

IEC 61850 CONFIGURATION

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PURPOSE AND SCOPE

This document defines the requirements for configuring National Grid substations to the IEC61850 standard. By following this specification interoperability between devices from different suppliers will be possible and to some extent interchangeability of devices can be achieved.

The IEC61850 standard is used for communication between the Substation Control System (SCS) and Intelligent Electronic devices (IEDs) over the Substation Bus, herein referred as the Station Bus, and for communication between IEDs and Merging Units (MUs) over the so called Process Bus.

The standard also uses a Substation Configuration Language (SCL) that standardises the information modelling and communication configuration, which is crucial for interoperability.

The Architecture for Substation Secondary Systems (AS³) mandated in this specification is based on the process bus topology and communication functions defined in IEC61850-7-1, as well as the “Golden Rules” mentioned in Section 1.

The scope of this specification will allow for process bus redundancy to ensure improved reliability for the standard bay solutions developed for the UK National Grid. This leads to a topology and communication function requirements as shown in the example in Figure 1. The numbers refer to standard communication functions and data flow as shown below:

1. Sampled value exchange for CTs and VTs
2. Fast exchange of I/O data for protection and control ,
3. Control and trip signals
4. Engineering
5. Monitoring and supervision
6. Control-Centre communication (not part of the scope of this specification)

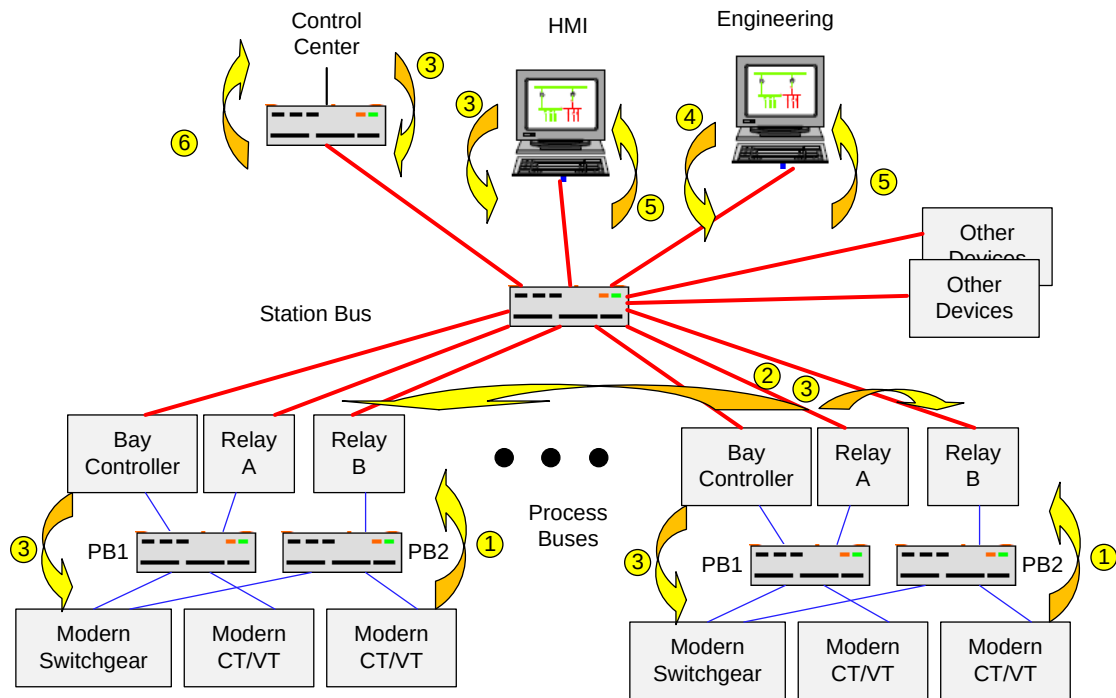


Figure 1: An Example of IEC 61850 topology for Substation Secondary Systems

PART 1 – PROCEDURAL

1 GENERAL REQUIREMENTS

Protection and Control solutions using the IEC61850 standard shall be compliant with and certified to IEC61850 (edition 2 or later) and compliance with requirements for cyber security as detailed in IEC62351 shall be demonstrated.

The design shall implement the AS³ architecture (see Section 3) and shall implement the following “Golden Rules”:

- All trip signals shall be received by the breakers within 10ms excluding inter-trip send
- No single activity on the main 1 system shall affect the main 2 system
- No single failure shall result in the loss of control of more than one bay
- Facilities shall be available to isolate a bay for testing (Protection & Control)
- The Protection and Control application/philosophy shall comply with the National Grid Technical Specifications relevant to the application.

2 ENGINEERING PROCESS

2.1 Requirements for SICAP solutions

A Single Line Diagram as per SICAP policy shall be used to export an SSD file (in XML format), rather than a circuit diagram. The SSD file can then be imported into the System Configuration Tool. It includes the layout of the substation as well as the needed functions for the bay.

A type registered solution consisting of an IID (File 'X') and SCD file shall be configured according to system requirements (settings, additions, I/O). This shall be followed by the bay configuration which shall be tested in a bay level FAT.

All SCDs/SEDs from the bays shall be put together in a substation SCD to test substation functions (interlocking, ATCC, etc). After the substation is configured all IED configuration files (IIDs) need to be updated so that the IEDs can communicate with each other. This shall then be tested in a specific FAT for the different functions.

Informative: The communication between IEDs in previous solutions was hardwired, and a scheme indicates the connection. This can also be done with the new process. (Please refer to the Appendices, for example tests of GOOSE signals). The aim of the System Interface FAT is to validate interface parameters such as data sets, GCBs, RCBs, MAC addresses etc.

The updated IED configuration files (CIDs, File 'Y') shall be loaded into the IEDs on site and a SAT shall be performed.

2.2 Roles in the engineering process

Roles in the design process shall be clearly defined. These roles should comply with NG Standard TP107. The following table states the main roles with their abbreviations:

DE (NG)	Design Engineer (National Grid)
SE (NG)	Settings Engineer (National Grid)
DVE (NG)	Design Verification Engineer (National Grid)
SE (Sup)	Settings Engineer (Supplier)
DE (Sup)	Design Engineer (Supplier)
CO (NG)	Commissioning Officer (National Grid)
SI (Sup)	System Integrator (Supplier)
CE (Sup)	Commissioning Engineer (Supplier)
SAP (NG)	Senior Authorised Person (National Grid)

2.3 Tools in the engineering process

The Single Line Diagram (SLD) to System Specification Description (SSD) translation shall be provided as XML data for import into the System Configuration.

Every manufacturer should use its own specific tools for configuration.

The IED configuration tool shall provide an IID file which can be loaded into the system configuration tool.

The IED configuration tool shall be able to use an SCD file to generate a CID parameterisation file, which can be loaded to the specified IED for testing.

The system configuration tool shall provide an SCD file, which is used for the System Interface Communications FAT as well as for Bay Level Type Registration.

2.4 Description of the engineering process

2.4.1 Definitions of process steps

The Design Engineer (National Grid) and Design Verification Engineer (Supplier) shall agree on the final design of the substation.

The Design Engineer (National Grid) shall approve the substation layout with a specific SSD design program. Several programs are available, for this document Visual SCL is used for illustration.

The final design shall then be supplied in a format of XML to the Design Verification Engineer (Supplier) and the Design Engineer (Supplier).

The Design Engineer (Supplier) together with the Settings Engineer (Supplier) shall prepare the IED configuration and agree on the IED configuration prior to the factory acceptance test (FAT) with the Commissioning Officer (National Grid).

Every Design Engineer (Suppliers) shall provide an IID file or SCD file if necessary to the System Integrator (Supplier), who designs the substation configuration description (SCD). The IID file shall contain the input/output-configuration needed for the System Interface Communications FAT which would typically include Data Sets, GCBs, RCBs and MAC addresses.

The SCD shall contain all System Interface Communication parameters.

Where different suppliers are involved, the System Interface communications FAT shall be carried out by either:

Using the devices which contain the configuration directly. I.e. all IEDs have to be connected in the System Interface Communications FAT or

Using simulation software that can simulate system interface communication with the supplied ICD files. I.e. only the IED under Test is required along with the SLC/SCP.

The project plan shall demonstrate that sufficient time is allowed for in the programme for System Interface Communication design and testing.

The Commissioning Officer (National Grid) and the Design Engineer (Supplier) shall agree on the method of System Interface Communications FAT.

After Completing the System Interface Communications FAT, the resultant CID file(s) shall be given back to the supplier for loading into the IED(s) on site.

The Design Engineer (Supplier) and the Commissioning Engineer (Supplier) shall carry out the site acceptance test (SAT) according to CH21 and TP107 procedures.

Every process step shall comply with CH21 and TP107 procedures.

2.4.2 Type Registration of an AS3 bay solution

Uncontrolled When Printed

The type registered solution shall produce an SCD file that can be used for future substation configurations.

Within the type registered SCD file all internal GOOSE messages shall be configured. Furthermore only signals which are needed for the communication interface should be made available in the template and tested for the GOOSE function.

The system shall be configured and tested according to the following diagrams:

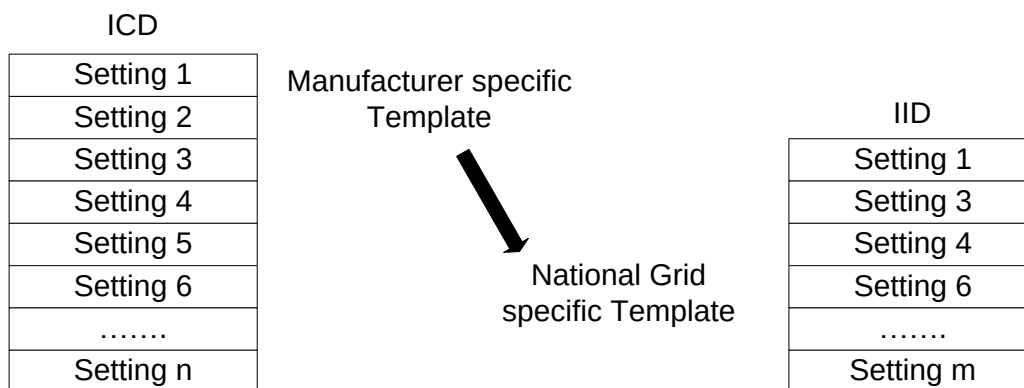


Figure 3: Converting manufacturer template to NG specific template

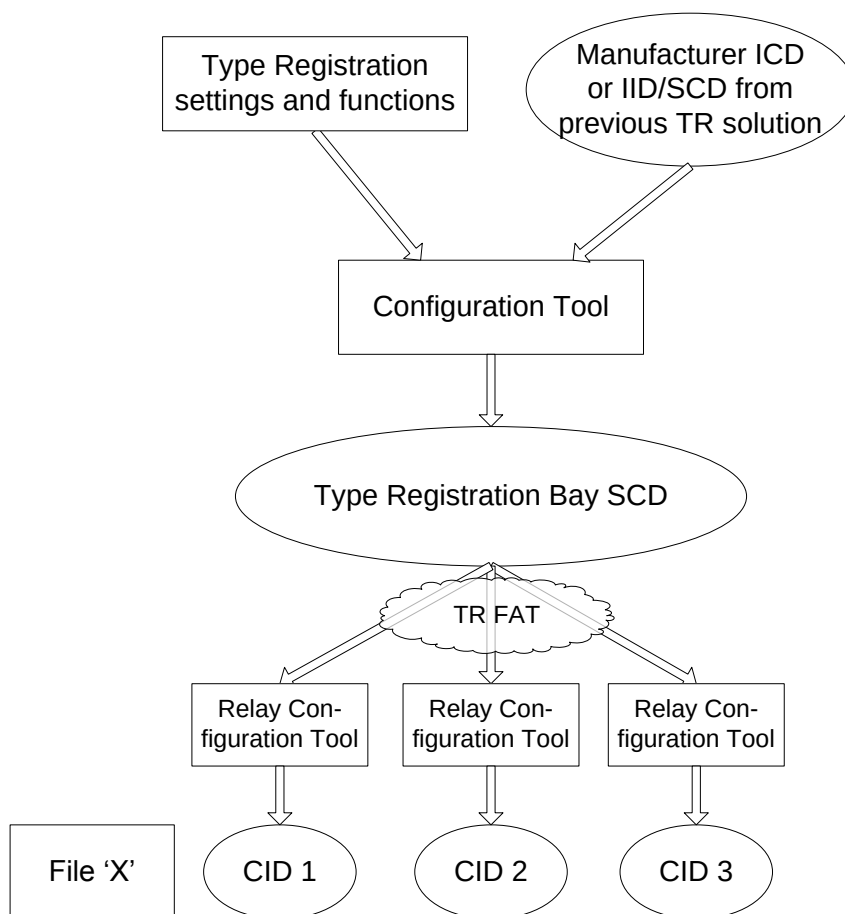


Figure 4: Type Registration of a Bay Solution

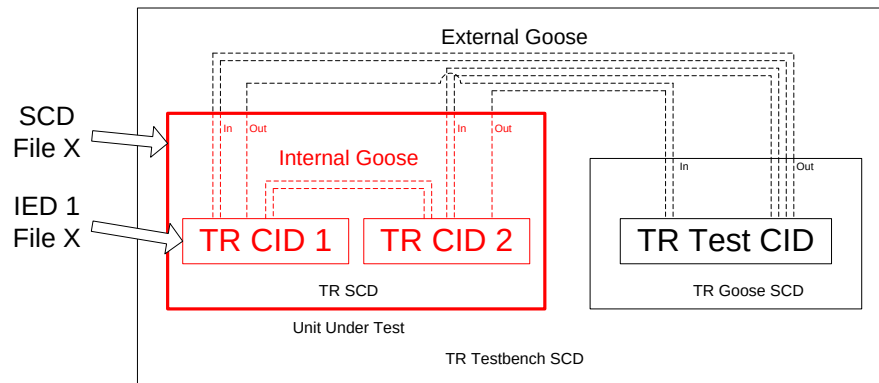


Figure 5: Type Registration Test-Bench

Comment: The files within the TR SCD are CIDs for the TR solution. However as the configuration is not site specific, they are IIDs for the Site.

For comparison according to TP107, the 'IED File x' needs to be compared with the 'IED File y' from the process described in 2.4.1.

2.4.3 Engineering of a new substation using type registered templates

A new substation shall only use SBSs which are type registered according to the process described in 2.4.2.

The system shall be configured according to the process described in 2.4.1.

File comparison as described in TP107 shall be carried out according to the following

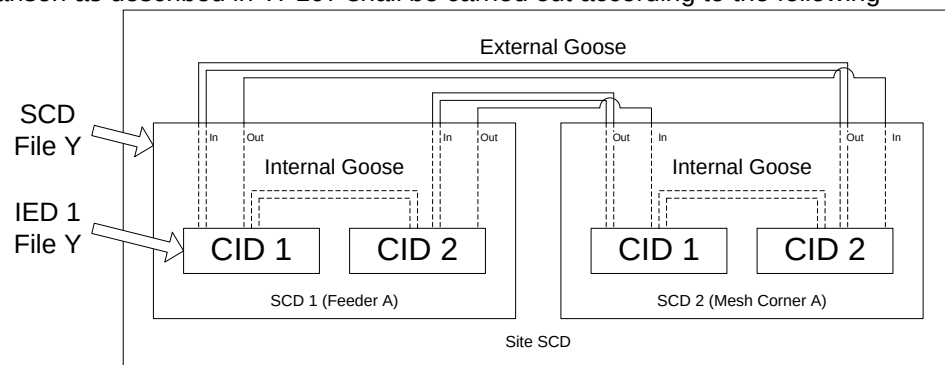


diagram:

Figure 6: FAT diagram

Further templates shall be designed to simplify the engineering process:

- Bay type definition: This definition is for standard bays within a substation, e.g. standard 400/132kV transformer bay (SSD format). This document will provide a GEM style format for the SBS.
- Bay solutions: Standard bay type solutions with more than one IED , e.g. Feeder bay solution, including inter relay communication and standard parameters (1st Main protection, 2nd Main Protection, DAR). This will produce a standard Bay SCD (refer to Section 3.5 for layout).

If a standard solution exists for any substation configuration description (SCD), this should be used as a template to configure the substation.

The process of creating a substation configuration shall be designed according to the following flowchart. Templates should be designed where feasible.

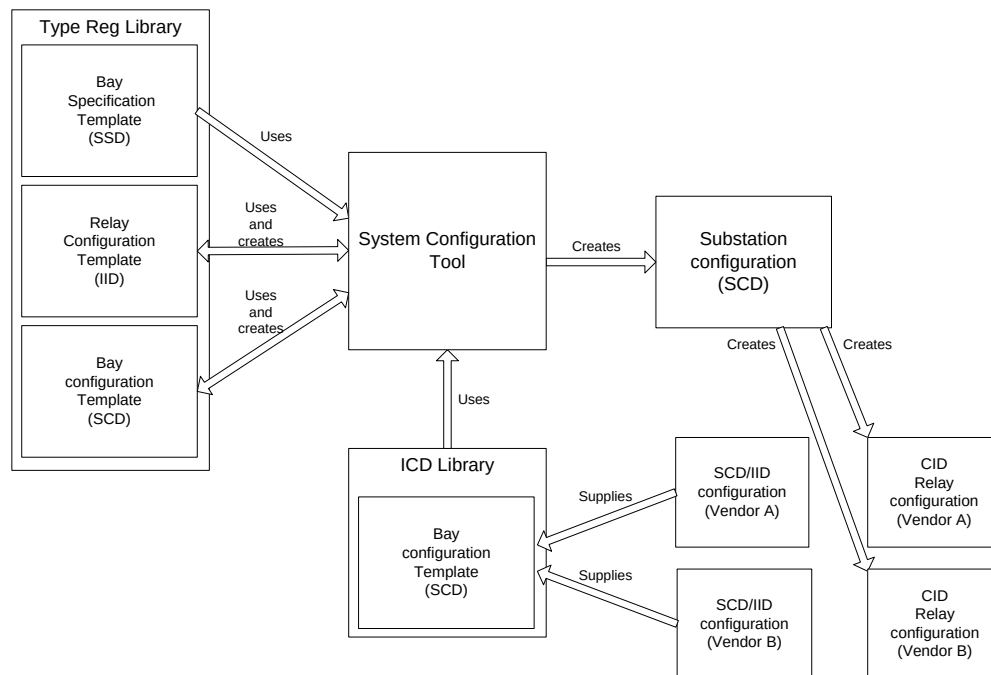


Figure 7: Working with substation templates

2.4.4 Substation extension and modification

The latest SCD from the site to be modified shall be taken and verified against the NG Standardised version.

The new substation shall only use type registered SBSs, otherwise the SBS shall be type registered first (see 3.4.2).

The process for a modification shall be followed as described in chapter 2.4.1.

When a modification is needed the existing SCD shall be given to the System Integrator (Supplier), who shall then extend the substation accordingly.

If an SCD file does not exist, a new SCD shall be designed including all necessary devices.

Comment: An example for a new bay within an existing substation can be found in the Appendix. It explains the process of how the different programs and files interact with each other.

3 ARCHITECTURE FOR SUBSTATION SECONDARY SYSTEMS (AS3)

3.1 Architecture and Data Flow

All protection and control solutions shall comply with the Architecture for Substation Secondary Systems (AS3) as described below using the IEC61850 Edition 2 group of standards.

Each bay shall have two individual Process Buses which connect to all devices that can accept or send process bus data within the circuit as shown in Figure 8.

Synchronising and High Accuracy Metering (HAM) VTs shall be connected to a specific MU which is connected to the Interbay Process Bus (Measurement Bus).

Each device shall connect to the Station Bus to communicate to the Substation Control System.

Connection between the Process Bus and the Station Bus shall not exist, unless a filter switch is used to filter the IEC 61850 9-2 (sampled values) data from the IEC 61850 8-1 data.

Local Bay Protection tripping shall be carried out via the Process Bus (GOOSE tripping).

Back tripping shall be carried out via the Process Bus if possible; or the Station Bus via a pair of protection relays; i.e FPFM & FPSM relays (The BCU should not be used unless the backtripping is initiated from the BCU in which case this can be either Process or Station Bus).

Synchronising shall be carried out via the Interbay Process Bus unless busbar VTs are provided in which case this would not be required.

General interbay communication for substation automation and control (ATCC, interlocking, etc.) shall be sent via the Station Bus (GOOSE messages).

All Client Server communication (SCS, Controls, Alarms, etc.) shall be sent via the Station Bus.

Each circuit shall contain the following

- 3 or more Merging Units (MU) – shown as AMUs
- 2 Circuit Breaker Controllers (CBC) per circuit breaker – shown as DMUs
- 1 or more General Switch Controller (GSC) (Disconnecter / Earth Switch) – shown as DMU
- 1 or more Main Protection Devices (MP)
- 1 Backup and Auxillary Protection Device (BUP)
- 1 Operational Metering Device (OMS) (Optional)
- 1 Bay Control Unit (BCU) (Optional)

The topology shall be compliant to IEC62439

The topology shall be designed to the following diagram:

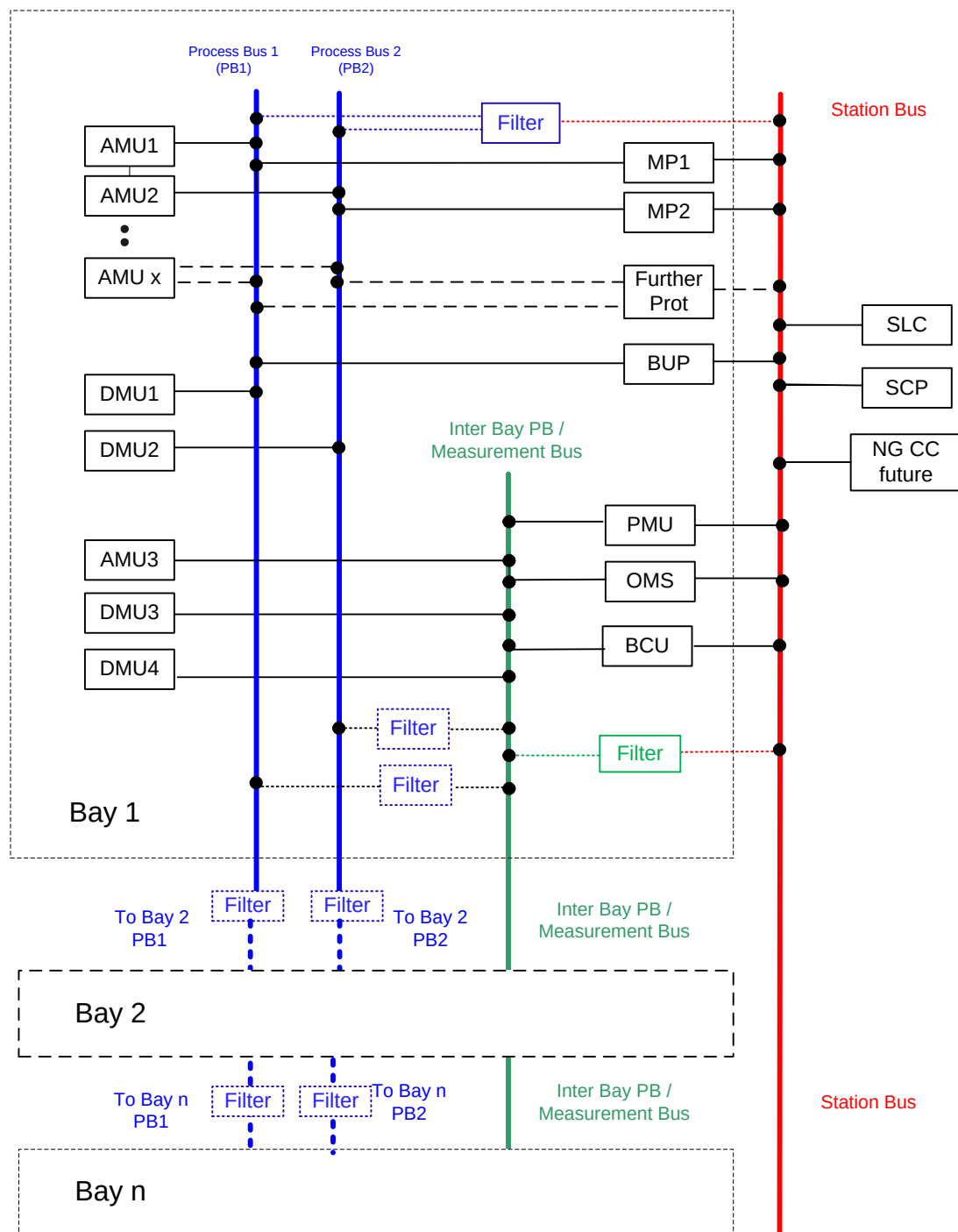


Figure 8: Process Bus Architecture

The architecture in Figure 8 is based on IEC61850-7-1 (topology and communication functions of substation automation systems), with the consideration of process bus redundancy and inter bay process bus/measurement bus for synchronisation functions across bays.

The substation automation functions are supported by the communication functions as follows:

- sampled value exchange for CTs and VTs via all Process Buses,
- control and trip signals, GOOSE, for the local bay control and tripping via Process

Bus,

- control and trip signals, GOOSE, for inter bay control and tripping via Interbay Process Bus,
- control and trip signals, GOOSE for Local HMI and gateway to Control Center via Station Bus
- fast exchange of I/O data for protection and control (vendor specific for application such as Mesh DAR, ACS etc..) via Station Bus,
- client and server function monitoring and supervision via station bus, possibly extending to PB level via a filter switch (e.g. for TX monitoring etc.)
- client and server function for control-centre communication between the station bus and remote control centre via a router/gateway (not included in this specification).

The layout of each bus is up to be designed by the supplier. It can be point-to-point, redundant star or redundant ring topology. However, each bay shall have 2 process busses and 1 Interbay Process Bus.

Filters may be introduced for different manufacturer's devices. The devices can either just be connected to the Process Bus and connect to the Station Bus via a filter or connect to the Station Bus directly.

Interconnections between Process Busses shall use appropriate filters. This would typically be required for Mesh Corner substations.

3.2 Station Bus requirements

The communications on the Station Bus shall comply with the relevant parts of the IEC61850 series of standards, in particular IEC61850-8-1 for MMS and GOOSE.

The Station Bus shall provide a link between all bays within a substation.

The Station bus shall be implemented using a fibre optic network where possible and shall comply with TS3.24.01.

3.3 Process bus requirements

3.3.1 Time synchronisation

Clock synchronisation shall be provided via redundant master clocks.

Time synchronisation should support IEEE1588, however star distributed 1PPS time synchronisation is acceptable.

Time synchronisation shall be accurate within 1µs when it appears at the IED.

1pps signal shall be provided via multimode fibre-optic ST connectors.

3.3.2 Bay Process Bus

All measured values shall comply with the IEC 61850 9-2 standard and should follow UCA implementation guidelines currently called IEC 61850 9-2 Lite Edition (LE).

Every transmitted sampled value shall contain a validity bit. When sampled values are valid, they shall be used for operation. When the sampled value is not valid, the protection should

indicate an error on the protection system. When the Merging Unit is not available, the protection shall be blocked and an error on the protection system shall be indicated.

Every transmitted value shall contain a test bit. If the test bit is active, trip signals shall be blocked.

During commissioning the Merging Unit shall be switched into test mode. All sampled values shall have the test bit active. Trips shall be blocked so that the protection can be tested, (i.e. Ed 2 test or test/blocked mode).

GOOSE messages for all applications (such as tripping, control, etc.) shall comply with IEC61850-8-1.

3.3.3 Interbay Process Bus

Each bay which requires circuit breaker synchronisation or High Accuracy Metering (HAM) shall include an additional Merging Unit which shall be connected to the Interbay Process Bus.

Like the Bay Process Bus, the Interbay Process Bus shall implement IEC61850-9-2 LE.

The Interbay Process Bus shall be used for synchronising VT measurements and High Accuracy Metering (HAM) only however a link to the station bus via a filter switch may be provided if required, as shown in Figure 8. If the bus is used for other functions this shall be approved by NG.

If a bay needs to synchronise to close its breaker, a VT selection scheme shall identify the correct VT to synchronise to. The VT selection scheme shall be local to each bay.

If Busbar VTs are provided no VT measurements need to be provided on the Interbay Process Bus

3.4 Topology and naming convention

3.4.1 The IEC61850 definition for the substation shall consist of the following topology levels

- a) Substation Level
- b) Voltage Level (400kV, 275kV, etc.)
- c) Bay Level (Feeder Bay, Transformer Bay, Mesh Corner Bay, etc.)
- d) Function (Protection, Switchgear, Instrument Transformer, etc.)
- e) Logical Node (PDIS, PDIF, XCBR, etc.)
- f) Subfunction (Zone 1, Zone 2, etc)
- g) Data (Mode, Behaviour)
- h) Attribute (Control Value, Status Value)

Informative: Examples can be found in the Appendix, 2 examples are given here

Example1: HARK/4/IEDname/PROT/PDIF1/Mod.CtIVal

Example2: STEW/1/IEDname/CTRL/XSWI1/Pos.stVal

A full view of Levels can be found in the Appendices

3.4.2 The IED configuration shall be defined as follows

- a) IED name, which consist of
 - (i) Bay name (6 Characters)
 - (ii) Physical device (6 Characters)
- b) Function (PROT, CTRL, etc.)
- c) Logical Node, which can be:
 - (i) Standard functions:
 - Function name (PDIS, PDIF, etc)
 - Suffix of 2 numbers (max 99)
 - (ii) Generic Process I/O (GGIO)
 - Prefix (6 Characters, please see Appendix for clarification)
 - Function name (GGIO)
 - Suffix of 2 numbers (Max 99)
- d) Data
- e) Attribute

Comment: Examples can be found in the Appendix

3.4.3 The SLD shall define the Logical Nodes (LN) only, each manufacturer can decide which Logical Device (LD) the LN's reside within.

3.4.4 Naming Convention

- a) Circuit Breaker
 - (i) All circuit breakers have XCBR as the main logical node. If only one breaker exists, the breaker shall have the suffix '1'.
 - (ii) A HV breaker shall have the suffix '1' and the LV breaker the suffix '2'
 - (iii) A breaker between the higher number bus bar and the series reactor shall have the suffix '1', the other one suffix '2'.
 - (iv) On a bus bar the incoming feeder/transformer breaker shall be numbered from left to right on the SLD, after that the outgoing feeder, again from left to right on the SLD.
- b) Disconnectors
 - (i) All disconnectors shall use the logical node XSWI
 - (ii) Main or Reserve disconnectors shall have the suffix 4 or 6 accordingly to their equipment name (104 or 106)

- (iii) Line or transformer disconnectors shall have the suffix 3 (e.g. 103)
 - (iv) If a second main and/or reserve bar is connected a 2 shall indicate this together with the normal suffix (e.g. 24 for 104 on LV disconnector)
 - (v) In a mesh corner the mesh breakers are called according to their name (224, 228 -> XSWI4, XSWI8), the mesh disconnector has the suffix 3. Transformer disconnectors are numbered through from 1 (e.g. XSWI1 and XSWI2), feeder disconnectors, too, but start from 5 (e.g. XSWI5, XSWI6)
 - (vi) For a Series reactor the naming is according to their names in the single line diagram, e.g. : 142A -> XSWI21, 143b -> XSWI32
- c) Earth switches
- (i) All earth switches shall use the logical node XSWI as well, however they use the ranges 11 to 19 (HV or Main 1) and 31 to 39 (LV or Main 2)
 - (ii) Earth switches are numbered according to their corresponding letter (e.g 101A -> XSWI 11, 101F -> XSWI 16; for LV 101A -> XSWI 31, 101F -> XSWI 36)
 - (iii) In a bus coupler / bus section, earth switches are numbered according to the naming from the side and the letter (e.g. P11A -> XSWI11, P21B -> XSWI22)
- d) Further Equipment
- (i) All transformers shall use the logical node YPTR and shall start with the main transformer and then auxiliary or tertiary transformers (e.g Main transformer -> YPTR1, Auxiliary transformer -> YPTR2)
 - (ii) Shunt and Series reactor shall use the logical node ZREA and there shall only be one per bay solution. If more are used a logical naming convention shall be applied.
 - (iii) Shunt Capacitors shall use the logical node ZCAP and there shall only be one per bay solution. If more are used a logical naming convention shall be applied.
 - (iv) Voltage transformer shall use the logical node TVTR and there shall only be one voltage transformer used per bay solution. If more are used a logical naming convention shall be applied.
 - (v) Current transformer
 - All current transformers shall use the logical node TCTR.
 - TCTR1 shall be a standalone current transformer (Feeder CT), the mesh CT for the mesh corner itself, the HV CT, the CT before the series reactor, shunt reactor and shunt capacitor, the main or the higher numbered bar bus section CT and the first incoming CT for bus bars.
 - TCTR2 shall be the mesh CT for the next mesh corner, the LV CT, the CTs after the series reactor, shunt reactor and shunt capacitor, the reserve or the lower numbered bar bus section CT and the next logical CT for bus bars (can be incoming or feeding).
 - TCTR3 shall be the auxiliary CT for transformers, the first transformer on a mesh and the next logical CT for a bus bar (can be incoming or feeding).

- TCTR4 shall be the tertiary CT for transformers, the second transformer on a mesh and the next logical CT for a bus bar (can be incoming or feeding).
- TCTR5 shall be the first feeder on a mesh and the next logical CT for a bus bar (can be incoming or feeding).
- TCTR6 shall be the second feeder on a mesh.

Informative: For clarification, please compare to the Standard Bay Solutions within the next chapter and the substation example in the Appendix.

3.5 Standard bay solutions

3.5.1 General Bay information

Standard Logical Nodes as defined in IEC61850-7-4 shall be used where possible.

If a standard logical node cannot be used or is not available due to the requirement, a Generic Process I/O (GGIO) or Generic Automation Process Control (GAPC) shall be used.

When a GGIO or GAPC is defined, a standard template shall be created and approved by NG as part of the Type Registration process.

All logical nodes which are used for inter relay communication shall be made available to the supplier or the system integrator via an SCD file.

All logical nodes which are used for the substation control system shall be made available to the supplier of the substation control system via the relevant SCD file.

3.5.2 Feeder Bay solution

- a) A standard Double Bus Feeder Bay solution shall consist of the following equipment and naming:

- (i) Circuit Breaker (XCBR1)
- (ii) Line Disconnecter (XSWI3)
- (iii) Main Bar Disconnecter (XSW4)
- (iv) Reserve Bar Disconnecter (XSW6)
- (v) Earth switch 1 (XSWI11)
- (vi) Earth switch 2 (XSWI12)
- (vii) Line VT (TVTR1)
- (viii) Line CT (TCTR1)

- b) A standard Feeder Bay solution shall consist of the following Function Nodes:

- (i) Logical Node Zero (LN0)
- (ii) Physical Device Information (LPHD)
- (iii) Interlocking (CILO)

- (iv) Measurement (MMXU)
- (v) Differential Protection (PDIF)
- (vi) Distance Protection (PDIS)
- (vii) Transient Earth Fault (PTEF)
- (viii) Time Overcurrent Protection (PTOC)
- (ix) Disturbance Recorder function (RDRE)
- (x) Breaker Failure Protection (RBRF)
- (xi) Directional Element (RDIR)
- (xii) Fault Locator (RFLO)
- (xiii) Auto Reclosing (RREC)
- (xiv) Synchronising (RSYN)

c) A standard Feeder Bay shall have the following arrangement:

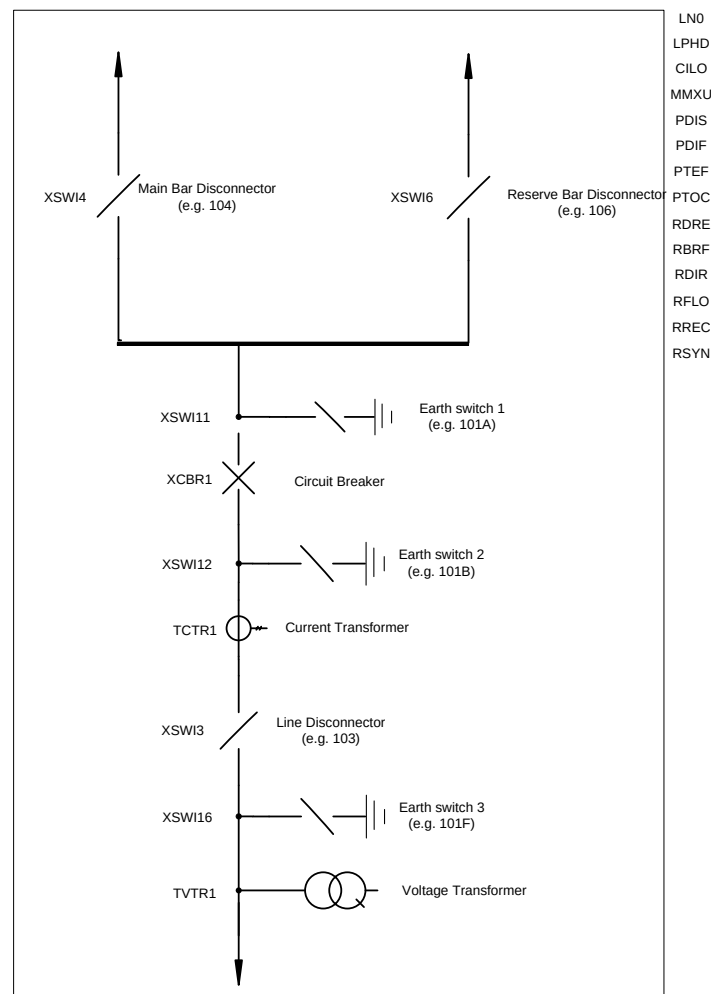


Figure 9: Standard Feeder Bay solution

3.5.3 Transformer Bay

a) Transformer HV Functions

(i) Standard Transformer HV functions shall consist of the following equipment and naming:

- Power Transformer (YPTR1)
- Earthing Transformer (YPTR2)
- HV Circuit Breaker (XCBR1)
- HV Disconnector (XSWI3)
- HV Main Bar Disconnector (XSW4)
- HV Reserve Bar Disconnector (XSW6)
- HV Earth Switch 1 (XSWI11)
- HV Earth Switch 2 (XSWI12)
- Transformer VT (TVTR1)
- HV CT (TCTR1)
- LV CT (TCTR2)
- Earthing / Auxiliary Transformer CT (TCTR3)
- Tertiary Transformer CT (TCTR4)

(ii) Standard Transformer HV functions shall consist of the following Function Nodes:

- Logical Node Zero (LN0)
- Physical Device Information (LPHD)
- Interlocking (CILO)
- Differential Protection (PDIF)
- Directional Comparison (PDIR)
- Harmonic Restraint (PHAR)
- Instantaneous Overcurrent (PIOC)
- Transient Earth Fault (PTEF)
- Time Overcurrent Protection (PTOC)
- Thermal Overload (PTTR)
- Disturbance Recorder function (RDRE)
- Breaker Failure Protection (RBRF)
- Auto Reclosing (RREC)
- Synchronising (RSYN)

(iii) The HV side of a standard Transformer Bay shall have the following arrangement:

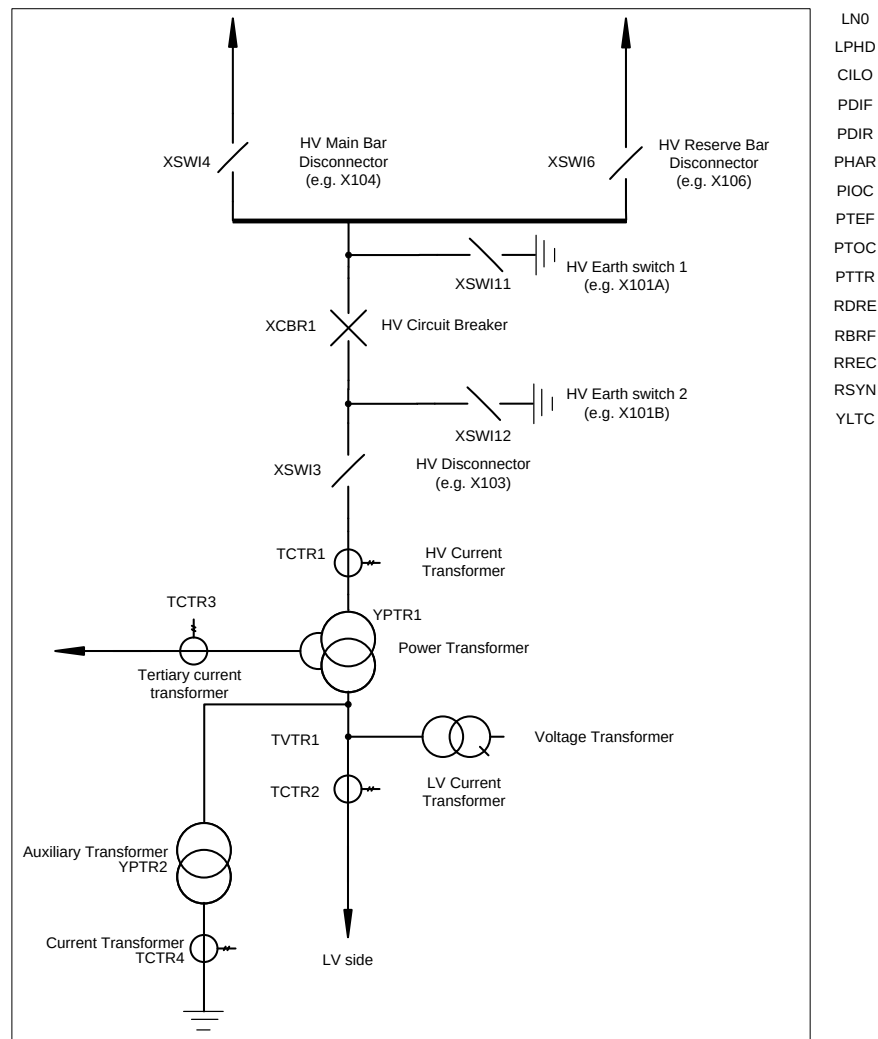


Figure 10: Standard Transformer HV Bay solution

b) Transformer LV Functions

(i) Standard Transformer LV functions shall consist of the following equipment and naming:

- Power Transformer (YPTR1)
- Tap Changer (YLTC1)
- LV Circuit Breaker (XCBR1)
- LV Disconnector (XSWI3)
- LV Main Bar Disconnector (XSWI4)
- LV Reserve Bar Disconnector (XSWI6)
- LV Earth Switch 1 (XSWI11)
- LV Earth Switch 2 (XSWI12)
- Transformer VT (TVTR1)
- LV CT (TCTR1)

(ii) Standard Transformer LV functions shall consist of the following Function Nodes:

- Logical Node Zero (LN0)
- Physical Device Information (LPHD)
- Automatic Tap Change Control (ATCC)
- Interlocking (CILO)
- Metering (MMTR)
- Measurement (MMXU)
- Instantaneous Overcurrent (PIOC)
- Time Overcurrent Protection (PTOC)
- Disturbance Recorder function (RDRE)
- Breaker Failure Protection (RBRF)
- Auto Reclosing (RREC)
- Synchronising (RSYN)

(iii) The LV side of a standard Transformer Bay shall have the following arrangement:

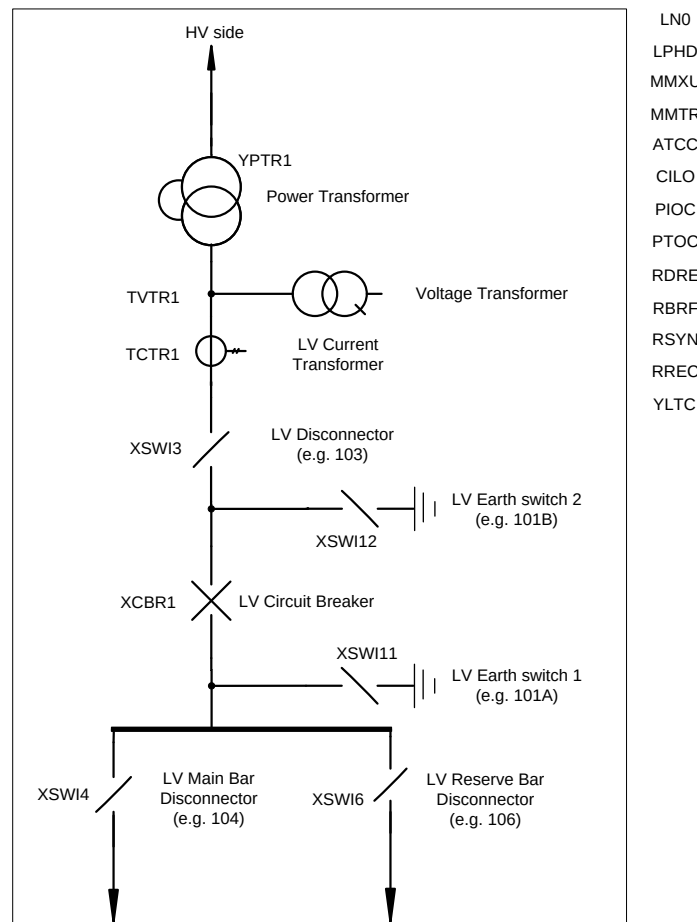


Figure 11: Standard Transformer LV Bay solution

3.5.4 Mesh Corner Bay

- a) A standard Mesh Corner Bay solution shall consist of the following equipment and naming:

- (i) Circuit Breaker (XCBR)
 - (ii) Sequential Isolator 1 (XSWI4)
 - (iii) Sequential Isolator 2 (XSWI8)
 - (iv) Mesh Corner Disconnecter (XSWI3)
 - (v) Circuit 1 Disconnecter (XSWI1)
 - (vi) Circuit 2 Disconnecter (XSWI2)
 - (vii) Circuit 3 Disconnecter (XSWI5)
 - (viii) Circuit 4 Disconnecter (XSWI6)
 - (ix) Mesh Breaker Earth switch 1 (XSWI12)
 - (x) Mesh Breaker Earth switch 2 (XSWI13)
 - (xi) Mesh Earth switch 1 (XSWI11)
 - (xii) Mesh Earth switch 2 (XSWI14)
 - (xiii) Mesh Corner CT (TCTR1)
 - (xiv) Attached Corner CT (TCTR2)
 - (xv) Transformer 1 CT (TCTR3)
 - (xvi) Transformer 2 CT (TCTR4)
 - (xvii) Feeder 1 CT (TCTR5)
 - (xviii) Feeder 2 CT (TCTR6)
- b) A standard Mesh Corner Bay solution shall consist of the following Function Nodes:
- (i) Logical Node Zero (LN0)
 - (ii) Physical Device Information (LPHD)
 - (iii) Interlocking (CILO)
 - (iv) Differential Protection (PDIF)
 - (v) Instantaneous Overcurrent (PIOC)
 - (vi) Transient Earth Fault (PTEF)
 - (vii) Time Overcurrent Protection (PTOC)
 - (viii) Disturbance Recorder function (RDRE)
 - (ix) Breaker Failure Protection (RBRF)
 - (x) Auto Reclosing (RREC)
 - (xi) Synchronising (RSYN)

- c) A standard Mesh Corner Bay shall have the following arrangement:

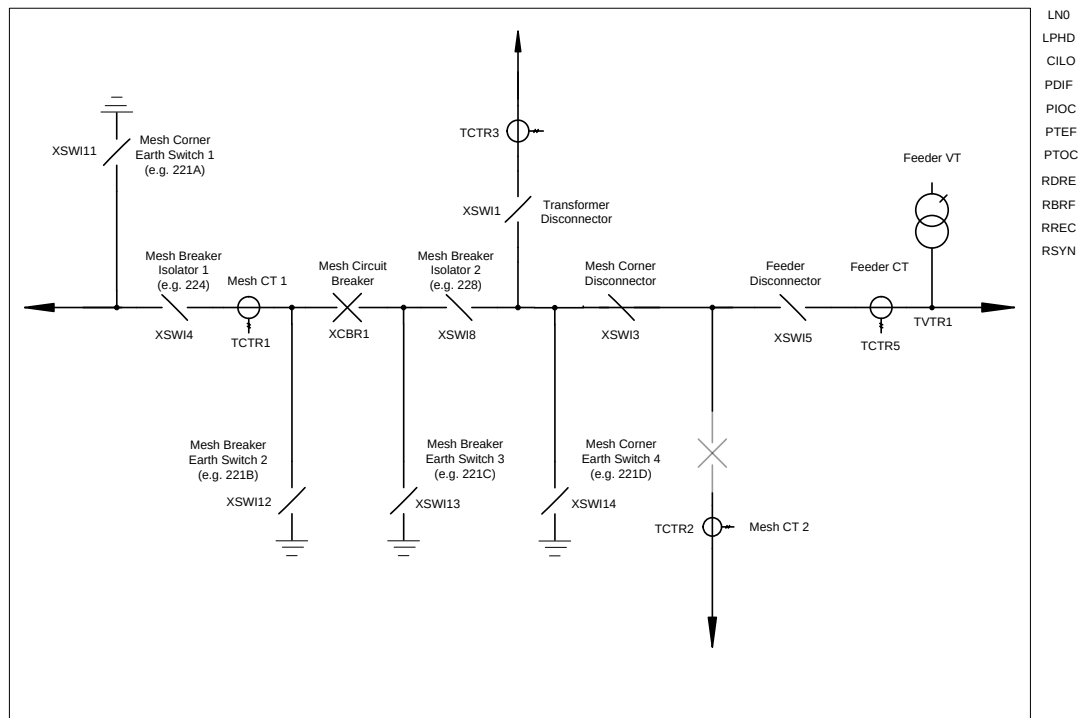


Figure 12: Standard Mesh Corner Bay solution

3.5.5 Shunt Reactor Bay

- a) A standard Shunt Reactor Bay solution shall consist of the following equipment and naming:
- (i) Shunt Reactor (ZREA1)
 - (ii) SR Circuit Breaker (XCBR1)
 - (iii) Shunt Reactor Disconnector (XSWI3)
 - (iv) Main Earth switch (XSWI11)
 - (v) SR Earth switch (XSWI12)
 - (vi) Main CT (TCTR1)
 - (vii) SR CT (TCTR2)
- b) A standard Shunt Reactor Bay solution shall consist of the following Protection Functions:
- (i) Logical Node Zero (LNO)
 - (ii) Physical Device Information (LPHD)
 - (iii) Reactive Power Control (ARCO)
 - (iv) Interlocking (CILO)

- (v) Differential Protection (PDIF)
 - (vi) Transient Earth Fault (PTEF)
 - (vii) Time Overcurrent Protection (PTOC)
 - (viii) Disturbance Recorder function (RDRE)
 - (ix) Breaker Failure Protection (RBRF)
- c) A standard Shunt Reactor Bay shall have the following arrangement:

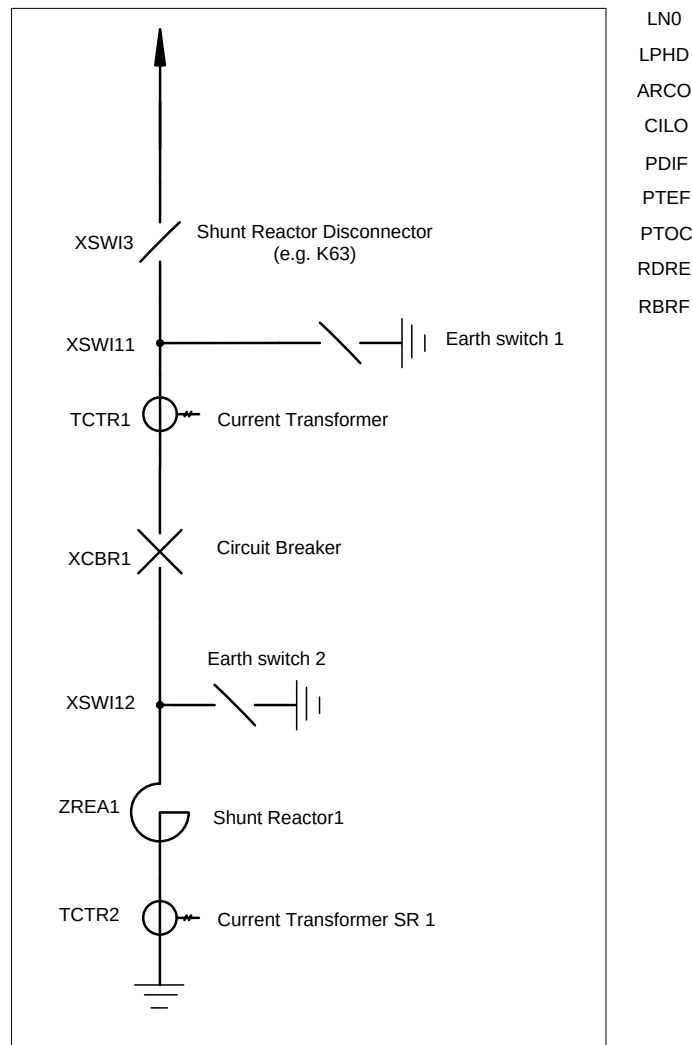


Figure 13: Standard Shunt Reactor Bay solution

3.5.6 Series Reactor Bay

- a) A standard Series Reactor Bay solution shall consist of the following equipment and naming:
- (i) Series Reactor (ZREA1)
 - (ii) Bypass Circuit Breaker (XCBR1)
 - (iii) Bypass Disconnect 1 (XSWI21)

- (iv) Bypass Disconnecter 2 (XSWI22)
 - (v) Series Reactor Disconnecter 1 (XSWI31)
 - (vi) Series Reactor Disconnecter 2 (XSWI32)
 - (vii) Earth Switch 1 (XSWI11)
 - (viii) Earth Switch 2 (XSWI12)
 - (ix) Earth Switch 3 (XSWI13)
 - (x) Earth Switch 4 (XSWI14)
 - (xi) CT on Substation 1 Side (TCTR1)
 - (xii) CT on Substation 2 Side (TCTR2)
- b) A standard Series Reactor Bay solution shall consist of the following Protection Functions:
- (i) Logical Node Zero (LN0)
 - (ii) Physical Device Information (LPHD)
 - (iii) Reactive Power Control (ARCO)
 - (iv) Interlocking (CILO)
 - (v) Differential Protection (PDIF)
 - (vi) Transient Earth Fault (PTEF)
 - (vii) Time Overcurrent Protection (PTOC)
 - (viii) Disturbance Recorder function (RDRE)
 - (ix) Breaker Failure Protection (RBRF)
 - (x) Synchronising (RSYN)
- c) A standard Series Reactor Bay solution shall have the following arrangement:

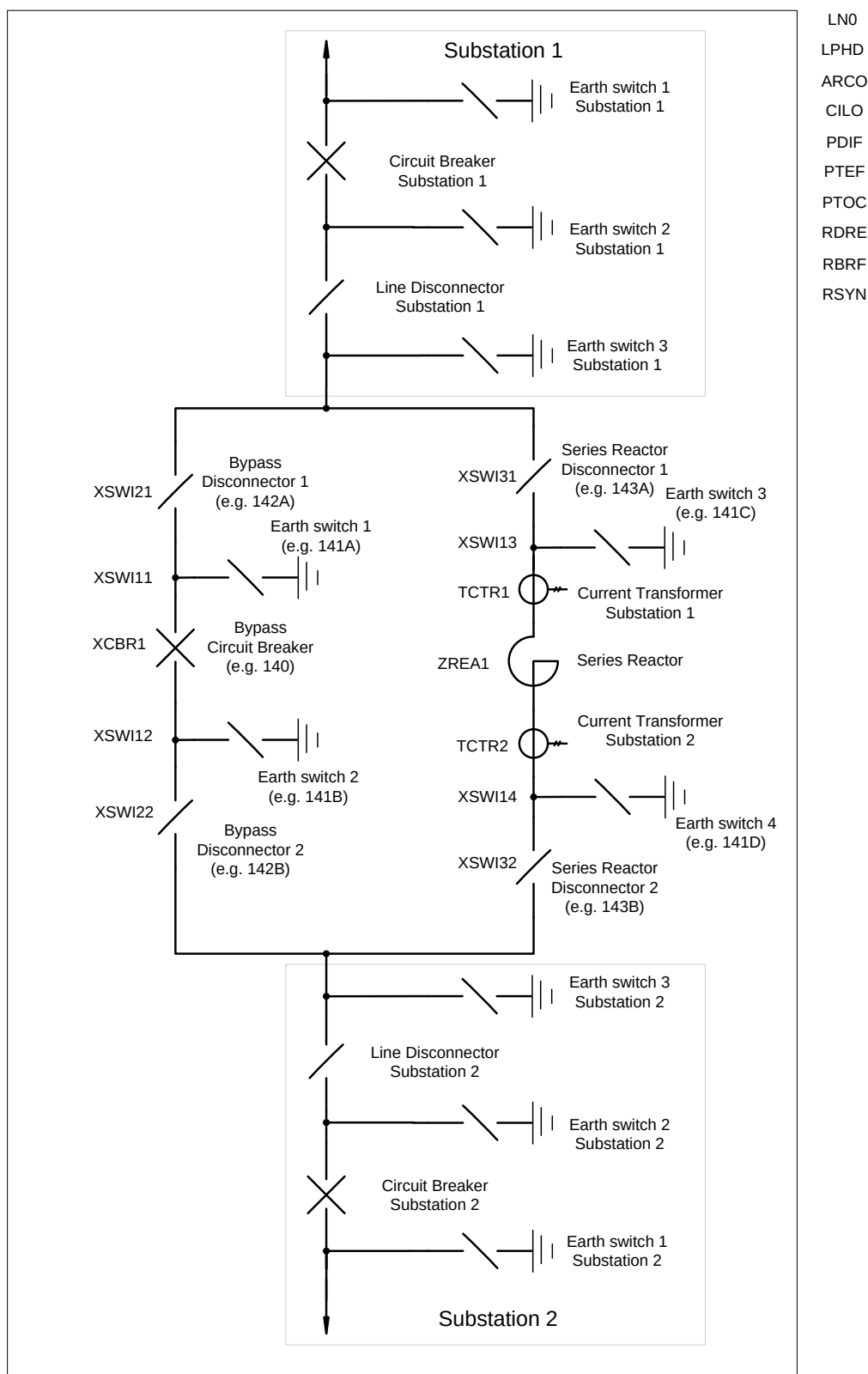


Figure 14: Standard Series Reactor bay solution

3.5.7 Mechanical Switched Capacitor with Damping Network (MSCDN) Bay

- a) A standard MSCDN Bay solution shall consist of the following equipment and naming:
 - (i) Shunt Capacitor (ZCAP1)