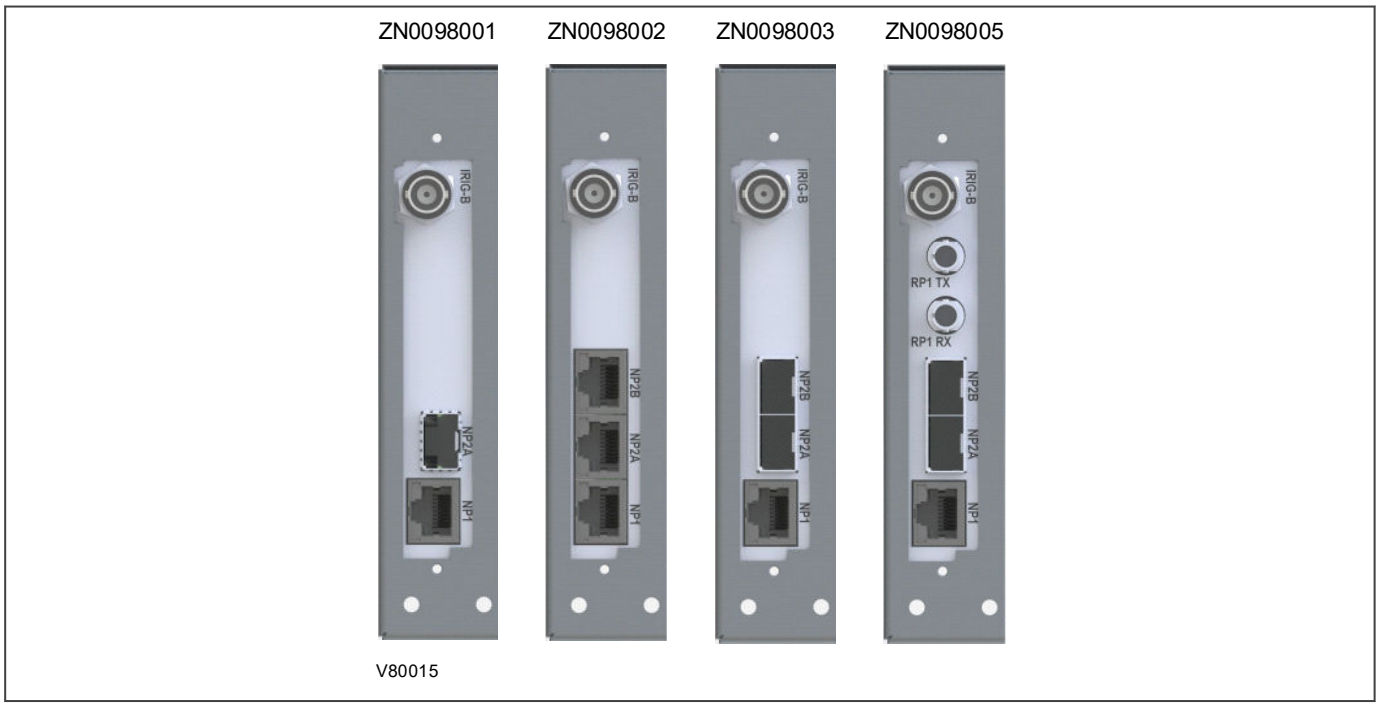


Figure 225: Board connectors

IRIG-B Connector

- Centre connection: Signal
- Outer connection: Earth

RJ45 Connector (NP1, NP2A and NP2B optional)

Pin	Signal Name	Signal Definition
1	TXP	Transmit (positive)
2	TXN	Transmit (negative)
3	RXP	Receive (positive)
4	-	Not used
5	-	Not used
6	RXN	Receive (negative)
7	-	Not used
8	-	Not used

LC Optical Fibre Connectors (NP2A and NP2B optional)

Connector	SFP
A	TX
B	RX

Optical Fibre Connectors (ST only on part ZN0098005)

Connector	Serial Courier, IEC 60870-5-103, DNP3
RP1	TX
RP1	RX

18.7 ETHERNET CONFIGURATION

All configuration of Ethernet parameters and protocol services for both the monitoring/engineering port and the station bus port is done in **IED Configurator.** Any MiCOM P40 IED with an Ethernet board is required to have these parameters configured by sending an MCL file to the IED (not recommended to configure via Settings/HMI). Refer also to the MiCOM S1 Agile User Guide for additional information on configuring and sending MCL files.

The monitoring/engineering port is named "Network Port 1" and the redundant IEC 61850 station bus port is named "Network Port 2".

Network Port 1 (NP1) and Network Port 2 (NP2) have independent IP address and subnet configuration parameters, as detailed in the sub-section below. These parameters can be configured in IED Configurator, or optionally from the Front Panel UI.

The IP addresses can be in the range 0.0.0.0 to 223.255.255.255. This means it can be configured as either a Class A, B or C address.

Class	Address Range
A	0.0.0.0 to 127.255.255.255
B	128.0.0.0 to 191.255.255.255
C	192.0.0.0 to 223.255.255.255

The NP1 and NP2 IP addresses must not be configured in the same subnet.

The primary and secondary server IP addresses for RADIUS, syslog and SNMP must also be in these ranges.

18.7.1 NETWORK CONFIGURATION

To set the IP address of the monitoring/engineering port:

1. From the main window click the **Communications** section.
2. Navigate to the Network Port 1.
3. Enter the required IP address, network mask and gateway.
4. The media is not configurable for the engineering port, as they are always RJ45 copper ports.

To set the IP address of the station bus port:

1. From the main window click the **Communications** section.
2. Navigate to the Network Port 2.
3. Enter the required IP address, network mask and gateway.
4. In the Network Port 2 General configuration section, the redundancy options become available.
5. If the board supports redundancy, choose the redundant protocol desired (Failover, RSTP, PRP and HSR).
6. Each protocol has its own protocol specific settings, covered in each protocol's section.
7. The media is not configurable for the station bus port, as they are always enabled according to the ordering code. The media section is available for legacy boards only.

18.7.2 PRP CONFIGURATION

To view or configure the PRP Parameters:

1. Set the redundancy mode to **PRP**.
   - **Multicast Address:** Use this field to configure the multicast destination address. All DANPs in the network must be configured to operate with the same multicast address for the purpose of network supervision.
   - **Life Check Interval:** This defines how often a node sends a PRP_Supervision frame. All DANPs shall be configured with the same Life Check Interval.

18.7.3 HSR CONFIGURATION

To view or configure the HSR Parameters:

Set the redundancy mode to HSR.

- **Multicast Address:** Use this field to configure the multicast destination address. All DANPs in the network must be configured to operate with the same multicast address for the purpose of network supervision.
- **Life Check Interval**: This defines how often a node sends an HSR Supervision frame. All DANPs shall be configured with the same Life Check Interval.

18.7.4 RSTP CONFIGURATION

To view or configure the RSTP Parameters:

Set the redundancy mode to **RSTP**.

Parameter	Default value (second)	Minimum value (second)	Maximum value (second)
Bridge Max Age	20	6	40
Bridge Hello Time	2	1	10
Bridge Forward Delay	15	4	30
Bridge Priority	32768	0	61440

18.7.5 FAILOVER CONFIGURATION

To view or configure the Failover Parameters:

1. Set the redundancy mode to **Failover**.
   - Port A and Port B radio button allows to select your main port for the Failover. The name of the port in the board is also shown.
   - The Failover time defines how long it takes for the redundancy switch over to trigger. The minimum value is 2s.

18.7.6 SNTP IP ADDRESS CONFIGURATION

To configure the SNTP server IP address:

1. From the main window click the **SNTP** button.
2. The General configuration allows to set the frequency of the polling of the SNTP server. It also has a check-box **IED is a clock source** to configure the IED to be a SNTP server itself, to retransmit its date and time.
3. Under External Server 1 and 2, set the IP address of the SNTP server.

18.8 REDUNDANCY PROTOCOLS

REB variants for each of the following protocols are available:

- PRP (Parallel Redundancy Protocol)
- HSR (High-availability Seamless Redundancy)
- RSTP (Rapid Spanning Tree Protocol)
- Failover

PRP and HSR are open standard, so their implementation is compatible with any standard PRP or HSR device respectively. PRP and HSR provide "bumpless" redundancy. RSTP is also an open standard, so its implementation is compatible with any standard RSTP devices. RSTP provides redundancy, however, it is not "bumpless", the standard instead utilises a loop free topology that is recalculated when a device fails and does not forward messages during recalculation.

18.8.1 PARALLEL REDUNDANCY PROTOCOL (PRP)

Power system companies have traditionally used proprietary protocols for redundant communications. This is because standardized protocols could not meet the requirements for real-time systems. Even a short loss of connectivity may result in loss of functionality.

However, Parallel Redundancy Protocol (PRP) uses the IEC 62439 standard in Dual Star Topology networks, designed for IEDs from different manufacturers to operate with each other in a substation redundant-Ethernet network. PRP provides bumpless redundancy for real-time systems and is the standard for double Star-topology networks in substations.

18.8.1.1 PRP NETWORKS

Redundant networks usually rely on the network’s ability to reconfigure if there is a failure. However, PRP uses two independent networks in parallel.

PRP implements the redundancy functions in the end nodes rather than in network elements. This is one major difference to RSTP. An end node is attached to two similar LANs of any topology which operate in parallel.

The sending node replicates each frame and transmits them over both networks. The receiving node processes the frame that arrives first and discards the duplicate. Therefore, there is no distinction between the working and backup path. The receiving node checks that all frames arrive in sequence and that frames are correctly received on both ports.

The PRP layer manages this replicate and discard function and hides the two networks from the upper layers. This scheme works without reconfiguration and switchover, so it stays available ensuring no data loss.

There should be no common point of failure between the two LANs. Therefore, they are not powered by the same source and cannot be connected directly together. They are identical in protocol at the MAC level but may differ in performance and topology. Both LANs must be on the same subnet so all IP addresses must be unique.

18.8.1.2 NETWORK ELEMENTS

A PRP compatible device has two ports that operate in parallel. Each port is connected to a separate LAN. In the IEC 62439 standard, these devices are called DANP (Doubly Attached Node running PRP). A DAN has two ports, one MAC address and one IP address.

A Single Attached Node (SAN) is a non-critical node attached to only one LAN. SANs that need to communicate with each other must be on the same LAN.

The following diagram shows an example of a PRP network. The Doubly Attached Nodes DANP 1 and DANP 2 have full node redundancy. The Singly Attached Nodes SAN 1 and SAN 4 do not have any redundancy. Singly attached nodes can be connected to both LANs using a Redundancy Box (RedBox). The RedBox converts a singly attached node into a doubly attached node. Devices such as PCs with one network board, printers, and IEDs with

one network board are singly attached nodes. A SAN behind a RedBox appears like a DAN so is called a Virtual DAN (VDAN).

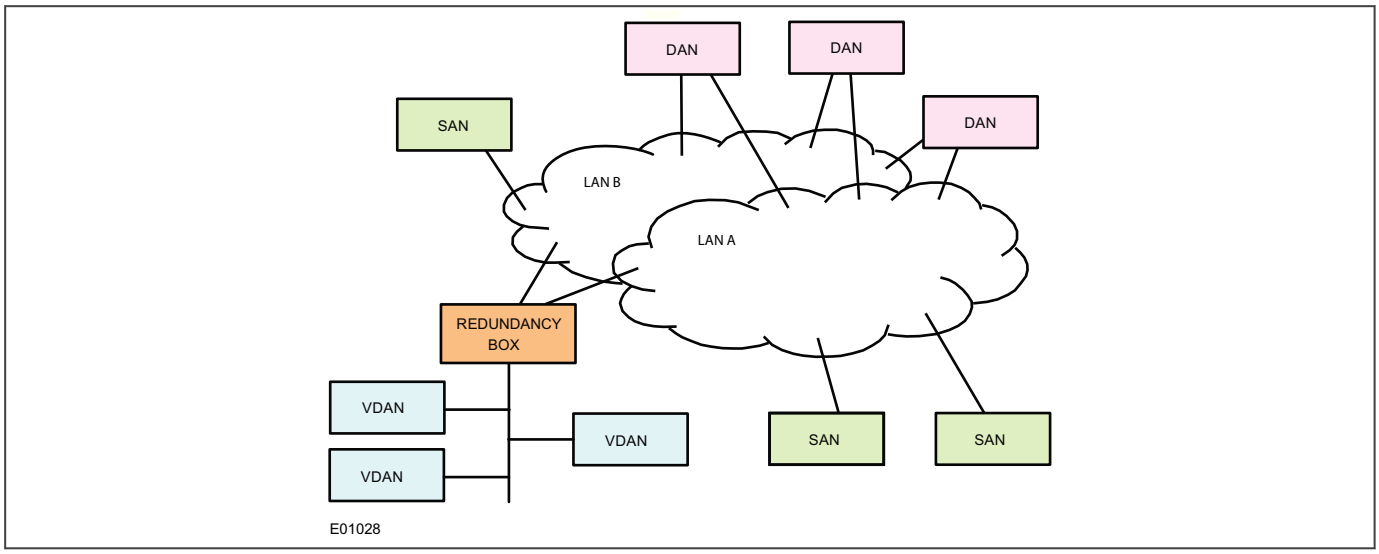


Figure 226: Example PRP redundant network

In a DAN, both ports share the same MAC address, so it does not affect the way devices talk to each other in an Ethernet network (Address Resolution Protocol at layer 2). Every data frame is seen by both ports.

When a DAN sends a frame of data, the frame is duplicated on both ports and therefore on both LAN segments. This provides a redundant path for the data frame if one of the segments fails. Under normal conditions, both LAN segments are working, and each port receives identical frames. There are two ways of handling this: Duplicate Accept and Duplicate Discard.

The GE Vernova RedBox is the H49 switch. This is compatible with any other vendor's PRP device.

18.8.2 HIGH-AVAILABILITY SEAMLESS REDUNDANCY (HSR)

HSR is standardised in IEC 62439-3 (clause 5) for use in ring topology networks. Similar to PRP, HSR provides bumpless redundancy and meets the most demanding needs of substation automation. HSR has become the reference standard for ring-topology networks in the substation environment. The HSR implementation of the redundancy Ethernet board (REB) is compatible with any standard HSR device.

HSR works on the premise that each device connected in the ring is a doubly attached node running HSR (referred to as DANH). Similar to PRP, singly attached nodes such as printers are connected via Ethernet Redundancy Boxes (RedBox).

18.8.2.1 HSR MULTICAST TOPOLOGY

When a DANH is sending a multicast frame, the frame (C frame) is duplicated (A frame and B frame), and each duplicate frame A/B is tagged with the destination MAC address and the sequence number. The frames A and B differ only in their sequence number, which is used to identify one frame from the other. Each frame is sent to the network via a separate port. The destination DANH receives two identical frames, removes the HSR tag of the first frame received and passes this (frame D) on for processing. The other duplicate frame is discarded. The nodes forward frames from one port to the other unless it was the node that injected it into the ring.

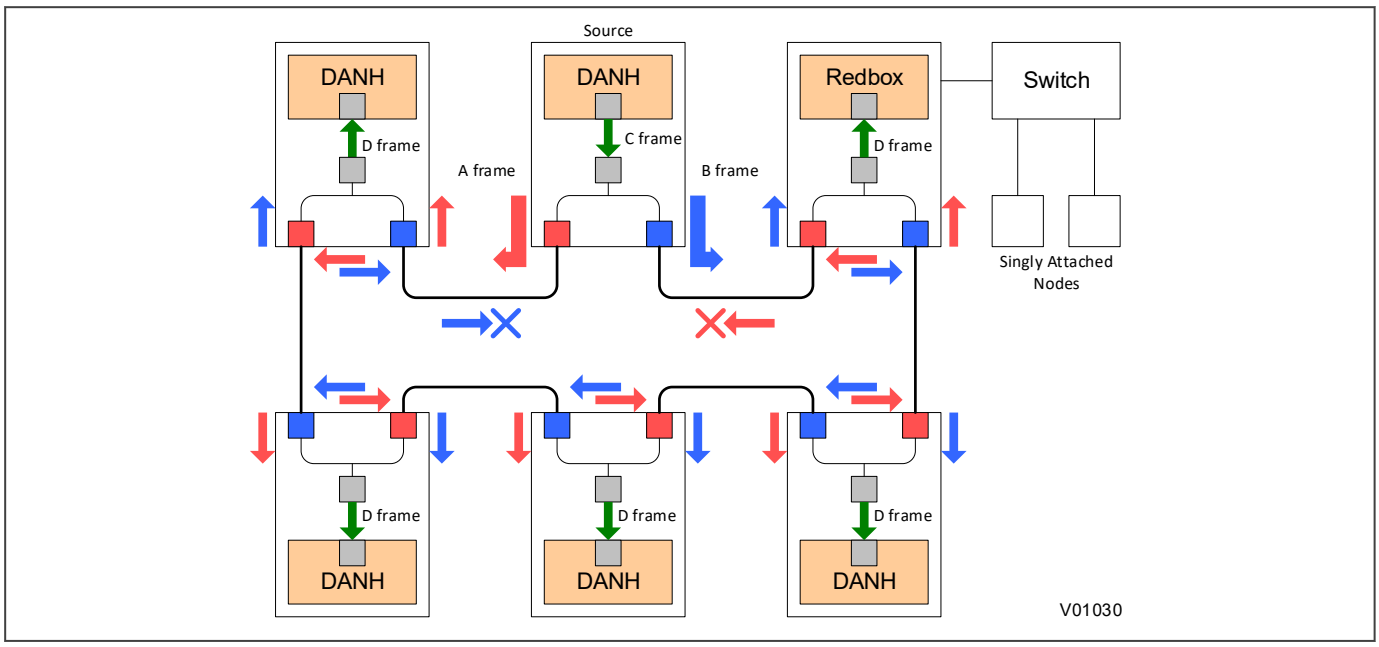


Figure 227: HSR multicast topology

Only about half of the network bandwidth is available in HSR for multicast or broadcast frames because both duplicate frames A & B circulate the full ring.

18.8.2.2 HSR UNICAST TOPOLOGY

With unicast frames, there is just one destination, and the frames are sent to that destination alone. All non-recipient devices simply pass the frames on. They do not process them in any way. In other words, D frames are produced only for the receiving DANH. This is illustrated below.

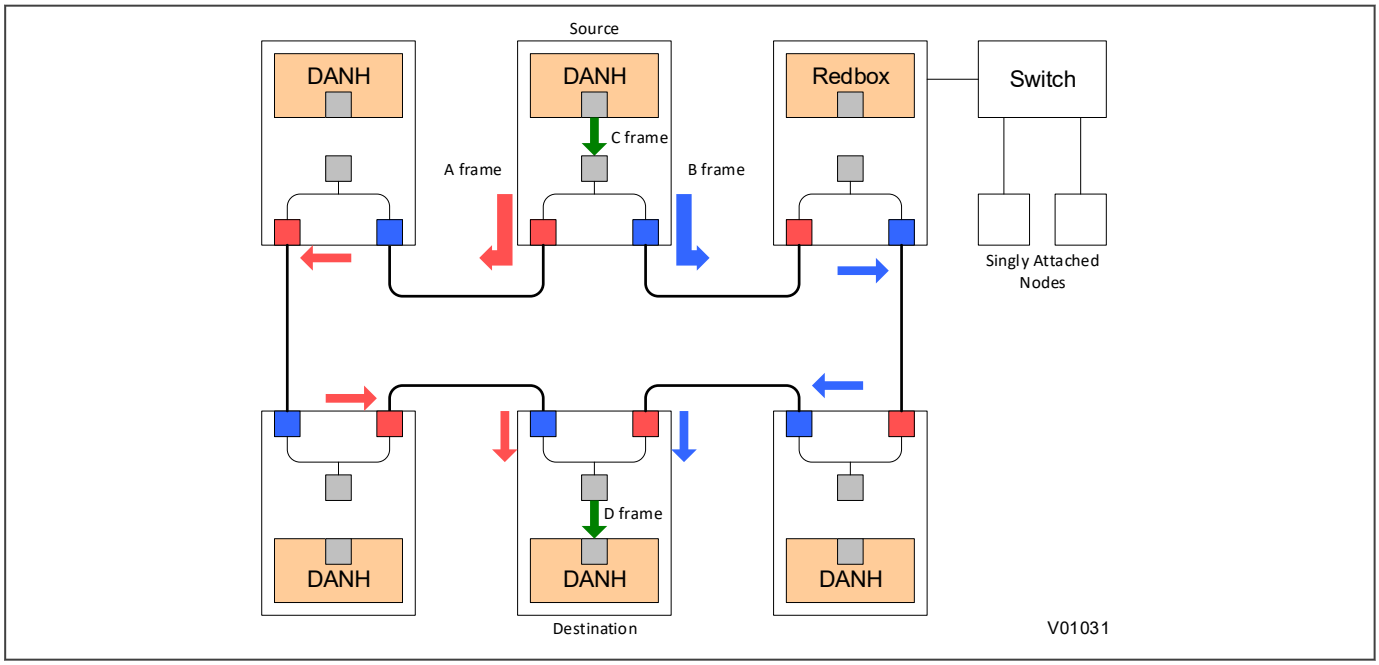


Figure 228: HSR unicast topology

For unicast frames, the whole bandwidth is available as both frames A & B stop at the destination node.

18.8.2.3 HSR APPLICATION IN THE SUBSTATION

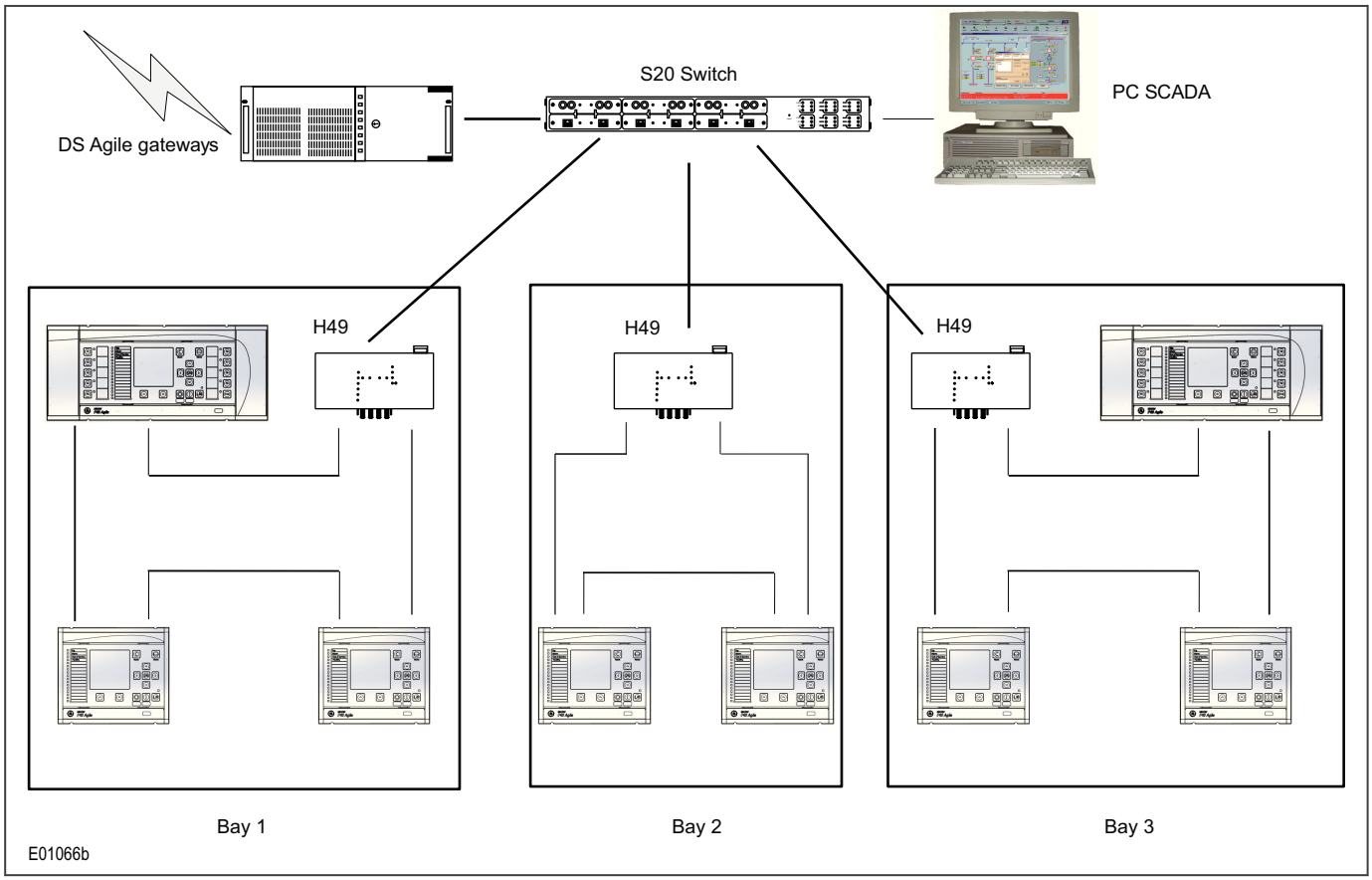


Figure 229: HSR application in the substation

18.8.2.4 RAPID SPANNING TREE PROTOCOL (RSTP)

RSTP is a standard used to quickly reconnect a network fault by finding an alternative path, allowing loop-free network topology. Although RSTP can recover network faults quickly, the fault recovery time depends on the number of devices and the topology. The recovery time also depends on the time taken by the devices to determine the root bridge and compute the port roles (discarding, learning, forwarding). The devices do this by exchanging Bridge Protocol Data Units (BPDUs) containing information about bridge IDs and root path costs. See the IEEE 802.1D 2004 standard for further information.

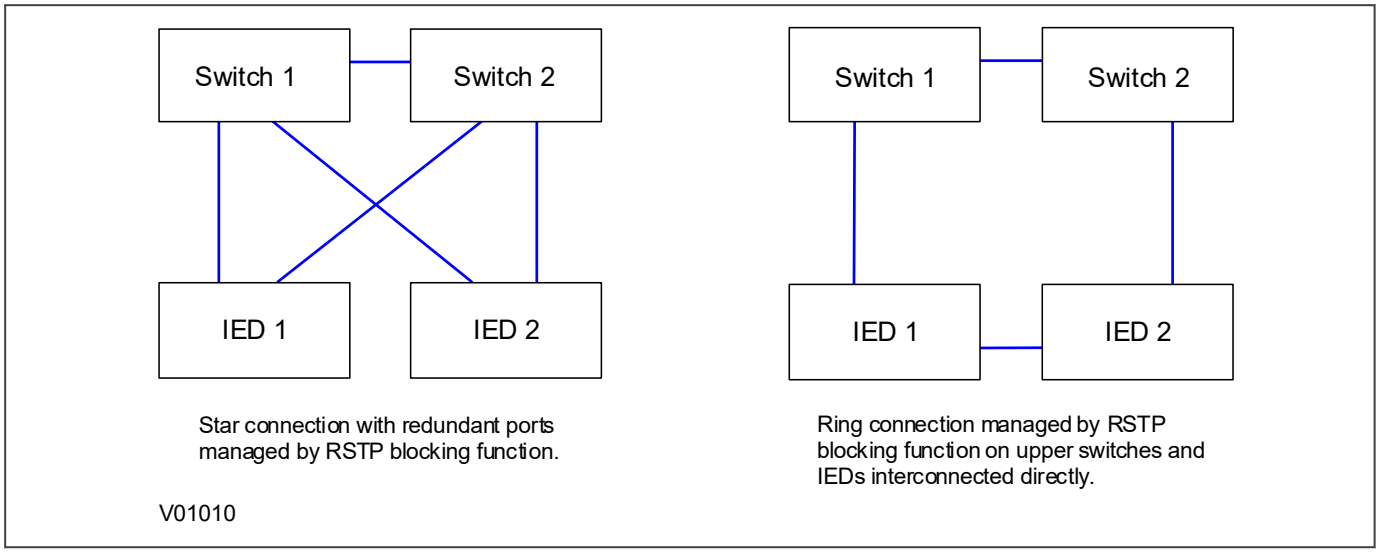


Figure 230: IED attached to redundant Ethernet star or ring circuit

The RSTP solution is based on open standards. It is therefore compatible with other Manufacturers' IEDs that use the RSTP protocol. The RSTP recovery time is typically 300 ms but it increases with network size, therefore cannot achieve the desired bumpless redundancy.

To ensure optimal performance of the protocol, make sure that one of the Ethernet switches is always the root of the RSTP topology.

18.8.2.5 FAILOVER

Failover is a simple redundancy mechanism that is not tied to any protocol. It works by selecting a main port and a switching time that can be as low as 2 seconds. When the main port link fails, the redundant port becomes physically active. At no point are both ports physically active, which means it can be used on any redundant or non-redundant network.

18.9 SECURE SHELL (SSH) COMMUNICATION

Secure Shell, commonly known as SSH, is a cryptographic network protocol designed to enable secure communication between devices over potentially unsecured networks. It is predominantly used to access and control remote systems securely and is commonly used for system administration, file transfers, and secure tunneling. Unlike older protocols such as Telnet, FTP, or Rlogin, which transmit data in plaintext and are susceptible to interception, SSH encrypts all communications, ensuring confidentiality, integrity, and authenticity.

SSH works on a client-server model where the client initiates a connection to the server, typically using the standard TCP port 22. Once the connection is established, a secure handshake occurs where cryptographic keys are exchanged, and the server presents its host key to the client. If the client recognises this key (for instance, from a previous connection saved in the known_hosts file), trust is established, and a symmetric session key is negotiated using asymmetric encryption techniques.

18.9.1 SSH COMMUNICATION BETWEEN S1 AGILE AND THE IED

S1 Agile configuration software (version 3.1.0 onwards) communicates with the IED (version AB onwards) over Ethernet through a secure tunnelled Courier protocol channel using SSHv2 on TCP port 22. The IED has an SSH server implemented and S1 Agile acts as the SSH client. To avoid connection to any rogue IED, the client (S1 Agile, in this case) supports server authentication based on a host key. Once S1 Agile receives a host key from the server, it will check if the key is already marked as "trusted", if not then S1 Agile will display a key fingerprint to the user for manually validating and confirming if the server (IED, in this case) can be "trusted". Although the server authentication can be disabled in S1 Agile, GE Vernova, strongly recommend keeping this feature "Enabled". The IED also supports client authentication using a configurable passcode. When initiating a connection, the user is presented with a Connection Parameters window, where the Client Passcode must be entered. By default, the Client Passcode is set to SSHPassphrase1#. The user needs to enter this string before the user himself is authenticated. Although client authentication can be disabled in the IED using the configurable setting, GE Vernova strongly recommend keeping this feature "Enabled". The default client passcode can be changed by users with the SECADM role within the S1 Agile software using Supervise Device Menu. The IED supports the disabling of the Courier protocol as part of hardening.

Note:
The default client passcode is SSHPassphrase1#

By default, S1 Agile version 3.1.0 or later uses SSH-based authentication when communicating with IEDs running firmware version AB or later. For IEDs belonging to other families or running earlier firmware versions, the software automatically falls back to using the legacy RPC (Remote Procedure Call) protocol for authentication and communication.

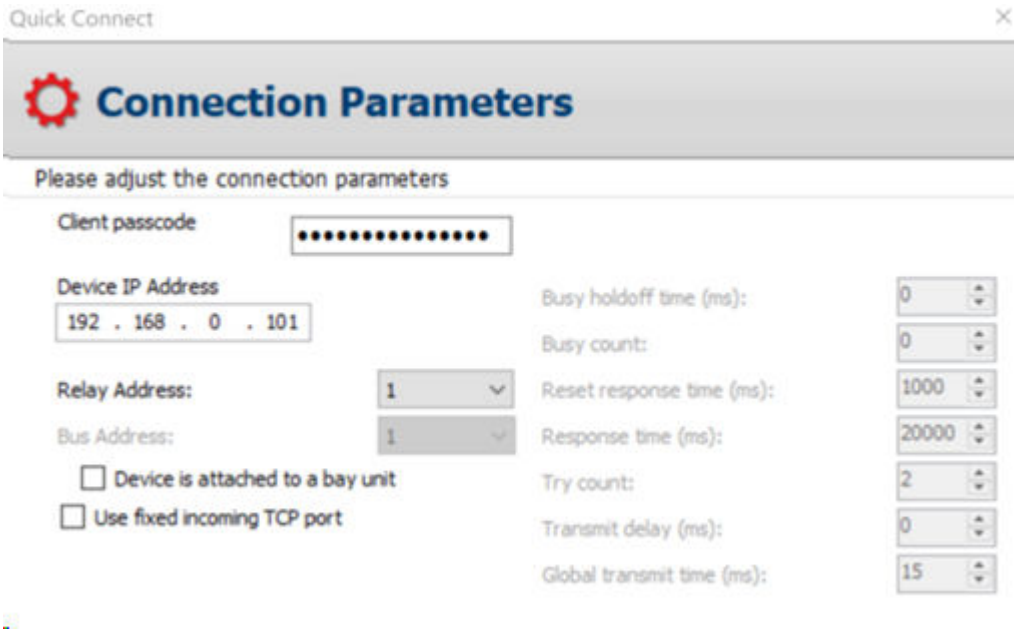


Figure 231: S1 Agile connection parameters window

18.10 SIMPLE NETWORK MANAGEMENT PROTOCOL (SNMP)

Simple Network Management Protocol (SNMP) is a network protocol designed to manage devices in an IP network. SNMP uses a Management Information Base (MIB) that contains information about parameters to supervise. The MIB format is a tree structure, with each node in the tree identified by a numerical Object Identifier (OID). Each OID identifies a variable that can be read or set using SNMP with the appropriate software. The information in the MIB is standardised.

Each system in a network (workstation, server, router, bridge, etc.) maintains a MIB that reflects the status of the managed resources on that system, such as the version of the software running on the device, the IP address assigned to a port or interface, the amount of free hard drive space, or the number of open files. The MIB does not contain static data, but is instead an object-oriented, dynamic database that provides a logical collection of managed object definitions. The MIB defines the data type of each managed object and describes the object.

The SNMP-related branches of the MIB tree are located in the internet branch, which contains two main types of branches:

- Public branches (mgmt=2), which are defined by the Internet Engineering Task Force (IETF).
- Private branches (private=4), which are assigned by the Internet Assigned Numbers Authority (IANA). These are defined by the companies and organisations to which these branches are assigned.

The following figure shows the structure of the SNMP MIB tree. There are no limits on the width and depth of the MIB tree.

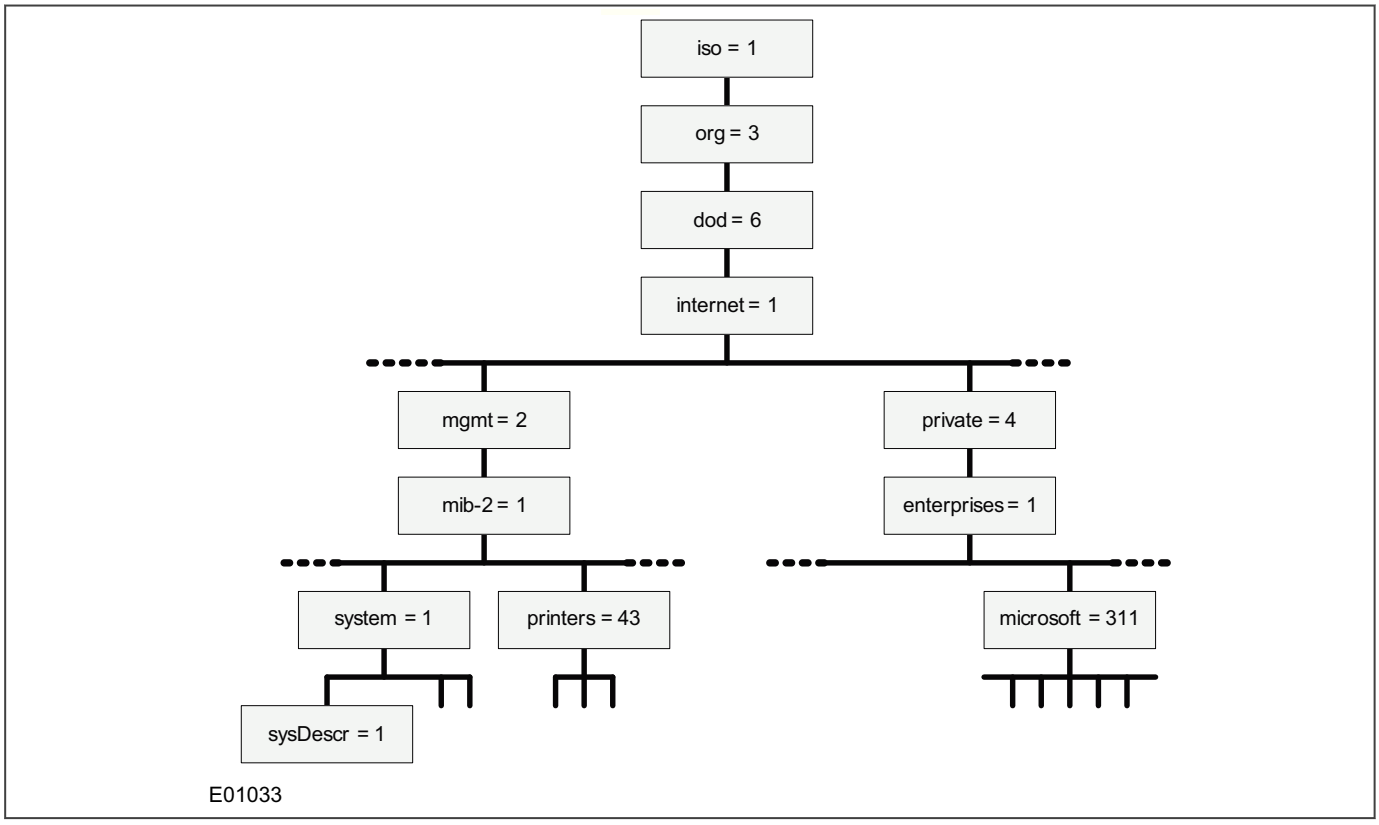


Figure 232: SNMP MIB tree

The top four levels of the hierarchy are fixed. These are:

- International Standards Organisation (iso)
- Organisation (org)
- Department of Defence (dod)
- Internet

Management (mgmt) is the main public branch. It defines network management parameters common to devices from all vendors. Underneath the Management branch is MIB-II (mib-2), and beneath this are branches for common management functions such as system management, printers, host resources, and interfaces.

The private branch of the MIB tree contains branches for large organisations, organised under the enterprises branch. This is not applicable to GE Vernova.

18.10.1 SNMP MIBS COMPATIBLE WITH THE IED

Our IED supports four different MIBs, all available for download on the GE website:

- IEC-62439-3-MIB: Standard PRP/HSR MIB.
- RMON-MIB: Standard Remote Monitoring MIB.
- GE-PX4X-MIB.mib: Private MIB that contains all the information specific to the relay. For example, model and serial number.
- GE-GRID-MIB.mib: Private MIB that only contains manufacturer information.

The information within the MIBs can be read using a simple text app like Notepad, or the MIB can be explored using an MIB Browser.

The private branch of the MIB tree contains branches for large organisations, organised under the enterprises branch. This is not applicable to GE Vernova.

18.10.2 SNMP MANAGEMENT INFORMATION BASES

SNMP uses a Management Information Base (MIB), which contains information about parameters to supervise. The MIB format is a tree structure, with each node in the tree identified by a numerical Object Identifier (OID). Each OID identifies a variable that can be read using SNMP with the appropriate software. The information in the MIB is standardised.

Each device in a network (workstation, server, router, bridge, etc.) maintains a MIB that reflects the status of the managed resources on that system, such as the version of the software running on the device, the IP address assigned to a port or interface, the amount of free hard drive space, or the number of open files. The MIB does not contain static data, but is instead an object-oriented, dynamic database that provides a logical collection of managed object definitions. The MIB defines the data type of each managed object and describes the object.

18.10.3 MAIN PROCESSOR MIBS STRUCTURE

The Main Processor MIB uses a private OID with a specific number assigned by the IANA. Some items in this MIB also support SNMP traps (where indicated). These are items that can automatically notify a host without being read.

Address											Name	Trigger Trap?
0											ROOT NODE	
	1										ISO	
		3									Org	
			6								DOD	
				1							Internet	
					4						Private	
						1					Enterprise	

Address											Name	Trigger Trap?
							43534				(IANA No)	
								1			Px4x	
									1		System Data	
										1	Description	YES
										2	Plant Reference	YES
										3	Model Number	NO
										4	Serial Number	NO
										5	Frequency	NO
										6	Plant Status	YES
										7	Active Group	YES
										8	Software Ref.1	NO
										9	Software Ref.2	NO
										10	Access Level (UI)	YES
									2		Date and Time	
										1	Date Time	NO
										2	IRIG-B Status	YES
										3	Battery Status	YES
										4	Active Sync source	YES
										5	SNTP Server 1	NO
										6	SNTP Server 2	NO
										7	SNTP Status	YES
										8	PTP Status	YES
									3		System Alarms	
										1	Invalid Message Format	YES
										2	Main Protection Fail	YES
										3	Comms Changed	YES
										4	Max Prop. Alarm	YES
										5	9-2 Sample Alarm	YES
										6	9-2LE Cfg Alarm	YES
										7	Battery Fail	YES
										8	Rear Communication Fail	YES
										9	GOOSE IED Missing	YES
										10	Intermicom loopback	YES
										11	Intermicom message fail	YES
										12	Intermicom data CD fail	YES
										13	Intermicom Channel fail	YES
										14	Backup setting fail	YES
										15	User Curve commit to flash failure	YES
										16	SNTP time Sync fail	YES
										17	PTP failure alarm	YES
									4		Device Mode	
										1	IED Mod/Beh	YES
										2	Simulation Mode of Subscription	YES

18.10.4 NEW SNMP SYSTEM OBJECTS

The following elements have been added to the SNMP structure to more accurately describe the new functionalities added in the Ethernet boards:

18.10.4.1 NEW SNMP TRAPS

Changes in the Physical link statuses (Up or Down status) of NP1, NP2A, NP2B ethernet ports will be reported as SNMP traps.

The objects for these link statuses are added in MIB (GE-PX4X-MIB.mib). Below are the IDs for Network Port link objects:

- **np1Link**: 1.3.6.1.4.1.55461.1.6.1
- **np2ALink**: 1.3.6.1.4.1.55461.1.6.2
- **np2Blink**: 1.3.6.1.4.1.55461.1.6.3

18.10.4.2 NEW SNMP OBJECTS

The following objects have been added to MIB (GE-PX4X-MIB.mib) to add more visibility to the behaviour of the Ethernet board.

- **np2Redundancy:** .1.3.6.1.4.1.55461.1.6.4, represents active redundancy protocol set in the device.
- **rstpRootIdentifier**: .1.3.6.1.4.1.55461.1.6.5, represents RSTP Rot Bridge Identifier. It is a combination of Root bridge's priority and its MAC address.
- **rstpTimeSinceTopoChange**: .1.3.6.1.4.1.55461.1.6.6, represents the time elapsed since last RSTP topology change.
- **rstpTopoChangeCount**: .1.3.6.1.4.1.55461.1.6.7, represents RSTP topology change count.

18.10.5 SNMP ALARM ENHANCEMENT

An SNMP alarm is triggered by the relay when a security event occurs, if SNMP trap destination IP is configured in the settings.

18.10.5.1 SNMP ALARM FORMAT

The format of the SNMP trap/alarm for security events consists of three parts as described below.

"Event Description, Username, Interface".

Event Description: Short description of the alarm, same as the description present in Security event.

Username: User associated with the event, provided only when Username is available for the Security event.

Interface: Interface on which Security event has occurred, same as the interface information present in Security event.

18.10.5.2 LIST OF SNMP ALARMS

No.	Security Events	SNMP Trap Text
1	SECUR_EVT_PW_SET_NON_COMPLIANT	User Password change failed - policy check failed
2	SECUR_EVT_PW_MODIFIED	User password changed successfully
3	SECUR_EVT_PW_ENTRY_NOW_BLOCKED	User locked - wrong credentials
4	SECUR_EVT_PW_ENTRY_UNBLOCKED	User unlocked
5	SECUR_EVT_PW_ENTERED_WHILE_BLOCKED	Log-in attempt when user is locked
6	SECUR_EVT_INVALID_PW_ENTERED	Log-in failed - wrong credentials

No.	Security Events	SNMP Trap Text
7	SECUR_EVT_PW_TIMED_OUT	Log-in failed - credentials expired
8	SECUR_EVT_RECOVERY_PW_ENTERED	Recovery password entered
9	SECUR_EVT_IED_SEC_CODE_READ	Security Code read
10	SECUR_EVT_IED_SEC_CODE_TMR_EXPIRED	Security Code Timer expired
11	SECUR_EVT_PORT_DISABLED	Port Disabled
12	SECUR_EVT_PORT_ENABLED	Port Enabled
13	SECUR_EVT_PSL_SETTINGS_DOWNLOADED	PSL Settings downloaded to device
14	SECUR_EVT_DNP_SETTINGS_DOWNLOADED	DNP Settings downloaded to device
15	SECUR_EVT_61850_CONFIG_DOWNLOADED	IEC61850 Config downloaded to device
16	SECUR_EVT_USER_CURVES_DOWNLOADED	User Curves downloaded to device
17	SECUR_EVT_SETTING_GRP_DOWNLOADED	Setting Group downloaded to device
18	SECUR_EVT_DR_SETTINGS_DOWNLOADED	DR Settings downloaded to device
19	SECUR_EVT_PSL_SETTINGS_UPLOADED	PSL Settings uploaded from device
20	SECUR_EVT_DNP_SETTINGS_UPLOADED	DNP Settings uploaded from device
21	SECUR_EVT_61850_CONFIG_UPLOADED	IEC61850 Config uploaded from device
22	SECUR_EVT_USER_CURVES_UPLOADED	User Curves uploaded from device
23	SECUR_EVT_PSL_CONFIG_UPLOADED	PSL Config uploaded from device
24	SECUR_EVT_SETTINGS_UPLOADED	Settings uploaded from device
25	SECUR_EVT_CS_SETTINGS_CHANGED	Control & Support settings changed
26	SECUR_EVT_DR_SETTINGS_CHANGED	Disturbance Record Settings changed
27	SECUR_EVT_SETTING_GROUP_CHANGED	Setting Group changed
28	SECUR_EVT_DEFAULT_SETTINGS_RESTORED	Default Settings restored
29	SECUR_EVT_DEFAULT_USRCURVE_RESTORED	Default User Curve restored
30	SECUR_EVT_POWER_ON	Device Powered On
31	SECUR_EVT_RADIUS_UNAVAIL	RADIUS server not available
32	SECUR_EVT_SESSION_LIMIT	Active user sessions limit reached
33	SECUR_EVT_SLD_FILE_DOWNLOADED	SLD File downloaded to device
34	SECUR_EVT_SLD_FILE_UPLOADED	SLD File uploaded from device
35	SECUR_EVT_RBAC_LOGIN	Log-in successful
36	SECUR_EVT_RBAC_LOGOUT	Log-out (user logged out)
37	Bypass mode Activated	Bypass Mode Activated
38	Bypass mode Deactivated	Bypass Mode Deactivated
39	RADIUS Secret Key changed	RADIUS Secret Key changed
40	SECUR_EVT_SEC_SETTINGS_RESTORED	Security settings restored
41	Switch to Golden Image	Device switching to Firmware update mode
42	Fallback to Device Authentication	Fallback to Device Authentication
43	User logged out due to inactivity timeout.	Log-out by user inactivity (timeout)
44	Security events upload	Security Events uploaded from device

No.	Security Events	SNMP Trap Text
45	SSH Passcode change	SSH pass code change
46	SSH Client Authentication Fail	Failed client authentication
47	SSH Client Authentication Success	Successful client authentication
48	New User added	User account created successfully
49	User deleted	User account deleted successfully
50	User role change	Permission changed successfully
51	User name change	User renamed successfully

18.11 DATA PROTOCOLS

The products support a wide range of protocols to make them applicable to many industries and applications. The exact data protocols supported by a particular product depend on its chosen application, but the following table gives a list of the data protocols that are typically available.

DATA PROTOCOLS

Data Protocol	Layer 1 Interface	Description
Courier	USB, K-Bus, RS232, RS485, Ethernet	Standard for SCADA communications developed by GE Vernova
IEC 60870-5-103	RS485	IEC standard for SCADA communications
DNP 3.0	RS485	Standard for SCADA communications
IEC 61850	Ethernet	IEC standard for substation automation. Facilitates interoperability.

The relationship of these protocols to the lower-level physical layer protocols are as follows:

Data Protocols	IEC 60870-5-103 DNP3.0 Courier	IEC 61850 Courier	Courier	Courier	Courier
Data Link Layer	EIA(RS)485	Ethernet	EIA(RS)232	K-Bus	USB
Physical Layer	Copper or Optical Fibre				USB Type B

The product supports switchable serial communication data protocol on the Rear Port 1 (RP1) interface (it is no longer necessary to select the protocol as a product order option). This setting cell is RP1 Protocol in the COMMUNICATIONS column. For example, the product can now be configured to provide IEC 61850 on the Ethernet interface and DNP3.0 on the serial port concurrently.

18.11.1 COURIER

This section should provide sufficient detail to enable understanding of the Courier protocol at a level required by most users. For situations where the level of information contained in this manual is insufficient, further publications (R6511 and R6512) containing in-depth details about the protocol and its use, are available on request.

Courier is a GE Vernova proprietary communication protocol. Courier uses a standard set of commands to access a database of settings and data in the IED. This allows a master to communicate with a number of slave devices. The application-specific elements are contained in the database rather than in the commands used to interrogate it, meaning that the master station does not need to be preconfigured. Courier also provides a sequence of event (SOE) and disturbance record extraction mechanism.

18.11.1.1 PHYSICAL CONNECTION AND LINK LAYER

Courier can be used with four physical layer protocols: USB, K-Bus, EIA(RS)232 or EIA(RS)485.

Several connection options are available for Courier:

- The front USB port (for connection to Settings application software on, for example, a laptop).
- Rear Port 1 (RP1) - for permanent SCADA connection via serial RS485 or K-Bus
- Optional fibre port (RP1 in slot A) - for permanent SCADA connection via serial optical fibre
- Optional Rear Port 2 (RP2) - for permanent SCADA connection via serial RS485, K-Bus, or RS232

Optional Ethernet board (NIC) - for remote communication with the S1 Agile settings application software across an Ethernet network.

For either of the serial rear ports, both the IED address, and baud rate can be selected using the front panel menu or by the settings application software.

Note:
*Changing the **RP2 Port Config** setting (K-Bus, EIA(RS)232) requires the IED to be rebooted, for the change to become effective.*

18.11.1.2 COURIER DATABASE

The Courier database is two-dimensional and resembles a table. Each cell in the database is referenced by a row and column address. Both the column and the row can take a range from 0 to 255 (0000 to FFFF Hexadecimal. Addresses in the database are specified as hexadecimal values, for example, 0A02 is column 0A row 02. Associated settings or data are part of the same column. Row zero of the column has a text string to identify the contents of the column and to act as a column heading.

The product-specific menu databases contain the complete database definition.

18.11.1.3 SETTINGS CATEGORIES

There are two main categories of settings in protection IEDs:

- Control and support settings
- Protection settings

With the exception of the Disturbance Recorder settings, changes made to the control and support settings are implemented immediately and stored in non-volatile memory. Changes made to the Protection settings and the Disturbance Recorder settings are stored in ‘scratchpad’ memory and are not immediately implemented. These need to be committed by writing to the ***Save Changes*** cell in the *CONFIGURATION* column.

18.11.1.4 SETTING CHANGES

Courier provides two mechanisms for making setting changes. Either method can be used for editing any of the settings in the database.

Method 1

This uses a combination of three commands to perform a settings change:

First, enter Setting mode: This checks that the cell is settable and returns the limits.

1. Preload Setting: This places a new value into the cell. This value is echoed to ensure that setting corruption has not taken place. The validity of the setting is not checked by this action.
2. Execute Setting: This confirms the setting change. If the change is valid, a positive response is returned. If the setting change fails, an error response is returned.
3. Abort Setting: This command can be used to abandon the setting change.

This is the most secure method. It is ideally suited to on-line editors because the setting limits are extracted before the setting change is made. However, this method can be slow if many settings are being changed because three commands are required for each change.

Method 2

The Set Value command can be used to change a setting directly. The response to this command is either a positive confirm or an error code to indicate the nature of a failure. This command can be used to implement a setting more rapidly than the previous method; however, the limits are not extracted. This method is therefore most suitable for off-line setting editors such as MiCOM S1 Agile, or for issuing preconfigured control commands.

18.11.1.5 EVENT EXTRACTION

You can extract events either automatically (rear serial port only) or manually (either serial port). For automatic extraction, all events are extracted in sequential order using the Courier event mechanism. This includes fault and maintenance data if appropriate. The manual approach allows you to select events, faults, or maintenance data as desired.

18.11.1.5.1 AUTOMATIC EVENT RECORD EXTRACTION

This method is intended for continuous extraction of event and fault information as it is produced. It is only supported through the rear Courier port.

When new event information is created, the ***Event*** bit is set in the ***Status*** byte. This indicates to the Master device that event information is available. The oldest, non-extracted event can be extracted from the IED using the ***Send Event*** command. The IED responds with the event data.

Once an event has been extracted, the ***Accept Event*** command can be used to confirm that the event has been successfully extracted. When all events have been extracted, the ***Event*** bit is reset. If there are more events still to be extracted, the next event can be accessed using the ***Send Event*** command as before.

18.11.1.5.2 MANUAL EVENT RECORD EXTRACTION

The *VIEW RECORDS* column (location 01) is used for manual viewing of event, fault, and maintenance records. The contents of this column depend on the nature of the record selected. You can select events by event number and directly select a fault or maintenance record by number.

Event Record Selection ('Select Event' cell: 0101)

This cell can set the number of stored events. For simple event records (Type 0), cells 0102 to 0105 contain the event details. A single cell is used to represent each of the event fields. If the event selected is a fault or maintenance record (Type 3), the remainder of the column contains the additional information.

Fault Record Selection ('Select Fault' cell: 0106)

This cell can be used to select a fault record directly, using a value between 0 and 99 to select one of up to a hundred stored fault records. (0 is the most recent fault and 99 is the oldest). The column then contains the details of the fault record selected.

Maintenance Record Selection ('Select Maint' cell: 01F0)

This cell can be used to select a maintenance record using a value between 0 and 9. This cell operates in a similar way to the fault record selection.

If this column is used to extract event information, the number associated with a particular record changes when a new event or fault occurs.

Event Types

The IED generates events under certain circumstances such as:

- Change of state of output contact
- Change of state of opto-input
- Protection element operation
- Alarm condition
- Setting change
- Password entered/timed-out

Event Record Format

The IED returns the following fields when the Send Event command is invoked:

- Cell reference
- Time stamp
- Cell text
- Cell value

The Menu Database contains tables of possible events and shows how the contents of the above fields are interpreted. Fault and Maintenance records return a Courier Type 3 event, which contains the above fields plus two additional fields:

- Event extraction column
- Event number

These events contain additional information, which is extracted from the IED using column B4. Row 01 contains a ***Select Record*** setting that allows the fault or maintenance record to be selected. This setting should be set to the event number value returned in the record. The extended data can be extracted from the IED by uploading the text and data from the column.

18.11.1.6 DISTURBANCE RECORD EXTRACTION

The stored disturbance records are accessible through the Courier interface. The records are extracted using column (B4).

The ***Select Record*** cell can be used to select the record to be extracted. Record 0 is the oldest non-extracted record. Older records which have already been extracted are assigned positive values, while younger records are assigned negative values. To help automatic extraction through the rear port, the IED sets the ***Disturbance*** bit of the ***Status*** byte, whenever there are non-extracted disturbance records.

Once a record has been selected, using the above cell, the time and date of the record can be read from the ***Trigger Time*** cell (B402). The disturbance record can be extracted using the block transfer mechanism from cell B40B and saved in the COMTRADE format. The settings application software software automatically does this.

18.11.1.7 PROGRAMMABLE SCHEME LOGIC SETTINGS

The programmable scheme logic (PSL) settings can be uploaded from and downloaded to the IED using the block transfer mechanism.

The following cells are used to perform the extraction:

- ***Domain*** cell (B204): Used to select either PSL settings (upload or download) or PSL configuration data (upload only)
- ***Sub-Domain*** cell (B208): Used to select the Protection Setting Group to be uploaded or downloaded.
- ***Version*** cell (B20C): Used on a download to check the compatibility of the file to be downloaded.
- ***Transfer Mode*** cell (B21C): Used to set up the transfer process.
- ***Data Transfer*** cell (B120): Used to perform upload or download.

The PSL settings can be uploaded and downloaded to and from the IED using this mechanism. The settings application software must be used to edit the settings. It also performs checks on the validity of the settings before they are transferred to the IED.

The language of a recovered PSL file depends on the language of a settings file sent on the same interface used to recover the PSL file. All interfaces are set by default to English, which means by default, the relay will recover the PSL file in English on all interfaces.

As an example, if the PSL file needs to be recovered in French through the front port, the user is required to send the settings file to the relay in French through the front port prior to recovering the PSL file. While the PSL file will be

recovered in French through the front port, it will still be recovered in English through Ethernet and the rear RS485 port if available, unless and until the settings file is sent in French on those interfaces as well.

18.11.1.8 TIME SYNCHRONISATION

The time and date can be set using the time synchronisation feature of the Courier protocol. The device will correct for the transmission delay. The time synchronisation message may be sent as either a global command or to any individual IED address. If the time synchronisation message is sent to an individual address, then the device will respond with a confirm message. If sent as a global command, the (same) command must be sent twice. A time synchronisation Courier event will be generated/produced whether the time-synchronisation message is sent as a global command or to any individual IED address.

If the clock is being synchronised using the IRIG-B input then it will not be possible to set the device time using the Courier interface. An attempt to set the time using the interface will cause the device to create an event with the current date and time taken from the IRIG-B synchronised internal clock.

18.11.1.9 COURIER CONFIGURATION

To configure the device:

1. Select the *CONFIGURATION* column and check that the ***Comms settings*** cell is set to `Visible`.
2. Select the *COMMUNICATIONS* column.
3. Move to the first cell down (***RP1 Protocol***). Set this to the chosen communication protocol – in this case `Courier`.
4. Move down to the next cell (***RP1 Address***). This cell controls the address of the RP1 port on the device. Up to 32 IEDs can be connected to one spur. It is therefore necessary for each IED to have a unique address so that messages from the master control station are accepted by one IED only. Courier uses an integer number between 1 and 254 for the Relay Address. It is set to 255 by default, which must be changed. It is important that no two IEDs share the same address.
5. Move down to the next cell (***RP1 InactivTimer***). This cell controls the inactivity timer. The inactivity timer controls how long the IED waits without receiving any messages on the rear port before revoking any password access that was enabled and discarding any changes. For the rear port this can be set between 1 and 30 minutes.
6. If the optional fibre optic connectors are fitted, the ***RP1 PhysicalLink*** cell is visible. This cell controls the physical media used for the communication (Copper or Fibre optic).
7. Move down to the next cell (***RP1 Card Status***). This cell is not settable. It displays the status of the chosen physical layer protocol for RP1.
8. Move down to the next cell (***RP1 Port Config***). This cell controls the type of serial connection. Select between K-Bus or RS485.
9. If using EIA(RS)485, the next cell (***RP1 Comms Mode***) selects the communication mode. The choice is either IEC 60870 FT1.2 for normal operation with 11-bit modems, or 10-bit no parity. If using K-Bus this cell will not appear.
10. If using EIA(RS)485, the next cell down controls the baud rate. Three baud rates are supported; 9600, 19200 and 38400. If using K-Bus this cell will not appear as the baud rate is fixed at 64 kbps.

18.11.2 IEC 60870-5-103

The specification IEC 60870-5-103 (Telecontrol Equipment and Systems Part 5 Section 103: Transmission Protocols), defines the use of standards IEC 60870-5-1 to IEC 60870-5-5, which were designed for communication with protection equipment.

This section describes how the IEC 60870-5-103 standard is applied to the Px40 platform. It is not a description of the standard itself. The level at which this section is written assumes that the reader is already familiar with the IEC 60870-5-103 standard.

This section should provide sufficient detail to enable understanding of the standard at a level required by most users.

The IEC 60870-5-103 interface is a master/slave interface with the device as the slave device. The device conforms to compatibility level 2, as defined in the IEC 60870-5-103.standard.

The following IEC 60870-5-103 facilities are supported by this interface:

- Initialization (reset)
- Time synchronisation
- Event record extraction
- General interrogation
- Cyclic measurements
- General commands
- Disturbance record extraction
- Private codes

18.11.2.1 PHYSICAL CONNECTION AND LINK LAYER

Two connection options are available for IEC 60870-5-103:

- Rear Port 1 (RP1) - for permanent SCADA connection via RS485
- Optional fibre port (RP1 in slot A) - for permanent SCADA connection via optical fibre

If the optional fibre optic port is fitted, a menu item appears in which the active port can be selected. However, the selection is only effective following the next power up.

The IED address and baud rate can be selected using the front panel menu or by the settings application software.

18.11.2.2 INITIALISATION

Whenever the device has been powered up, or if the communication parameters have been changed a reset command is required to initialize the communications. The device will respond to either of the two reset commands; Reset CU or Reset FCB (Communication Unit or Frame Count Bit). The difference between the two commands is that the Reset CU command will clear any unsent messages in the transmit buffer, whereas the Reset FCB command does not delete any messages.

The device will respond to the reset command with an identification message ASDU 5. The Cause of Transmission (COT) of this response will be either Reset CU or Reset FCB depending on the nature of the reset command. The content of ASDU 5 is described in the IEC 60870-5-103 section of the Menu Database, available from GE Vernova separately if required.

In addition to the above identification message, it will also produce a power up event.

18.11.2.3 TIME SYNCHRONISATION

The time and date can be set using the time synchronisation feature of the IEC 60870-5-103 protocol. The device will correct for the transmission delay as specified in IEC 60870-5-103. If the time synchronisation message is sent as a send/confirm message, then the device will respond with a confirm message. A time synchronisation Class 1 event will be generated/produced whether the time-synchronisation message is sent as a send confirm or a broadcast (send/no reply) message.

If the clock is being synchronised using the IRIG-B input, then it will not be possible to set the device time using the IEC 60870-5-103 interface. An attempt to set the time via the interface will cause the device to create an event with the current date and time taken from the IRIG-B synchronised internal clock.

18.11.2.4 CONFIGURABLE IEC 60870-5-103 SIGNAL LIST

From Software Version 91 onwards, there is a setting cell which allows the IEC 60870-5-103 private range signals to be selected and de-selected from IEC 60870-5-103 communication.

The IEC 60870-5-103 standard (compatible range) signals, that are provided according to the relay type and implementation, are always enabled. These signals cannot be disabled.

This setting cell is ***Config Mode*** in the *PROTOCOL CFG* column.

There are two settings associated with this cell. These are:

Setting	Description
Fixed	In this mode, the IED behaviour for IEC 60870-5-103 protocol is identical to pre-Software Version 91 IEDs. All the implemented signals (IEC 60870-5-103 compatible range and private range signals) are enabled for IEC 60870-5-103 communication. The COT behaviour will be according to the device IEC 60870-5-103 profile. This mode is provided for backward compatibility. This is the default setting.
Std+UserConfig	In this mode, the user can select which IEC 60870-5-103 private range signals are enabled for IEC 60870-5-103 communication. The selection is done using DDB mask setting cells in the *PROTOCOL CFG* column. The DDB mask value controls only the signal selection (enabled or disabled) for IEC 60870-5-103 communication. It does not modify the COT behaviour of the signals. The COT behaviour of the private range signals will be according to the device IEC 60870-5-103 profile. By default, only IEC 60870-5-103 standard signals are enabled. All private range signals are disabled.

When the ***Config Mode*** cell is set to `Std+UserConfig`, the DDB masks become visible in the *PROTOCOL CFG* column. These masks function in a similar way to the DDB masks in the *RECORD CONTROL* column. Editing these masks controls the DDB signals that are enabled for communication of the equivalent IEC 60870-5-103 private range signal, as listed in the IEC 60870-5-103 profile in the Menu Database.

Within these masks, only individual DDBs that are equivalent to IEC 60870-5-103 private range signals are editable. By default, all of the individual DDBs that are equivalent to IEC 60870-5-103 private range signals are set to 0 (zero), that is disabled for communication. Setting any individual DDB to 1 (one), enables the equivalent IEC 60870-5-103 private range signal for communication.

Within these masks, individual DDBs that are either equivalent to IEC 60870-5-103 standard range signals, or do not have any equivalent IEC 60870-5-103 private range signal, are not editable.

18.11.2.5 SPONTANEOUS EVENTS

Events are categorized using the following information:

- Function type
- Information Number

The IEC 60870-5-103 profile in the Menu Database contains a complete listing of all events produced by the device.

From Software Version 91 onwards, the IEC 60870-5-103 private range signals can be individually selected for spontaneous communication, by setting the ***Config Mode*** cell to `Std+UserConfig` and configuring the DDB masks as required.

18.11.2.6 GENERAL INTERROGATION (GI)

The GI request can be used to read the status of the device, the function numbers, and information numbers that will be returned during the GI cycle. These are shown in the IEC 60870-5-103 profile in the Menu Database.

From Software Version 91 onwards, the IEC 60870-5-103 private range signals can be individually selected for GI reporting, by setting the ***Config Mode*** cell to `Std+UserConfig` and configuring the DDB masks as required.

18.11.2.7 CYCLIC MEASUREMENTS

The device will produce measured values using ASDU 9 on a cyclical basis, this can be read from the device using a Class 2 poll (note ADSU 3 is not used). The rate at which the device produces new measured values can be controlled using the measurement period setting. This setting can be edited from the front panel menu or using MiCOM S1 Agile. It is active immediately following a change.

The device transmits its measurands with maximum value of 2.4 times the rated value of the measurement.

18.11.2.8 COMMANDS

A list of the supported commands is contained in the Menu Database. The device will respond to other commands with an ASDU 1, with a cause of transmission (COT) indicating 'negative acknowledgement'.

18.11.2.9 TEST MODE

It is possible to disable the device output contacts to allow secondary injection testing to be performed using either the front panel menu or the front serial port. The IEC 60870-5-103 standard interprets this as 'test mode'. An event will be produced to indicate both entry to and exit from test mode. Spontaneous events and cyclic measured data transmitted whilst the device is in test mode will have a COT of 'test mode'.

18.11.2.10 DISTURBANCE RECORDS

The disturbance records are stored in uncompressed format and can be extracted using the standard mechanisms described in IEC 60870-5-103.

> *Note:*
> *IEC 60870-5-103 only supports up to 8 records.*

18.11.2.11 COMMAND/MONITOR BLOCKING

The device supports a facility to block messages in the monitor direction (data from the device) and also in the command direction (data to the device). Messages can be blocked in the monitor and command directions using one of the two following methods

- The menu command ***RP1 CS103Blcking*** in the *COMMUNICATIONS* column
- The DDB signals Monitor Blocked and Command Blocked

18.11.2.12 IEC 60870-5-103 CONFIGURATION

To configure the device:

1. Select the *CONFIGURATION* column and check that the ***Comms settings*** cell is set to `Visible`.
2. Select the *COMMUNICATIONS* column.
3. Move to the first cell down (***RP1 Protocol***). Set this to the chosen communication protocol - in this case `IEC 60870-5-103`.
4. Move down to the next cell (***RP1 Address***). This cell controls the IEC 60870-5-103 address of the IED. Up to 32 IEDs can be connected to one spur. It is therefore necessary for each IED to have a unique address so that messages from the master control station are accepted by one IED only. IEC 60870-5-103 uses an integer number between 0 and 254 for the address. It is important that no two IEDs have the same IEC 60870 5 103 address. The IEC 60870-5-103 address is then used by the master station to communicate with the IED.
5. Move down to the next cell (***RP1 Baud Rate***). This cell controls the baud rate to be used. Two baud rates are supported by the IED, `9600 bits/s` and `19200 bits/s`. Make sure that the baud rate selected on the IED is the same as that set on the master station.

6. Move down to the next cell (***RP1 Meas Period***). The next cell down controls the period between IEC 60870-5-103 measurements. The IEC 60870-5-103 protocol allows the IED to supply measurements at regular intervals. The interval between measurements is controlled by this cell and can be set between 1 and 60 seconds.
7. If the optional fibre optic connectors are fitted, the ***RP1 PhysicalLink*** cell is visible. This cell controls the physical media used for the communication (Copper or Fibre optic).
8. The next cell down (***RP1 CS103Blcking***) can be used for monitor or command blocking.
9. There are three settings associated with this cell; these are:

Setting	Description
Disabled	No blocking selected.
Monitor Blocking	When the monitor blocking DDB Signal is active high, either by energising an opto input or control input, reading of the status information and disturbance records is not permitted. When in this mode the device returns a "Termination of general interrogation" message to the master station.
Command Blocking	When the command blocking DDB signal is active high, either by energising an opto input or control input, all remote commands will be ignored (i.e. CB Trip/Close, change setting group etc.). When in this mode the device returns a "negative acknowledgement of command" message to the master station.

18.11.3 DNP 3.0

This section describes how the DNP 3.0 standard is applied in the product. It is not a description of the standard itself. The level at which this section is written assumes that the reader is already familiar with the DNP 3.0 standard.

The descriptions given here are intended to accompany the device profile document that is included in the Menu Database document. The DNP 3.0 protocol is not described here, please refer to the documentation available from the user group. The device profile document specifies the full details of the DNP 3.0 implementation. This is the standard format DNP 3.0 document that specifies which objects; variations and qualifiers are supported. The device profile document also specifies what data is available from the device using DNP 3.0. The IED operates as a DNP 3.0 slave and supports subset level 2, as described in the DNP 3.0 standard, plus some of the features from level 3.

The DNP 3.0 protocol is defined and administered by the DNP Users Group. For further information on DNP 3.0 and the protocol specifications, please see the DNP website (www.dnp.org).

18.11.3.1 PHYSICAL CONNECTION AND LINK LAYER

DNP 3.0 can be used with EIA(RS)485.

Several connection options are available for DNP 3.0

- Rear Port 1 (RP1) - for permanent SCADA connection via RS485
- Optional fibre port (RP1 in slot A) - for permanent SCADA connection via optical fibre

The baud rate can be selected using the front panel menu or by the settings application software.

When using a serial interface, the data format is: 1 start bit, 8 data bits, 1 stop bit and optional configurable parity bit.

18.11.3.2 OBJECT 1 BINARY INPUTS

Object 1, binary inputs, contains information describing the state of signals in the IED, which mostly form part of the digital data bus (DDB). In general, these include the state of the output contacts and opto-inputs, alarm signals, and protection start and trip signals. The ‘DDB number’ column in the device profile document provides the DDB numbers for the DNP 3.0 point data. These can be used to cross-reference to the DDB definition list. See the

relevant Menu Database document. The binary input points can also be read as change events using Object 2 and Object 60 for class 1-3 event data.

Note:
For the DNP Events to be transmitted it is mandatory to have the corresponding DDBs of the Configured Point Index to be included in the Courier Event Record. The RECORD CONTROL Menu lists all the DDBs, and the mask settings control their inclusion/exclusion as a Courier Event.

18.11.3.3 OBJECT 10 BINARY OUTPUTS

Object 10, binary outputs, contains commands that can be operated using DNP 3.0. Therefore, the points accept commands of type pulse on (null, trip, close) and latch on/off as detailed in the device profile in the relevant Menu Database document, and execute the command once for either command. The other fields are ignored (queue, clear, trip/close, in time and off time).

There is an additional image of the Control Inputs. Described as Alias Control Inputs, they reflect the state of the Control Input, but with a dynamic nature.

- If the Control Input DDB signal is already SET and a new DNP SET command is sent to the Control Input, the Control Input DDB signal goes momentarily to RESET and then back to SET.
- If the Control Input DDB signal is already RESET and a new DNP RESET command is sent to the Control Input, the Control Input DDB signal goes momentarily to SET and then back to RESET.

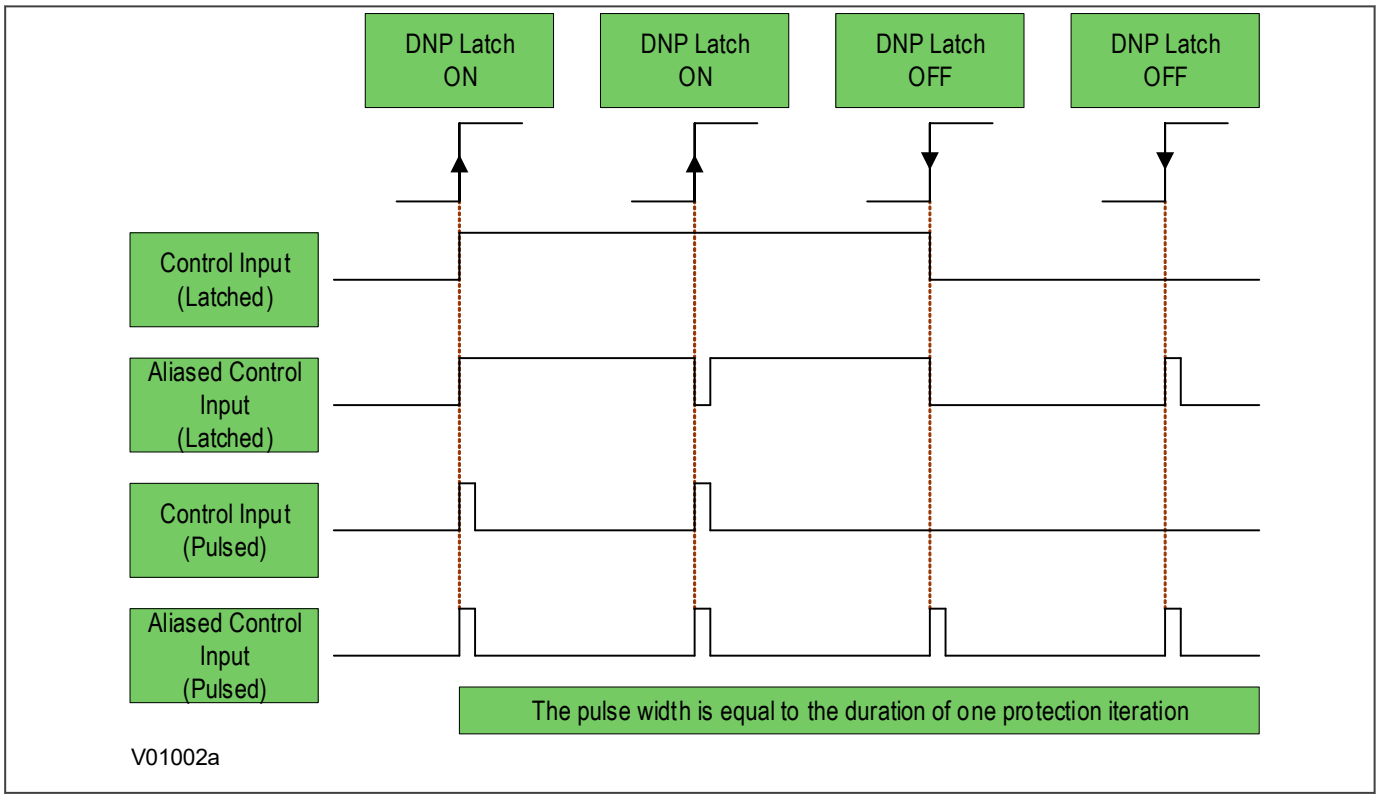


Figure 233: Control input behaviour

Many of the IEDs functions are configurable so some of the Object 10 commands described in the following sections may not be available. A read from Object 10 reports the point as off-line and an operate command to Object 12 generates an error response.

Examples of Object 10 points that may be reported as off-line are:

- Activate setting groups: Ensure setting groups are enabled
- CB trip/close: Ensure remote CB control is enabled
- Reset NPS thermal: Ensure NPS thermal protection is enabled
- Reset thermal O/L: Ensure thermal overload protection is enabled
- Reset RTD flags: Ensure RTD Inputs is enabled
- Control inputs: Ensure control inputs are enabled

18.11.3.4 OBJECT 20 BINARY COUNTERS

Object 20, binary counters, contains cumulative counters and measurements. The binary counters can be read as their present 'running' value from Object 20, or as a 'frozen' value from Object 21. The running counters of object 20 accept the read, freeze and clear functions. The freeze function takes the current value of the object 20 running counter and stores it in the corresponding Object 21 frozen counter. The freeze and clear function resets the Object 20 running counter to zero after freezing its value.

Binary counter and frozen counter change event values are available for reporting from Object 22 and Object 23 respectively. Counter change events (Object 22) only report the most recent change, so the maximum number of events supported is the same as the total number of counters. Frozen counter change events (Object 23) are generated whenever a freeze operation is performed, and a change has occurred since the previous freeze command. The frozen counter event queues store the points for up to two freeze operations.

18.11.3.5 OBJECT 30 ANALOGUE INPUT

Object 30, analogue inputs, contains information from the IED's measurements columns in the menu. All Object 30 points can be reported as 16 or 32-bit integer values with flag, 16 or 32-bit integer values without flag, as well as short floating point values.

Analogue values can be reported to the master station as primary, secondary or normalized values (which takes into account the IED's CT and VT ratios), and this is settable in the *COMMUNICATIONS* column in the IED. Corresponding deadband settings can be displayed in terms of a primary, secondary or normalized value. Deadband point values can be reported and written using Object 34 variations.

The deadband is the setting used to determine whether a change event should be generated for each point. The change events can be read using Object 32 or Object 60. These events are generated for any point which has a value changed by more than the deadband setting since the last time the data value was reported.

Any analogue measurement that is unavailable when it is read is reported as offline. For example, the frequency would be offline if the current and voltage frequency is outside the tracking range of the IED. All Object 30 points are reported as secondary values in DNP 3.0 (with respect to CT and VT ratios).

18.11.3.6 OBJECT 40 ANALOGUE OUTPUT

The conversion to fixed-point format requires the use of a scaling factor, which is configurable for the various types of data within the IED such as current, voltage, and phase angle. All Object 40 points report the integer scaling values and Object 41 is available to configure integer scaling quantities.

18.11.3.7 OBJECT 50 TIME SYNCHRONISATION

Function codes 1 (read) and 2 (write) are supported for Object 50 (time and date) variation 1. The DNP Need Time function (the duration of time waited before requesting another time sync from the master) is supported and is configurable in the range 1 - 30 minutes.

If the clock is being synchronised using the IRIG-B input, then it will not be possible to set the device time using the Courier interface. An attempt to set the time using the interface will cause the device to create an event with the current date and time taken from the IRIG-B synchronised internal clock.

18.11.3.8 DNP3 DEVICE PROFILE

This section describes the specific implementation of DNP version 3.0 within GE Vernova MiCOM P40 Agile IEDs for both compact and modular ranges.

The devices use the DNP 3.0 Slave Source Code Library version 3 from Triangle MicroWorks Inc.

This document, in conjunction with the DNP 3.0 Basic 4 Document Set, and the DNP Subset Definitions Document, provides complete information on how to communicate with the devices using the DNP 3.0 protocol.

This implementation of DNP 3.0 is fully compliant with DNP 3.0 Subset Definition Level 2. It also contains many Subset Level 3 and above features.

18.11.3.8.1 DNP3 DEVICE PROFILE TABLE

The following table provides the device profile in a similar format to that defined in the DNP 3.0 Subset Definitions Document. While it is referred to in the DNP 3.0 Subset Definitions as a “Document”, it is just one component of a total interoperability guide. This table, in combination with the subsequent Implementation and Points List tables should provide a complete interoperability/configuration guide for the device.

The following table provides the device profile in a similar format to that defined in the DNP 3.0 Subset Definitions Document. While it is referred to in the DNP 3.0 Subset Definitions as a "Document", it is just one component of a total interoperability guide. This table, in combination with the subsequent Implementation and Points List tables should provide a complete interoperability/configuration guide for the device.

DNP 3.0 Device Profile Document	
Vendor Name:	GE Vernova
Device Name:	MiCOM P40Agile Protection Relays - compact and modular range
Models Covered:	All models
Highest DNP Level Supported*: * This is the highest DNP level FULLY supported. Parts of level 3 are also supported	For Requests: Level 2 For Responses: Level 2
Device Function:	Slave
Notable objects, functions, and/or qualifiers supported in addition to the highest DNP levels supported (the complete list is described in the DNP 3.0 Implementation Table): For static (non-change event) object requests, request qualifier codes 00 and 01 (start-stop), 07 and 08 (limited quantity), and 17 and 28 (index) are supported in addition to the request qualifier code 06 (no range (all points)) Static object requests sent with qualifiers 00, 01, 06, 07, or 08 will be responded with qualifiers 00 or 01 Static object requests sent with qualifiers 17 or 28 will be responded with qualifiers 17 or 28 For change-event object requests, qualifiers 17 or 28 are always responded 16-bit and 32-bit analogue change events with time may be requested The read function code for Object 50 (time and date) variation 1 is supported Analogue Input Deadbands, Object 34, variations 1 through 3, are supported Floating Point Analogue Output Status and Output Block Objects 40 and 41 are supported Sequential file transfer, Object 70, variations 2 through 7, are supported Device Attribute Object 0 is supported	
Maximum Data Link Frame Size (octets):	Transmitted: 292 Received: 292
Maximum Application Fragment Size (octets)	Transmitted: Configurable (100 to 2048). Default 2048 Received: 249
Maximum Data Link Retries:	Fixed at 2
Maximum Application Layer Retries:	None
Requires Data Link Layer Confirmation:	Configurable to Never or Always

DNP 3.0 Device Profile Document	
Requires Application Layer Confirmation:	When reporting event data (Slave devices only) When sending multi-fragment responses (Slave devices only)
Timeouts while waiting for:	
Data Link Confirm:	Configurable
Complete Application Fragment:	None
Application Confirm:	Configurable
Complete Application Response:	None
Others:	
Data Link Confirm Timeout:	Configurable from 0 (Disabled) to 120s, default 10s.
Application Confirm Timeout:	Configurable from 1 to 120s, default 2s.
Select/Operate Arm Timeout:	Configurable from 1 to 10s, default 10s.
Need Time Interval (Set IIN1-4):	Configurable from 1 to 30, default 10min.
Application File Timeout	60 s
Analog Change Event Scan Period:	Fixed at 0.5s
Counter Change Event Scan Period	Fixed at 0.5s
Frozen Counter Change Event Scan Period	Fixed at 1s
Maximum Delay Measurement Error:	2.5 ms
Time Base Drift Over a 10-minute Interval:	7 ms
Sends/Executes Control Operations:	
Write Binary Outputs:	Never
Select/Operate:	Always
Direct Operate:	Always
Direct Operate - No Ack:	Always
Count > 1	Never
Pulse On	Always
Pulse Off	Sometimes
Latch On	Always
Latch Off	Always
Queue	Never
Clear Queue	Never
Note: Paired Control points will accept Pulse On/Trip and Pulse On/Close, but only single point will accept the Pulse Off control command.	
Reports Binary Input Change Events when no specific variation requested:	Configurable to send one or the other
Reports time-tagged Binary Input Change Events when no specific variation requested:	Binary input change with time
Sends Unsolicited Responses:	Never
Sends Static Data in Unsolicited Responses:	Never No other options are permitted
Default Counter Object/Variation:	Configurable, Point-by-point list attached Default object: 20 Default variation: 1
Counters Roll Over at:	32 bits
Sends multi-fragment responses:	Yes

DNP 3.0 Device Profile Document	
Sequential File Transfer Support:	
Append File Mode	No
Custom Status Code Strings	No
Permissions Field	Yes
File Events Assigned to Class	No
File Events Send Immediately	Yes
Multiple Blocks in a Fragment	No
Max Number of Files Open	1

18.11.3.8.2 DNP3 IMPLEMENTATION TABLE

The implementation table provides a list of objects, variations and control codes supported by the device:

Object			Request (Library Will Parse)				Response (Library Will Respond With)			
Object Number	Variation Number	Description	Function Codes (dec)		Qualifier Codes (hex)		Function Codes (dec)		Qualifier Codes (hex)	
1	0	Binary Input (Variation 0 is used to request default variation)	1 22	(read) (assign class)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
1	1 (default - see note 1)	Binary Input	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
1	2	Binary Input with Flag	1	(read)	00, 01 06 07, 08 17, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
2	0	Binary Input Change - Any Variation	1	(read)	06 07, 08	(no range, or all) (limited qty)				
2	1	Binary Input Change without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
2	2	Binary Input Change with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
10	0	Binary Output Status - Any Variation	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
10	2 (default - see note 1)	Binary Output Status	1	(read)	00, 01 06 07, 08 17, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
12	1	Control Relay Output Block	3 4 5 6	(select) (operate) (direct op) (dir. op, noack)	17, 28	(index)	129	response		echo of request
20	0	Binary Counter - Any Variation	1 22	(read) (assign class)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
			7 8 9 10	(freeze) (freeze noack) (freeze clear) (frz. cl. Noack)	00, 01 06 07, 08	(start-stop) (no range, or all) (limited qty)				
20	1	32-Bit Binary Counter with Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
20	2	16-Bit Binary Counter with Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)

Object			Request (Library Will Parse)				Response (Library Will Respond With)			
Object Number	Variation Number	Description	Function Codes (dec)		Qualifier Codes (hex)		Function Codes (dec)		Qualifier Codes (hex)	
20	5 (default - see note 1)	32-Bit Binary Counter without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
20	6	16-Bit Binary Counter without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
21	0	Frozen Counter - Any Variation	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
21	1	32-Bit Frozen Counter with Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
21	2	16-Bit Frozen Counter with Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
21	5	32-Bit Frozen Counter with Time of Freeze	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 1)
21	6	16-Bit Frozen Counter with Time of Freeze	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) 17, 28 (index - see note 1)
21	9 (default - see note 1)	32-Bit Frozen Counter without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
21	10	16-Bit Frozen Counter without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
`22	0	Counter Change Event - Any Variation	1	(read)	06 07, 08	(no range, or all) (limited qty)				
22	1 (default - see note 1)	32-Bit Counter Change Event without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
22	2	16-Bit Counter Change Event without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
22	5	32-Bit Counter Change Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
22	6	16-Bit Counter Change Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
23	0	Frozen Counter Event (Variation 0 is used to request default variation)	1	(read)	06 07, 08	(no range, or all) (limited qty)				
23	1 (default - see note 1)	32-Bit Frozen Counter Event	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
23	2	16-Bit Frozen Counter Event	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
23	5	32-Bit Frozen Counter Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
23	6	16-Bit Frozen Counter Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
30	0	Analog Input - Any Variation	1 22	(read) (assign class)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
30	1	32-Bit Analog Input	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)

Object			Request (Library Will Parse)				Response (Library Will Respond With)			
Object Number	Variation Number	Description	Function Codes (dec)		Qualifier Codes (hex)		Function Codes (dec)		Qualifier Codes (hex)	
30	2	16-Bit Analog Input	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
30	3 (default - see note 1)	32-Bit Analog Input without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
30	4	16-Bit Analog Input without Flag	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
30	5	Short floating point	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
32	0	Analog Change Event - Any Variation	1	(read)	06 07, 08	(no range, or all) (limited qty)				
32	1 (default - see note 1)	32-Bit Analog Change Event without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
32	2	16-Bit Analog Change Event without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
32	3	32-Bit Analog Change Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
32	4	16-Bit Analog Change Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
32	5	Short floating point Analog Change Event without Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
32	7	Short floating point Analog Change Event with Time	1	(read)	06 07, 08	(no range, or all) (limited qty)	129	response	17, 28	(index)
34	0	Analog Input Deadband (Variation 0 is used to request default variation)	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
34	1	16 Bit Analog Input Deadband	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
			2	(write)	00, 01 07, 08 17, 27, 28	(start-stop) (limited qty) (index)				
34	2 (default - see note 1)	32 Bit Analog Input Deadband	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
			2	(write)	00, 01 07, 08 17, 27, 28	(start-stop) (limited qty) (index)				
34	3	Short Floating Point Analog Input Deadband	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
			2	(write)	00, 01 07, 08 17, 27, 28	(start-stop) (limited qty) (index)				
40	0	Analog Output Status (Variation 0 is used to request default variation)	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)				
40	1 (default - see note 1)	32-Bit Analog Output Status	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)

Object			Request (Library Will Parse)				Response (Library Will Respond With)			
Object Number	Variation Number	Description	Function Codes (dec)		Qualifier Codes (hex)		Function Codes (dec)		Qualifier Codes (hex)	
40	2	16-Bit Analog Output Status	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
40	3	Short Floating Point Analog Output Status	1	(read)	00, 01 06 07, 08 17, 27, 28	(start-stop) (no range, or all) (limited qty) (index)	129	response	00, 01 17, 28	(start-stop) (index - see note 2)
41	1	32-Bit Analog Output Block	3 4 5 6	(select) (operate) (direct op) (dir. op, noack)	17, 28 27	(index) (index)	129	response		echo of request
41	2	16-Bit Analog Output Block	3 4 5 6	(select) (operate) (direct op) (dir. op, noack)	17, 28 27	(index) (index)	129	response		echo of request
41	3	Short Floating Point Analog Output Block	3 4 5 6	(select) (operate) (direct op) (dir. op, noack)	17, 27, 28	(index)	129	response		echo of request
50	1 (default - see note 1)	Time and Date	1	(read)	07	(limited qty = 1)	129	response	07	(limited qty = 1)
			2	(write)	07	(limited qty = 1)				
60	0	Not defined								
60	1	Class 0 Data	1	(read)	06	(no range, or all)				
60	2	Class 1 Data	1	(read)	06 07, 08	(no range, or all) (limited qty)				
			22	(assign class)	06	(no range, or all)				
60	3	Class 2 Data	1	(read)	06 07, 08	(no range, or all) (limited qty)				
			22	(assign class)	06	(no range, or all)				
60	4	Class 3 Data	1	(read)	06 07, 08	(no range, or all) (limited qty)				
			22	(assign class)	06	(no range, or all)				
70	0	File Event - Any Variation	1	(read)	06 07, 08	(no range, or all) (limited qty)				
			22	(assign class)	06	(no range, or all)				
70	2	File Authentication	29	(authenticate)	5b	(free-format)	129	response		5B (free-format)
70	3	File Command	25 27	(open) (delete)	5b	(free-format)				
70	4	File Command Status	26 30	(close) (abort)	5b	(free-format)	129	response		5B (free-format)
70	5	File Transfer	1	(read)	5b	(free-format)	129	response		5B (free-format)
70	6	File Transfer Status					129	response		5B (free-format)
70	7	File Descriptor	28	(get file info)	5b	(free-format)	129	response		5B (free-format)
80	1	Internal Indications	1	(read)	00, 01	(start-stop)	129	response	00, 01	(start-stop)
		No Object (function code only)	13	(cold restart)						
		No Object (function code only)	14	(warm restart)						
		No Object (function code only)	23	(delay meas.)						

Note:
A Default variation refers to the variation responded to when variation 0 is requested and/or in class 0, 1, 2, or 3 scans.

Note:
For static (non-change-event) objects, qualifiers 17 or 28 are only responded to when a request is sent with qualifiers 17 or 28, respectively. Otherwise, static object requests sent with qualifiers 00, 01, 06, 07, or 08, will be responded to with qualifiers 00 or 01. For change-event objects, qualifiers 17 or 28 are always responded to.

18.11.3.8.3 DNP3 INTERNAL INDICATIONS

The following table lists the DNP3.0 Internal Indications (IIN) and identifies those that are supported by the device.

The IIN form an information element used to convey the internal states and diagnostic results of a device. This information can be used by a receiving station to perform error recovery or other suitable functions. The IIN is a two-octet field that follows the function code in all responses from the device. When a request cannot be processed due to formatting errors or the requested data is not available, the IIN is always returned with the appropriate bits set.

Bit	Indication	Description	Supported
Octet 1			
0	All stations message received	Set when a request is received with the destination address of the all stations address (6553510). It is cleared after the next response (even if a response to a global request is required). This IIN is used to let the master station know that a "broadcast" message was received by the relay.	Yes
1	Class 1 data available	Set when data that has been configured as Class 1 data is ready to be sent to the master. The master station should request this class data from the relay when this bit is set in a response.	Yes
2	Class 2 data available	Set when data that has been configured as Class 2 data is ready to be sent to the master. The master station should request this class data from the relay when this bit is set in a response.	Yes
3	Class 3 data available	Set when data that has been configured as Class 3 data is ready to be sent to the master. The master station should request this class data from the relay when this bit is set in a response.	Yes
4	Time-synchronisation required	The relay requires time synchronisation from the master station (using the Time and Date object). This IIN is cleared once the time has been synchronised. It can also be cleared by explicitly writing a 0 into this bit of the Internal Indication object.	Yes
5	Local	Set when some or all of the relays digital output points (Object 10/12) are in the Local state. That is, the relays control outputs are NOT accessible through the DNP protocol. This IIN is clear when the relay is in the Remote state. That is, the relays control outputs are fully accessible through the DNP protocol.	No
6	Device in trouble	Set when an abnormal condition exists in the relay. This IIN is only used when the state cannot be described by a combination of one or more of the other IIN bits.	No
7	Device restart	Set when the device software application restarts. This IIN is cleared when the master station explicitly writes a 0 into this bit of the Internal Indications object.	Yes
Octet 2			
0	Function code not implemented	The received function code is not implemented within the relay.	Yes
1	Requested object(s) unknown	The relay does not have the specified objects or there are no objects assigned to the requested class. This IIN should be used for debugging purposes and usually indicates a mismatch in device profiles or configuration problems.	Yes
2	Out of range	Parameters in the qualifier, range or data fields are not valid or out of range. This is a 'catch-all' for application request formatting errors. It should only be used for debugging purposes. This IIN usually indicates configuration problems.	Yes
3	Buffer overflow	Event buffer(s), or other application buffers, have overflowed. The master station should attempt to recover as much data as possible and indicate to the user that there may be lost data. The appropriate error recovery procedures should be initiated by the user.	Yes
4	Already executing	The received request was understood but the requested operation is already executing.	
5	Bad configuration	Set to indicate that the current configuration in the relay is corrupt. The master station may download another configuration to the relay.	Yes

Bit	Indication	Description	Supported
6	Reserved	Always returned as zero.	
7	Reserved	Always returned as zero.	

18.11.3.8.4 DNP3 RESPONSE STATUS CODES

When the device processes Control Relay Output Block (Object 12) requests, it returns a set of status codes; one for each point contained within the original request. The complete list of codes appears in the following table:

Code Number	Identifier Name	Description
0	Success	The received request has been accepted, initiated, or queued.
1	Timeout	The request has not been accepted because the 'operate' message was received after the arm timer (Select Before Operate) timed out. The arm timer was started when the select operation for the same point was received.
2	No select	The request has not been accepted because no previous matching 'select' request exists. (An 'operate' message was sent to activate an output that was not previously armed with a matching 'select' message).
3	Format error	The request has not been accepted because there were formatting errors in the control request ('select', 'operate', or 'direct operate').
4	Not supported	The request has not been accepted because a control operation is not supported for this point.
5	Already active	The request has not been accepted because the control queue is full or the point is already active.
6	Hardware error	The request has not been accepted because of control hardware problems.
7	Local	The request has not been accepted because local access is in progress.
8	Too many operations	The request has not been accepted because too many operations have been requested.
9	Not authorized	The request has not been accepted because of insufficient authorisation.
127	Undefined	The request not been accepted because of some other undefined reason.

Note:
Code numbers 10 through to 126 are reserved for future use.

18.11.3.8.5 DNP3 CONFIGURATION

To configure the device:

1. Select the *CONFIGURATION* column and check that the ***Comms settings*** cell is set to `Visible`.
2. Select the *COMMUNICATIONS* column.
3. Move to the first cell down (***RP1 Protocol***). Set this to the chosen communication protocol – in this case `DNP3.0`.
4. Move down to the next cell (***RP1 Address***). This cell controls the DNP3.0 address of the IED. Up to 32 IEDs can be connected to one spur, therefore it is necessary for each IED to have a unique address so that messages from the master control station are accepted by only one IED. DNP3.0 uses a decimal number between 1 and 65519 for the Relay Address. It is important that no two IEDs have the same address.
5. Move down to the next cell (***RP1 Baud Rate***). This cell controls the baud rate to be used. Six baud rates are supported by the IED 1200 bps, 2400 bps, 4800 bps, 9600 bps, 19200 bps and 38400 bps. Make sure that the baud rate selected on the IED is the same as that set on the master station.

6. Move down to the next cell (***RP1 Parity***). This cell controls the parity format used in the data frames. The parity can be set to be one of *None*, *Odd* or *Even*. Make sure that the parity format selected on the IED is the same as that set on the master station.
7. If the optional fibre optic connectors are fitted, the ***RP1 PhysicalLink*** cell is visible. This cell controls the physical media used for the communication (Copper or Fibre optic).
8. Move down to the next cell (***RP1 Time Sync***). This cell affects the time synchronisation request from the master by the IED. It can be set to *enabled* or *disabled*. If enabled, it allows the DNP3.0 master to synchronise the time on the IED.

18.11.3.8.5. DNP3 CONFIGURATOR 1

A PC support package for DNP3.0 is available as part of the supplied settings application software (MiCOM S1 Agile) to allow configuration of the device's DNP3.0 response. The configuration data is uploaded from the device to the PC in a block of compressed format data and downloaded in a similar manner after modification. The new DNP3.0 configuration takes effect after the download is complete. To restore the default configuration at any time, from the *CONFIGURATION* column, select the ***Restore Defaults*** cell then select *All Settings*.

In MiCOM S1 Agile, the DNP3.0 data is shown in three main folders, one folder each for the point configuration, integer scaling and default variation (data format). The point configuration also includes screens for binary inputs, binary outputs, counters and analogue input configuration.

If the device supports DNP Over Ethernet, the configuration related settings are done in the folder **DNP Over Ethernet**.

18.11.4 IEC 61850

This section describes how the IEC 61850 standard is applied to GE Vernova products. It is not a description of the standard itself. The level at which this section is written assumes that the reader is already familiar with the IEC 61850 standard.

IEC 61850 is the international standard for Ethernet-based communication in substations. It enables integration of all protection, control, measurement and monitoring functions within a substation, and additionally provides the means for interlocking and inter-tripping. It combines the convenience of Ethernet with the security that is so essential in substations today.

This product supports IEC 61850 Edition 2 and Edition 2.1 only.

18.11.4.1 BENEFITS OF IEC 61850

The standard provides:

- Standardised models for IEDs and other equipment within the substation
- Standardised communication services (the methods used to access and exchange data)
- Standardised formats for configuration files
- Peer-to-peer communication

The standard adheres to the requirements laid out by the ISO OSI model and therefore provides complete vendor interoperability and flexibility on the transmission types and protocols used. This includes mapping of data onto

Ethernet, which is becoming more and more widely used in substations, in favour of RS485. Using Ethernet in the substation offers many advantages, most significantly including:

- Ethernet allows high-speed data rates (currently 100 Mbps, rather than tens of kbps or less used by most serial protocols)
- Ethernet provides the possibility to have multiple clients
- Ethernet is an open standard in everyday use
- There is a wide range of Ethernet-compatible products that may be used to supplement the LAN installation (hubs, bridges, switches)

18.11.4.2 IEC 61850 INTEROPERABILITY

A major benefit of IEC 61850 is interoperability. IEC 61850 standardises the data model of substation IEDs, which allows interoperability between products from multiple vendors.

An IEC 61850-compliant device may be interoperable, but this does not mean it is interchangeable. You cannot simply replace a product from one vendor with that of another without reconfiguration. However, the terminology is pre-defined and anyone with prior knowledge of IEC 61850 should be able to integrate a new device very quickly without having to map all the new data. IEC 61850 brings improved substation communications and interoperability to the end user, at a lower cost.

18.11.4.3 THE IEC 61850 DATA MODEL

The data model of any IEC 61850 IED can be viewed as a hierarchy of information, whose nomenclature and categorisation is defined and standardised in the IEC 61850 specification.

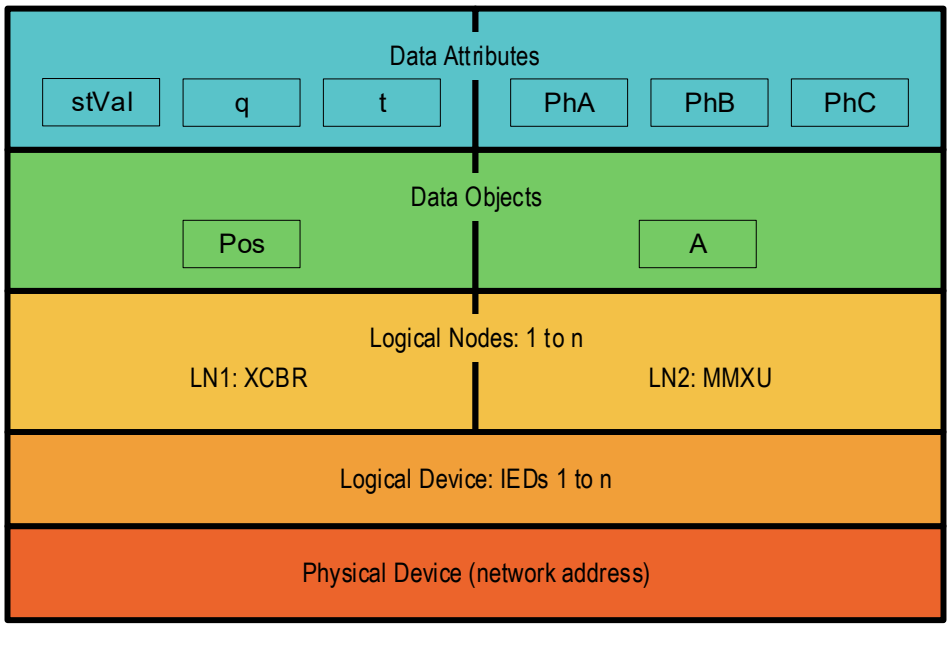


Figure 234: Data model layers in IEC 61850

The levels of this hierarchy can be described as follows:

Data Frame format

Layer	Description
Physical Device	Identifies the actual IED within a system. Typically, the device's name or IP address can be used (for example Feeder_1 or 10.0.0.2.
Logical Device	Identifies groups of related Logical Nodes within the Physical Device. For the MiCOM IEDs, multiple Logical Devices exist, for System (root LD) and various Control, Measurements, Protection, and Records LDs.
Wrapper/Logical Node Instance	Identifies the major functional areas within the IEC 61850 data model. Either 3 or 6 characters are used as a prefix to define the functional group (wrapper) while the actual functionality is identified by a 4 character Logical Node name suffixed by an instance number. For example, XCBR1 (circuit breaker), MMXU1 (measurements), FrqPTOF2 (overfrequency protection, stage 2).
Data Object	This next layer is used to identify the type of data you will be presented with. For example, Pos (position) of Logical Node type XCBR.
Data Attribute	This is the actual data (measurement value, status, description, etc.). For example, stVal (status value) indicating actual position of circuit breaker for Data Object type Pos of Logical Node type XCBR.

18.11.4.4 IEC 61850 IN MICOM P40 IEDS

IEC 61850 is implemented by use of a separate Ethernet board. This Ethernet board manages the majority of the IEC 61850 implementation and data transfer to avoid any impact on the performance of the protection functions.

To communicate with an IEC 61850 IED on Ethernet, it is necessary only to know its IP address. This can then be configured into either:

- An IEC 61850 client (or master), for example a bay computer (MiCOM C264)
- An HMI
- An MMS browser, with which the full data model can be retrieved from the IED, without any prior knowledge of the IED

The IEC 61850 compatible interface standard provides capability for the following:

- Read access to measurements
- Refresh of all measurements at a standard rate.
- Generation of non-buffered and buffered multi-client reports on change of status or measurement
- SNTP time synchronisation over an Ethernet link. (This is used to synchronise the IED's internal real time clock.
- GOOSE peer-to-peer communication
- Disturbance record extraction by IEC 61850 MMS file transfer. The record is extracted as an ASCII format COMTRADE file
- Controls (Direct and Select Before Operate)

Note:
Setting changes are not supported in the current IEC 61850 implementation. Currently these setting changes are carried out using the settings application software.

18.11.4.5 IEC 61850 DATA MODEL IMPLEMENTATION

The data model naming adopted in the IEDs has been standardised for consistency. The Logical Nodes are allocated under Logical Devices, as appropriate.

The data model is described in the Model Implementation Conformance Statement (MICS) document, which is available as a separate document.

18.11.4.6 IEC 61850 COMMUNICATION SERVICES IMPLEMENTATION

The IEC 61850 communication services which are implemented in the IEDs are described in the Protocol Implementation Conformance Statement (PICS) document, which is available as a separate document.

18.11.4.7 IEC 61850 PEER-TO-PEER (GOOSE) COMMUNICATIONS

The implementation of IEC 61850 Generic Object Oriented Substation Event (GOOSE) enables faster communication between IEDs offering the possibility for a fast and reliable system-wide distribution of input and output data values. The GOOSE model uses multicast services to deliver event information. Multicast messaging means that messages are sent to selected devices on the network. The receiving devices can specifically accept frames from certain devices and discard frames from the other devices. It is also known as a publisher-subscriber system. When a device detects a change in one of its monitored status points it publishes a new message. Any device that is interested in the information subscribes to the data it contains.

18.11.4.8 GOOSE MESSAGE VALIDATION

Whenever a new GOOSE message is received its validity is checked before the dataset is decoded and used to update the Programmable Scheme Logic. As part of the validation process a check is made for state and sequence number anomalies. If an anomaly is detected, the 'out-of-order' GOOSE message is discarded. When a message is discarded the last valid message remains active until a new valid GOOSE message is received or its validity period (TAL) expires.

Out-of-order GOOSE message indicators and reporting are provided to the subscriber via the IEC 61850 LGOS logical node.

18.11.4.9 MAPPING GOOSE MESSAGES TO VIRTUAL INPUTS

Each GOOSE signal contained in a subscribed GOOSE message can be mapped to any of the virtual inputs within the PSL. The virtual inputs allow the mapping to internal logic functions for protection control, directly to output contacts or LEDs for monitoring.

An IED can subscribe to all GOOSE messages but only the following data types can be decoded and mapped to a virtual input:

- BOOLEAN
- BSTR2
- INT16
- INT32
- INT8
- UINT16
- UINT32
- UINT8

18.11.4.10 IEC 61850 GOOSE CONFIGURATION

All GOOSE configuration is performed using the IEC 61850 Configurator tool available in the MiCOM S1 Agile software application.

All GOOSE publishing configuration can be found under the **GOOSE Publishing** tab in the configuration editor window. All GOOSE subscription configuration parameters are under the **External Binding** tab in the configuration editor window.

Settings to enable GOOSE signalling and to apply Test Mode are available using the HMI.

18.11.4.11 ETHERNET FUNCTIONALITY

IEC 61850 **Associations** are unique and made between the client and server. If Ethernet connectivity is lost for any reason, the associations are lost and will need to be re-established by the client. The IED has a **TCP_KEEPALIVE** function to monitor each association and terminate any which are no longer active.

The IED allows the re-establishment of associations without disruption of its operation, even after its power has been removed. As the IED acts as a server in this process, the client must request the association. Uncommitted settings are cancelled when power is lost, and reports requested by connected clients are reset. The client must re-enable these when it next creates the new association to the IED.

18.11.4.12 IEC 61850 CONFIGURATION

To configure the MiCOM P40 IED for IEC 61850, it is necessary to use the IEC 61850 IED Configurator software tool, which is part of the MiCOM S1 Agile settings application software.

IEC 61850 allows IEDs to be directly configured from a configuration file. The IEDs system configuration capabilities are determined from an IED Capability Description file (ICD), supplied with the product. By using ICD files from the products to be installed, you can design, configure and test (using simulation tools), a substation's entire protection scheme before the products are installed into the substation.

To help with this process, the S1 Agile provides an IEC 61850 IED Configurator tool, which allows the pre-configured IEC 61850 configuration file (SCL format) to be imported. The Ethernet and IEC 61850 configuration is transferred to the IED as a MCL file. As well as this, you can manually create MCL configuration files for all products, based on their original IED capability description (ICD file).

Other features include:

- The extraction of configuration data for viewing and editing.
- A sophisticated error checking sequence to validate the configuration data before sending to the IED.

Note:
Some configuration data is available in the IEC61850 CONFIG. column, allowing read-only access to basic configuration data.

18.11.4.12.1 IEC 61850 CONFIGURATION BANKS

There are two configuration banks:

- Active Configuration Bank
- Inactive Configuration Bank

Any new configuration sent to the IED as an MCL file is automatically stored in the Inactive Configuration Bank, therefore not immediately affecting the current configuration.

Following this, the IEC 61850 IED Configurator tool can be used to transmit a command, which authorises activation of the new configuration contained in the inactive configuration bank. This is done by switching the active and inactive configuration banks. The capability of switching the configuration banks is also available using the *IEC61850 CONFIG.* column of the HMI.

The SCL Name and Revision attributes of both configuration banks are available in the *IEC61850 CONFIG.* column of the HMI.

18.11.4.12.2 IEC 61850 NETWORK CONNECTIVITY

Configuration of the IP parameters and SNTP (Simple Network Time Protocol) time synchronisation parameters is performed by the IEC 61850 Configurator tool. If these parameters are not available using an SCL (Substation Configuration Language) file, they must be configured manually.

Every IP address on the Local Area Network must be unique. Duplicate IP addresses result in conflict and must be avoided. Most IEDs check for a conflict on every IP configuration change and at power up and they raise an alarm if an IP conflict is detected.

The IED can be configured to accept data from other networks using the ***Gateway*** setting. If multiple networks are used, the IP addresses must be unique across networks.

18.11.4.13 IEC 61850 EDITION 2

Many parts of the IEC 61850 standard have now been released as the second edition. This offers some significant enhancements including:

- Improved interoperability
- Many new logical nodes
- Better defined testing: it is now possible to perform off-line testing and simulation of functions

Edition 2 implementation requires use of version 3.8 of the IEC 61850 configurator, which is installed with version 2.0.1 of MiCOM S1 Agile.

18.11.4.13.1 BACKWARD COMPATIBILITY

IEC 61850 System - backward compatibility

An Edition 1 IED can operate with an Edition 2 IEC 61850 system, provided that the Edition 1 IEDs do not subscribe to GOOSE messages with data objects or data attributes which are only available in Edition 2.

The following figure explains this concept:

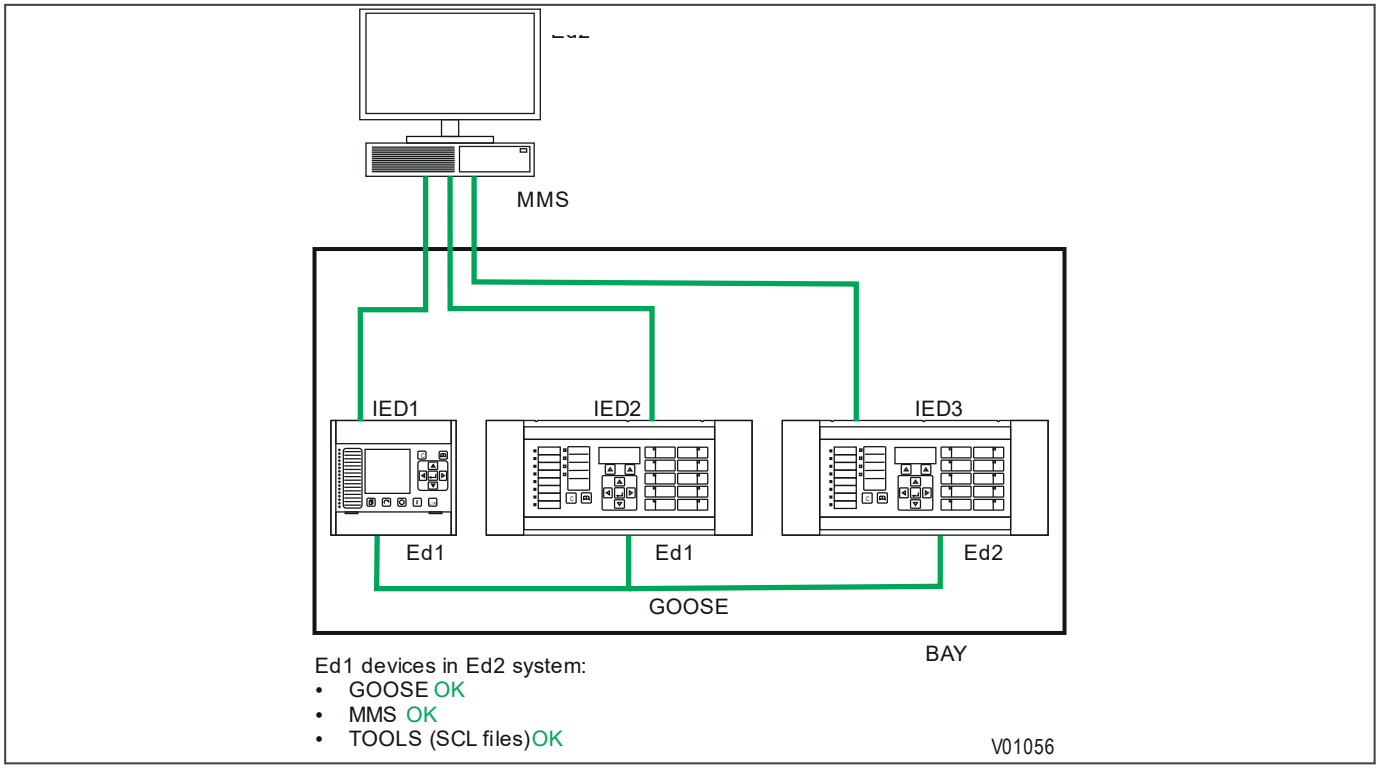


Figure 235: Edition 2 system - backward compatibility

An Edition 2 IED cannot normally operate within an Edition 1 IEC 61850 system. An Edition 2 IED can work for GOOSE messaging in a mixed system, providing the client is compatible with Edition 2.

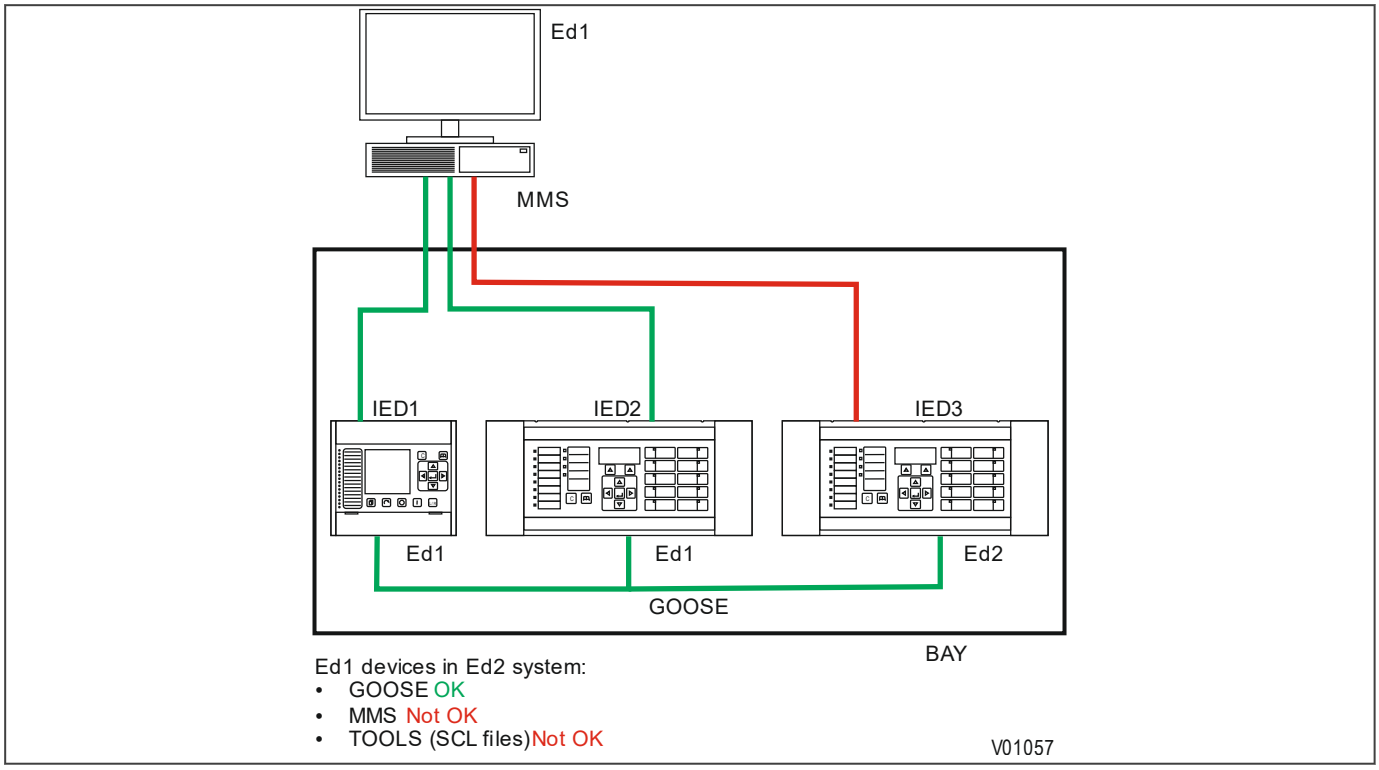


Figure 236: Edition 1 system - forward compatibility issues

18.11.4.13.2 EDITION-2 COMMON DATA CLASSES

The following common data classes (CDCs) are new to Edition 2 and therefore should not be used in GOOSE control blocks in mixed Edition 1 and Edition 2 systems

- Histogram (HST)
- Visible string status (VSS)
- Object reference setting (ORG)
- Controllable enumerated status (ENC)
- Controllable analogue process value (APC)
- Binary controlled analogue process value (BAC)
- Enumerated status setting (ENG)
- Time setting group (TSG)
- Currency setting group (CUG)
- Visible string setting (VSG)
- Curve shape setting (CSG)

Of these, only ENS and ENC types are available from a MiCOM P40 IED when publishing GOOSE messages, so Data Objects using these Common Data Classes should not be published in mixed Edition 1 and Edition 2 systems.

For compatibility between Edition 1 and Edition 2 IEDs, SCL files using SCL schema version "2.1" must be used. For a purely Edition 2 system, use the schema version "2007B4".

18.11.5 READ ONLY MODE

With IEC 61850 and Ethernet/Internet communication capabilities, security has become an important issue. For this reason, all relevant GE Vernova IEDs have been adapted to comply with the latest cyber-security standards.

In addition to this, a facility is provided which allows you to enable or disable the communication interfaces. This feature is available for products using Courier, IEC 60870-5-103, or IEC 61850.

18.11.5.1 IEC 60870-5-103 PROTOCOL BLOCKING

If Read-Only Mode is enabled for RP1 or RP2 with IEC 60870-5-103, the following commands are blocked at the interface:

- Write parameters (=change setting) (private ASDUs)
- General Commands (ASDU20), namely:
  - INF16 auto-recloser on/off
  - INF19 LED reset
  - Private INFs (for example: CB open/close, Control Inputs)

The following commands are still allowed:

- Poll Class 1 (Read spontaneous events)
- Poll Class 2 (Read measurands)
- GI sequence (ASDU7 'Start GI', Poll Class 1)
- Transmission of Disturbance Records sequence (ASDU24, ASDU25, Poll Class 1)
- Time Synchronisation (ASDU6)
- General Commands (ASDU20), namely:
  - INF23 activate characteristic 1
  - INF24 activate characteristic 2
  - INF25 activate characteristic 3
  - INF26 activate characteristic 4

Note:
For IEC 60870-5-103, Read Only Mode function is different from the existing Command block feature.

18.11.5.2 COURIER PROTOCOL BLOCKING

If Read-Only Mode is enabled for RP1 or RP2 with Courier, the following commands are blocked at the interface:

- Write settings
- All controls, including:
  - Reset Indication (Trip LED)
  - Operate Control Inputs
  - CB operations
  - Auto-reclose operations
  - Reset demands
  - Clear event/fault/maintenance/disturbance records
  - Test LEDs & contacts

The following commands are still allowed:

- Read settings, statuses, measurands
- Read records (event, fault, disturbance)
- Time synchronisation
- Change active setting group

18.11.5.3 IEC 61850 PROTOCOL BLOCKING

If Read-Only Mode is enabled for the Ethernet interfacing with IEC 61850, the following commands are blocked at the interface:

- All controls, including:
  - Enable/disable protection
  - Operate Control Inputs
  - CB operations (Close/Trip, Lock)
  - Reset LEDs

The following commands are still allowed:

- Read statuses, measurands
- Generate reports
- Extract disturbance records
- Time synchronisation
- Change active setting group

18.11.5.4 READ-ONLY SETTINGS

The following settings are available for enabling or disabling Read Only Mode.

- RP1 Read Only
- RP2 Read Only (only for products that have RP2)
- NIC Read Only (where Ethernet is available)

18.11.5.5 READ-ONLY DDB SIGNALS

The remote read only mode is also available in the PSL using three dedicated DDB signals:

- RP1 Read Only
- RP2 Read Only (only for products that have RP2)
- NIC Read Only (where Ethernet is available)

Using the PSL, these signals can be activated by opto-inputs, Control Inputs and function keys if required.

18.12 TIME SYNCHRONISATION

Effective management of today's energy systems requires precise time recording of events experienced by different devices across the network. This is achieved by synchronising real-time clocks across the devices and can be achieved in different ways. This device supports synchronisation in various ways depending on the chosen options and communication protocols.

- Using the IRIG-B input (if fitted)
- Using the SNTP time protocol (for Ethernet IEC 61850 versions)
- Using IEEE 1588 Precision Time Protocol (PTP)
- By using the time synchronisation functionality inherent in the data protocols

The time synchronisation sources can be configured in a priority order using the Primary Source and Secondary Source cells in the DATE AND TIME column. If the Primary source becomes unavailable, the Secondary source will be used, if available.

All the protection functionality implemented in this device operates entirely independently of the real time clock. It does not matter to the protection if the clock is not set or is incorrectly synchronised. Even though the time stamping of any associated records may be compromised, the protection functionality will not.

18.12.1 IRIG-B

IRIG stands for Inter Range Instrumentation Group, which is a standards body responsible for standardising different time code formats. There are several different formats starting with IRIG-A, followed by IRIG-B and so on. The letter after the "IRIG" specifies the resolution of the time signal in pulses per second (PPS). IRIG-B, the one which we use has a resolution of 100 PPS. IRIG-B is used when accurate time-stamping is required.

The following diagram shows a typical GPS time-synchronised substation application. The satellite RF signal is picked up by a satellite dish and passed on to receiver. The receiver receives the signal and converts it into time signal suitable for the substation network. IEDs in the substation use this signal to govern their internal clocks and event recorders.

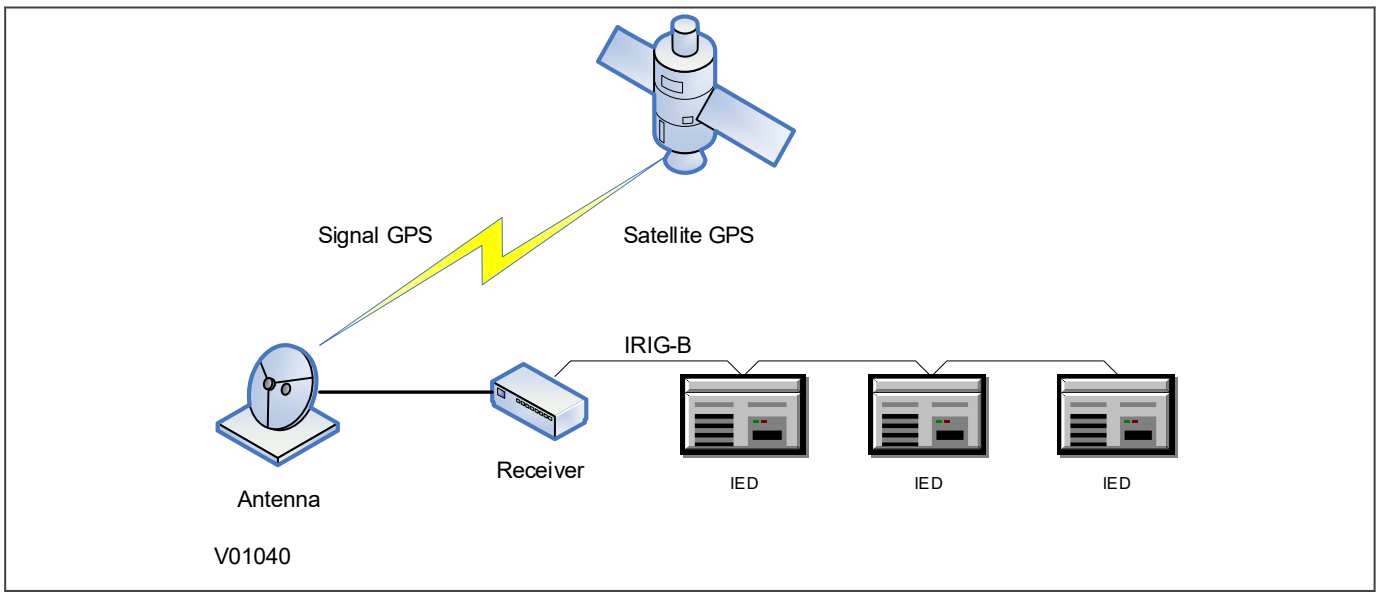


Figure 237: GPS satellite timing signal

The IRIG-B time code signal is a sequence of one second time frames. Each frame is split up into ten 100 mS slots as follows:

- Time-slot 1: Seconds
- Time-slot 2: Minutes
- Time-slot 3: Hours
- Time-slot 4: Days
- Time-slot 5 and 6: Control functions
- Time-slots 7 to 10: Straight binary time of day

The first four time-slots define the time in BCD (Binary Coded Decimal). Time-slots 5 and 6 are used for control functions, which control deletion commands and allow different data groupings within the synchronisation strings. Time-slots 7-10 define the time in SBS (Straight Binary Second of day).

18.12.1.1 IRIG-B IMPLEMENTATION

Depending on the chosen hardware options, the product can be equipped with an IRIG-B input for time synchronisation purposes. The IRIG-B interface is implemented either on a dedicated board, or together with other communication functionality such as Ethernet. The IRIG-B interface connector is a BNC connector. IRIG-B signals are usually presented as an RF-modulated signal. The boards support universal IRIG-B, which means they accept demodulated or modulated IRIG-B.

To set the device to use IRIG-B, use the setting ***IRIG-B Sync*** cell in the *DATE AND TIME* column.

The IRIG-B status can be viewed in the ***IRIG-B Status*** cell in the *DATE AND TIME* column.

18.12.2 SNTP

SNTP is used to synchronise the clocks of computer systems over packet-switched, variable-latency data networks, such as IP. SNTP can be used as the time synchronisation method for models using IEC 61850 over Ethernet. A time synchronisation accuracy of within 5 ms is possible.

The device is synchronised by the main SNTP server. This is achieved by entering the IP address of the SNTP server into the IED using the IEC 61850 Configurator software described in the settings application software manual. A second server is also configured with a different IP address for backup purposes.

This function issues an alarm when there is a loss of time synchronisation on the SNTP server. This could be because there is no response or no valid clock signal.

The HMI menu does not contain any configurable settings relating to SNTP, as the only way to configure it is using the IEC 61850 Configurator. However, it is possible to view some parameters in the *COMMUNICATIONS* column under the sub-heading SNTP parameters. Here you can view the SNTP server addresses and the SNTP poll rate in the cells ***SNTP Server 1***, ***SNTP Server 2*** and ***SNTP Poll rate*** respectively.

The SNTP time synchronisation status is displayed in the ***SNTP Status*** cell in the *DATE AND TIME* column.

18.12.2.1 LOSS OF SNTP SERVER SIGNAL ALARM

This function issues an alarm when there is a loss of time synchronisation on the SNTP server. It is issued when the SNTP sever has not detected a valid time synchronisation response within its 5 second window. This is because there is no response or no valid clock. The alarm is mapped to IEC 61850.

18.12.3 IEEE 1588 PRECISION TIME PROTOCOL

The MiCOM P40 modular products support IEEE 1588 Precision Time Protocol (PTP) as a slave-only clock. MiCOM relays are profile unaware, which means that they will accept synchronisation from any PTP profile. Power Utility Profile (IEC 61850-9-3) is specifically designed to perform well for substation related applications, with PMU applications needing the most stringent requirements.

PTP can be used to replace or supplement IRIG-B and SNTP time synchronisation so that the IED can be synchronised using Ethernet messages from the substation LAN without any additional physical connections being required.

A dedicated DDB signal (***PTP Failure***) is provided to indicate failure of PTP.

18.12.3.1 ACCURACY AND DELAY CALCULATION

A time synchronisation accuracy of within 3 ms is possible. Both peer-to-peer or end-to-end mode delay measurement can be used.In peer-to-peer mode, delays are measured between each link in the network and are compensated for. This provides greater accuracy but requires that every device between the Grand Master and Slaves supports the peer-to-peer delay measurement.

In end-to-end mode, delays are only measured between each Grand Master and Slave. The advantage of this mode is that the requirements for the switches on the network are lower; they do not need to independently calculate delays. The main disadvantage is that more inaccuracy is introduced, because the method assumes that forward and reverse delays are always the same, which may not always be correct.

When using end-to-end mode, the IED can be connected in a ring or line topology using RSTP or Self-Healing Protocol without any additional Transparent Clocks. But because the IED is a slave-only device, additional inaccuracy is introduced. The additional error will be less than 1ms for a network of eight devices.

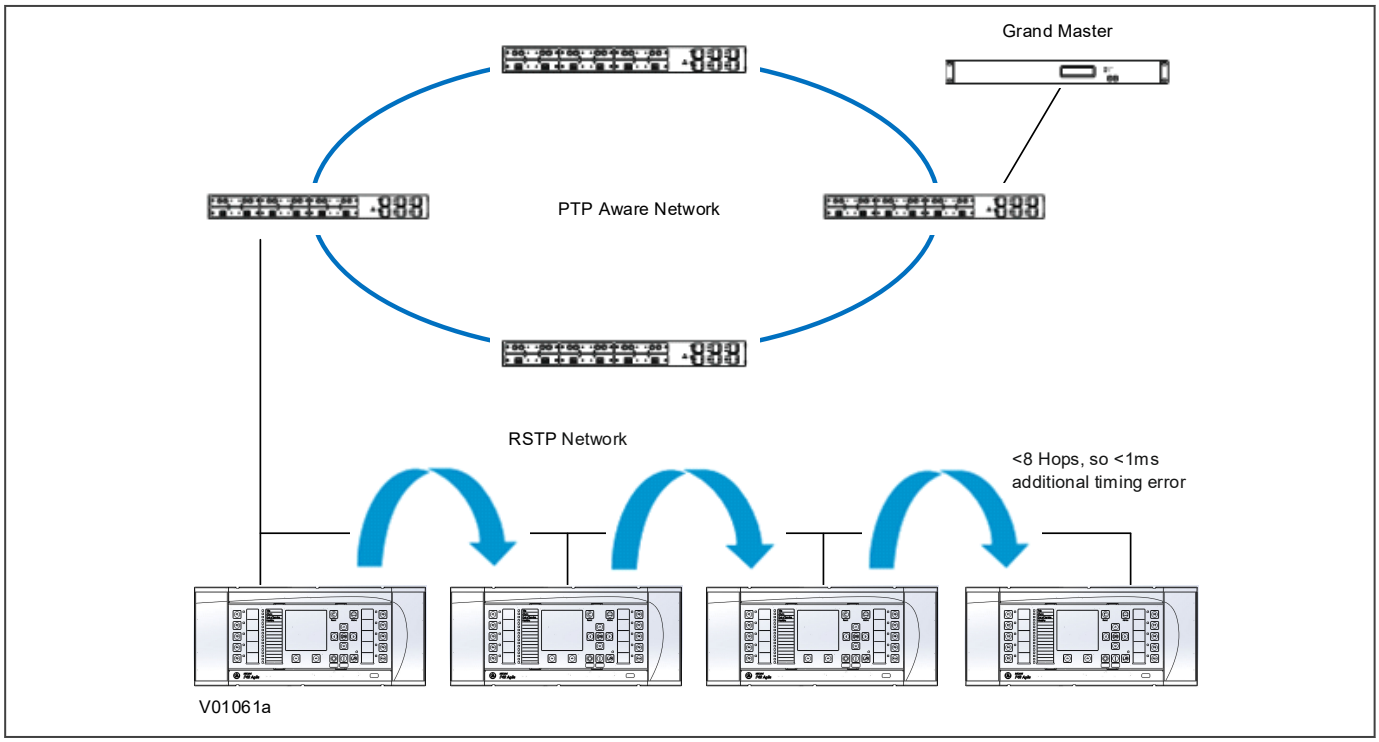


Figure 238: Timing error using ring or line topology

18.12.3.2 PTP DOMAINS

PTP traffic can be segregated into different domains using Boundary Clocks. These allow different PTP clocks to share the same network while maintaining independent synchronisation within each grouped set.

The PTP domain number can be configured in MiCOM P40 modular products using the ***Domain Number*** cell in the *DATE AND TIME* column. The domain number needs to be configured to match the domain of the local network.

18.12.4 TIME SYNCHRONISATION USING THE COMMUNICATION PROTOCOLS

All communication protocols have in-built time synchronisation mechanisms. If an external time synchronisation mechanism such as IRIG-B, SNTP, or IEEE 1588 PTP is not used to synchronise the devices, the time synchronisation mechanism within the relevant serial protocol is used. The real time is usually defined in the master station and communicated to the relevant IEDs via one of the rear serial ports using the chosen protocol. It is also possible to define the time locally using settings in the *DATE AND TIME* column.

The time synchronisation for each protocol is described in the relevant protocol description section.

CHAPTER 19

CYBERSECURITY

19.1 DISCLAIMER

GE Vernova Grid Automation products are digital devices designed to be installed and operated in utility substations & industrial plant environments and connected to secure private networks. GE Vernova IEDs should not be connected to the public internet.

GE Vernova strongly recommends that users protect their digital devices using a defense-in-depth strategy which will protect their products, their network, their systems and interfaces against cyber security threats. This includes, but is not limited to, placing digital devices inside the control system network security perimeter, deploying and maintaining access controls, monitoring and intrusion detection, security awareness training, security policies, network segmentation and firewalls installation, strong and active password management, data encryption, antivirus and other mitigating applicable technologies.

GE Vernova IEDs are available with standard features, and in some products additional optional software options, which provide cyber security mechanisms to help users protect against cyber security intrusion. GE Vernova strongly recommends using all available cyber security options.

For additional details and recommendations on how to protect the GE Vernova IEDs, please see Cyber Security sections of the manuals. GE Vernova Grid Automation may also provide additional instructions and recommendations to users from time to time relating to IED and cyber security threats or vulnerabilities.

It is the users' sole responsibility to make sure that all GE Vernova Grid Automation IEDs are installed and operated considering its cyber security capabilities, security context, and the instructions and recommendations provided to the user relating to GE Vernova. Users assume all risks and liability associated with damages or losses incurred in connection with any and all cyber security incidences.

IT IS THE SOLE RESPONSIBILITY OF THE USER TO SECURE THEIR NETWORK AND ASSOCIATED DEVICES AGAINST CYBER SECURITY INTRUSIONS OR ATTACKS. GE VERNOVA GRID AUTOMATION AND ITS AFFILIATES ARE NOT LIABLE FOR ANY DAMAGES AND/OR LOSSES ARISING FROM OR RELATED TO SUCH SECURITY INTRUSION OR ATTACKS.

19.2 OVERVIEW

In the past, substation networks were traditionally isolated and the protocols and data formats used to transfer information between devices were often proprietary.

For these reasons, the substation environment was very secure against cyber-attacks. The terms used for this inherent type of security are:

- Security by isolation (if the substation network is not connected to the outside world, it cannot be accessed from the outside world).
- Security by obscurity (if the formats and protocols are proprietary, it is very difficult to interpret them).

However, note that these are not recognised defences against attackers.

The increasing sophistication of protection schemes, coupled with the advancement of technology and the desire for vendor interoperability, has resulted in standardisation of networks and data interchange within substations. Today, devices within substations use standardised protocols for communication. Furthermore, substations can be interconnected with open networks, such as the internet or corporate-wide networks, which use standardised protocols for communication. This introduces a major security risk making the grid vulnerable to cyber-attacks, which could in turn lead to major electrical outages.

Clearly, there is now a need to secure communication and equipment within substation environments. This chapter describes the security measures that have been put in place for our range of Intelligent Electronic Devices (IEDs).

Note:
Cyber-security compatible devices do not enforce NERC compliance, they merely facilitate it. It is the responsibility of the user to ensure that compliance is adhered to as and when necessary.

This chapter contains the following sections:

Disclaimer 446
Overview 447
The Need for Cybersecurity 448
Standards 449
Cyber-Security Implementation 453
Roles and Permissions 454
User Authentication 457
SNMP Configuration 474
Returning The IED To Factory 475
Security Event Management 476

19.3 THE NEED FOR CYBERSECURITY

Cybersecurity provides protection against unauthorised disclosure, transfer, modification, or destruction of information or information systems, whether accidental or intentional. To achieve this, there are several security requirements:

- Confidentiality (preventing unauthorised access to information)
- Integrity (preventing unauthorised modification)
- Availability/Authentication (preventing the denial of service and assuring authorised access to information)
- Non-repudiation (preventing the denial of an action that took place)
- Traceability/Detection (monitoring and logging of activity to detect intrusion and analyse incidents)

The threats to Cybersecurity may be unintentional (e.g. natural disasters, human error), or intentional (e.g. cyber-attacks by hackers).

Good Cybersecurity can be achieved with a range of measures, such as closing down vulnerability loopholes, implementing adequate security processes and procedures and providing technology to help achieve this.

Examples of vulnerabilities are:

- Indiscretions by personnel (users keep passwords on their computer)
- Bad practice (users do not change default passwords, or everyone uses the same password to access all substation equipment)
- Bypassing of controls (users turn off security measures)
- Inadequate technology (substation is not firewalled)

Examples of availability issues are:

- Equipment overload, resulting in reduced or no performance
- Expiry of a certificate preventing access to equipment

To help tackle these issues, standards organisations have produced various standards. Compliance with these standards significantly reduces the threats associated with lack of Cybersecurity.

19.4 STANDARDS

There are several standards, which apply to substation cyber-security. The standards currently applicable to Grid Automation Systems and IEDs are NERC and IEEE1686.

Standard	Country	Description
NERC CIP (North American Electric Reliability Corporation)	USA	Framework for the protection of the grid critical Cyber Assets
BDEW (German Association of Energy and Water Industries)	Germany	Requirements for Secure Control and Telecommunication Systems
ANSI ISA 99	USA	ICS oriented then Relevant for EPU completing existing standard and identifying new topics such as patch management
IEEE 1686	International	International Standard for substation IED cyber-security capabilities
IEC 62351	International	Power systems management and associated information exchange - Data and communications security
IEC 62443	International	Security for industrial automation and control systems
ISO/IEC 27002	International	Framework for the protection of the grid critical Cyber Assets
NIST SP800-53 (National Institute of Standards and Technology)	USA	Complete framework for SCADA SP800-82and ICS cyber-security
CPNI Guidelines (Centre for the Protection of National Infrastructure)	UK	Clear and valuable good practices for Process Control and SCADA security

19.4.1 NERC COMPLIANCE

The North American Electric Reliability Corporation (NERC) created a set of standards for the protection of critical infrastructure. These are known as the CIP standards (Critical Infrastructure Protection). These were introduced to ensure the protection of 'Critical Cyber Assets', which control or have an influence on the reliability of North America’s electricity generation and distribution systems.

These standards have been compulsory in the USA for several years now. Compliance auditing started in June 2007, and utilities face extremely heavy fines for non-compliance.

NERC CIP standards

CIP Standard	Description
CIP-002 Critical Cyber Assets	Define and document the Critical Assets and the Critical Cyber Assets
CIP-003 Security Management Controls	Define and document the Security Management Controls required to protect the Critical Cyber Assets
CIP-004 Personnel and Training	Define and Document Personnel handling and training required protecting Critical Cyber Assets
CIP-005 Electronic Security	Define and document logical security perimeters where Critical Cyber Assets reside. Define and document measures to control access points and monitor electronic access
CIP-006 Physical Security	Define and document Physical Security Perimeters within which Critical Cyber Assets reside

CIP Standard	Description
CIP-007 Systems Security Management	Define and document system test procedures, account and password management, security patch management, system vulnerability, system logging, change control and configuration required for all Critical Cyber Assets
CIP-008 Incident Reporting and Response Planning	Define and document procedures necessary when Cyber-security Incidents relating to Critical Cyber Assets are identified
CIP-009 Recovery Plans	Define and document Recovery plans for Critical Cyber Assets

19.4.1.1 CIP 002

CIP 002 concerns itself with the identification of:

- Critical assets, such as overhead lines and transformers
- Critical cyber assets, such as IEDs that use routable protocols to communicate outside or inside the Electronic Security Perimeter; or are accessible by dial-up

Power Utility Responsibilities	GE Vernova's Contribution
Create the list of the assets	We can help the power utilities to create this asset register automatically. We can provide audits to list the Cyber assets

19.4.1.2 CIP 003

CIP 003 requires the implementation of a Cybersecurity policy, with associated documentation, which demonstrates the management's commitment and ability to secure its Critical Cyber Assets.

The standard also requires change control practices whereby all entity or vendor-related changes to hardware and software components are documented and maintained.

Power Utility Responsibilities	GE Vernova's Contribution
To create a Cybersecurity policy	We can help the power utilities to have access control to its critical assets by providing centralized Access control. We can help the customer with its change control by providing a section in the documentation where it describes changes affecting the hardware and software.

19.4.1.3 CIP 004

CIP 004 requires that personnel with authorized cyber access or authorized physical access to Critical Cyber Assets, (including contractors and service vendors), have an appropriate level of training.

Power Utility Responsibilities	GE Vernova's Contribution
To provide appropriate training of its personnel	We can provide Cybersecurity training

19.4.1.4 CIP 005

CIP 005 requires the establishment of an Electronic Security Perimeter (ESP), which provides:

- The disabling of ports and services that are not required
- Permanent monitoring and access to logs (24x7x365)
- Vulnerability Assessments (yearly at a minimum)
- Documentation of Network Changes

Power Utility Responsibilities	GE Vernova's Contribution
To monitor access to the ESP To perform the vulnerability assessments To document network changes	To disable all ports not used in the IED To monitor and record all access to the IED

19.4.1.5 CIP 006

CIP 006 states that Physical Security controls, providing perimeter monitoring and logging along with robust access controls, must be implemented and documented. All cyber assets used for Physical Security are considered critical and should be treated as such:

Power Utility Responsibilities	GE Vernova's Contribution
Provide physical security controls and perimeter monitoring Ensure that people who have access to critical cyber assets don’t have criminal records	GE Vernova cannot provide additional help with this aspect

19.4.1.6 CIP 007

CIP 007 covers the following points:

- Test procedures
- Ports and services
- Security patch management
- Antivirus
- Account management
- Monitoring

Power Utility Responsibilities	GE Vernova's Contribution
To provide an incident response team and have appropriate processes in place	Test procedures, we can provide advice and help on testing. Ports and services, our devices can disable unused ports and services Security patch management, we can provide assistance Antivirus, we can provide advise and assistance Account management, we can provide advice and assistance Monitoring, our equipment monitors and logs access

19.4.1.7 CIP 008

CIP 008 requires that an incident response plan be developed, including the definition of an incident response team, their responsibilities and associated procedures.

Power Utility Responsibilities	GE Vernova's Contribution
To provide an incident response team and have appropriate processes in place.	GE Vernova Vernova cannot provide additional help with this aspect.

19.4.1.8 CIP 009

CIP 009 states that a disaster recovery plan should be created and tested with annual drills.

Power Utility Responsibilities	GE Vernova's Contribution
To implement a recovery plan	To provide guidelines on recovery plans and backup/restore documentation

19.4.2 IEEE 1686-2013

IEEE 1686-2013 is an IEEE Standard for substation IEDs' Cybersecurity capabilities. It proposes practical and achievable mechanisms to achieve secure operations.

The following features described in this standard apply:

- Passwords are 8 characters long and can contain upper-case, lower-case, numeric and special characters.
- Passwords are never displayed or transmitted to a user.
- IED functions and features are assigned to different password levels. The assignment is fixed.
- The audit trail is recorded, listing events in the order in which they occur, held in a circular buffer.
- Records contain all defined fields from the standard and record all defined function event types where the function is supported.
- No password defeat mechanism exists. Instead a secure recovery password scheme is implemented.
- Unused ports (physical and logical) may be disabled.

19.5 CYBER-SECURITY IMPLEMENTATION

GE Vernova IEDs have always been and will continue to be equipped with state-of-the-art security measures. Due to the ever-evolving communication technology and new threats to security, this requirement is not static. Hardware and software security measures are continuously being developed and implemented to mitigate the associated threats and risks.

MiCOM 5th Generation P40 products provide enhanced security through the following features:

- An Authentication, Authorization, Accounting (AAA) Remote Authentication Dial-In User Service (RADIUS) client that is managed centrally, enables user attribution, provides accounting of all user activities, and uses secure standards based on strong cryptography for authentication and credential protection. In other words, this option uses a RADIUS.
- Server for user authentication. There is provision for both remote (RADIUS) and local (device) authentication.
- A Role-Based Access Control (RBAC) system in line with IEC 62351-8:2020 that provides a permission model that allows access to the device operations and configurations based on specific roles and individual user accounts configured on the AAA server.
- Security event reporting through both proprietary security event log (separate from the main events file) and the Syslog and SNMP protocols for supporting Security Information Event Management (SIEM) systems for centralised cybersecurity monitoring.
- Encryption of passwords - stored within the IED, in network messages between the MiCOM S1 Agile software and the IED, and in network messages between the RADIUS server and the IED (subject to the RADIUS server configuration).
- Secure firmware upgrade process.

19.5.1 INITIAL SETUP: DEFAULT USERNAMES AND DEFAULT PASSWORDS

The requirements for initial setup of the IED for cyber-security and RBAC will depend on:

1. which interfaces, if any, the cyber-security is required,
2. the intended authentication method, as defined in the setting ***Auth. Method*** in *SECURITY CONFIG* column (see the Authentication Methods section).

When the authentication method is configured as `Device Only`, there are four pre-defined profiles.

User Name	Default Password	IEC 62351-8 Roles
ADMIN1	ChangeMe1#	SECADM
RBACMNT1	ChangeMe2#	RBACMNT
ENGG1	ChangeMe3#	ENGINEER
VIEWER1	ChangeMe4#	VIEWER

During the first logon, it is Mandatory to change the Default Passwords, and the IED or MiCOM S1 Agile software will prompt the user to change it. The new password must comply with the strength defined by the Password Policy setting, detailed in the ***Password Policy*** section of this chapter.

When the authentication method is configured as ‘Server + Device’, and authentication using RADIUS is required, users must be set up on the RADIUS server (see the RADIUS users section). These users are separate from the pre-defined Device users. RADIUS server information must be configured in the IED to connect to the RADIUS server(s) for Server authentication (see the RADIUS server settings section). It is recommended that the RADIUS shared secret be changed from the default (see the RADIUS client-server validation section).

19.6 ROLES AND PERMISSIONS

19.6.1 ROLES

The P40 Agile products supports all the mandatory pre-defined roles as per IEC 62351-8:2020.

IEC 62351-8 Roles	Value
VIEWER	0
OPERATOR	1
ENGINEER	2
INSTALLER	3
SECADM	4
SECAUD	5
RBACMNT	6

Individual user accounts can be configured to have one or more of these roles.

- VIEWER: Can view all values and settings
- OPERATOR: Can view values and perform control operations
- ENGINEER: Can view values, and change settings of the device
- INSTALLER: Specific role required to perform firmware updates
- SECADM: Security Administrator - Can edit/modify Users and roles and configure security settings
- SECAUD: Security Auditor - Can view Security Log files
- RBACMNT: RBAC Management can change role to permission assignment

Only one role of one type is allowed to be logged in at a time from any interface. For example, one Operator can be logged in but not a second Operator at the same time from any other interface. This prevents subsets of settings from being changed at the same time.

19.6.2 PERMISSIONS

Authentication and authorization are two different processes. An authenticated user cannot perform any action on the IED unless a privilege has been explicitly granted to them. This is the concept of “least privileges” access.

Privileges must be granted to users through roles. A role is a collection of privileges, and roles are granted to users. It is possible to have multiple roles for a user. The privilege/role matrix is stored on the IED. This is known as Role-Based-Access Control (RBAC).

On successful user authentication, the IED will load the user’s role list. If the user’s role changes, the user must logout and log back in to exercise his/her privileges.

The table below shows the predefined permissions assignment for the predefined Roles according to IEC 62351-8:2020

Value	Role Name (revision = 1)	Permission										
		LISTOBJECTS	READVALUES	DATASET	REPORTING	FILEREAD	FILEWRITE	FILEMNGT	CONTROL	CONFIG	SETTINGGROUP	SECURITY
<0>	VIEWER	C	C		X	C_1						
<1>	OPERATOR	X	X		X	C_1			X		X	
<2>	ENGINEER	X	X	X	X	X_1	X_1	X_1		X	X	
<3>	INSTALLER	X	X		X	X_2	X_2			X	X	
<4>	SECADM	X	X	X		X_4	X_4	X_4		X		X
<5>	SECAUD	X	X		X	X_3						
<6>	RBACMNT	X	X		X			X_4		X		
<7 ...32767>	Reserved	For future use of IEC defined roles.										
<-32768 .. -1>	Private	Defined by external agreement. Not guaranteed to be inoperable.										

C = Conditional read access, clarification of specific data objects may be necessary (e.g., VIEWER may not access security settings, but process values)
C_1 = Conditional read access to files of filetype data
X_1 = Access to files of type data and config
X_2 = Access to files of type config and firmware (updates)
X_3 = Access to files of type audit log
X_4 = Access to files of type security (config)

Note:
OPERATOR role is required for Alarm Acknowledgement and Function Key control.

The table below shows the predefined permissions description according to IEC 62351-8:2020

Permission	Description
LISTOBJECTS	Allows the subject/role to discover what objects are present within an IED by presenting the type and ID of those objects. If this permission is granted to a subject/role, the object for which the READVALUES permission has not been granted are not readable. This permission basically relates to all objects defined in IEC 61850 and allows a query on the existence of the data objects.
READVALUES	Allows the subject/role to obtain the values for all or some objects that are present within an IED in addition to the type and ID. This permission basically relates to all objects defined in IEC 61850 that provide a value and allows a read action on the actual values of the data objects.
DATASET	Allows the subject/role to have full service access (e.g., createDataSet, deleteDataSet) for both persistent and non-persistent DataSets.
REPORTING	Allows the subject/role to use buffered reporting as well as unbuffered reporting. Reporting relates to buffered and unbuffered report control blocks of a logical node.
FILEREAD	Allows the subject/role to perform read actions on file objects.
FILEWRITE	Allows the subject/role to perform write actions on file objects. This permission includes the FILEREAD permission.
CONTROL (group)	Allows the subject/role to perform control operations on all or some controllable objects that are present within an IED. Control services are for instance select or operate and relate to data objects defined in IEC 61850.

Permission	Description
CONFIG	Allows the subject/role to locally or remotely configure all or some objects that are present within an IED. This relates to data attributes of the IEC 61850 functional constraints CF, DC and SP.
SETTINGGROUP	Allows the subject/role to remotely configure SettingGroup control block. For example, this relates to the switching between different configured SettingGroups. SettingGroups also contains the IEC 61850 functional constraints SE.
FILEMNGT	Allows the subject/role to delete existing files on the IEDS.
SECURITY	Allows the subject/role to perform actions on all security related data objects, reportings, logs or files.

Specific product related permissions are listed in the tables below. Roles are mapped to Access Level definitions: A cross indicates that specific actions can be done by a user with the role allocated.

Extract Files	Role Name							
File Type	None Logged	VIEWER	OPERATOR	ENGINEER	INSTALLER	SECADM	SECAUD	RBACMNT
Setting				X	X	X	X	X
PSL				X	X			
MCL (IEC 61850)				X	X			
DNP3				X	X			
SLD				X	X			
Events (operational)		X	X	X				
Security Events							X	
Disturbance Records		X	X	X				

Sending Files	Role Name							
File Type	None Logged	VIEWER	OPERATOR	ENGINEER	INSTALLER	SECADM	SECAUD	RBACMNT
Setting				X	X	X		
PSL				X	X			
MCL (IEC 61850)				X	X			
DNP3				X	X			
SLD				X	X			
Menu Text				X	X			

19.7 USER AUTHENTICATION

19.7.1 AUTHENTICATION METHODS

The IED supports Bypass (no authentication), Device authentication and Server authentication.

Authentication Method	Description	User Interface
Bypass Auth.	IED does not provide security, any user (Local) can access the IED without logging in. IED does not validate user and password. In this case, there is no need to enter username and password to login. Bypass cannot be enabled on Rear Port 1, Rear Port 2 and Ethernet Ports.	Front Panel UI Front Port (USB port) (Local interfaces only)
Device Only	IED allows role access using local authentication.	Front Panel UI Front Port (USB port) Rear Port 1 Rear Port 2 Network Port 1 Network Port 2
Server + Device	IED uses RADIUS server authentication to validate the user first. And it allows fallback to device authentication if the RADIUS server(s) are unavailable.	Front Panel UI Front Port (USB port) Rear Port 1 Rear Port 2 Network Port 1 Network Port 2

If ***Bypass Auth.*** is enabled, the IED ignores the ***Auth. Method*** setting.

The ***Auth. Method*** setting offers the following options for user authentication:

- *Server + Device* (This is the default setting for IEDs with NIC (Ethernet Board) fitted)
- *Device Only* (This is the default setting for IEDs without NIC (Ethernet Board) fitted)

Only users with a SECADM role may change the ***Auth. Method*** setting. If the SECADM user changes it, the role remains logged in. Only when the user logs-out is their access-level revoked.

19.7.2 BYPASS

In ***Bypass Auth.*** mode, the IED does not provide user authentication - any user can login. IED does not validate user and password. The bypass security feature provides an easier access, with no authentication and encryption for situations when this is considered safe. Only users with SECADM role can enable Bypass mode. For this reason, it is recommended to always maintain at least one user with the SECADM role in the IED.

There are three modes for authentication bypass:

1. *Disabled* - no interfaces in ***Bypass Auth.*** mode (normal authentication is active)
2. *Local* - Bypass authentication when using Front Port and Front Panel
3. *Front Panel* - will bypass authentication Front Panel User Interface

Bypass authentication for Bypass mode:	Front Port	Front Panel UI
Disabled		
Local	X	X
Front Panel		X

The DDB signal ***Security Bypass*** is available to indicate that the IED is in ***Bypass Auth.*** mode.

The Front Panel UI will display "BYPASSED" at the top of the screen to indicate that the IED is in ***Bypass Auth***. mode.



19.7.3 LOGIN

A user can only login through the following methods:

- Front Panel User Interface
- Using MiCOM S1 Agile, connected to either the Front Port, Rear Port 1 or 2, or Ethernet Network Port 1 or 2.

A maximum of 20 characters username and 16 characters password are allowed for both device and RADIUS authentication from MiCOM S1 Agile.

19.7.3.1 FRONT PANEL LOGIN

Front panel User Interface supports both Device authentication and Server authentication. The P40 gives the user the option to enter the user credentials via UI panel. To access the Login window, select the Login text in the top banner using the arrow keys.



R80008

For both Device authentication or Server authentication, the user can enter any valid username and password combination. For ease of typing, it is preferable to do login using MiCOM S1 Agile.

After successful log in, a confirmation message is displayed, showing the logged in username at the top of the screen. For example:



R80010

19.7.3.2 LOGIN FAILED

When Authentication fails, a failure message is displayed:



19.7.3.3 OTHER LOGIN PROMPTS

For cases where the bypass is disabled and the user attempts an action which requires a user login, the Login Window appears after the error message. This is applicable while changing any setting values or pressing buttons which require user management - the Function Key, for example.

19.7.3.4 MICOM S1 LOGIN

When the user attempts to login, MiCOM S1 Agile will prompt the user with a login dialog box that contains a username and password entry fields. For both Device authentication or Server authentication, the user can enter any valid combination of username and password.

19.7.3.4.1 WARNING BANNER

After successful authentication and authorisation to access the IED, MiCOM S1 Agile will display a security warning banner to the user.

If **I Agree** is selected, the integrated authentication and authorisation is completed. Selecting **I Disagree** causes the program to close and the login user to logout.

For S1 Agile authentication, this is a pop-up dialog that the user must click to acknowledge.

19.7.4 USER SESSIONS

Only one role of one type is allowed to be logged in at a time from any interface. If the role has been logged in from one interface, an attempt to login the same role will result in a message being displayed, as below.



R60015

Open sessions will be automatically closed by the IED after a configurable session timeout.

The inactivity timer configuration setting defines the period of time that the IED waits in idleness before a logged in user is automatically logged out.

If there is any data change that does not commit to IED, the data change is discarded when user logged out. If there is any access that does not finish, the access will fail when user logged out. Front panel will display the default page when user reaches the defined inactivity time.

If the keypad is inactive for configured UI inactivity timer, the user logout message is displayed and the front panel user interface reverts to the Viewer access level.

The following settings are available in the ***SECURITY CONFIG*** column to support configurable inactivity timers.

- ***FP InactivTimer***
- ***UI InactivTimer***
- ***NIC Tunl Timeout***

Setting Name	Description	Min	Max	Default	Units	User Role Required
Attempts Limit	Number of failed authentications before the device blocks subsequent authentication attempts for the lockout period. A value of 0 means Lockout is disabled.	0 (lockout disabled)	99	3	-	SECADM
Lockout Period	The period of time in seconds a user is prevented from logging in, after being locked out.	1	5940	30	sec	SECADM
FP InactivTimer	FP Inactivity Timer is the time of idleness on Front Port before a logged in user is automatically logged out and revert the access level to the viewer role	0 (no Inactivity Timeout)	30	10	min	SECADM
UI InactivTimer	UI Inactivity Timer is the time of idleness on Front Panel before a logged in user is automatically logged out and revert the access level to the viewer role	0 (no Inactivity Timeout)	30	10	min	SECADM

Setting Name	Description	Min	Max	Default	Units	User Role Required
NIC Tunl Timeout	NIC Tunl Timeout is the time of idleness on Ethernet Port (NIC) before a logged in user is automatically logged out and revert the access level to the viewer role	1	30	5	min	SECADM

The recommended settings for ***Attempts Limit*** is *3* and ***Lockout Period*** is *30 sec* to discourage brute force attacks. If the Lockout period is too large, anybody can lockout Device users.

The following settings are available in the *COMMUNICATIONS* column to configure the inactivity timers for rear serial ports:

- ***KBUS InactTmr*** for RP1, if Courier Protocol is selected
- ***RP2 InactivTimer*** for RP2

19.7.5 USER LOCKING POLICY

A local user locking policy is implemented for Device access:

- This user locking policy applies to both Device users.
- The account is unlocked at the first successful login after the ***Lockout Period***
- If the user consecutively fails to login at the configured number of ***Attempts Limit***, the user account will be locked for the configured ***Lockout Period***

Each user account records how long it has been locked if the account is locked.

Each user account records how many times it has consecutively failed to login. User account failed times include all interfaces login attempts. For example, if the ***Attempts Limit*** setting is *3* and the operator failed to login from front panel 2 times, and they changed to login from the Courier interface, but failed again, then the Operator would be locked out.

When the IED is powered on, these ***Attempts Limit*** counter resets to zero.

When the user account exceeds the ***Attempts Limit*** it is locked for ***Lockout period***, at that time ***Attempt limit*** resets to zero.

The locked user account will be unlocked automatically, after the configured “Lockout Period” is expired.

If the locked account attempts to login the IED from the Front Panel, the unsuccessful login attempt screen is displayed.

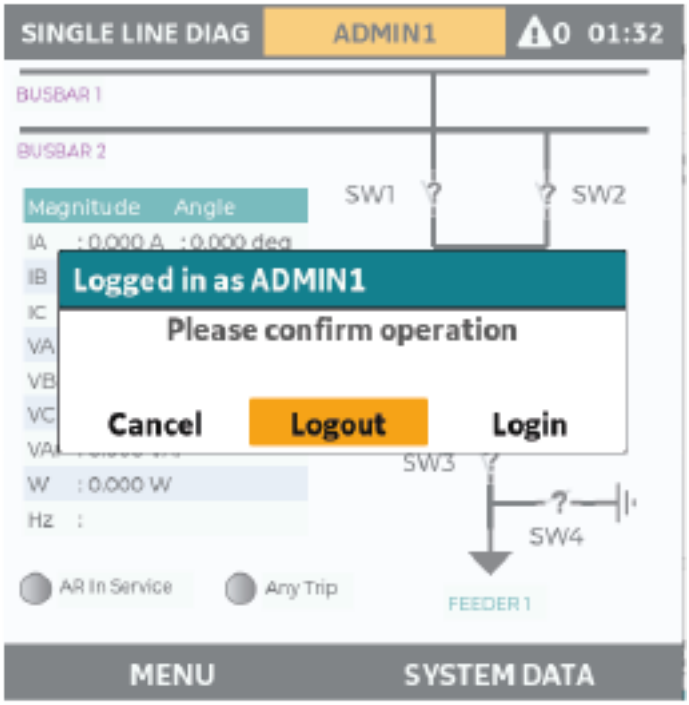
19.7.6 LOGOUT

Each user should ***Log out*** after reading or configuring the IED.

The user can only log out from the front panel, if they logged in from the front panel. If the user logged in from S1 Agile, they have to logout from S1 Agile.

19.7.6.1 FRONT PANEL LOGOUT

Go to the top of the banner and select the current logged in User. You may be prompted to log out with the following display:



R80013

If you confirm, the following screen is displayed for 2 seconds and then the action will be recorded in the security events file:



R80014

If you decide not to log out (i.e. you cancel), the logout screen would be cancelled.

19.7.6.2 MICOM S1 LOGOUT

Right-click on the device name in the System Explorer panel in MiCOM S1 Agile and select Log Off.

In the Log Off confirmation dialog, click Yes. The action will be recorded in the security events file.

19.7.7 PASSWORD POLICY

Cyber-security requires strong passwords and validation for NERC compliance. The IED will enforce one of two levels of password strength according to the ***Password Policy*** setting.

The NERC password complexity policy requires an alpha-numeric password (for all accesses, front panel, and network/local port) that meets the following **mandatory** requirements:

1. Passwords cannot contain the user's account name or parts of the user's full name that exceed two consecutive characters.
2. Passwords must be at least eight characters in length, but not exceed 16 characters in length.

Strict passwords rules must contain characters from all four categories as shown below:

a. English uppercase characters (A through Z).
b. English lowercase characters (a through z).
c. Numeric (digits 0 through 9).
d. Special non-alphanumeric characters (such as @,!,#,{, but not limited to only those)

Normal password rules: Any 3 out of 4 conditions as in strict password rules.

For Device authentication, the IED will enforce that configured passwords meet these requirements. The user can select which policies are required by selecting either Strict or Normal in the Password Policy setting under DEVICE RBAC.

Setting Name	Description	Min	Max	Default	Units	User Role Required
Password Policy	Selection of whether strict or normal rules apply for device authentication password policy	Normal	Strict	Strict	-	SECADM

For Server authentication, the password complexity and user locking policy is defined in the external RADIUS server.

19.7.8 PASSWORD EXPIRY

For Device authentication users, it is possible to select a configurable time (in days) for the password to be changed by the user.

Under *DEVICE RBAC* Settings, select ***Password Expiry*** to be Enabled. The setting of ***Disabled*** disables the password expiry check by the IED. If enabled, Max Password Age can be selected, this is in the range of days.

Setting Name	Description	Min	Max	Default	Units	User Role Required
Password Expiry	Selection of whether Password Expiry is enforced by the IED for device authentication	Disabled	Enabled	Enabled	-	SECADM
Max Password Age	Period in days if Password Expiry is enabled, the device passwords need to be changed	30	730	180	days	SECADM

When the Max Password Age has been reached and if the user attempts to login using the front panel UI, the following window will be shown.



R80011

The user will be presented with a screen to save the new password.



R80012

19.7.9 CHANGE PASSWORD

All the Device users will need to change the default password at the first logon.

The initial password change can be done either from the front panel User Interface, or from MiCOM S1 Agile using the **Change/Set Password** option in the **Supervise Device** dialog box.

Any further password change can only be done from MiCOM S1 Agile using the **Change/Set Password** option in the **Supervise Device** dialog box.

Users with SECADM and RBACMNT roles can change the password of any user. Users with other roles can change only their own password.

Caution:
It is recommended that user passwords are changed periodically.

19.7.10 RADIUS AUTHENTICATION

When the ***Auth. Method*** setting is configured as *Server + Device*, a user must log in with a username and password that has been predefined on the RADIUS server. RADIUS communication will work with either NP1 or NP2, provided that the device can reach the RADIUS server. This requires that the server resides in the same subnet as NP1/NP2.

This log in can be performed from any interface, as described in the Login section. The IED will authenticate the user to the active RADIUS server, over the Ethernet connection.

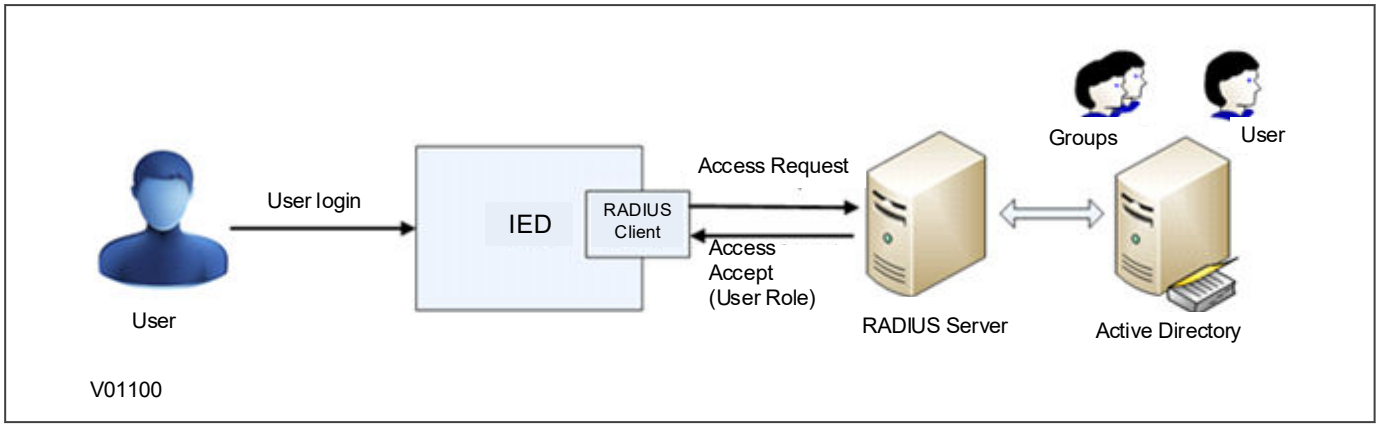


Figure 239: RADIUS server/client communication

19.7.10.1 RADIUS USERS

For Server authentication, RADIUS users and passwords are created in the RADIUS server (in the Active Directory), not in the IED.

The username must be from the ASCII Subset of 32 to 122 which includes upper and lower case letters, digits and several special characters.

Each RADIUS user must have a password that meets the password policy of the Active Directory (not the password policy of the P40) and have one of the supported roles assigned in the Active Directory.

The number of RADIUS users is not limited by the IED.

RADIUS password changes are done in the Active Directory (after password expiration).

19.7.10.2 RADIUS CLIENT

Two RADIUS servers are supported by the IED in the configuration for redundancy. The IED will try each in sequence until one responds.

The IED will first try server 1 up to the configured number of retries, leaving a request timeout between each request. If, after this point there is still no valid answer from server 1, the IED will switch to server 2 and repeat for up to the configured number of retries.

If the number of retries for the second server is exceeded the IED will fallback to Device authentication. A **RADIUS Server unavailable** security event is also logged under this condition.

The RADIUS implementation supports the following authentication protocols:

- EAP-TTLS-MSCHAP2
- PAP
- EAP-PEAP-MSCHAP2
- PAP EAP-TTLS-PAP (Default)

The RADIUS implementation queries the Role ID vendor attribute and establish the logged in user security context with that role.

RADIUS Config.	Value
Vendor ID	2910
Vendor Attribute	1
Standard Values	
VIEWER	0
OPERATOR	1
ENGINEER	2
INSTALLER	3
SECADM	4
SECAUD	5
RBACMNT	6

19.7.10.3 RADIUS SERVER SETTINGS

The following RADIUS server information must be configured in the IED to connect to the RADIUS server(s) for Server authentication.

Setting Name	Description	Min	Max	Default	Units	User Role Required
RADIUS Pri IP	IP address of Server 1. Default value indicates no Primary RADIUS server is configured, and so RADIUS is disabled.	0.0.0.0	255.255.255.255	0.0.0.0	-	SECADM
RADIUS Sec IP	IP address of Server 2. Default value indicates no Secondary RADIUS server is configured	0.0.0.0	255.255.255.255	0.0.0.0	-	SECADM
RADIUS Auth Port	RADIUS authentication port	1	65535	1812	-	SECADM
RADIUS Security	Authentication protocol to be used by RADIUS server	EAP-TTLS-MSCHAP2 PAP EAP-PEAP-MSCHAP2 PAP EAP-TTLS-PAP		PAP EAP-TTLS-PAP	-	SECADM
RADIUS Timeout	Timeout in seconds between re-transmission requests	1	900	2	sec	SECADM
RADIUS Retries	Number of retries before giving up	1	99	10	-	SECADM
RADIUS Secret	Shared Secret used in authentication. It is only displayed as asterisks.	1 character	64 characters	ChangeMe1#	-	SECADM
RADIUS NAS ID	NAS-Identifier for RADIUS	1 character	20 characters	MiCOM P40	-	SECADM

The data cell ***RADIUS Status*** indicates the status of the currently selected RADIUS server. This will display either *Disabled*, *Server OK*, or *Failed*.

19.7.10.4 RADIUS ACCOUNTING

RADIUS accounting is not supported by the IED. The user can achieve accounting through syslog (see the SYSLOG section).

19.7.10.5 RADIUS CLIENT-SERVER VALIDATION

Client-server validation is achieved using a shared secret. The IED must be configured with the ***RADIUS Secret*** setting to match the shared secret configured in the RADIUS server. It is recommended (but not enforced) that this setting meets the P40 password requirements. The device supports RADIUS secret of 1-64 characters.

MiCOM S1 Agile provides an option to save ***RADIUS Secret*** to the device. This can be achieved by logging to the device with a SECADM profile and accessing Supervise Device -> ***RADIUS Secret***.

> *Note:*
> *It is recommended that the shared secret be changed from the default before using RADIUS authentication.*

The IED does not support exchange of CA certificates. The RADIUS server may send a certificate, but the IED will not verify it.

19.7.11 RECOVERY

19.7.11.1 RESTORE TO LOCAL FACTORY DEFAULT

The ***Restore Defaults*** setting is available to facilitate NERC CIP compliance requirements for decommissioning critical cyber devices. Only the **Administrator** role can change this setting.

The ***Restore Defaults*** setting under the *CONFIGURATION* column is used to restore a setting group to factory default settings.

0 = *No Operation*

1 = *All Settings*

2 = *Setting Group 1*

3 = *Setting Group 2*

4 = *Setting Group 3*

5 = *Setting Group 4*

To restore the default values to the settings in any setting group, set the ***Restore Defaults*** setting to the relevant Group number. Alternatively, it is possible to set the ***Restore Defaults*** setting to *All Settings* to restore the default values to all the IEDs settings, not only one setting group.

> *Note:*
> *Restoring defaults to all settings includes the rear communication port settings, which may result in communication via the rear port being disrupted if the new (default) settings do not match those of the master station.*

Data (events, DR, fault records, protection counters etc.) is left untouched. When decommissioning critical cyber IEDs, users may want to clear all data and events as well.

19.7.11.2 PASSWORD RESET PROCEDURE

If you mislay a devices password (if Administrator forgets their password), the passwords can be reset to default using a recovery password. To obtain the recovery password you must contact the Contact Centre and supply the Serial Number (TEST ID) and the security code. The Contact Centre will use these details to generate a Recovery Password.

The Serial Number required is a six-digit code followed by one letter, found in the SYSTEM DATA column of the IED. It is the same as the TEST ID shown on the label on top of the IED.

The security code is a 16-character string of uppercase characters. It is a read-only parameter. The device generates its own security code randomly. A new code is generated under the following conditions:

- On power up
- Whenever settings are set back to default
- On expiry of validity timer (see below)
- When the recovery password is entered

This reset procedure can be only accomplished through front panel exclusively and cannot be done over any other interface. As soon as the security code is displayed on the front panel User Interface, a validity timer is started. This validity timer is set to 72 hours and is not configurable. This provides enough time for the Contact Centre to manually generate and send a recovery password. The Service Level Agreement (SLA) for recovery password generation is one working day, so 72 hours is sufficient time, even allowing for closure of the Contact Centre over weekends and bank holidays.

The procedure is:

The security code is displayed on confirmation. The validity timer is then started. The security code can only be read from the front panel.

This reset procedure can be only accomplished through front panel exclusively and cannot be done over the Ethernet/serial port, but only when physically present in front of the IED. In the event of losing all passwords (if the Administrator forgets their password) the user could reset the IED to default passwords, following the procedure below:

1. User navigates to ***Security Code*** cell in *SECURITY CONFIG* column
2. To prevent accidental reading of the IED ***Security Code***, the cell will initially display a warning message:

```
PRESS ENTER TO
READ SEC. CODE
```

3. Press Enter to read the ***Security Code***.
4. User sends an email to the Contact Centre providing the full IED serial number and displayed ***Security Code***, using a recognisable corporate email account
5. Contact Centre emails the user with the Recovery Password. The recovery password is intended for recovery only. It is not a replacement password that can be used continually. It can only be used once - for password recovery.
6. User logs in with the username **ADMINISTRATOR** and the recovery password into the ***Password*** setting in *SYSTEM DATA* column.
7. Then IED will prompt

```
RESET PASSWORD?
ENTER or CLEAR
```

8. Press Enter to continue the reset procedure
9. If the recovery password successfully validates, the default passwords are restored for each access level for Device authentication.
10. Change ***Auth. Method*** setting to `Server + Device` if applicable.

Note:
Restoring passwords to defaults does not affect any other settings and does not provoke reboot of the IED. The protection and control functions of the IED are always maintained.

19.7.11.3 ACCESS LEVEL DDBS

The current level of access for each interface is available for use in the Programmable Scheme Logic (PSL) as these DDB signals:

- ***HMI Access Lvl 1***
- ***HMI Access Lvl 2***
- ***FPort AccessLvl1***
- ***FPort AccessLvl2***
- ***RPrt1 AccessLvl1***
- ***RPrt1 AccessLvl2***
- ***RPrt2 AccessLvl1***
- ***RPrt2 AccessLvl2***

Each pair of DDB signals indicates the access level as follows:

- Level 1 off, Level 2 off = 0
- Level 1 on, Level 2 off = 1
- Level 1 off, Level 2 on = 2
- Level 1 on, Level 2 on = 3

KEY:

HMI = Human Machine Interface

(Front Panel User Interface)

FPort = Front Port

RPrt = Rear Port

Lvl = Level

19.7.12 PORT HARDENING: PHYSICAL PORTS

It is possible to disable unused physical ports. Enabling/Disabling of physical ports can be done either via the Front Panel or by sending the modified settings to the IED. These settings are under the PORT HARDENING: PHYSICAL PORTS Section of SECURITY CONFIG column. A user with SECADM role is needed to perform this action. This action cannot be done via the Supervise Device dialog box using MiCOM S1 Agile.

The following ports can be disabled, depending on the model.

- Front Port (***Front Port*** setting)
- Rear Port 1 (***Rear Port 1*** setting)
- Rear Port 2 (***Rear Port 2*** setting)
- Ethernet Network Port 1 (***Network Port 1*** Setting)
- Ethernet Network Port 2 (***Network Port 2*** Setting)

19.7.13 PORT HARDENING: LOGICAL PORTS (PROTOCOLS)

It is possible to disable unused logical ports. Enabling/Disabling of logical ports can be done either via the Front Panel or via sending the modified settings to the IED. These settings are under the PORT HARDENING: LOGICAL PORTS Section of the SECURITY CONFIG column. A user with SECADM role is needed to perform this action, This action cannot be done via the Supervise Device dialog box using MiCOM S1 Agile.

The following NIC protocols can be disabled:

- Courier Tunnel (for S1 Agile remote connection over Ethernet)
- IEC 61850
- SNTP
- PTP
- SNMP
- SYSLOG

19.7.14 SERVICE (PROTOCOL) MAPPING: ETHERNET NETWORK PORTS 1 AND 2

This section details which of the Ethernet protocols are available on each of Network Port 1 and Network Port 2, and whether these are configurable or fixed mappings. Settings for the configurable service mappings are under the PORT HARDENING: SERVICE MAP section of the *SECURITY CONFIG* column.

Service	Port	Network Port 1	Network Port 2	Fixed/Configurable	Setting
IEC 61850	102/TCP	No	Yes	Fixed to NP2.	
SNTP	123/UDP	No	Yes	Fixed to NP2.	
PTP	-	No	Yes	Fixed to NP2.	
SSH (for S1 Agile)	22/TCP	Yes - only one port at a time	Yes - only one port at a time	Configurable - NP1 or NP2	Courier Tunnel
SNMP	161/UDP, 162/UDP	Yes - only one port at a time	Yes - only one port at a time	Configurable - NP1 or NP2	SNMP
Syslog	514/UDP	Yes - only one port at a time	Yes - only one port at a time	Configurable - NP1 or NP2	SYSLOG

19.7.15 SUPERVISE DEVICE DIALOG BOX

Supervise Device	Role Name							
	None Logged	VIEWER	OPERATOR	ENGINEER	INSTALLER	SECADM	SECAUD	RBACMNT
Active Group			X	X	X			
Reset Cell			X					
Breakers			X					
Device Address				X	X	X		
Date and Time			X	X	X			
Bypass Options						X		
Active MCL Bank				X	X			
Device User Management						X		X
Own Password Change		X	X	X	X	X	X	X
RADIUS Secret						X		

Supervise Device	Role Name							
	None Logged	VIEWER	OPERATOR	ENGINEER	INSTALLER	SECADM	SECAUD	RBACMNT
SNMP Security						X		
Clear Records				X				
Restore Defaults				X	X			
Restore Security Settings						X		
SSH Client Passcode						X		

19.7.16 SECURE FIRMWARE UPGRADE

IEC 62351-8:2020 has defined a specific INSTALLER Role which can do firmware upgrades on the IEDs. The default users in the Device Authentication does not have any users with the INSTALLER Role. If a requirement exists to upgrade the Firmware of the IED, then the following mandatory steps must be taken before starting the firmware update:

- Using MiCOM S1 Agile, create a new user having the INSTALLER Role
- Using MiCOM S1 Agile, log into the device using the user having the INSTALLER Role. Change the default password
- Use the Firmware Download Tool and log into the IED, using the newly created user and changed password
- Once these steps are done, the firmware update process can continue.

The device supports Secure Firmware Update. The firmware files are checked for validity prior to updating of the IED. The main steps in the secure firmware update process are as follows:

- The ‘PX40 Download and Calibration’ firmware tool opens the secure firmware ZIP file and extracts its contents [Compressed Images and Signatures].
- The ‘PX40 Download and Calibration’ firmware tool transfers the firmware files [Compressed Images and Signatures] to IED Main CPU Board.
- IED validates the Compressed Images and extracts them.
- After successful validation, only then will the settings be cleared.
- In case of validation failure, IED will display the ERROR CODE and after that, the user can reboot the relay to its previous state.
- IED updates it Main CPU Board, Co-processor Board and Ethernet Board storage and verifies it.
- Finally, the Main CPU Board initiates an IED reboot.

Key steps in this process will be logged in the security events - see the Security Event Management section of this chapter for further details.

Any firmware upgrade should be organised through the GE Vernova Grid Automation After Sales Service departments, or a regional Local Service Centre. The firmware upgrade should normally be performed by GE Vernova personnel, or by suitably prepared and competent persons after instruction from GE Vernova personnel. A separate MiCOM P40 firmware download procedure guide is available.

Note:
It is not possible to update the firmware on the IED which is under Bypass mode.

Note:
During the firmware update, only the security events file is retained - all other configuration and record files are erased during a firmware upgrade.

19.8 SNMP CONFIGURATION

You configure the SNMP interface using the HMI panel or using the SNMP Security option in the Supervise Device dialog box by a user with SECADM role. Two different versions are available: SNMPv2c and SNMPv3:

To enable the SNMP interface:

1. Select the SECURITY CONFIG column and scroll to the SNMP PARAMETERS heading
2. You can select either v2C, V3 or both. Selecting None will disable the main processor SNMP interface.

SNMP Trap Configuration

SNMP traps allow for unsolicited reporting between the IED and up to two SNMP managers with unique IP addresses. The device MIB details what information can be reported using Traps. To configure the SNMP Traps:

1. Move down to the cell ***Trap Dest. IP 1*** and enter the IP address of the first destination SNMP manager. Setting this cell to `0.0.0.0` disables the first Trap interface.
2. Move down to the cell ***Trap Dest. IP 2*** and enter the IP address of the second destination SNMP manager. Setting this cell to `0.0.0.0` disables the Second Trap interface.

SNMP V3 Security Configuration

SNMPv3 provides a higher level of security via authentication and privacy protocols. The IED adopts a secure SNMPv3 implementation with a user-based security model (USM).

Authentication is used to check the identity of users; privacy allows for encryption of SNMP messages. Both are optional;however you must enable authentication in order to enable privacy. To configure these security options:

1. If SNMPv3 has been enabled, set the ***Security Level*** setting. There are three levels: without authentication and without privacy (`noAuthNoPriv`), with authentication but without privacy (`authNoPriv`), and with authentication and with privacy (`authPriv`).
2. If Authentication is enabled, use the ***Auth Protocol*** setting to select the authentication type. There are two options: `HMAC-MD5-96` or `HMAC-SHA-96`.
3. Using the ***Auth Password*** setting, enter the password (up to 20 characters) to be used by the IED for authentication.
4. Using the ***Auth Protocol*** setting, select one of the two available mechanisms for encryption of messages to be used by the IED (CBC-DES or CFB-AES128).
5. If privacy is enabled, use the ***Encrypt Password*** setting to set the encryption password (up to 20 characters) that will be used by the IED for encryption.

> *Note:*
> *When setting the SNMP browser for RBAC compatible relays, the Context Name should be 'px4x'.*

SNMP V2C Security Configuration

SNMPv2c implements authentication between the master and agent using a parameter called the ***Community Name***. This is effectively the password, but it is not encrypted during transmission (this makes it inappropriate for some scenarios in which case version 3 should be used instead). To configure the SNMP 2c security:

1. If SNMPv2c has been enabled, use the ***Community Name*** setting to set the password that will be used by the IED and SNMP manager for authentication. This may be between one and 8 characters.

19.9 RETURNING THE IED TO FACTORY

MiCOM P40 5th Generation products provide enhanced security, and there is no mechanism to bypass the implemented user management. If the IED is returned to the factory for repair or technical analysis, to facilitate the Engineers gaining access to the configuration and stored records in the IED, it is proposed that the IED is returned to the factory with one of the following options:

- Bypass enabled on the front port
- A new user with all Roles is created and left with a default password. If the details of this user are passed to the factory, the IED can be logged in after changing the default password. If the newly created user's password has been modified, it will be required that the modified password is provided

19.10 SECURITY EVENT MANAGEMENT

To implement NERC-compliant cyber-security, a range of security events are logged by the IED in three separate methods:

- In the Security Events file (security audit log) - a Courier events file that can be extracted and viewed by MiCOM S1 Agile
- As syslog events
- As SNMP events (traps)

19.10.1 SECURITY EVENTS: COURIER

The P40 supports the IEC 62351-14 format of security event messages. These are logged into a separate security audio log file named "Security events" that can be extracted and viewed by MiCOM S1 Agile, in addition to the operational events file. The maximum number of security events is 2048.

Event	IEC 62443-4 Category	IEC 62351-14 Severity	IEC 62351-14 Mnemonic	IEC 62351-14 ID / Private ID	Text	Extra Info
SECUR_EVT_PW_SET_ NON_COMPLIANT	62443-AUDIT_ LOG	Info	USER_PW_ CHANGE_ FAIL_POLICY	IEC 62351-14:1.31	User Password change failed - policy check failed	
SECUR_EVT_PW_ MODIFIED	62443-CONFIG_ CHANGE	Notice	USER_PW_ CHANGE_OK	IEC 62351-14:1.25	User password changed successfully	Interface
SECUR_EVT_PW_ ENTRY_NOW_ BLOCKED	62443-ACCESS_ CONTROL	Notice	LOCK_USER_ WRONG_CR	IEC 62351-14:1.7	User locked - Wrong credentials	Interface
SECUR_EVT_PW_ ENTRY_UNBLOCKED	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-001	User unlocked	Interface
SECUR_EVT_PW_ ENTERED_WHILE_ BLOCKED	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-002	Log-in attempt when user is locked	Interface
SECUR_EVT_INVALID_PW _ENTERED	62443-ACCESS_ CONTROL	Notice	LOGIN_FAIL_ WRONG_ CR	IEC 62351-14:1.3	Log-in failed - Wrong credentials	Interface
SECUR_EVT_PW_ TIMED_OUT	62443-ACCESS_ CONTROL	error	LOGIN_FAIL_ CRED_ EXPIRE	IEC 62351-14:1.4	Log-in failed - credentials expired.	Interface
SECUR_EVT_ RECOVERY_PW_ ENTERED	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-004	Recovery password entered	Interface
SECUR_EVT_IED_SEC_ CODE_READ	62443-AUDIT_ LOG	Info	-	2910-MiCP40-005	Security Code read	Interface
SECUR_EVT_IED_SEC_ CODE_TMR_ EXPIRED	62443-AUDIT_ LOG	Info	-	2910-MiCP40-006	Security Code Timer expired	Interface
SECUR_EVT_PORT_ DISABLED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-007	Port Disabled	Interface
SECUR_EVT_PORT_ ENABLED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-008	Port Enabled	Interface, Port number
SECUR_EVT_PSL_ SETTINGS_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-009	PSL Settings downloaded to device	Interface, Port number
SECUR_EVT_DNP_ SETTINGS_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-010	DNP Settings downloaded to device	Interface, Group number

Event	IEC 62443-4 Category	IEC 62351-14 Severity	IEC 62351-14 Mnemonic	IEC 62351-14 ID / Private ID	Text	Extra Info
SECUR_EVT_TRACE_ DATA_DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-011	TRACE Data downloaded to device	Interface
SECUR_EVT_61850_ CONFIG_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-012	IEC61850 Config downloaded to device	Interface
SECUR_EVT_USER_ CURVES_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-013	User Curves downloaded to device	Interface
SECUR_EVT_SETTING_G RP_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-014	Setting Group downloaded to device	Interface, Curve number
SECUR_EVT_DR_ SETTINGS_ DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-015	DR Settings downloaded to device	Interface, Group number
SECUR_EVT_PSL_ SETTINGS_ UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-016	PSL Settings uploaded from device	Interface
SECUR_EVT_DNP_ SETTINGS_ UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-017	DNP Settings uploaded from device	Interface, Group number
SECUR_EVT_TRACE_ DATA_UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-018	TRACE Data uploaded from device	Interface
SECUR_EVT_61850_ CONFIG_UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-019	IEC61850 Config uploaded from device	Interface
SECUR_EVT_USER_ CURVES_UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-020	User Curves uploaded from device	Interface
SECUR_EVT_PSL_ CONFIG_UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-021	PSL Config uploaded from device	Interface, Curve number
SECUR_EVT_ SETTINGS_ UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-022	Settings uploaded from device	Interface, Group number
SECUR_EVT_CS_ SETTINGS_CHANGED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-023	Control & Support settings changed	Interface
SECUR_EVT_DR_ SETTINGS_CHANGED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-024	Disturbance Record Settings changed	Interface
SECUR_EVT_ SETTING_GROUP_ CHANGED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-025	Setting Group changed	Interface
SECUR_EVT_ DEFAULT_SETTINGS_ RESTORED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-026	Default Settings restored	Interface, Group number
SECUR_EVT_ DEFAULT_USRCURVE_ RESTORED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-027	Default User Curve restored	Interface
SECUR_EVT_POWER_ON	62443- CONTROL_ SYSTEM	Notice	-	2910-MiCP40-028	Device Powered On	Interface, Curve number
SECUR_EVT_RADIUS_ UNAVAIL	62443-AUDIT_ LOG	warning	RBAC_NO_ RADIUS	IEC 62351-8:1.3	RADIUS server not available	Interface
SECUR_EVT_ SESSION_LIMIT	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-030	Active user sessions limit reached	Interface

Event	IEC 62443-4 Category	IEC 62351-14 Severity	IEC 62351-14 Mnemonic	IEC 62351-14 ID / Private ID	Text	Extra Info
SECUR_EVT_SLD_ FILE_DOWNLOADED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-031	SLD File downloaded to device	Interface
SECUR_EVT_SLD_ FILE_UPLOADED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-032	SLD File uploaded from device	Interface
SECUR_EVT_RBAC_ LOGIN	62443-ACCESS_ CONTROL	Notice	LOGIN_OK	IEC-62351-14:1.1	Log-in successful	Interface
SECUR_EVT_RBAC_ LOGOUT	62443-ACCESS_ CONTROL	Notice	LOGOUT_ USER	IEC 62351-14:1.8	Log-out (user logged out)	Interface
Bypass mode Activated	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-033	Bypass Mode Activated	Interface
Bypass mode Deactivated	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-034	Bypass Mode Deactivated	Interface
SECUR_EVT_RADIUS_ KEY_CHANGED	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-044	RADIUS Secret Key changed	Interface
SECUR_SEC_ SETTINGS_ RESTORED	62443-BACKUP_ RESTORE	Notice	-	2910-MiCP40-041	Security settings restored	Interface
Switch to Golden Image	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-045	Device switching to Firmware update mode	Interface
FIRMWARE_ VALIDATION_ SUCCESS	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-035	Firmware Digital Signature check successful	Interface
FIRMWARE_ VALIDATION_FAIL	62443-AUDIT_ LOG	warning	-	2910-MiCP40-036	Firmware Digital Signature check failed	Interface
Firmware update process started	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-046	Firmware update initiated	Interface
Fail to receive firmware files	62443-AUDIT_ LOG	Warning	-	2910-MiCP40-047	Firmware files transfer failed	Interface
Fail to update firmware	62443-AUDIT_ LOG	Warning	-	2910-MiCP40-048	Firmware update failed	Interface
Firmware update process success	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-049	Firmware update successful	Interface, Previous FW version, Latest FW version
Serial&Model number update success	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-050	Serial/Model number update successful	
Serial&Model number update fail	62443-AUDIT_ LOG	Warning	-	2910-MiCP40-051	Serial/Model number update failed	Interface
NP1 MAC update success	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-052	NP1 MAC address update successful	Interface

Event	IEC 62443-4 Category	IEC 62351-14 Severity	IEC 62351-14 Mnemonic	IEC 62351-14 ID / Private ID	Text	Extra Info
NP1 MAC update fail	62443-AUDIT_ LOG	Warning	-	2910-MiCP40-053	NP1 MAC address update failed	Interface
NP2 MAC update success	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-054	NP2 MAC address update successful	Interface
NP2 MAC update fail	62443-AUDIT_ LOG	Warning	-	2910-MiCP40-055	NP2 MAC address update failed	Interface
Fallback to Device Authentication	62443-ACCESS_ CONTROL	Warning	-	2910-MiCP40-056	Fallback to Device Authentication	Interface
User logged out due to inactivity timeout	62443-ACCESS_ CONTROL	Notice	LOGOUT_ TIMEOUT	IEC 62351-14:1.9	Log-out by user inactivity (timeout).	Interface
Security events upload	62443-AUDIT_ LOG	Notice	-	2910-MiCP40-042	Security Events uploaded from device	Interface
SSH Passcode change	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-057	SSH pass code change	Interface
SSH Client Authentication Fail	62443-ACCESS_ CONTROL	Warning	-	2910-MiCP40-059	Failed client authentication	Interface
SSH Client Authentication Success	62443-ACCESS_ CONTROL	Notice	-	2910-MiCP40-058	Successful client authentication	Interface
New User added	62443-CONFIG_ CHANGE	Notice	USER_ ACCNT_ CREATE_OK	IEC 62351-14:2.15	User account created successfully.	Interface
User deleted	62443-CONFIG_ CHANGE	Notice	USER_ ACCNT_DEL_OK	IEC 62351-14:2.21	User account deleted successfully.	Interface
User role change	62443-CONFIG_ CHANGE	Notice	USER_ PERMISSION_ CHANGE_OK	IEC 62351-14:2.11	Permission changed successfully.	Interface
User name change	62443-CONFIG_ CHANGE	Notice	-	2910-MiCP40-060	User renamed successfully	Interface

Where the Interface values in "Extra Info" parameter are: "UI", "FP", "RP1", "RP2", "NET", "HMI".

19.10.2 SECURITY EVENTS: SYSLOG

Security events are also logged to a remote server and are based on Syslog [RFC 5424].

All login and logout attempts from local and central authentication, whether successful or failed, are logged. The contents of each successful or failed, login and logout security event include a specific username.

The security log cannot be cleared by any of the available roles.

The contents of each login and/or logout security event include the relevant interface. The following interfaces are supported:

Interface	Abbr.
Front Port	FP
Rear Port 1	RP1
Rear Port 2	RP2
Network Port 1 or 2	NET
Front Panel	UI

The following events are available to be logged to the syslog server:

Security Event	SNMP Trap Text
SECUR_EVT_PW_SET_NON_COMPLIANT	User Password change failed - policy check failed
SECUR_EVT_PW_MODIFIED	User password changed successfully
SECUR_EVT_PW_ENTRY_NOW_BLOCKED	User locked – Wrong credentials
SECUR_EVT_PW_ENTRY_UNBLOCKED	User unlocked
SECUR_EVT_PW_ENTERED_WHILE_BLOCKED	Log-in attempt when user is locked
SECUR_EVT_INVALID_PW_ENTERED	Log-in failed - Wrong credentials
SECUR_EVT_PW_TIMED_OUT	Log-in failed - credentials expired.
SECUR_EVT_RECOVERY_PW_ENTERED	Recovery password entered
SECUR_EVT_IED_SEC_CODE_READ	Security Code read
SECUR_EVT_IED_SEC_CODE_TMR_EXPIRED	Security Code Timer expired
SECUR_EVT_PORT_DISABLED	Port Disabled
SECUR_EVT_PORT_ENABLED	Port Enabled
SECUR_EVT_PSL_SETTINGS_DOWNLOADED	PSL Settings downloaded to device
SECUR_EVT_DNP_SETTINGS_DOWNLOADED	DNP Settings downloaded to device
SECUR_EVT_61850_CONFIG_DOWNLOADED	IEC61850 Config downloaded to device
SECUR_EVT_USER_CURVES_DOWNLOADED	User Curves downloaded to device
SECUR_EVT_SETTING_GRP_DOWNLOADED	Setting Group downloaded to device
SECUR_EVT_DR_SETTINGS_DOWNLOADED	DR Settings downloaded to device
SECUR_EVT_PSL_SETTINGS_UPLOADED	PSL Settings uploaded from device
SECUR_EVT_DNP_SETTINGS_UPLOADED	DNP Settings uploaded from device
SECUR_EVT_61850_CONFIG_UPLOADED	IEC61850 Config uploaded from device

Security Event	SNMP Trap Text
SECUR_EVT_USER_CURVES_UPLOADED	User Curves uploaded from device
SECUR_EVT_PSL_CONFIG_UPLOADED	PSL Config uploaded from device
SECUR_EVT_SETTINGS_UPLOADED	Settings uploaded from device
SECUR_EVT_CS_SETTINGS_CHANGED	Control & Support settings changed
SECUR_EVT_DR_SETTINGS_CHANGED	Disturbance Record Settings changed
SECUR_EVT_SETTING_GROUP_CHANGED	Setting Group changed
SECUR_EVT_DEFAULT_SETTINGS_RESTORED	Default Settings restored
SECUR_EVT_DEFAULT_USRCURVE_RESTORED	Default User Curve restored
SECUR_EVT_RADIUS_UNAVAIL	RADIUS server not available
SECUR_EVT_SESSION_LIMIT	Active user sessions limit reached
SECUR_EVT_SLD_FILE_DOWNLOADED	SLD File downloaded to device
SECUR_EVT_SLD_FILE_UPLOADED	SLD File uploaded from device
SECUR_EVT_RBAC_LOGIN	Log-in successful
SECUR_EVT_RBAC_LOGOUT	Log-out (user logged out)
Bypass mode Activated	Bypass Mode Activated
Bypass mode Deactivated	Bypass Mode Deactivated
RADIUS Secret Key changed	RADIUS Secret Key changed
SECUR_EVT_SEC_SETTINGS_RESTORED	Security settings restored
Switch to Golden Image	Device switching to Firmware update mode
Fallback to Device Authentication	Fallback to Device Authentication
User logged out due to inactivity timeout.	Log-out by user inactivity (timeout)
Security events upload	Security Events uploaded from device
SSH Passcode change	SSH pass code change
SSH Client Authentication Fail	Failed client authentication
SSH Client Authentication Success	Successful client authentication
New User added	User account created successfully.
User deleted	User account deleted successfully.
User role change	Permission changed successfully.

19.10.3 SYSLOG CLIENT

The IED supports security event reporting through the Syslog protocol for supporting Security Information Event Management (SIEM) systems for centralized cyber security Monitoring over UDP protocol.

The IED is a Syslog client that supports two Syslog servers. The following settings are available in the *SECURITY CONFIG.* column.

Setting Name	Description	Min	Max	Default	Units	User Role Required
SysLog Pri IP	The IP address of the target Syslog server (Primary)	0.0.0.0	223.255.255.254	0.0.0.0	-	SECADM
SysLog Sec IP	The IP address of the target Syslog server (Secondary)	0.0.0.0	223.255.255.254	0.0.0.0	-	SECADM
SysLog Port	The UDP port number of the target Syslog server	1	65535	514	-	SECADM

19.10.4 SYSLOG FUNCTIONALITY

P40 supports IEC 62351-14 based cyber security event monitoring and is based on Syslog [RFC 5424].

Sample Syslog messages are shown below:

Event	Access Method	Syslog Message (As from Syslog Server)
IED Powered On	UI	5492, 2024-06-12T19:18:28.982Z, 423991K, GE_RE_P543_____AB0_o, MiCP40_POWER_ON, 2910-MiCP40-028, notice, IECCTRLSYS, Device Powered On, UI
ADMIN1 Log-in successful	FP	5523, 2024-06-12T20:04:26.851Z, 423991K, GE_RE_P543_____AB0_o, LOGIN_OK, IEC 62351-14:1.1, notice, IECACCCTRL, ADMIN1, SECAM, Log-in successful, FP
SSH Successful client authentication (S1 Agile)	NET	5460, 2024-06-12T18:04:45.359Z, 423991J, GE_RE_P546_____AB0_o, MiCP40_SSH_CLIENT_AUTH_SUCCESS, 2910-MiCP40-058, notice, IECACCCTRL, Successful client authentication, NET
Firmware update successful	FP	5476, 2024-06-12T19:18:19.004Z, 423991K, GE_RE_P543_____AB0_o, MiCP40_FW_UPDATE_SUCCESS, 2910-MiCP40-049, notice, IECCONFCHG, Firmware update successful, FP, P546_____AB0_o to P543_____AB0_o

19.10.5 SECURITY EVENTS: SNMP

Security events can also be sent as SNMP traps to a remote SNMP server. These traps are supported in both V2c and V3 versions of SNMP. For further information related to the full SNMP interface in P40, refer to the SNMP section in the COMMUNICATIONS chapter.

The format of the SNMP traps for security events consists of three parts as described below:

"Event Description, Username, Interface"

- Event Description: Short description of the alarm, same as the description present in Security event.
- Username: User associated with the event, provided only when Username is available for the Security event.
- Interface: Interface on which Security event has occurred, same as the interface information present in Security event.

The following events are available to be logged to the SNMP server:

Security Event	SNMP Trap Text
SECUR_EVT_PW_SET_NON_COMPLIANT	User Password change failed - policy check failed
SECUR_EVT_PW_MODIFIED	User password changed successfully
SECUR_EVT_PW_ENTRY_NOW_BLOCKED	User locked – Wrong credentials
SECUR_EVT_PW_ENTRY_UNBLOCKED	User unlocked
SECUR_EVT_PW_ENTERED_WHILE_BLOCKED	Log-in attempt when user is locked
SECUR_EVT_INVALID_PW_ENTERED	Log-in failed - Wrong credentials
SECUR_EVT_PW_TIMED_OUT	Log-in failed - credentials expired.
SECUR_EVT_RECOVERY_PW_ENTERED	Recovery password entered
SECUR_EVT_IED_SEC_CODE_READ	Security Code read
SECUR_EVT_IED_SEC_CODE_TMR_EXPIRED	Security Code Timer expired
SECUR_EVT_PORT_DISABLED	Port Disabled
SECUR_EVT_PORT_ENABLED	Port Enabled
SECUR_EVT_PSL_SETTINGS_DOWNLOADED	PSL Settings downloaded to device
SECUR_EVT_DNP_SETTINGS_DOWNLOADED	DNP Settings downloaded to device
SECUR_EVT_61850_CONFIG_DOWNLOADED	IEC61850 Config downloaded to device
SECUR_EVT_USER_CURVES_DOWNLOADED	User Curves downloaded to device
SECUR_EVT_SETTING_GRP_DOWNLOADED	Setting Group downloaded to device
SECUR_EVT_DR_SETTINGS_DOWNLOADED	DR Settings downloaded to device
SECUR_EVT_PSL_SETTINGS_UPLOADED	PSL Settings uploaded from device
SECUR_EVT_DNP_SETTINGS_UPLOADED	DNP Settings uploaded from device
SECUR_EVT_61850_CONFIG_UPLOADED	IEC61850 Config uploaded from device
SECUR_EVT_USER_CURVES_UPLOADED	User Curves uploaded from device
SECUR_EVT_PSL_CONFIG_UPLOADED	PSL Config uploaded from device
SECUR_EVT_SETTINGS_UPLOADED	Settings uploaded from device
SECUR_EVT_CS_SETTINGS_CHANGED	Control & Support settings changed
SECUR_EVT_DR_SETTINGS_CHANGED	Disturbance Record Settings changed
SECUR_EVT_SETTING_GROUP_CHANGED	Setting Group changed

Security Event	SNMP Trap Text
SECUR_EVT_DEFAULT_SETTINGS_RESTORED	Default Settings restored
SECUR_EVT_DEFAULT_USRCURVE_RESTORED	Default User Curve restored
SECUR_EVT_POWER_ON	Device Powered On
SECUR_EVT_RADIUS_UNAVAIL	RADIUS server not available
SECUR_EVT_SESSION_LIMIT	Active user sessions limit reached
SECUR_EVT_SLD_FILE_DOWNLOADED	SLD File downloaded to device
SECUR_EVT_SLD_FILE_UPLOADED	SLD File uploaded from device
SECUR_EVT_RBAC_LOGIN	Log-in successful
SECUR_EVT_RBAC_LOGOUT	Log-out (user logged out)
Bypass mode Activated	Bypass Mode Activated
Bypass mode Deactivated	Bypass Mode Deactivated
RADIUS Secret Key changed	RADIUS Secret Key changed
SECUR_EVT_SEC_SETTINGS_RESTORED	Security settings restored
Switch to Golden Image	Device switching to Firmware update mode
Fallback to Device Authentication	Fallback to Device Authentication
User logged out due to inactivity timeout.	Log-out by user inactivity (timeout)
Security events upload	Security Events uploaded from device
SSH Passcode change	SSH pass code change
SSH Client Authentication Fail	Failed client authentication
SSH Client Authentication Success	Successful client authentication
New User added	User account created successfully.
User deleted	User account deleted successfully.
User role change	Permission changed successfully.

CHAPTER 20

INSTALLATION

20.1 CHAPTER OVERVIEW

This chapter provides information about installing the product.

This chapter contains the following sections:

Chapter Overview 486
Handling the Goods 487
Mounting the Device 488
Cables and Connectors 491
Case Dimensions 495

20.2 HANDLING THE GOODS

Our products are of robust construction but require careful treatment before installation on site. This section discusses the requirements for receiving and unpacking the goods, as well as associated considerations regarding product care and personal safety.



Caution:
Before lifting or moving the equipment you should be familiar with the Safety Information chapter of this manual.

20.2.1 RECEIPT OF THE GOODS

On receipt, ensure the correct product has been delivered. Unpack the product immediately to ensure there has been no external damage in transit. If the product has been damaged, make a claim to the transport contractor and notify us promptly.

For products not intended for immediate installation, repack them in their original delivery packaging.

20.2.2 UNPACKING THE GOODS

When unpacking and installing the product, take care not to damage any of the parts and make sure that additional components are not accidentally left in the packing or lost. Do not discard any CDROMs or technical documentation (where included). These should accompany the unit to its destination substation and put in a dedicated place.

The site should be well lit to aid inspection, clean, dry and reasonably free from dust and excessive vibration. This particularly applies where installation is being carried out at the same time as construction work.

20.2.3 STORING THE GOODS

If the unit is not installed immediately, store it in a place free from dust and moisture in its original packaging. Keep any dehumidifier bags included in the packing. The dehumidifier crystals lose their efficiency if the bag is exposed to ambient conditions. Restore the crystals before replacing it in the carton. Ideally regeneration should be carried out in a ventilating, circulating oven at about 115°C. Bags should be placed on flat racks and spaced to allow circulation around them. The time taken for regeneration will depend on the size of the bag. If a ventilating, circulating oven is not available, when using an ordinary oven, open the door on a regular basis to let out the steam given off by the regenerating silica gel.

On subsequent unpacking, make sure that any dust on the carton does not fall inside. Avoid storing in locations of high humidity. In locations of high humidity the packaging may become impregnated with moisture and the dehumidifier crystals will lose their efficiency.

The device can be stored between –25º to +70ºC for unlimited periods or between -40°C to + 85°C for up to 96 hours (see technical specifications).

To avoid deterioration of electrolytic capacitors, power up units that are stored in a de-energised state once a year, for one hour continuously.

20.2.4 DISMANTLING THE GOODS

If you need to dismantle the device, always observe standard ESD (Electrostatic Discharge) precautions. The minimum precautions to be followed are as follows:

- Use an antistatic wrist band earthed to a suitable earthing point.
- Avoid touching the electronic components and PCBs.

20.3 MOUNTING THE DEVICE

The products are dispatched either individually or as part of a panel or rack assembly.

Individual products are normally supplied with an outline diagram showing the dimensions for panel cut-outs and hole centres.

The products are designed so the fixing holes in the mounting flanges are only accessible when the access covers are open.

If you use a P991 or MMLG test block with the product, when viewed from the front, position the test block on the right-hand side of the associated product. This minimises the wiring between the product and test block, and allows the correct test block to be easily identified during commissioning and maintenance tests.

20.3.1 FLUSH PANEL MOUNTING

Panel-mounted devices are flush mounted into panels using M4 SEMS Taptite self-tapping screws with captive 3 mm thick washers (also known as a SEMS unit).



Caution:
Do not use conventional self-tapping screws, because they have larger heads and could damage the faceplate.

Alternatively, you can use tapped holes if the panel has a minimum thickness of 2.5 mm.

For applications where the product needs to be semi-projection or projection mounted, a range of collars are available.

If several products are mounted in a single cut-out in the panel, mechanically group them horizontally or vertically into rigid assemblies before mounting in the panel.



Caution:
Do not fasten products with pop rivets because this makes them difficult to remove if repair becomes necessary.

20.3.2 RACK MOUNTING

Panel-mounted variants can also be rack mounted using single-tier rack frames (our part number FX0021 001), as shown in the figure below. These frames are designed with dimensions in accordance with IEC 60297 and are supplied pre-assembled ready to use. On a standard 483 mm (19 inch) rack this enables combinations of case widths up to a total equivalent of size 80TE to be mounted side by side.

The two horizontal rails of the rack frame have holes drilled at approximately 26 mm intervals. Attach the products by their mounting flanges using M4 Taptite self-tapping screws with captive 3 mm thick washers (also known as a SEMS unit).



Caution:
Risk of damage to the front cover molding. Do not use conventional self-tapping screws, including those supplied for mounting MiDOS products because they have slightly larger heads.

Once the tier is complete, the frames are fastened into the racks using mounting angles at each end of the tier.



Figure 240: Rack mounting of products

Products can be mechanically grouped into single tier (4U) or multi-tier arrangements using the rack frame. This enables schemes using products from different product ranges to be pre-wired together before mounting.

Use blanking plates to fill any empty spaces. The spaces may be used for installing future products or because the total size is less than 80TE on any tier. Blanking plates can also be used to mount ancillary components. The part numbers are as follows:

Case size summation	Blanking plate part number
5TE	GJ2028 001
10TE	GJ2028 002
20TE	GJ2028 004
40TE	GJ2028 008
60TE	GJ2028 012

20.3.3 REFURBISHMENT SOLUTIONS

A feature of 5th Generation MiCOM products is their fit, form, and functionality compatibility with previous generations of similar devices. Pin-for-pin compatibility with our older products eases upgrade refurbishment of existing installations to accommodate the advantages of new developments with minimal disruption. If upgrading from previous MiCOM products, or even to replace some of our legacy products (such as MiDOS MBCH or K-series KBCH), the process is simple:

- Take the order code (CORTEC) of the older device being removed
- Translate to today's latest GE Vernova MiCOM model (adding Ethernet options if required)
- Order the new 5th Generation equivalent P40 device
- Use the S1 Agile toolsuite to extract settings and logic and convert the settings
- Detach the medium duty terminal blocks from your old device, making sure you leave the wiring attached.

- Although it may be possible to reuse the (heavy duty) CT/VT terminal blocks, we recommend that those supplied on the new IED are used during refurbishment. In this case, acting with due caution, disconnect the wiring to these terminals.
- Carefully examine the terminal blocks to ensure there is no physical damage
- Attach any detached terminal blocks and disconnected wiring from your old device to the new IED
- We recommend applying rated current and voltage to the relay CT/VT inputs through secondary injection testing to check the continuity of the CT/VT terminal block connections before re-energisation.
- Download your converted files
- Test (*), then return circuit to service.

* See the Commissioning Instructions chapter for more information on testing

Please contact GA.support@gevernova.com for further advice or assistance.

20.4 CABLES AND CONNECTORS

This section describes the type of wiring and connections that should be used when installing the device. For pin-out details please refer to the Hardware Design chapter or the wiring diagrams.

Caution:
Before carrying out any work on the equipment you should be familiar with the Safety Section and the ratings on the equipment's rating label.

20.4.1 TERMINAL BLOCKS

The device may use one or more of the terminal block types shown in the following diagram. The terminal blocks are fastened to the rear panel with screws.

- Heavy duty (HD) terminal blocks for CT and VT circuits
- Medium duty (MD) terminal blocks for the power supply, relay outputs and rear communications port
- MiDOS terminal blocks for CT and VT circuits
- RTD/CLIO terminal block for connection to analogue transducers

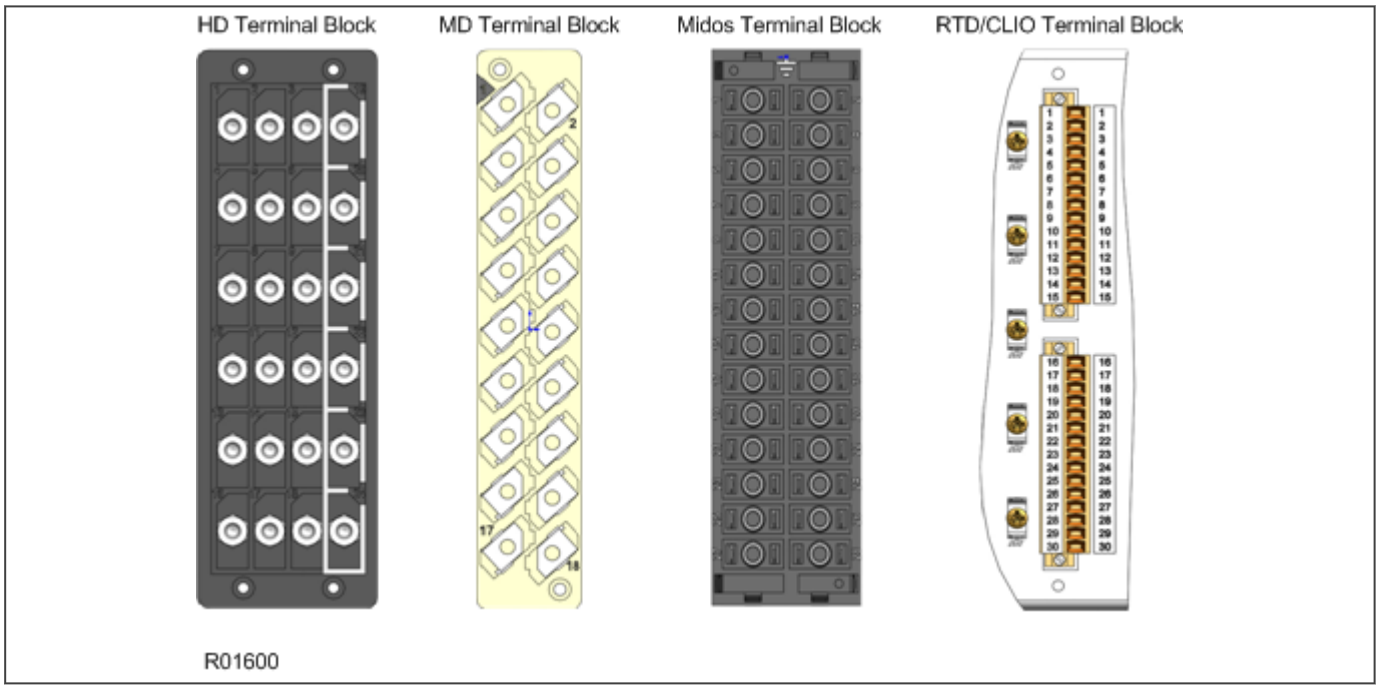


Figure 241: Terminal block types

MiCOM products are supplied with sufficient M4 screws for making connections to the rear mounted terminal blocks using ring terminals, with a recommended maximum of two ring terminals per terminal.

If required, M4 90° crimp ring terminals can be supplied in three different sizes depending on wire size. Each type is available in bags of 100.

Part number	Wire size	Insulation color
ZB9124 901	0.25 - 1.65 mm^2 (22 – 16 AWG)	Red
ZB9124 900	1.04 - 2.63 mm^2 (16 – 14 AWG)	Blue

Note:
IP2x shields and side cover panels may be fitted to provide IP20 ingress protection for MiCOM terminal blocks. The shields and covers can be attached during installation or retrofitted to upgrade existing installations. The shields are supplied with four language fitting instructions, publication number: IP2x-TM-4L-n (where n is the current issue number). For more information, contact your local sales office or our worldwide Contact Centre.

20.4.2 POWER SUPPLY CONNECTIONS

These should be wired with 1.5 mm PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

The wire should have a minimum voltage rating of 300 V RMS.



Caution:
Protect the auxiliary power supply wiring with a maximum 16 A high rupture capacity (HRC) type NIT or TIA fuse.

20.4.3 EARTH CONNNECTION

Every device must be connected to the cubicle earthing bar using the M4 earth terminal.

Use a wire size of at least 2.5 mm^2 terminated with a ring terminal.

Due to the physical limitations of the ring terminal, the maximum wire size you can use is 6.0 mm^2 using ring terminals that are not pre-insulated. If using pre insulated ring terminals, the maximum wire size is reduced to 2.63 mm^2 per ring terminal. If you need a greater cross-sectional area, use two wires in parallel, each terminated in a separate ring terminal.

The wire should have a minimum voltage rating of 300 V RMS.

Note:
To prevent any possibility of electrolytic action between brass or copper ground conductors and the rear panel of the product, precautions should be taken to isolate them from one another. This could be achieved in several ways, including placing a nickel-plated or insulating washer between the conductor and the product case, or using tinned ring terminals.

20.4.4 CURRENT TRANSFORMERS

Current transformers would generally be wired with 2.5 mm^2 PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

Due to the physical limitations of the ring terminal, the maximum wire size you can use is 6.0 mm^2 using ring terminals that are not pre-insulated. If using pre insulated ring terminals, the maximum wire size is reduced to 2.63 mm^2 per ring terminal. If you need a greater cross-sectional area, use two wires in parallel, each terminated in a separate ring terminal.

The wire should have a minimum voltage rating of 300 V RMS.



Caution:
Current transformer circuits must never be fused.

Note:
If there are CTs present, spring-loaded shorting contacts ensure that the terminals into which the CTs connect are shorted before the CT contacts are broken.

Note:
For 5A CT secondaries, we recommend using 2 x 2.5 mm^2 PVC insulated multi-stranded copper wire.

20.4.5 VOLTAGE TRANSFORMER CONNECTIONS

Voltage transformers should be wired with 2.5 mm^2 PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

The wire should have a minimum voltage rating of 300 V RMS.

20.4.6 WATCHDOG CONNECTIONS

These should be wired with 1 mm PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

The wire should have a minimum voltage rating of 300 V RMS.

20.4.7 EIA(RS)485 AND K-BUS CONNECTIONS

For connecting the EIA(RS485) / K-Bus ports, use 2-core screened cable with a maximum total length of 1000 m or 200 nF total cable capacitance.

To guarantee the performance specifications, you must ensure continuity of the screen, when daisy chaining the connections.

Two-core screened twisted pair cable should be used. It is important to avoid circulating currents, which can cause noise and interference, especially when the cable runs between buildings. For this reason, the screen should be continuous and connected to ground at one end only, normally at the master connection point.

The K-Bus signal is a differential signal and there is no signal ground connection. If a signal ground connection is present in the bus cable then it must be ignored. At no stage should this be connected to the cable's screen or to the product’s chassis. This is for both safety and noise reasons.

A typical cable specification would be:

- Each core: 16/0.2 mm^2 copper conductors, PVC insulated
- Nominal conductor area: 0.5 mm^2 per core
- Screen: Overall braid, PVC sheathed

20.4.8 IRIG-B CONNECTION

The IRIG-B input and BNC connector have a characteristic impedance of 50 ohms. We recommend that connections between the IRIG-B equipment and the product are made using coaxial cable of type RG59LSF with a halogen free, fire retardant sheath.

20.4.9 OPTO-INPUT CONNECTIONS

These should be wired with 1 mm^2 PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

Each opto-input has a selectable preset ½ cycle filter. This makes the input immune to noise induced on the wiring. This can, however slow down the response. If you need to switch off the ½ cycle filter, either use double pole switching on the input, or screened twisted cable on the input circuit.



Caution:
Protect the opto-inputs and their wiring with a maximum 16 A high rupture capacity (HRC) type NIT or TIA fuse.

20.4.10 OUTPUT RELAY CONNECTIONS

These should be wired with 1 mm PVC insulated multi-stranded copper wire terminated with M4 ring terminals.

20.4.11 ETHERNET METALLIC CONNECTIONS

If the device has a metallic Ethernet connection, it can be connected to either a 10Base-T or a 100Base-TX Ethernet hub. Due to noise sensitivity, we recommend this type of connection only for short distance connections, ideally where the products and hubs are in the same cubicle. For increased noise immunity, CAT 6 (category 6) STP (shielded twisted pair) cable and connectors can be used.

The connector for the Ethernet port is a shielded RJ-45. The pin-out is as follows:

Pin	Signal name	Signal definition
1	TXP	Transmit (positive)
2	TXN	Transmit (negative)
3	RXP	Receive (positive)
4	-	Not used
5	-	Not used
6	RXN	Receive (negative)
7	-	Not used
8	-	Not used

20.4.12 ETHERNET FIBRE CONNECTIONS

We recommend the use of fibre-optic connections for permanent connections in a substation environment. The 100 Mbps fibre optic port uses type LC connectors (one for Tx and one for Rx), compatible with 50/125 µm or 62.5/125 µm multimode fibres at 1300 nm wavelength.

20.4.13 USB CONNECTION

The IED has a type B USB socket inside the bottom compartment. A standard USB printer cable (type A one end, type B the other end) can be used to connect a local PC to the IED. This cable is the same as that used for connecting a printer to a PC.

20.4.14 GPS FIBRE CONNECTION

Some products use a GPS 1 PPS timing signal. If applicable, this is connected to a fibre-optic port on the coprocessor board in slot B. The fibre-optic port uses an ST type connector, compatible with fibre multimode 50/125 µm or 62.5/125 µm – 850 nm.

20.4.15 FIBRE COMMUNICATION CONNECTIONS

The fibre optic port consists of one or two channels using ST type connectors (one for Tx and one for Rx). The type of fibre used depends on the option selected.

850 nm and 1300 nm multimode systems use 50/125 µm or 62.5/125 µm multimode fibres. 1300 nm and 1550 nm single mode systems use 9/125 µm single mode fibres.

20.5 CASE DIMENSIONS

Not all products are available in all case sizes.

20.5.1 CASE DIMENSIONS 40TE

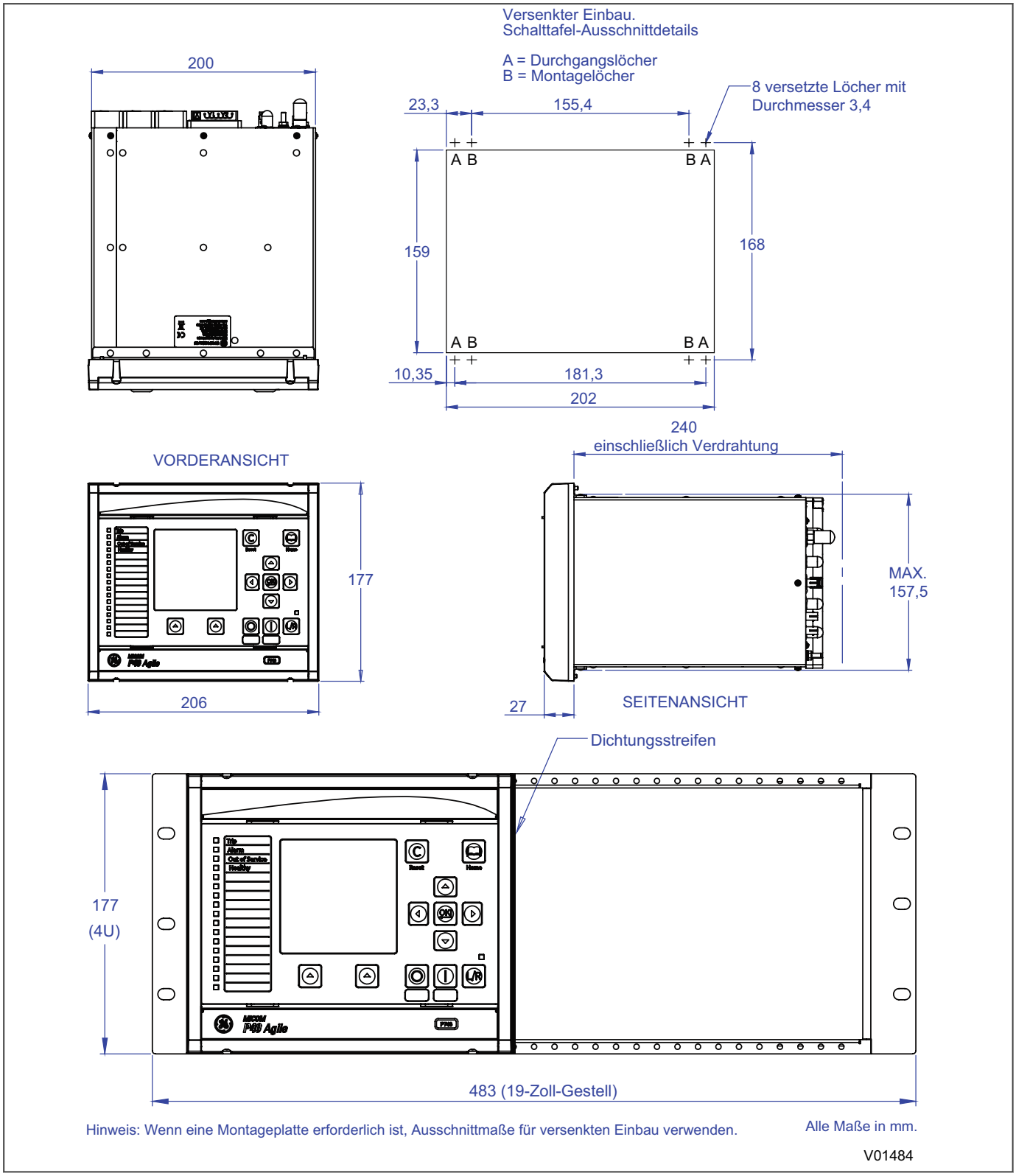


Figure 242: 40TE case dimensions

20.5.2 CASE DIMENSIONS 60TE

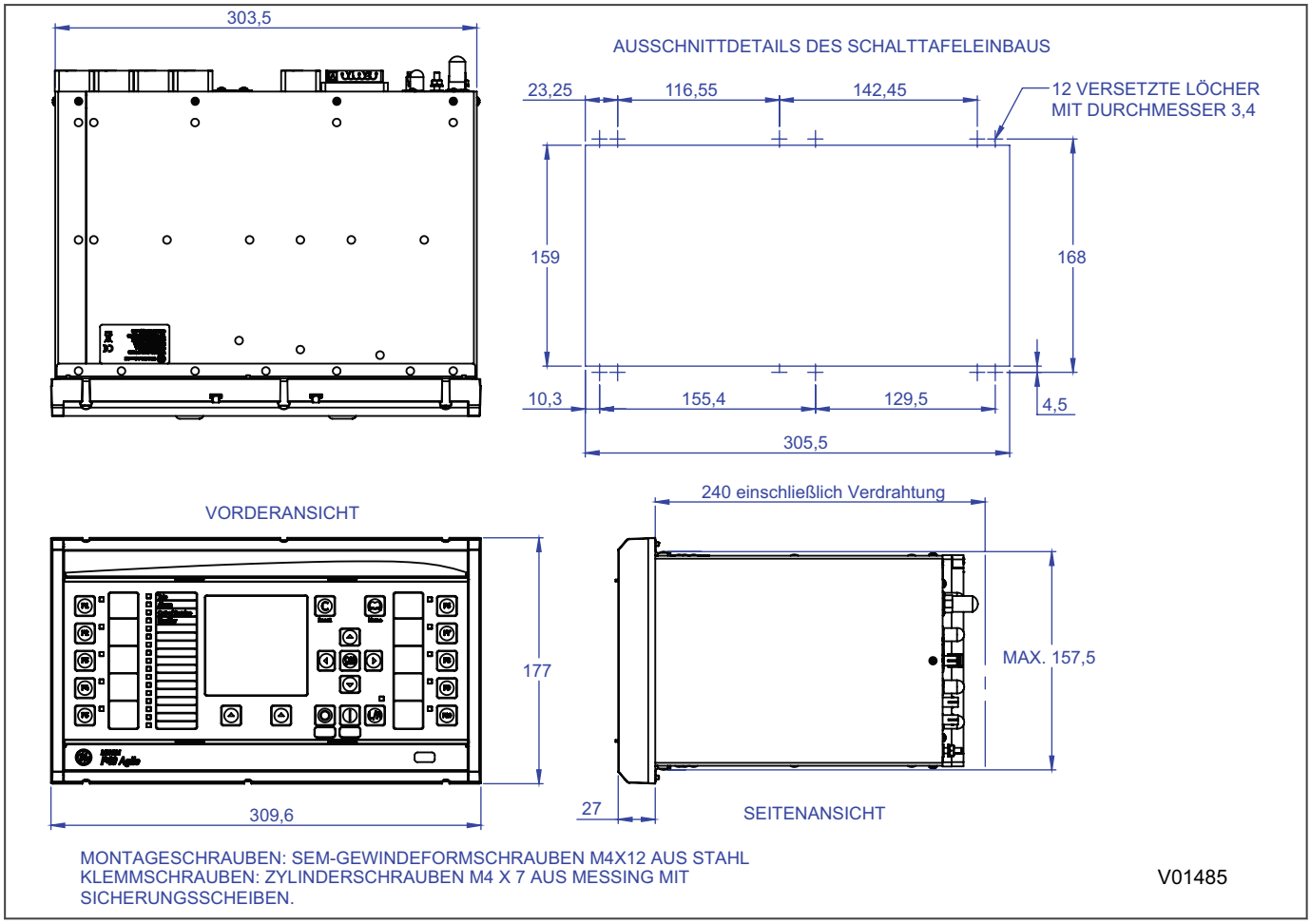


Figure 243: 60TE case dimensions

20.5.3 CASE DIMENSIONS 80TE

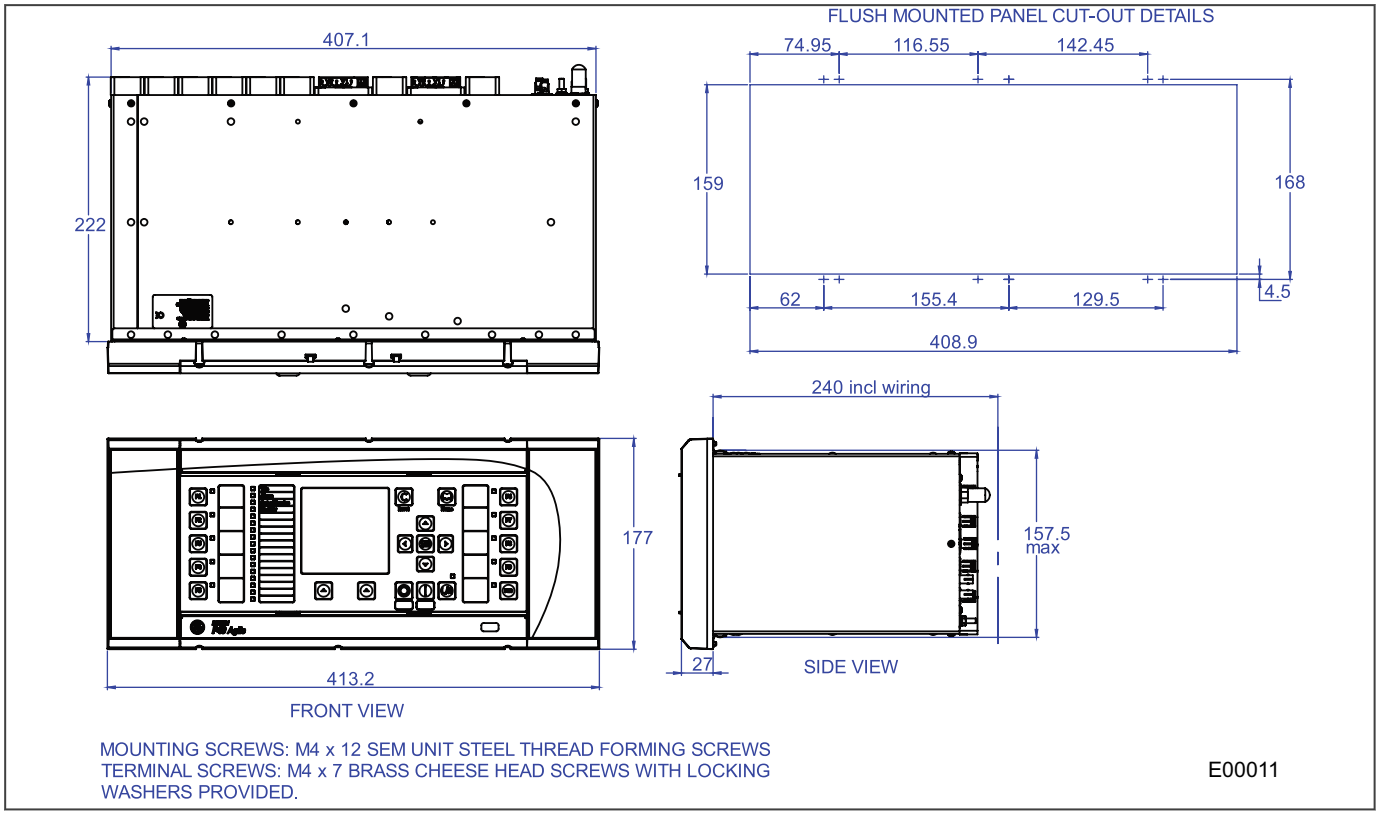


Figure 244: 80TE case dimensions

CHAPTER 21

COMMISSIONING INSTRUCTIONS

21.1 CHAPTER OVERVIEW

This chapter contains the following sections:

Chapter Overview 500
General Guidelines 501
Commissioning Test Menu 502
Commissioning Equipment 506
Product Checks 508
Electrical Intermicom Communication Loopback 517
Setting Checks 519
IEC 61850 Edition 2 Testing 521
Protection Timing Checks 526
System Check and Check Synchronism 528
Check Trip and Autoreclose Cycle 530
Onload Checks 531
Final Checks 533

21.2 GENERAL GUIDELINES

GE Vernova IEDs are self-checking devices and will raise an alarm in the unlikely event of a failure. This is why the commissioning tests are less extensive than those for non-numeric electronic devices or electro-mechanical relays.

To commission the devices, you (the commissioning engineer) do not need to test every function. You need only verify that the hardware is functioning correctly and that the application-specific software settings have been applied. You can check the settings by extracting them using the settings application software, or by means of the front panel interface (HMI panel).

The menu language is user-selectable, so you can change it for commissioning purposes if required.

Note:
Remember to restore the language setting to the customer's preferred language on completion.



Caution:
Before carrying out any work on the equipment you should be familiar with the contents of the Safety Section or Safety Guide SFTY/4LM as well as the ratings on the equipment's rating label.



Warning:
With the exception of the CT shorting contacts check, do not disassemble the device during commissioning.

21.3 COMMISSIONING TEST MENU

The IED provides several test facilities under the *COMMISSION TESTS* menu heading. There are menu cells that allow you to monitor the status of the opto-inputs, output relay contacts, internal Digital Data Bus (DDB) signals and user-programmable LEDs. This section describes these commissioning test facilities.

21.3.1 OPTO I/P STATUS CELL (OPTO-INPUT STATUS)

This cell can be used to monitor the status of the opto-inputs while they are sequentially energised with a suitable DC voltage. The cell is a binary string that displays the status of the opto-inputs where '1' means energised and '0' means de-energised. If you move the cursor along the binary numbers, the corresponding label text is displayed for each logic input.

21.3.2 RELAY O/P STATUS CELL (RELAY OUTPUT STATUS)

This cell can be used to monitor the status of the relay outputs. The cell is a binary string that displays the status of the relay outputs where '1' means energised and '0' means de-energised. If you move the cursor along the binary numbers, the corresponding label text is displayed for each relay output.

The cell indicates the status of the output relays when the IED is in service. You can check for device damage by comparing the status of the output contacts with their associated bits.

Note:
*When the **Test Mode** cell is set to `Contacts Blocked`, the relay output status indicates which contacts would operate if the IED was in-service. It does not show the actual status of the output relays, as they are blocked.*

21.3.3 TEST PORT STATUS CELL

This cell displays the status of the DDB signals that have been allocated in the ***Monitor Bit*** cells. If you move the cursor along the binary numbers, the corresponding DDB signal text string is displayed for each monitor bit.

By using this cell with suitable monitor bit settings, the state of the DDB signals can be displayed as various operating conditions or sequences are applied to the IED. This allows you to test the Programmable Scheme Logic (PSL).

21.3.4 MONITOR BIT 1 TO 8 CELLS

The eight Monitor Bit cells allows you to select eight DDB signals that can be observed in the Test Port Status cell or downloaded via the front port.

Each Monitor Bit cell can be assigned to a particular DDB signal. You set it by entering the required DDB signal number from the list of available DDB signals.

The pins of the monitor/download port used for monitor bits are as follows:

Monitor Bit	1	2	3	4	5	6	7	8
Monitor/Download Port Pin	11	12	15	13	20	21	23	24

The signal ground is available on pins 18, 19, 22 and 25.



Caution:
The monitor/download port is not electrically isolated against induced voltages on the communications channel. It should therefore only be used for local communications.

21.3.5 TEST MODE CELL

This cell allows you to perform secondary injection testing. It also lets you test the output contacts directly by applying menu-controlled test signals.

To go into test mode, select the `Test Mode` option in the ***Test Mode*** cell. This takes the IED out of service causing an alarm condition to be recorded and the ***Out of Service*** LED to illuminate. This also freezes any information stored in the *CB CONDITION* column. In IEC 60870-5-103 protocol versions, it changes the Cause of Transmission (COT) to Test Mode. In IEC 61850 protocol, it changes the quality test flag to q.test = true. See section 10.1 for further detail of IEC 61850 test mode.

In Test Mode, the output contacts are still active. To disable the output contacts you must select the `Contacts Blocked` option.

Once testing is complete, return the device back into service by setting the ***Test Mode*** Cell back to `Disabled`.



Caution:
When the cell is in Test Mode, the Scheme Logic still drives the output relays, which could result in tripping of circuit breakers. To avoid this, set the *Test Mode* cell to `Contacts Blocked`.

Note:
`Test mode` and `Contacts Blocked` mode can also be selected by energising an opto-input mapped to the Test Mode signal, and the Contact Block signal respectively.

21.3.6 TEST PATTERN CELL

The ***Test Pattern*** cell is used to select the output relay contacts to be tested when the ***Contact Test*** cell is set to `Apply Test`. The cell has a binary string with one bit for each user-configurable output contact, which can be set to '1' to operate the output and '0' to not operate it.

21.3.7 CONTACT TEST CELL

When the `Apply Test` command in this cell is issued, the contacts set for operation change state. Once the test has been applied, the command text on the LCD will change to ***No Operation*** and the contacts will remain in the Test state until reset by issuing the `Remove Test` command. The command text on the LCD will show ***No Operation*** after the `Remove Test` command has been issued.

Note:
*When the **Test Mode** cell is set to `Contacts Blocked` the **Relay O/P Status** cell does not show the current status of the output relays and therefore cannot be used to confirm operation of the output relays. Therefore it will be necessary to monitor the state of each contact in turn.*

21.3.8 TEST LEDS CELL

When the `Apply Test` command in this cell is issued, the user-programmable LEDs illuminate for approximately 2 seconds before switching off, and the command text on the LCD reverts to ***No Operation***.

21.3.9 TEST AUTORECLOSE CELL

Where the IED provides an auto-reclose function, this cell will be available for testing the sequence of circuit breaker trip and auto-reclose cycles.

The *Trip 3 Pole* option in the ***Test Autoreclose*** cell causes the device to perform the first three phase trip/ reclose cycle so that associated output contacts can be checked for operation at the correct times during the cycle. Once the trip output has operated the command text will revert to *No Operation* whilst the rest of the auto-reclose cycle is performed. To test subsequent three-phase autoreclose cycles, you repeat the *Trip 3 Pole* command. You can also test the single phases with *Trip Pole A*, *Trip Pole B* and *Trip Pole C*.

Note:
The default settings for the programmable scheme logic has the AR Trip Test signals mapped to the Trip Input signals. If the programmable scheme logic has been changed, it is essential that these signals retain this mapping for the Test Autoreclose facility to work.

21.3.10 STATIC TEST MODE

Static Test Mode can be set to *Enabled* or *Disabled*. When the Static Test mode is enabled it allows injection test that don't support dynamic switching to be used to commission and test the device.

Dynamic secondary injection test sets are able to accurately mimic real power system faults. The test sets mimic an instantaneous fault “shot”, with the real rate of rise of current, and the decaying DC exponential component. Dynamic injection test sets are available, which cater for all three phases, providing a six signal set of analogue inputs: Va, Vb, Vc, Ia, Ib, Ic. Such injection test sets can be used with the device, with no special testing limitations.

Static test sets, also known as Static Simulators, may not properly provide or simulate:

- A healthy pre-fault voltage
- A real fault shot (instead a gradually varying current or voltage would be used)
- The rate of rise of current and DC components
- A complete set of three-phase analogue inputs
- Real dynamic step changes in current and voltage.

Some of the protection in this product is based on delta techniques which recognise step changes in actual power system quantities. Because these may not be produced by static test sets,, certain functions are can be disabled or bypassed to allow injection testing with static test sets. Enabling the ***Static Test Mode*** option does this..

For the tests, the delta directional line is replaced by a conventional distance directional line. Extra filtering of distance comparators is used so the filtering slows to use a fixed one cycle window. Memory polarising is replaced by cross-polarising from unfaulted phases.

Note:
Trip times may be up to ½ cycle longer when tested in the static mode, due to the nature of the test voltage and current, and the slower filtering. This is normal, and perfectly acceptable.

21.3.11 LOOPBACK MODE

Loopback Mode can be used to test InterMiCOM^{64} signalling.

Note:
If the cell is set to Internal, only the IED software is checked. If the cell is set to External, both the software and hardware are checked.

When the device is switched into Loopback Mode, it automatically uses generic addresses 0-0. It responds as if it is connected to a remote device. The sent and received IM^{64} signals continue to be routed to and from the signals defined in the programmable logic.

Note:
Loopback mode can also be selected by energising an opto-input mapped to the Loopback signal.

21.3.12 IM64 TEST PATTERN

This cell is used with the ***IM64 Test Mode*** cell to set a 16-bit pattern (8 bits per channel), which is transmitted whenever the ***IM64 Test Mode*** cell is set to `Enabled`. The ***IM64 TestPattern*** cell has a binary string with one bit for each user-defined Inter-MiCOM command. These can be set to '1' to operate the IM64 output under test conditions and '0' for no operation.

21.3.13 IM64 TEST MODE

When the `Enable` command in this cell is issued, the InterMiCOM^{64} commands change to reflect the state of the values set in the ***IM64 TestPattern*** cell. If the cell is set to Disabled, the InterMiCOM^{64} commands reflect the state of the signals generated by the protection and control functions.

21.3.14 RED AND GREEN LED STATUS CELLS

These cells contain binary strings that indicate which of the user-programmable red and green LEDs are illuminated when accessing from a remote location. A '1' indicates that a particular LED is illuminated.

Note:
*When the status in both **Red LED Status** and **Green LED Status** cells is '1', this indicates the LEDs illumination is yellow.*

21.4 COMMISSIONING EQUIPMENT

Specialist test equipment is required to commission this product. We recognise three classes of equipment for commissioning :

- Recommended
- Essential
- Advisory

Recommended equipment constitutes equipment that is both necessary, and sufficient, to verify correct performance of the principal protection functions.

Essential equipment represents the minimum necessary to check that the product includes the basic expected protection functions and that they operate within limits.

Advisory equipment represents equipment that is needed to verify satisfactory operation of features that may be unused, or supplementary, or which may, for example, be integral to a distributed control/automation scheme. Operation of such features may, perhaps, be more appropriately verified as part of a customer defined commissioning requirement, or as part of a system-level commissioning regime.

21.4.1 RECOMMENDED COMMISSIONING EQUIPMENT

The minimum recommended equipment is a multifunctional three-phase AC current and voltage injection test set featuring :

- Controlled three-phase AC current and voltage sources,
- Transient (dynamic) switching between pre-fault and post-fault conditions (to generate delta conditions),
- Dynamic impedance state sequencer (capable of sequencing through 4 impedance states),
- Integrated or separate variable DC supply (0 - 250 V)
- Integrated or separate AC and DC measurement capabilities (0-440V AC, 0-250V DC)
- Integrated and/or separate timer,
- Integrated and/or separate test switches.

In addition, you will need :

- A portable computer, installed with appropriate software to liaise with the equipment under test (EUT). Typically this software will be proprietary to the product's manufacturer (for example MiCOM S1 Agile).
- Suitable electrical test leads.
- Electronic or brushless insulation tester with a DC output not exceeding 500 V
- Continuity tester
- Verified application-specific settings files

21.4.2 ESSENTIAL COMMISSIONING EQUIPMENT

As an absolute minimum, the following equipment is required:

- AC current source coupled with AC voltage source
- Variable DC supply (0 - 250V)
- Multimeter capable of measuring AC and DC current and voltage (0-440V AC, 0-250V DC)
- Timer
- Test switches
- Suitable electrical test leads
- Continuity tester

21.4.3 ADVISORY TEST EQUIPMENT

Advisory test equipment may be required for extended commissioning procedures:

- Current clamp meter
- Multi-finger test plug:
  - P992 for test block type P991
  - MMLB for test block type MMLG blocks
- Electronic or brushless insulation tester with a DC output not exceeding 500 V
- KITZ K-Bus - EIA(RS)232 protocol converter for testing EIA(RS)485 K-Bus port
- EIA(RS)485 to EIA(RS)232 converter for testing EIA(RS)485 Courier/IEC60870-5-103/DNP3 port
- A portable printer (for printing a setting record from the portable PC) and or writeable, detachable memory device
- Phase angle meter
- Phase rotation meter
- Fibre-optic power meter.
- Fibre optic test leads (minimum 2). 10m minimum length, multimode 50/125 µm or 62.5µm terminated with BFOC (ST) 2.5 connectors for testing the fibre-optic RP1 port.

21.5 PRODUCT CHECKS

These product checks are designed to ensure that the device has not been physically damaged prior to commissioning, is functioning correctly and that all input quantity measurements are within the stated tolerances.

If the application-specific settings have been applied to the IED prior to commissioning, you should make a copy of the settings. This will allow you to restore them at a later date if necessary. This can be done by:

- Obtaining a setting file from the customer.
- Extracting the settings from the IED itself, using a portable PC with appropriate setting software.

If the customer has changed the password that prevents unauthorised changes to some of the settings, either the revised password should be provided, or the original password restored before testing.

Note:
If the password has been lost, a recovery password can be obtained from GE Vernova.

21.5.1 PRODUCT CHECKS WITH THE IED DE-ENERGISED



Warning:
The following group of tests should be carried out without the auxiliary supply being applied to the IED and, if applicable, with the trip circuit isolated.

The current and voltage transformer connections must be isolated from the IED for these checks. If a P991 test block is provided, the required isolation can be achieved by inserting test plug type P992. This open circuits all wiring routed through the test block.

Before inserting the test plug, you should check the scheme diagram to ensure that this will not cause damage or a safety hazard (the test block may, for example, be associated with protection current transformer circuits). The sockets in the test plug, which correspond to the current transformer secondary windings, must be linked before the test plug is inserted into the test block.



Warning:
Never open-circuit the secondary circuit of a current transformer since the high voltage produced may be lethal and could damage insulation.

If a test block is not provided, the voltage transformer supply to the IED should be isolated by means of the panel links or connecting blocks. The line current transformers should be short-circuited and disconnected from the IED terminals. Where means of isolating the auxiliary supply and trip circuit (for example isolation links, fuses and MCB) are provided, these should be used. If this is not possible, the wiring to these circuits must be disconnected and the exposed ends suitably terminated to prevent them from being a safety hazard.

21.5.1.1 VISUAL INSPECTION



Warning:
Check the rating information under the top access cover on the front of the IED.



Warning:
Check that the IED being tested is correct for the line or circuit.



Warning:
Record the circuit reference and system details.



Warning:
Check the CT secondary current rating and record the CT tap which is in use.

Carefully examine the IED to see that no physical damage has occurred since installation.

Ensure that the case earthing connections (bottom left-hand corner at the rear of the IED case) are used to connect the IED to a local earth bar using an adequate conductor.

21.5.1.2 CURRENT TRANSFORMER SHORTING CONTACTS

Check the current transformer shorting contacts to ensure that they close when the heavy-duty terminal block is disconnected from the current input board.

The heavy-duty terminal blocks are fastened to the rear panel using four crosshead screws. These are located two at the top and two at the bottom.

Note:
Use a magnetic bladed screwdriver to minimise the risk of the screws being left in the terminal block or lost.

Pull the terminal block away from the rear of the case and check with a continuity tester that all the shorting switches being used are closed.

21.5.1.3 INSULATION

Insulation resistance tests are only necessary during commissioning if explicitly requested.

Isolate all wiring from the earth and test the insulation with an electronic or brushless insulation tester at a DC voltage not exceeding 500 V. Terminals of the same circuits should be temporarily connected together.

The insulation resistance should be greater than 100 MΩ at 500 V.

On completion of the insulation resistance tests, ensure all external wiring is correctly reconnected to the IED.

21.5.1.4 EXTERNAL WIRING



Caution:
Check that the external wiring is correct according to the relevant IED and scheme diagrams. Ensure that phasing/phase rotation appears to be as expected.

21.5.1.5 WATCHDOG CONTACTS

Using a continuity tester, check that the Watchdog contacts are in the following states:

Terminals	Contact State with Product De-energised
11 - 12 on power supply board	Closed
13 - 14 on power supply board	Open

21.5.1.6 POWER SUPPLY

Depending on its nominal supply rating, the IED can be operated from either a DC only or an AC/DC auxiliary supply. The incoming voltage must be within the operating range specified below.

Without energising the IED measure the auxiliary supply to ensure it is within the operating range.

Nominal supply rating DC	Nominal Supply Rating AC RMS	DC Operating Range	AC Operating Range
24 - 54 V	N/A	19 to 65 V	N/A
48 - 125 V	30 - 100 V	37 to 150 V	24 - 110 V
110 - 250 V	100 - 240 V	87 to 300 V	80 to 265 V

Note:
The IED can withstand an AC ripple of up to 15% of the upper rated voltage on the DC auxiliary supply.



Warning:
Do not energise the IED or interface unit using the battery charger with the battery disconnected as this can irreparably damage the power supply circuitry.



Caution:
Energise the IED only if the auxiliary supply is within the specified operating ranges. If a test block is provided, it may be necessary to link across the front of the test plug to connect the auxiliary supply to the IED.

21.5.2 PXXX_CI_PRODUCTCHECKSENERGISED



Warning:
The current and voltage transformer connections must remain isolated from the IED for these checks. The trip circuit should also remain isolated to prevent accidental operation of the associated circuit breaker.

The following group of tests verifies that the IED hardware and software is functioning correctly and should be carried out with the supply applied to the IED.

21.5.2.1 WATCHDOG CONTACTS

Using a continuity tester, check that the Watchdog contacts are in the following states when energised and healthy.

Terminals	Contact State with Product Energised
11 - 12 on power supply board	Open
13 - 14 on power supply board	Closed

21.5.2.2 TEST GRAPHICAL HMI

The Graphical HMI is designed to operate in a wide range of substation ambient temperatures. For this purpose, the IEDs have an ***LCD Brightness*** setting. The brightness is factory pre-set, but it may be necessary to adjust the contrast to give the best in-service display.

To change the contrast, you can increment or decrement the ***LCD Brightness*** cell in the *CONFIGURATION* column.



Caution:
Before applying a brightness setting, make sure that it will not make the display so light or dark that the menu text becomes unreadable. It is possible to restore the visibility of a display by downloading a setting file, and setting the LCD Brightness within the typical range of 7 - 11.

21.5.2.3 DATE AND TIME

The date and time is stored in memory, which is backed up by a supercapacitor.

The method for setting the date and time depends on whether an IRIG-B signal is being used or not. The IRIG-B signal will override the time, day and month settings, but not the initial year setting. For this reason, you must ensure you set the correct year, even if the device is using IRIG-B to maintain the internal clock.

You set the Date and Time by one of the following methods:

- Using the front panel to set the ***Date and Time*** cells respectively
- By sending a courier command to the ***Date/Time*** cell (Courier reference 0801)

Note:
If the auxiliary supply fails, the time and date will be maintained by the supercapacitor. Therefore, when the auxiliary supply is restored, you should not have to set the time and date again. To test this, remove the IRIG-B signal, and then remove the auxiliary supply. Leave the device de-energised for approximately 30 seconds. On re energisation, the time should be correct.

When using IRIG-B to maintain the clock, the IED must first be connected to the satellite clock equipment (usually an RT430), which should be energised and functioning.

1. Set the IRIG-B Sync cell in the *DATE AND TIME* column to `Enabled`.
2. Ensure the IED is receiving the IRIG-B signal by checking that cell IRIG-B Status reads `Active`.
3. Once the IRIG-B signal is active, adjust the time offset of the universal co coordinated time (satellite clock time) on the satellite clock equipment so that local time is displayed.
4. Check that the time, date and month are correct in the Date/Time cell. The IRIG-B signal does not contain the current year so it will need to be set manually in this cell.
5. Reconnect the IRIG-B signal.

If the time and date is not being maintained by an IRIG-B signal, ensure that the IRIG-B Sync cell in the *DATE AND TIME* column is set to `Disabled`.

1. Set the date and time to the correct local time and date using Date/Time cell or using the serial protocol.

21.5.2.4 TEST LEDS

On power-up, all LEDs should first flash yellow. Following this, the green "Healthy" LED should illuminate indicating that the device is healthy.

The IED's non-volatile memory stores the states of the alarm, the trip, and the user-programmable LED indicators (if configured to latch). These indicators may also illuminate when the auxiliary supply is applied.

If any of these LEDs are ON then they should be reset before proceeding with further testing. If the LEDs successfully reset (the LED goes off), no testing is needed for that LED because it is obviously operational.

21.5.2.5 TEST ALARM AND OUT-OF-SERVICE LEDS

The alarm and out of service LEDs can be tested using the *COMMISSION TESTS* menu column.

1. Set the ***Test Mode*** cell to `Contacts Blocked`.
2. Check that the out of service LED illuminates continuously and the alarm LED flashes.

It is not necessary to return the ***Test Mode*** cell to `Disabled` at this stage because the test mode will be required for later tests.

21.5.2.6 TEST TRIP LED

The trip LED can be tested by initiating a manual circuit breaker trip. However, the trip LED will operate during the setting checks performed later. Therefore no further testing of the trip LED is required at this stage.

21.5.2.7 TEST USER-PROGRAMMABLE LEDS

To test these LEDs, set the Test LEDs cell to `Apply Test`. Check that all user-programmable LEDs illuminate.

21.5.2.8 TEST FIELD VOLTAGE SUPPLY

The IED generates a field voltage of nominally 48 V that can be used to energise the opto-inputs (alternatively the substation battery may be used).

1. Measure the field voltage across the terminals 7 and 9 of the power supply terminal block
2. Check that the field voltage is within the range 40 V to 60 V when no load is connected and that the polarity is correct.
3. Repeat for terminals 8 and 10.

21.5.2.9 TEST OPTO-INPUTS

This test checks that all the opto-inputs on the IED are functioning correctly.

The opto-inputs should be energised one at a time. For terminal numbers, please see the external connection diagrams in the "Wiring Diagrams" chapter. Ensuring correct polarity, connect the supply voltage to the appropriate terminals for the input being tested.

The status of each opto-input can be viewed using either the ***Opto I/P Status*** cell in the *SYSTEM DATA* column, or the ***Opto I/P Status*** cell in the *COMMISSION TESTS* column.

A '1' indicates an energised input and a '0' indicates a de-energised input. When each opto-input is energised, one of the characters on the bottom line of the display changes to indicate the new state of the input.

21.5.2.10 TEST OUTPUT RELAYS

This test checks that all the output relays are functioning correctly.

1. Ensure that the IED is still in test mode by viewing the ***Test Mode*** cell in the *COMMISSION TESTS* column. Ensure that it is set to `Contacts Blocked`.
2. The output relays should be energised one at a time. To select output relay 1 for testing, set the Test Pattern cell as appropriate.
3. Connect a continuity tester across the terminals corresponding to output relay 1 as shown in the external connection diagram.
4. To operate the output relay set the Contact Test cell to `Apply Test`.
5. Check the operation with the continuity tester.
6. Measure the resistance of the contacts in the closed state.

7. Reset the output relay by setting the Contact Test cell to `Remove Test`.
8. Repeat the test for the remaining output relays.
9. Return the IED to service by setting the Test Mode cell in the *COMMISSION TESTS* menu to `Disabled`.

21.5.2.11 TEST SERIAL COMMUNICATION PORT RP1

You need only perform this test if the IED is to be accessed from a remote location with a permanent serial connection to the communications port. The scope of this test does not extend to verifying operation with connected equipment beyond any supplied protocol converter. It verifies operation of the rear communication port (and if applicable the protocol converter) and varies according to the protocol fitted.

21.5.2.11.1 CHECK PHYSICAL CONNECTIVITY

The rear communication port RP1 is presented on terminals 16, 17 and 18 of the power supply terminal block. Screened twisted pair cable is used to make a connection to the port. The cable screen should be connected to pin 16 and pins 17 and 18 are for the communication signal:

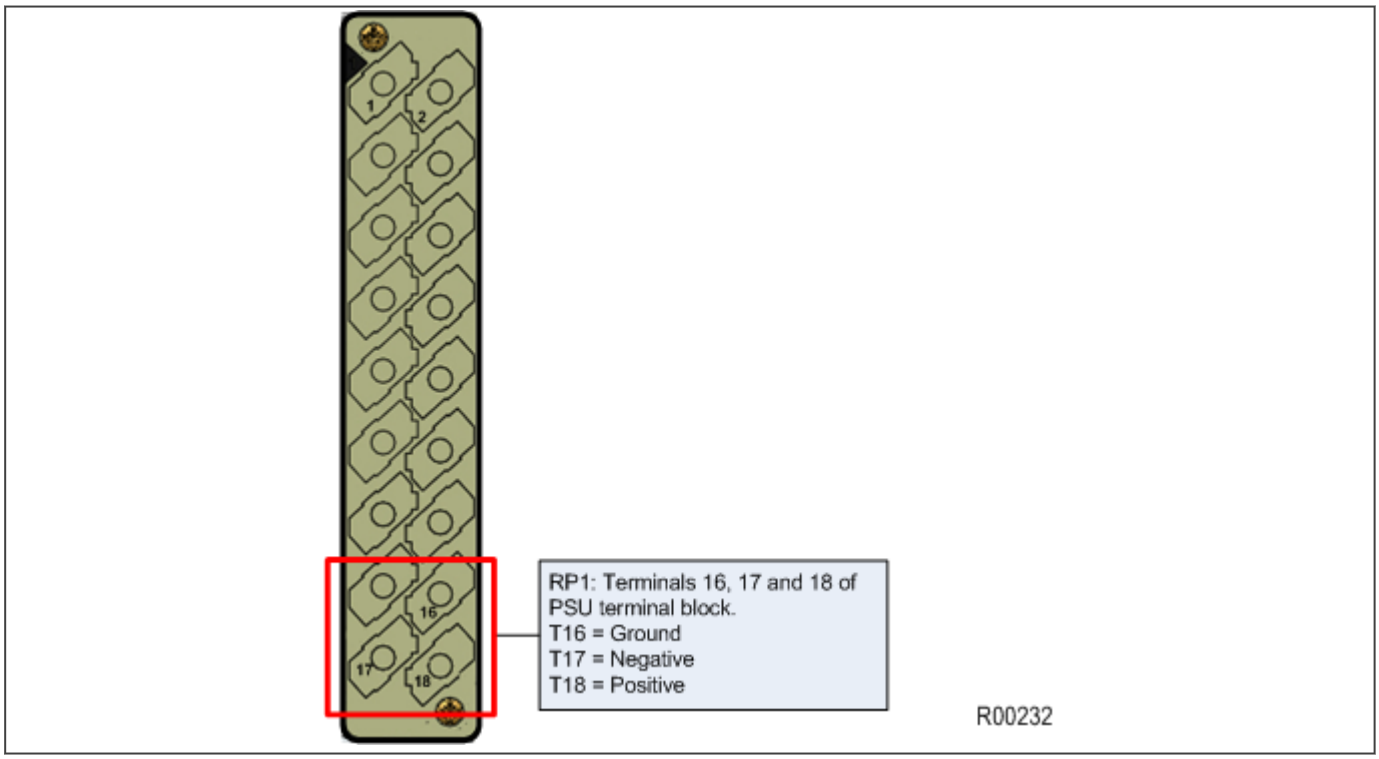


Figure 245: RP1 physical connection

For K-Bus applications, pins 17 and 18 are not polarity sensitive and it does not matter which way round the wires are connected. EIA(RS)485 is polarity sensitive, so you must ensure the wires are connected the correct way round (pin 18 is positive, pin 17 is negative).

If K-Bus is being used, a Kitz protocol converter (KITZ101, KITZ102 OR KITZ201) will have been installed to convert the K-Bus signals into RS232. Likewise, if RS485 is being used, an RS485-RS232 converter will have been installed. In the case where a protocol converter is being used, a laptop PC running appropriate software (such as MiCOM S1 Agile) can be connected to the incoming side of the protocol converter. An example for K-bus to RS232 conversion is shown below. RS485 to RS232 would follow the same principle, only using a RS485-RS232 converter. Most modern laptops have USB ports, so it is likely you will also require a RS232 to USB converter too.

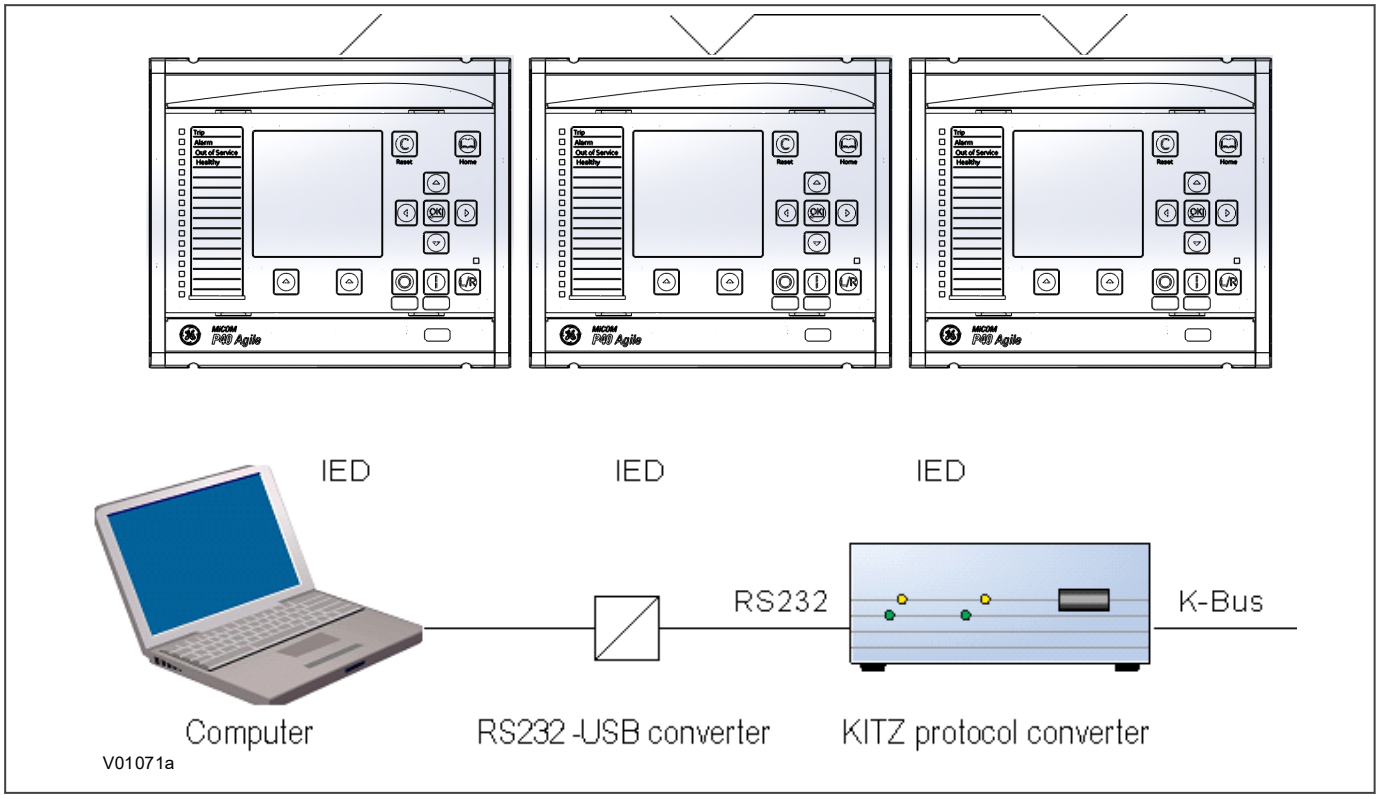


Figure 246: Remote communication using K-bus

Fibre Connection

Some models have an optional fibre optic communications port fitted (on a separate communications board). The communications port to be used is selected by setting the Physical Link cell in the *COMMUNICATIONS* column, the values being `Copper` or `K-Bus` for the RS485/K-bus port and `Fibre Optic` for the fibre optic port.

21.5.2.11.2 CHECK LOGICAL CONNECTIVITY

The logical connectivity depends on the chosen data protocol, but the principles of testing remain the same for all protocol variants:

1. Ensure that the communications baud rate and parity settings in the application software are set the same as those on the protocol converter.
2. For Courier models, ensure that you have set the correct RP1 address
3. Check that communications can be established with this IED using the portable PC/Master Station.

21.5.2.12 TEST SERIAL COMMUNICATION PORT RP2

RP2 is an optional second serial port board providing additional serial connectivity. It provides two 9-pin D-type serial port connectors SK4 and SK5. Both ports are configured as DTE (Date Terminal Equipment) ports. That means they can be connected to communications equipment such as a modem with a straight-through cable.

SK4 can be configured as an EIA(RS232), EIA(RS485), or K-Bus connection for Courier protocol only, whilst SK5 is fixed to EIA(RS)232 for InterMiCOM signalling only.

It is not the intention of this test to verify the operation of the complete communication link between the IED and the remote location, just the IED's rear communication port and, if applicable, the protocol converter.

The only checks that need to be made are as follows:

1. Set the ***RP2 Port Config*** cell in the *COMMUNICATIONS* column to the required physical protocol; (K-Bus, EIA(RS)485, or EIA(RS)232.
2. Set the IED's Courier address to the correct value (it must be between 1 and 254).

21.5.2.13 TEST ETHERNET COMMUNICATION

For products that employ Ethernet communications, we recommend that testing be limited to a visual check that the correct ports are fitted and that there is no sign of physical damage.

If there is no board fitted or the board is faulty, a NIC link alarm will be raised (providing this option has been set in the ***NIC Link Report*** cell in the *COMMUNICATIONS* column).

21.5.3 SECONDARY INJECTION TESTS

Secondary injection testing is carried out to verify the integrity of the VT and CT readings. All devices leave the factory set for operation at a system frequency of 50 Hz. If operation at 60 Hz is required, you must set this in the Frequency cell in the *SYSTEM DATA* column.

The PMU must be installed and connected to a 1pps fibre optic synchronising signal and a demodulated IRIG-B signal, provided by a device such as a REASON RT430.

Connect the current and voltage outputs of the test set to the appropriate terminals of the first voltage and current channel and apply nominal voltage and current with the current lagging the voltage by 90 degrees.

21.5.3.1 TEST CURRENT INPUTS

This test verifies that the current measurement inputs are configured correctly.

1. Using secondary injection test equipment such as an Omicron, apply and measure nominal rated current to each CT in turn.
2. Check its magnitude using a multi-meter or test set readout. Check this value against the value displayed on the HMI panel (usually in *MEASUREMENTS 1* column).
3. Record the displayed value. The measured current values will either be in primary or secondary Amperes. If the Local Values cell in the *MEASURE'T SETUP* column is set to `Primary`, the values displayed should be equal to the applied current multiplied by the corresponding current transformer ratio (set in the *CT AND VT RATIOS* column). If the Local Values cell is set to Secondary, the value displayed should be equal to the applied current.

> *Note:*
> *If a PC connected to the IED using the rear communications port is being used to display the measured current, the process will be similar. However, the setting of the Remote Values cell in the MEASURE'T SETUP column will determine whether the displayed values are in primary or secondary Amperes.*

The measurement accuracy of the IED is +/- 1%. However, an additional allowance must be made for the accuracy of the test equipment being used.

21.5.3.2 TEST VOLTAGE INPUTS

This test verifies that the voltage measurement inputs are configured correctly.

1. Using secondary injection test equipment, apply and measure the rated voltage to each voltage transformer input in turn.
2. Check its magnitude using a multimeter or test set readout. Check this value against the value displayed on the HMI panel (usually in *MEASUREMENTS 1* column).
3. Record the value displayed. The measured voltage values will either be in primary or secondary Volts. If the Local Values cell in the *MEASURE'T SETUP* column is set to `Primary`, the values displayed should be

equal to the applied voltage multiplied by the corresponding voltage transformer ratio (set in the *CT AND VT RATIOS* column). If the Local Values cell is set to Secondary, the value displayed should be equal to the applied voltage.

Note:
If a PC connected to the IED using the rear communications port is being used to display the measured current, the process will be similar. However, the setting of the Remote Values cell in the MEASURE'T SETUP column will determine whether the displayed values are in primary or secondary Amperes.

The measurement accuracy of the IED is +/- 1%. However, an additional allowance must be made for the accuracy of the test equipment being used.

21.6 ELECTRICAL INTERMICOM COMMUNICATION LOOPBACK

If the IED is used in a scheme with standard InterMiCOM communication (Electrical Teleprotection), you need to configure a loopback for testing purposes.

21.6.1 SETTING UP THE LOOPBACK

The communication path may include various connectors and signal converters before leaving the substation. We therefore advise making the loopback as close as possible to where the communication link leaves the substation. This way, as much of the wiring as possible and all associated communication signal converters are included in the test.

1. Set *CONFIGURATION* > ***InterMiCOM*** to `Enabled`.
2. Set *INTERMICOM COMMS* > ***Ch Statistics*** and ***Ch Diagnostics*** to `Visible`.
3. Check that *INTERMICOM COMMS* > ***IM H/W Status*** displays OK. This means the InterMiCOM hardware is fitted and initialised.

21.6.2 LOOPBACK TEST

INTERMICOM COMMS > ***Loopback Mode*** allows you to test the InterMiCOM channel. In normal service it must be disabled. *INTERMICOM COMMS* > ***Loopback Status*** shows the status of the InterMiCOM loopback mode.

Note:
If INTERMICOM COMMS > ***Loopback Mode*** *is set to* `Internal`*, only the internal software of the device is checked. This is useful for testing functionality if no communications connections are made. Use the 'External' setting during commissioning because it checks both the software and hardware. When the IED is switched into either Internal or External Loopback Mode it automatically inhibits InterMiCOM messages to the PSL by setting all eight InterMiCOM message command states to zero.*

Set *INTERMICOM COMMS* > ***Loopback Mode*** to `External` and form a communications loopback by connecting the transmit signal (pin 2) to the receive signal (pin 3).

Note:
The DCD signal must be held high (by connecting pin 1 to pin 4) if the connected equipment does not support DCD.

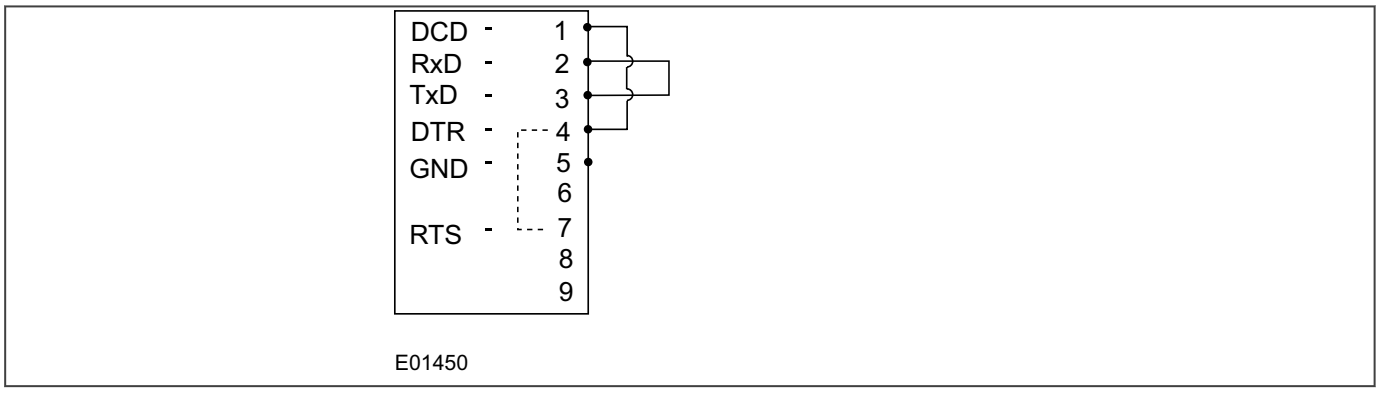


Figure 247: InterMicom loopback testing

The loopback mode is shown on the front panel by an Alarm LED and the message IM Loopback on the LCD.

Check that all connections are correct and the software is working correctly.

Check that *INTERMICOM COMMS* > ***Loopback Status*** shows OK.

21.6.2.1 INTERMICOM COMMAND BITS

To test the InterMiCOM command bits, go to the *INTERMICOM COMMS* column and do the following:

1. Enter any test pattern in the ***Test Pattern*** cell in the by scrolling through and changing selected bits between 1 and 0. The entered pattern is transmitted through the loopback.
2. Check that the ***IM Output Status*** cell matches the applied Test Pattern.
3. Check that all 8 bits in the ***IM Input Status*** cell are zero.

21.6.2.2 INTERMICOM CHANNEL DIAGNOSTICS

Check that the following cells in the *INTERMICOM COMMS* column all read **OK**.

- ***Data CD Status***
- ***FrameSync Status***
- ***Message Status***
- ***Channel Status***

21.6.2.3 SIMULATING A CHANNEL FAILURE

1. Simulate a failure of the communications link by breaking a connection and checking that some of these cells show **Fail**.
2. Restore the communications loopback and ensure that the four diagnostic cells display **OK.**

> *Note:*
> *Some or all of these cells show **Fail** depending on the communications configuration and the way the link has failed.*

21.7 SETTING CHECKS

The setting checks ensure that all of the application-specific settings (both the IED's function and Programmable Scheme Logic settings) have been correctly applied.

> *Note:*
> *If applicable, the trip circuit should remain isolated during these checks to prevent accidental operation of the associated circuit breaker.*

21.7.1 APPLY APPLICATION-SPECIFIC SETTINGS

There are two different methods of applying the settings to the IED

- Transferring settings to the IED from a pre-prepared setting file using MiCOM S1 Agile
- Enter the settings manually using the IED's front panel HMI

21.7.1.1 TRANSFERRING SETTINGS FROM A SETTINGS FILE

This is the preferred method for transferring function settings. It is much faster and there is a lower margin for error.

1. Connect a PC running the Settings Application Software to the IED's front port, or a rear Ethernet port. Alternatively connect to the rear Courier communications port, using a KITZ protocol converter if necessary.
2. Power on the IED
3. Enter the IP address of the device if it is Ethernet enabled
4. Right-click the appropriate device name in the System Explorer pane and select **Send**
5. In the **Send to** dialog select the setting files and click **Send**

> *Note:*
> *The device name may not already exist in the system shown in **System Explorer**. In this case, perform a **Quick Connect** to the IED, then manually add the settings file to the device name in the system. Refer to the Settings Application Software help for details of how to do this.*

21.7.1.2 ENTERING SETTINGS USING THE HMI

1. Starting at the default display, press the Down cursor key to show the first column heading.
2. Use the horizontal cursor keys to select the required column heading.
3. Use the vertical cursor keys to view the setting data in the column.
4. To return to the column header, either press the Up cursor key for a second or so, or press the **Cancel** key once. It is only possible to move across columns at the column heading level.
5. To return to the default display, press the Up cursor key or the Cancel key from any of the column headings. If you use the auto-repeat function of the Up cursor key, you cannot go straight to the default display from one of the column cells because the auto-repeat stops at the column heading.
6. To change the value of a setting, go to the relevant cell in the menu, then press the **Enter** key to change the cell value. A flashing cursor on the LCD shows that the value can be changed. You may be prompted for a password first.
7. To change the setting value, press the vertical cursor keys. If the setting to be changed is a binary value or a text string, select the required bit or character to be changed using the left and right cursor keys.

8. Press the **Enter** key to confirm the new setting value or the **Clear** key to discard it. The new setting is automatically discarded if it is not confirmed within 15 seconds.
9. For protection group settings and disturbance recorder settings, the changes must be confirmed before they are used. When all required changes have been entered, return to the column heading level and press the down cursor key. Before returning to the default display, the following prompt appears.

```
Update settings?
ENTER or CLEAR
```

10. Press the **Enter** key to accept the new settings or press the **Clear** key to discard the new settings.

Note:
If the menu time-out occurs before the setting changes have been confirmed, the setting values are also discarded.
Control and support settings are updated immediately after they are entered, without the Update settings prompt.
It is not possible to change the PSL using the IED's front panel HMI.



Caution:
Where the installation needs application-specific PSL, the relevant .psl files, must be transferred to the IED, for each and every setting group that will be used. If you do not do this, the factory default PSL will still be resident. This may have severe operational and safety consequences.

21.8 IEC 61850 EDITION 2 TESTING

21.8.1 USING IEC 61850 EDITION 2 TEST MODES

In a conventional substation, functionality typically resides in a single device. It is usually easy to physically isolate these functions, as the hardwired connects can simply be removed. Within a digital substation architecture however, functions may be distributed across many devices. This makes isolation of these functions difficult, because there are no physical wires that can be disconnected on an Ethernet network. Logical isolation of the various functions is therefore necessary.

With IEDs that support IEC 61850 Edition 2, it is possible to use a test mode to conduct online testing. The advantages of this are as follows:

- The IED can be placed into test mode, to allow testing the IED using test input signals, and with all protection functions and output contacts active.
- The IED can be placed into test/blocked mode, to allow testing the IED using test input signals, and with all protection functions active but output contacts disabled.
- GOOSE message outputs are tagged so that receiving devices can recognise they are test signals.
- An IED receiving simulated GOOSE or Sampled Value messages from test devices can differentiate these from normal process messages, and respond appropriately.

21.8.1.1 IED TEST MODE BEHAVIOUR

IEC 61850 Edition 2 defines how the IED responds to test messages in the IED test modes, and whether the relay output contacts are activated or not.

You can select the mode of operation of the P40 IED by:

- Using the front panel HMI, with the setting ***IED Test Mode*** under the *COMMISSION TESTS* column.
- Using an IEC 61850 MMS control service to ***System/LLN0.Mod***
- Using an opto-input via PSL with the signal ***Block Contacts***

The following table summarises the P40 IED behaviour under the different modes:

IED Test Mode Setting	IEC 61850 Mod	Result
Disabled	on	• Normal IED behaviour • IED only responds to incoming GOOSE and SV messages with quality q.test = false
Test	test	• Protection remains enabled • IED responds to incoming GOOSE and SV messages with both quality q.test = true and q.test = false • Relay output contacts are still active • IEC 61850 message outputs have 'quality' q.test = true • IED responds to incoming IEC 61850 MMS messages with only quality q.test = true
Contacts Blocked	test/blocked	• Protection remains enabled • IED responds to incoming GOOSE and SV messages with both quality q.test = true and q.test = false • Relay output contacts are disabled • IEC 61850 message outputs have quality q.test = true • IED responds to incoming IEC 61850 MMS messages with only quality q.test = true

Setting the Test or Contacts Blocked mode puts the whole IED into test mode. The IEC 61850 data object ***Beh*** in all Logical Nodes (except LPHD and any protection Logical Nodes that have Beh = 5 (off) due to the function being disabled) will be set to 3 (test) or 4 (test/blocked) as applicable.

21.8.2 SIMULATED INPUT BEHAVIOUR

Simulated GOOSE messages and sampled value streams can be used during testing.

The ***Subscriber Sim*** setting in the *COMMISSION TESTS* column controls whether a device listens to simulated signals or to real ones. An IEC 61850 control service to System/LPHD.Sim can also be used to change this value.

The device may be presented with both real signals and test signals. An internal state machine is used to control how the device switches between signals:

- The IED will continue subscribing to the 'real' GOOSE1 (in green) until it receives the first simulated GOOSE 1 (in red). This will initiate subscription changeover.
- After changeover to this new state, the IED will continue to subscribe to the simulated GOOSE 1 message (in red). Even if this simulated GOOSE 1 message disappears, the real GOOSE 1 message (in green) will still not be processed. This means all Virtual Inputs derived from the GOOSE 1 message will go to their default state.
- The only way to bring the IED out of this state is to set the ***Subscriber Sim*** setting back to False. The IED will then immediately stop processing the simulated messages and start processing real messages again.
- During above steps, IED1 will continuously process the real GOOSE 2 and GOOSE 3 messages as normal because it has not received any simulated messages for these that would initiate a changeover.

The process is represented in the following figure:

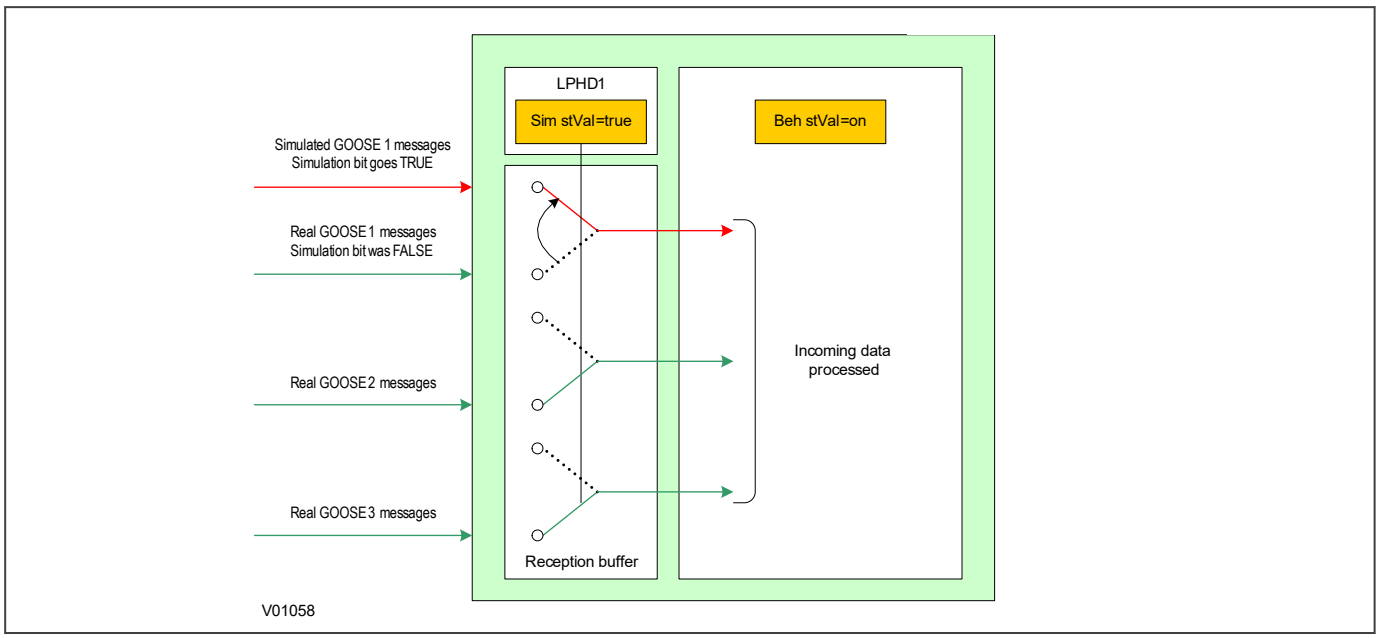


Figure 248: Simulated input behaviour

21.8.3 TESTING EXAMPLES

These examples show how you test the IED with and without simulated values. Depending on the IED Test Mode, it may respond by operating plant (for example by tripping the circuit breaker) or it may not operate plant.

21.8.3.1 TEST PROCEDURE FOR REAL VALUES

This procedure is for testing with real values without operating plant.

1. Set device into 'Contacts Blocked' Mode
   Select *COMMISSION TESTS* → ***IED Test Mode*** → `Contacts Blocked`
2. Confirm new behaviour has been enabled
   View *COMMISSION TESTS* → ***IED Mod/eh***, and check that it shows `Test-blocked`
3. Set device into Simulation Listening Mode
   Select *COMMISSION TESTS* → ***Subscriber Sim*** = `Disabled`
4. Inject real signals using a test device connected to the merging units. The device will continue to listen to 'real' GOOSE messages and ignore simulated messages received.
5. Verify function based on test signal outputs
   Binary outputs (e.g. CB trips) will not operate. All transmitted GOOSE and MMS data items will be tagged with the 'quality' parameter set to 'test', so that the receiver understands that they have been issued by a device under test and can respond accordingly. This is summarised in the following diagram

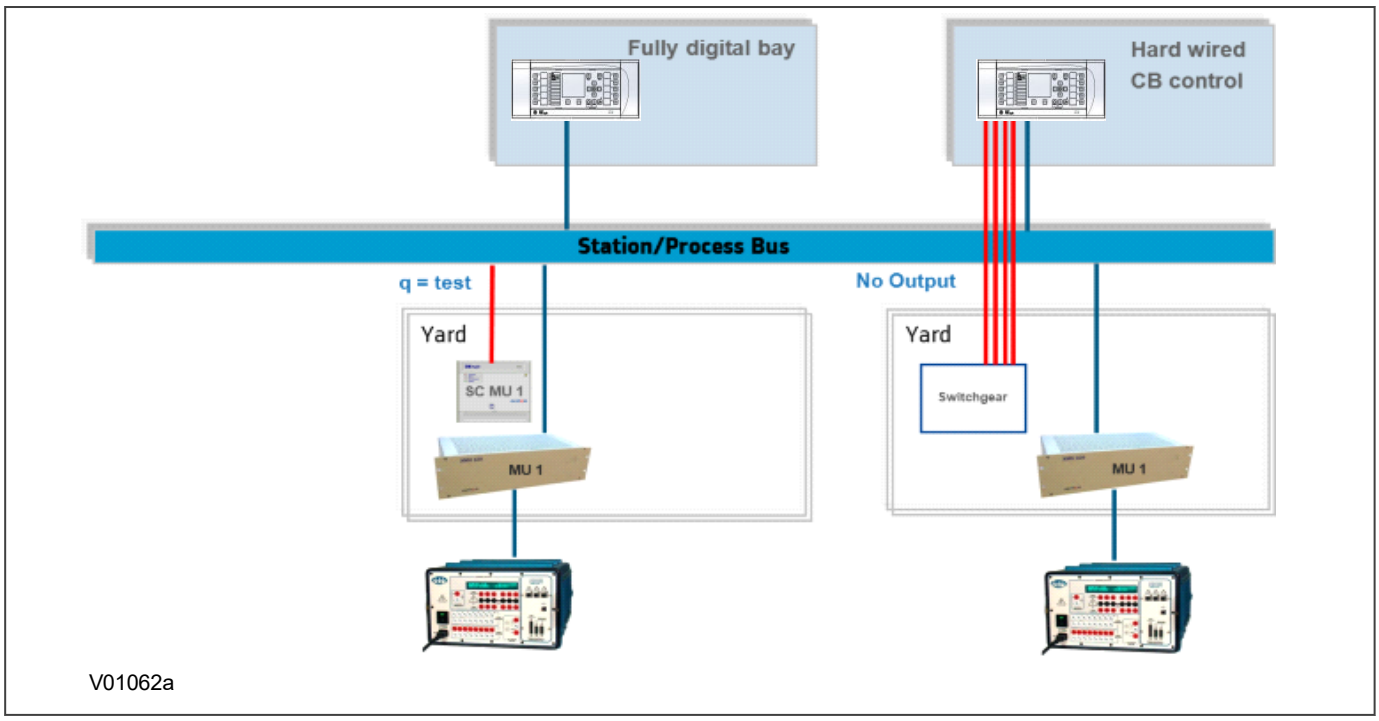


Figure 249: Test example 1

21.8.3.2 TEST PROCEDURE FOR SIMULATED VALUES - NO PLANT

This procedure is for testing with simulated values without operating plant.

1. Set device into 'Contacts Blocked' Mode
   Select *COMMISSION TESTS* → ***IED Test Mode*** → `Contacts Blocked`
2. Confirm new behaviour has been enabled
   View *COMMISSION TESTS* → ***IED Mod/Beh***, and check that it shows `test-blocked`
3. Set device into Simulation Listening Mode
   Select *COMMISSION TESTS* → ***Subscriber Sim*** = `Enabled`
4. Inject simulated signals using a test device connected to the Ethernet network. The device will continue to listen to 'real' GOOSE messages until a simulated message is received. Once the simulated messages are

received, the corresponding ‘real’ messages are ignored until the device is taken out of test mode. Each message is treated separately, but sampled values are considered as a single message.

5. Verify function based on test signal outputs

   Binary outputs (e.g. CB trips) will not operate. All transmitted GOOSE and MMS data items will be tagged with the 'quality' parameter set to 'test', so that the receiver understands that they have been issued by a device under test and can respond accordingly. This is summarised in the following diagram

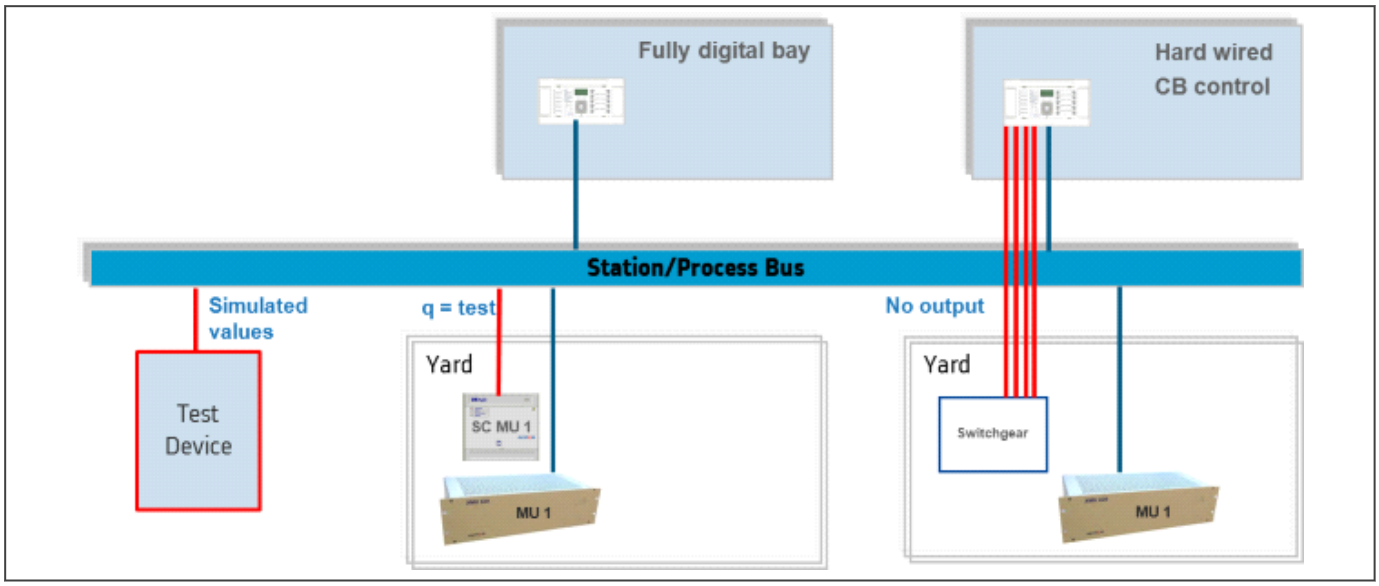


Figure 250: Test example 2

21.8.3.3 TEST PROCEDURE FOR SIMULATED VALUES - WITH PLANT

This procedure is for testing with simulated values with operating plant.

1. Set device into 'Contacts Blocked' Mode

   Select *COMMISSION TESTS* → ***IED Test Mode*** → `Test`

2. Confirm new behaviour has been enabled

   View *COMMISSION TESTS* → ***IED Mod/Beh***, and check that it shows `Test`

3. Set device into Simulation Listening Mode

   Select *COMMISSION TESTS* → ***Subscriber Sim*** = `Enabled`

4. Inject simulated signals using a test device connected to the Ethernet network.

   The device will continue to listen to ‘real’ GOOSE messages until a simulated message is received. Once the simulated messages are received, the corresponding ‘real’ messages are ignored until the device is taken out of IED test mode. Each message is treated separately, but sampled values are considered as a single message.

5. Verify function based on test signal outputs.

   Binary outputs (e.g. CB trips) will operate as normal. All transmitted GOOSE and MMS data items will be tagged with the 'quality' parameter set to 'test', so that the receiver understands that they have been issued by a device under test and can respond accordingly. This is summarised in the following diagram:

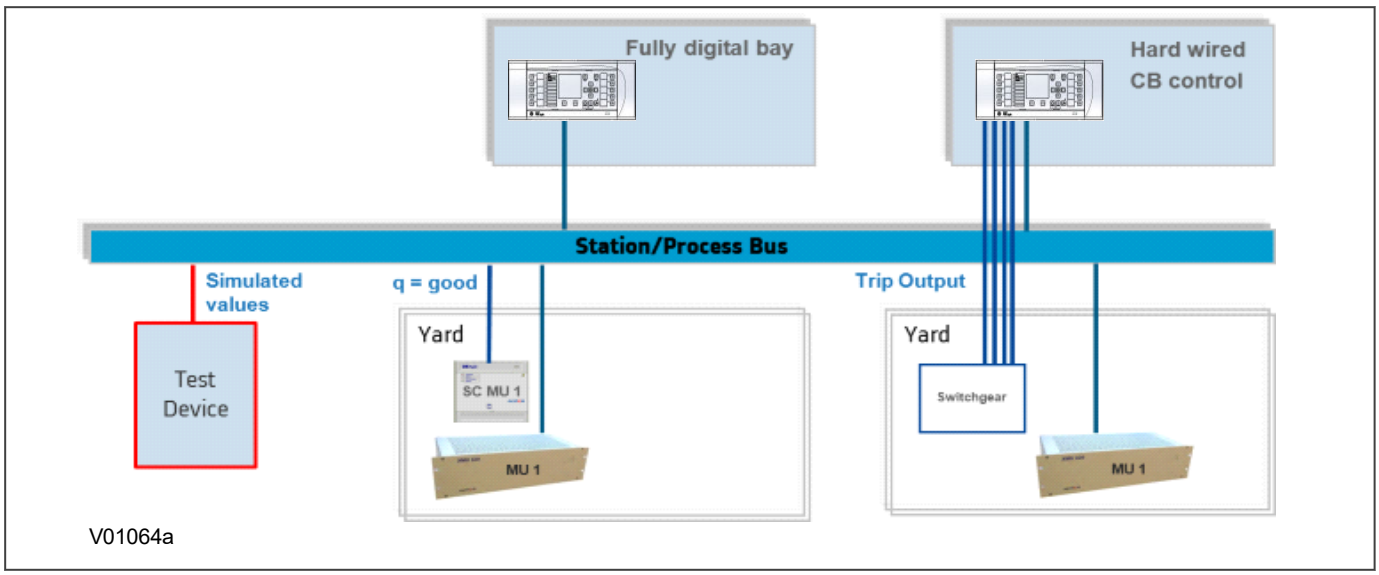


Figure 251: Test example 3

21.8.3.4 CONTACT TEST

The ***Apply Test*** command in this cell is used to change the state of the contacts set for operation.

If the device has been put into 'Contact Blocked' mode using an input signal (via the ***Block Contacts*** DDB signal) then the ***Apply Test*** command will not execute. This is to prevent a device that has been blocked by an external process having its contacts operated by a local operator using the HMI.

If the ***Block Contacts*** DDB is not set and the ***Apply Test*** command in this cell is issued, contacts change state and the command text on the LCD changes to `No Operation`. The contacts remain in the Test state until reset by issuing the ***Remove Test*** command. The command text on the LCD shows `No Operation` after the ***Remove Test*** command has been issued.

Note:
*When the **IED Test Mode** cell is set to Contacts Blocked, the **Relay O/P Status** cell does not show the current status of the output relays so cannot be used to confirm operation of the output relays. Therefore it is necessary to monitor the state of each contact in turn.*

21.9 PROTECTION TIMING CHECKS

There is no need to check every protection function. Only one protection function needs to be checked as the purpose is to verify the timing on the processor is functioning correctly.

21.9.1 OVERCURRENT CHECK

If the overcurrent protection function is being used, test the overcurrent protection for stage 1.

1. Check for any possible dependency conditions and simulate as appropriate.
2. In the *CONFIGURATION* column, disable all protection elements other than the one being tested.
3. Make a note of which elements need to be re-enabled after testing.
4. Connect the test circuit.
5. Perform the test.
6. Check the operating time.

21.9.2 CONNECTING THE TEST CIRCUIT

1. Use the PSL to determine which output relay will operate when an overcurrent trip occurs.
2. Use the output relay assigned to ***Trip Output A***.
3. Use the PSL to map the protection stage under test directly to an output relay.

> *Note:*
> *If using the default PSL, use output relay 3 as this is already mapped to the DDB signal **Trip Command Out**.*

4. Connect the output relay so that its operation will trip the test set and stop the timer.
5. Connect the current output of the test set to the A-phase current transformer input.

   If the ***I>1 Directional*** cell in the *OVERCURRENT* column is set to `Directional Fwd`, the current should flow out of terminal 2. If set to `Directional Rev`, it should flow into terminal 2.

   If the ***I>1 Directional*** cell in the *OVERCURRENT* column has been set to `Directional Fwd` or `Directional Rev`, the rated voltage should be applied to terminals 20 and 21.
6. Ensure that the timer starts when the current is applied.

> *Note:*
> *If the timer does not stop when the current is applied and stage 1 has been set for directional operation, the connections may be incorrect for the direction of operation set. Try again with the current connections reversed.*

21.9.3 PERFORMING THE TEST

1. Ensure that the timer is reset.
2. Apply a current of twice the setting shown in the ***I>1 Current Set*** cell in the *OVERCURRENT* column.
3. Note the time displayed when the timer stops.
4. Check that the red trip LED has illuminated.

21.9.4 CHECK THE OPERATING TIME

Check that the operating time recorded by the timer is within the range shown below.

For all characteristics, allowance must be made for the accuracy of the test equipment being used.

Characteristic	Operating Time at Twice Current Setting and Time Multiplier/Time Dial Setting of 1.0	
	Nominal (seconds)	Range (seconds)
DT	I>1 Time Delay setting	Setting ±2%
IEC S Inverse	10.03	9.53 - 10.53
IEC V Inverse	13.50	12.83 - 14.18
IEC E Inverse	26.67	24.67 - 28.67
UK LT Inverse	120.00	114.00 - 126.00
IEEE M Inverse	3.8	3.61 - 4.0
IEEE V Inverse	7.03	6.68 - 7.38
IEEE E Inverse	9.50	9.02 - 9.97
US Inverse	2.16	2.05 - 2.27
US ST Inverse	12.12	11.51 - 12.73

Note:
With the exception of the definite time characteristic, the operating times given are for a Time Multiplier Setting (TMS) or Time Dial Setting (TDS) of 1. For other values of TMS or TDS, the values need to be modified accordingly.
For definite time and inverse characteristics there is an additional delay of up to 0.02 second and 0.08 second respectively.
You may need to add this the IED's acceptable range of operating times.



Caution:
On completion of the tests, you must restore all settings to customer specifications.

21.10 SYSTEM CHECK AND CHECK SYNCHRONISM

This function performs a comparison between the line voltage and the bus voltage.

There are two voltage inputs to compare:

- one from the voltage transformer input from the line side of the circuit breaker (Main VT)
- one from the VT on the bus side of the circuit breaker (CS VT).

In most cases the line VT input is three phase, whereas the bus VTs are single phase.

The bus VT inputs are normally single phase so the system voltage checks are made on single phases and the VT may be connected to either a phase-to-phase or phase to neutral voltage.

For these reasons, the IED has to be programmed with the appropriate connection. The ***CS Input*** setting in the *CT AND VT RATIOS* column can be set to A-N, B-N, C-N, A-B, B-C or C-A according to the application.

The single-phase bus VT inputs each have associated phase shift and voltage magnitude compensation settings to compensate for healthy voltage angle and magnitude differences between the check sync VT input and the selected main VT reference phase. These are:

- ***CS VT Ph Shift*** and ***CS VT Mag***

Any voltage measurements or comparisons using bus VT inputs are made using the compensated values.

Each circuit breaker controlled can have two stages of check synchronism enabled according to the settings:

- ***System Checks***, ***CS1 Status*** and ***CS2 Status***

When the system voltage check conditions are satisfied, the relevant DDB signals are asserted high as follows:

- DDB (883): Check Sync 1 OK
- DDB (884): Check Sync 2 OK

These DDB signals should be mapped to the monitor/download port and used to indicate that the system check synchronism condition has been satisfied.

21.10.1 SYSTEM CHECK AND CHECK SYNCHRONISM

This function performs a comparison between the line voltage and the bus voltage.

There are two voltage inputs to compare:

- one from the voltage transformer input from the line side of the circuit breaker (Main VT)
- one from the VT on the bus side of the circuit breaker (CS VT).

In most cases the line VT input is three phase, whereas the bus VTs are single phase.

The bus VT inputs are normally single phase so the system voltage checks are made on single phases and the VT may be connected to either a phase-to-phase or phase to neutral voltage.

For these reasons, the IED has to be programmed with the appropriate connection. The ***CS Input*** setting in the *CT AND VT RATIOS* column can be set to A-N, B-N, C-N, A-B, B-C or C-A according to the application.

The single-phase bus VT inputs each have associated phase shift and voltage magnitude compensation settings to compensate for healthy voltage angle and magnitude differences between the check sync VT input and the selected main VT reference phase. These are found in the *CT AND VT RATIOS* column and comprise:

- ***CS VT PhShift*** and ***CS VT Mag***

Any voltage measurements or comparisons using bus VT inputs are made using the compensated values.

There are two stages of check synchronism enabled according to the settings in the *SYSTEM CHECKS* column.

- ***CS1 Status*** and ***CS2 Status***

When the system voltage check conditions are satisfied, the relevant DDB signals are asserted high as follows:

- DDB (883): ***Check Sync 1 OK***
- DDB (884): ***Check Sync 2 OK***

21.10.2 CHECK SYNCHRONISM PASS

1. Taking note of the check synchronism settings, identify the appropriate VT input terminals and inject voltage signals that should satisfy the system voltage check synchronism criteria.
2. Check that the DDB signals are asserted high.

21.10.3 CHECK SYNCHRONISM FAIL

1. Change the voltage signals so that the criteria are not satisfied
2. Check that the appropriate DDB signals are driven low

21.11 CHECK TRIP AND AUTORECLOSE CYCLE

If the auto-reclose function is being used, the circuit breaker trip and auto reclose cycle can be tested automatically by using the application-specific settings.

To test the trip and close operation without operating the breaker, the following conditions must be satisfied:

- The ***CB Healthy*** DDB signal should either not be mapped, or if it is mapped it must be asserted high.
- The CB status inputs (52A, etc.) should either not be mapped, or if they are mapped they should be activated to mimic the circuit breaker operation.
- Some models can be configured for single-pole tripping. If configured for single pole tripping, either set *CT/VT RATIO* > ***VT Connected*** to `No`, or apply appropriate voltage signals to prevent the pole dead logic from converting to 3-pole tripping.

1. To test the first three-phase auto-reclose cycle, set *COMMISSION TESTS* > ***Test Autoreclose*** to `Trip 3 Pole`. The IED performs a trip/reclose cycle.
2. Repeat this operation to test the subsequent three-phase auto-reclose cycles.
3. Check all output relays (used for such as circuit breaker tripping and closing, or blocking other devices) operate at the correct times during the trip/close cycle.

Check the auto-reclose cycles for single phase trip conditions one at a time by sequentially setting *COMMISSION TESTS* > ***Test Autoreclose*** to `Trip Pole A`, `Trip Pole B` and `Trip Pole C`.

21.12 ONLOAD CHECKS



Warning:
Onload checks are potentially very dangerous and may only be carried out by qualified and authorised personnel.

Onload checks can only be carried out if there are no restrictions preventing the energisation of the plant, and the other devices in the group have already been commissioned.

Remove all test leads and temporary shorting links, then replace any external wiring that has been removed to allow testing.



Warning:
If any external wiring has been disconnected for the commissioning process, replace it in accordance with the relevant external connection or scheme diagram.

21.12.1 CONFIRM VOLTAGE CONNECTIONS

1. Using a multimeter, measure the voltage transformer secondary voltages to ensure they are correctly rated.
2. Check that the system phase rotation is correct using a phase rotation meter.
3. Compare the values of the secondary phase voltages with the measured voltage magnitude values, which can be found in the *MEASUREMENTS 1* menu column.

Cell in MEASUREMENTS 1 Column	Corresponding VT Ratio in CT/VT RATIOS Column
VAB MAGNITUDE *VBC MAGNITUDE* *VCA MAGNITUDE* *VAN MAGNITUDE* *VBN MAGNITUDE* *VCN MAGNITUDE*	Main VT Primary/Main VT Sec'y
C/S Voltage Mag	CS VT Primary/CS VT Secondary

If the ***Local Values*** cell is set to `Secondary`, the values displayed should be equal to the applied secondary voltage. The values should be within 1% of the applied secondary voltages. However, an additional allowance must be made for the accuracy of the test equipment being used.

If the ***Local Values*** cell is set to `Primary`, the values displayed should be equal to the applied secondary voltage multiplied the corresponding voltage transformer ratio set in the *CT & VT RATIOS* column. The values should be within 1% of the expected values, plus an additional allowance for the accuracy of the test equipment being used.

21.12.2 CONFIRM CURRENT CONNECTIONS

1. Measure the current transformer secondary values for each input either by:
   a. reading from the device's HMI panel (providing it has first been verified by a secondary injection test)
   b. using a current clamp meter
2. Check that the current transformer polarities are correct by measuring the phase angle between the current and voltage, either against a phase meter already installed on site and known to be correct or by determining the direction of power flow by contacting the system control centre.
3. Ensure the current flowing in the neutral circuit of the current transformers is negligible.

If the ***Local Values*** cell is set to `Secondary`, the values displayed should be equal to the applied secondary voltage. The values should be within 1% of the applied secondary voltages. However, an additional allowance must be made for the accuracy of the test equipment being used.

If the ***Local Values*** cell is set to `Primary`, the values displayed should be equal to the applied secondary voltage multiplied the corresponding voltage transformer ratio set in the *CT & VT RATIOS* column. The values should be within 1% of the expected values, plus an additional allowance for the accuracy of the test equipment being used.

21.12.3 ON-LOAD DIRECTIONAL TEST

This test ensures that directional overcurrent and fault locator functions have the correct forward/reverse response to fault and load conditions. For this test you must first know the actual direction of power flow on the system. If you do not already know this you must determine it using adjacent instrumentation or protection already in-service.

- For load current flowing in the Forward direction (power export to the remote line end), the ***A Phase Watts*** cell in the *MEASUREMENTS 2* column should show positive power signing.
- For load current flowing in the Reverse direction (power import from the remote line end), the ***A Phase Watts*** cell in the *MEASUREMENTS 2* column should show negative power signing.

> *Note:*
> *This check applies only for Measurement Modes 0 (default), and 2. This should be checked in the MEASURE'T SETUP column (**Measurement Mode** = 0 or 2). If measurement modes 1 or 3 are used, the expected power flow signing would be opposite to that shown above.*

In the event of any uncertainty, check the phase angle of the phase currents with respect to their phase voltage.

21.13 FINAL CHECKS

1. Remove all test leads and temporary shorting leads.
2. If you have had to disconnect any of the external wiring in order to perform the wiring verification tests, replace all wiring, fuses and links in accordance with the relevant external connection or scheme diagram.
3. The settings applied should be carefully checked against the required application-specific settings to ensure that they are correct, and have not been mistakenly altered during testing.
4. Ensure that all protection elements required have been set to `Enabled` in the *CONFIGURATION* column.
5. Ensure that the IED has been restored to service by checking that the ***Test Mode*** cell in the *COMMISSION TESTS* column is set to `Disabled`.
6. If the IED is in a new installation or the circuit breaker has just been maintained, the circuit breaker maintenance and current counters should be zero. These counters can be reset using the ***Reset All Values*** cell. If the required access level is not active, the device will prompt for a password to be entered so that the setting change can be made.
7. If the menu language has been changed to allow accurate testing it should be restored to the customer's preferred language.
8. If a P991/MMLG test block is installed, remove the P992/MMLB test plug and replace the cover so that the protection is put into service.
9. Ensure that all event records, fault records, disturbance records, alarms and LEDs and communications statistics have been reset.

Note:
Remember to restore the language setting to the customer's preferred language on completion.

CHAPTER 22

MAINTENANCE AND TROUBLESHOOTING

22.1 CHAPTER OVERVIEW

The Maintenance and Troubleshooting chapter provides details of how to maintain and troubleshoot products based on the Px4x and P40Agile platforms. Always follow the warning signs in this chapter. Failure to do so may result injury or defective equipment.



Caution:
Before carrying out any work on the equipment you should be familiar with the contents of the Safety Section or the Safety Guide SFTY/4LM and the ratings on the equipment's rating label.

The troubleshooting part of the chapter allows an error condition on the IED to be identified so that appropriate corrective action can be taken.

If the device develops a fault, it is usually possible to identify which module needs replacing. It is not possible to perform an on-site repair to a faulty module.

If you return a faulty unit or module to the manufacturer or one of their approved service centres, you should include a completed copy of the Repair or Modification Return Authorization (RMA) form.

This chapter contains the following sections:

Chapter Overview 535
Maintenance 536
Troubleshooting 544

22.2 MAINTENANCE

22.2.1 MAINTENANCE CHECKS

In view of the critical nature of the application, GE Vernova products should be checked at regular intervals to confirm they are operating correctly. GE Vernova products are designed for a life in excess of 20 years.

The devices are self-supervising and so require less maintenance than earlier designs of protection devices. Most problems will result in an alarm, indicating that remedial action should be taken. However, some periodic tests should be carried out to ensure that they are functioning correctly and that the external wiring is intact. It is the responsibility of the customer to define the interval between maintenance periods. If your organisation has a Preventative Maintenance Policy, the recommended product checks should be included in the regular program. Maintenance periods depend on many factors, such as:

- The operating environment
- The accessibility of the site
- The amount of available manpower
- The importance of the installation in the power system
- The consequences of failure

Although some functionality checks can be performed from a remote location, these are predominantly restricted to checking that the unit is measuring the applied currents and voltages accurately, and checking the circuit breaker maintenance counters. For this reason, maintenance checks should also be performed locally at the substation.



Caution:
Before carrying out any work on the equipment you should be familiar with the contents of the Safety Section or the Safety Guide SFTY/4LM and the ratings on the equipment's rating label.

22.2.1.1 ALARMS

First check the alarm status LED to see if any alarm conditions exist. If so, press the Read key repeatedly to step through the alarms.

After dealing with any problems, clear the alarms. This will clear the relevant LEDs.

22.2.1.2 OPTO-ISOLATORS

Check the opto-inputs by repeating the commissioning test detailed in the Commissioning chapter.

22.2.1.3 OUTPUT RELAYS

Check the output relays by repeating the commissioning test detailed in the Commissioning chapter.

22.2.1.4 MEASUREMENT ACCURACY

If the power system is energised, the measured values can be compared with known system values to check that they are in the expected range. If they are within a set range, this indicates that the A/D conversion and the calculations are being performed correctly. Suitable test methods can be found in Commissioning chapter.

Alternatively, the measured values can be checked against known values injected into the device using the test block, (if fitted) or injected directly into the device's terminals. Suitable test methods can be found in the Commissioning chapter. These tests will prove the calibration accuracy is being maintained.

22.2.2 REPLACING THE DEVICE

If your product should develop a fault while in service, depending on the nature of the fault, the watchdog contacts will change state and an alarm condition will be flagged. In the case of a fault, you can replace either the complete device or just the faulty PCB, identified by the in-built diagnostic software.

If possible you should replace the complete device, as this reduces the chance of damage due to electrostatic discharge and also eliminates the risk of fitting an incompatible replacement PCB. However, we understand it may be difficult to remove an installed product and you may be forced to replace the faulty PCB on-site. The case and rear terminal blocks are designed to allow removal of the complete device, without disconnecting the scheme wiring.



Caution:
Replacing PCBs requires the correct on-site environment (clean and dry) as well as suitably trained personnel.



Caution:
If the repair is not performed by an approved service centre, the warranty will be invalidated.



Caution:
Before carrying out any work on the equipment, you should be familiar with the contents of the Safety Information section of this guide or the Safety Guide SFTY/4LM, as well as the ratings on the equipment's rating label. This should ensure that no damage is caused by incorrect handling of the electronic components.



Warning:
Before working at the rear of the device, isolate all voltage and current supplying it.

Note:
The current transformer inputs are equipped with integral shorting switches which will close for safety reasons, when the terminal block is removed.

To replace the complete device:

1. Carefully disconnect the cables not connected to the terminal blocks (e.g. IRIG-B, fibre optic cables, earth), as appropriate, from the rear of the device.
2. Remove the terminal block screws using a magnetic screwdriver to minimise the risk of losing the screws or leaving them in the terminal block.
3. Without exerting excessive force or damaging the scheme wiring, pull the terminal blocks away from their internal connectors.
4. Remove the terminal block screws that fasten the device to the panel and rack. These are the screws with the larger diameter heads that are accessible when the access covers are fitted and open.
5. Withdraw the device from the panel and rack. Take care, as the device will be heavy due to the internal transformers.
6. To reinstall the device, follow the above instructions in reverse, ensuring that each terminal block is relocated in the correct position and the chassis ground, IRIG-B and fibre optic connections are replaced. The terminal blocks are labelled alphabetically with 'A' on the left hand side when viewed from the rear.

Once the device has been reinstalled, it should be re-commissioned as set out in the Commissioning chapter.

Caution:
If the top and bottom access covers have been removed, some more screws with smaller diameter heads are made accessible. Do NOT remove these screws, as they secure the front panel to the device.

Note:
There are four possible types of terminal block: RTD/CLIO input, heavy duty, medium duty, and MiDOS. The terminal blocks are fastened to the rear panel with slotted or cross-head screws depending on the type of terminal block. Not all terminal block types are present on all products.

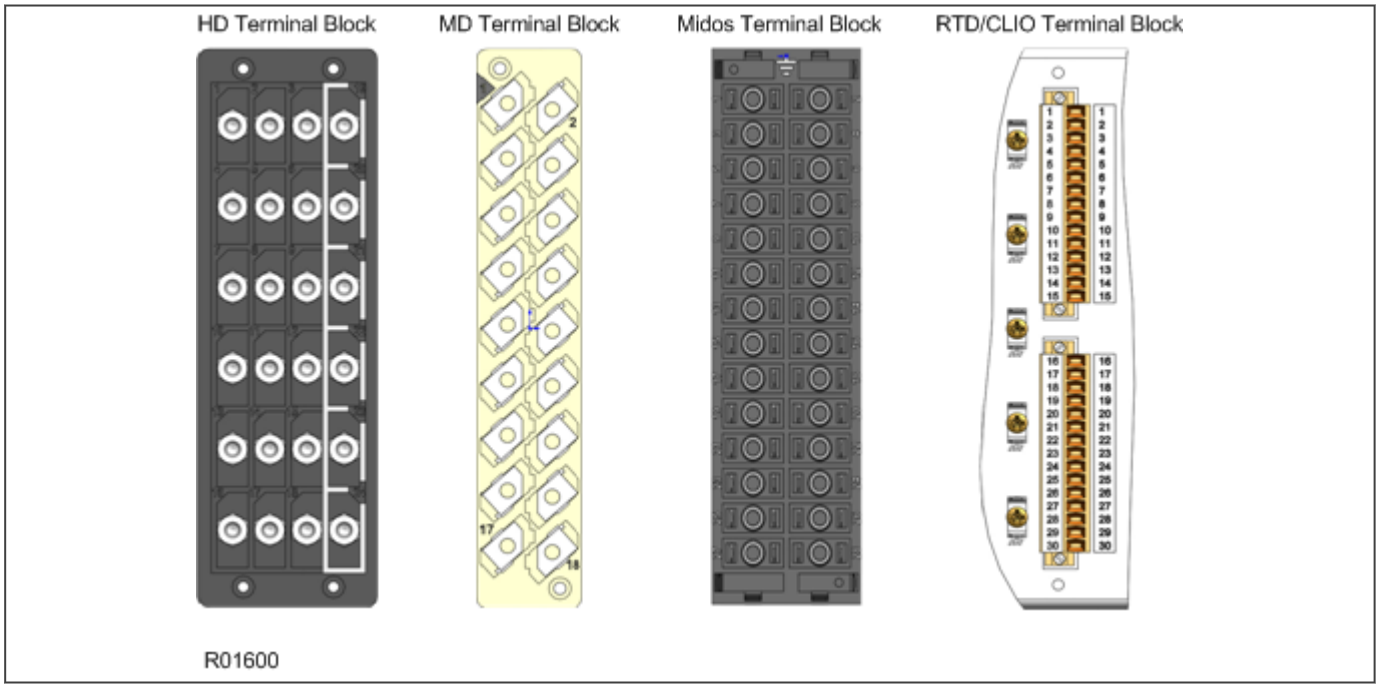


Figure 252: Possible terminal block types

22.2.3 REPAIRING THE DEVICE

If your product should develop a fault while in service, depending on the nature of the fault, the watchdog contacts will change state and an alarm condition will be flagged. In the case of a fault, either the complete unit or just the faulty PCB, identified by the in-built diagnostic software, should be replaced.

Replacement of printed circuit boards and other internal components must be undertaken by approved Service Centres. Failure to obtain the authorization of after-sales engineers prior to commencing work may invalidate the product warranty.

We recommend that you entrust any repairs to Automation Support teams, which are available world-wide.

22.2.4 REMOVING THE FRONT PANEL

Warning:
Before removing the front panel to replace a PCB, you must first remove the auxiliary power supply and wait 5 seconds for the internal capacitors to discharge. You should also isolate voltage and current transformer connections and trip circuit.



Caution:
Before removing the front panel, you should be familiar with the contents of the Safety Information section of this guide or the Safety Guide SFTY/4LM, as well as the ratings on the equipment's rating label.

To remove the front panel:

1. Open the top and bottom access covers. You must open the hinged access covers by more than 90° before they can be removed.
2. If fitted, remove the transparent secondary front cover.
3. Apply outward pressure to the middle of the access covers to bow them and disengage the hinge lug, so the access cover can be removed. The screws that fasten the front panel to the case are now accessible.
4. Undo and remove the screws. The 40TE case has four cross-head screws fastening the front panel to the case, one in each corner, in recessed holes. The 60TE/80TE cases have an additional two screws, one midway along each of the top and bottom edges of the front plate.
5. When the screws have been removed, pull the complete front panel forward to separate it from the metal case. The front panel is connected to the rest of the circuitry by a 64-way ribbon cable.
6. The ribbon cable is fastened to the front panel using an IDC connector; a socket on the cable and a plug with locking latches on the front panel. Gently push the two locking latches outwards which eject the connector socket slightly. Remove the socket from the plug to disconnect the front panel.



Caution:
Do not remove the screws with the larger diameter heads which are accessible when the access covers are fitted and open. These screws hold the device in its mounting (panel or cubicle).



Caution:
The internal circuitry is now exposed and is not protected against electrostatic discharge and dust ingress. Therefore ESD precautions and clean working conditions must be maintained at all times.

22.2.5 REPLACING PCBS

1. To replace any of the PCBs, first remove the front panel.
2. Once the front panel has been removed, the PCBs are accessible. The numbers above the case outline identify the guide slot reference for each printed circuit board. Each printed circuit board has a label stating the corresponding guide slot number to ensure correct relocation after removal. To serve as a reminder of the slot numbering there is a label on the rear of the front panel metallic screen.
3. Remove the 64-way ribbon cable from the PCB that needs replacing
4. Remove the PCB in accordance with the board-specific instructions detailed later in this section.

Note:
To ensure compatibility, always replace a faulty PCB with one of an identical part number.

22.2.5.1 REPLACING THE MAIN PROCESSOR BOARD

The main processor board is situated in the front panel. This board contains application-specific settings in its non-volatile memory. You may wish to take a backup copy of these settings. This could save time in the re-commissioning process.

To replace the main processor board:

1. Remove front panel.
2. Place the front panel with the user interface face down and remove the six screws from the metallic screen, as shown in the figure below. Remove the metal plate.
3. Remove the screws that hold the main processor board in position.
4. Carefully disconnect the ribbon cable. Take care as this could easily be damaged by excessive twisting.
5. Replace the main processor board
6. Reassemble the front panel using the reverse procedure. Make sure the ribbon cable is reconnected to the main processor board and that all eight screws are refitted.
7. Refit the front panel.
8. Refit and close the access covers then press the hinge assistance T-pieces so they click back into the front panel moulding.
9. Once the unit has been reassembled, carry out the standard commissioning procedure as defined in the Commissioning chapter.

Note:
After replacing the main processor board, all the settings required for the application need to be re-entered. This may be done either manually or by downloading a settings file.

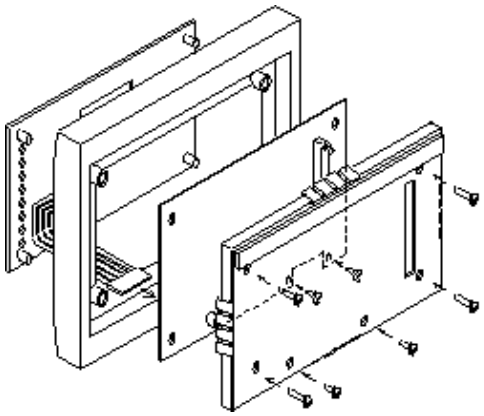


Figure 253: Front panel assembly

22.2.5.2 REPLACEMENT OF COMMUNICATIONS BOARDS

Most products will have at least one communications board of some sort fitted. There are several different boards available offering various functionality, depending on the application. Some products may even be fitted with two boards of different types.

To replace a faulty communications board:

1. Remove front panel.
2. Disconnect all connections at the rear.
3. The board is secured in the device case by two screws, one at the top and another at the bottom. Remove these screws carefully as they are not captive in the rear panel.
4. Gently pull the communications board forward and out of the case.

5. Before fitting the replacement PCB check that the number on the round label next to the front edge of the PCB matches the slot number into which it will be fitted. If the slot number is missing or incorrect, write the correct slot number on the label.
6. Fit the replacement PCB carefully into the correct slot. Make sure it is pushed fully back and that the securing screws are refitted.
7. Reconnect all connections at the rear.
8. Refit the front panel.
9. Refit and close the access covers then press the hinge assistance T-pieces so they click back into the front panel moulding.
10. Once the unit has been reassembled, commission it according to the Commissioning chapter.

22.2.5.3 REPLACEMENT OF THE INPUT MODULE

Depending on the product, the input module consists of two or three boards fastened together and is contained within a metal housing. One board contains the transformers and one contains the analogue to digital conversion and processing electronics. Some devices have an additional auxiliary transformer contained on a third board.

To replace an input module:

1. Remove front panel.
2. The module is secured in the case by two screws on its right-hand side, accessible from the front, as shown below. Move these screws carefully as they are not captive in the front plate of the module.
3. On the right-hand side of the module there is a small metal tab which brings out a handle (on some modules there is also a tab on the left). Grasp the handle(s) and pull the module firmly forward, away from the rear terminal blocks. A reasonable amount of force is needed due to the friction between the contacts of the terminal blocks.
4. Remove the module from the case. The module may be heavy, because it contains the input voltage and current transformers.
5. Slot in the replacement module and push it fully back onto the rear terminal blocks. To check that the module is fully inserted, make sure the v-shaped cut-out in the bottom plate of the case is fully visible.
6. Refit the securing screws.
7. Refit the front panel.
8. Refit and close the access covers then press the hinge assistance T-pieces so they click back into the front panel moulding.
9. Once the unit has been reassembled, commission it according to the Commissioning chapter.



Caution:
With non-mounted IEDs, the case needs to be held firmly while the module is withdrawn. Withdraw the input module with care as it suddenly comes loose once the friction of the terminal blocks is overcome.

Note:
If individual boards within the input module are replaced, recalibration will be necessary. We therefore recommend replacement of the complete module to avoid on-site recalibration.

22.2.5.4 REPLACEMENT OF THE POWER SUPPLY BOARD



Caution:
Before removing the front panel, you should be familiar with the contents of the Safety Information section of this guide or the Safety Guide SFTY/4LM, as well as the ratings on the equipment's rating label.

The power supply board is fastened to an output relay board with push fit nylon pillars. This doubled-up board is secured on the extreme left hand side, looking from the front of the unit.

1. Remove front panel.
2. Pull the power supply module forward, away from the rear terminal blocks and out of the case. A reasonable amount of force is needed due to the friction between the contacts of the terminal blocks.
3. Separate the boards by pulling them apart carefully. The power supply board is the one with two large electrolytic capacitors.
4. Before reassembling the module, check that the number on the round label next to the front edge of the PCB matches the slot number into which it will be fitted. If the slot number is missing or incorrect, write the correct slot number on the label
5. Reassemble the module with a replacement PCB. Push the inter-board connectors firmly together. Fit the four push fit nylon pillars securely in their respective holes in each PCB.
6. Slot the power supply module back into the housing. Push it fully back onto the rear terminal blocks.
7. Refit the front panel.
8. Refit and close the access covers then press the hinge assistance T-pieces so they click back into the front panel moulding.
9. Once the unit has been reassembled, commission it according to the Commissioning chapter.

22.2.5.5 REPLACEMENT OF THE I/O BOARDS

There are several different types of I/O boards, which can be used, depending on the product and application. Some boards have opto-inputs, some have relay outputs and others have a mixture of both.

1. Remove front panel.
2. Gently pull the board forward and out of the case
3. If replacing the I/O board, make sure the setting of the link above IDC connector on the replacement board is the same as the one being replaced.
4. Before fitting the replacement board check the number on the round label next to the front edge of the board matches the slot number into which it will be fitted. If the slot number is missing or incorrect, write the correct slot number on the label.
5. Carefully slide the replacement board into the appropriate slot, ensuring that it is pushed fully back onto the rear terminal blocks.
6. Refit the front panel.
7. Refit and close the access covers then press at the hinge assistance T-pieces so they click back into the front panel moulding.
8. Once the unit has been reassembled, commission it according to the Commissioning chapter.

22.2.6 RECALIBRATION

Recalibration is not needed when a PCB is replaced, unless it is one of the boards in the input module. If any of the boards in the input module is replaced, the unit must be recalibrated.

Although recalibration is needed when a board inside the input module is replaced, it is not needed if the input module is replaced in its entirety.

Although it is possible to carry out recalibration on site, this requires special test equipment and software. We therefore recommend that the work be carried out by the manufacturer, or entrusted to an approved service centre.

22.2.7 SUPERCAPACITOR DISCHARGED

The supercapacitor maintains charge for two weeks with the IED de-energised. When first energising the IED after this time there may be a ***SuperCap Alarm*** due to the supercapacitor voltage dropping below a pre-defined

threshold. The ***SuperCap Alarm*** will clear after approximately 30 minutes of IED being energised, and once cleared there will be enough charge in the supercapacitor to maintain the RTC.

Note:
The Real Time Clock will be reset if the supercapacitor is fully discharged.

22.2.8 CLEANING



Warning:
Before cleaning the device, ensure that all AC and DC supplies and transformer connections are isolated, to prevent any chance of an electric shock while cleaning.

Only clean the equipment with a lint-free cloth dampened with clean water. Do not use detergents, solvents or abrasive cleaners as they may damage the product's surfaces and leave a conductive residue.

22.3 TROUBLESHOOTING

22.3.1 SELF-DIAGNOSTIC SOFTWARE

The device includes several self-monitoring functions to check the operation of its hardware and software while in service. If there is a problem with the hardware or software, it should be able to detect and report the problem, and attempt to resolve the problem by performing a reboot. In this case, the device would be out of service for a short time, during which the 'Healthy' LED on the front of the device is switched OFF and the watchdog contact at the rear is ON. If the restart fails to resolve the problem, the unit takes itself permanently out of service; the 'Healthy' LED stays OFF and watchdog contact stays ON.

If a problem is detected by the self-monitoring functions, the device attempts to store a maintenance record to allow the nature of the problem to be communicated to the user.

The self-monitoring is implemented in two stages: firstly a thorough diagnostic check which is performed on boot-up, and secondly a continuous self-checking operation, which checks the operation of the critical functions whilst it is in service.

22.3.2 POWER-UP ERRORS

If the IED does not appear to power up, use the following to determine whether the fault is in the external wiring, auxiliary fuse, IED power supply module or IED front panel.

Test	Check	Action
1	Measure the auxiliary voltage on terminals 1 and 2. Verify the voltage level and polarity against the rating label on the front. Terminal 1 is –dc, 2 is +dc	If the auxiliary voltage is correct, go to test 2. Otherwise check the wiring and fuses in the auxiliary supply.
2	Check the LEDs and LCD backlight switch on at power-up. Also check the N/O (normally open) watchdog contact for closing.	If the LEDs and LCD backlight switch on, or the contact closes and no error code is displayed, the error is probably on the main processor board in the front panel. If the LEDs and LCD backlight do not switch on and the contact does not close, go to test 3.
3	Check the output (nominally 48 V DC).	If there is no field voltage, the fault is probably in the IED power supply module.

22.3.3 ERROR MESSAGE OR CODE ON POWER-UP

The IED performs a self-test during power-up. If it detects an error, a message appears on the LCD and the power-up sequence stops. If the error occurs when the IED application software is running, a maintenance record is created and the device reboots.

Test	Check	Action
1	Is an error message or code permanently displayed during power up?	If the IED locks up and displays an error code permanently, go to test 2. If the IED prompts for user input, go to test 4. If the IED reboots automatically, go to test 5.
2	Record displayed error, and then remove and re-apply IED auxiliary supply.	Record whether the same error code is displayed when the IED is rebooted. If no error code is displayed, contact the local service centre stating the error code and IED information. If the same code is displayed, go to test 3.

Test	Check	Action
3	Error Code Identification The following text messages (in English) are displayed if a fundamental problem is detected, preventing the system from booting: Bus Fail – address lines SRAM Fail – data lines FLASH Fail format error FLASH Fail checksum Code Verify Fail The following hex error codes relate to errors detected in specific IED modules:	These messages indicate that a problem has been detected on the IED's main processor board in the front panel.
3.1	0c140005/0c0d0000	Input Module (including opto-isolated inputs)
3.2	0c140006/0c0e0000	Output IED boards
3.3	The last four digits provide details on the actual error.	Other error codes relate to hardware or software problems on the main processor board. Contact GE Vernova with details of the problem for a full analysis.
4	The IED displays a message for corrupt settings and prompts for the default values to be restored for the affected settings.	The power-up tests have detected corrupted IED settings. Restore the default settings to allow the power-up to complete, and then reapply the application-specific settings.
5	The IED resets when the power-up is complete. A record error code is displayed	Error 0x0E080000, programmable scheme logic error due to excessive execution time. If the IED powers up successfully, check the programmable logic for feedback paths. Other error codes relate to software errors on the main processor board.

22.3.4 OUT OF SERVICE LED ON AT POWER-UP

Test	Check	Action	
1	Using the IED menu, confirm the Commission Test or Test Mode setting is Enabled. If it is not Enabled, go to test 2.	If the setting is Enabled, disable the test mode and make sure the Out of Service LED is OFF.	
2	Select the *VIEW RECORDS* column then view the last maintenance record from the menu.	Check for the H/W Verify Fail maintenance record. This indicates a discrepancy between the IED model number and the hardware. Examine the ***Maint Data***; cell. This indicates the causes of the failure using bit fields: Bit Meaning	
		0	The application type field in the model number does not match the software ID
		1	The application field in the model number does not match the software ID
		2	The variant 1 field in the model number does not match the software ID
		3	The variant 2 field in the model number does not match the software ID
		4	The protocol field in the model number does not match the software ID

Test	Check	Action	
		5	The language field in the model number does not match the software ID
		6	The VT type field in the model number is incorrect (110 V VTs fitted)
		7	The VT type field in the model number is incorrect (440 V VTs fitted)
		8	The VT type field in the model number is incorrect (no VTs fitted)

22.3.5 ERROR CODE DURING OPERATION

The IED performs continuous self-checking. If the IED detects an error it displays an error message, logs a maintenance record and after a short delay resets itself. A permanent problem (for example due to a hardware fault) is usually detected in the power-up sequence. In this case the IED displays an error code and halts. If the problem was transient, the IED reboots correctly and continues operation. By examining the maintenance record logged, the nature of the detected fault can be determined.

22.3.6 MAL-OPERATION DURING TESTING

22.3.6.1 FAILURE OF OUTPUT CONTACTS

An apparent failure of the relay output contacts can be caused by the configuration. Perform the following tests to identify the real cause of the failure. The self-tests verify that the coils of the output relay contacts have been energized. An error is displayed if there is a fault in the output relay board.

Test	Check	Action
1	Is the Out of Service LED ON?	If this LED is ON, the device may be in test mode or the protection has been disabled due to a hardware verify error.
2	Examine the Contact status in the Commissioning section of the menu.	If the relevant bits of the contact status are operated, go to test 4; if not, go to test 3.
3	Examine the fault record or use the test port to check the protection element is operating correctly.	If the protection element does not operate, check the test is correctly applied. If the protection element operates, check the programmable logic to make sure the protection element is correctly mapped to the contacts.
4	Using the Commissioning or Test mode function, apply a test pattern to the relevant relay output contacts. Consult the correct external connection diagram and use a continuity tester at the rear of the device to check the relay output contacts operate.	If the output relay operates, the problem must be in the external wiring to the device. If the output relay does not operate the output relay contacts may have failed (the self-tests verify that the relay coil is being energized). Ensure the closed resistance is not too high for the continuity tester to detect.

22.3.6.2 FAILURE OF OPTO-INPUTS

The opto-isolated inputs are mapped onto the IED's internal DDB signals using the programmable scheme logic. If an input is not recognised by the scheme logic, use the ***Opto I/P Status*** cell in the *COMMISSION TESTS* column to check whether the problem is in the opto-input itself, or the mapping of its signal to the scheme logic functions.

If the device does not correctly read the opto-input state, test the applied signal. Verify the connections to the opto-input using the wiring diagram and the nominal voltage settings in the *OPTO CONFIG* column. To do this:

1. Select the nominal voltage for all opto-inputs by selecting one of the five standard ratings in the ***Global Nominal V*** cell.
2. Select `Custom` to set each opto-input individually to a nominal voltage.
3. Using a voltmeter, check that the voltage on its input terminals is greater than the minimum pick-up level (See the Technical Specifications chapter for opto pick-up levels).

If the signal is correctly applied, this indicates failure of an opto-input, which may be situated on standalone opto-input board, or on an opto-input board that is part of the input module. Separate opto-input boards can simply be replaced. If, however, the faulty opto-input board is part of the input module, the complete input module should be replaced. This is because the analogue input module cannot be individually replaced without dismantling the module and recalibration of the IED.

22.3.6.3 INCORRECT ANALOGUE SIGNALS

If the measured analogue quantities do not seem correct, use the measurement function to determine the type of problem. The measurements can be configured in primary or secondary terms.

1. Compare the displayed measured values with the actual magnitudes at the terminals.
2. Check the correct terminals are used.
3. Check the CT and VT ratios set are correct.
4. Check the phase displacement to confirm the inputs are correctly connected.

22.3.7 PSL EDITOR TROUBLESHOOTING

A failure to open a connection could be due to one or more of the following:

- The IED address is not valid (this address is always 1 for the front port)
- Password in not valid
- Communication set-up (COM port, Baud rate, or Framing) is not correct
- Transaction values are not suitable for the IED or the type of connection
- The connection cable is not wired correctly or broken
- The option switches on any protocol converter used may be incorrectly set

22.3.7.1 DIAGRAM RECONSTRUCTION

Although a scheme can be extracted from an IED, a facility is provided to recover a scheme if the original file is unobtainable.

A recovered scheme is logically correct but much of the original graphical information is lost. Many signals are drawn in a vertical line down the left side of the canvas. Links are drawn orthogonally using the shortest path from A to B. Any annotation added to the original diagram such as titles and notes are lost.

Sometimes a gate type does not appear as expected. For example, a single-input AND gate in the original scheme appears as an OR gate when uploaded. Programmable gates with an inputs-to-trigger value of 1 also appear as OR gates

22.3.7.2 PSL VERSION CHECK

The PSL is saved with a version reference, time stamp and CRC check (Cyclic Redundancy Check). This gives a visual check whether the default PSL is in place or whether a new application has been downloaded.

22.3.8 REPAIR AND MODIFICATION PROCEDURE

Please follow these steps to return an Automation product to us:

1. Get the Repair and Modification Return Authorization (RMA) form
   An electronic version of the RMA form is available from the following:
   GA.support@gevernova.com
2. Fill in the RMA form
   Fill in only the white part of the form.
   Please ensure that all fields marked **(M)** are completed such as:
   - Equipment model
   - Model No. and Serial No.
   - Description of failure or modification required (please be specific)
   - Value for customs (in case the product requires export)
   - Delivery and invoice addresses
   - Contact details
3. Send the RMA form to your local contact
   For a list of local service contacts worldwide, email us at:
   GA.support@gevernova.com
4. The local service contact provides the shipping information
   Your local service contact provides you with all the information needed to ship the product:
   - Pricing details
   - RMA number
   - Repair centre address

   If required, an acceptance of the quote must be delivered before going to the next stage.
5. Send the product to the repair centre
   - Address the shipment to the repair centre specified by your local contact
   - Make sure all items are packaged in an anti-static bag and foam protection
   - Make sure a copy of the import invoice is attached with the returned unit
   - Make sure a copy of the RMA form is attached with the returned unit
   - E-mail or fax a copy of the import invoice and airway bill document to your local contact.

CHAPTER 23

TECHNICAL SPECIFICATIONS

23.1 CHAPTER OVERVIEW

This chapter describes the technical specifications of the product.

This chapter contains the following sections:

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Interfaces 551
Performance of Current Protection Functions 555
Performance of Voltage Protection Functions 560
Performance of Frequency Protection Functions 563
Advanced Frequency 564
Performance of Power Protection Functions 567
Autoreclose 568
Monitoring, Control and Supervision 569
Measurements and Recording 570
Ratings 572
Input/Output Connections 575
Mechanical Specifications 577
Type Tests 578
Environmental Conditions 579
Electromagnetic Compatibility 580
Regulatory Compliance 583

23.2 INTERFACES

23.2.1 GRAPHICAL HMI

Graphical HMI	
Screen size	4.0" diagonal
Display format	480 x 480 Dots
Number of colour	16.7M
Dimensions	77 mm (H) x 80 mm (V) x 2.3 mm (D)
Active area	71.86 mm (H) x 70.18 mm (V)
Display mode	Transmissive/normally black
Viewing direction	All round
Backlight type	LED, white
Operating temperature	-30°C ~ +85°C
Storage temperature	-40°C ~ +90°C

23.2.2 FRONT USB PORT

Front USB Port	
Use	For local connection to laptop for configuration purposes and firmware downloads
Connector	USB type B
Isolation	Isolation to ELV level
Constraints	Maximum cable length 5 m

23.2.3 REAR SERIAL PORT 1

Rear Serial Port 1 (RP1)	
Use	For SCADA communications (multi-drop)
Standard	EIA(RS)485, K-bus
Connector	General purpose block, M4 screws (2 wire)
Cable	Screened twisted pair (STP)
Supported Protocols *	Courier, IEC-60870-5-103, DNP3.0
Isolation	Isolation to SELV level
Constraints	Maximum cable length 1000 m

23.2.4 FIBRE REAR SERIAL PORT 1

Optional Fibre Rear Serial Port (RP1)	
Main Use	Serial SCADA communications over fibre
Connector	IEC 874-10 BFOC 2.5 –(ST®) (1 each for Tx and Rx)
Fibre type	Multimode 50/125 µm or 62.5/125 µm
Supported Protocols	Courier, IEC870-5-103, DNP 3.0
Wavelength	850 nm

23.2.5 REAR SERIAL PORT 2

Optional Rear Serial Port (RP2)	
Use	For SCADA communications (multi-drop)
Standard	EIA(RS)485, K-bus, EIA(RS)232
Designation	SK4
Connector	9 pin D-type female connector
Cable	Screened twisted pair (STP)
Supported Protocols	Courier
Isolation	Isolation to SELV level
Constraints	Maximum cable length 1000 m for RS485 and K-bus, 15 m for RS232

23.2.6 OPTIONAL REAR SERIAL PORT (SK5)

Optional Rear Serial Port for Teleprotection	
Use	For teleprotection in distance products
Standard	EIA(RS)232
Designation	SK5
Connector	9 pin D-type female connector
Cable	Screened twisted pair (STP)
Supported Protocols	InterMiCOM (IM)
Isolation	Isolation to SELV level
Constraints	Maximum cable length 15 m

23.2.7 IRIG-B (DEMODULATED)

IRIG-B Interface (Demodulated)	
Use	External clock synchronisation signal
Standard	IRIG 200-98 format B00X
Connector	BNC
Cable type	50 ohm coaxial
Isolation	Isolation to SELV level
Input signal	TTL level
Input impedance	10 k ohm at dc
Accuracy	+/-1 ms

23.2.8 IRIG-B (MODULATED)

IRIG-B Interface (Modulated)	
Use	External clock synchronisation signal
Standard	IRIG 200-98 format B12X
Connector	BNC
Cable type	50 ohm coaxial
Isolation	Isolation to SELV level

IRIG-B Interface (Modulated)	
Input signal	Peak to peak, 200 mV to 20 mV
Input impedance	6 k ohm at 1000 Hz
Accuracy	+/-1 ms

23.2.9 REAR ETHERNET PORT COPPER

Rear Ethernet Port Using CAT 5/6/7 Wiring	
Main Use	Substation Ethernet communications
Standard	IEEE 802.3 100BaseTX
Connector	RJ45
Cable type	Screened twisted pair (STP)
Isolation	1.5 kV
Supported Protocols	Courier (tunnelled), IEC 61850, PTP, SNTP, SNMP, RADIUS, syslog
Redundancy Protocols Supported	PRP (Parallel Redundancy Protocol) HSR (High-availability Seamless Redundancy) RSTP (Rapid Spanning Tree Protocol) Failover
Constraints	Maximum cable length 100 m

23.2.10 REAR ETHERNET PORT FIBRE

Rear Ethernet Port using Fibre-optic Cabling	
Main Use	Substation Ethernet communications
Connector	IEC 874-10 BFOC 2.5 - (LC®) (1 each for Tx and Rx)
Standard	IEEE 802.3 100 BaseFX
Fibre type	Multimode 50/125 µm (OM2 or OM3) or 62.5/125 µm (OM1)
Supported Protocols	Courier (tunnelled), IEC 61850, PTP, SNTP, SNMP, RADIUS, syslog
Redundancy Protocols Supported	PRP (Parallel Redundancy Protocol) HSR (High-availability Seamless Redundancy) RSTP (Rapid Spanning Tree Protocol) Failover
Wavelength	1310 nm

23.2.10.1 100 BASE FX RECEIVER CHARACTERISTICS

Parameter	Sym	Min.	Typ.	Max.	Unit
Input Optical Power Minimum at Window Edge	PIN Min. (W)	-31.0		-12.0	dBm avg.
Input Optical Power Minimum at Eye Center	PIN Min. (C)		-34.5	-31.8	Bm avg.
Input Optical Power Maximum	PIN Max.	-14	-11.8		dBm avg.

Note:
Conditions: TA = 0°C to 70°C

23.2.10.2 100 BASE FX TRANSMITTER CHARACTERISTICS

Parameter	Sym	Min.	Typ.	Max.	Unit
Output Optical Power BOL 62.5/125 µm NA = 0.275 Fibre EOL	PO	-20	-17.0	-14.0	dBm avg.
Output Optical Power BOL 50/125 µm NA = 0.20 Fibre EOL	PO	-24.0	-21.0	-17.0	dBm avg.
Optical Extinction Ratio	ER	10			dB
Output Optical Power at Logic "0" State	$P_{O(off)}$			-45	dBm avg.

Note:
Conditions: TA = 0°C to 70°C

23.3 PERFORMANCE OF CURRENT PROTECTION FUNCTIONS

23.3.1 PHASE OVERCURRENT PROTECTION

Accuracy	
IDMT pick-up	1.05 x setting +/-5%
DT pick-up	Setting +/-5%
Drop-off (IDMT and DT)	0.95 x setting +/-5%
IDMT operate time	+/-5% or 40 ms, whichever is greater *
IEEE reset time	+/-5% or 40 ms, whichever is greater **
DT operate time	+/-2% or 25 ms, whichever is greater (non-directional) * +/-2% or 40 ms, whichever is greater (directional) *
DT reset time	+/-5% or 40 ms, whichever is greater **
Repeatability	< 5%
Characteristic UK	IEC 60255-151: 2009
Characteristic US	IEEE C37.112 1996

23.3.1.1 TRANSIENT OVERREACH AND OVERSHOOT

Additional tolerance due to increasing X/R ratios	+/-5% over the X/R ratio of 1 to 90
Overshoot overcurrent elements	< 30 ms

23.3.1.2 PHASE OVERCURRENT DIRECTIONAL PARAMETERS

Accuracy	
Directional boundary pickup (RCA +/-90%)	+/-2° ◆
Directional boundary hysteresis	<2°
Directional boundary repeatability	<2%

23.3.1.3 VOLTAGE DEPENDENT OVERCURRENT PROTECTION

Accuracy	
Voltage threshold pick-up	1.05 x setting +/-5%
Voltage threshold drop-off	Setting +/-5%
Current threshold pick-up	0.95 x setting +/-5%
Current threshold drop-off	+/-5% or 40 ms, whichever is greater *

Note:
These specifications apply to both VCO and VRO.

23.3.1.4 LOAD BLINDER FOR OVERCURRENT PROTECTION

Accuracy	
Impedance Magnitude Pick-up	Setting +/-10% [1]
Impedance Angle Pick-up	Setting +/-5% [1]

Accuracy	
V< Pick-up	Setting +/-5%
I2> Pick-up	Setting +/-5%

Note:
[1] Reference conditions: Pick-up and drop-off cycles set to default of 1 cycle.

23.3.1.5 COLD LOAD PICK-UP PROTECTION

Performance of the cold load protection functions is similar to the independent overcurrent protection.

23.3.1.6 SELECTIVE OVERCURRENT PROTECTION

Accuracy	
Fast Block operation	<25 ms
Fast Block reset	<30 ms

23.3.2 MEASURED EARTH FAULT PROTECTION

Accuracy	
IDMT pick-up	1.05 x setting +/-5%
DT pick-up	Setting +/-5%, or 20 mA, whichever is greater
Drop-off (IDMT and DT)	0.95 x setting +/-5%
IDMT operate time	+/-5% or 40 ms, whichever is greater *
IEEE reset time	+/-5% or 40 ms, whichever is greater **
Repeatability	<5%
DT operate time	+/-2% or 25 ms, whichever is greater (non-directional) * +/-2% or 40 ms, whichever is greater (directional) *
DT reset time	+/-5% or 40 ms, whichever is greater **

23.3.3 DERIVED EARTH FAULT PROTECTION

Accuracy	
IDMT pick-up	1.05 x setting +/-5%
DT pick-up	Setting +/-5%, or 20 mA, whichever is greater
Drop-off (IDMT and DT)	0.95 x setting +/-5%
IDMT operate time	+/-5% or 40 ms, whichever is greater *
IEEE reset time	+/-10% or 40 ms, whichever is greater **
Repeatability	<5%
DT operate time	+/-2% or 25 ms, whichever is greater (non-directional) * +/-2% or 40 ms, whichever is greater (directional) *
DT reset time	+/-5% or 40 ms, whichever is greater **

23.3.3.1 EARTH FAULT DIRECTIONAL PARAMETERS

Zero Sequence Polarising Accuracy	
Directional boundary pick-up (RCA +/- 90°)	+/-2° ◆
Hysteresis	<3°

Zero Sequence Polarising Accuracy	
VN> pick-up	Setting +/-10%
VN> drop-off	0.9 x setting +/-10%

Negative Sequence Polarising Accuracy	
Directional boundary pick-up (RCA +/- 90°)	+/-2° ◆
Hysteresis	<3°
V2> pick-up	Setting +/-10%
V2> drop-off	0.9 x setting +/-10%
I2> pick-up	Setting +/-10%
I2> drop-off	0.9 x setting +/-10%

23.3.4 SENSITIVE EARTH FAULT PROTECTION

IDMT Pick-up	1.05 x Setting +/-5%
DT Pick-up	Setting +/-5%
Drop-off (IDMT + DT)	0.95 x setting +/-5%
IDMT operate time	+/-5% or 40 ms, whichever is greater *
IEEE reset time	+/-5% or 40 ms, whichever is greater **
DT operate time	+/-2% or 25 ms, whichever is greater (non-directional) * +/-2% or 40 ms, whichever is greater (directional) *
DT reset time	+/-5% or 40 ms, whichever is greater **
Repeatability	<5%

Note:
SEF claims apply to SEF input currents of no more than 2 x In. For input ranges above 2 x In, the claim is not supported.

23.3.4.1 SENSITIVE EARTH FAULT PROTECTION DIRECTIONAL ELEMENT

Directional Accuracy	
Directional boundary pick-up (RCA+/-90°)	+/-5° ◆
Hysteresis	<3°
VN> pick-up	Setting +/-10%
VN> drop-off	0.9 x setting +/-10%

Wattmetric SEF Accuracy	
Pick-up P = 0 W	ISEF> +/-5% or 5 mA
Pick-up P > 0 W	P > +/-5%
Drop-off P = 0 W	0.95 x ISEF> +/-5% or 5 mA
Drop-off P > 0 W	0.9 x P> +/-5% or 5 mA
Boundary accuracy	+/-5° with hysteresis < 1°
Repeatability	<1%

SEF CosΦ Accuracy	
Pick-up	Setting +/-5% for angles RCA+/-60°
Drop-off	0.95 x setting +/-5%
Repeatability	+/-2%

SEF SinΦ Accuracy	
Pick-up	Setting +/-5% for angles RCA+/-60° to RCA+/-90°
Drop-off	0.9 x setting +/-5%
Repeatability	+/-2%

23.3.5 RESTRICTED EARTH FAULT PROTECTION

Low Impedance	
Pick-up	Setting +/-5%
Drop-off	0.8 x setting +/-5%
Operating time	<60 ms
Repeatability	<5%

High Impedance	
Pick-up	Setting +/-10%
Operating time	<30 ms
Repeatability	<5%

23.3.6 NEUTRAL ADMITTANCE PROTECTION

YN, BN, GN measurements	+/-5%
YN, BN, GN pick-up	Setting +/-5%
YN, BN, GN drop-off	0.88 x setting +/-5%
DT operate	Setting +/-2% + (<5 cycles)
Reset claim	Setting +/-2% + (<5 cycles)
Directional boundary accuracy	+/- 2° ◆
VN	Setting +/-5%

23.3.7 NEGATIVE SEQUENCE OVERCURRENT PROTECTION

IDMT pick-up	1.05 x Setting +/-5%
DT pick-up	Setting +/-5%
Drop-off (IDMT and DT)	0.95 x Setting +/-5%
IDMT operate time	+/-5% or 40 ms, whichever is greater
DT operate time	+/-2% or 60 ms, whichever is greater
DT Reset time	Setting +/-5%

23.3.7.1 NEGATIVE SEQUENCE OVERCURRENT PROTECTION DIRECTIONAL PARAMETERS

Directional boundary pick-up (RCA+/-90%)	+/-2° ◆
Directional boundary hysteresis	<1°
Directional boundary repeatability	<1%

23.3.8 CIRCUIT BREAKER FAIL AND UNDERCURRENT PROTECTION

I< Pick-up	Setting +/-10% or 0.025 In, whichever is greater
I< Drop-off	Setting +/-5% or 20 mA, whichever is greater
Operate time	<12 ms ✦
Timers	+/-2% or 20 ms, whichever is greater
Reset time	<15 ms

Note:
✦ Operating time measured with applied current of 20% above thermal setting.

23.3.9 BROKEN CONDUCTOR PROTECTION

Pick-up	Setting +/-2.5%
Drop-off	0.95 x setting +/-2.5%
DT operate time	+/-2% or 40 ms, whichever is greater
Reset time	<30 ms
I< Pick-up	Setting +/-10% or 0.025 In, whichever is greater

23.3.10 THERMAL OVERLOAD PROTECTION

Thermal alarm pick-up	Calculated trip time +/-10%
Thermal overload pick-up	Calculated trip time +/-10%
Cooling time accuracy	+/-15% of theoretical
Repeatability	<5%

Note:
** Reference conditions: Injected value is 2 x pick-up value or more, effective range (0.1 - 20In).*
*** Reference conditions: Injected value instantaneously reduced to 0 (zero) from 2 x pick-up value.*
◆ Reference conditions: Tested with nominal voltage or current.

23.4 PERFORMANCE OF VOLTAGE PROTECTION FUNCTIONS

23.4.1 OVERVOLTAGE PROTECTION

Pick-up (DT)	Setting +/-1%
Pick-up (IDMT)	1.02 x setting +/-2%
Drop-off (DT and IDMT)	0.98 x setting +/-2%
DT operate time	+/-2% or 50 ms, whichever is greater ⌑
IDMT operate time	+/-5% or 50 ms, whichever is greater ⌑
Reset	<75 ms
Repeatability	<1%

23.4.2 UNDERVOLTAGE PROTECTION

Pick-up (DT)	Setting +/-5%
Pick-up (IDMT)	0.98 x setting +/-2%
Drop-off (DT and IDMT)	1.02 x setting +/-2%
DT operate time	+/-2% or 50 ms, whichever is greater ⌑
IDMT operate time	+/-5% or 50 ms, whichever is greater ⌑
Reset	<35 ms
Repeatability	<1%

23.4.3 RESIDUAL OVERVOLTAGE PROTECTION

Pick-up (DT)	Setting +/-5%
Pick-up (IDMT)	1.05 x setting +/-5%
Drop-off (DT and IDMT)	0.95 x Setting +/-5%
DT operate time	+/-2% or 60 ms, whichever is greater ⌑
IDMT operate time	+/-5% or 65 ms, whichever is greater ⌑
Instantaneous operation	<50 ms
Reset	<35 ms
Repeatability	<10%

23.4.4 COMPENSATED OVERVOLTAGE PROTECTION

Pick-up (DT)	Setting +/-1%
Pick-up (IDMT)	1.02 x Setting +/-2%
Drop-off (DT and IDMT)	(1-(**Cp V Hysteresis** setting))* setting +/-2%

DT operate time	+/-2% or 40 ms, whichever is greater ⌑
IDMT operate time	+/-2% or 40 ms, whichever is greater ⌑
Reset	<75 ms
Repeatability	<1%

23.4.5 NEGATIVE SEQUENCE OVERVOLTAGE PROTECTION

Pick-up	Setting +/-5%
Drop-off	0.95 x setting +/-5%
DT operate time (accelerated)	+/-2% or 45 ms, whichever is greater ⌑
DT operate time (normal operation)	+/-2% or 65 ms, whichever is greater ⌑
Repeatability	<5%

23.4.6 VOLTAGE MONITOR

Live Voltage Accuracy	
Pick-up	Setting +/-3% or +/-0.1 V, whichever is greater
Drop-off	(0.98 x setting) +/-3% or +/-0.1 V, whichever is greater
Repeatability	<1%

Dead Voltage Accuracy	
Pick-up	Setting +/-3% or +/-0.1 V, whichever is greater
Drop-off	(1.02 x setting) +/-3% or +/-0.1 V, whichever is greater
Repeatability	<1%

Diff Voltage Accuracy	
Pick-up	Setting +/-3% or +/-0.1 V, whichever is greater
Drop-off	(0.98 x setting) +/-3% or +/-0.1 V, whichever is greater
Repeatability	<1%

Overvoltage Accuracy	
Pick-up	Setting +/-3% or +/-0.1 V, whichever is greater
Drop-off	(0.98 x setting) +/-3% or +/-0.1 V, whichever is greater
Repeatability	<1%

Undervoltage Accuracy	
Pick-up	Setting +/-3% or +/-0.1 V, whichever is greater
Drop-off	(1.02 x setting) +/-3% or +/-0.1 V, whichever is greater
Repeatability	<1%

23.4.7 CHECK SYNCHRONISATION

Accuracy (CS1/CS2)	
Phase Angle	
Pick-up	(Setting-2°) ±1° *
Drop-off	(Setting-1°) ±1° *
Repeatability	<1%
Slip Frequency	
Pick-up	Setting ±0.01 Hz
Drop-off	(0.95 x Setting) ±0.01 Hz
Repeatability	<1%
Slip Timer	
Timers	+/-1% or 40 ms, whichever is greater
Reset time	<30 ms
Repeatability	<10 ms

Note:
** **CS VT Ph Shift** setting = 0°*

23.4.8 SYSTEM SPLIT

SS Phase Angle Accuracy	
Pick-up	(Setting +2°) +/-1°
Drop-off	(Setting +1°) +/-1°
Repeatability	<1%

SS Undervoltage Accuracy	
Pick-up	Setting +/-3%
Drop-off	1.02 x setting
Repeatability	<1%

SS Timer	
Timers	Setting +/-1% or 40 ms, whichever is greater
Reset time	<30 ms
Repeatability	<10 ms

Note:
** Reference conditions: Injected value is 2 x pick-up value or more, effective range (0.1 - 20In).*
¤ Reference conditions: Injected value is 0.7 x pick-up or less for undervoltage and 1.2 x pick-up or more for overvoltage, effective range (0.2 - 2Vn).

23.5 PERFORMANCE OF FREQUENCY PROTECTION FUNCTIONS

23.5.1 OVERFREQUENCY PROTECTION

Accuracy	
Pick-up	Setting +/-10 mHz
Drop-off	Setting -20 mHz +/-10 mHz
Operating timer	+/-2% or 50 ms, whichever is greater

Operating and Reset Time	
Operating time (Fs/Ff ratio less than 2)	<125 ms
Operating time (Fs/Ff ratio between 2 and 30)	<150 ms
Operating time (Fs/Ff ratio greater than 30)	<200 ms
Reset time	<200 ms

Note:
Reference conditions: Tested using step changed in frequency with Freq. Av Cycles setting = 0 and no intentional time delay.
Fs = start frequency - frequency setting
Ff = frequency setting - end frequency

23.5.2 UNDERFREQUENCY PROTECTION

Accuracy	
Pick-up	Setting +/-10 mHz
Drop-off	Setting + 20 mHz +/-10 mHz
Operating timer	+/-2% or 50 ms, whichever is greater

Operating and Reset Time	
Operating time (Fs/Ff ratio less than 2)	<100 ms
Operating time (Fs/Ff ratio between 2 and 6)	<160 ms
Operating time (Fs/Ff ratio greater than 6)	<230 ms
Reset time	<200 ms

Note:
Reference conditions: Tested using step changed in frequency with Freq. Av Cycles setting = 0 and no intentional time delay.
Fs = start frequency - frequency setting
Ff = frequency setting - end frequency

23.6 ADVANCED FREQUENCY

23.6.1 ADVANCED OVERFREQUENCY PROTECTION

Accuracy	
Pick-up	Setting +/-5 mHz
Drop-off	(Setting -25 mHz) +/-5 mHz
Operating timer	+/-2% or 50 ms, whichever is greater

Operating and Reset Time	
Operating time (Fs/Ff ratio less than 2)	<125 ms
Operating time (Fs/Ff ratio between 2 and 30)	<150 ms
Operating time (Fs/Ff ratio greater than 30)	<200 ms
Reset time	<200 ms

Note:
Reference conditions: Tested using step changed in frequency with Freq. Av Cycles setting = 0 and no intentional time delay.
Fs = start frequency - frequency setting
Ff = frequency setting - end frequency

23.6.2 ADVANCED UNDERFREQUENCY PROTECTION

Accuracy	
Pick-up	Setting +/-5 mHz
Drop-off	(Setting +25 mHz) +/-5 mHz
Operating timer	+/-2% or 50 ms, whichever is greater

Operating and Reset Time	
Operating time (Fs/Ff ratio less than 2)	<125 ms
Operating time (Fs/Ff ratio between 2 and 6)	<160 ms
Operating time (Fs/Ff ratio greater than 6)	<230 ms
Reset time	<200 ms

Note:
Reference conditions: Tested using step changed in frequency with Freq. Av Cycles setting = 0 and no intentional time delay.
Fs = start frequency - frequency setting
Ff = frequency setting - end frequency

23.6.3 INDEPENDENT RATE OF CHANGE OF FREQUENCY PROTECTION

Accuracy	
Pick-up (df/dt)	Setting +/-3% or +/-10 mHz/s, whichever is greater
Drop-off (df/dt, for settings between 10 mHz/s and 100 mHz/s)	(Setting -5 mHz/s) +/-3% or +/-10 mHz/s, whichever is greater
Drop-off (df/dt, for settings greater than 100 mHz/s)	(0.95 x Setting) +/-3% or +/-10 mHz/s, whichever is greater
Operating timer	+/-2% or 50 ms, whichever is greater

Operating and Reset Time	
Operating time (for ramps 2 x setting or greater)	<300 ms
Operating time (for ramps 1.3 x setting or greater)	<475 ms
Reset time	<150 ms

Note:
Reference Conditions: Tested with df/dt Average Cycles = 2, df/dt Smoothing Factor = 0.01, for df/dt settings greater than 0.1 Hz/s, and no intentional time delay.

23.6.4 SUPERVISED RATE OF CHANGE OF FREQUENCY PROTECTION

Accuracy	
Pick-up (f)	Setting +/-10 mHz
Pick-up (df/dt)	Setting +/-3% or +/-10 mHz/s, whichever is greater
Drop-off (f, underfrequency)	(Setting +20 mHz) +/-10 mHz
Drop-off (f, overfrequency)	(Setting -20 mHz) +/-10 mHz
Drop-off (df/dt, for settings between 10 mHz/s and 100 mHz/s)	(Setting -5 mHz/s) +/-3% or +/-10 mHz/s, whichever is greater
Drop-off (df/dt, for settings greater than 100 mHz/s)	(0.95 x Setting) +/-3% or +/-10 mHz/s, whichever is greater

Operating and Reset Time	
Operating time (for ramps 2 x setting or greater)	<300 ms
Operating time (for ramps 1.3 x setting or greater)	<475 ms
Reset time	<150 ms

Note:
Reference Conditions: Tested with df/dt Average Cycles = 2, df/dt Smoothing Factor = 0.01, for df/dt settings greater than 0.1 Hz/s, and no intentional time delay.

23.6.5 AVERAGE RATE OF CHANGE OF FREQUENCY PROTECTION

Accuracy	
Pick-up (f)	Setting +/-10 mHz
Pick-up (Df/Dt)	Setting +/-100 mHz/s
Drop-off (falling)	(Setting +20 mHz) +/-10 mHz
Drop-off (rising)	(Setting -20 mHz) +/-10 mHz

Accuracy	
Operating timer	+/-2% or 30 ms, whichever is greater

Operating Time	
Operating time (Freq. Av Cycles setting = 0)	<125 ms

Note:
Reference conditions: To maintain accuracy, the minimum time delay setting should be:
Dt> 0.375 x Df + 0.23 (f0r Df setting < 1 Hz)
Dt> 0.156 x Df + 0.47 (for Df setting > = 1 Hz)

23.6.6 LOAD RESTORATION

Pick-up	Setting +/-2.5%
Drop-off	0.95% x setting +/-2.5%
Restoration timer	+/-2% or 50 ms, whichever is greater
Holding timer	+/-2% or 50 ms, whichever is greater

23.7 PERFORMANCE OF POWER PROTECTION FUNCTIONS

23.7.1 OVERPOWER/UNDERPOWER PROTECTION

Pick-up	Setting +/-10%
Reverse/overpower drop-off	0.95 x setting +/-10%
Low forward power drop-off	1.05 x setting +/-10%
Angle variation pick-up	+/-2°
Angle variation drop-off	+/-2.5°
Operating time	+/-2% or 50 ms, whichever is greater
Repeatability	<5%
Disengagement time	<50 ms
tRESET	+/-5%
Instantaneous operating time	<50 ms

23.8 AUTORECLOSE

Accuracy	
Timers	+/-20 ms or 2%, whichever is greater

23.9 MONITORING, CONTROL AND SUPERVISION

23.9.1 VOLTAGE TRANSFORMER SUPERVISION

Fast block operation, loss of 1 and 2 phases	<1 cycle
Fast Block operation, loss of 3 phases	<1.5 cycle
Time delay	+/-2% or 30 ms, whichever is greater

23.9.2 STANDARD CURRENT TRANSFORMER SUPERVISION

IN> Pick-up	Setting +/-5%
VN< Pick-up	Setting +/-5%
IN> Drop-off	0.9 x setting +/-5%
VN< Drop-off	1.05 x setting +/-5% or 1 V, whichever is greater
Time delay operation	Setting +/-2% or 30 ms, whichever is greater
CTS block operation	<1 cycle
CTS reset	<35 ms

23.9.3 CB STATE AND CONDITION MONITORING

Accuracy	
Timers	+/-40 ms or 2%, whichever is greater
Broken current accuracy	+/-5%
Reset time	<30 ms

23.9.4 PSL TIMERS

Output conditioner timer	Setting +/-2% or 50 ms, whichever is greater
Dwell conditioner timer	Setting +/-2% or 50 ms, whichever is greater
Pulse conditioner timer	Setting +/-2% or 50 ms, whichever is greater

23.10 MEASUREMENTS AND RECORDING

23.10.1 GENERAL

General Measurement Accuracy	
Current (0.05 to 2 In)	+/-0.5% or 4mA whichever is greater (1A input) +/-0.5% or 20mA whichever is greater (5A input)
Voltage (0.05 to 2 Vn)	+/-0.5% or 100mV whichever is greater
Phase	+/-2° at rated voltage and current
Frequency (45 to 65 Hz)	+/-0.025 Hz
Power (W) (0.2 to 2 Vn and 0.05 to 3 In)	+/-5.0% of reading at unity power factor
Reactive power (Vars) (0.2 to 2 Vn and 0.05 to 3 In)	+/-5.0% of reading at zero power factor
Apparent power (VA) (0.2 to 2 Vn and 0.05 to 3 In)	+/-5.0% of reading
Energy (Wh) (0.2 to 2 Vn and 0.2 to 3 In)	+/-5.0% of reading at unity power factor
Energy (Varh) (0.2 to 2 Vn and 0.2 to 3In)	+/-5.0% of reading at zero power factor

23.10.2 DISTURBANCE RECORDS

Disturbance Records Data	
Minimum record duration	0.1 s
Maximum record duration	10.5 s
Minimum number of records at 10.5 seconds	100
Magnitude and relative phases accuracy	+/-5% of applied quantities
Duration accuracy	+/-2%
Trigger position accuracy	+/-2% (minimum Trigger 100 ms)
Resolution	48 samples per cycle (frequency tracked to +/-0.025 Hz)
Maximum number of digital (binary) channels	128
Maximum number of analog channels	8
High frequency attenuation (analog channels)	>3dB above 420Hz

23.10.3 EVENT, FAULT AND MAINTENANCE RECORDS

Event, Fault & Maintenance Records	
Record location	Flash memory
Viewing method	Front panel display or Settings Application Software
Extraction method	Extracted via USB, RP1, RP2, NIC (Ethernet) port
Number of event records	Up to 5000 time tagged event records (newest overwrites oldest)
Number of fault records	Up to 100
Number of maintenance records	Up to 10
Event time stamp resolution	1 ms

23.10.4 FAULT LOCATOR

Accuracy	
Fault Location	Typically <5% of line length Reference conditions: solid fault applied on line

23.11 RATINGS

23.11.1 AC MEASURING INPUTS

AC Measuring Inputs	
Nominal frequency	50 Hz or 60 Hz (settable)
Operating range	45 to 65 Hz
Phase rotation	ABC or CBA

23.11.2 CURRENT TRANSFORMER INPUTS

AC Current Inputs	
Nominal current (In)	1A or 5A
Nominal burden per phase	<0.2 VA at In
AC current thermal withstand (5A input)	20 A (continuous operation) 150 A (for 10 s) 500 A (for 1 s)
AC current thermal withstand (1A input)	4 A (continuous operation) 30 A (for 10 s) 100 A (for 1 s)
Linearity	Standard: Linear up to 64 × In (non-offset AC current) Sensitive: Linear up to 2 × In (non-offset AC current)

23.11.3 VOLTAGE TRANSFORMER INPUTS

AC Voltage Inputs	
Nominal voltage (Vn)	100 V to 120 V (ph-ph) or 57.74 V to 69.28 V (ph-n)
Nominal burden per VT input *1	<0.003 VA @ 69.3 V (ph-n) <0.01 VA @ 138.6 V (ph-n)
Linearity for each VT input	Linear up to 200 Vac rms
Continuous rating for each VT input	240 Vac rms
10 seconds rating for each VT input	312 Vac rms

Note:
*Reference Conditions: * = Overfrequency operating range 50/60 Hz and over temperature range 20° +/-5°C.*

23.11.4 AUXILIARY SUPPLY VOLTAGE

Nominal operating range	CORTEC option (DC only) 24 to 48 V DC CORTEC option (rated for AC or DC operation) 48 to 110 V DC 40 to 100 V AC rms CORTEC option (rated for AC or DC operation) 110 to 250 V DC 100 to 240 V AC rms

Maximum operating range	CORTEC option (DC only) 19 to 65 V DC CORTEC option (rated for AC or DC operation) 37 to 150 V DC 32 to 110 V AC rms CORTEC option (rated for AC or DC operation) 87 to 300 V DC 80 to 265 V AC rms
Frequency range for AC supply	45 to 65 Hz
Ripple	<15% for a DC supply (compliant with IEC 60255-26:2013)
Power up time	<11 seconds

23.11.5 NOMINAL BURDEN

Quiescent burden	11.2 W or 22 VA
2nd rear communications port	1.25 W or 2.5 VA
Each relay output burden	0.13 W or 0.25 VA per output relay
Each opto-input burden (24 - 27 V)	0.065 W or 0.13 VA max
Each opto-input burden (30 - 34 V)	0.065 W or 0.13 VA max
Each opto-input burden (48 - 54 V)	0.125 W or 0.25 VA max
Each opto-input burden (110 - 125 V)	0.36 W or 0.72 VA max
Each opto-input burden (220 - 250 V)	0.9 W or 1.8 VA max

23.11.6 POWER SUPPLY INTERRUPTION

Standard	IEC 60255-26:2013 (DC and AC)
24-48V DC SUPPLY 100% interruption without de-energising	20 ms at 24 V (half and full load) 50 ms at 36 V (half and full load) 100 ms at 48 V (half and full load)
48-110V DC SUPPLY 100% interruption without de-energising	20 ms at 37 V (half and full load) 50 ms at 60 V (half and full load) 100 ms at 72 V (half load) 100 ms at 85 V (full load) 200 ms at 110 V (half and full load)
110-250V DC SUPPLY 100% interruption without de-energising	20 ms at 87 V (half load) 50 ms at 110 V (half load) 50 ms at 98 V (full load) 100 ms at 160 V (half load) 100 ms at 135 V (full load) 200 ms at 210 V (half load) 200 ms at 174 V (full load)
40-100V AC SUPPLY 100% voltage dip without de-energising	50 ms at 32 V (half load) 10 ms at 32 V (full load)
100-240V AC SUPPLY 100% voltage dip without de-energising	50 ms at 80 V (full and half load)

Note:
Maximum loading = all inputs/outputs energised.
Quiescent or 1/2 loading = 1/2 of all inputs/outputs energised.

23.11.7 SUPERCAPACITOR

Discharge time	>14 days

23.12 INPUT/OUTPUT CONNECTIONS

23.12.1 ISOLATED DIGITAL INPUTS

Opto-isolated Digital Inputs (Opto-inputs)	
Compliance	ESI 48-4
Rated nominal voltage	24 to 250 V dc
Operating range	19 to 265 V dc
Withstand	300 V dc
Recognition time with half-cycle ac immunity filter removed	<2 ms
Recognition time with filter on	<12 ms

23.12.1.1 NOMINAL PICKUP AND RESET THRESHOLDS

Nominal Battery Voltage	Logic Levels: 60-80% DO/PU	Logic Levels: 50-70% DO/PU
24/27 V	Logic 0 <16.2 V, Logic 1 >19.2 V	Logic 0 <12 V, Logic 1 >16.8 V
30/34	Logic 0 <20.4 V, Logic 1 >24 V	Logic 0 <15 V, Logic 1 >21 V
48/54	Logic 0 <32.4 V, Logic 1 >38.4 V	Logic 0 <24 V, Logic 1 >33.6 V
110/125	Logic 0 <75 V, Logic 1 >88 V	Logic 0 <55 V, Logic 1 >77 V
220/250	Logic 0 <150 V, Logic 1 >176 V	Logic 0 <110 V, Logic 1 >154 V

Note:
Filter is required to make the opto-inputs immune to induced AC voltages.

23.12.2 STANDARD OUTPUT CONTACTS

Compliance	In accordance with IEC 60255-1:2009
Use	General purpose relay outputs for signalling, tripping and alarming
Rated voltage	300 V
Maximum continuous current	10 A
Short duration withstand carry	30 A for 3 s 250 A for 30 ms
Make and break, dc resistive	50 W
Make and break, dc inductive	62.5 W (L/R = 50 ms)
Make and break, ac resistive	2500 VA resistive (cos phi = unity)
Make and break, ac inductive	2500 VA inductive (cos phi = 0.7)
Make and carry, dc resistive	30 A for 3 s, 10000 operations (subject to a maximum load of 7500W))
Make, carry and break, dc resistive	4 A for 1.5 s, 10000 operations (subject to the above limit for make and break, dc resistive load)
Make, carry and break, dc inductive	0.5 A for 1 s, 10000 operations (subject to the above limit for make and break, dc inductive load)
Make, carry and break ac resistive	30 A for 200 ms, 2000 operations (subject to the above limits)
Make, carry and break ac inductive	10 A for 1.5 s, 10000 operations (subject to the above limits)
Loaded contact	10000 operations min.
Unloaded contact	100000 operations min.

Operate time	<5 ms
Reset time	<10 ms

23.12.3 HIGH BREAK OUTPUT CONTACTS

Compliance	In accordance with IEC 60255-1:2009
Use	For applications requiring high rupture capacity
Rated voltage	300 V
Maximum continuous current	10 A DC
Short duration withstand carry	30 A DC for 3 s 250 A for 30 ms
Make and break, dc resistive	7500 W
Make and break, dc inductive	2500 W (L/R = 50 ms)
Make and carry, dc resistive	30 A for 3 s, 10000 operations (subject to the above limits)
Make, carry and break, dc resistive	30 A for 3 s, 5000 operations (subject to the above limit for make and break, dc resistive load) 30 A for 200 ms, 10000 operations (subject to the above limit for make and break, dc resistive load)
Make, carry and break, dc inductive	10 A for 40 ms, 10000 operations (subject to the above limit for make and break, dc inductive load) 10 A for 20 ms (250 V, 4 shots per second, subject to the above limit for make and break, dc inductive load)
Loaded contact	10,000 operations minimum.
Unloaded contact	100,000 operations minimum.
Operate time	<0.2 ms
Reset time	<8 ms
MOV Protection	Maximum voltage 330 V DC

23.12.4 WATCHDOG CONTACTS

Use	Non-programmable contacts for relay healthy/relay fail indication
Breaking capacity, dc resistive	30 W
Breaking capacity, dc inductive	15 W (L/R = 40 ms)
Breaking capacity, ac inductive	375 VA inductive (cos phi = 0.7)

23.13 MECHANICAL SPECIFICATIONS

23.13.1 PHYSICAL PARAMETERS

Case Types*	40TE 60TE 80TE
Weight (40TE case)	7 kg - 8 kg (depending on chosen options)
Weight (60TE case)	9 kg - 12 kg (depending on chosen options)
Weight (80TE case)	13 kg - 16 kg (depending on chosen options)
Dimensions in mm (w x h x l) (40TE case)	W: 206.0 mm H: 177.0 mm D: 243.1 mm
Dimensions in mm (w x h x l) (60TE case)	W: 309.6 mm H: 177.0 mm D: 243.1 mm
Dimensions in mm (w x h x l) (80TE case)	W 413.2 mm H 177.0 mm D 243.1 mm
Mounting	Panel, rack, or retrofit

Note:
**Case size is product dependent.*

23.13.2 ENCLOSURE PROTECTION

Against dust and dripping water (front face)	IP52 as per IEC 60529:1989/A2:2013
Protection against dust (whole case)	IP50 as per IEC 60529:1989/A2:2013
Protection for sides of the case (safety)	IP30 as per IEC 60529:1989/A2:2013
Protection for rear of the case (safety)	IP10 as per IEC 60529:1989/A2:2013

23.13.3 MECHANICAL ROBUSTNESS

Vibration test per EN 60255-21-1:1998	Response: class 2, Endurance: class 2
Shock and bump immunity per EN 60255-21-2:1988	Shock response: class 2, Shock withstand: class 1, Bump withstand: class 1
Seismic test per EN 60255-21-3: 1993	Class 2

23.13.4 TRANSIT PACKAGING PERFORMANCE

Primary packaging carton protection	ISTA 1C
Vibration tests	3 orientations, 7 Hz, amplitude 5.3 mm, acceleration 1.05g
Drop tests	10 drops from 610 mm height on multiple carton faces, edges and corners

23.14 TYPE TESTS

23.14.1 INSULATION

Compliance	IEC 60255-27: 2013
Insulation resistance	>100 M ohm at 500 V DC (Using only electronic/brushless insulation tester)

23.14.2 CREEPAGE DISTANCES AND CLEARANCES

Compliance	IEC 60255-27: 2013
Pollution degree	3
Overvoltage category	III
Impulse test voltage (not RJ45)	5 kV
Impulse test voltage (RJ45)	1 kV

23.14.3 HIGH VOLTAGE (DIELECTRIC) WITHSTAND

IEC Compliance	IEC 60255-27: 2013
Between all independent circuits	2 kV ac rms for 1 minute
Between independent circuits and protective earth conductor terminal	2 kV ac rms for 1 minute
Between all case terminals and the case earth	2 kV ac rms for 1 minute
Across open watchdog contacts	1 kV ac rms for 1 minute
Across open contacts of changeover output relays	1 kV ac rms for 1 minute
Between all RJ45 contacts and protective earth	1 kV ac rms for 1 minute
Between all screw-type EIA(RS)485 contacts and protective earth	1 kV ac rms for 1 minute
ANSI/IEEE Compliance	ANSI/IEEE C37.90-2005
Across open contacts of normally open output relays	1.5 kV ac rms for 1 minute
Across open contacts of normally open changeover output relays	1 kV ac rms for 1 minute
Across open watchdog contacts	1 kV ac rms for 1 minute

23.14.4 IMPULSE VOLTAGE WITHSTAND TEST

Compliance	IEC 60255-27: 2013
Between all independent circuits	Front time: 1.2 µs, Time to half-value: 50 µs, Peak value: 5 kV, 0.5 J
Between terminals of all independent circuits	Front time: 1.2 µs, Time to half-value: 50 µs, Peak value: 5 kV, 0.5 J
Between all independent circuits and protective earth conductor terminal	Front time: 1.2 µs, Time to half-value: 50 µs, Peak value: 5 kV, 0.5 J

Note:
Exceptions are communications ports and normally-open output contacts, where applicable.

23.15 ENVIRONMENTAL CONDITIONS

23.15.1 AMBIENT TEMPERATURE RANGE

Compliance	IEC 60255-27: 2013
Test Method	IEC 60068-2-1:2007 and IEC 60068-2-2 2007
Operating temperature range	-25°C to +55°C (continuous)
Storage and transit temperature range	-25°C to +70°C (continuous)

23.15.2 TEMPERATURE ENDURANCE TEST

Temperature Endurance Test	
Test Method	IEC 60068-2-1: 2007 and 60068-2-2: 2007
Operating temperature range	-40°C (96 hours) +70°C (96 hours)
Storage and transit temperature range	-40°C (96 hours) +70°C (96 hours)

23.15.3 AMBIENT HUMIDITY RANGE

Compliance	IEC 60068-2-78: 2012 and IEC 60068-2-30: 2005
Durability	56 days at 93% relative humidity and +40°C
Damp heat cyclic	Six (12 + 12) hour cycles, 93% RH, +25 to +55°C

23.15.4 CORROSIVE ENVIRONMENTS

Compliance, Industrial corrosive environment/poor environmental control	IEC 60068-2-42: 2003, IEC 60068-2-43: 2003, IEC 60068-2-52: 1996
Sulphur Dioxide, IEC 60068-2-42: 2003	21 days exposure to elevated concentrations (25ppm) of SO_2 at 75% relative humidity and +25°C
Hydrogen Sulphide, IEC 60068-2-43: 2003	21 days exposure to elevated concentrations (10ppm) of H_2S at 75% relative humidity and +25°C
Salt mist, IEC 60068-2-52: 1996	7 days, KB severity 3

23.16 ELECTROMAGNETIC COMPATIBILITY

23.16.1 1 MHZ BURST HIGH FREQUENCY DISTURBANCE TEST

Compliance	IEC 60255-26:2013
Common-mode test voltage (level 3)	2.5 kV
Differential test voltage (level 3)	1.0 kV

23.16.2 DAMPED OSCILLATORY TEST

Compliance	EN61000-4-18: 2011: Level 3, 100 kHz and 1 MHz. Level 4: 3 MHz, 10 MHz and 30 MHz, IEC 60255-26:2013
Common-mode test voltage (level 3)	2.5 kV
Common-mode test voltage (level 4)	4.0 kV
Differential mode test voltage	1.0 kV

23.16.3 IMMUNITY TO ELECTROSTATIC DISCHARGE

Compliance	IEC 60255-26:2013, IEC 61000-4-2:2009
Class 4 Condition	15 kV discharge in air to user interface, display, and exposed metalwork
Class 3 Condition	8 kV discharge in air to all communication ports

23.16.4 ELECTRICAL FAST TRANSIENT OR BURST REQUIREMENTS

Compliance	IEC 60255-26:2013, IEC 61000-4-4:2012
Applied to communication inputs	Amplitude: 2 kV, burst frequency 5 kHz and 100 KHz (level 4)
Applied to power supply and all other inputs except for communication inputs	Amplitude: 4 kV, burst frequency 5 kHz and 100 KHz (level 4)

23.16.5 SURGE WITHSTAND CAPABILITY

Compliance	IEEE/ANSI C37.90.1: 2012
Condition 1	4 kV fast transient and 2.5 kV oscillatory applied common mode and differential mode to opto inputs, output relays, CTs, VTs, power supply
Condition 2	4 kV fast transient and 2.5 kV oscillatory applied common mode to communications, IRIG-B

23.16.6 SURGE IMMUNITY TEST

Compliance	IEC 60255-26:2013, IEC 61000-4-5:2014 + AMD1:2017
Pulse duration	Time to half-value: 1.2/50 µs
Between all groups and protective earth conductor terminal	Amplitude 4 kV
Between terminals of each group (excluding communications ports, where applicable)	Amplitude 2 kV

23.16.7 IMMUNITY TO RADIATED ELECTROMAGNETIC ENERGY

Compliance	IEC 60255-26:2013, IEC 61000-4-3:2006 + A2:2010
Frequency band	80 MHz to 3.0 GHz
Spot tests at	80, 160, 380, 450, 900, 1850, 2150 MHz
Test field strength	10 V/m
Test using AM	1 kHz @ 80%
Compliance	IEEE/ANSI C37.90.2: 2004
Frequency band	80 MHz to 1 GHz
Spot tests at	80, 160, 380, 450 MHz
Waveform	1 kHz @ 80% am and pulse modulated
Field strength	35 V/m

23.16.8 RADIATED IMMUNITY FROM DIGITAL COMMUNICATIONS

Compliance	IEC 61000-4-3:2006 + A2:2010
Frequency bands	800 to 960 MHz, 1.4 to 2.0 GHz
Test field strength	30 V/m
Test using AM	1 kHz/80%

23.16.9 RADIATED IMMUNITY FROM DIGITAL RADIO TELEPHONES

Compliance	IEC 60255-26:2013, IEC 61000-4-3:2006 + A2:2010
Frequency bands	900 MHz and 1.89 GHz
Test field strength	10 V/m

23.16.10 IMMUNITY TO CONDUCTED DISTURBANCES INDUCED BY RADIO FREQUENCY FIELDS

Compliance	IEC 60255-26:2013, IEC 61000-4-6:2013 Level 3
Frequency bands	150 kHz to 80 MHz
Test disturbance voltage	10 V rms

Test using AM	1 kHz @ 80%
Spot tests	27 MHz and 68 MHz

23.16.11 MAGNETIC FIELD IMMUNITY

Compliance	IEC 61000-4-8:2009 Level 5 IEC 61000-4-9:2016 Level 5 IEC 61000-4-10:2016 Level 5
IEC 61000-4-8 test	100 A/m applied continuously, 1000 A/m applied for 3 s
IEC 61000-4-9 test	1000 A/m applied in all planes
IEC 61000-4-10 test	100 A/m applied in all planes at 100 kHz/1 MHz with a burst duration of 2 seconds

23.16.12 CONDUCTED EMISSIONS

Compliance	IEC 60255-26:2013, EN 55032: 2015 + A1:2020
Power supply test 1	0.15 - 0.5 MHz, 79 dBµV (quasi peak) 66 dBµV (average)
Power supply test 2	0.5 - 30 MHz, 73 dBµV (quasi peak) 60 dBµV (average)
RJ45 test 1 (where applicable)	0.15 - 0.5 MHz, 97 dBµV (quasi peak) 84 dBµV (average)
RJ45 test 2 (where applicable)	0.5 - 30 MHz, 87 dBµV (quasi peak) 74 dBµV (average)

23.16.13 RADIATED EMISSIONS

Compliance	IEC 60255-26:2013
Test 1	30 - 230 MHz, 40 dBµV/m at 10 m measurement distance
Test 2	230 - 1 GHz, 47 dBµV/m at 10 m measurement distance
Test 3	1 - 2 GHz, 76 dBµV/m at 10 m measurement distance

23.16.14 POWER FREQUENCY

Compliance	IEC 60255-26:2013
Opto-inputs (Compliance is achieved using the opto-input filter)	300 V common-mode (Class A) 150 V differential mode (Class A)

Note:
Compliance is achieved using the opto-input filter.

23.17 REGULATORY COMPLIANCE

Compliance with the European Commission Directive on EMC and LVD is demonstrated using a technical file.

CE

23.17.1 EMC COMPLIANCE: 2014/30/EU

The product specific Declaration of Conformity (DoC) lists the relevant harmonised standard(s) or conformity assessment used to demonstrate compliance with the EMC directive.

23.17.2 LVD COMPLIANCE: 2014/35/EU

The product specific Declaration of Conformity (DoC) lists the relevant harmonized standard(s) or conformity assessment used to demonstrate compliance with the LVD directive.

Safety related information, such as the installation I overvoltage category, pollution degree and operating temperature ranges are specified in the Technical Data section of the relevant product documentation and/or on the product labelling.

Unless otherwise stated in the Technical Data section of the relevant product documentation, the equipment is intended for indoor use only. Where the equipment is required for use in an outdoor location, it must be mounted in a specific cabinet or housing to provide the equipment with the appropriate level of protection from the expected outdoor environment.

23.17.3 R&TTE COMPLIANCE: 2014/53/EU

Radio and Telecommunications Terminal Equipment (R&TTE) directive 2014/53/EU.

Conformity is demonstrated by compliance to both the EMC directive and the Low Voltage directive, to zero volts.

23.17.4 UL/CUL COMPLIANCE

If marked with this logo, the product is compliant with the requirements of the Canadian and USA Underwriters Laboratories.

The relevant UL file number and ID is shown on the equipment.

c UL us

APPENDIX A

ORDERING OPTIONS

CORTEC Order Code Matrix	1-3	4	5	6	7	8	9	#	#	12-13	#	#
Feeder Management Relay	P14	3								AC		
Feeder Management Relay with optional autoreclose & synchronising												
Nominal Auxiliary Supply Voltage												
24-54 Vdc			7									
48-125 Vdc (40-100 Vac)			8									
110-250 Vdc (100-240 Vac)			9									
CT and VT Ratings												
In = 1/5A, Vn = 100 - 120Vac				1								
Hardware Options												
Standard - 1 x RS485 rear serial communications port provided with all ordering options (Courier, -103, DNP3 ready)					1							
With additional IRIG-B (Modulated)					2							
With additional IRIG-B (Modulated) & Serial Fibre Optic comms					4							
Single Ethernet 1 LC Duplex port + Universal IRIG-B + 1588 + 1 RJ45 Maintenance Port					U							
Redundant Ethernet PRP/HSR/RSTP/Failover 2 LC Duplex port + IEC870-103 Serial Fibre ST ports + Universal IRIG-B + 1588 + 1 RJ45 Maintenance Port					V							
Redundant Ethernet PRP/HSR/RSTP/Failover 2 RJ45 + Universal IRIG-B + 1588 + 1 RJ45 Maintenance Port					W							
Redundant Ethernet PRP/HSR/RSTP/Failover 2 LC Duplex ports + Universal IRIG-B + 1588 + 1 RJ45 Maintenance Port					Y							

Input/Output Options	Case Size Compatibility												
8 inputs, 7 outputs	40TE					A							
8 inputs, 8 outputs	40TE					B							
8 inputs, 14 outputs	60TE					C							
12 inputs, 11 outputs	60TE					D							
12 inputs, 12 outputs	40TE, 60TE					E							
16 inputs, 7 outputs	40TE, 60TE					F							
16 inputs, 14 outputs	60TE					G							
16 inputs, 16 outputs	60TE					H							
16 inputs, 16 outputs + 4 High-Speed High-Break	60TE					J							
16 inputs, 21 outputs	60TE					K							
16 inputs, 24 outputs	60TE					L							
16 inputs, 30 outputs + 8 High-Speed High-Break	80TE					O							
20 inputs, 20 outputs	60TE, 80TE					P							
24 inputs, 14 outputs	60TE, 80TE					R							
24 inputs, 16 outputs	60TE, 80TE					S							
24 inputs, 16 outputs + 8 High-Speed High-Break	80TE					T							
24 inputs, 24 outputs	80TE					U							
24 inputs, 32 outputs	80TE					V							
28 inputs, 43 outputs	80TE					Y							
32 inputs, 14 outputs	80TE					Z							
32 inputs, 24 outputs	80TE					1							
32 inputs, 32 outputs	80TE					2							
40 inputs, 24 outputs	80TE					4							
40 inputs, 32 outputs	80TE					5							
48 inputs, 16 outputs	80TE					7							

Product Specific Options													
Standard Version							A						
Case Size and Mounting													
40TE Case - Flush/Panel Mounting with Harsh Env. Coating, with USB Port, without Function Keys								U					
60TE Case - Flush/Panel Mounting with Harsh Env. Coating, with USB Port and 10 Function Keys								V					
80TE Case - Flush/Panel Mounting with Harsh Env. Coating, with USB Port and 10 Function Keys								S					
80TE Case - 19" Rack Mounting with Harsh Env. Coating, with USB Port and 10 Function Keys								T					
Product Features													
Basic Feeder									A				
Advanced Feeder (Auto reclose and Check Sync)									B				
Software Version													
Enhanced cybersecurity, concurrent protocols, 5000 events, 100 fault records, 1050s oscillography										AC			
Customer-Specific Additions													
Standard version											0		
Customer-specific configuration/options											A		
Hardware Version													
5th Generation Hardware, Graphical Colour HMI with High Performance Processing												Q	

APPENDIX B

SETTINGS AND SIGNALS

Tables containing a full list of settings for each model are provided in a separate Excel file, attached as an embedded resource. If using Adobe Acrobat Reader, click on the button below to open the spreadsheet.

This manual must be opened with a PDF viewer capable of opening attachments, such as Adobe Acrobat Reader or Nitro PDF. If using Nitro PDF, attachments are shown in the attachment pane. To show or hide the attachments pane, look in the sidebar and click the attachments tab.

Note:
An Open File dialogue box may open with a warning message about potential harm from programs, macros or viruses. The file supplied does not contain any harmful content, and may be safely opened.

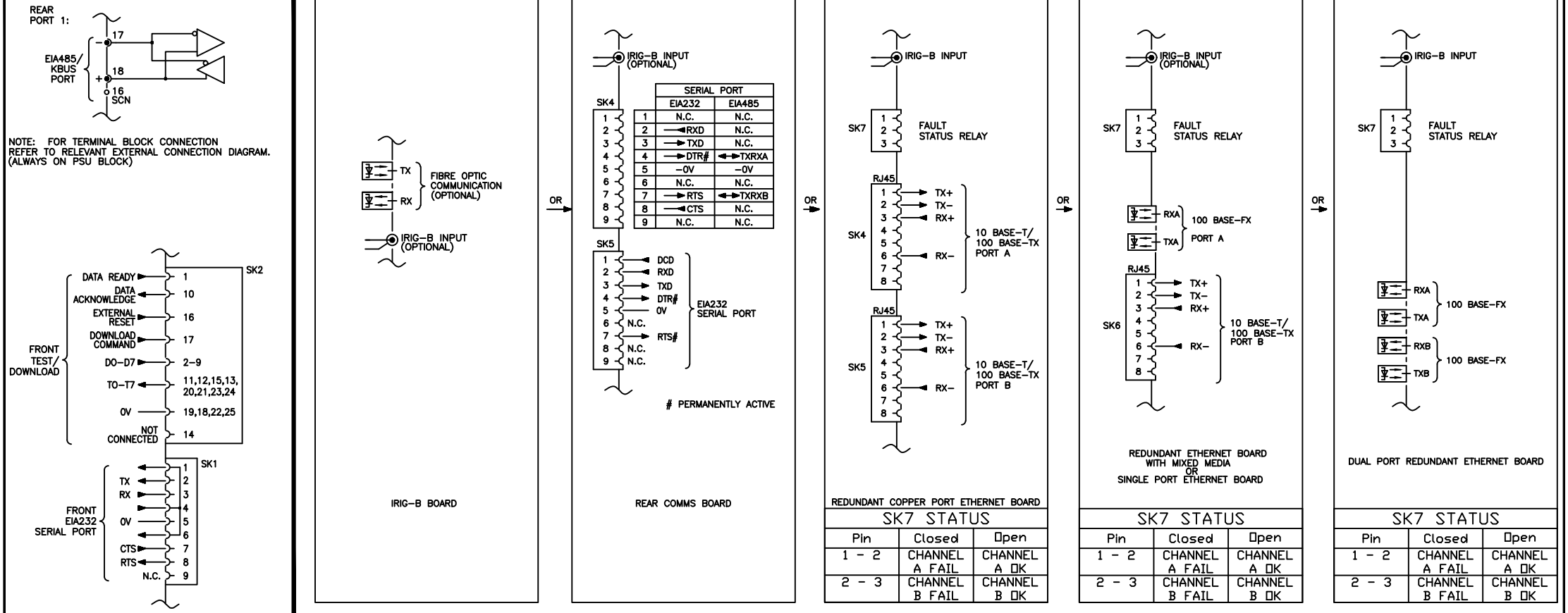
Settings and Signals

APPENDIX C

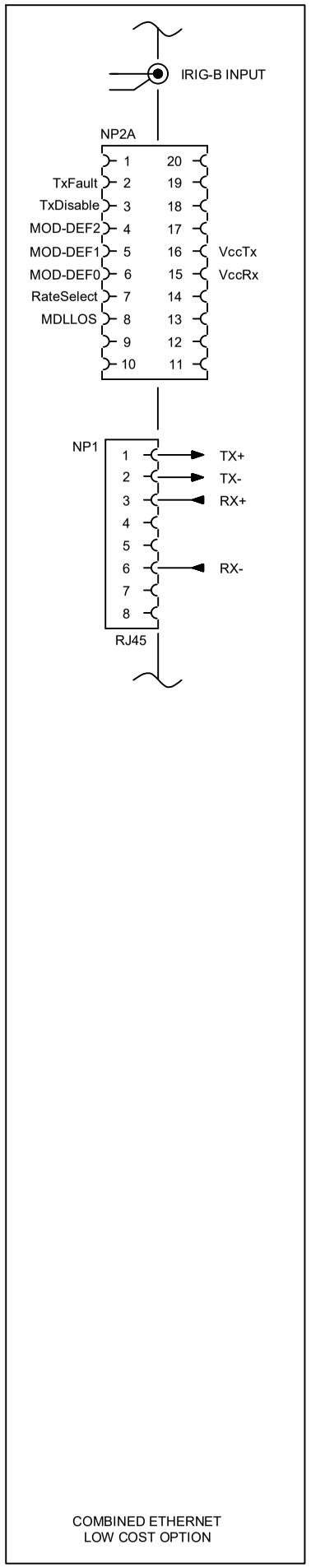
WIRING DIAGRAMS

Model	CORTEC Option*	Input/Output Options and Case Size Compatibility		Drawing-Sheet	Issue
All	-	Comms Options MiCOM Px40 Platform		10Px4001-1 10Px4001-2	N B
P143	I/O Option A	8 Inputs, 7 Outputs	(40TE)	10P14313-1	A
	I/O Option B	8 Inputs, 8 Outputs	(40TE)	10P14314-1	A
	I/O Option C	8 Inputs, 14 Outputs	(60TE)	10P14318-1	A
	I/O Option D	12 Inputs, 11 Outputs	(60TE)	10P14319-1	A
	I/O Option E	12 Inputs, 12 Outputs	(40TE) (60TE)	10P14316-1 10P14320-1	A A
	I/O Option F	16 Inputs, 7 Outputs	(40TE) (60TE)	10P14317-1 10P14321-1	A A
	I/O Option G	16 Inputs, 14 Outputs	(60TE)	10P14322-1	A
	I/O Option H	16 Inputs, 16 Outputs	(60TE)	10P14323-1	A
	I/O Option J	16 Inputs, 16 Outputs + 4 High-Speed High-Break	(60TE)	10P14323-1	A
	I/O Option K	16 Inputs, 21 Outputs	(60TE)	10P14324-1	A
	I/O Option L	16 Inputs, 24 Outputs	(60TE)	10P14325-1	A
	I/O Option O	16 inputs, 30 outputs + 8 High-Speed High-Break	(80TE)	10P14329-1	A
	I/O Option P	20 Inputs, 20 Outputs	(60TE) (80TE)	10P14326-1 10P14330-1	A A
	I/O Option R	24 Inputs, 14 Outputs	(60TE) (80TE)	10P14302-1 10P14331-1	H A
	I/O Option S	24 Inputs, 16 Outputs	(60TE) (80TE)	10P14328-1 10P14332-1	A A
	I/O Option T	24 Inputs, 16 Outputs + 8 High-Speed High-Break	(80TE)	10P14333-1	A
	I/O Option U	24 Inputs, 24 Outputs	(80TE)	10P14334-1	A
	I/O Option V	24 Inputs, 32 Outputs	(80TE)	10P14335-1	A
	I/O Option Y	28 Inputs, 43 Outputs	(80TE)	10P14343-1	A
	I/O Option Z	32 Inputs, 14 Outputs	(80TE)	10P14337-1	A
	I/O Option 1	32 Inputs, 24 Outputs	(80TE)	10P14338-1	A
	I/O Option 2	32 Inputs, 32 Outputs	(80TE)	10P14339-1	A
	I/O Option 4	40 Inputs, 24 Outputs	(80TE)	10P14340-1	A
	I/O Option 5	40 Inputs, 32 Outputs	(80TE)	10P14344-1	A
	I/O Option 7	48 Inputs, 16 Outputs	(80TE)	10P14345-1	A

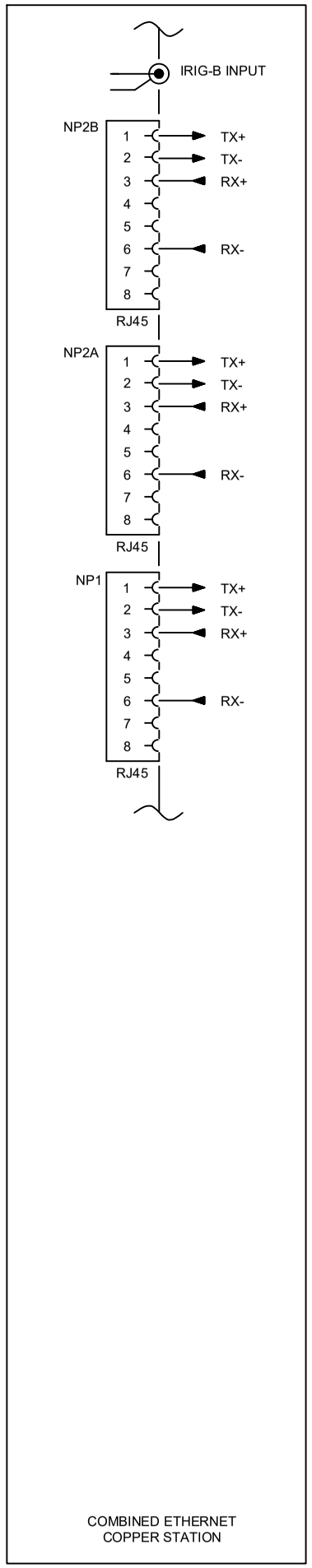
* When selecting the applicable wiring diagram(s), refer to the appropriate model CORTEC.



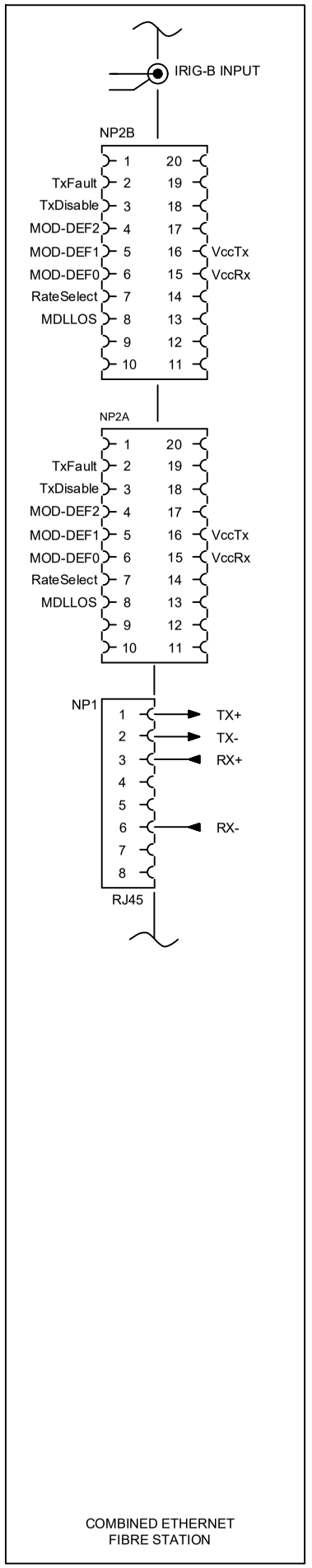
Issue: N	Status: **Approved**	Revision Notes: CID008567 - Outline update only	Title: EXTERNAL CONNECTION DIAGRAM: COMMS OPTIONS MICOM Px40 PLATFORM		
Date: 10/10/2024	Name: S Burton	PROPRIETARY AND CONFIDENTIAL INFORMATION This document is the property of GE Vernova (GEV) and contains proprietary information of GEV. This document is loaned on the express condition that neither it nor the information contained therein shall be disclosed to others without the express written consent of GEV, and that the information shall be used by the recipient only as approved expressly by GEV. This document shall be returned to GEV upon its request. This document may be subject to certain restrictions under U.S. export control laws and regulations. © GE VERNOVA Company, GEV CONFIDENTIAL UNPUBLISHED WORK.	Drg No: **10PX4001**	PLM No: A20022917	Sht: 1 / Next Sht: 2
Date:	Chkd:				GE VERNOVA



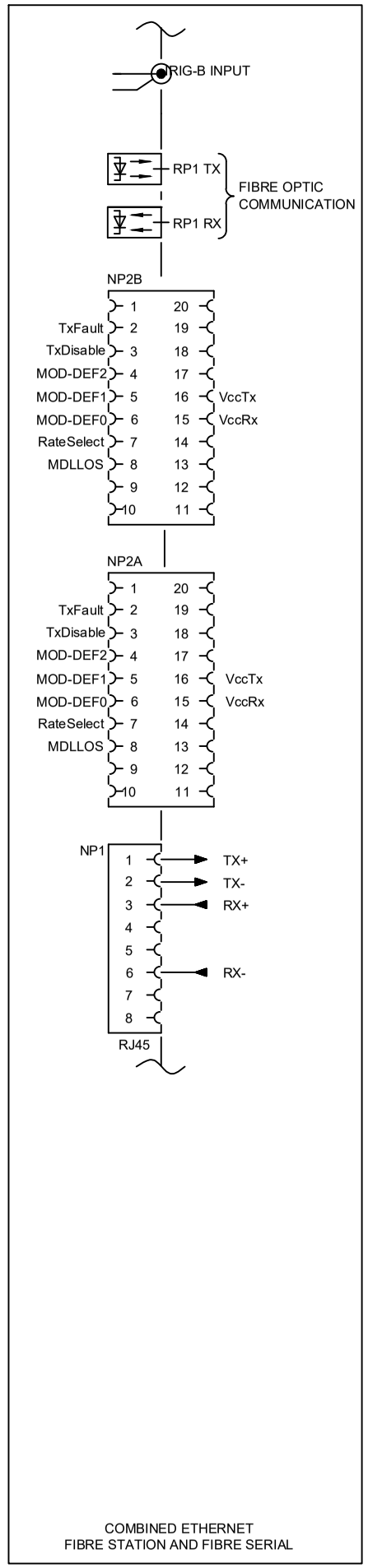
COMBINED ETHERNET
LOW COST OPTION



COMBINED ETHERNET
COPPER STATION

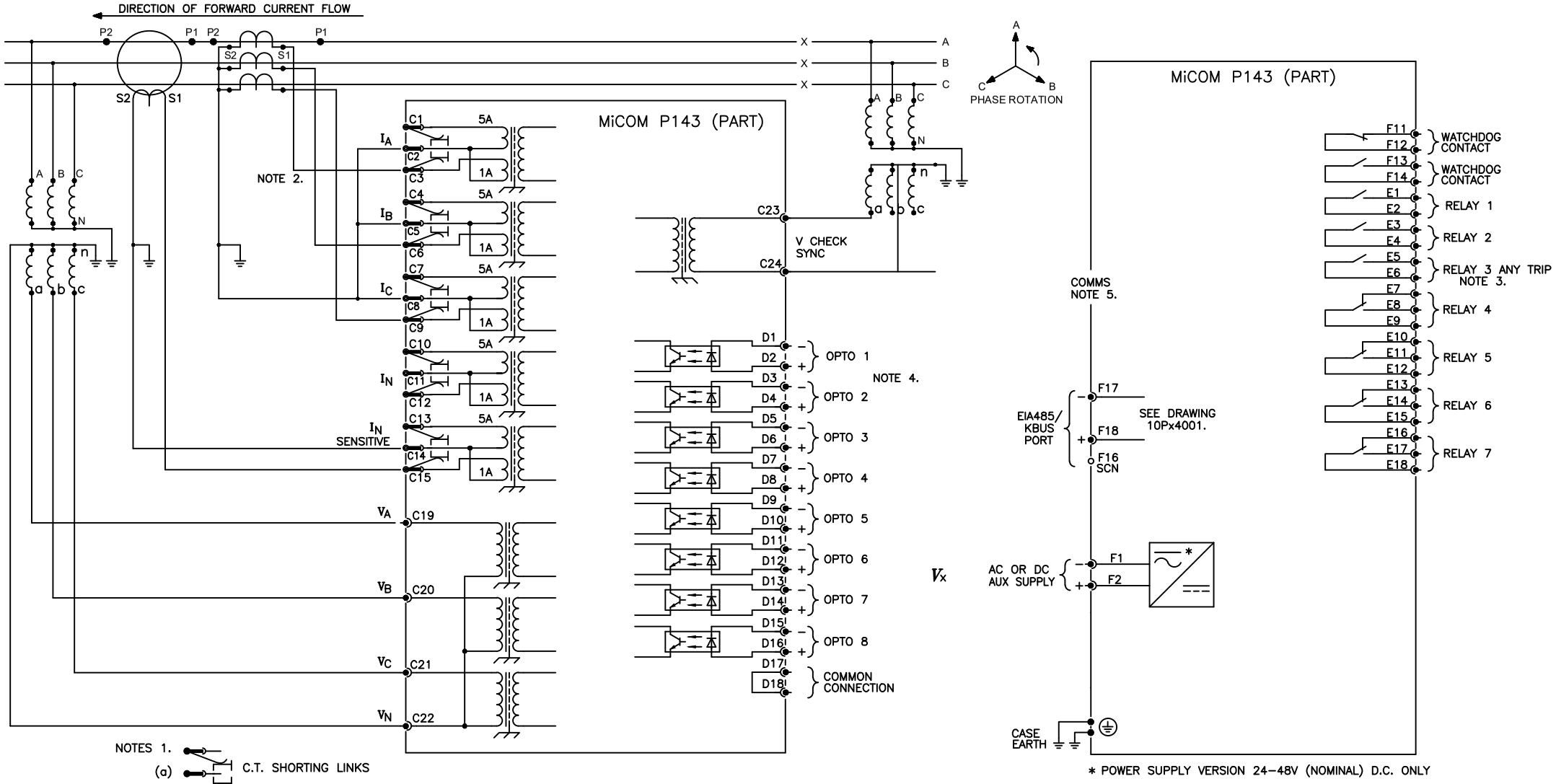


COMBINED ETHERNET
FIBRE STATION



COMBINED ETHERNET
FIBRE STATION AND FIBRE SERIAL

Issue: B	Status: **Approved**	Revision Notes: CID008567 - Outline update only	Title: EXTERNAL CONNECTION DIAGRAM COMMS OPTIONS MICOM Px40			
Date: 10/10/2024	Name: S Burton	PROPRIETARY AND CONFIDENTIAL INFORMATION This document is the property of GE Vernova (GEV) and contains proprietary information of GEV. This document is loaned on the express condition that neither it nor the information contained therein shall be disclosed to others without the express written consent of GEV, and that the information shall be used by the recipient only as approved expressly by GEV. This document shall be returned to GEV upon its request. This document may be subject to certain restrictions under U.S. export control laws and regulations. © GE VERNOVA Company, GEV CONFIDENTIAL UNPUBLISHED WORK.	Drg No: **10PX4001**	PLM No: A20095995	Sht: 2 Next Sht: -	GE VERNOVA
Date:	Chkd:					



NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

9–WAY & 25–WAY FEMALE D–TYPE SOCKET

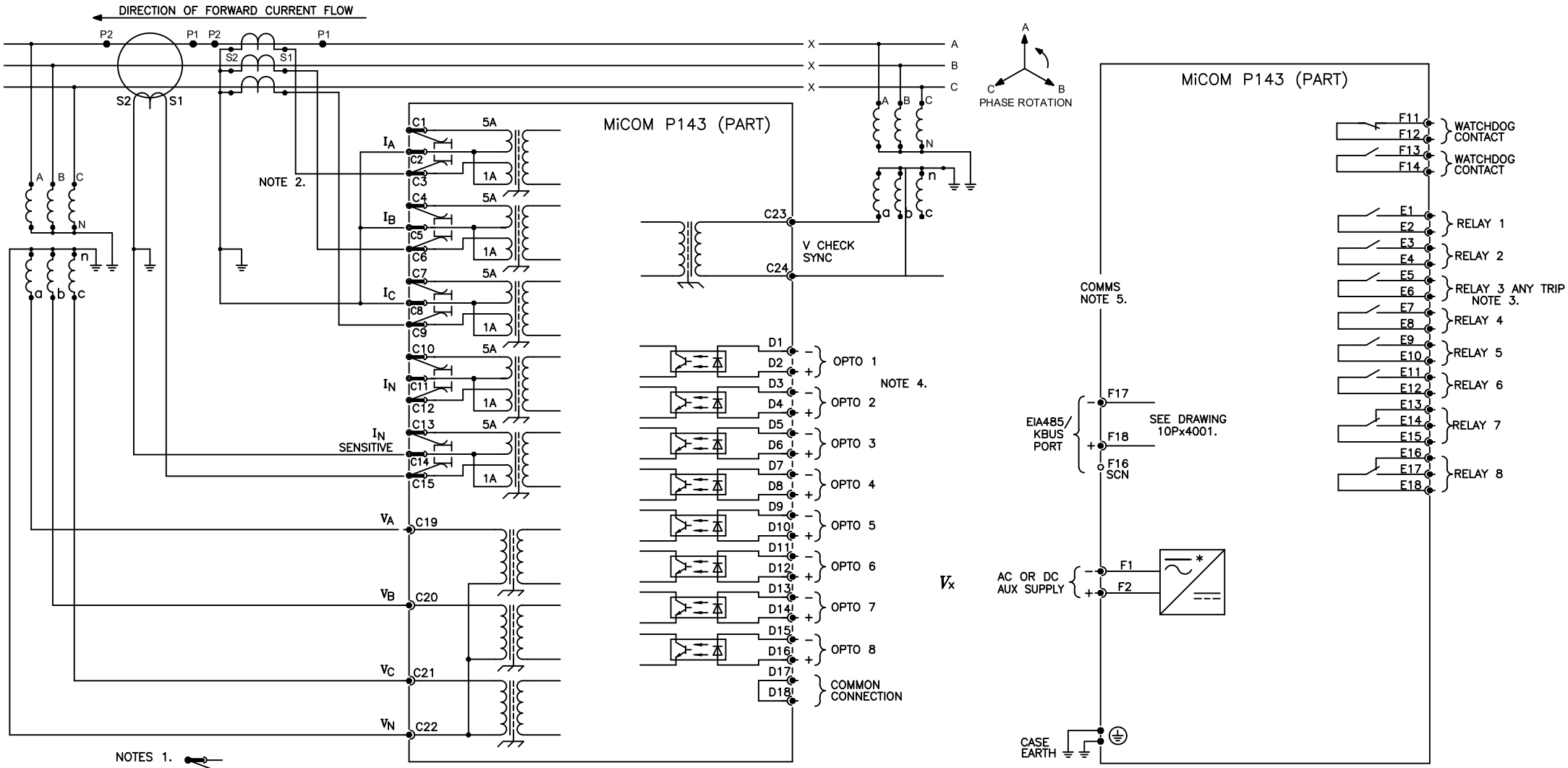
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: INITIAL ISSUE. CID009196.	Title: EXT CONN DIAG: FEEDER PROT RELAY (40TE) DIRECTIONAL PHASE O.C. & S.E.F. AUTO-RECLOSE & CHECK SYNCH (8 I/P & 7 0/P)		
Date: 15/12/2025	Name: S WOOTTON		Drg No: **10P14313**	PLM No: A20135226	Sht: 1
Date: 15/12/2025	Chkd: J HUTCHINS				Next Sht: -

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

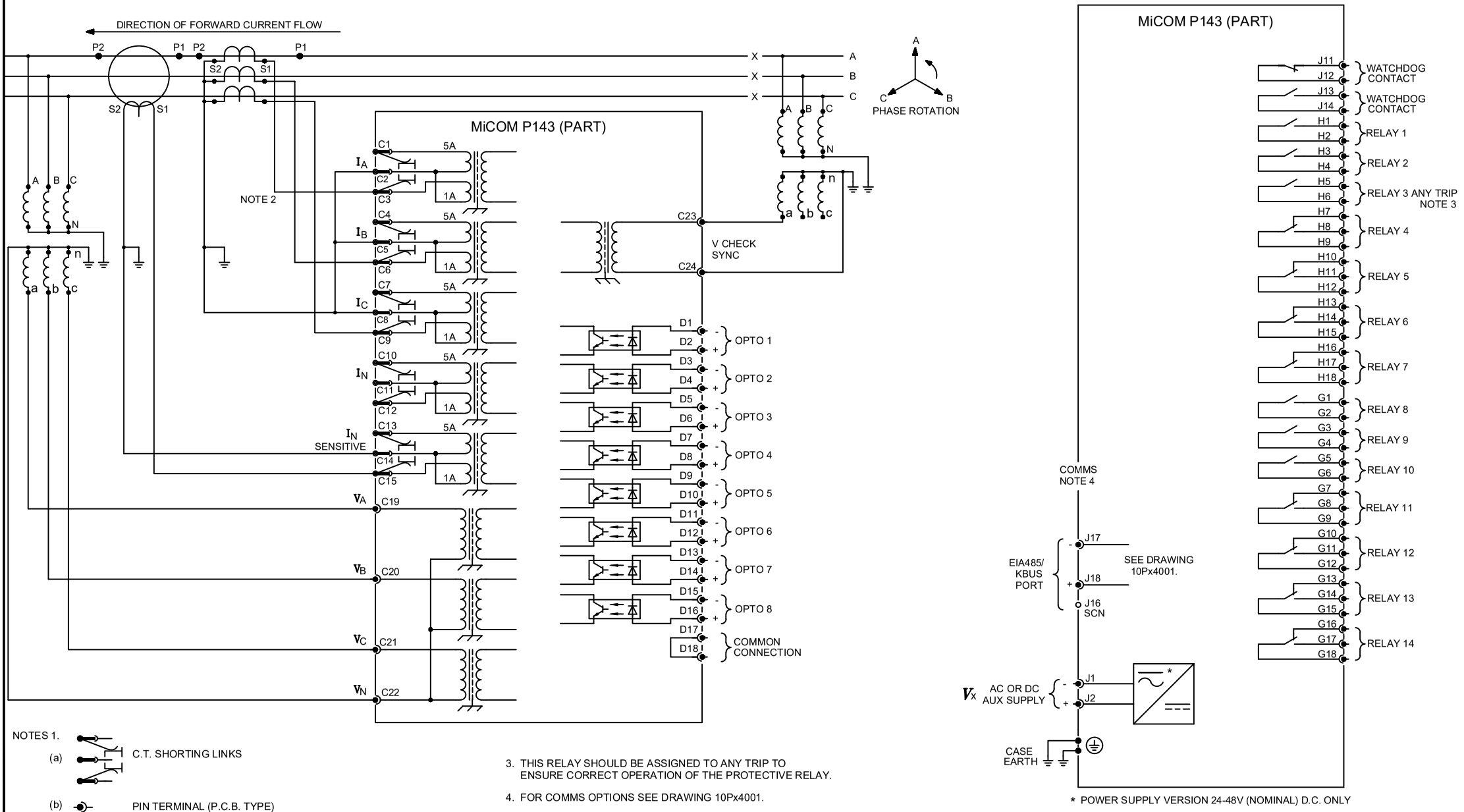
9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT CONN DIAG: FEEDER PROT RELAY (40TE) DIRECTIONAL PHASE O.C. & S.E.F. AUTO-RECLOSE & CHECK SYNCH (8 I/P & 8 0/P)			
Date: 15/12/2025	Name: S WOOTTON		Drg No: **10P14314**	PLM No: A20135227	Sht: 1	GE VERNOVA
Date: 15/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.

3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.

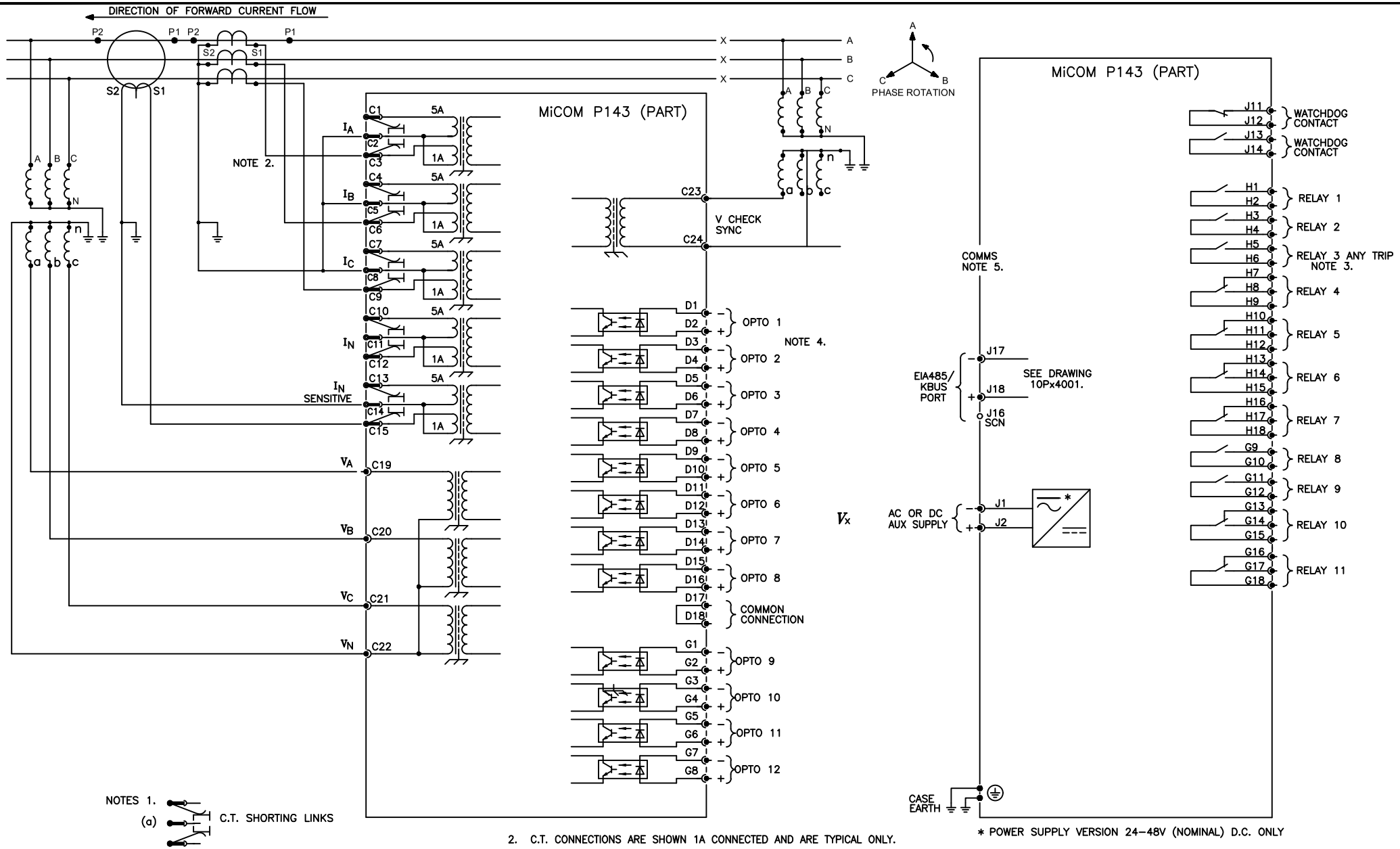
4. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24-48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (8 I/P & 14 O/P)		
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14318**	PLM No: A20135307	Sht: 1
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -

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GE VERNOVA



NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

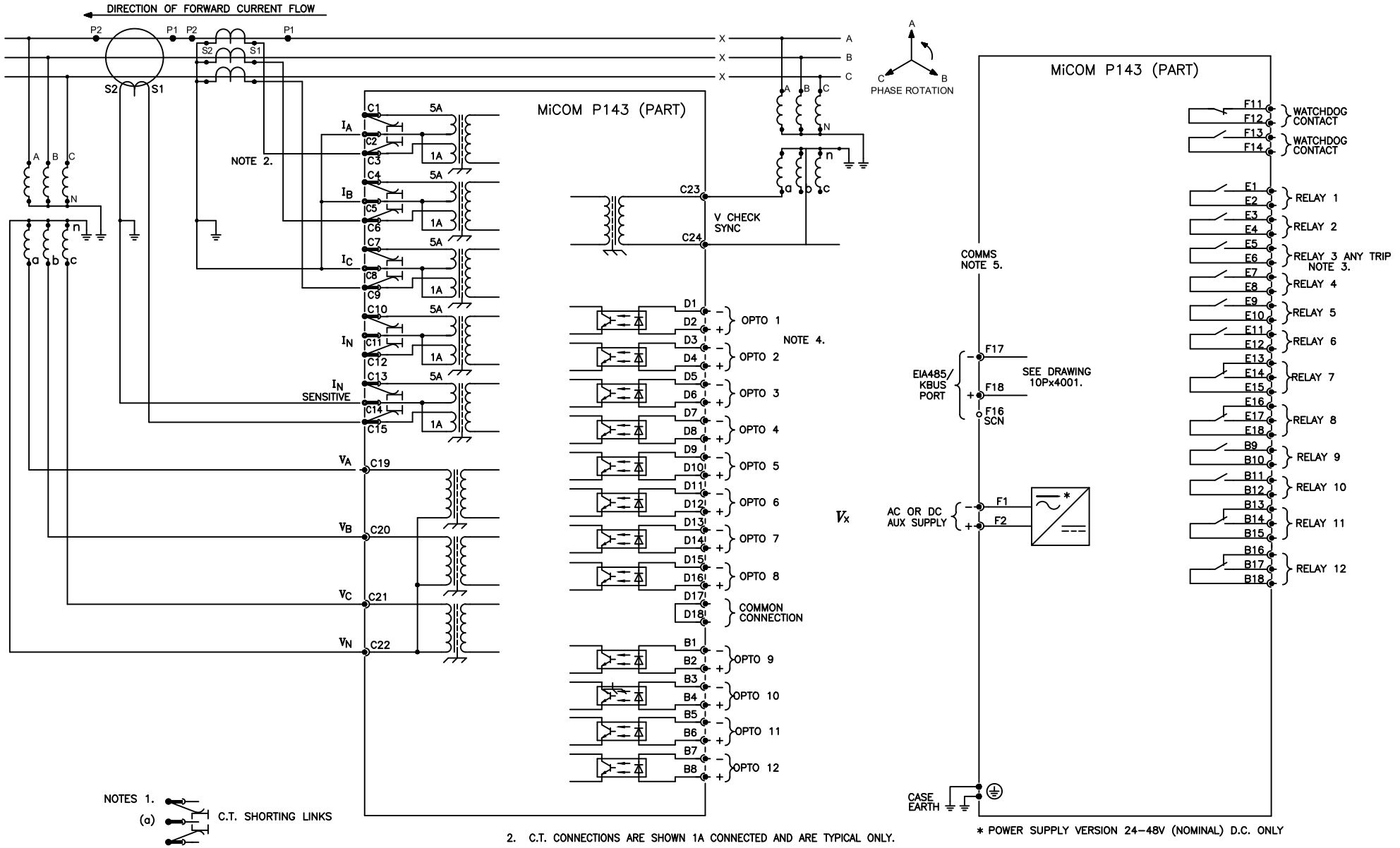
9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (12 I/P & 11 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14319**	PLM No: A20135308	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

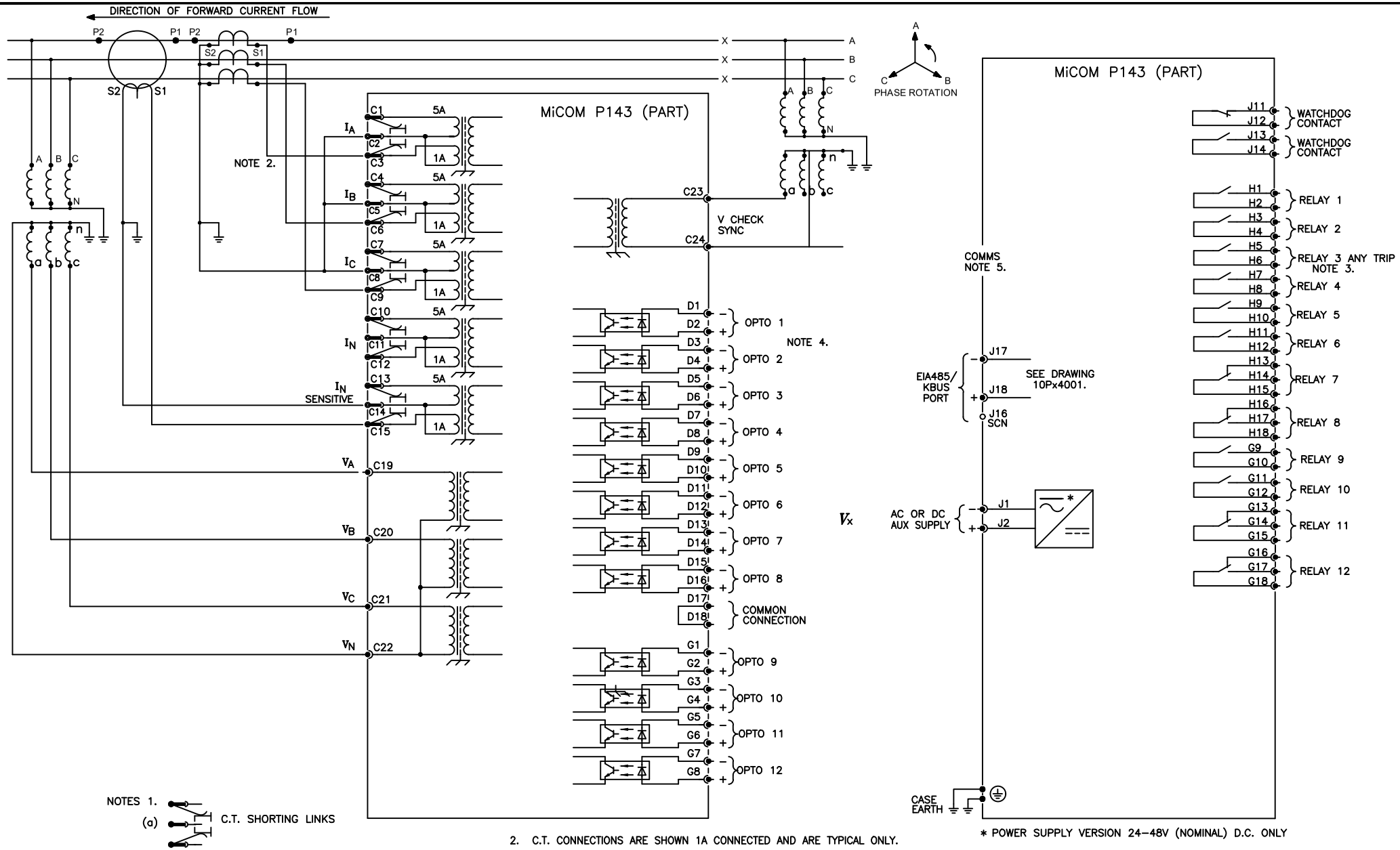
9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: INITIAL ISSUE. CID009196.	Title: EXT CONN DIAG: FEEDER PROT RELAY (40TE) DIRECTIONAL PHASE O.C. & S.E.F. AUTO-RECLOSE & CHECK SYNCH (12 I/P & 12 0/P)			
Date: 15/12/2025	Name: S WOOTTON		Drg No: **10P14316**	PLM No: A20135267	Sht: 1	GE VERNOVA
Date: 15/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

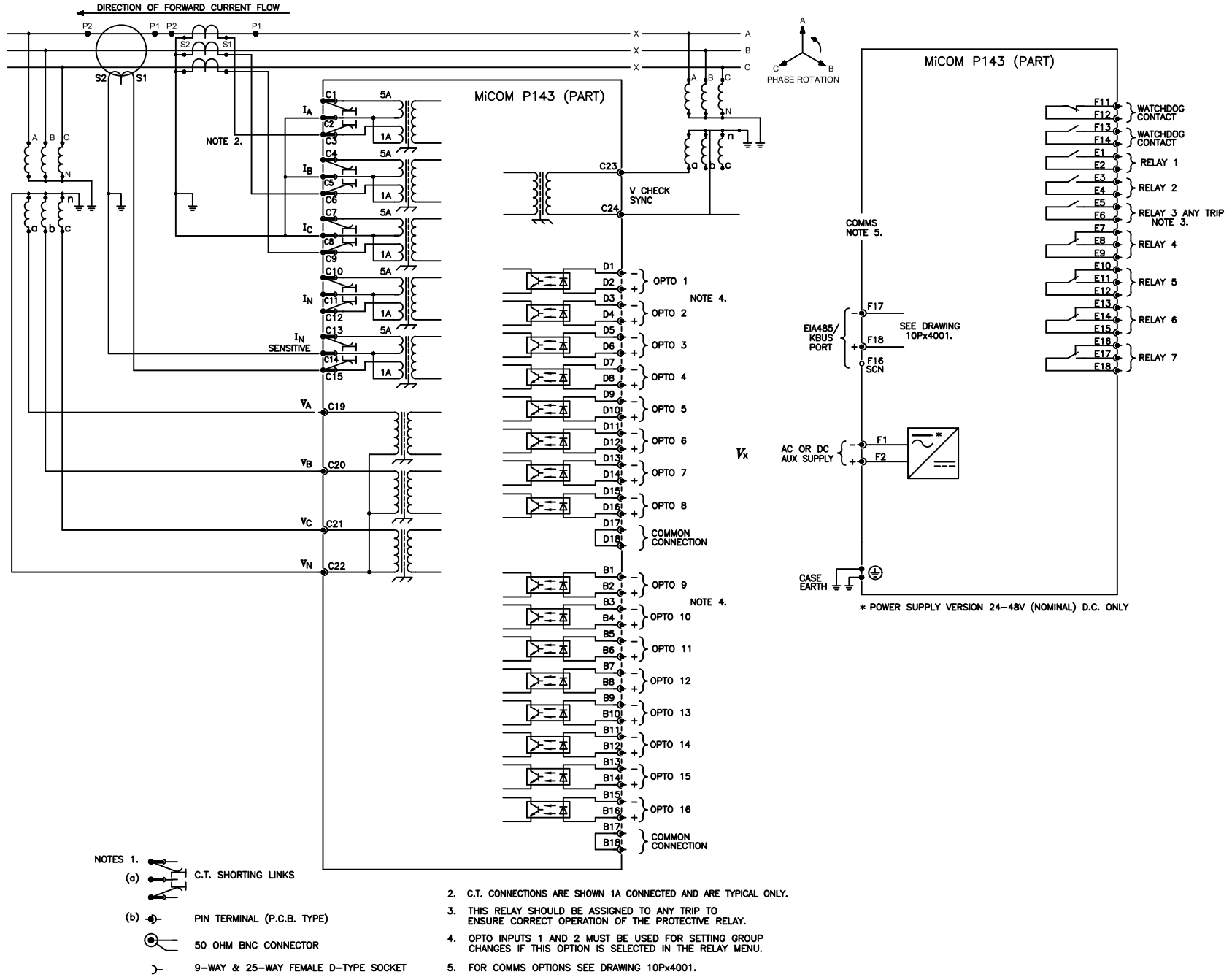
9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

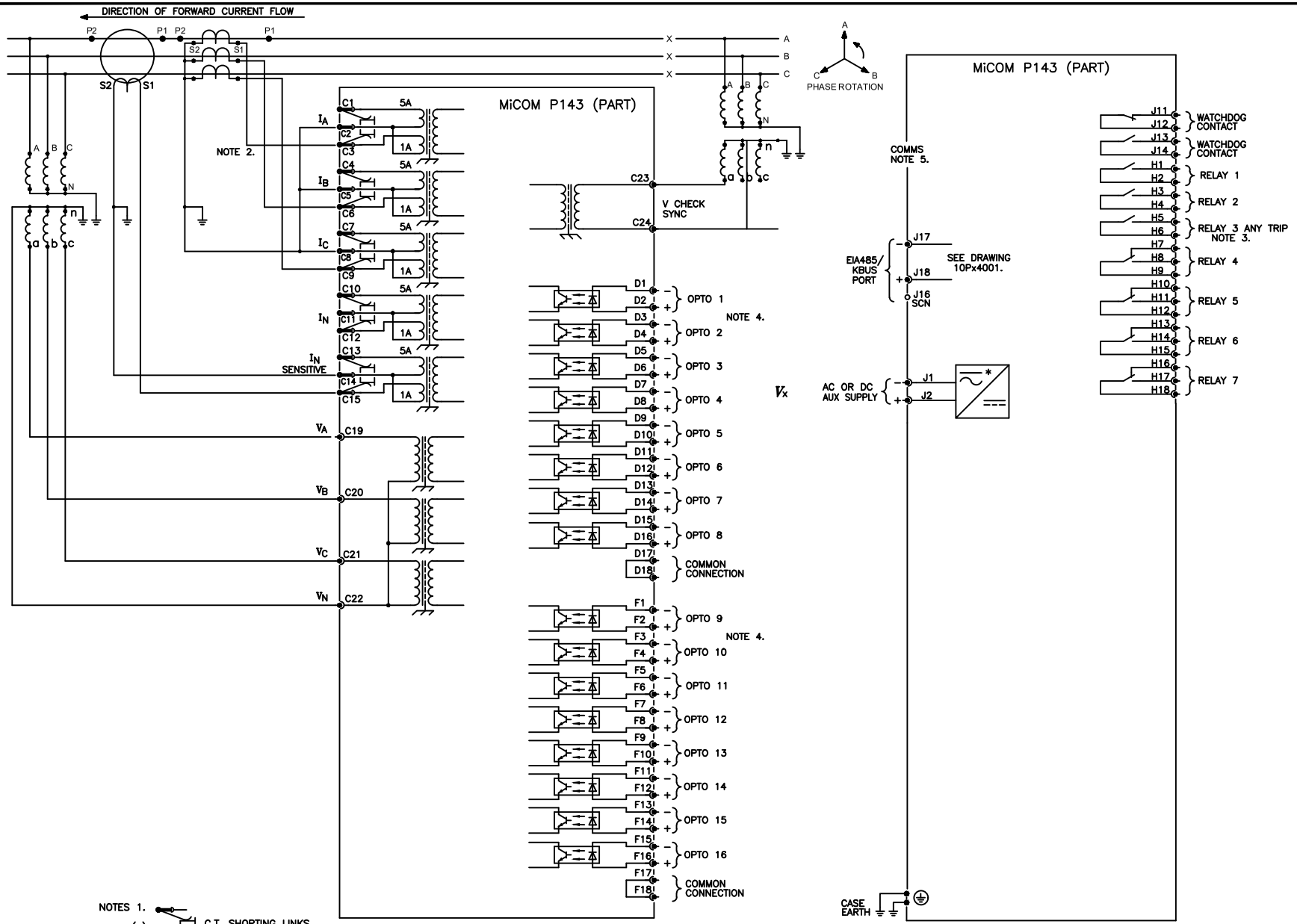
Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (12 I/P & 12 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14320**	PLM No: A20135326	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT CONN DIAG: FEEDER PROT RELAY (40TE) DIRECTIONAL PHASE O.C. & S.E.F. AUTO-RECLOSE & CHECK SYNCH (16 I/P & 7 0/P)			
Date: 15/12/2025	Name: S WOOTTON		Drg No: **10P14317**	PLM No: A20135268	Sht: 1	GE VERNOVA
Date: 15/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

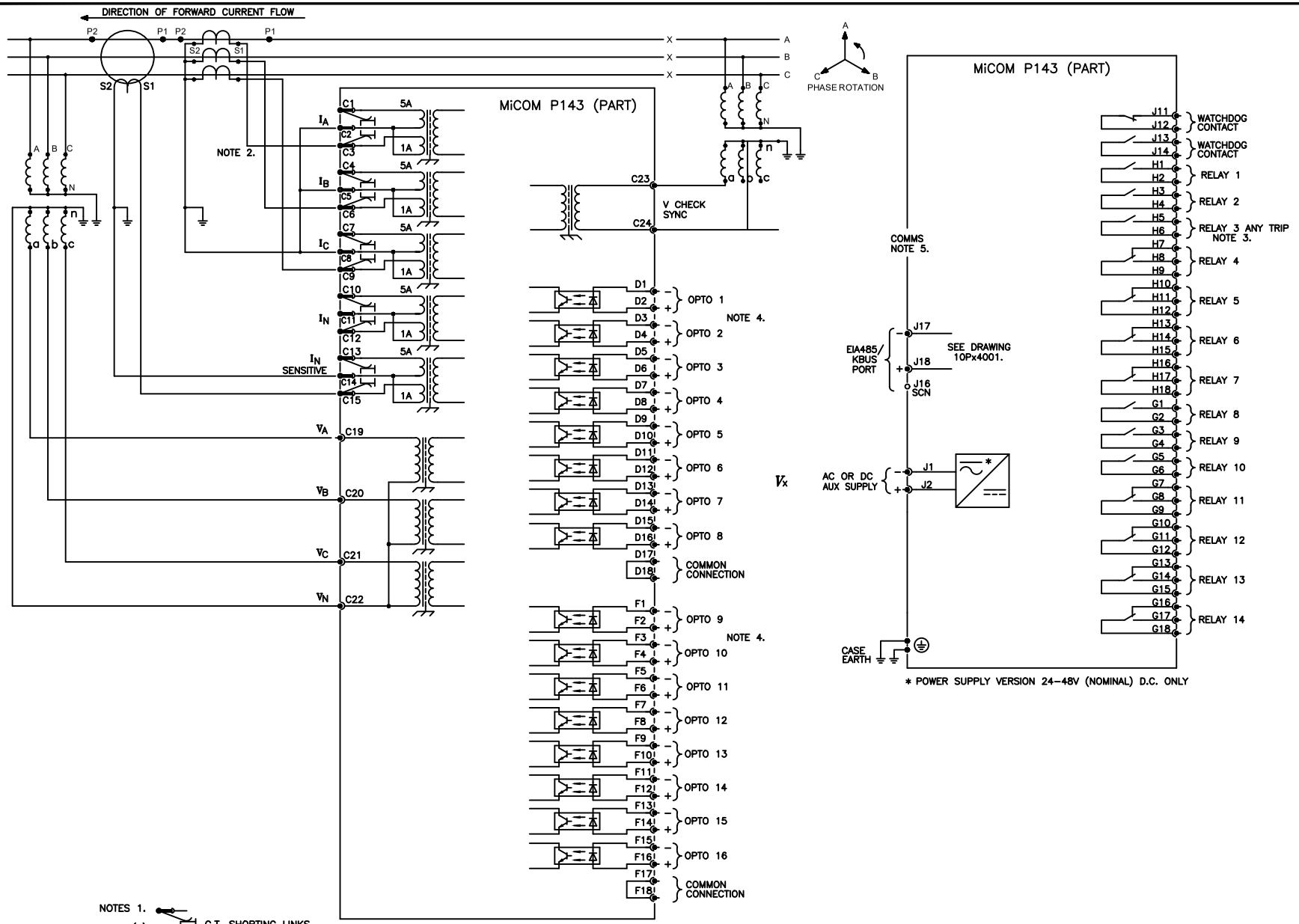
9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 7 O/P)		
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14321**	PLM No: A20135327	Sht: 1
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

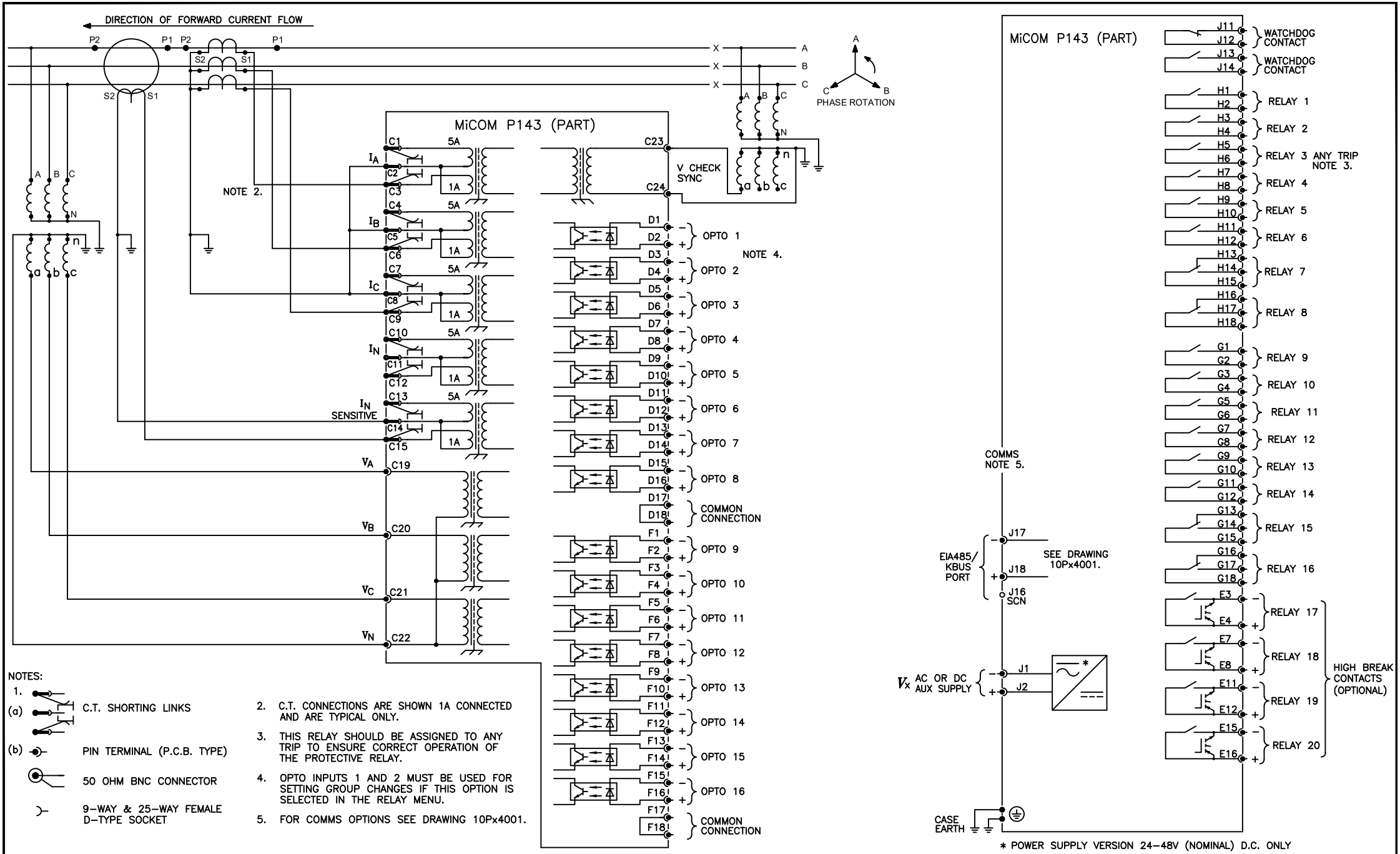
50 OHM BNC CONNECTOR

9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

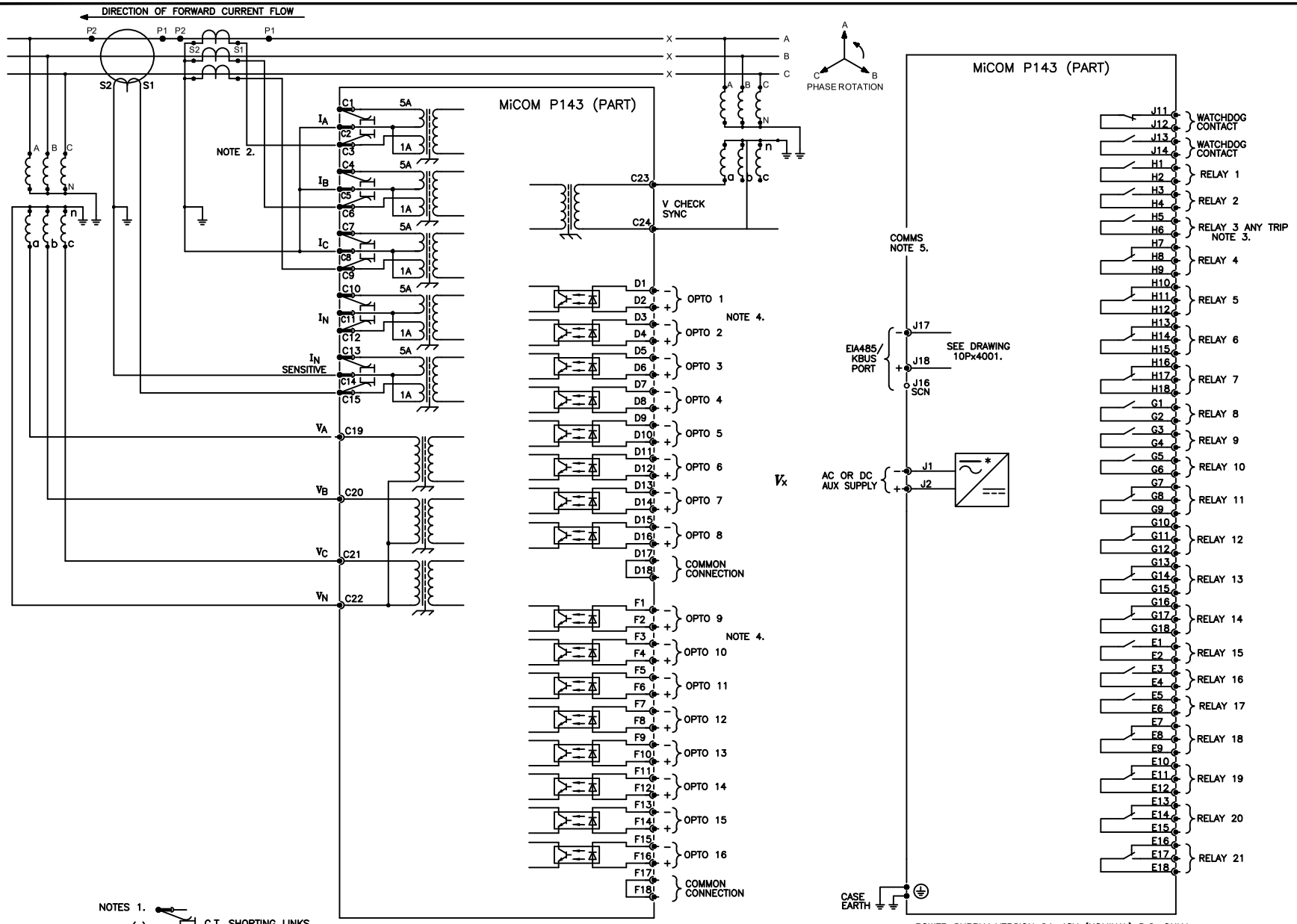
Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 14 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14322**	PLM No: A20135328	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIR'NAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 16 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14323**	PLM No: A20135329	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

50 OHM BNC CONNECTOR

9-WAY & 25-WAY FEMALE D-TYPE SOCKET

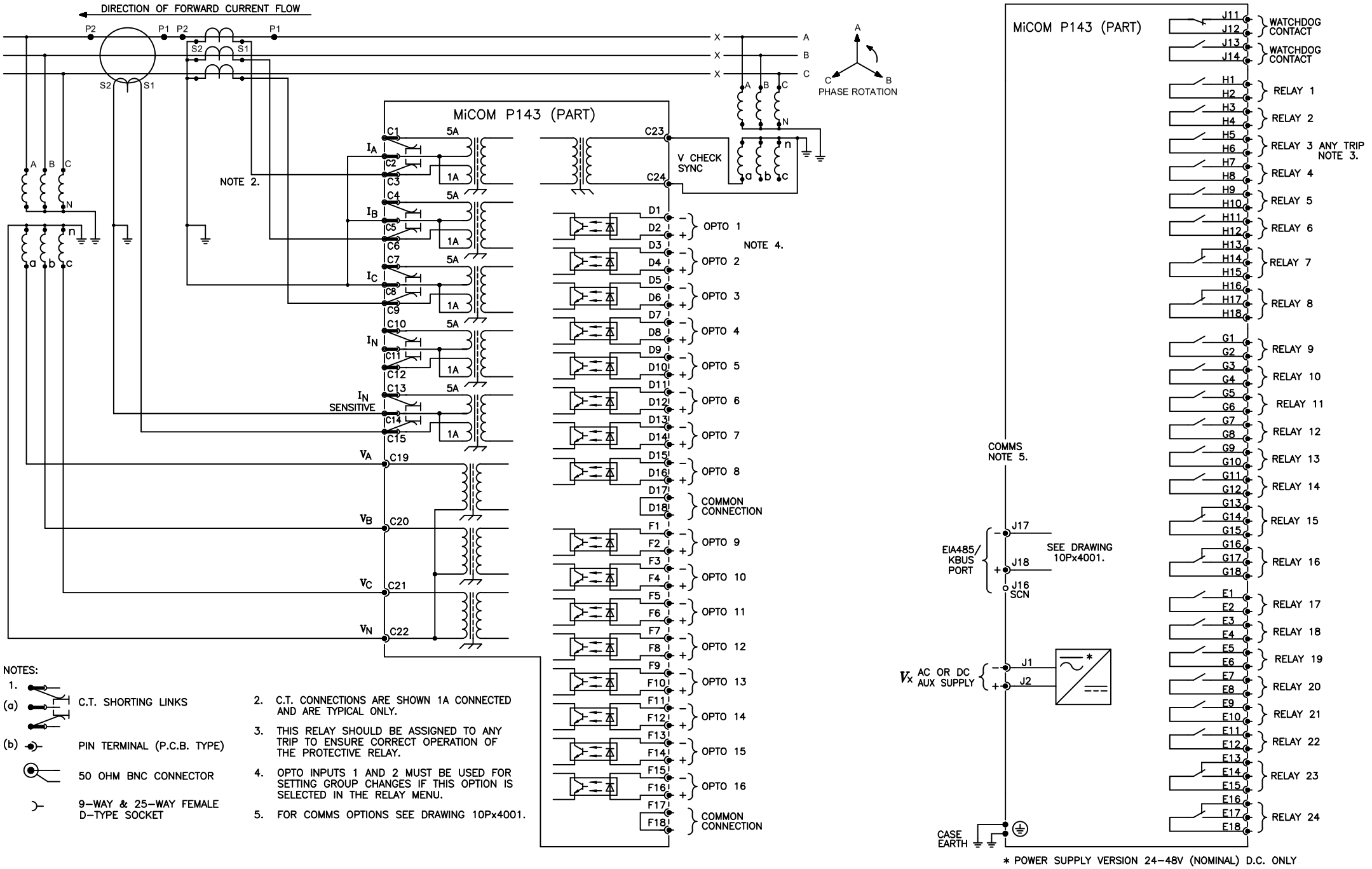
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24-48V (NOMINAL) D.C. ONLY

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 21 O/P)		
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14324**	PLM No: A20135346	Sht: 1
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -

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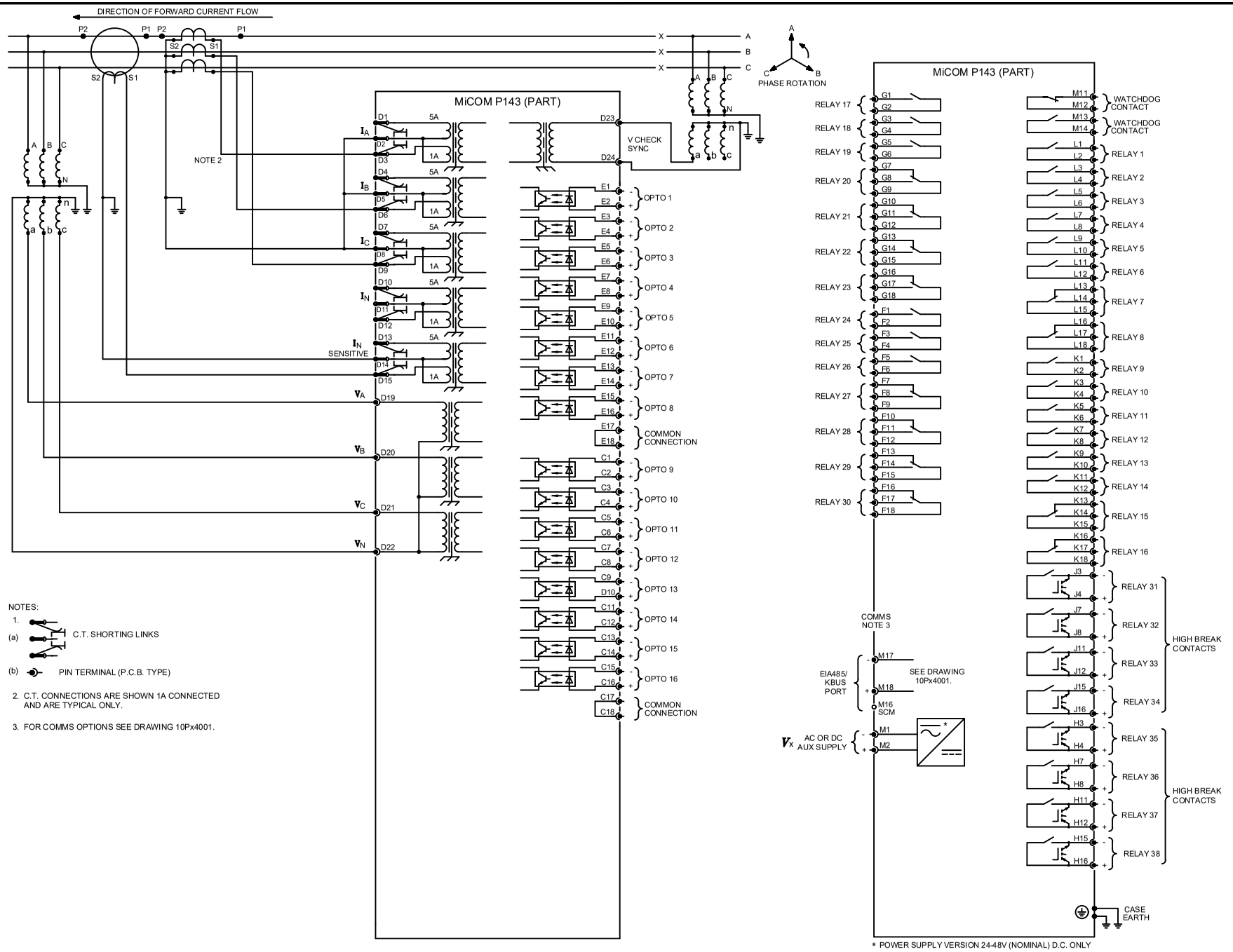
NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
   50 OHM BNC CONNECTOR
   9–WAY & 25–WAY FEMALE D–TYPE SOCKET
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIR'NAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 24 O/P)
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14325**
Date: 16/12/2025	Chkd: J HUTCHINS		PLM No: A20135347
			Sht: 1 / Next Sht: -

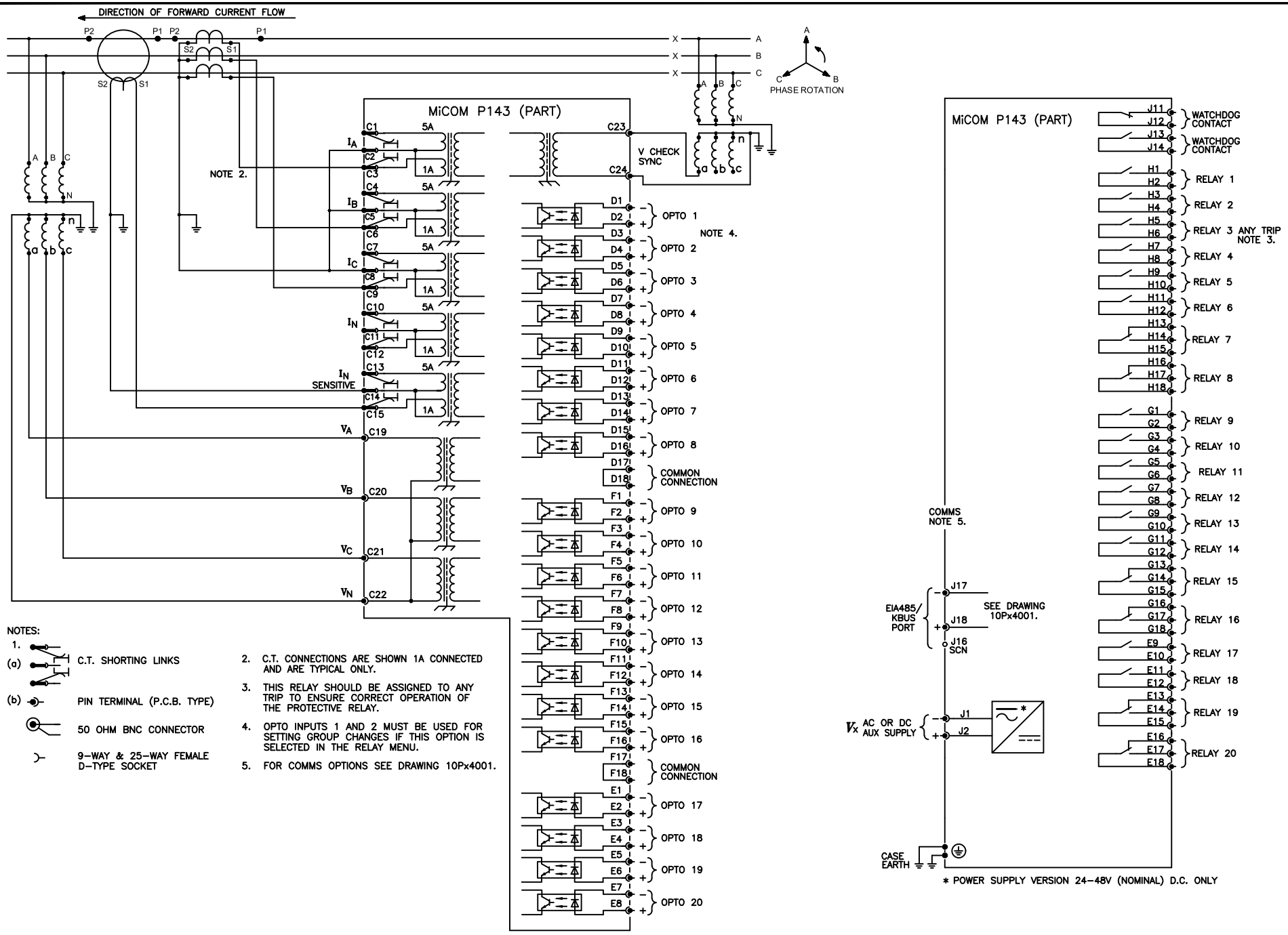
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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (16 I/P & 30 O/P + 8 HI BRK RELAYS)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14329-1	PLM No: A20135393	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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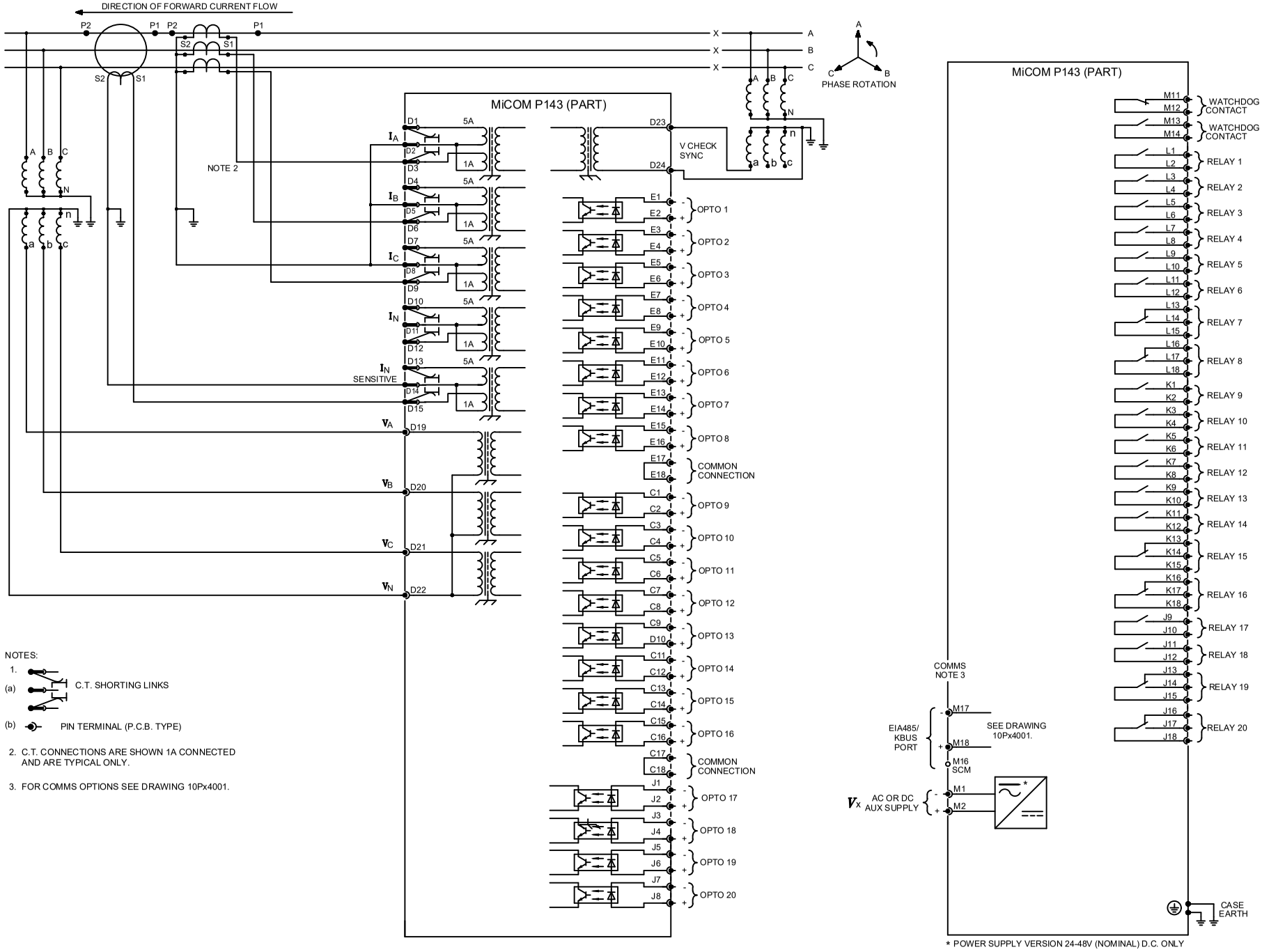


NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
   50 OHM BNC CONNECTOR
   9–WAY & 25–WAY FEMALE D–TYPE SOCKET
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
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4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIR'NAL PHASE O/C & E/F WITH AUTO-RECLOSE (20 I/P & 20 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14326**	PLM No: A20135348	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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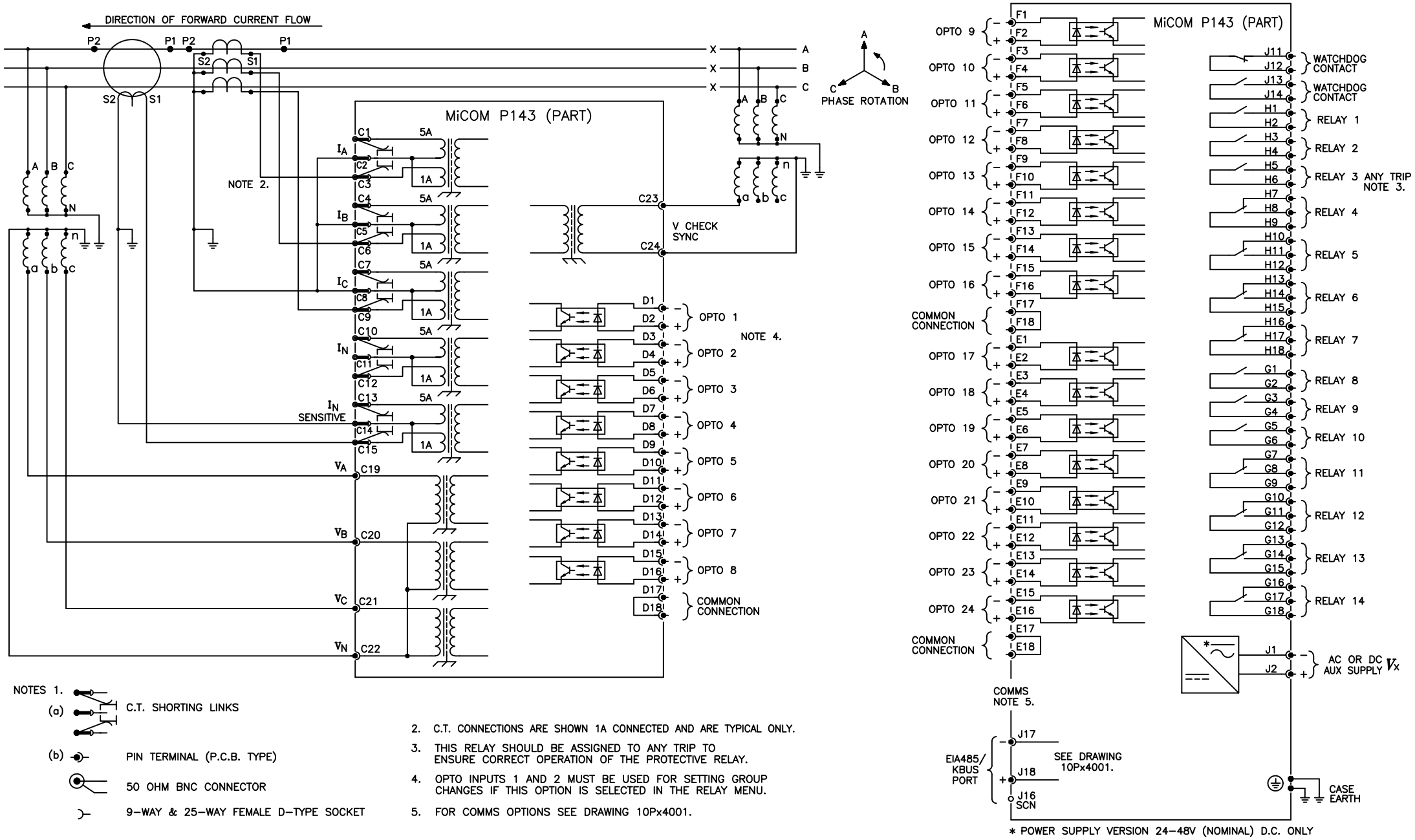


NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (20 I/P & 20 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14330-1	PLM No: A20135406	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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NOTES 1.

(a) C.T. SHORTING LINKS

(b) PIN TERMINAL (P.C.B. TYPE)

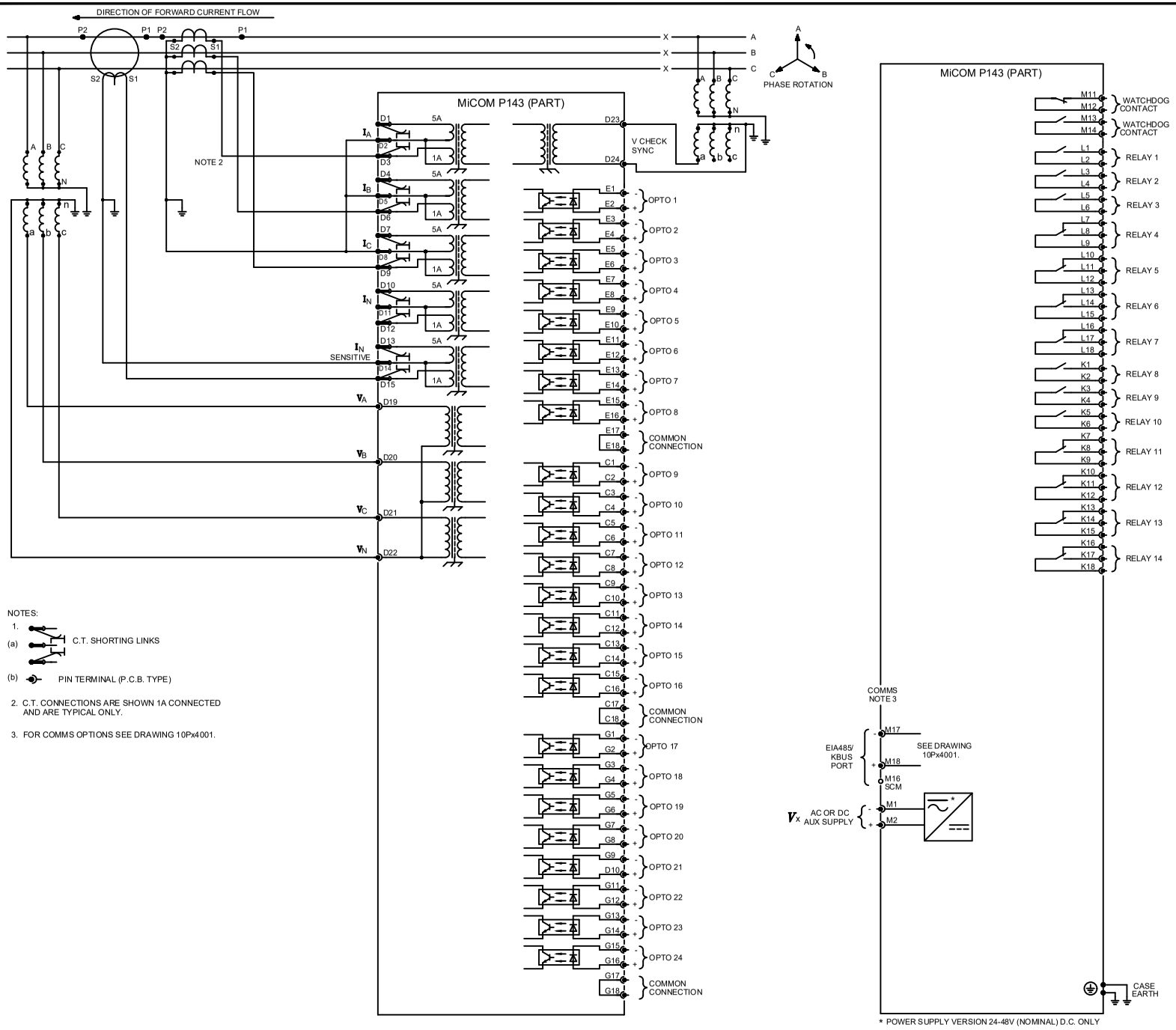
50 OHM BNC CONNECTOR

9–WAY & 25–WAY FEMALE D–TYPE SOCKET

2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

* POWER SUPPLY VERSION 24–48V (NOMINAL) D.C. ONLY

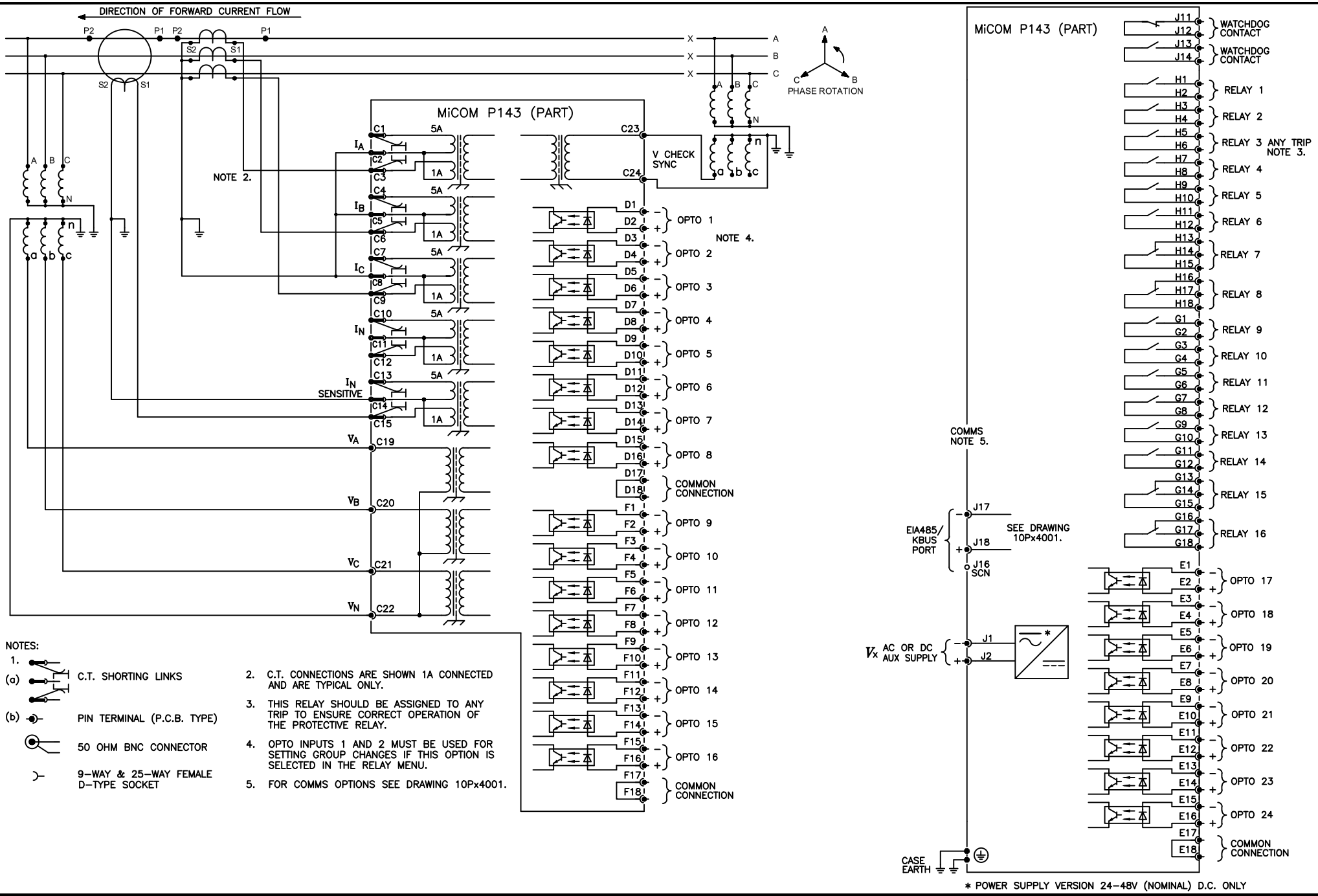
Issue: H	Status: **Approved**	Revision Notes: CID008567 - Outline update only	Title: EXT CONN DIAG: FEEDER PROTEC'N RELAY (60TE) DIRECT'AL PH O.C. & S.E.F. AUTO-RECLOSE & CHECK SYNCH (24 I/P & 14 O/P)		
Date: 10/10/2024	Name: S Burton	PROPRIETARY AND CONFIDENTIAL INFORMATION This document is the property of GE Vernova (GEV) and contains proprietary information of GEV. This document is loaned on the express condition that neither it nor the information contained therein shall be disclosed to others without the express written consent of GEV, and that the information shall be used by the recipient only as approved expressly by GEV. This document shall be returned to GEV upon its request. This document may be subject to certain restrictions under U.S. export control laws and regulations. © GE VERNOVA Company, GEV CONFIDENTIAL UNPUBLISHED WORK.	Drg No: **10P14302**	PLM No: A20057368	Sht: 1
Date:	Chkd:			Next Sht: -	GE VERNOVA



Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 14 O/P)		
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14331-1	PLM No: A20135426	Sht: 1
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -

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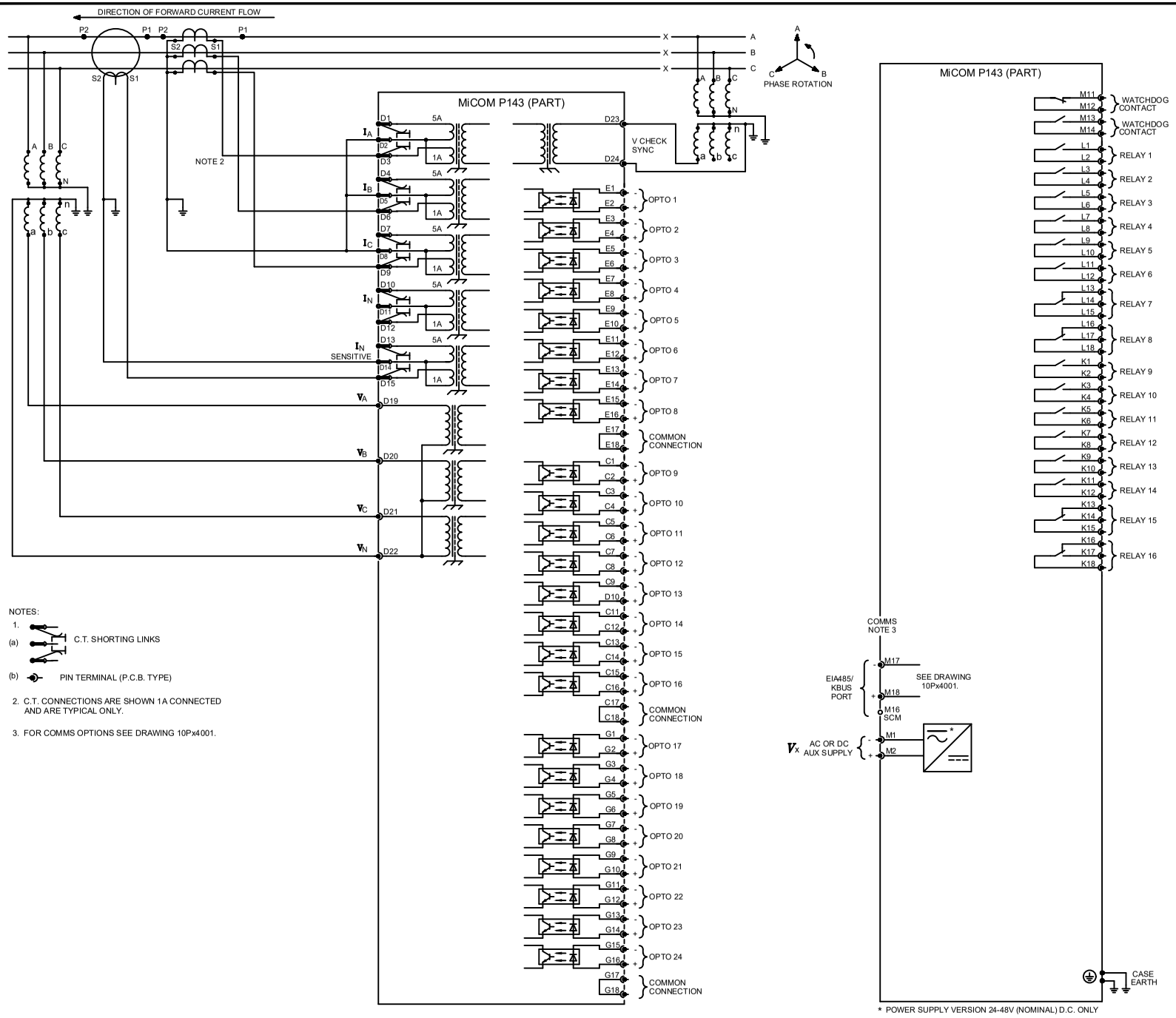


NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
   50 OHM BNC CONNECTOR
   9–WAY & 25–WAY FEMALE D–TYPE SOCKET
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. THIS RELAY SHOULD BE ASSIGNED TO ANY TRIP TO ENSURE CORRECT OPERATION OF THE PROTECTIVE RELAY.
4. OPTO INPUTS 1 AND 2 MUST BE USED FOR SETTING GROUP CHANGES IF THIS OPTION IS SELECTED IN THE RELAY MENU.
5. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

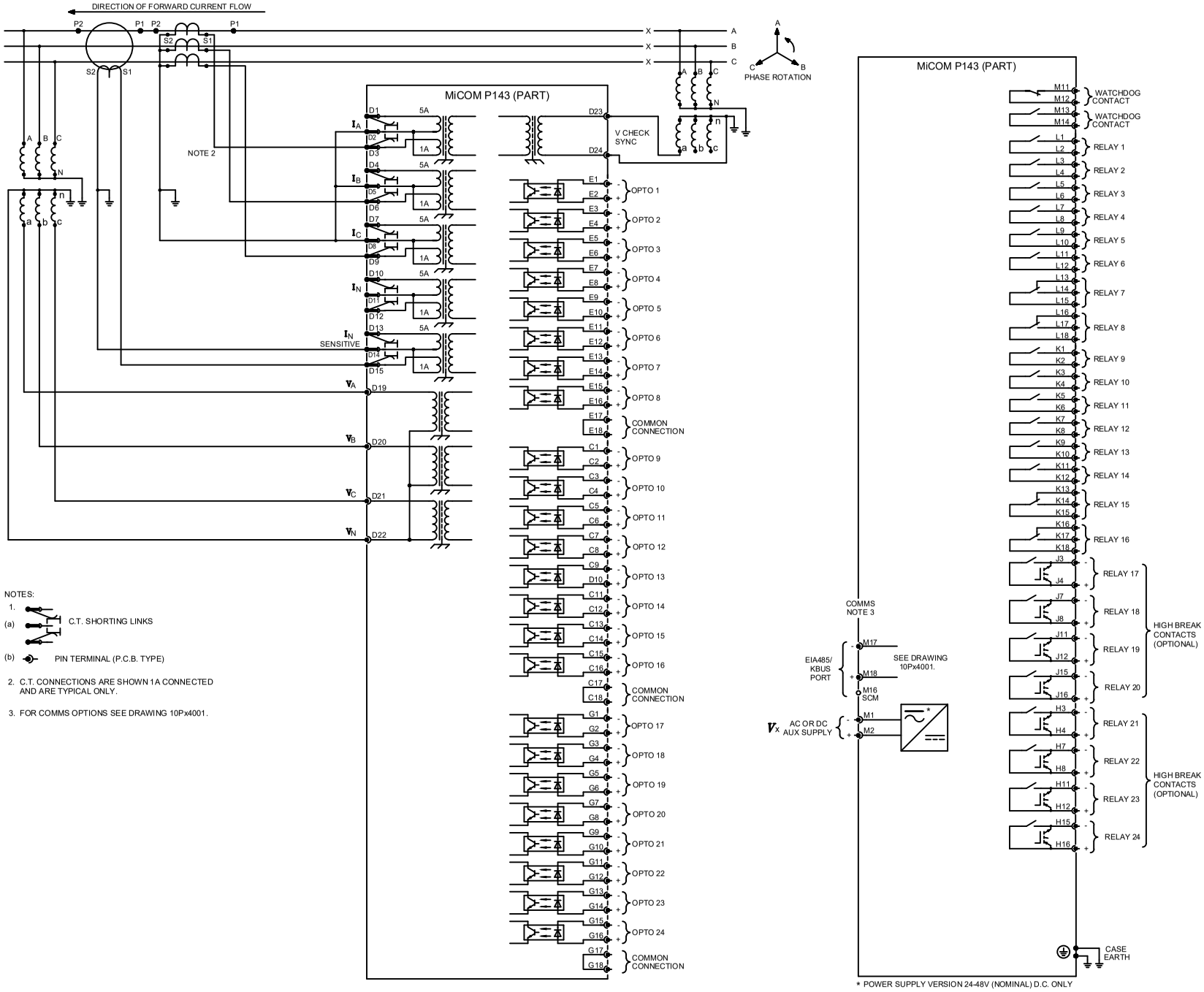
Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT. CONN. DIAG: FEEDER PROT. RELAY (60TE) DIR'NAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 16 O/P)			
Date: 16/12/2025	Name: S WOOTTON		Drg No: **10P14328**	PLM No: A20135392	Sht: 1	GE VERNOVA
Date: 16/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 16 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14332-1	PLM No: A20135447	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

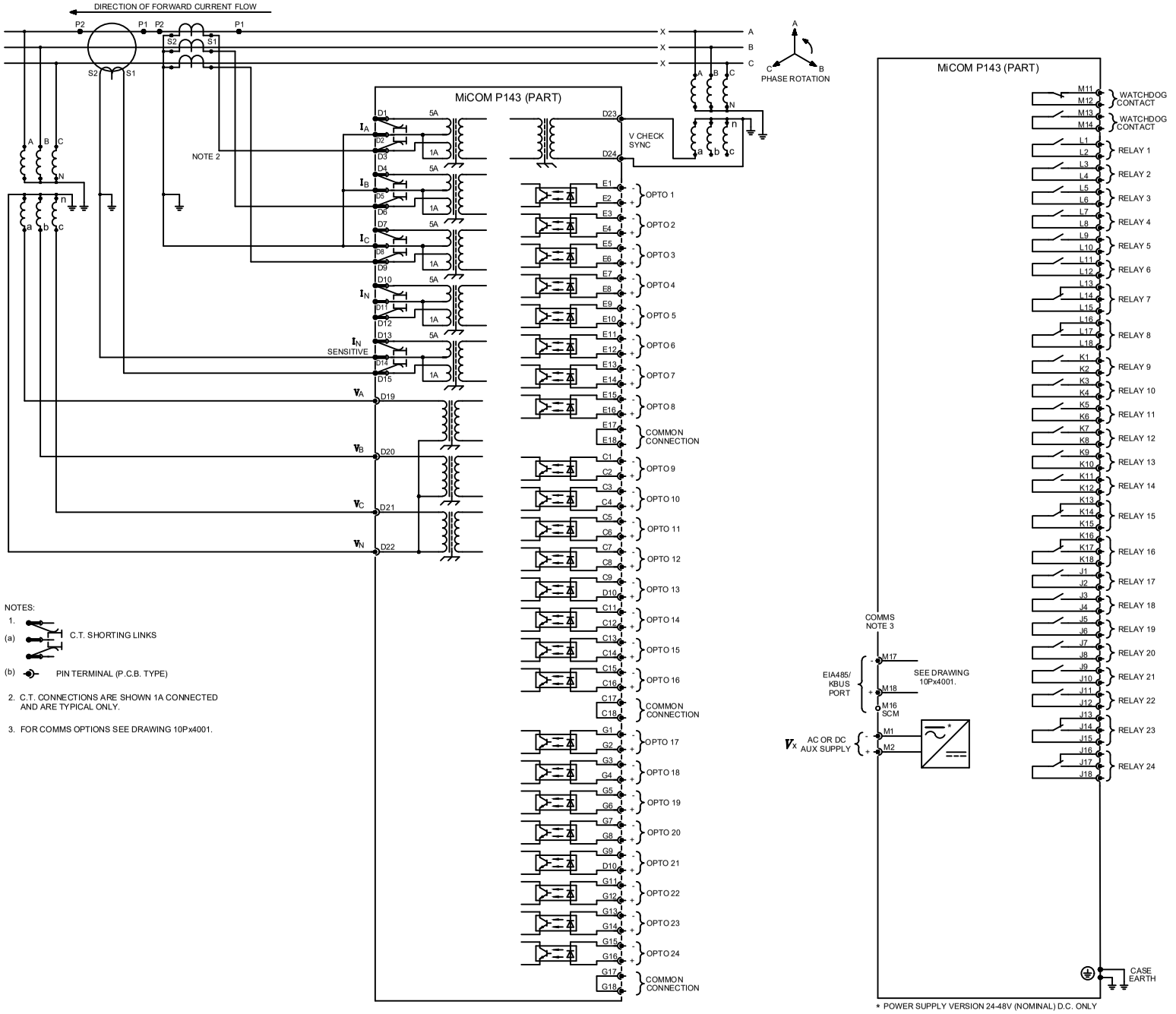
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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 16 O/P + 8 HI BRK RELAYS)		
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14333-1	PLM No: A20135646	Sht: 1
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -

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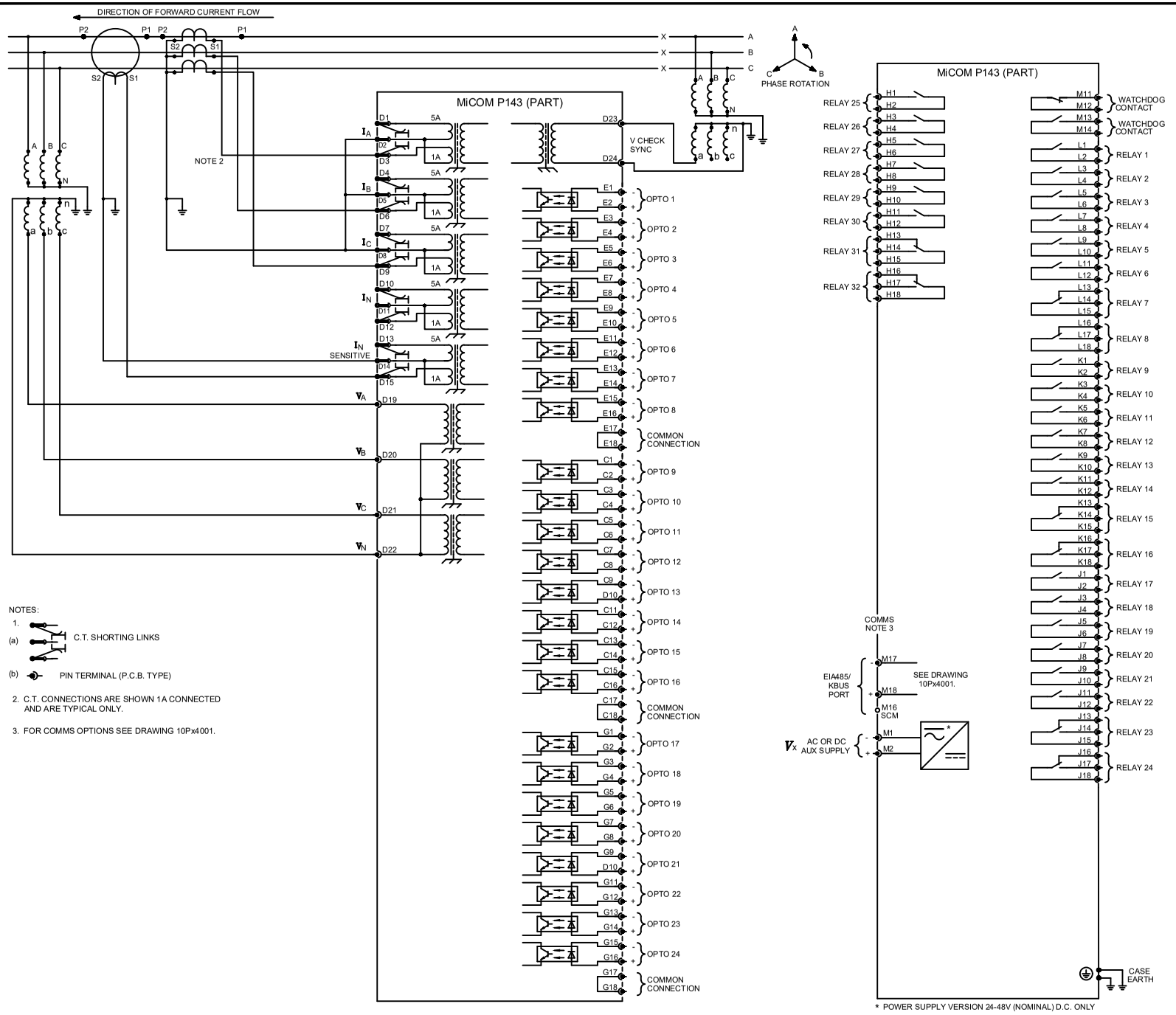
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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 24 O/P)		
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14334-1	PLM No: A20135453	Sht: 1
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -

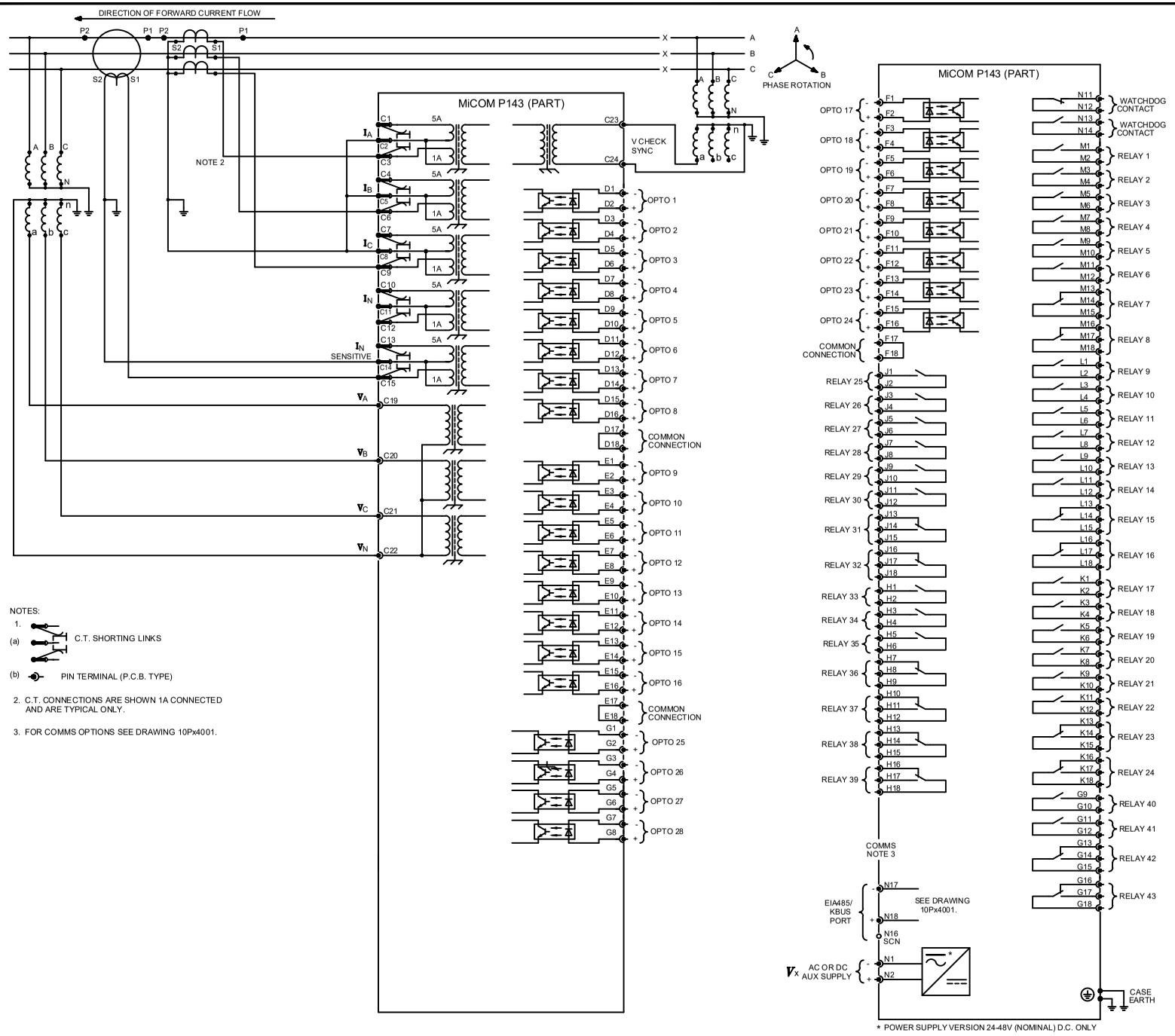
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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (24 I/P & 32 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14335-1	PLM No: A20135466	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

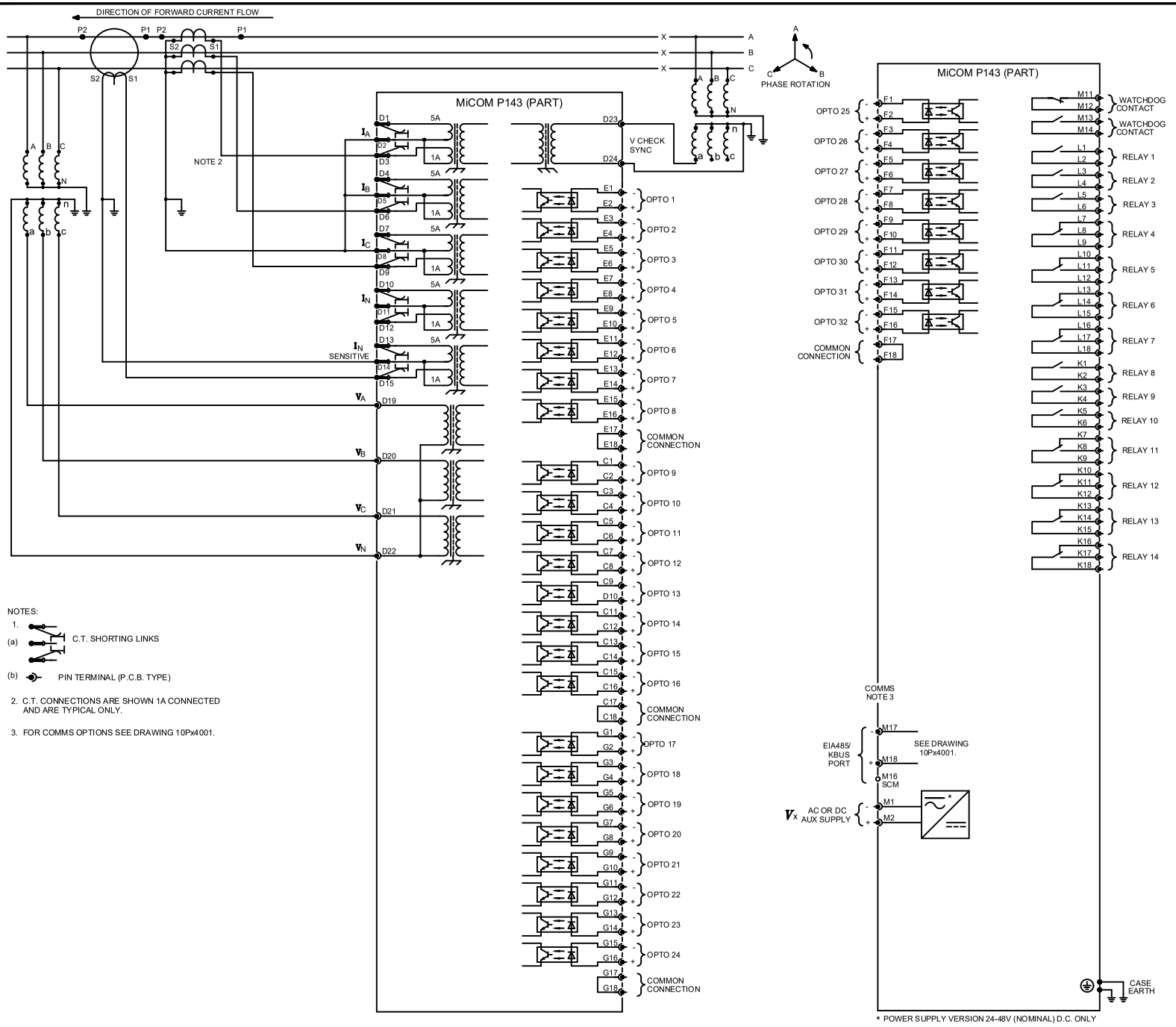
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Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (28 I/P & 43 O/P)		
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14343-1	PLM No: A20136021	Sht: 1
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -

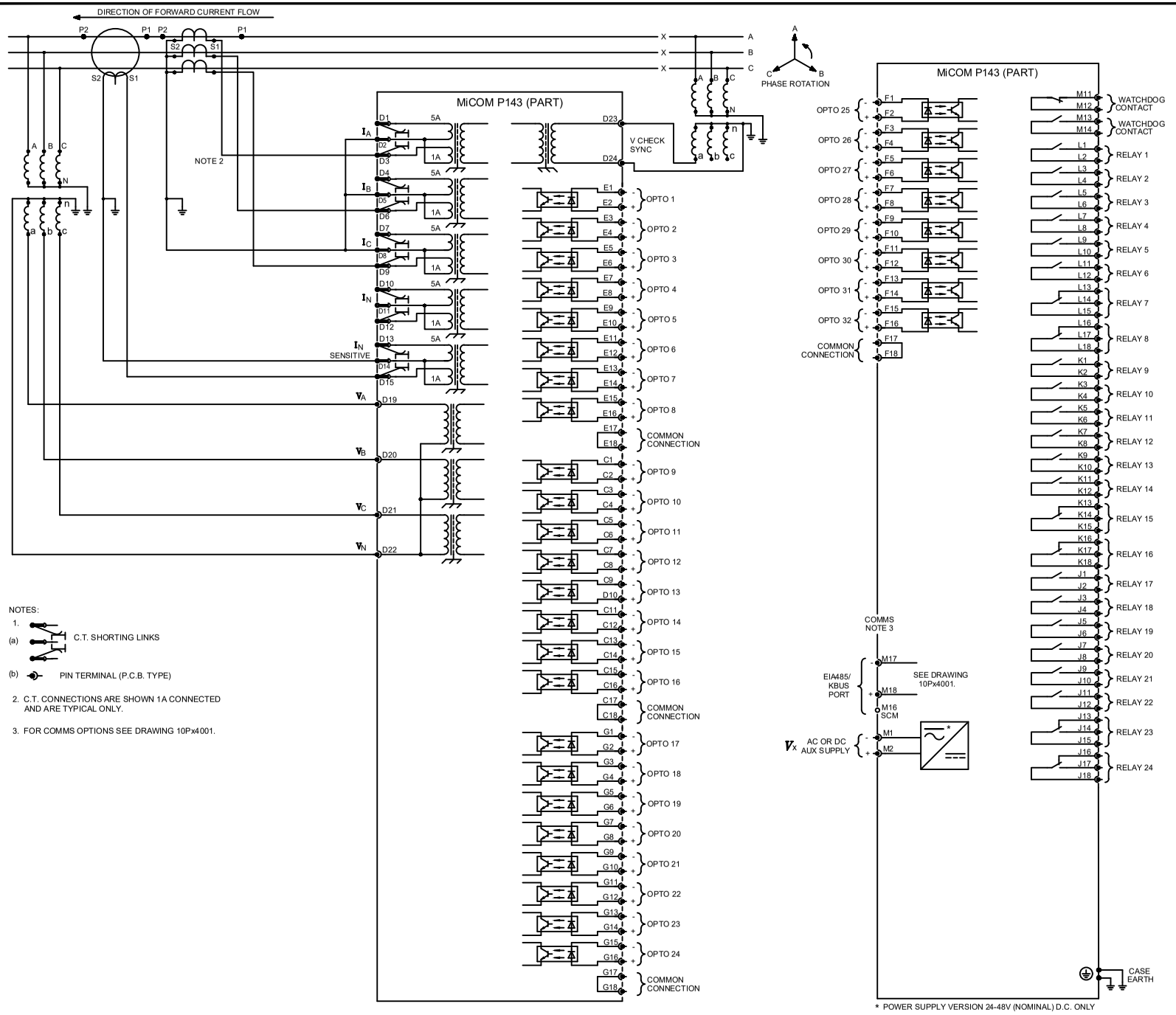
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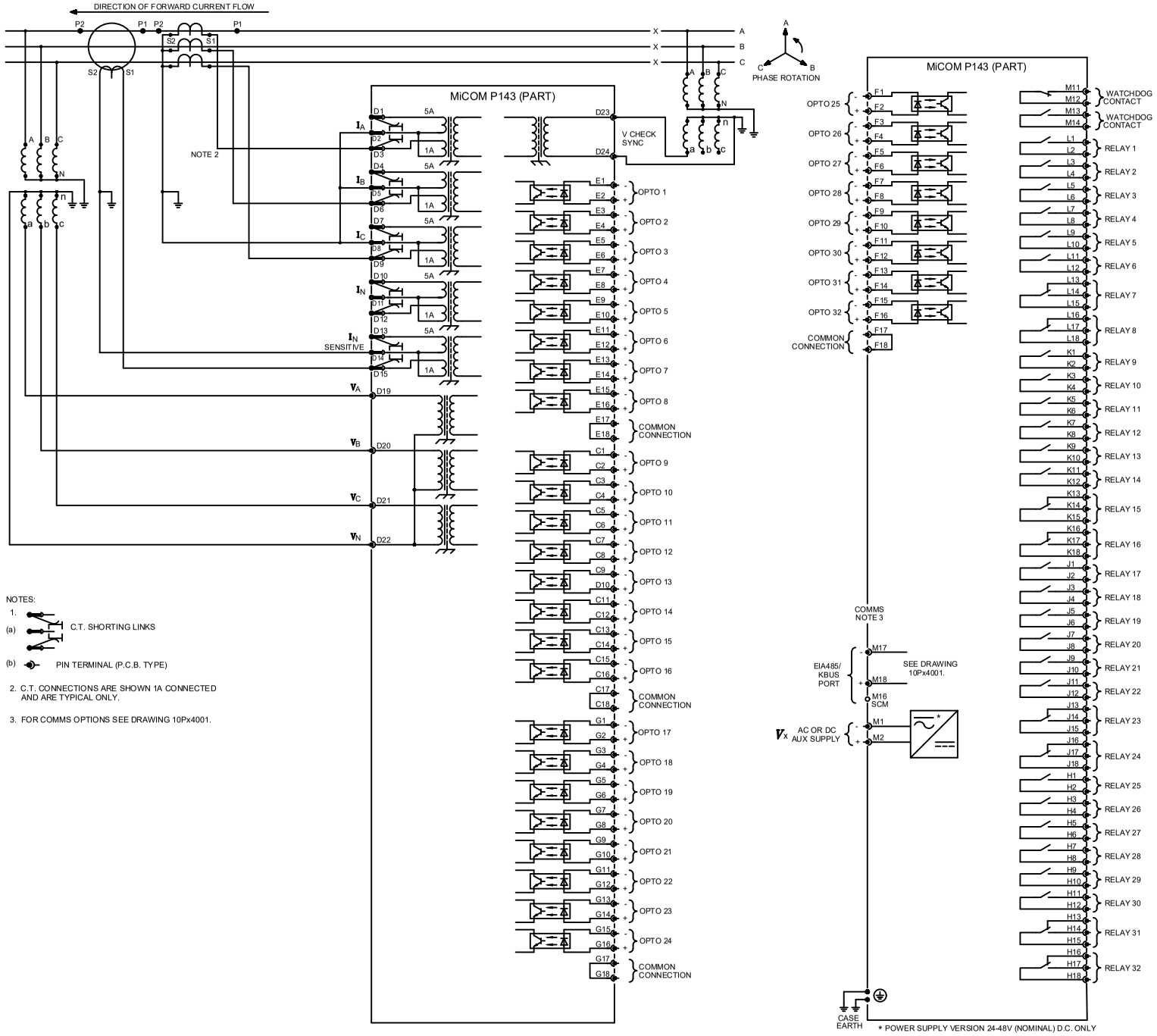


Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (32 I/P & 14 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14337-1	PLM No: A20135467	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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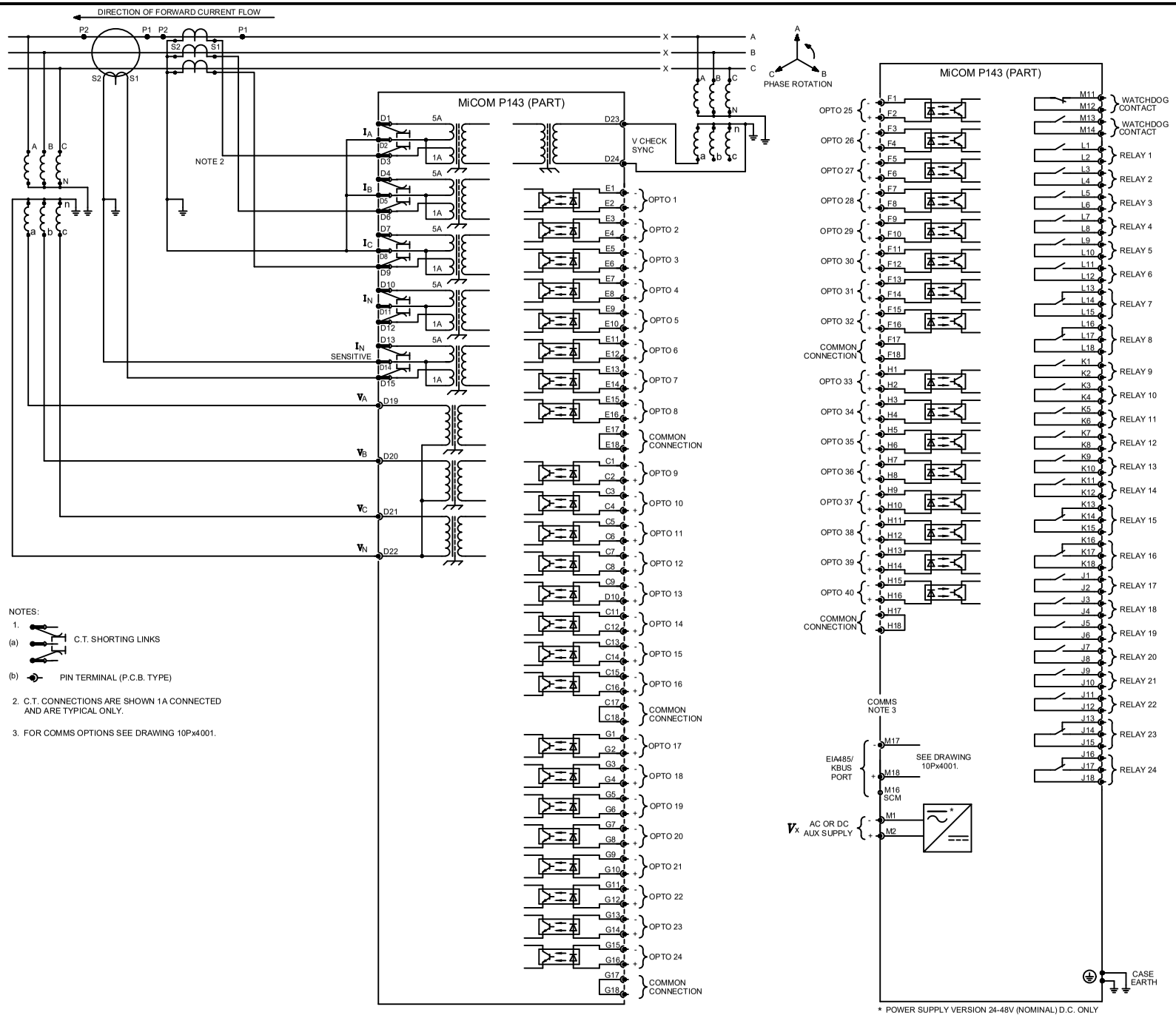
Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (32 I/P & 24 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14338-1	PLM No: A20135468	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS	©2024 GE Vernova Inc. propriety and confidential information. All Rights Reserved. This document is the property of GE Vernova and may not be reproduced, transmitted, stored, or copied in whole or in part, or used to furnish information to others, without the prior written permission of GE Vernova. GE is a trademark of General Electric Company and is used under trademark license.			Next Sht: -	



Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (32 I/P & 32 O/P)		
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14339-1	PLM No: A20135469	Sht: 1
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -

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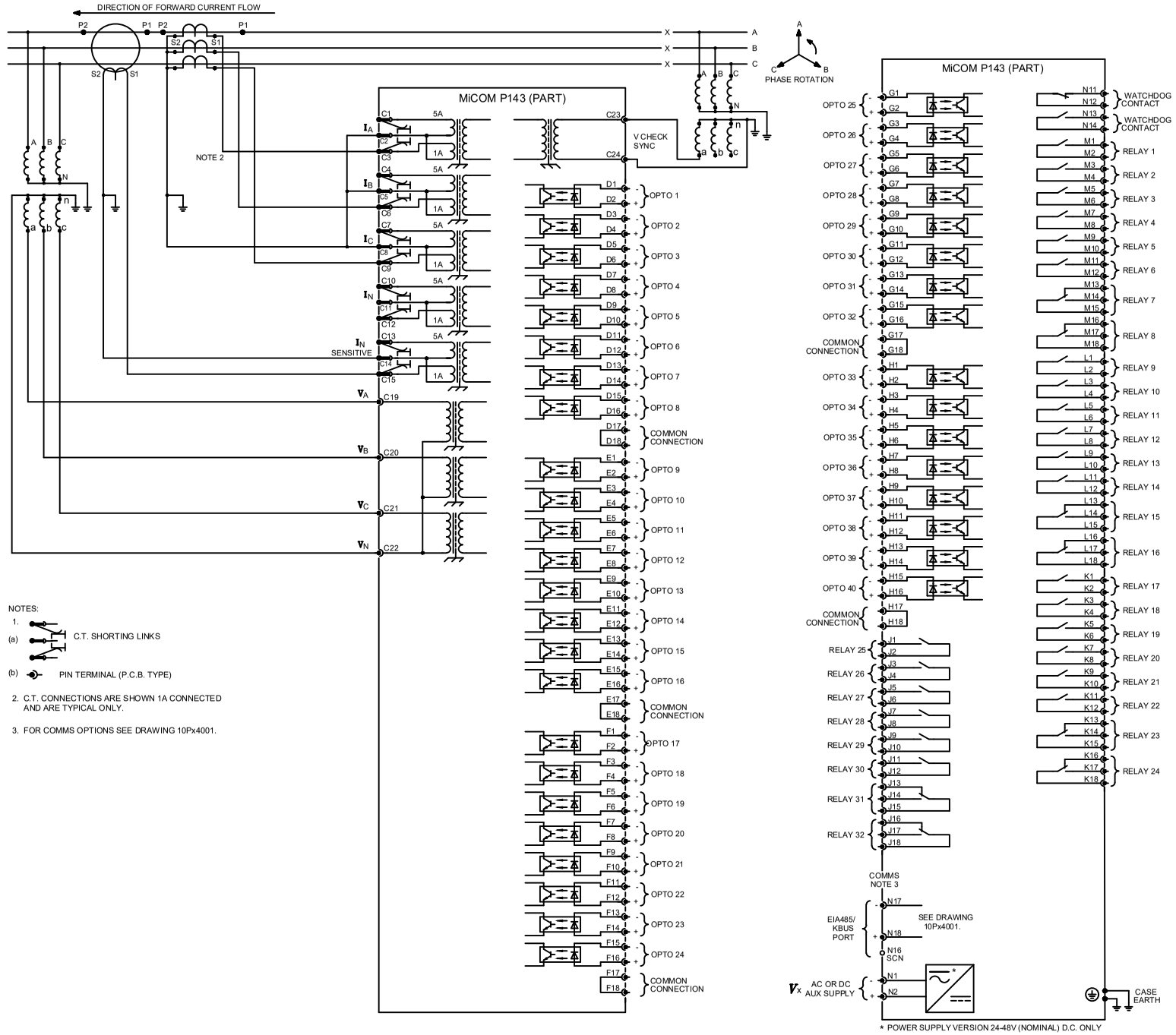


NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (40 I/P & 24 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14340-1	PLM No: A20135470	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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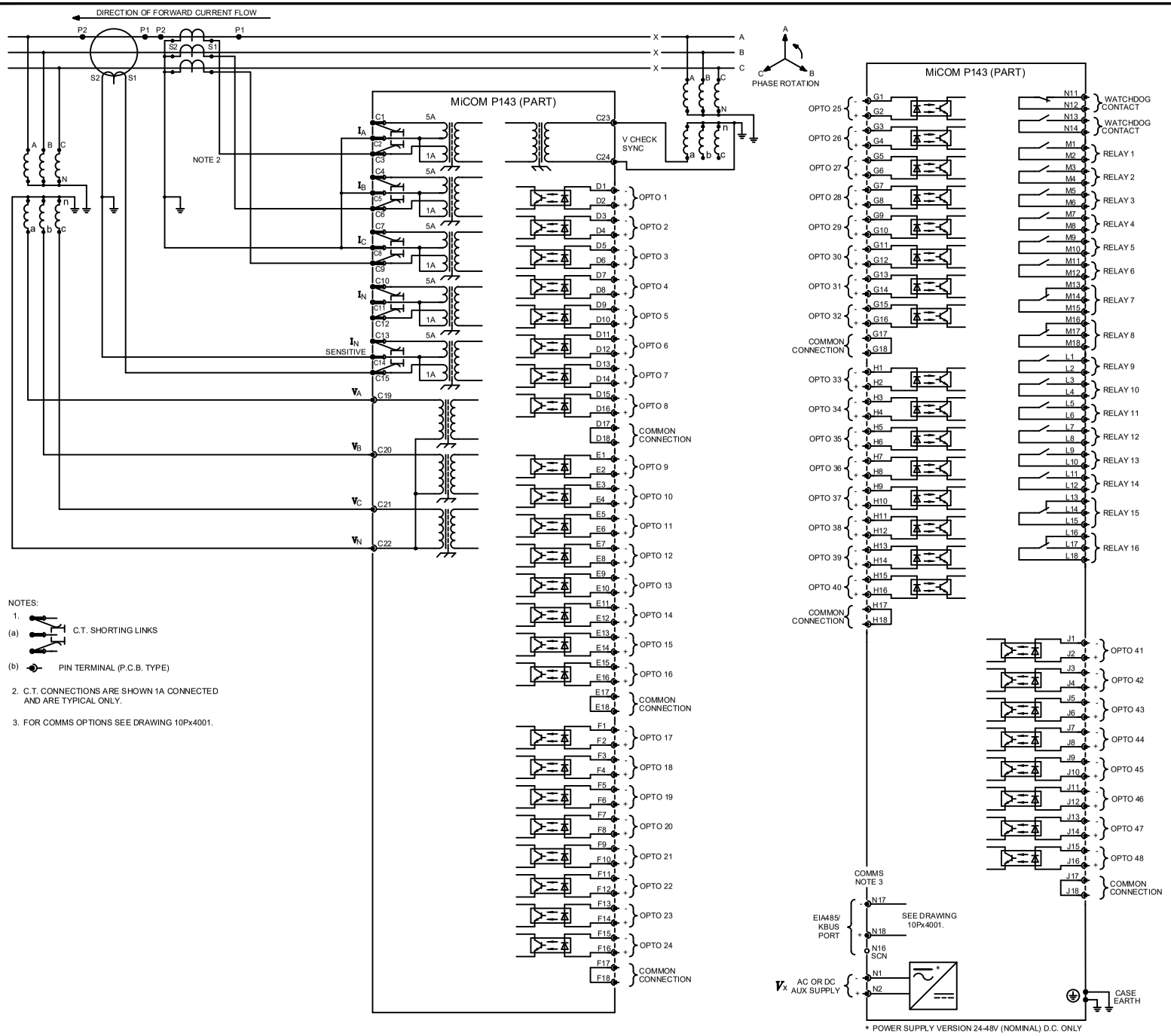
NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (40 I/P & 32 O/P)
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14344-1
Date: 18/12/2025	Chkd: J HUTCHINS		PLM No: A20136076
			Sht: 1
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NOTES:

1. (a) C.T. SHORTING LINKS
   (b) PIN TERMINAL (P.C.B. TYPE)
2. C.T. CONNECTIONS ARE SHOWN 1A CONNECTED AND ARE TYPICAL ONLY.
3. FOR COMMS OPTIONS SEE DRAWING 10Px4001.

Issue: A	Status: **Approved**	Revision Notes: CID009196. INITIAL ISSUE.	Title: EXT.CONN DIAG FEEDER PROT.RELAY (80TE) DIRECTIONAL PHASE O/C & E/F WITH AUTO-RECLOSE (48 I/P & 16 O/P)			
Date: 18/12/2025	Name: S WOOTTON		Drg No: 10P14345-1	PLM No: A20136086	Sht: 1	GE VERNOVA
Date: 18/12/2025	Chkd: J HUTCHINS				Next Sht: -	

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