IEC TR 61850-7-500

Edition 1.0 2017-07

TECHNICAL REPORT

colour inside

Communication networks and systems for power utility automation – Part 7-500: Basic information and communication structure – Use of logical nodes for modeling application functions and related concepts and guidelines for substations

IEC TR 61850-7-500:2017-07(en)

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COMMUNICATION NETWORKS AND SYSTEMS FOR POWER UTILITY AUTOMATION –

Part 7-500: Basic information and communication structure – Use of logical nodes for modeling application functions and related concepts and guidelines for substations

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IEC TR 61850-7-500, which is a technical report, has been prepared by IEC technical committee 57: Power systems management and associated information exchange.

The text of this technical report is based on the following documents:

Enquiry draft	Report on voting
57/1817/DTR	57/1865/RVDTR

Full information on the voting for the approval of this technical report can be found in the report on voting indicated in the above table.

This document has been drafted in accordance with the ISO/IEC Directives, Part 2.

A list of all parts in the IEC 61850 series, published under the general title *Communication networks and systems for power utility automation*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under "http://webstore.iec.ch" in the data related to the specific document. At this date, the document will be

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

A bilingual version of this publication may be issued at a later date.

IMPORTANT – The 'colour inside' logo on the cover page of this publication indicates that it contains colours which are considered to be useful for the correct understanding of its contents. Users should therefore print this document using a colour printer.

INTRODUCTION

This part of IEC 61850, which is a technical report, shows the use of Logical Nodes as defined in IEC 61850-7-4 for application functions in the substation domain. IEC 61850 defines Communication Networks and Systems for Power Utility Automation, and more specifically the communication architecture for subsystems like substation automation systems. The sum of all subsystems may also result in the description of the communication architecture for the overall power system management. The defined architecture provides in IEC 61850-7-x both a power utility-specific data model and also a substation domain specific data model with abstract definitions of data objects classes and services independently from the specific protocol stacks, implementations, and operating systems. The mapping of these abstract classes and services to communication stacks is outside the scope of IEC 61850-7-x and may be found in IEC 61850-8-x and in IEC 61850-9-x.

IEC 61850-7-1 gives an overview of the basic communication architecture to be used for all applications in the power utility domain. IEC 61850-7-3 defines common attribute types and common data classes related to all applications in the power system domain. The attributes of the common data classes may be accessed using services defined in IEC 61850-7-2. These common data classes are used in this part to define the compatible data objects classes.

To reach interoperability, all data objects in the data model (IEC 61850-7-4, IEC 61850-7-3) need a strong definition with regard to syntax and semantics. The semantics of the data objects are mainly provided by names assigned to common logical nodes and data objects they contain as defined in IEC 61850-7-4, and dedicated logical nodes are defined in domain-specific parts (IEC 61850-7-x) e.g. for hydro power control systems in IEC 61850-7-410. Interoperability is reached with minimum effort if as many as possible of the data objects are defined as mandatory. Because of different philosophies and technical features, some data objects, especially settings, were declared as optional in this edition of the standard. After some experience has been gained with this standard, this decision may be reviewed in the next edition of the relevant parts of the standard.

A data object with full semantics is only one of the elements required to achieve interoperability. Standardized access to the data objects is defined in compatible, power utility and domain specific services (see IEC 61850-7-2). Since data objects and services are hosted by devices (IED), a proper device model is also needed. To describe both the device capabilities and the interaction of the devices in the related system, a configuration language is also needed as defined in IEC 61850-6 by the System/Substation Configuration description Language (SCL).

A lot of functions in power systems are complex combinations of local Logical Nodes in one IED, or distributed Logical Nodes in many IEDs linked by a dedicated data exchange. For some functions different solution concepts exist resulting in different implementations. Depending on the kind of differences they may result in increased requirements for system integration engineering tools or, in the worst case, destroy interoperability. The goal of this informative document is to show the most common application of Logical Nodes in modelling simple and complex application functions, to improve common understanding in modelling and data exchange in general, and finally to stimulate implementations which support in any case interoperability.

The data model of IEC 61850 i.e. the Logical Nodes (LN) contain only the data provided by the application functions described but not the source where the data which are needed as input for the application functions are from. This gap is also closed in this document either expicitely by naming the input data or implicitely by showing the connections between the different LNs used.

COMMUNICATION NETWORKS AND SYSTEMS FOR POWER UTILITY AUTOMATION –

Part 7-500: Basic information and communication structure – Use of logical nodes for modeling application functions and related concepts and guidelines for substations

1 Scope

This part of IEC 61850, which is a technical report, describes the use of the information model for devices and functions of IEC 61850 in applications in substation automation systems, but it may also be used as informative input for the modeling of any other application domain. In particular, it describes the use of compatible logical node names and data objects names for communication between Intelligent Electronic Devices (IED) for use cases. This includes the relationship between Logical Nodes and Data Objects for the given use cases. If needed for the understanding of the use cases, the application of services is also described informatively. If different options cannot be excluded they are also mentioned.

The modelling of the use cases given in this document are based on the class model introduced in IEC 61850-7-1 and defined in IEC 61850-7-2. The logical node and data names used in this document are defined in IEC 61850-7-4 and IEC 61850-7-3, the services applied in IEC 61850-7-2. The naming conventions of IEC 61850-7-2 are also applied in this document.

If extensions are needed in the use cases, the normative naming rules for multiple instances and private, compatible extensions of Logical Node (LN) Classes and Data Object Names defined in IEC 61850-7-1 are considered.

IEC 61850-7-5 describes in examples the use of logical nodes for modeling application functions and related concepts and guidelines in general, independently from any application domain respectively valid for all application domains in the electric power system (substation automation, distributed energy resources, hydro power, wind power, etc.). This document describes in examples the use of logical nodes for application functions in substation automation including also line protection between substations. It also implies some tutorial material where helpful. However it is recommended to read IEC 61850-5 and IEC 61850-7-1 in conjunction with IEC 61850-7-3 and IEC 61850-7-2 first.

2 Normative references

The following documents are referred to in the text in such a way that some or all of their content constitutes requirements of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

IEC 60255-24/IEEE C37.111:2013, *Measuring relays and protection equipment – Part 24: Common format for transient data exchange (COMTRADE) for power systems*

IEC 61588, *Precision clock synchronization protocol for networked measurement and control systems*

IEC TS 61850-2, *Communication networks and systems in substations – Part 2: Glossary*

IEC 61850-5:2013, *Communication networks and systems for power utility automation – Part 5: Communication requirements for functions and device models*

IEC 61850-7-1, *Communication networks and systems for power utility automation – Part 7-1: Basic communication structure – Principles and models*

IEC 61850-7-2:2010, *Communication networks and systems for power utility automation – Part 7-2: Basic information and communication structure – Abstract communication service interface (ACSI)*

IEC 61850-7-3, *Communication networks and systems for power utility automation – Part 7-3: Basic communication structure – Common data classes*

IEC 61850-7-4:2010, *Communication networks and systems for power utility automation – Part 7-4: Basic communication structure – Compatible logical node classes and data object classes*

IEC 61850-8-1, *Communication networks and systems for power utility automation – Part 8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3*

IEC 61850-9-2, *Communication networks and systems for power utility automation – Part 9-2: Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3*

IEC/IEEE 61850-9-3, *Communication networks and systems for power utility automation – Part 9-3: Precision time protocol profile for power utility automation*

IEC 61869-9, *Instrument transformers – Part 9: Digital interface for instrument transformers*

IEC 62271-3, *High-voltage switchgear and controlgear – Part 3: Digital interfaces based on IEC 61850*

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

For the purposes of this document, the terms and definitions given in IEC TS 61850-2 and the following apply.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

3.1.1
application functions
functions which perform a dedicated task in the utility automation system to allow the control, protection, monitoring and supervision of the power system in a given domain such as substation automation

3.1.2
domains
well-defined areas in the utility automation system respectively in the power system

3.1.3
use cases
samples for application functions or for a set of interacting ones to performing a dedicated task

3.1.4
1-out-of-n control
state of the substation control when only one of the n switches in the substation is allowed to be controlled (opened or closed) at the same time

3.2 Abbreviated terms

The abbreviated terms of IEC 61850-7-3 and IEC 61850-7-4 will be used. The following terms are listed since they need to be highlighted or are missing in the referenced parts.

AIS	Air insulated substation
ARC	Autoreclosure
BIED	Breaker IED means process near circuit breaker controller same as CBC
CC	Control Center used as more generic term instead of NCC (Network Control Center)
DCC	Process near disconnector controller IED according to IEC 62271-3 instead of SIED (switch IED)
CBC	Process near circuit breaker controller IED according to IEC 62271-3 instead of BIED (breaker IED)
ESC	Process near earthing switch controller IED according to IEC 62271-3 instead of SIED (switch IED)
GIS	Gas insulated substation
GOOSE	Generic Object Oriented Substation Event according to IEC 61850-8-1
GPS	Global Positioning System (US)
HMI	Human Machine Interface
IED	Intelligent Electronic Device
ITL	Interlocking
LV	Low Voltage
MMS	Manufacturing Messaging Specification
MU	a) Merging Unit used for process near IED sampling analogue measurement of current and voltage, performing A/D conversion and merging data from different measurement points in one or many SV streams as far as applicable b) Merging Unit used as LD name containing LNs for analogue data like TVTR and TCTR
SBO	Select before Operate
SCSM	Specific Communication Service Mapping
SER	Sequence of Event Recording
SIED	Switch IED means process near disconnector/earthing switch controller same as DCC and/or ESC
SV	Sampled values data stream according to IEC 61850-9-2

4 Basics of substation automation with IEC 61850

4.1 Architecture

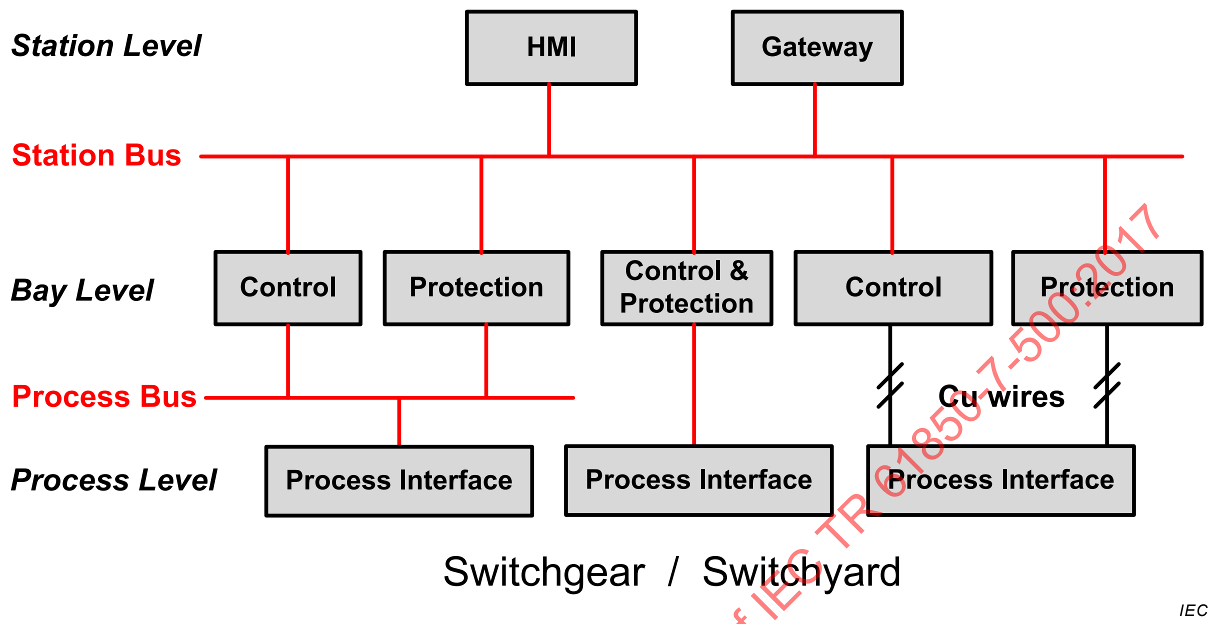


Figure 1 – Architecture of a substation automation system

The architecture example given in Figure 1 describes the most common implementation of substation automation systems with station level, bay level and process level. The boxes (Intelligent Electronic Device: IED) are the containers for the functions. The communication between the levels are named station and process bus. The naming refers to the physical allocation of the communication systems between the levels only and not to a functionality which is discussed below. Based on the common allocation of functions to station (including HMI and Gateway), bay and process level IEDs the following definitions apply:

- The station bus is the communication network between station level devices (station computer, gateway, etc.) and the bay level IEDs (protection, control, monitoring devices etc).
- The process bus is the communication network between bay level IEDs (protection, control, monitoring devices etc) and the process level interface for switchyard devices (breakers, disconnectors, earthing switches, busbars, power transformers, current and voltage transformers, etc.).

4.2 Communication and relevance of bus definitions

IEC 61850 defines the object model, the communication services to access and to exchange the data, the engineering process and the mapping of the services onto a protocol.

All services are applicable for communication over both the above-defined station bus and process bus. Based on the common allocation of functions also a common allocation of services to the busses is assumed. Some allocations are very intuitive, i.e. the sampled value (SV) service runs over the process bus since the samples of current and voltage come from instrument transformers or sensors on the process level. However voltage samples representing the busbar voltage for the synchrocheck may come over the station bus.

Since the function allocation and, therefore, the allocation of data of the object model is not the same everywhere and not fixed regarding the evolution of substation automation over time, the terms “station bus” and “process bus” do not have an implementation-independent meaning. These terms do not exist in the title of any standard parts. They refer to the defined services only, i.e.

- IEC 61850-8-1: Specific communication service mapping (SCSM) – Mappings to MMS (ISO 9506-1 and ISO 9506-2) and to ISO/IEC 8802-3 refers to the Client-Server communication and the GOOSE messages and
- IEC 61805-9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3 refers the transmission of sampled values.

Therefore, the terms “station bus” and “process bus” will be used only if they are of benefit for the reader of this document.

5 Summary of substation automation functions

5.1 HMI and related station level functions

Accessing the system

- Access control & access security management
- Access authority and access logging
- Operator access to the system: control, parameter switching, data retrieval
- Display of data and information: single line, alarm list, measurands
- Storage of data in the station computer: historical data, disturbance files
- Log management: archiving, sorting, etc.

5.2 Operational or control functions

Operating and supervising the system

- Operational control: switching devices, tap changer, LV devices
- Indication handling: switchgear position, etc.
- Event (SER) and alarm handling: recording, logging, acknowledgement (for alarms only)
- Parameter setting and parameter set switching: protection, ARC on/off, ITL override, etc.
- Data retrieval: setting, parameters, disturbance records, etc.

5.3 Monitoring and metering functions

Process/status data from the primary and secondary process/system

- Metering: revenue metering, operative measuring, calculation of U, I, P, Q, f, φ
- Power equipment and system monitoring: switchgear and transformer load, power quality
- Disturbance recording: Fault recording and fault location

5.4 Local automation functions (protection and others)

Performing local decisions without human intervention

- Protection: line, transformer, busbar, generator, level, impedance, differential protection, zero voltage protection, fault location
- Automation: local synchrocheck and autoreclosure
- Bay interlocking: blocking and release of circuit breakers, disconnectors and earthing switches

5.5 Distributed automation functions (protection and others)

Using global data for local decisions

- Distributed busbar protection

- Substation topology detection with attributes if applicable
- Station interlocking: busbar coupler, busbar disconnector, busbar earthing switch
- Distributed synchrocheck
- Synchronized switching: point on wave switching
- Automatic switching sequences: line on/off, busbar changeover, infeed switch-over
- Load shedding and restoration according to different criteria, including frequency, rate of change of frequency, load, priorities
- FACTS, reactive and active power compensation

5.6 System support functions

Maintaining a reliable, synchronized and communicating system

- System supervision: self-supervision, alarm generation, etc.
- System Management: maintenance modes, updates, engineering
- Configuration management: configuration, setting, down-/up-loading of configuration files, etc.
- Time synchronization: time reception (e.g. GPS) and distribution, tagging of events (1 ms), phasors and samples (1 µs)
- Communication: inside the substation, outside the substation to control centers CC, maintenance centers, administration system
- Cyber security management at all levels within the substation automation system

NOTE 1 The classification of the functions given above is not standardized but are introduced to provide an overview about substation automation functions. This classification is found in Clause 5 and some details in Annex F of IEC 61850-5:2013.

NOTE 2 Above, all functions related to substation automation have been summarized in dedicated groups for easy overview. There is not a one to one relationship between these functions and the function which are modelled in this report.

6 Basic interaction of control and protection functions modeled by logical nodes

Figures 2 and 3 show the relationship of the application functions as described by the logical nodes and the data exchange in between. One application function may be modelled by more than one LN as indicated by the colours in Figure 2 (e.g. green for switchgear control) but some LNs may belong to more than one function such as switchgear or instrument transformers (own colours).

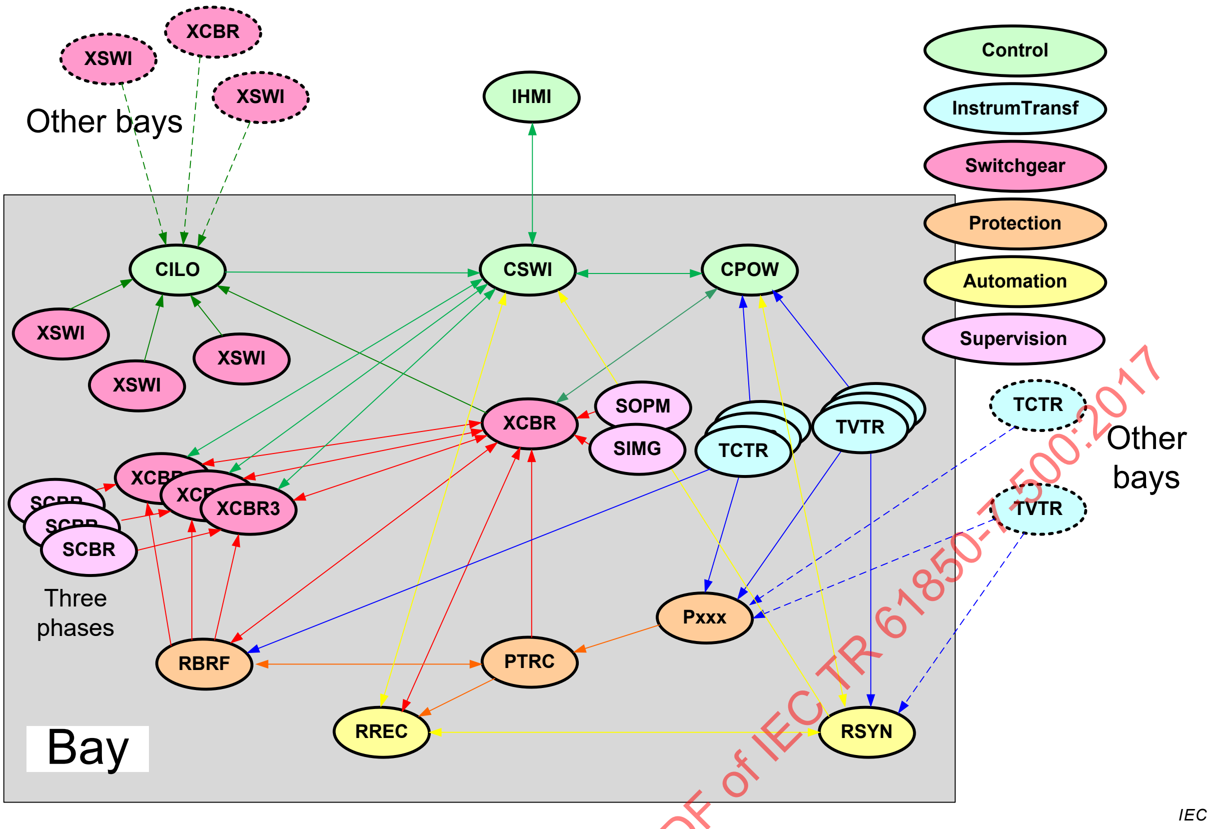


Figure 2 – Interaction of LNs for the application functions in SA focused on XCBR

Table 1 – Short summary of logical nodes names

Logical node class name	Short function related description
CILO	Interlocking
CPOW	Point-on-wave switching controller
CSWI	Switch controller (per XCBR and XSWI)
IHMI	Human Machine Interface (Operators access)
PTRC	Trip conditioning combines starts and operates from protection functions to one trip and configurable indications.
Pxxx	Protection function xxx
RBRF	Breaker failure protection
RREC	Autorecloser
RSYN	Synchrocheck
SCBR	Circuit breaker supervision
SIMG	Insulation medium supervision (gas)
SOPM	Supervision of operating mechanism
SSWI	Circuit switch supervision
TCTR	Current instrument transformer/sensor
TVTR	Voltage instrument transformer/sensor
XCBR	Circuit breaker
XSWI	Disconnector or earthing/grounding switch

The different colors of the LNs represent some common LN groups, i.e.

- “green” control LNs starting with C and I (IHMI)
- “blue” instrument transformer/sensor LNs starting with T
- “red” switchgear LNs starting with X
- “brown” protection LNs starting with P
- “yellow” automatic/protection related LNs starting with R
- “pink” supervision LNs starting with S

The different colors of the links between the LNs represent data exchange between LNs of some well-defined application functions, i.e.

- “green” between HMI LNs and control LNs, and between control LNs and switchgear LNs
- “blue” between instrument transformers/sensors LNs and protection/automation LNs consuming the provided data
- “red” between protection/protection related/automatic LNs and switchgear LNs
- “yellow” between protection related functions and control functions

Dashed LNs and dashed links refer to remote functions/LNs i.e. from another bay.

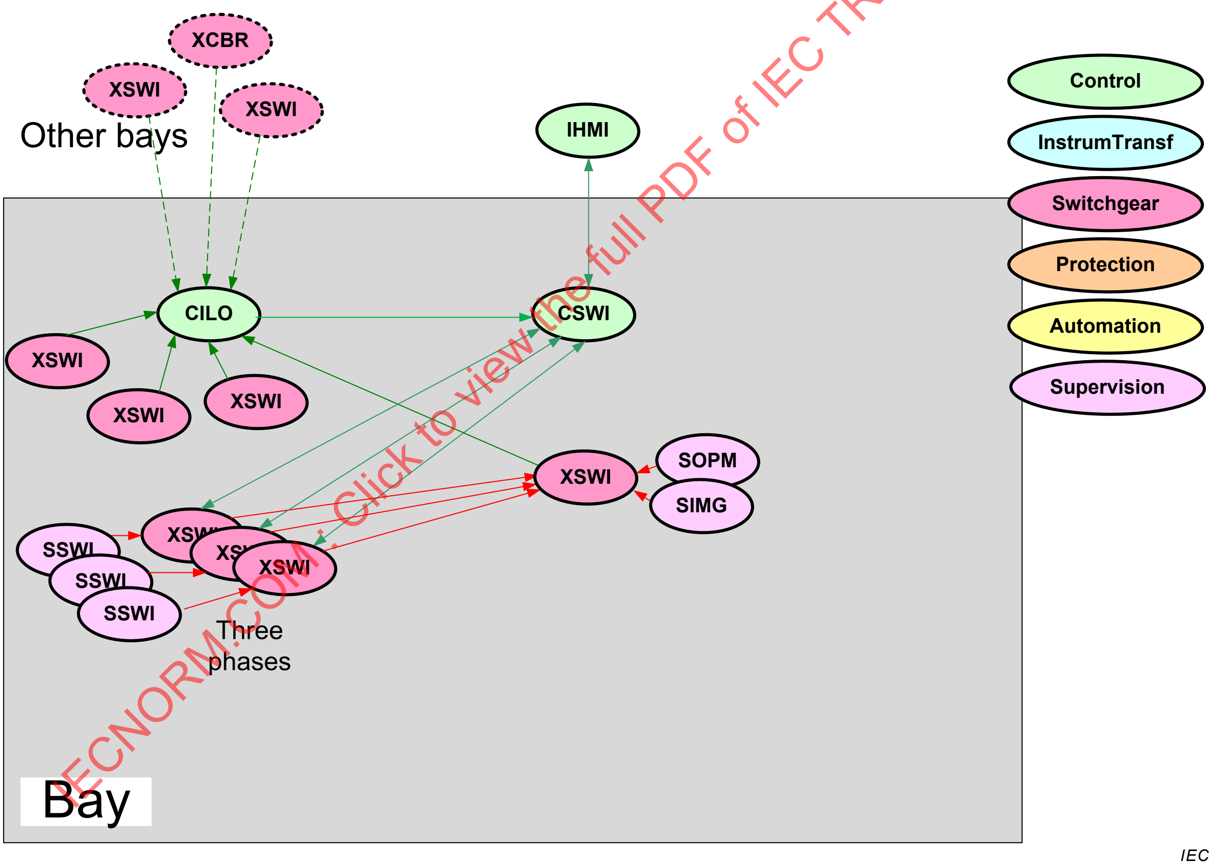


Figure 3 – Interaction of LNs for the application functions in SA focused on XSWI

This document cannot define mandatory links between the Logical Nodes but these links are derived from the definition of the Logical Nodes referring to well-defined application functions. From this it is clear which LNs exchange what data for a correctly operating application function. Therefore, the resulting links are in most cases de facto mandatory.

7 Function allocation and logical architecture

7.1 Allocation of functions to IEDs

Logically, the data are exchanged between the Logical Nodes representing the application functions. These Logical Nodes are grouped in Logical Devices (see e.g. IEC 61850-7-5) and hosted by Intelligent Electronic Devices (IED). Same as station and process bus, the IEDs represent only the implementation aspect. But the physical communication interfaces belong to the IEDs, their knowledge is important for the physical communication system.

The physical allocation of functions which describe interfaces to the outside world is important. For example, process near functions are with preference near to the process level (switchgear). Therefore, the term IED with a functional naming like bay protection unit (BPU) will be used only if it is of benefit for the reader of this document.

7.2 Data Model as used in this Technical Report

The complete data model according to IEC 61850-7-1, IEC 61850-7-2, IEC 61850-7-3 and IEC 61850-7-4 consists of Physical Device (referred to as LPHD), Logical Devices (LD) containing the administrative (LLN0) and functional Logical Nodes (e.g. CSWI, XCBR). The LNs contain Data Objects (DO) and these Data Attributes (DA) according to the related Common Data Classes (CDC) as summarized in IEC 61850-7-5. For the “Use of logical nodes for modeling applications and related concepts and guidelines for Substations” only the application function-related parts are relevant, i.e. the data model level from the Logical Nodes downwards, if not the higher levels, are mentioned explicitly. The higher levels have administrative features and may be important for the implementation.

7.3 Logical architecture

7.3.1 Station level

The station level comprises functions which are valid for the complete substation e.g. the station level HMI (LN IHMI) and the gateway (LN ITCI) to the (remote) control centre.

7.3.2 Bay level

The bay level comprises all functions which belong to a single bay like the bay protection (e.g. LN PTOC, LN PDIS, etc.) and bay control (e.g. LN CSWI, LN CILO, etc.) as well as automation functions which may include multiple bays by interbay communication. For bays the name feeder is also used; known in more detail as line bays or transformer bays. However also the complete diameter in a 1 ½ breaker arrangement may be named bay. The bay level is always a subset of the complete substation; the bay functions act on the bay level only (see also definition 3.5.3 of IEC 61850-5:2013).

7.3.3 Process level

The process level comprises the switchyard apparatus which the substation automation is for. Monitoring, control and protection functions acquire data from the process level and act on this process if applicable. The process level is described by LNs which represent switchyard components like XCBR, XSWI, TVTR, TCTR, YTPR, GGIO, etc.

7.4 Interfaces

7.4.1 Interface to CC and other remote operator places

The substation automation system has one or more interface towards (remote) control (control centre, CC) or to other work and maintenance places. Normally, remote operators and experts or remote archiving systems are working in the background. Related LNs are ITCI (telecontrol interface) and ITMI (telemonitoring interface). Refer also to IEC TR 61850-90-2.

7.4.2 Interface to neighbouring substation

The interface to the neighbouring substation serves mainly for the data exchange as needed for line protection and direct intertrip, but may also be used to include the position of the remote line disconnector and line disconnector into the local interlocking. This is a data exchange between IEDs for the hosted automation functions. The related LN is ITPC (teleprotection communication interface). Refer also to IEC TR 61850-90-1 which was integrated into IEC 61850-7-4:2010.

7.4.3 Interface to the process (switchyard)

The interface to the switchyard may be allocated to the process level. In the past it was realized by a lot of parallel copper wires for binary and analogue signals operating with common voltages (110 V, 70 V, more) and well standardized currents (1 A, 5 A). In the future it will consist of electronics in process devices or near the process (switchyard) hosting the process level LNs (e.g. XCBR, XSWI, TVTR, TCTR, YTPR, GGIO, etc.) which acquire and issue signals and communicate with the bay level IEDs by network communication (process bus).

7.4.4 Implementation remark

This logical architecture may have some influence on the physical implementation but by no means determines the implementation of the physical architecture.

8 Communication system architectures

8.1 Modeling and communication architectures

As mentioned in 4.2, when specifying a substation automation system the use of the terms “process bus” and “station bus” do not have a real functional meaning, due to the fact that the actual architecture of the communication network is not yet fixed. Based on the actual requirements it is possible to use a single physical network to which all IEDs are connected. In such case a process bus or station bus cannot be identified as such although there is communication between station level, bay level and process level.

Therefore, it is more appropriate to speak of a communication interface instead of a bus as the architecture of the communication infrastructure is not predefined. So within a substation a station interface, a bay interface and a process interface can be identified. Nevertheless together with the function allocation to the interfaces, the services to be handled by these interfaces and the performance requested is clear in the most of the cases.

In this technical report providing guidelines for object modeling the communication network will be identified as network to provide the exchange of data between logical nodes with help of IEDs and other physical communicating elements like switches.

Despite the common architecture given in Figure 1 the physical architecture of the communication system depends strongly on function allocation and communication requirements. In reverse the choice of specific communication architectures will have an impact on the functions and their performance.

Because of this mutual interaction, these remarks about the communication architecture are included also in the more generic cross-domain document IEC 61850-7-5.

8.2 Specific modeling aspects of the process interface

8.2.1 Merging unit and data sampling

Additional configuration aspects must be taken into account when applying the time critical SV service according to IEC 61850-9-2 to stream voltage and current samples from the instrument transformers or sensors on process level to the protection and control devices at bay level over the so-called process bus. The use cases given in this subclause describe the relationship between the allocation of functions, the communication services (time critical or non-time critical) and the mapping to physical interfaces.

In accordance with IEC 61869-9, a merging unit (MU) is a physical device in which a logical device “merging unit” is implemented which provides sampled values by the logical nodes current transformer (TCTR) and/or voltage transformer (TVTR) being the publisher of the time critical data stream according to IEC 61850-9-2.

Normally, also other data from the merging unit are of interest. It may be the internal name plate of the MU or the external name plates of the instrument transformers. Also writing and reading of configuration data may be applicable and requested. It is important to notice that also important status data like EEHealth or TVTR.FuFail (fuse failure) are normally reported by using the related client-server service. Therefore, as a prerequisite for a comprehensive modeling of the MU an IEC 61850-8-1 server interface (non-time critical data) has to be considered for any MU implementation.

8.2.2 Breaker IED and switchgear control

The switchgear is basically represented by logical nodes XCBR or XSWI. The application of the time critical GOOSE service according to IEC 61850-8-1 is needed between the control (CSWI) and protection (Pxxx-PTRC) at bay level and the switchgear to operate or trip the switchgear. It refers for time-critical functions, also to the position indication from the switchgear.

Normally, other data from the breaker IED (CBC) are also of interest. This may be the internal name plate of the CBC or the external name plates of XCBR. Writing and reading of configuration data may also be applicable and requested. Important status information like EEHealth is normally reported by using the related client-server service. Therefore, as a prerequisite for a comprehensive modeling of the CBC IED, an IEC 61850-8-1 MMS server implementation beside the GOOSE publishing or subscription shall be considered for any CBC realization.

8.2.3 Time synchronization

Both MU and the CBC should subscribe to a time synchronization source at least using SNTP for the mandatory time tagging of events (accuracy 1 ms). The much higher accuracy of 1 µs needed for the sampling by the MU unit shall be provided either by 1 PPS signal over a dedicated link or alternatively by the Precision Time Protocol (PTP according to IEC 61850-9-3 as profile of IEC 61588) over Ethernet. All these synchronizations may be provided by a GPS controlled master clock. Note: If a PTP link to the MU and CBC exists, the 1 ms time tagging may be based also on PTP instead of SNTP.

8.3 Use cases

8.3.1 General remarks

In this subclause IEDs are mentioned for a better understanding of the different use cases.

8.3.2 Station bus and process bus separated

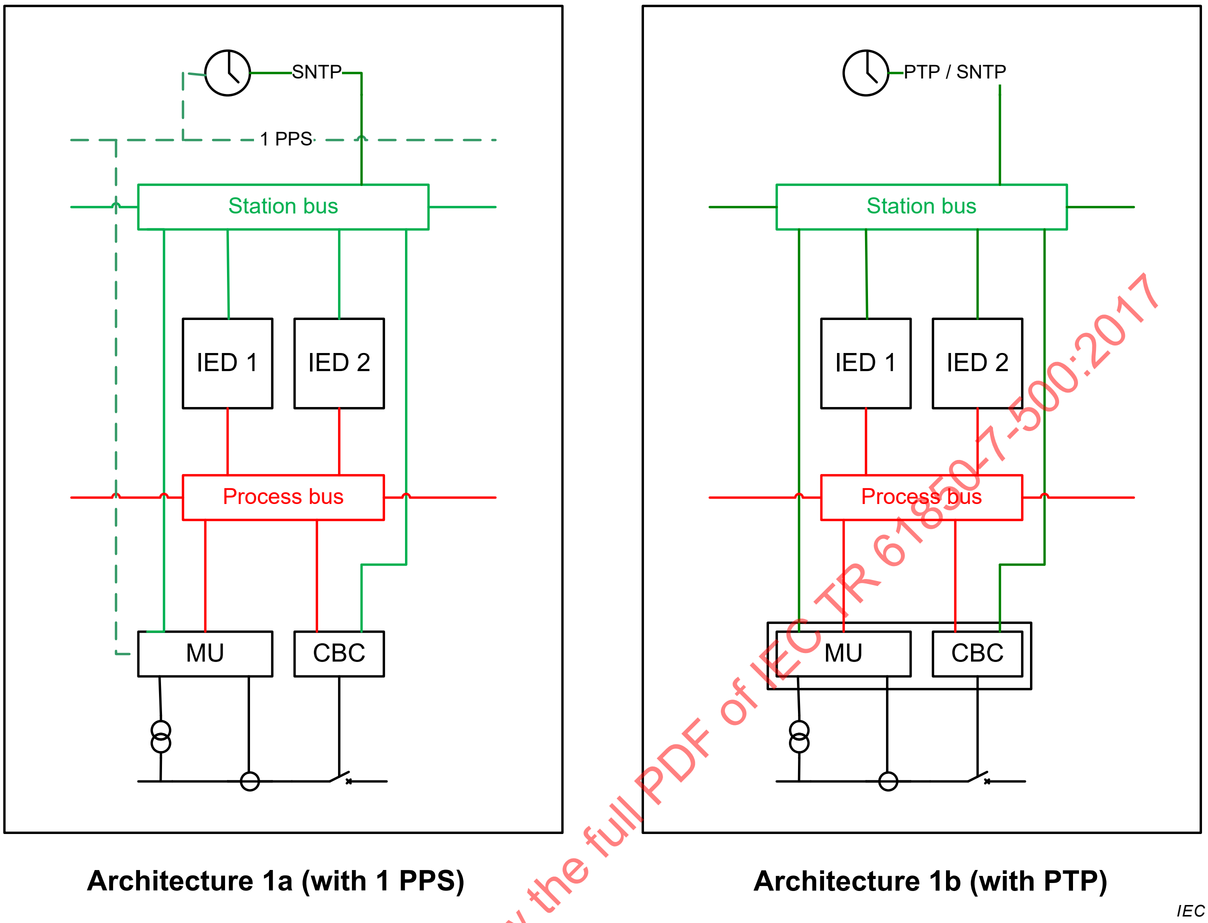


Figure 4 – Station bus and process bus separated

The architectures in Figure 4 have a full separation of process bus and station bus. Both the merging unit (MU) and breaker IED (CBC) are connected over the process bus (red lines) for time critical communication with the bay units IED1 and IED2 (for protection or/and control). The MU provides current and/or voltage samples in a stream according to IEC 61850-9-2. The CBC provides switchgear position(s) by GOOSE messages according to IEC 61850-8-1. In addition the commands and/or trips from the bay units to the switchgear represented by CBC are provided by the GOOSE messages.

The bay level IEDs as MMS servers are connected to the station bus (blue lines) and via this to the MMS client (HMI, not shown) handling all the non-time critical data exchange with the operator at station or remote CC level. MU and CBC can be dedicated IEDs (architecture 1a) or one common IED (architecture 1b).

Both the MU and the CBC are also connected for supervision and management as MMS servers directly to the station bus (blue lines) exchanging non time critical data with the operator at station or remote CC level.

The time synchronization for time tagging the events which happen both in CBC and MU is based on SNTP with an accuracy of 1 ms as specified in IEC 61850-8-1. The time synchronization with an accuracy of 1 µs as needed for the sampling in the MU is realized in architecture 1a by the 1PPS sync pulse over a dedicated wire (dashed green lines), in architecture 1b by the Precision Time Protocol (PTP according to IEC 61850-9-3 as profile of IEC 61588) by communication over Ethernet (blue lines).

The source for all the three time channels is always a GPS controlled master clock (green lines).

8.3.3 Station bus and process bus connected by proxy servers

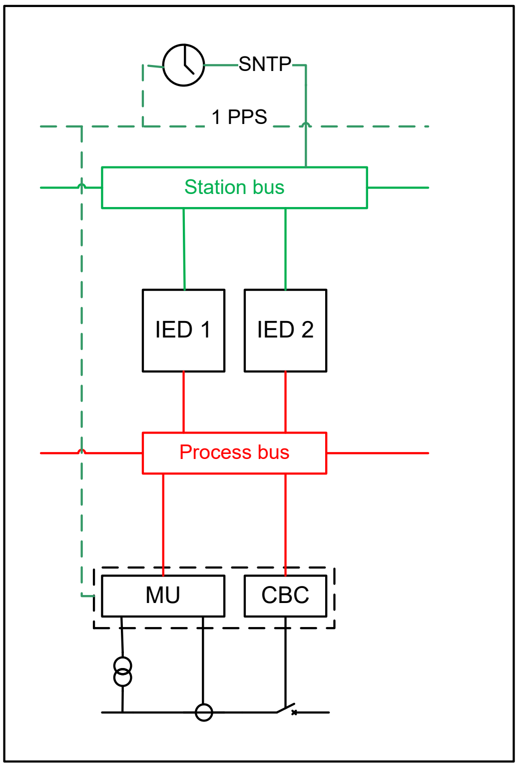
The architectures 2a and 2b in Figure 5 show the same full separation of process bus and station bus as the previous ones. Merging units (MU) and CBC are connected to the bay units IED1 and IED2 for protection or/and control by time critical communication (red lines). The MU provides current and/or voltage samples in a stream according to IEC 61850-9-2. The CBC provides switchgear position(s) by GOOSE messages according to IEC 61850-8-1. In addition the commands and/or trips from the bay units to the switchgear represented by CBC are realized by the GOOSE service. These are the strongest arguments for such an architecture, but nevertheless, any kind of data – also non-time-critical ones – may be transported also by GOOSE messages if applicable.

The bay level IEDs as MMS servers are connected to the station bus (blue lines) and via this to the MMS client (HMI, not shown) handling non-time critical data exchange.

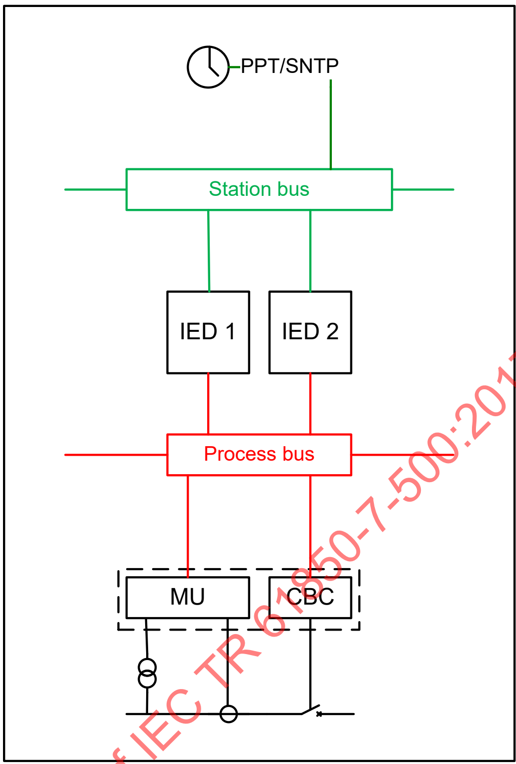
In addition, for non-time critical supervision and management both the MU and the BIED are connected to the bay units IED1 respectively IED2. Therefore, the bay units work as proxy servers for the non-time critical data from the MU and CBC.

The time synchronization for time tagging the events which happen both in CBC and MU is based on SNTP with an accuracy of 1 ms as specified in IEC 61850-8-1. The time synchronization with an accuracy of 1 µs as needed for the sampling in the MU is realized in architecture 2a by the 1PPS sync pulse over a dedicated wire (dashed green lines), in architecture 2b by the Precision Time Protocol (PTP according to IEC 61850-9-3 as profile of IEC 61588) by communication over Ethernet (blue lines). The bay units are also the time servers for the process units MU and CBC in case of SNTP and PTP.

The source for all time channels is always a GPS controlled master clock (green lines).



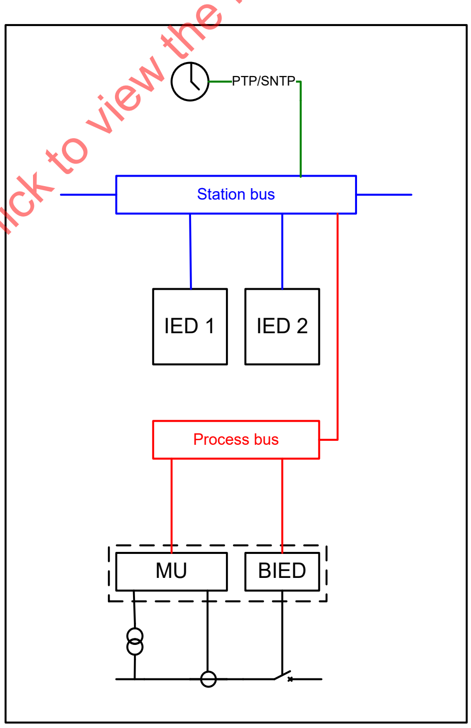
Architecture 2a (with 1 PPS)



Architecture 2b (with PPT)

IEC

Figure 5 – Station bus and process bus connected by proxy servers



Architecture 3

IEC

Figure 6 – Station bus and process bus interconnected

8.3.4 Station bus and process bus interconnected

The architecture 3 (see Figure 6) provides a combination of process bus and station bus. The merging units (MU), the breaker IED (CBC) controller and the bay units (IED1 and IED2) are de facto connected to the same bus (red/blue lines). Without bandwidth management, this use case might be restricted to substation automation systems with a very limited number of IEDs, merging units and switch controllers. Any active bandwidth management may be done by a multicast filtering switch between the station and process bus (see [1][1]).

Time synchronization is based on IEC 61850-9-3 for MUs and on SNTP for the BIEDs. Note that IEC 61850 requests the support of SNTP if applicable which means a client-server connection. However if implemented it is also possible to synchronize the CBC according to IEC 61850-9-3.

The source for any synchronization is always a GPS controlled master clock (green lines).

8.3.5 Common features for all three use case architectures

Both the MU and the BIED need a process bus interface, a station bus interface and a time synchronization interface. From the modeling point of view the LNs representing the functions in the MU respectively in the CBC need an interface for the time critical SV or GOOSE services, an interface for the non-time critical MMS services and a time synchronization service interface. It should be noted that interfaces may by merged in a dedicated implementation.

Table 2 summarizes the mapping of the services to interfaces according to the architectures. The numbering of interfaces (IF1 … IF3) should detail the demand for independent physical interfaces and is for illustration use only. The implementation might use different allocations and numbering of interfaces.

The three basic device types in a bay are listed on the top:

- Merging Unit (MU): The term is used very commonly for a process near IED collecting the analogue data e.g. by wires (more common) or non-IEC 61850 conformant communication (less common). They are sampled or resampled in the MU and then distributed as data streams according to IEC 61850-9-2. It contains, in addition to organizational LN instances like LLN0, the LNs TCTR and TVTR.
- Breaker IED (CBC): This term is used here for a process near IED collecting the binary information from switchgear and issuing commands towards the switchgear over wires (more common) or a non-IEC 61850 conformant communication (less common). They are converted to or re-converted from messages according to IEC 61850-8-1. It contains, in addition to organizational LN instances like LLN0, the LNs XCBR and XSWI. In Figure 5 and Figure 6 the dashed lines enclosing both MMXU and CBC indicated that both IEDs may be also merged into one unit which may be applicable e.g. in compact GIS installations.
- On the other side the IEDs may be split process oriented in an IED per measuring point i.e. the MU into one per phase and into one CBC per breaker respectively into DCC per disconnector and ESC earthing switch which may be applicable in extended AIS switchyard.
- (Bay level) IED: This term is used very common for bay level IEDs i.e. for bay level protection and control devices. It communicates according to IEC 61850 both with the MU and CBC over the process bus and with other IEDs and the station level over the station bus if applicable. It contains besides organizational LN instances like LLN0 the control LNs (CSWI, other C LNs) and protection LNs (PTOC, other P LNs).

Each of the three basic devices has four logical interfaces:

[1] Numbers in square brackets refer to the Bibliography.

- IF1/PB (process bus)
- IF2/SB (station bus)
- IF3/Sync (1 ms)
- IF4/Sync (1 µs)

Physically, different logical interfaces may be implemented together.

Each of these interfaces represents a client or server or another communication entity for the services according to IEC 61850-7-2.

IEC 61850-8-1 MMS server: source for all non-time critical messages like reports, file transfer, etc. and sink for commands

IEC 61850-8-1 MMS client: receiver for all non-time critical messages transmitted event driven or on request, etc. and source of commands

IEC 61850-8-1 GOOSE publisher: multicast source for time critical messages like block, trip, switch position to other IEDs

IEC 61850-8-1 GOOSE subscriber: receiver for time critical messages like block, trip, switch position from other IEDs

IEC 61850-9-2 SV publisher: multicast source for time critical voltage or/and current sample streams to other IEDs

IEC 61850-9-2 SV subscriber: receiver for time critical voltage or/and current sample streams from other IEDs

1 PPS (1 pulse per second) sender (masterclock): pulse for synchronization of IEDs supporting accuracy down to 1 µs over dedicated wire/fiber (not applicable for communication over Ethernet)

1 PPS (1 pulse per second) receiver (IED: MU, CBC): pulse for synchronization of IEDs supporting accuracy down to 1 µs over dedicated wire/fiber (not applicable for communication over Ethernet)

SNTP server: master clock (linked mostly to GPS as global time reference) for time synchronization supporting accuracy down to 1 ms over the communication network

SNTP client: slave clock (IED needing time synchronization for event tagging with 1 ms accuracy)

IEC 61850-9-3 PTP source according to IEC 61850-9-3: master clock (linked mostly to GPS as global time reference) for time synchronization supporting accuracy down to 1 µs using communication over Ethernet. Main application is for synchronized sampling of current and voltage

IEC 61850-9-3 PTP sink according to IEC 61850-9-3: slave clock in IEDs needing time synchronization down to 1 µs accuracy). Main use synchronized sampling of current and voltage

Proxy function: bay level IED appears as source of the process IED (MU, CBC) data

Table 2 – Mapping of communication services to architectures 1a, 1b, 2a, 2b, 3

	Merging Unit				CBC				IED			
	IF 1	IF 2	IF 3	IF 4	IF1	IF 2	IF 3	IF4	IF 1	IF 2	IF 3	IF4
Mapping	**PB**	**SB**	**Sync** 1 ms	**Sync** 1µs	**PB**	**SB**	**Sync** 1 ms	**Sync** 1µs	**SB**	**PB**	**Sync** 1 ms	**Sync** 1µs
IEC 61850-8-1 MMS Server	2a 2b 3	1a 1b			2a 2b 3	1a 1b			1a 1b 2a 2b 3			n/a
IEC 61850-8-1 MMS Client										2a 2b 3		
IEC 61850-8-1 GOOSE Publisher					1a 1b 2a 2b 3					1a 1b 2a 2b 3		
IEC 61850-8-1 GOOSE Subscriber					1a 1b 2a 2b 3					1a 1b 2a 2b 3		
IEC 61850-9-2 SV Publisher	1a 1b 2a 2b 3				n/a					n/a		
IEC 61850-9-2 SV Subscriber	n/a				n/a					1a 1b 2a 2b 3		
1PPS			n/a	1a 2a				n/a				
SNTP Server			n/a							2a 2b		
SNTP Client			n/a		2a 2b 3		1a 1b		1a 1b 2a 2b 3			
IEC 61850-9-3 Master										2b?		

	Merging Unit				CBC				IED			
	IF 1	IF 2	IF 3	IF 4	IF1	IF 2	IF 3	IF4	IF 1	IF 2	IF 3	IF4
Mapping	PB	SB	Sync 1 ms	Sync 1µs	PB	SB	Sync 1 ms	Sync 1µs	SB	PB	Sync 1 ms	Sync 1µs
IEC 61850-9-3 Slave				1b 2b 3		1b 2b 3		n/a				n/a
Proxy function									2a 2b	3		

9 Basic modeling principles

9.1 Protection, measurement and control

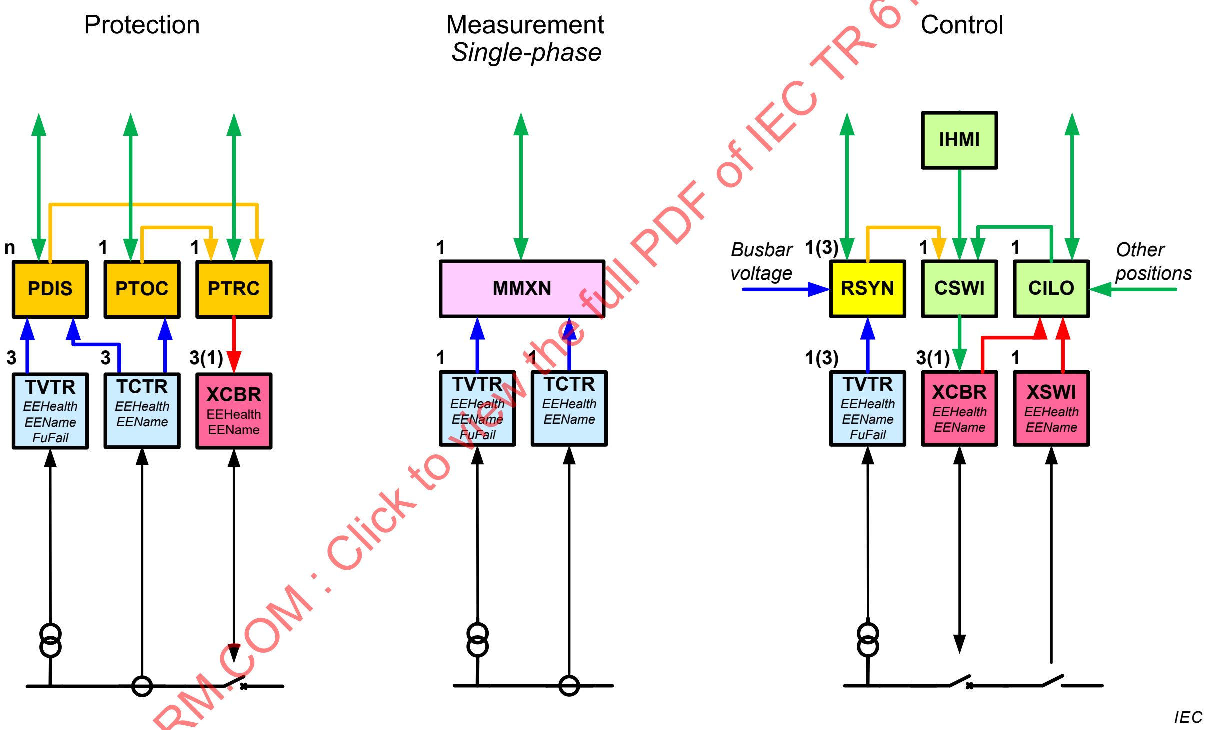


Figure 7 – Basic LN models for (a) protection, (b) measurement and (c) control

The number beside each LN in Figure 7 indicates the number of instances needed for the described application.

(a) The protections functions (examples PDIS and PTOC) need an input current and/or voltages provided by TVTR and TCTR. One instance per phase is needed. The result of the dedicated protection functions is a dedicated start (Str) and an operate (Op). The starts are normally combined to a common start indication (Str) and the operates to a common trip (Tr) send to the circuit breaker (XCBR). Both starts and operates may be combined in PTRC to some indications for other purposes.

It is assumed that the algorithm belongs to the core protection functions described by one Logical Node each. Therefore, IEC 61850 does not generally allow measurement LNs like MMXU between the protection function (Pxxx) and the process LN TVTR and TCTR to calculate some combination of the primary voltages and currents, e.g. the impedance for the distance protection.

There are as many instances (n) of PDIS as distance protection zones are used respectively implemented for the overall distance protection function. The identification of the instances, e.g. by an instance number postfix, is a local issue. Since start (Str) and Operate (Op) allow for a common trip or one per phase, the number of these protection instances is phase independent. Since TVTR and TCTR provide the voltage respectively current per phase only but the protections refer to all phases, three instances of TVTR and TCTR are needed. If the circuit breaker allows for single phase switching, three instances of XCBR are needed. As seen in Figure 15 a fourth XCBR is needed both for the common position needed for interlocking and the detection of phase discrepancy.

(b) MMXN calculates values like the power out of TVTR and TCTR from a single phase. The results may be used for the supervision of these data in an automatic function or by the operator. There is no direct feedback by an output to the power process.

Since (b) refers to single phase measurement only one instance of any shown LN is needed. For three-phase measurement the LN MMXU (1 instance) shall be applied instead of MMXN and three instances both of TVTR and TCTR are needed.

(c) The control command from the operator (IHMI, control service) to close a switch (in the example XCBR) is checked by CSWI for interlocking (release or block by CILO) and (in case of XCBR only) by RSYN for synchronism (ΔU, Δf, Δφ within a predefined interval). If the check results in a release, the command is issued to the switch (XCBR). If there are local reasons by the switch not to allow the operation (low SF6 density, etc.) the blocking conditions in XCBR will finally block the command. For the synchrocheck normally one phase is selected and checked (one instance of RSYN and one instance of TVTR). If the synchrocheck should have the option to switch the phase at operation time, all three instances of TVTR for the three phases have to be available. If all 3 phases should be checked i.e. ΔU, Δf, Δφ available per phase, three instances of RSYN have to be applied.

Both the switch control LN CSWI and the interlocking LN CILO take care of all three phases; therefore one instance each is applied. More complex is the situation for XCBR and XSWI which always provide the position of one phase. Since the interlocking needs the common position out of the three phases, a fourth XCBR, respectively XSWI, is needed. The command from CSWI is normally a three phase command, i.e. it shall be sent to the XCBR, respectively XSWI, of all three phases at the same time. Therefore, three XCBR for the commands are needed. If there is only one common control circuit for all three phases mechanically coupled, one XCBR is applicable for commands. It should be noted that CSWI may also operate a single phase only. Then we are back to three instances of XCBR again. The modelling of XCBR is discussed in detail in 13.3.

Note that point (c) refers to control and not to protection and condition-based monitoring.

9.2 Supervision

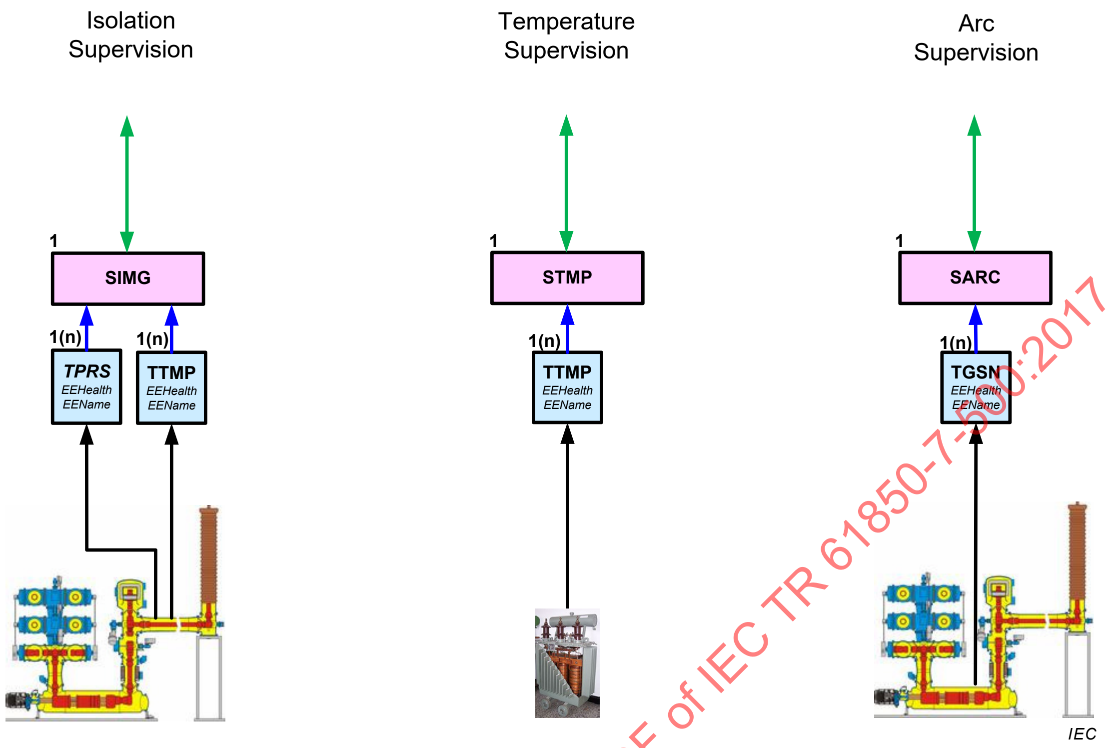


Figure 8 – Basic LN models for supervision of (a) insulation, (b) temperature and (c) arc

The number beside each LN in Figure 8 indicates the number of instances needed for the described application.

(a) The supervision of the gas insulation (SIMG) refers to gas density values. One use case is the supervision of the SF_6 density in GIS compartments. In many cases, there is no direct measurement of the density (but of pressure (TPRS) and temperature (TTMP) where the density is calculated from). Any response on the gas density result like warning, alarming or tripping may be started by the related status value in SIMG.

(b) The supervision of a temperature (STMP) e.g. in a transformer needs temperature sensors modelled by TTMP. In principal, more than one temperature sensor may be available and being included in the supervision. Any response on the temperature result like warning, alarming or tripping may be started by the related status value in STMP.

(c) Resulting from lightning or switching surges, from particles in the gas or in case of low gas density, arcs may result. Since there is no arc sensor LN, a generic sensor TGSN may be applied. Any response on the detected arc(s) result like warning, alarming or tripping may be started by the related status value in SARC.

Any single (one) supervision instance (Sxxx) may have inputs from many (n) sensor instances (Txxx).

The modelling of many condition based monitoring use cases is found in IEC TR 61850-90-3.

10 General modelling issues in substations

10.1 Basic modelling of three-phase systems

10.1.1 Acquisition of position indication

10.1.1.1 Phase and general position

Any switch in a three phase system has three breaking contacts (one per phase) with four position indications each (intermediate, off, on, bad). The same is valid for commands i.e. every phase has to be operated. The switches of the three phases may be coupled mechanically or operated separately. The switchgear models XSWI and XCBR refer to the single phase only. Some application functions as control (CSWI) and interlocking (CILO) need a position indication common for all three phases. Therefore, the three single phase indications are combined to a “Switch position general” (mandatory) in CSWI respectively to “Position general” (M/mandatory) in the fourth XCBR used for detection of “phase discrepancy” or the common position for interlocking. In CSWI the three phases in CSWI (PosA, PosB, PosC) are O/optional (see Figure 9).

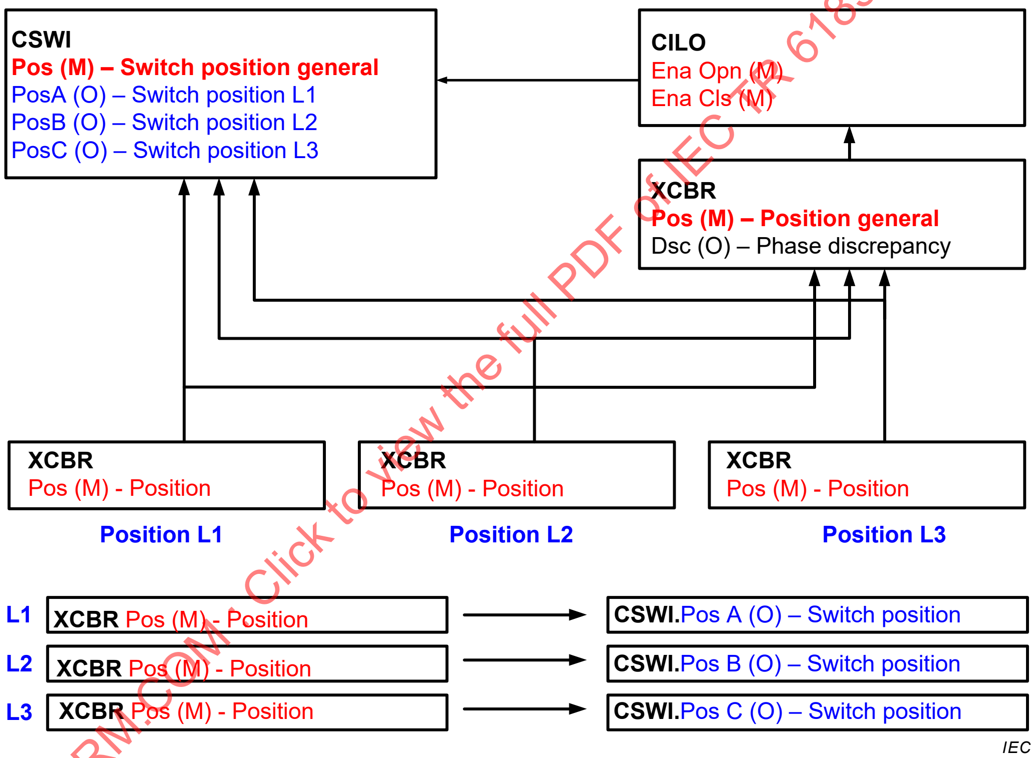


Figure 9 – Relation between the phase-related positions and the common position

10.1.1.2 Position filtering

In a three-phase system the three phases are displaced by 120° respectively by 2/3 π i.e. 20/3 ms (about 6,6 ms) for 50 Hz respectively 16/3 ms (about 5,5 ms) for 60 Hz. Therefore, the phase contacts (see XCBR) are open or closed with this time difference to get the same arcing behavior for all phases but resulting in a transient phase discrepancy by definition. This virtual phase discrepancy has to be masked either by some mechanical means or, in case of using IEDs, by software defined filters (time windows). In the same way unwanted intermediate positions may also be filtered out (see Figure 10). This may be helpful in some cases for displaying the position but it should be used with care because the important operation behavior of the circuit breaker to be monitored is lost. This filtering is needed both in the fourth XCBR and XSWI hiding the virtual phase discrepancy deciding about the common position. The common position evaluated by CSWI out of the subscribed phase XCBR positions will be sent as an actual position to the IHMI. The common position evaluated by the fourth XCBR out of the subscribed phase XCBR positions will be provided as an actual position to the CILO (interlocking). The phase discrepancy will also be calculated in this fourth XCBR. This solution with four XCBRs for a three-phase breaker considers the fact that both the common position and the phase discrepancy are native circuit breaker properties (LN group X). That means that the most convenient implementation of the 4th XCBR is in the IED CBC.

The information which is evaluated by CSWI belongs to the control system (LN group C).

Therefore, XCBR, XSWI and CSWI may all need the DO DscDlTmms (Discrepancy filtering/Delay Time in mms) as shown in Figure 10 hiding the virtual discrepancies. The physical discrepancies are not hidden if the window for the filtering time is set correctly.

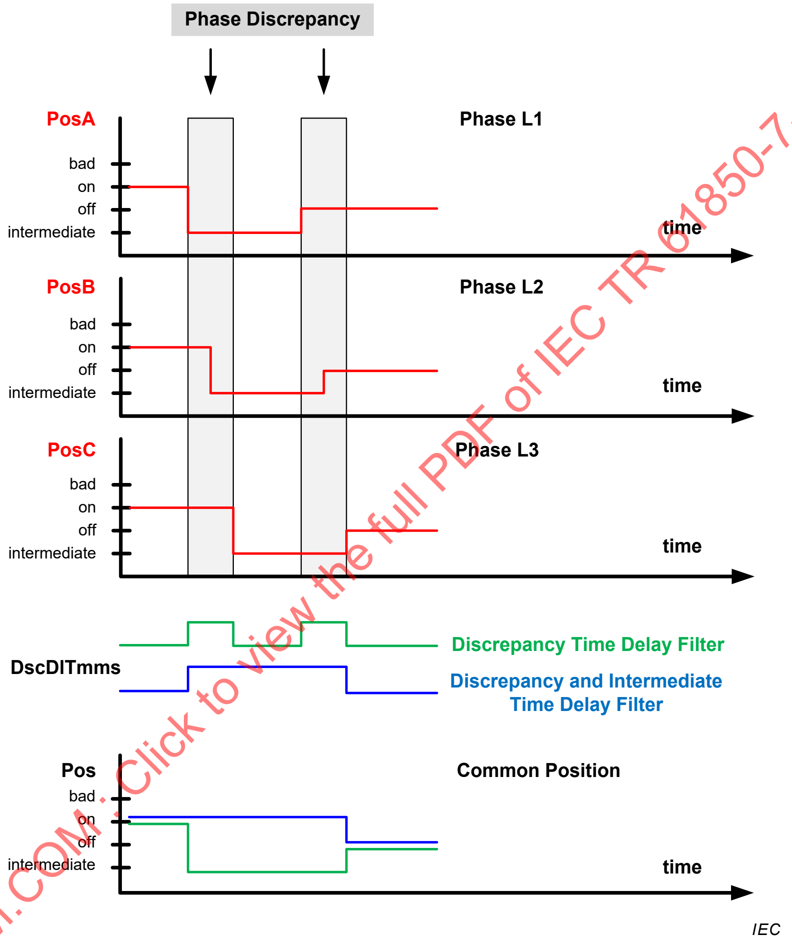


Figure 10 – Filtering of phase related position data to a common position

10.1.2 Acquisition of currents and voltages and the trips

For voltages and currents, there exists no counterpart to the common position as described in 10.1.1.2. All three phases of current and voltage are sampled directly at the same time to preserve the relationship of the phases at any instant of time. For example, over-current or under-voltage functions need the three currents, respectively the three voltages, distance protection functions the three currents and three voltages e.g. of one line, current differential protection functions two or more sets of three currents. The three phase system may also be transformed into other three-component systems like the positive sequence, negative sequence and zero sequence system. If a single phase fault is detected by protection and the circuit breaker is able to open one phase separately, the single phase is tripped; otherwise all three phases are tripped. These relations are sketched in Figure 11. “Red” indicates mandatory (M) and “blue” optional (O) data.

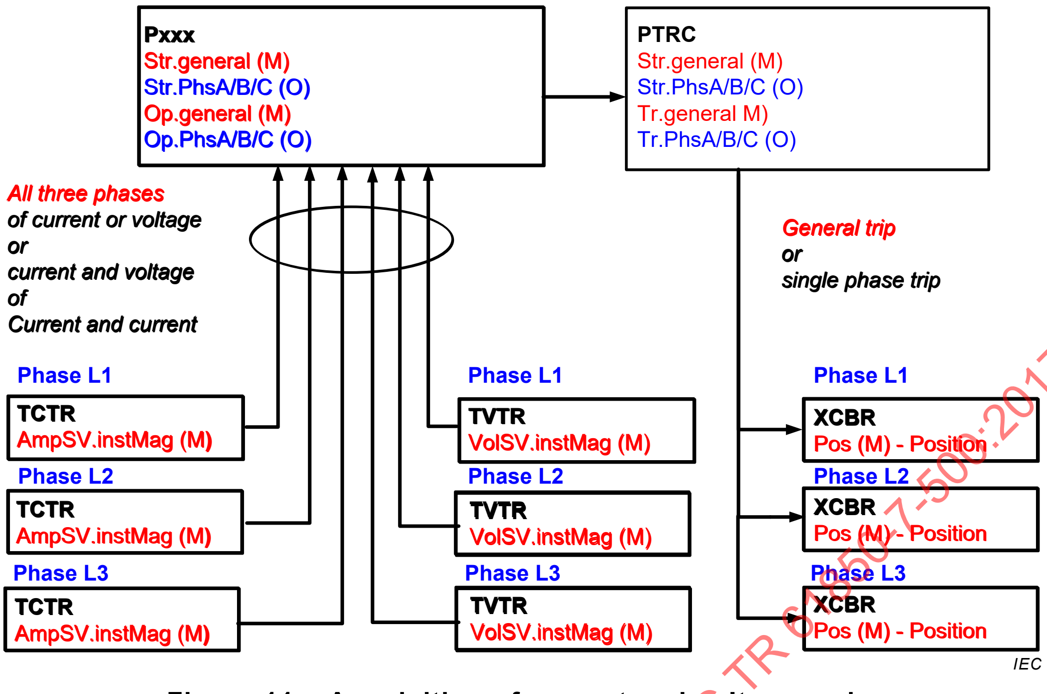


Figure 11 – Acquisition of current and voltage and tripping in the three phase system

10.2 Considering transmission times for GOOSE messages

The IEDs for automatic functions exchange GOOSE messages instead of being connected by copper wires. In many cases like interlocking or 1-out-of-n control, only one action shall be performed at the same time since the first action may have a negative impact on the second one or reverse. For example, interlocking conditions (“releases” vs. “blockings”) may be changed by any change of the position indications of any switch (circuit breaker, disconnector or grounding/earthing switch) including changes in the quality. The risk that an operation takes place at a time when the interlocking conditions are in change is the same as the chance that two commands are given at the same time on the time scales included and the checks applied:

1) Between the “select” detected in CSWI and the arrival of the following command “operate” in CSWI delayed by the transmission of the “selected” state back to the HMI, there is a time of ≥ 1 s determined mainly by the operator and much less by the transmission time between the HMI and the bay controller. Therefore, this time is also given in case of a local operation at the bay controller itself. Since during this time the interlocking conditions may be changed, the check for interlocking should be performed both for the “select” command and the “operate” command. Both checks are foreseen in the control service according to IEC 61850 but not mandatory. Nevertheless, for both steps the related check bit should be set “TRUE”.
2) The detection time of any start for the changes (“selected”, “switch position change”) shall be ≤ 1 ms regarding the normally requested event time tag of 1 ms. Waiting for the debouncing time (e.g. 5 ms) of a contact for confirmation of the state change is automatically covered by the related delay of the changed position indication.
3) The GOOSE transmission time of a detected action (“command”) or event (“selected”) to other IEDs may need 3 ms according to the highest performance class defined in IEC 61850-5, e.g. for the transmission of trips, starts, stops, blocks, etc. It also refers to other time critical functions like interlocking and blocking.
4) In case of losses after two repetitions with T_{min} = 2 ms the resulting delay would be 7 ms. Also in the case of 100 ms this time would be a factor 10 below the time interval between “select” and “operate” or between two commands given about the same time.
5) For SBO commands, the command would also be interrupted in case of a simultaneous “select” from two operator places or at least negatively checked at execution (“operate”) time. As result, in the worst case both commands would be cancelled.

6) Any communication interruption blocking the transmission of GOOSE messages between two IEDs like bay controllers would be detected within the TAL ("TimeAllowedtoLive") defined in IEC 61850-8-1 related to the GOOSE repetition factor T_{max} defined in IEC 61850-7-2. Note that the relationship between both times is not defined. Typically, TAL is about 10 % larger than T_{max}.

7) Any protection trip is independent of the selection and is either transmitted over the bus with a GOOSE message transmission time ≤ 3 ms or issued by a contact ≤ 10 ms. The risk of operating with wrong interlocking conditions because of a GOOSE communication depends mostly on the probability of having a communication loss exactly when the operator has to operate.

8) With reasonable assumptions it was calculated (see [2]) that interlocking with GOOSE messages will fulfil the highest safety requirements and be at least as good as any electromechanical wiring. Any electromechanical solution (wiring of contacts) cannot be better since the operation time of a sequence of hardwired interconnected contacts (relays) has to be considered (≥ 20 ms per relay). Also the probability for non-operating contacts, broken wires and incomplete supervised circuits shall be considered.

11 Control

11.1 Bay control without process bus

11.1.1 Basic diagram

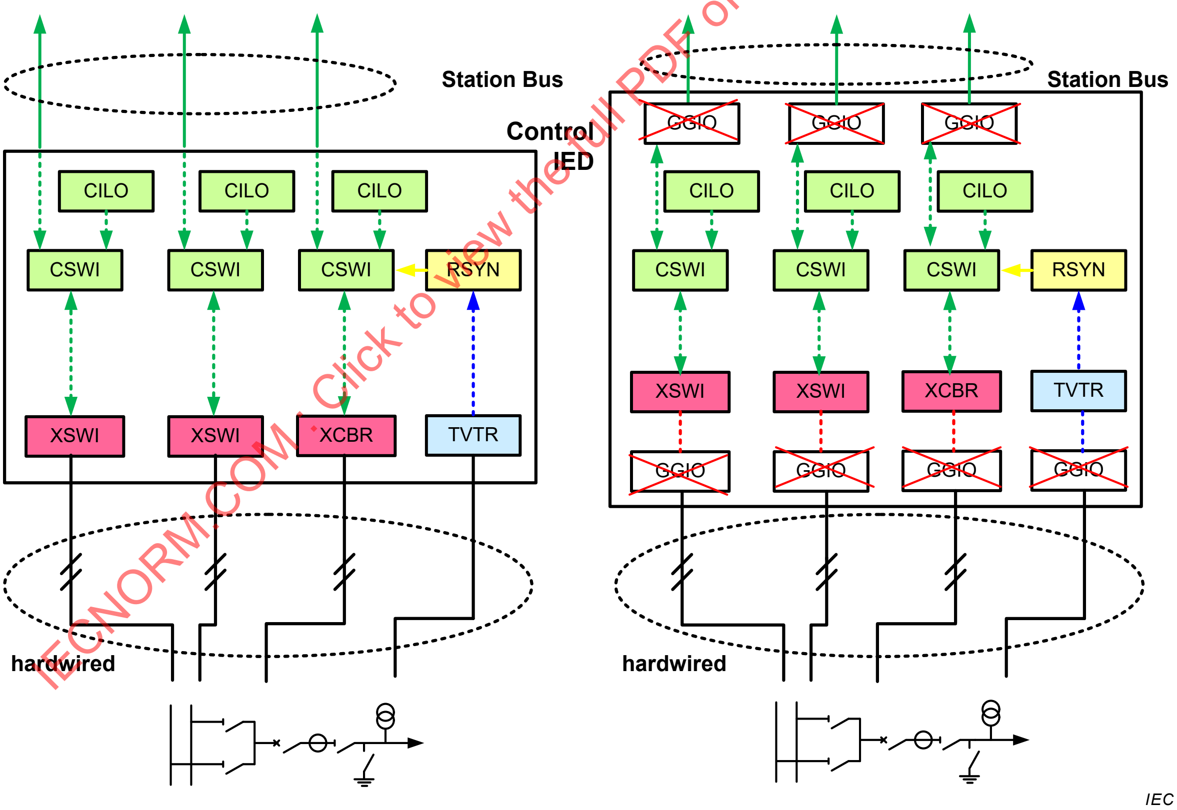


Figure 12 – Modelling bay control without process bus (left: ok, right: wrong)

The bay controller (control IED BCU) is connected to the station level and other bays (if applicable) by the station bus. The bay controller is hardwired (parallel copper wires) to the switchgear (process). External process states and measured values are converted to data according to the IEC 61850 data model in the BCU. Therefore, the boundary LNs are all in this IED. For simplicity, the switchgear is shown as single line diagram. The three phase case is described in 11.3.

11.1.2 General modeling rules

The modeling contains as many instances of the LN class CSWI as switching devices (XCBR, CSWI) have to be operated. Each switch is interlocked i.e. there are the same number of instances of the LN class CILO. The closing of the circuit breaker also has to be released by the synchrocheck function. Therefore, there will be as many instances of the LN class RSYN as circuit breakers are controlled by the control IED. Since the shown use case refers to parallel wire connection of the switchyard devices by copper wires, the switchyard devices shall be represented in the control IED i.e. by the relevant number of instances of the LN classes XCBR, XSWI and TVTR (local voltage for RSYN). Note for the model refinement that CSWI takes care for all three phases but XCBR, XSWI and TVTR for one single phase only. The exception is the 4th XCBR providing both for the common position of the three phases and the potential phase discrepancy.

All optional data of any function which are not made public i.e. are not transported out of the IED via the open communication system (station bus, process bus) shall not be modeled by LNs because they are hidden from the viewpoint of IEC 61850. It shall be recognized that also data which are normally logged only will be read out sometimes. If they are not standardized only proprietary tools may read and handle these ones. In additions for attributes like the switch positions per phase, the external name plate (EEName) or the external health (EEHealth) of all the switchyard devices may have to be reported sometime to someone. Therefore, they shall be modelled by the related LNs also. This means that any modelling neglecting LNs, DOs and DAs which look not to be needed for the time being shall be taken with care or better avoided. An example for a meaningful reduction is that DOs like Health for a multifunctional software shall not be implemented per LN but per logical device (LD) only.

11.1.3 Modeling with process interface nodes and the role of GGIO and GAPC

The general conclusion is that also without process bus, all boundary LNs (LNs starting with T and X) should be present in the IED if applicable. This also refers to the T nodes if the samples are not released out of the IED because only an application function inside the IED needs these samples. One specific example in addition to the common DOs EEHealth and EEName in the process interface nodes is the fuse failure of the instrument transformer for voltage (TVTR) which shall be modelled according to the modelling rules in IEC 61850-7-1 by the DO TVTR.FuFail and not by using GGIO (see Figure 12).

It is an important definition of Logical Nodes that the X and T nodes are the process representation/interface. Therefore, between the switchyard equipment and any defined functional boundary LN there is no GGIO allowed (see definition of GGIO in IEC 61850-7-4). The GGIO may only be used as generic process representation/interface node if there is no applicable boundary node (process representation) with semantics defined in this document. The same is valid for the station bus interface where all the datasets directly reference the data of the standardized functional Logical Nodes.

1) An example for an allowed use of GGIO is the missing “door model” (Figure 13). In this case the GGIO represents the door with states like open, closed, locked, unlocked, etc. GAPC acts as door controller with a not (yet) standardized control algorithm. At engineering time, both GGIO and GAPC are known. This is intended for work-around needed in a dedicated project because of missing LNs. Generally, for missing functions standardized LNs should be requested from the IEC.
2) If there is only a missing process interface model e.g. a cubicle door blocking some function e.g. CSWI, the GGIO (representing the cubicle door) data should be subscribed by the defined function CSWI to be blocked in this case.
3) If the data of existing process equipment like XSWI and XCBR are used for control by a new function not defined in the standard no GGIO but GAPC is needed.

If these examples happen in many projects, proprietary LNs with well-defined semantics should be introduced by the supplier instead of using GGIO or GAPC. By the latest at engineering time the meaning of the generic LNs and their data shall be well known to also provide interoperability in such cases. Nevertheless, it is highly recommended to bring needed but currently not standardized functions to the IEC for creating new LNs with a standard meaning. This would be of benefit for all suppliers and users and strongly simplify the maintenance of impacted products and systems.

Note that the use of LN GAPC for user defined logics is accepted and will be elaborated in the upcoming IEC TR 61850-90-11 but the requirement for defining the semantic meaning both of GAPC and its data to be communicated stays valid.

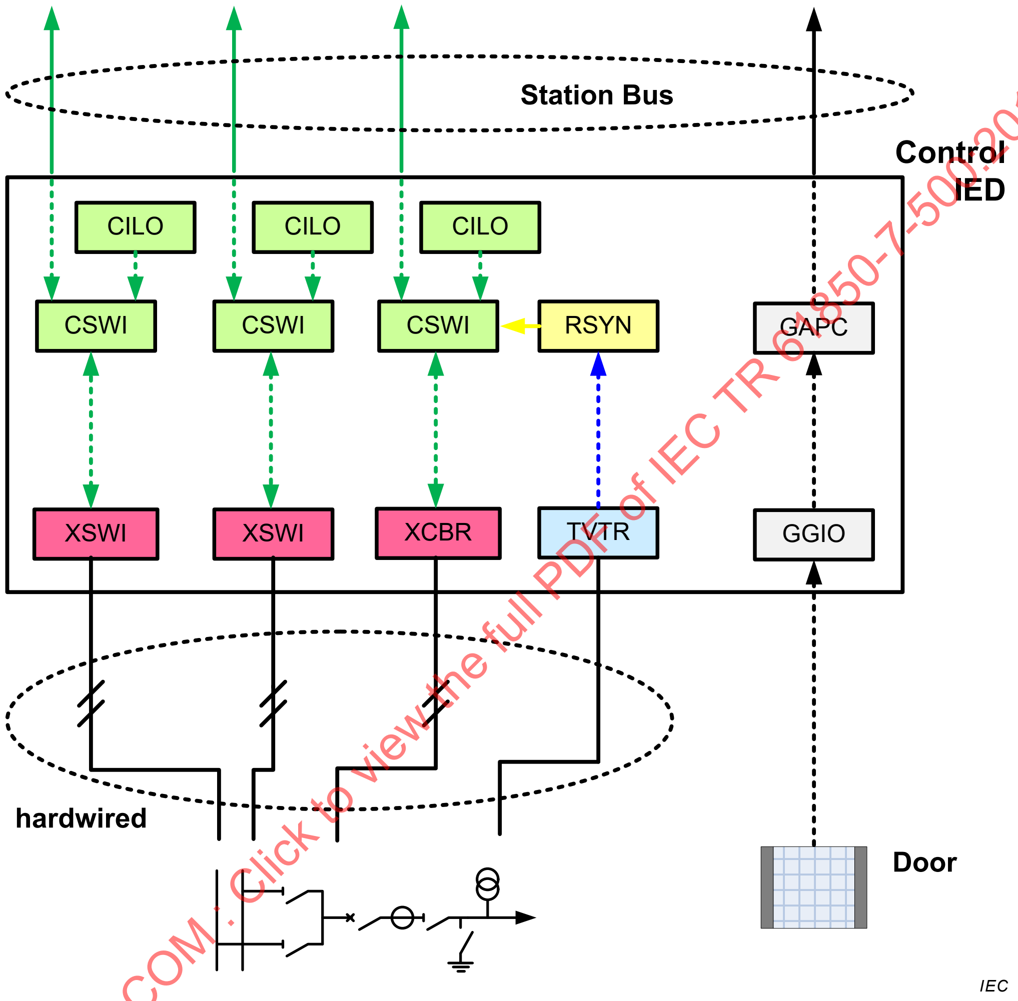


Figure 13 – Bay control with non-defined process object “door” represented by LN GGIO

11.2 Bay control with process bus

11.2.1 Basic diagram

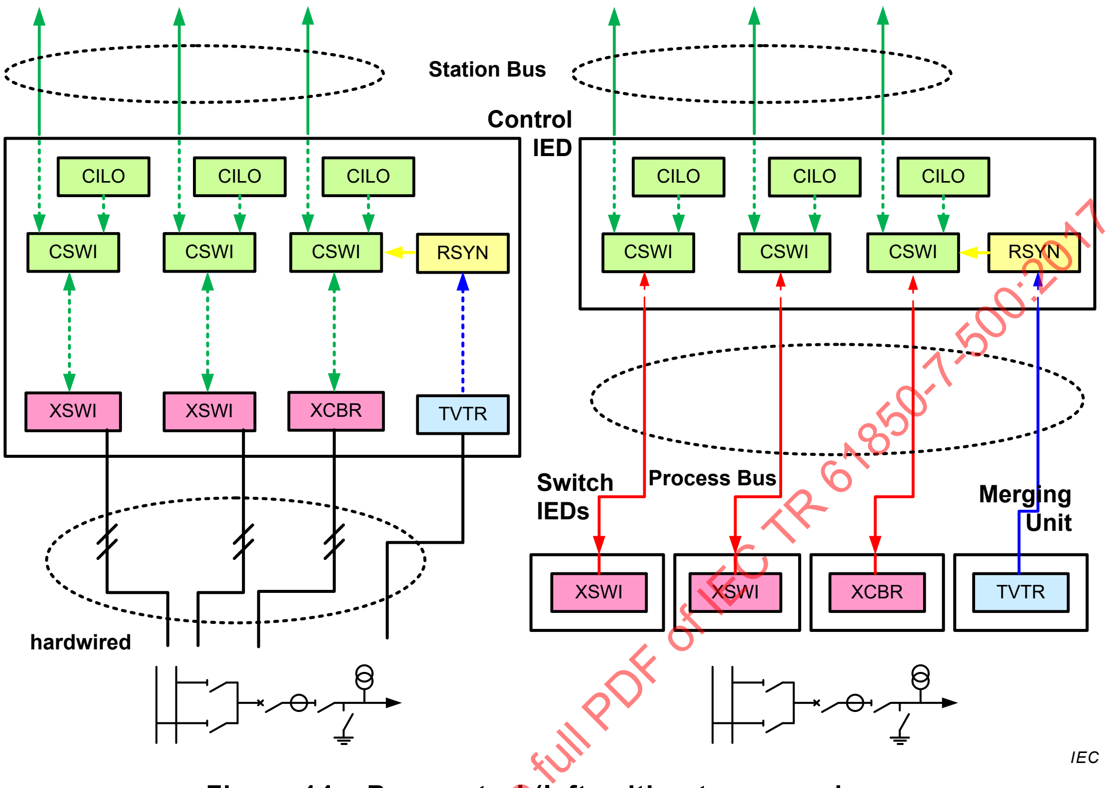


Figure 14 – Bay control (left: without process bus, right: with process bus)

This clear definition of the boundary LN classes as shown in Figure 14 facilitates the modeling and implementation of the bay control with process bus. All boundary LNs are allocated in dedicated IEDs i.e. in a Breaker IED (CBC) respectively in Switch IEDs (DCC). If these are dedicated per switch, combined as switchgear interface or integrated in the Merging Unit, IED is an implementation issue outside the scope of this document. All other comments regarding the role of GGIOs are valid also for control modeling with process bus. In particular, the boundary LNs (T…, X…) shall be in process near electronics (Switch IEDs, Merging Unit).

11.3 Control in the three-phase system

11.3.1 Interconnection of logical nodes

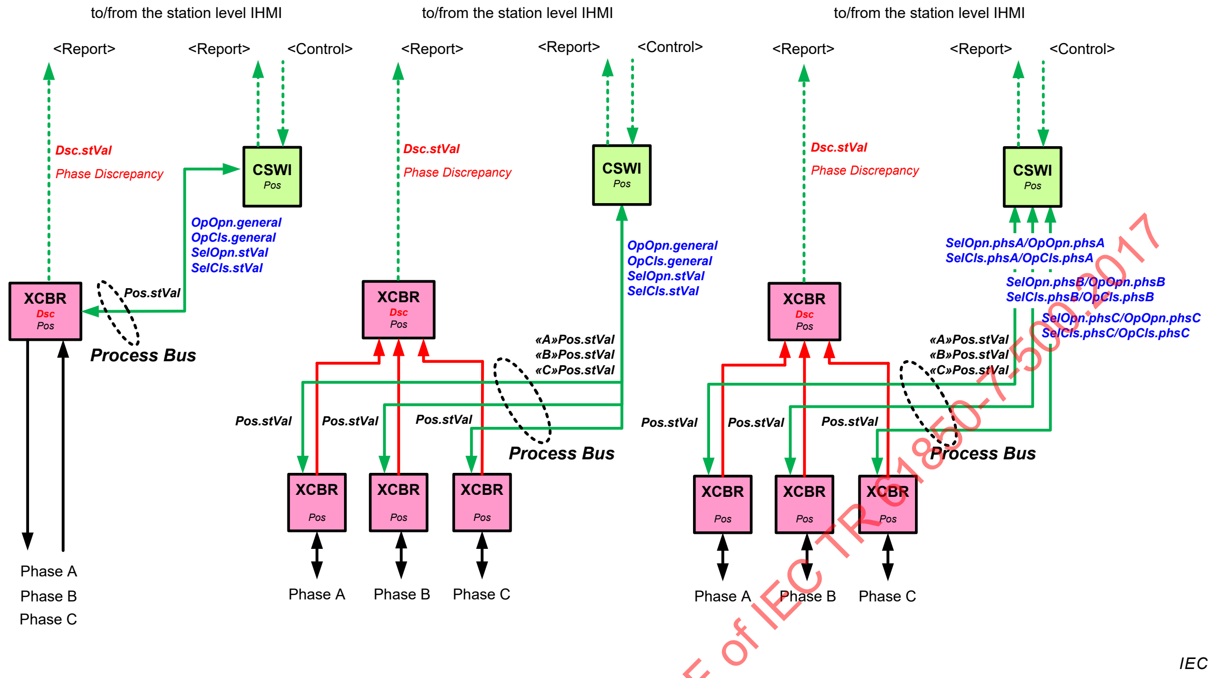


Figure 15 – Three-phase (left and middle) and single-phase control (right) with process bus

For switchgear like circuit breakers with three-phase control (i.e. all the three phases are always operated together) only one single XCBR may be sufficient for modeling. The CSWI issues the commands with the attribute "general" (left side of Figure 15). Nevertheless, by a mechanical fault there may be a phase discrepancy i.e. that not all contacts of the three phases are in the same position (intermediate, off, on, bad). Since XCBR is defined per phase it contains only one DO for position (Pos). In such a case the information about the phase discrepancy shall come from outside e.g. by a wired contact if any. The result will be Pos.stVal="bad" and Dsc.Val="true". There are no means to know which phase positions created the discrepancy. The same applies for supervision data as EEHealth. Therefore, modelling the circuit breaker with one instance of XCBR is not recommended.

Therefore, it is recommended to also model three-phase controlled switchgear by three plus one instances of XCBR, respectively XSWI. CSWI issues the commands with the attribute "general" (middle of Figure 15) which are subscribed by all three phase related XCBRs.

In the case of single phase control (used e.g. for de-icing) again four XCBR instances are needed for modeling. Any of the three XCBRs allocated to the three phases has its own Pos which may be operated independently by OpOpn/Cls.phsA/B/C (right of Figure 15). Based on these positions an additional XCBR common for all three phases identifies any phase discrepancy. In case of phase discrepancy (Dsc.stVal="TRUE") the result of the position of the fourth XCBR will be Pos.stVal="bad". The actual phase positions which have caused the phase discrepancy may be provided from the phase related XCBRs and from CSWI which may have besides the mandatory common Pos the optional phase positions PosA, PosB and PosC.

With process bus, the data are exchanged most likely by GOOSE messages. How to control by GOOSE messages is shown in 11.6. If the client-server control service is used, the modeling with the LNs is the same but the exchanged data are commands and position indications.

Without process bus, all LNs shown in Figure 15 are in one IED and their internal connections are out of the scope of IEC 61850. Nevertheless, the indication of internal links between the LNs in one IED may facilitate the understanding of modeling and the steps towards a distribution of LNs to more IEDs as e.g. needed for the implementation of process bus. For this the formal reference InRef (multiple instantiable) may also be used (optionally). Each LN may have one or several data named InRef1 to InRefn and used as input signals to the function represented by the LN. The common data class of InRef1 is ORG, “object reference setting group”. The data can be used to switch between actual and test incoming signals. IntAddr is not applicable for the relationship between LNs since this value represents a manufacturer specific internal address. The same is valid for BlkRef also which is a special case of InRef for blocking signals. A general discussion and more use cases will be found in the upcoming IEC 61850-7-5 [3].

11.4 Interlocking, synchrocheck and blocking

11.4.1 General remarks

The control service is defined as state machine in IEC 61850-7-2. The synchrocheck release provided by RSYN and the interlocking condition provided by CILO are checked in the command service sequence by the function represented of CSWI. These checks may be enabled or disabled by bits in the telegrams of the control service (interlocking override, synchrocheck override). The related attributes are

RSYN.Rel.stVal = TRUE or FALSE

CILO.EnaOpn.stVal = TRUE or FALSE

CILO.EnaCls.stVal = TRUE or FALSE

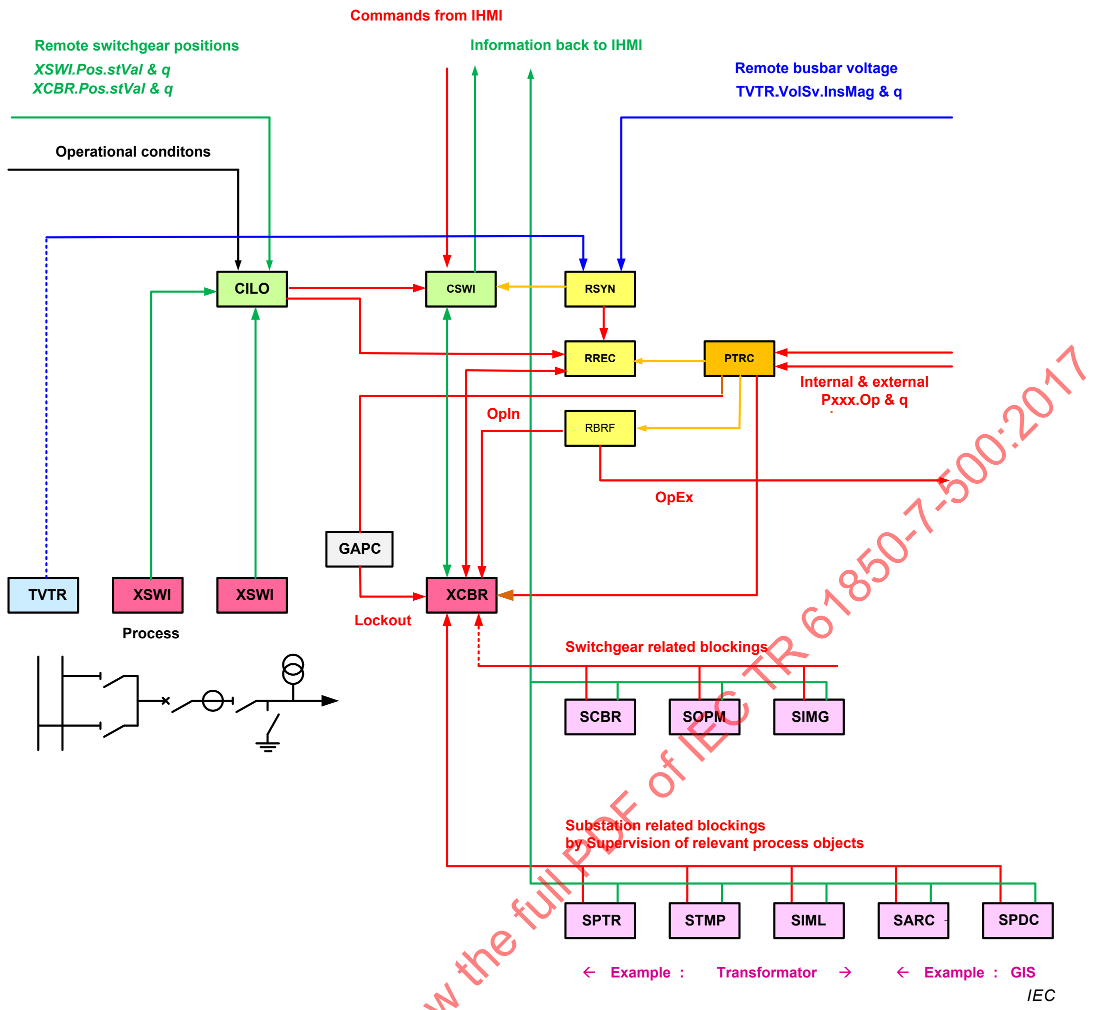


Figure 16 – Interlocking, synchrocheck and blocking check in control IED without PB

The operation may be blocked locally in the switchgear (e.g. circuit breaker modeled by XCBR) because of a local problem (e.g. mechanics) or by a remote command. Besides the blocking commands, all other impact is provided automatically. The local problems resulting in blocking may be detected by the supervision functions i.e. for the circuit breaker by SCBR, SOPM and SIMG (see also Figure 2 and Table 1). RSYN and CILO are shown in Figure 16 implemented in the bay control IED but may reside also in other IEDs (see Figure 17 with process bus). In this case the actual attribute values shall be transmitted by GOOSE to the bay control IED. The GAPC represents the not yet defined "Lockout function" blocking in some well-defined situations the closing of a tripped circuit breaker.

Note that based on the rules for the application of GGIO and GAPC discussed in 11.1.3 the GAPC for "lockout" should be replaced by a dedicated standardized LN with semantically well-defined DOs in the next edition of IEC 61850.

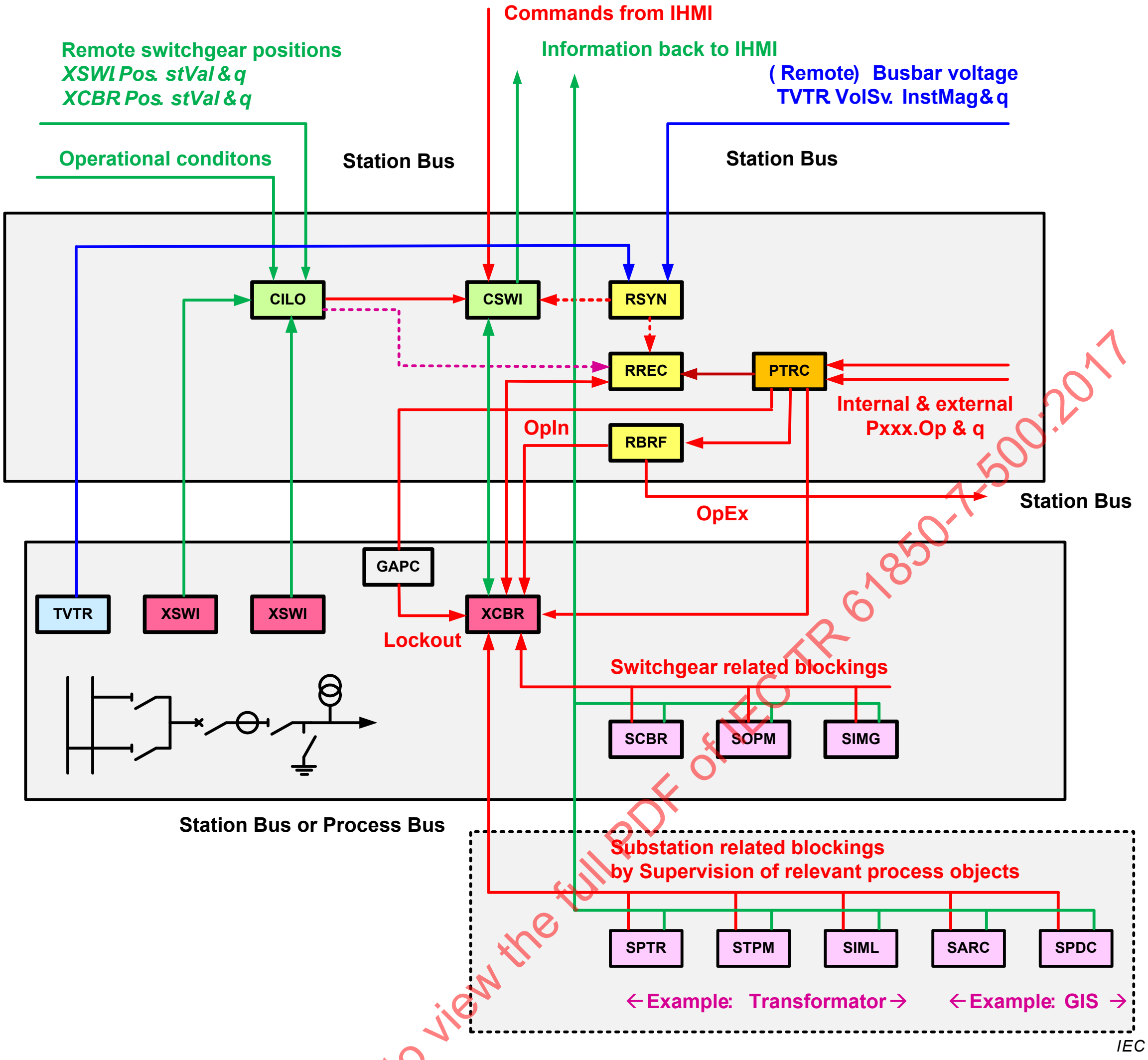


Figure 17 – Interlocking, synchrocheck and blocking check with process bus PB

11.4.2 Interlocking

11.4.2.1 Basics

The interlocking should forbid dangerous switching operations which may harm people or destroy equipment. The requirements are easily derived from the task and properties of the switches. Simple and common requirement examples are to avoid switching power to ground, creating a short circuit or breaking or connecting power by disconnectors which would destroy this kind of equipment. The releases or blockings are modeled by the LN CILO (one per switching device) and based either on Boolean interconnection of all the related switch positions or by a comprehensive topology detection with some basic interlocking rules based also on these switch positions. Usually no other information is needed to evaluate the basic interlocking conditions even if they might be supported by additional information like presence of voltage on the line to block earthing switches. The positions and resulting releases and blockings are transmitted by GOOSE messages between the bays or by a dedicated interlocking IED. To be prepared for any kind of interlocking algorithm and to simplify engineering it is recommended to include the position (including its quality) of all switches of one bay in the data set for the GOOSE messages since a few more entries have no noticeable impact on the size of the such messages.

11.4.2.2 Considering operation and transmission times

The interlocking conditions (“releases” vs. “blockings”) may be changed by any change of the position indications of any switch (circuit breaker, disconnector or ground/earthing switch) including changes in the quality. The risk that an operation takes place at a time when the interlocking conditions are in change depends on the time scales included and the checks applied (see 10.2). Therefore, the interlocking release or blocking should be checked both in the selection step avoiding not allowed operation and in the operation step considering any change between both steps which are separated by a time interval > 1 s since the operator is included. The GOOSE transmission time is important for the transfer of position changes resulting in detection of changed interlocking conditions and, depending on the implementation, also the distribution time of releases and blockings. The highest performance class for the transmission time of the GOOSE messages is 3 ms to be used for trips and other functions like interlocking and blocking according to IEC 61850-5. Using such transfer times the probability of unsafe conditions in the moment of interlocking check is minimized (see also 11.4.2.3).

11.4.2.3 Performance of GOOSE based interlocking

With reasonable assumptions it was calculated (see [2]) that interlocking with GOOSE messages will fulfill the highest safety requirements and is at least as good as any electromechanical wiring. Any electromechanical solution (wiring of contacts) cannot be better since the operation time of relays interconnected in series has to be considered (≥ 20 ms per relay). In addition, the probability for non-operating contacts, broken wires and incomplete supervise circuits has to be considered. Note that IEC 61850 offers all means for SW based interlocking with GOOSE communication but does not forbid electromechanical based interlocking. This decision is finally made by the user.

11.4.3 Blocking

By definition, blocking switching operations refers not to the condition of the rest of the switchgear but only to the behavior of the switch which is intended to be operated. There could be a mechanical problem with the operating mechanism, too low gas density or not enough drive energy. The blocking of switchgear could be also issued by an operator command to the X-nodes by the DO BlkOpn and BlkCls.

11.4.4 Recommendation

For implementation, all these conditions may be combined for release and blocking of a command in Boolean equations but a clear separation of Interlocking and Blocking simplifies the engineering and maintenance of the substation automation system. It is especially important if the Interlocking is made in a central unit or by topology algorithms which are different from the Boolean expressions. Therefore, this recommendation is essential for interoperability. The grouping of the different conditions for switchgear operation is shown in Figure 18.

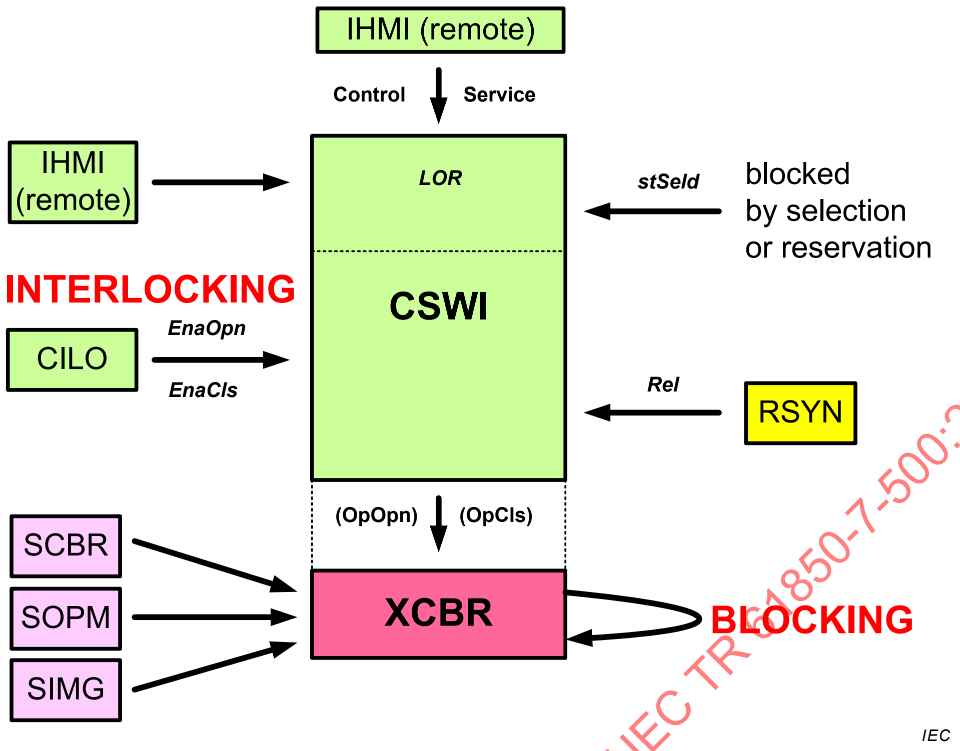


Figure 18 – Relation between interlocking, synchrocheck, blocking and control authority

11.4.5 Synchrocheck

The synchrocheck allows closing of an open circuit breaker only if both the amplitudes, phase angles and frequencies of the voltage on both sides are within predefined intervals. Therefore, the voltages shall be measured on both sides of the open circuit breaker. On the line side there is always a voltage transformer or a voltage sensor. Normally, the other side of the breaker is connected to the busbar and, therefore, the busbar voltage has to be available. Since at least conventional instrument transformers are expensive, the busbar instrument transformer is mostly skipped and the missing voltage substituted by the voltage transformer on any connected line. This means a dynamic topology determination which is still not yet defined in IEC 61850. Conventionally, the voltage is provided as secondary voltage of the instrument transformer by busbar voltage wires. IEC 61850 allows the transmission of this voltage in telegrams over a communication network e.g. over the station bus. The prerequisite is that the remote voltage samples are synchronized with the local ones in the range between 1 µs (see IEC 61850-5) and 4 µs (UCA Users Group Group recommendation). The synchronized sampling with this high precision is made by pulses (UCA Users Group recommendation) or by the precision time protocol defined in IEC 61850-9-3 as profile of IEC 61588.

11.5 Control authority

11.5.1 Operation 1 out of n

11.5.1.1 Basics

If more than one switch is operated at once, then overlapping of contact movement with dangerous power transfer may happen. Unpredictable transient events may occur. Therefore, as a general rule in most substations, only one of the switches should be operated at same time, at least in interconnected parts of the substation. This situation may be controlled by using the attribute “selected” (XSWI/XCBR.Pos.stSeld). The switch selected first (in the XCBR/XSWI model located without process bus in the bay control IED or with process bus in the breaker IED) is informing all other switches by sending out a GOOSE message containing XSWI/XCBR.Pos.stSeld = “TRUE”. If this GOOSE message is received by all the other bay control IEDs, any try to select a second switch should result in a negative acknowledgement.

Since control authority is seen as essential for switchgear control function in substations it is also part of function modelling.

11.5.1.2 Restricted selectivity

The basic approach allows only one operation per substation at a time. Depending on the ownership or operation philosophy parallel operations in different parts of the substation (voltage levels, ownership, etc.) may be allowed. This may be easily handled by the selective subscription of the GOOSE messages containing the selected position.

11.5.1.3 Considering operation and transmission times

The chance that two commands given are performed at the same time is determined by the time scales included and the checks applied (see 10.2). Compared to interlocking in case of the select and operate command in series separated by the response time of the operator (> 1 s), two operators try to operate at the same time. The detection of a started switchgear operation is typically done by distribution of the "selected" state of the switchgear position to be used for blocking the second "select" command. No parallel operations are possible.

As later the different bay units respectively the different bay control functions (CSWI) become aware of the "first selection" in the system as the risk for a "second selection" becomes higher.

The minimum time window for two simultaneous selections is then the transmission time of about ≥ 3 ms. The maximum time window for two simultaneous selections is the time between "select" and "operate" of about 1 s because the "operate" resets the "selected" state. If the second "select" command could not be blocked, two selections in the same time interval are detected and both selections have to be canceled. No parallel operations are possible.

11.5.2 Control authority management

11.5.2.1 Functional description

11.5.2.1.1 Local mode (Loc)

Control actions in a substation may be accomplished at different control levels. For safety reasons, an operator or service person if applicable must be able to isolate a level from the others by claiming the control authority for that level. The level where the operator or service person is just working by commands is always "local" for this person, all higher levels are "remote" for control actions. When the control mode status at one level is "local", any control actions coming from the "remote" levels should be blocked.

11.5.2.1.2 Local mode at station level (LocSta)

In some situations, a local operator may be required to isolate some bays or primary equipment from the CC, without having to put the whole substation in local mode. The operator sets a virtual tag on the bay/equipment through the station level HMI. The bay controller controlling the bay/equipment shall be aware of this tag to effectively block the commands coming from the CC.

11.5.2.1.3 Scope of controllable data for local or remote control

11.5.2.1.3.1 Controllable data objects

The control of controllable data objects is performed by the control service (see IEC 61850-7-2). These controllable data objects belonging to the "common data class for controls" (see IEC 61850-7-3) and are summarized in what follows:

- Controllable single point (SPC)
- Controllable double point (DPC)

- Controllable integer status (INC)
- Controllable enumerated status (ENC)
- Binary controlled step position information (BSC)
- Integer controlled step position information (ISC)
- Controllable analogue process value (APC)
- Binary controlled analogue process value (BAC)

11.5.2.1.3.2 Logical nodes with control authority and presence conditions

Only a limited number of controllable LNs contain the DOs Loc, LocKey and/or LocSta with the appropriate presence conditions (see IEC 61850-7-4).

Table 3 – Logical nodes with control authority and related presence conditions

LN / DO	Loc	LocKey	LocSta	MltLev
	M-O-C	M-O-C	M-O-C	M-O-C
	nds/ds	nds/ds	nds/ds	nds/ns
LLN0	O / na	O / na	O / na	O / na
LLN0	O / F	OF(Loc) / F	OF(Loc) / F	O / na
ANCR	O / F	OF(Loc) / F	OF(Loc) / F	F
ARCO	O / F	OF(Loc) / F	OF(Loc) / F	F
ARIS	O / F	OF(Loc) / F	OF(Loc) / F	F
ATCC	O / F	OF(Loc) / F	OF(Loc) / F	F
AVCO	O / F	OF(Loc) / F	OF(Loc) / F	F
CCGR	O / F	OF(Loc) / F	OF(Loc) / F	F
CSWI	O / F	OF(Loc) / F	OF(Loc) / F	F
CSYN	O / F	OF(Loc) / F	OF(Loc) / F	F
FSPT	O / F	OF(Loc) / F	OF(Loc) / F	F
GAPC	O / F	OF(Loc) / F	OF(Loc) / F	F
GGIO	O / F	OF(Loc) / F	OF(Loc) / F	F
IHMI	O / F	OF(Loc) / F	OF(Loc) / F	F
ITCI	O / F	OF(Loc) / F	OF(Loc) / F	F
KFAN	O / F	OF(Loc) / F	OF(Loc) / F	F
KFIL	O / F	OF(Loc) / F	OF(Loc) / F	F
KPMP	O / F	OF(Loc) / F	OF(Loc) / F	F
KVLV	O / F	OF(Loc) / F	OF(Loc) / F	F
XCBR	M / F	O / F	O / F	F
XSWI	M / F	O / F	O / F	F
YEFN	O / F	OF(Loc) / F	OF(Loc) / F	F
YLTC	O / F	OF(Loc) / F	OF(Loc) / F	F
YPSH	O / F	OF(Loc) / F	OF(Loc) / F	F
ZRRC	O / F	OF(Loc) / F	OF(Loc) / F	F

The meaning of table contents:

- LN Logical Device names in column,
- DO Data Object name in row

- nds/ds: LN instance is not derived from another one for statistics/is derived for statistics
- M-O-C: Mandatory-Optional-Conditional
- O Optional / M Mandatory / F Forbidden
- Loc (SPS) means the Local Remote control authority indication. If Loc is "false" the operation authority is at the higher level only (remote control). If Loc is "true", the control authority is allowed at this level (local control) only,
- LocKey (SPS) is the physical key or toggle switch to switch the control authority from remote to local and reverse. If LocKey is "true" the Loc has to be also set to “true”. If LocKey is in the LLN0 than this is valid for all control functions (i.e. represented by LNs containing the DO Loc) in the related LD.
- LocSta (SPC) allows to switch over the control authority at station level between the station level and the remote control level. If LocSta is "true" the control authority is at station level and the remote control from the control center is disabled. Otherwise the control from the remote control center is allowed.
- MltLev (SPC) selects the authority for local control (“true” – control from multiple levels is allowed, “false” (default) – no other control level allowed)
- OF(Loc)/T valid for LocKey and LocSta. If true, the operation has been switched (from remote) to local. This changeover is always done.

11.5.2.1.4 Conclusions for the impact of control authority conditions

Table 3 shows that the control authority may be used very selective. To avoid interoperability issues, the use of Loc, LocKey, LocSta and MltLev should be decided at engineering phase.

11.5.3 Logical node representation

11.5.3.1 Local and multilevel mode

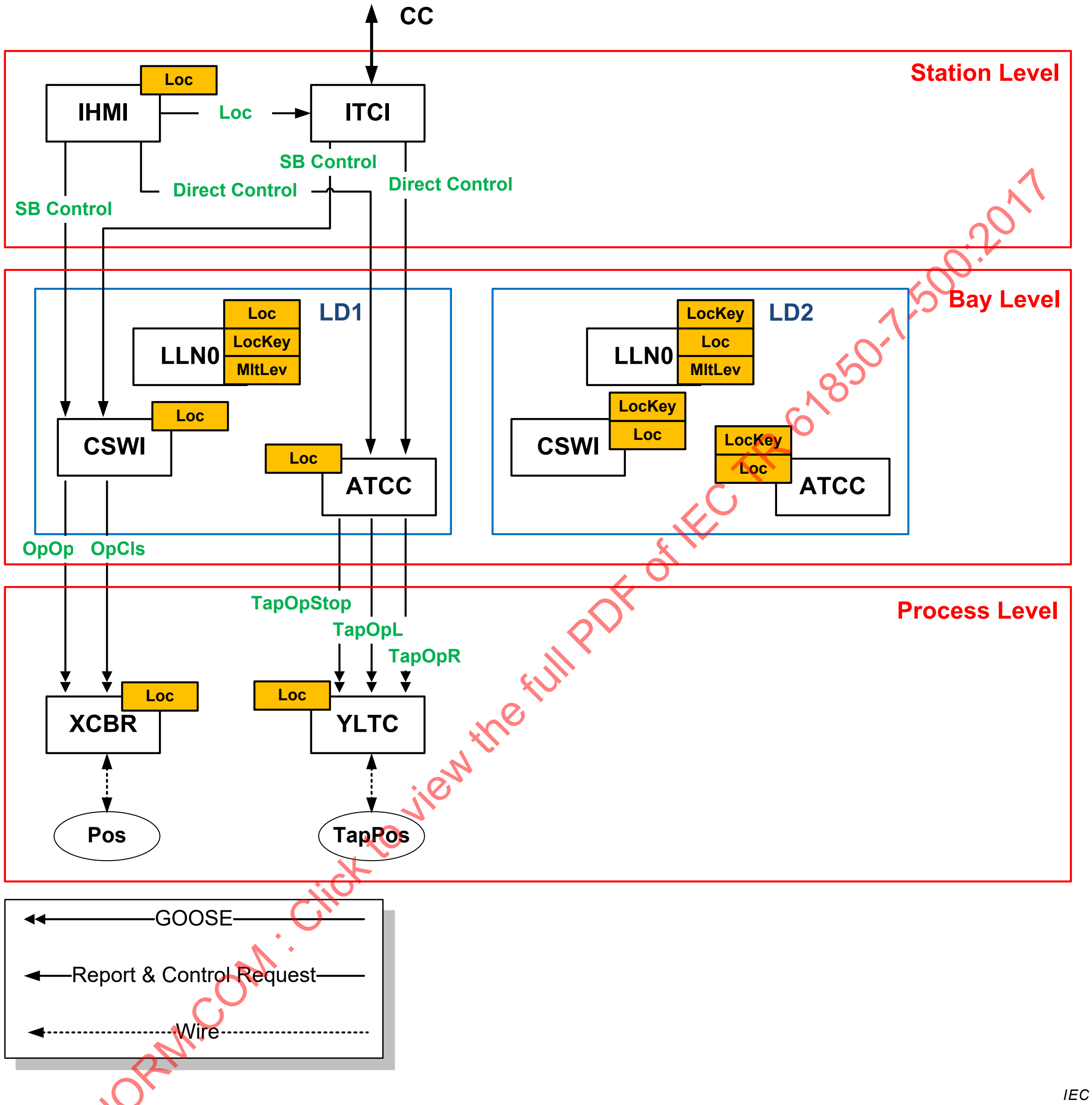


Figure 19 – Local remote authority switching at bay and process level

11.5.3.2 Diagram description

Figure 19 shows two use cases for using the Loc, LocKey and MltLev data in order to manage the control authority in the substation. The services shown are common examples.

At the substation level, control actions coming from the CC are blocked by setting the IHMI.Loc data to “true”.

At the bay level, the whole logical device may be switched between local and remote by the value of LLN0.Loc. This means that any control actions coming from the substation and CC levels are blocked.

In the modelling example LD1, the physical key LLN0.LocKey is used to switch LLN0.Loc setting the value Lxxx.Loc for all the individual LNs in the LD.

LD2 shows another variant where the local mode of the individual LNs can be controlled by individual physical keys Lxxx.LocKey. All related LNs show the resulting local mode status Lxxx.Loc.

At process level, the data Xxxx.Loc (mandatory) or Yxxx.Loc (optional if applicable) indicate if the control actions coming from all other control levels are blocked or not.

The MltLev as mentioned above is typically allocated in the LN LLN0 (e.g. LD1) at bay level.

Having it per LN would create a complex situation where some switchgear in one bay may be operated from different levels but others not. There are no use cases known where such an implementation would be needed and provides benefit. Therefore, the implementation of MltLev in the LLN0 at bay level is recommended only but the alternative not forbidden.

At process level, the use and, therefore, the implementation of MltLev is de facto forbidden since it would allow that in maintenance cases (Loc = “local”) the switchgear may also be operated additionally from remote.

11.5.3.3 Switching control authority at station level

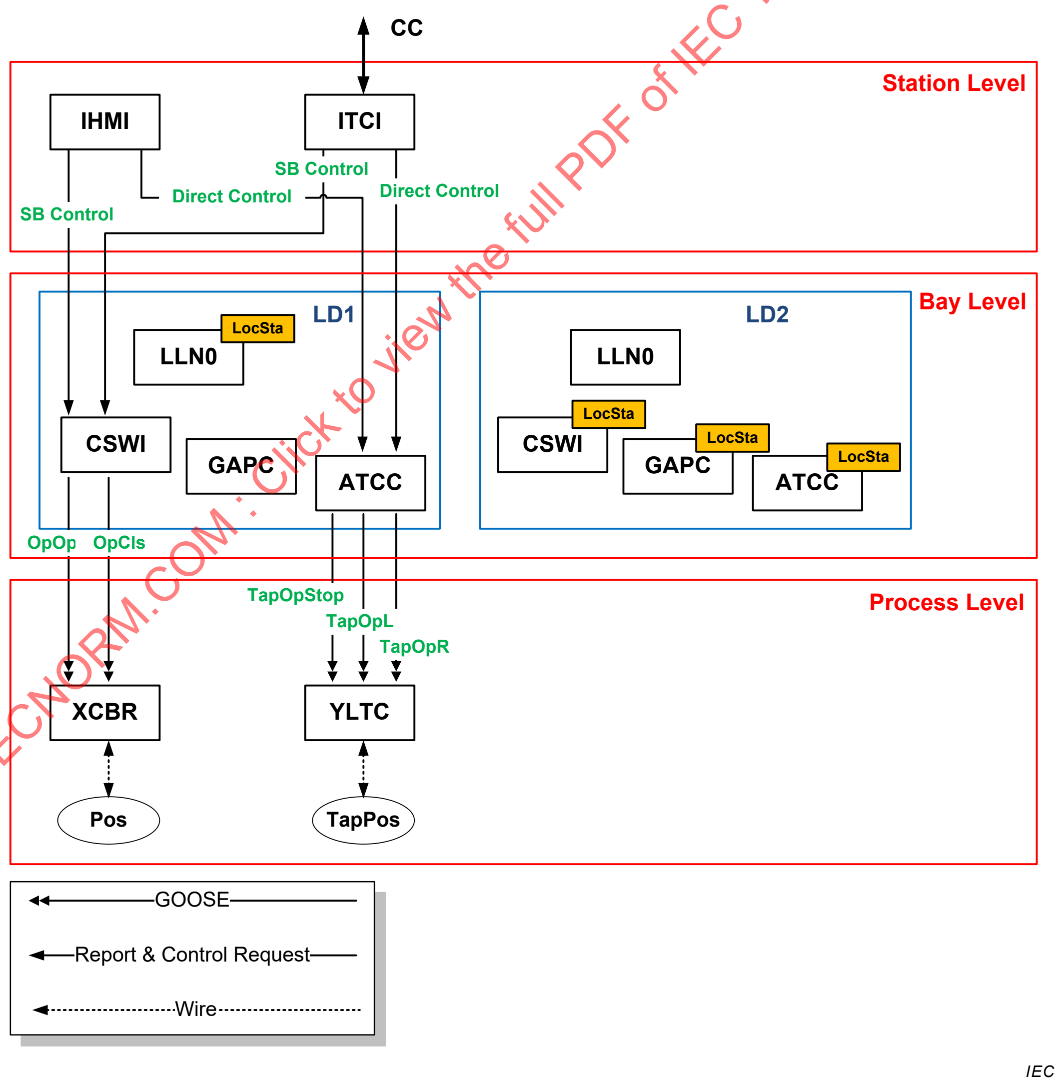


Figure 20 – Station level authority switching

11.5.3.4 Diagram description

Figure 20 shows the typical use cases. The services shown are common examples.

The controllable data LocSta (optional) is used for switching the control authority between station level HMI (LN IHMI) and network level (CC) via the telecontrol gateway (LN ITCI). It allows e.g. blocking control actions coming from the network level (CC). Control actions coming from the substation level are still allowed. The LocSta state is controlled from the substation level LN IHMI. The test for the acceptance of the control actions from network level (CC) is performed at the bay level allowing that part of the substation e.g. one voltage level is operated locally and the other one from remote. This is the recommended solution but it should be noted that LocSta could also be used at station level. Note that with the LocSta or Loc (see Figure 19) in IHMI only the control of the complete substation may be switched over.

Figure 20 shows variants where the local mode at station level can be used for a whole logical device (LD1) or for individual LNs (LD2). All possible options of control hierarchy are given by the merger of Figure 19 and Figure 20.

11.6 Operation of switchgear with process bus

11.6.1 The control service

The control service is defined in IEC 61850-7-2. The control service operates according to the control model attribute (ctlModel) in the common data classes of controllable data objects. There are e.g. ctlModel values for direct control or select before operate (SBO) both with normal and enhanced security. If not mentioned specifically, the SBO with enhanced security is applied since all other values may be seen as subsets of this most comprehensive one. It is also the most used one for operating switchgear and, therefore, the recommended one for this purpose.

11.6.2 Extension of the control model by GOOSE messages in tabular form

The control model which terminates in CSWI may be extended by GOOSE messages over the process bus to and from XCBR. All DOs needed are available in CSWI and XCBR. The selection (SelOpn, SelCls) is always per switch and not per phase. Table 4 and the diagrams in Figure 21 and Figure 22 explain this extension in detail.

Table 4 – Extension of the control model by GOOSE messages between CSWI and XCBR

[SelVal_req]					
WaitForSelection	entry/set	CSWI.SelOpn/Cls.stVal=TRUE	GOOSE	→	XCBR
	exit/set	CSWI.Pos.stSeld=TRUE	GOOSE	←	XCBR.Pos.stSeld=TRUE
[SelVal_req+]					
[Oper_req]					
WaitforChange					
	entry/set	CSWI.OpOpn/Cls.general=TRUE	GOOSE	→	XCBR
		CSWI.Pos.opOk=TRUE	GOOSE	←	XCBR.Pos.opOk=TRUE
[Oper_resp+]					
	exit/reset	CSWI.Pos.opOk=FALSE	GOOSE	←	XCBR.Pos.opOk=FALSE
	exit/reset	CSWI.OpOpn/Cls.general =FALSE	GOOSE	←	XCBR.Pos [new]
[state = new]		CSWI.Pos.stVal [new]			
[CmdTerm_resp+]					
EndSelection	entry/reset	CSWI.SelOpn/Cls.stVal=FALSE	GOOSE	←	XCBR
	exit/reset	CSWI.Pos.stSeld=FALSE	GOOSE	→	XCBR.Pos.stSeld=FALSE

A cancel will reset the CSWI.SelOpn/Cls.stVal to FALSE and the CBC will accept this by setting the XCBR.Pos.stSeld to FALSE.

The extensions work both for single and three phase control. The difference is that instead of the attribute “general” the attribute “phsA”, etc. will be sent.

11.6.3 Extension of the control model by a sequence of GOOSE control messages

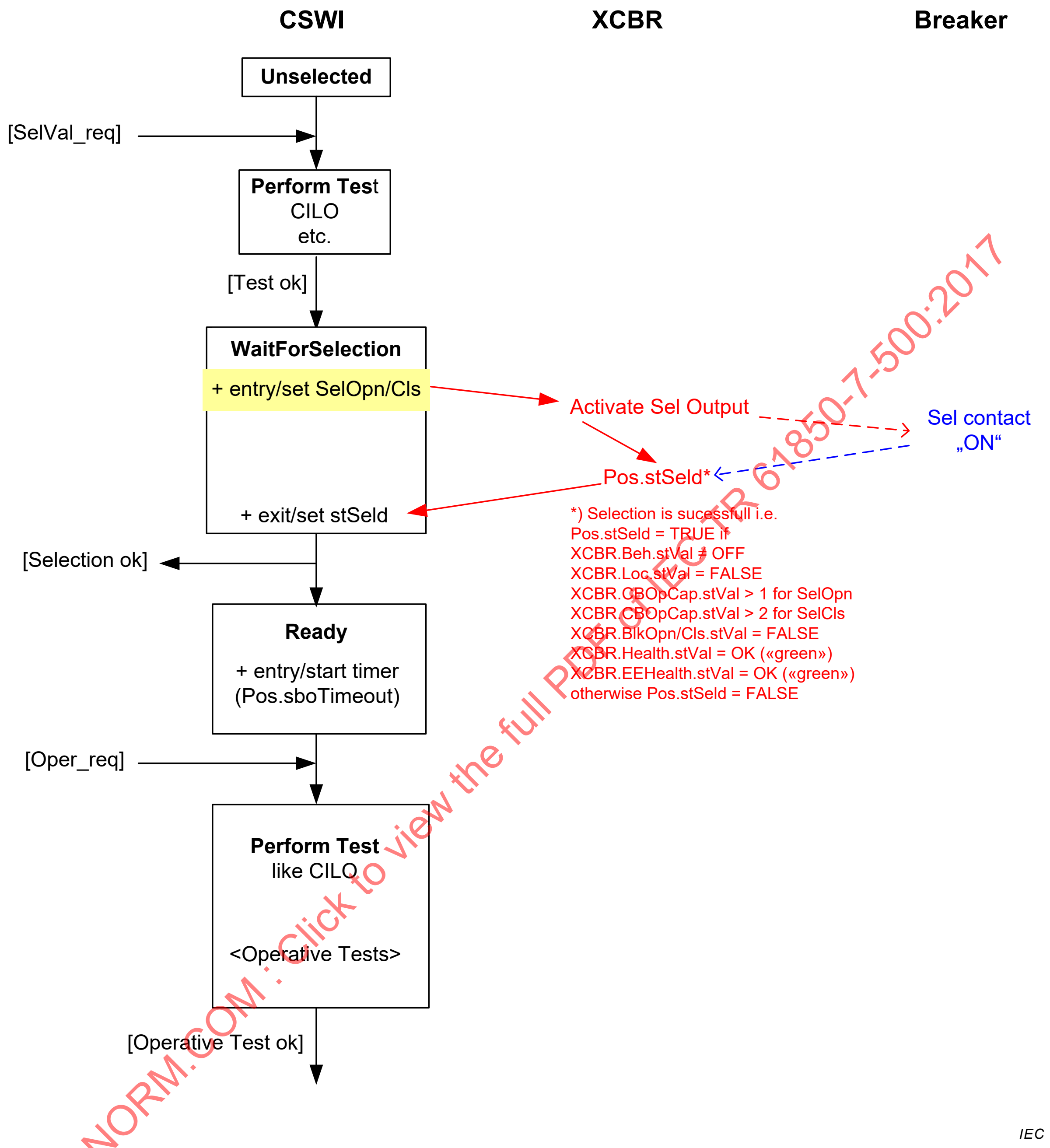


Figure 21 – Switch control (SBO with enhanced security) with a sequence of GOOSE control messages between BCU (“CSWI”) and CBC (“XCBR”) – Part 1

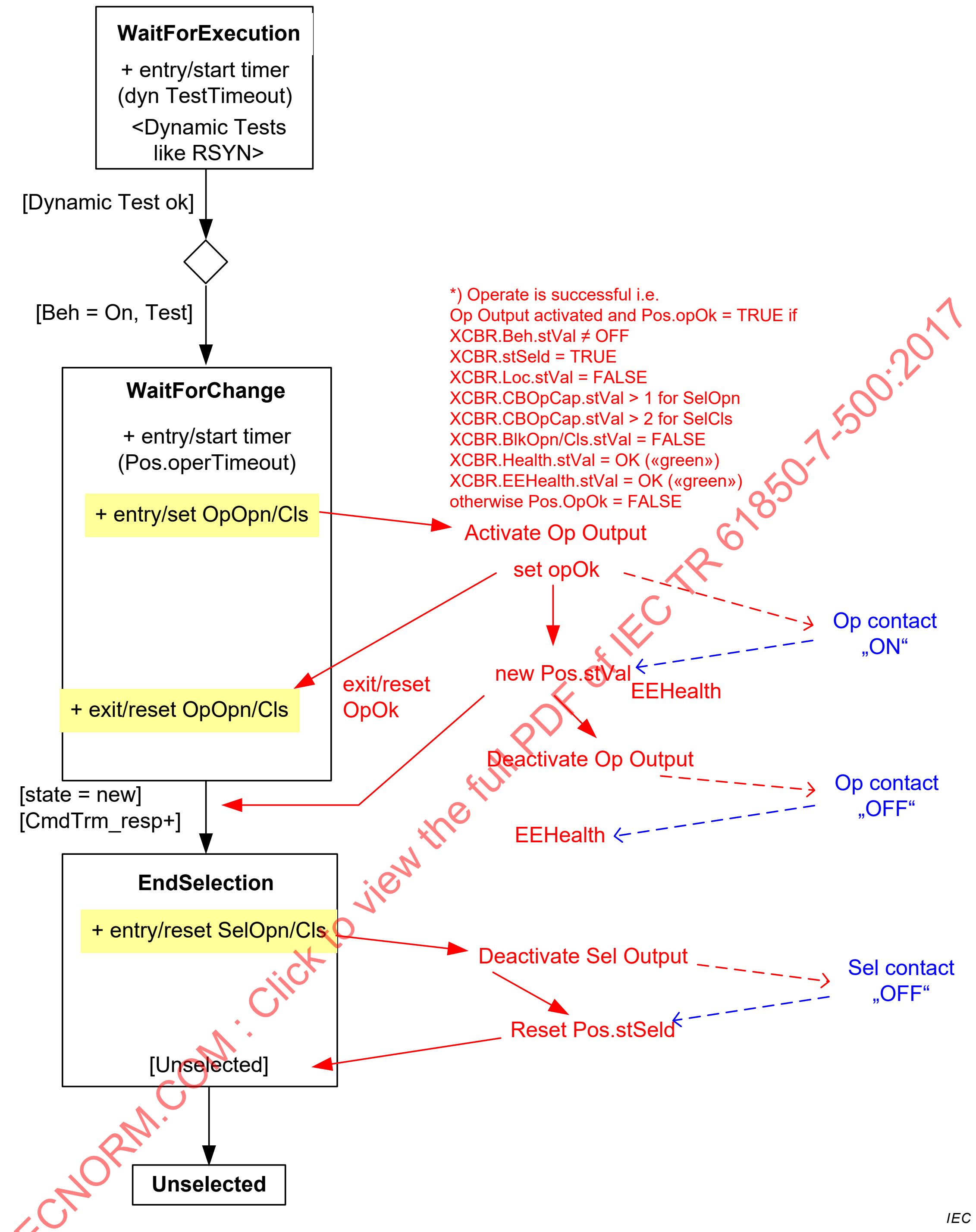


Figure 22 – Switch control (SBO with enhanced security) with a sequence of GOOSE control messages between BCU (“CSWI”) and CBC (“XCBR”) – Part 2

- In case of a positive selection by the GOOSE control message, the attribute Pos.stSeld will change from “False” to “True” and a GOOSE message to the BCU (CSWI) may be issued [SelVal resp-].
- In case of a negative selection by the GOOSE control message, the attribute Pos.stSeld will not change from “False” to “True” and no data change may issue a GOOSE message to BCU (CSWI). In that case the BCU needs to wait for a "Selected timeout” triggering a GOOSE message with the Pos.stSeld = “False” to BCU (CSWI) [SelVal resp-].
- This time is a local issue.
- In case the IHMI exceeds the SBO timeout the BCU will reset the CSWI.Pos.stSeld and the XSWI.Pos.stSeld will follow.

The electronic part of the command is supervised down to opOk. Finally, a negative acknowledgement of the control command (OpOpn/Cls) may be caused by a maloperation of the external power system equipment like the circuit breaker or missing control voltage. In this case the EEHealth.stVal shall be set to “alarm” according the definition of the attribute EEHealth.stVal in CBC to be IEC 61850-7-3. If intentionally configured, the change will create a GOOSE message and sent to the BCU.

Generally, this extension of the control service by GOOSE messages over the process bus refers to service parameters and model data which are changed by such a control. The control service and, therefore, also this extension may be applied to all data which may be changed from remote i.e. data objects (DO) with a common data class (CDC) ending with C for remote controllability (SPC, DPC, etc.). Other data which are reported normally are not included.

11.6.4 Alignment of the control model in CSWI and XCBR

All controllable data objects have a mandatory configuration attribute ctlModel with values like direct control, SBO, SBO with enhanced security etc. Only one value shall be selected at engineering time. The command service shall match this control model. Otherwise, the command shall be rejected.

By the process bus the control is implemented by GOOSE messages. The simplest modelling would be to extend the complete control service parameters from the CSWI to the XCBR by sending and receiving the appropriate GOOSE messages. This means providing all values by appropriate DOs (see use case above). The simplest case is when any control command is checked at CSWI level for acceptance and then send over a GOOSE message similar to direct control. Whatever is implemented, at engineering time the value sent by CSWI and the value expected by XCBR and reverse shall be in line. It shall be considered that SelOpn and SelCls are optional.

11.6.5 Behavior “Blocked” and “Testblocked” in case of process bus

In case of the process bus, the Mod/Beh “Blocked” and “Testblocked” are applied to XCBR and need – if the conventional test plugs should be avoided – the optional DOs opRcvd, opOk and tOpOk. To be prepared for advanced test concepts without HW manipulations, it is recommended to implement these three DOs with the XCBR i.e. in the process near IEDs.

12 Protection

12.1 Bay protection without process bus

12.1.1 Basic diagram

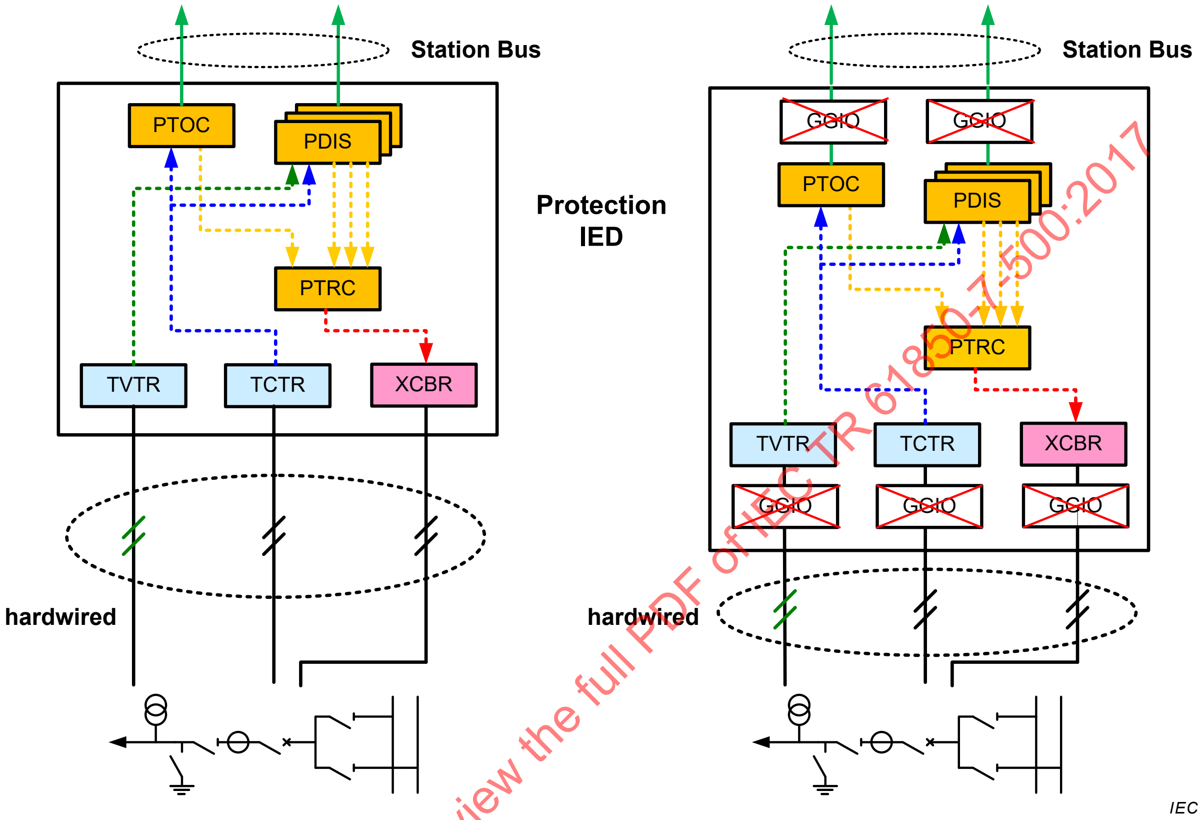


Figure 23 – Bay protection without process bus (left: modeling = ok, right: modeling = wrong)

The bay protection (Protection IED) is connected to the station level and other bays (if applicable) by the station bus providing communication over Ethernet as shown in Figure 23. The bay protection is hardwired (parallel copper wires) to the switchgear (process). External process states and measured values are converted to data according to the IEC 61850 data model in the Protection IED. Therefore, the boundary LNs are all in this IED. The switchgear is shown as single phase switches. The three phase case as normal is described in 12.1.2.

12.1.2 Modeling rules

Both the general modelling rules, the dedicated modeling with process interface nodes and the role of GGIO are the same as described in 11.1.2 and 11.1.3.

The general conclusion is that all boundary LNs starting here with T and X should be present also without the process bus. This refers also to the T nodes if the samples are stay contained in the IED. One specific example in addition to EEHealth and EEName is the fuse failure of the instrument transformer for voltage (TVTR) which shall be modeled according to the modelling rules in IEC 61850-7-1 by the TVTR.FuFail defined in IEC 61850-7-1 and not by using GGIO.

It should be noted that between the switchyard equipment and any defined functional boundary LN there is no GGIO allowed (see definition of GGIO in IEC 61850-7-4). The GGIO may only be used as generic boundary node like and X node if there is no applicable boundary node defined in IEC 61850-7-4. The same is valid at the station bus where the datasets e.g. for the GOOSE messages may not built with data from intermediate GGIOs but directly by data sets referencing to the data or attributes of the functional defined Logical Nodes.

12.2 Bay protection with process bus

12.2.1 Basic diagram

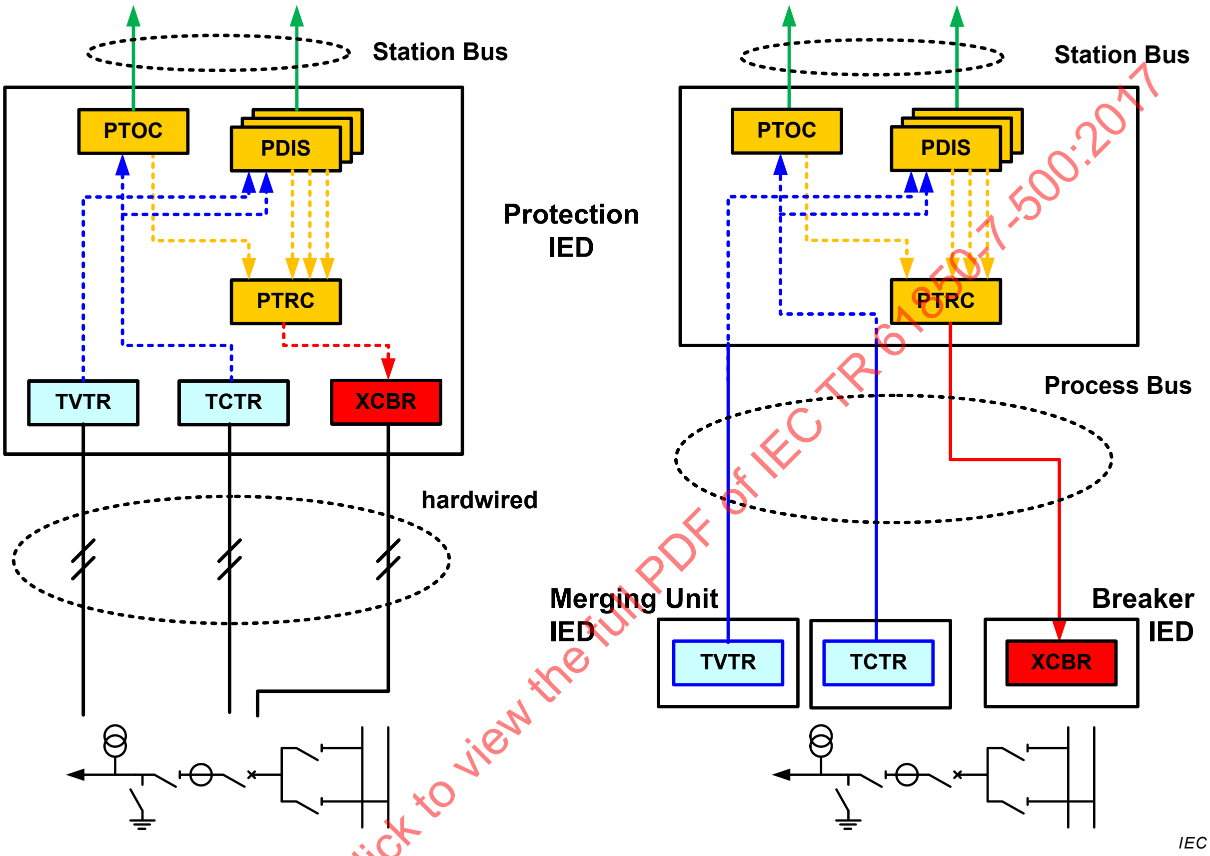


Figure 24 – Bay protection (left: without process bus, right: with process bus)

This also facilitates the modeling of the bay control with process bus as seen in Figure 24. All boundary LNs reside in dedicated IEDs i.e. in a Breaker IED (CBC) respectively in Switch IEDs (DCC). Whether these are dedicated per switch or combined as switchgear interface is an implementation issue outside the scope of this document. All other comments such as regarding GGIOs are valid also for control modeling with process bus. Especially, the boundary LNs (T…, X…) shall be in the process near electronics (Switch IEDs, Merging Unit).

12.2.2 Modeling protection of three-phase system

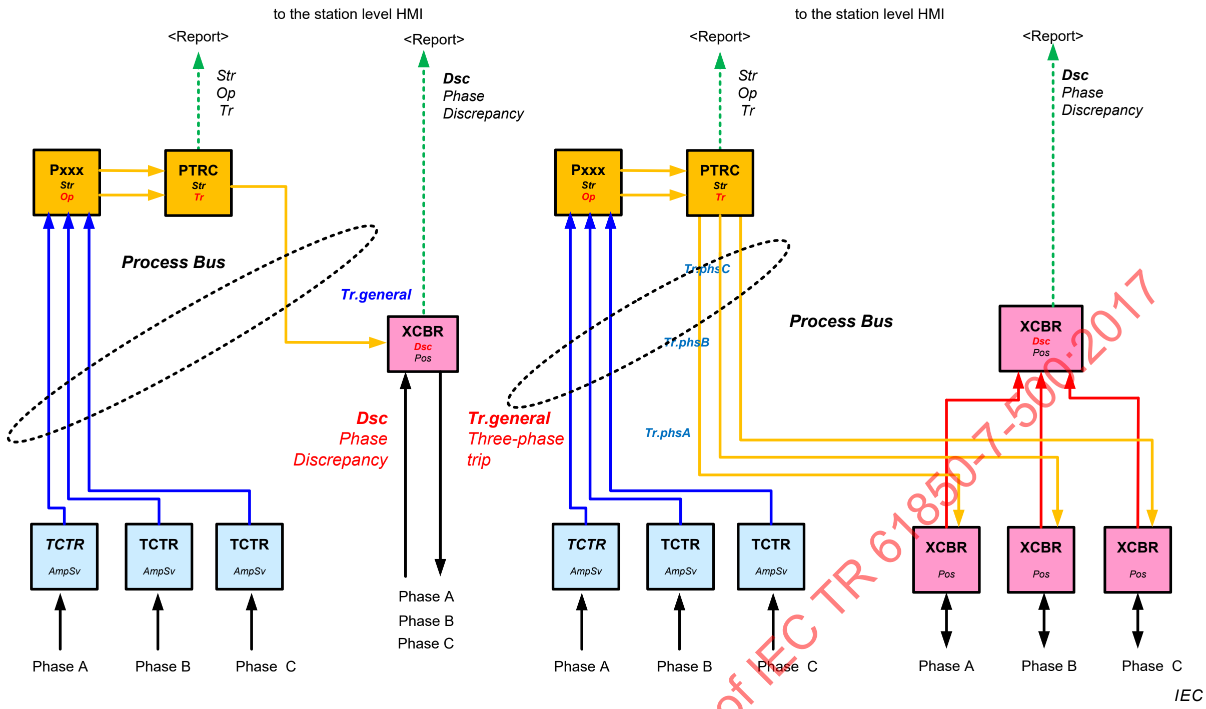


Figure 25 – Three-phase trip (left) and single-phase trip (right) with process bus

Currents (TCTR) and voltages (TVTR) are measured per phase. In Figure 25 only current measuring is shown. Based on currents and voltages (if applicable) protection functions issue a trip via PTRC in case of a fault. In normal switches especially at low voltages, all three phases are tripped together having a common trip mechanism. The modeling may be done with one XCBR but a potential phase discrepancy shall be announced from outside. Advanced switches, especially at higher voltage levels may be tripped per phases i.e. only the faulty phase is tripped. The protection, respectively PTRC, may send out a trip command with the attribute "general" or "phsA/phsB/phsC". In this case, there is one XCBR per phase and a common one. The phase discrepancy is calculated by this common XCBR based on the positions per phase.

If the trip is not conventionally hardwired, it is sent over the process bus in a GOOSE message for performance reasons. With process bus, the data are exchanged most conveniently by GOOSE messages.

Without process bus, all LNs shown in the Figure above are in one IED and their internal connections are out of the scope of IEC 61850. Nevertheless, the indication of internal links between the LNs in one IED may facilitate the understanding of modeling and the steps towards a distribution to more IEDs as e.g. needed for the implementation of process bus.

12.3 Modelling of a protection function by multiple instances

12.3.1 PDIF

The current differential protection is acquiring the instantaneous current values at the border of the protected object e.g.

- at both or multiple line ends for the line differential protection
- at both voltage levels for the transformer differential protection
- at all bays of the busbar for busbar differential protection

For local objects like transformer protection the function may be modelled by one LN PDIF which gets its currents from the TCTRs per phase and where the function is tripping in the same op step the breakers on both sides of the local object (PDIF.Op, PTRC.Tr, XCBR).

The related LNs PDIF at the border of the protected object are hosted at least for extended objects like lines in different IEDs which are connected by communication according to IEC 61850 (see also PDIS). The currents from the other end are provided by the LN RMXU. The trip decision (PDIF.op, PTRC.Tr) is done in parallel on both sides. The comparison of current samples from two different IEDs requests synchronized sampling with a time accuracy in the range between 1 µs (see IEC 61850-5) and 4 µs (UCA Users Group recommendation).

A use case of a line with 3 ends (T line) is given in Figure 38.

12.3.2 PDIS

The distance protection calculates the fault impedance by acquiring voltage and current locally by TCTR and TVTR per phase. The calculation of impedance from of current and voltage samples taken from two different IEDs requests synchronized sampling with a time accuracy in the range between 1 µs (see IEC 61850-5) and 4 µs (UCA Users Group recommendation).The settings make the distance protection sensitive for different distances, i.e. protection zones. Every protection zone is modelled by one PDIS instance. The reach of the first zone may be a little shorter than the line length (underreach) or a little bit longer than the line length (overreach). There, the fault may be seen by more than one distance protection in one of its zones. To keep the selectivity, the PDIS from both sides will exchange operate, block, permit, activate and direct trip signals depending on the protection scheme which is modelled by the LN PSCH.

A use case with communication according to IEC 61850 between the line ends is given in Figure 39.

12.4 Modelling of different stages of a protection function by multiple instances

12.4.1 Different trip levels and curves shown by PTOC as example

Nearly all functions have configuration parameters, especially protection functions. It may be single parameters like delay times, groups of related parameters which guarantee the wanted behaviour, or tripping curves likes the inverse curves for overcurrent protection. The parameters for protection functions may be seen in IEC 61850-7-4 with the related attributes in IEC 61850-7-3. If the function is needed only with one parameter set at time and parameter switching is supported, one instance of PTOC is sufficient. Otherwise, different instances of PTOC shall be applied from the beginning.

12.4.2 PDSC – Phase discrepancy protection

Sometimes, only one single phase of the three phase system is operated e.g. in case of a single phase trip to keep synchronization and power delivery to some extent or in case of deicing. If different positions of the breaker of the phases happen unwanted *phase discrepancy* is announced. If this state persists for some time (e.g. 200 ms) a final trip shall take the breaker out of operation. The detection of phase discrepancy by the position of the switches may be verified also by comparing the currents in a three phases. The phase discrepancy protection scheme is shown in Figure 26.

NOTE Sometimes phase discrepancy is named misleadingly pole discrepancy or the complete function pole discordance protection. Poles are defined as two or more breaking contacts in series which may be needed to interrupt fault currents at very high voltage levels (i.e. two chamber breaker). If these breaking points are not in the same position, pole discrepancy is announced.

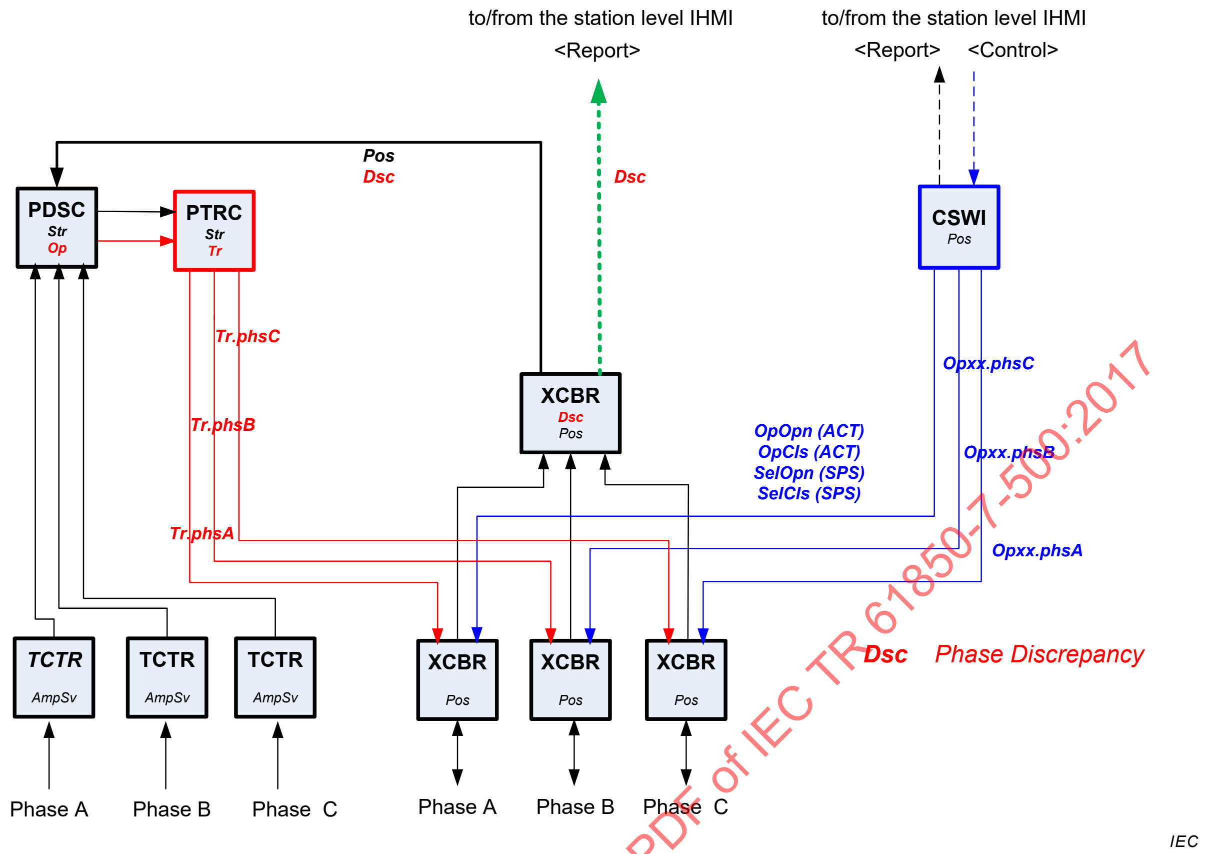


Figure 26 – Phase discrepancy protection

13 Redundant protection and control

13.1 Redundant protection

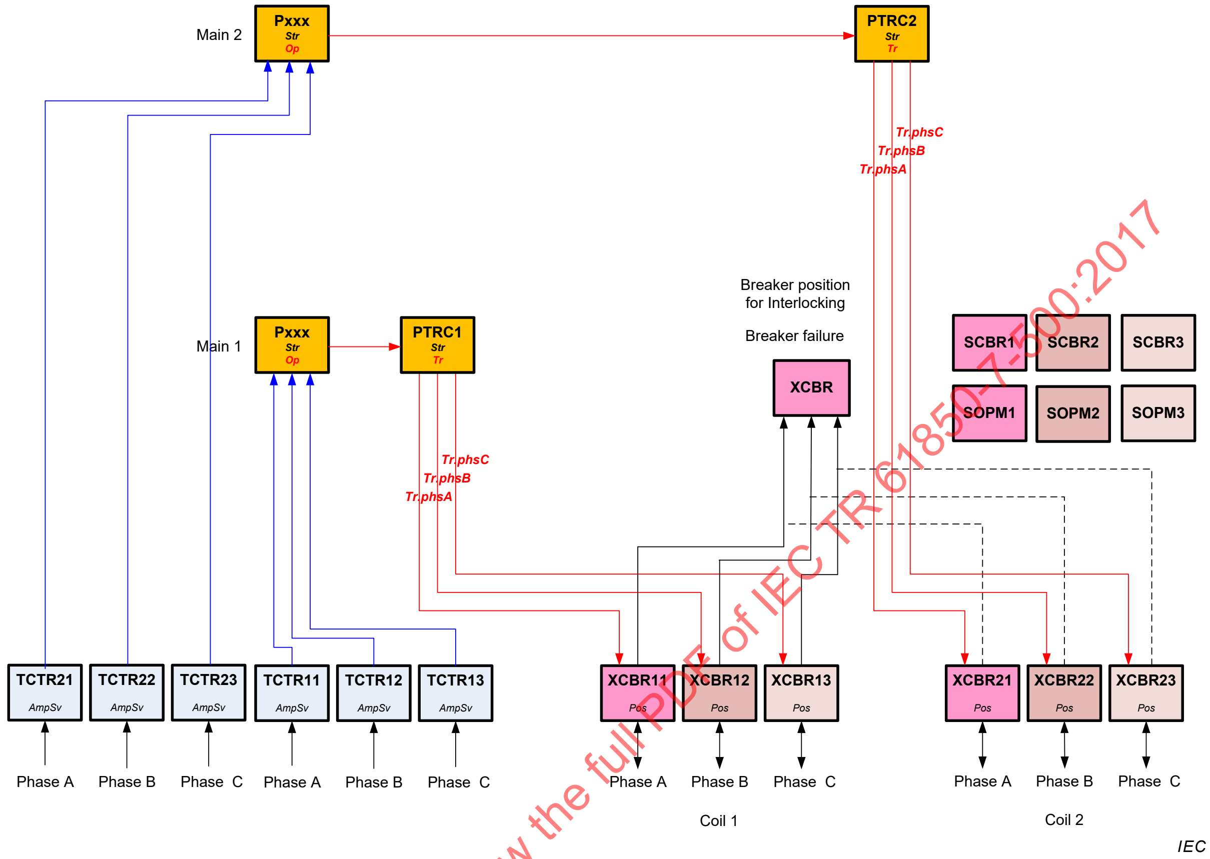


Figure 27 – Single phase tripping and supervision by main 1 and main 2 protection

“Redundant protection” means that two protections, normally named main 1 and main 2, are acting on the same circuit breaker. Both have their own set of instrument transformers i.e. in Figure 27 two sets of current transformers. This redundancy is not only a measure against losses but in case of different protection algorithms also an extension of the protected fault range. The redundant protections should be completely independent. Therefore, they act on their own trip coils at the circuit breaker. These trip coils per phase are represented by 6 XCBRs (11, 12, 13, 21, 22, 23). The 6 positions available by these XCBRs are combined to the single position in the breaker LN XCBR. This LN detects the phase discrepancy if there is any and provides otherwise a single circuit breaker position to any automation which needs such position e.g. for interlocking.

All the three phases of the circuit breaker have their own dedicated phase related breaker element supervised by SCBR (1,2,3) and their own dedicated drive mechanism supervised by SOPM (1,2,3).

13.2 Redundant control

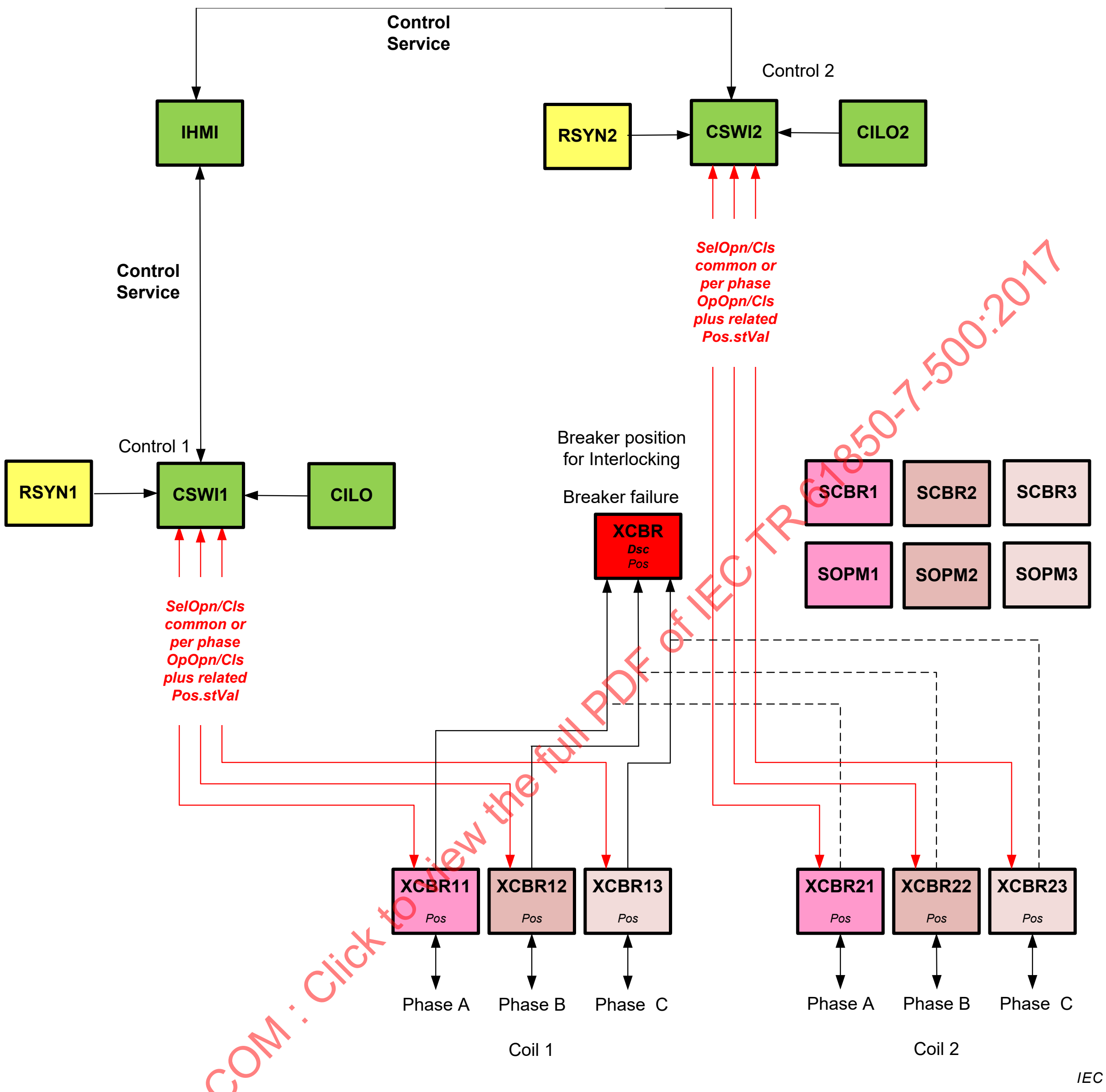


Figure 28 – Single phase redundant control

“Redundant control” means that two control functions as represented by CSWI1 and CSWI2 control the same circuit breaker. Both have a common IHMI as indicated in Figure 28. This redundancy is a measure against control channel losses. The redundant control should be independent from each other. Therefore, they act on their own control coils at the circuit breaker. These command coils per phase are represented by 6 XCBRs. The 6 positions available by these XCBRs are combined to the single position in the breaker XCBR. This LN detects the also the phase discrepancy if there is any and provides otherwise a single circuit breaker position to any automation which needs such position e.g. for interlocking.

Single phase control will be used by manual switching phased for de-icing and also by the single phase close command of the autorecloser RREC in case of single phase trips.

All the three phases of the circuit breaker have their own dedicated phase related breaker element supervised by SCBR (1,2,3) and their own dedicated drive mechanism supervised by SOPM (1,2,3).

13.3 Use of PTRC and testing

Most protection functions (LN Pxxx) provide in case of operation Start (DO Str) and Operate (DO Op) if applicable. All the Op are collected by the LN PTRC (named in Figure 29 PTRC1) which provides a common Trip (DO Str) for the circuit breaker. In addition, there is also a common Start (Str) and Operate (Op) as non-tripping information for other LNs and as information option for the HMI. The basic use of PTRC is shown in Figure 29.

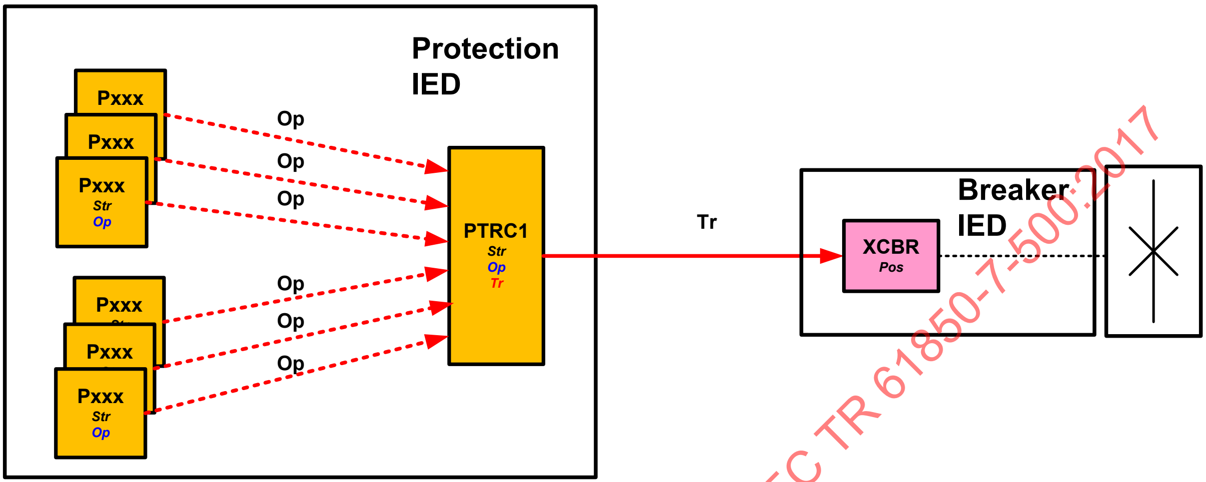


Figure 29 – Basic use of PTRC for protection tripping

Some protection LNs have a close relationship, especially the zones of the distance protection which are represented by one LN per zone. Therefore, the Op from all zones may be combined to a common Op i.e. by one dedicated PTRC (named in Figure 30 PTRC3). In addition, there may be other protection functions without a close relationship which sending their Op directly to PTRC1 (see Figure 30).

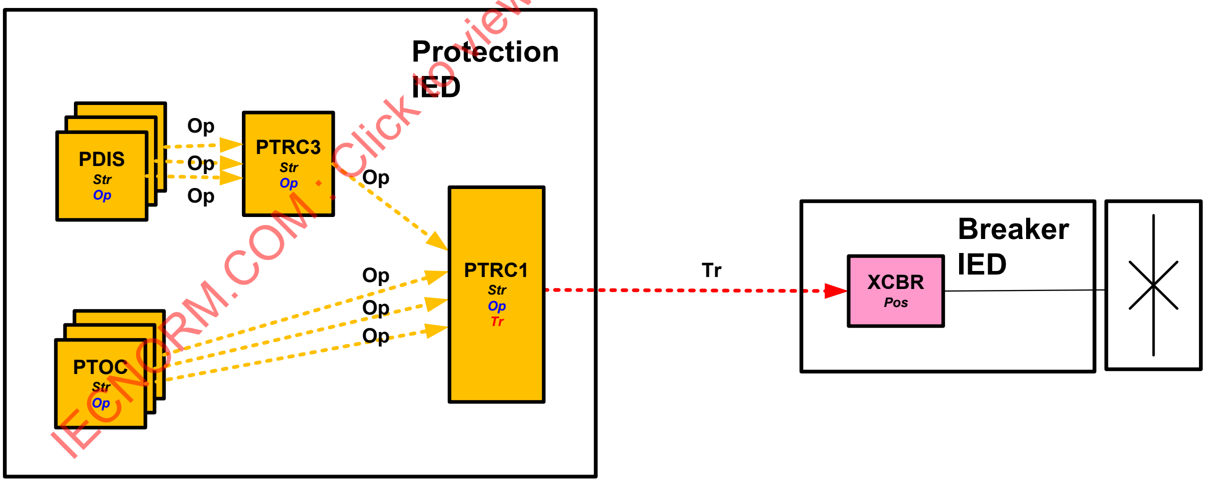


Figure 30 – PTRC used for grouping of closely related LNs

If all protection functions in one IED have to be tested together, the LNs shall be set by Mod (mandatory in the LLN0 of the Logical Device not shown here) in the Beh.stVal = “test”. If the circuit breaker is included in the test, XCBR shall be in the “test” mode also, otherwise or individually in the “test/blocked” mode to avoid issuing a trip to the circuit breaker and interrupting the power flow. It is not possible to test only one set of the protection functions and to leave the other in normal operation (“on”). If such an option is requested, two PTRCs as output of the IED are needed (see Figure 31).

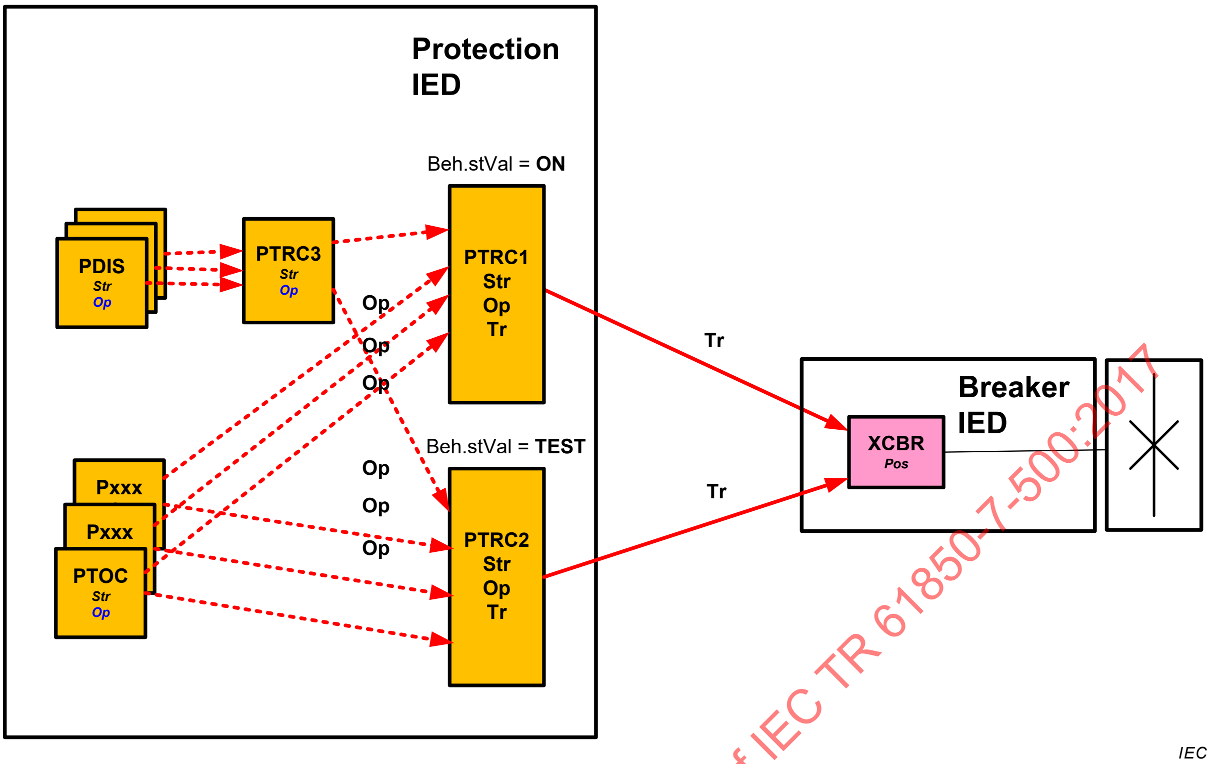


Figure 31 – Two PTRCs for partial testing of the protection functions

The principle is that all Op data will be sent both to PTRC1 (Beh “on”) and PTRC2 (Beh “test/blocked”). If the protection source or the PTRC3 is in Beh “on” it will send data with normal Op (test=”false”) which is processed by PTRC1 (Beh “on”) as valid and the circuit breaker will open (see Annex A of IEC 61850-7-4:2010).

If the source sends Op data with test=”true”, PTRC1 with Beh “on” would process it as invalid. Note: What “invalid processing” means is a local issue. To avoid in any case a trip by testing, the PTRC2 has to be in the Beh “test/blocked”. The split of closely related groups as defined by PTRC3 and test the components independently is not a meaningful use case. Finally, it has to be considered that the LN XCBR cannot show for some functions the Beh “on” mode and for some others Beh “test/blocked”.

14 Circuit breaker modelling by breaker related LNs (XCBR, SCBR and SOPM)

The modelling of a switch or here in the use case a circuit breaker by the LN XCBR per phase is applicable but needs some care since XCBR is not yet covering all details. A circuit breaker consists of 1 power switching contact per phase i.e. it provides one position indication (XCBR.Pos.stVal) but this contact is also ageing by abrasion caused by the switching arc (SCBR.AccAbr). Therefore the complete circuit breaker shall be modeled by 3 instances of XCBR in information direction. In command/trip direction, there are different options. Normally, a circuit breaker provides two trip coils/circuits (for main 1 and main 2 protection) and one close control coil/circuit. For the opening by control, normally one of the trip coils/circuits is used. If all three phases are strongly mechanical coupled, these three coils are valid for all three phases i.e. also for one common drive. Since these coils/circuits are not modelled in detail, the question remains: Is XCBR the circuit breaker or is XCBR the coil/circuit i.e. do we need three XCBR instances for one breaker? If the three phases are independent i.e. for single phase tripping we may need 6 instances of XCBR. What is the role of SOPM? Some examples are given already in Clauses 6 and 15.2 and also shown in Figure 27 and Figure 28. This pending issue will be resolved in the future (latest in the next edition of IEC 61850).

15 Dedicated functions

15.1 Disturbance recording

The disturbance recorder function as defined in IEC 61850-5 and modelled in IEC 61850-7-4 consists of an RDRE instance describing the recorder function with its settings and states common for the whole recorder and the RADR and RBDR LN instances representing a recording channel.

Each RADR instance refers to one analogue channel in the “IEEE Standard Format for transient data exchange (COMTRADE) for power systems” (see IEC 60255-24/IEEE C37.111:2013). Similarly each LN RBDR instance refers to one binary channel in the COMTRADE file format. This is the output of the recorder (accessible via MMS file services).

The trigger states of RDRE (status part of RcdTrg) and RADR or RBDR (ChTrg) are not independent. When the recorder is triggered via a control command to the RcdTrg DO at the RDRE LN instance, all channels shall reflect the trigger state in their RADR and RBDR instances via the ChTrg DO.

Because the resulting COMTRADE files shall contain all binary and analogue channels assigned to this recorder, also all channels shall be recorded, when one or more channels of the recorder are triggered by reaching its predefined trigger level. Also in this case, the recorder trigger state shall be reflected to the status part of the RcdStr DO in the RDRE instance and also to the ChTrg DOs of the RADR and RBDR instances representing the recorder channels.

When the central triggering via the RcdTrg DO of RDRE is applied, additional triggering via channel thresholds is only required in rare cases. Therefore ChTrg DOs of the channel LNs may be omitted, because the recorder trigger state is available at the RDRE LN.

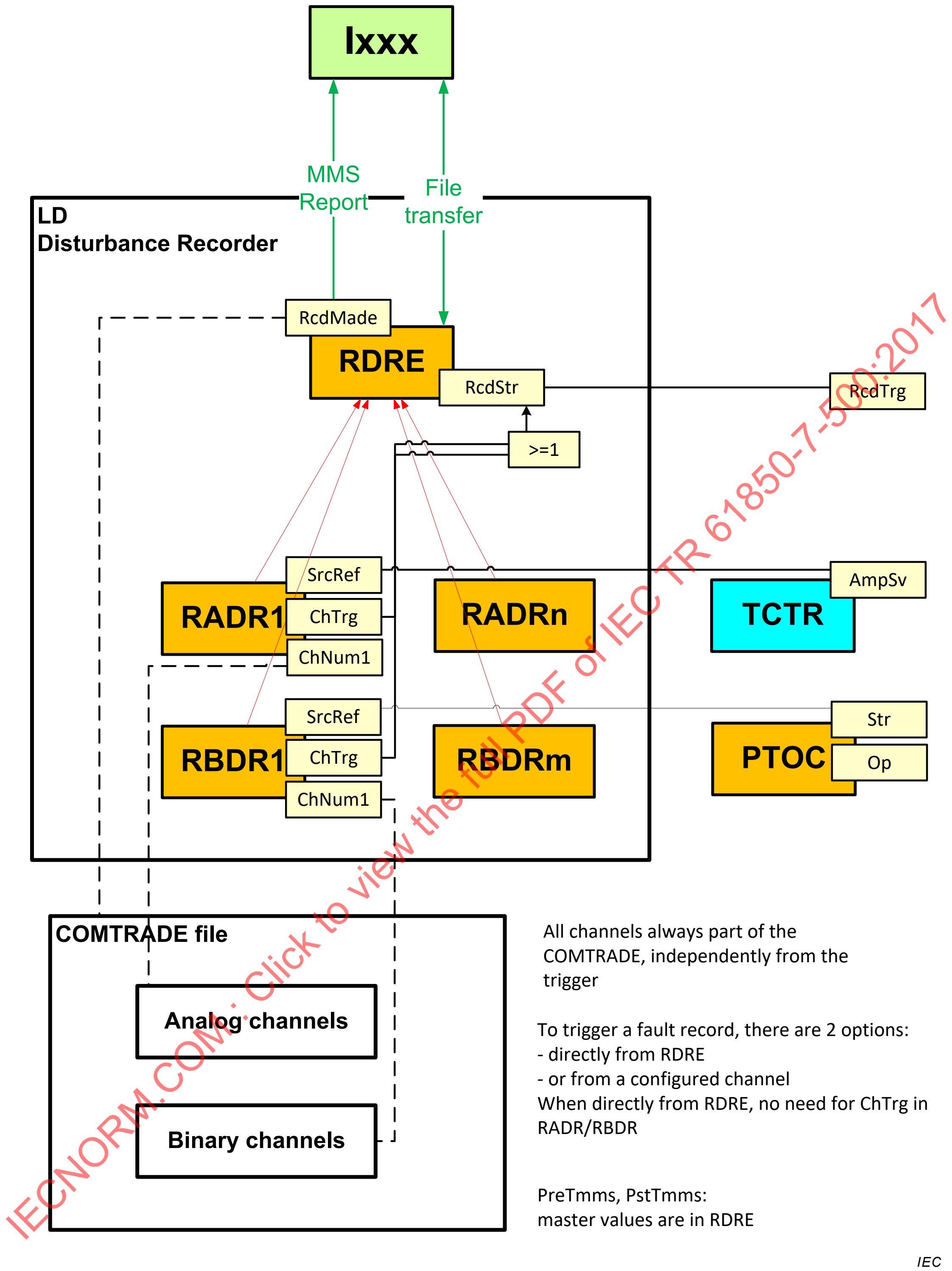


Figure 32 – Structure of the disturbance recorder (RDRE, RADR, RBDR)

Summary of the disturbance recorder (see Figure 32):

To start the fault recording, there are exist two basic options:

- trigger the channels directly from the RDRE
- trigger from a channels event (analogue limit crossing or binary signal change)

When directly triggered from RDRE, no need for a ChTrg in any RADR or RBDR.

Pre-trigger times and post-trigger times (PreTmms, PstTmms) are configured master values and are in RDRE.

Normally, all channels will be included in the COMTRADE file independently from the trigger which caused the recording.

15.2 Point-on-wave switching

Point-on-wave switching (also known as controlled switching or synchronous switching) means to open or close the circuit breaker at a predefined instant of time i.e. at a certain value of the sinusoidal current or voltage.

The most favorable moment of opening a circuit breaker would be at zero current facilitating the breaking of current. The similar situation exists for closing. The voltage differences should be minimum avoiding transient exchange currents (see inrush currents or loading current of idle GIS tubes). In this way expensive and critical closing resistors as used on the extra high voltage level may also be avoided. Other use cases are the closing of a shunt reactor or a capacitor bank.

The circuit breaker switching is based movement of contacts. Opening the contacts apart from current zero results in an arc which is extinguished at the next current zero. Closing a contact results in a decrease of the dielectric strength by decreasing distance of the contacts. Preignitions will occur always if the voltage across the contacts exceeds the actual dielectric strength. Regarding e.g. a 20 ms phase length for 50 Hz, the switching accuracy must be ≤ 1 ms. This accuracy requirement is less a challenge for the IED (software function) but more for the mechanics of the breaker.

If we neglect single phase tripping and de-icing operations, all three phases of the AC power system have to be opened or closed simultaneously. Regarding the phase angle difference of 120° between the phases it means that there is a time delay between the instant of the current extinction between each phase. The mechanical behavior may be influenced by the wear of previous operations, the time elapsed since the last operation the energy in the drive, the temperature in the drive and the breaker, by the gas density in the breaker chamber, etc. Depending on the mechanical design of the breaker and the different wear per phase, the behavior may be different for each phase regarding the requested high-precision timing.

The input is a command from the operator (or some automatics) and the continuously measured waves (current or voltage). The output is the timed command referring not only to the point on wave but also to the delay between issuing a command and the actual mechanical opening or closing of the breaker contacts. Because of the high precision operation, the application of LNs and services needed depend on the *implementation*.

If the point-on-wave switching controller is realized within one IED (IED1, see Figure 33) the sampling (TCTR, TVTR), the command time calculation (CPOW) and the issuing of the command (CPOW → XCBR) is an internal task. Both for the OpOpn* and the OpCls* issued by CPOW the * indicates the use of optional time stamp attributes (operTmPhsA, operTmPhsB and operTmPhsC) in the CDC ACT. Interlocking (CILO) and Synchrocheck (RSYN) may also be implemented in the same IED1. The voltages, the currents and the operate output are hardwired. Interoperability is not an issue.

If the waves (current or voltage) are coming over the process bus, the IED2 may contain the MU providing synchronized samples (precision time protocol, PTPI) and the IED1 only the point-on-wave switching controller without sampling (Figure 34). The commands are time-synchronized referring to the incoming samples. An alternative would be for the controller to also get the PTP time signal for synchronization.

Using both for the wave sampling (TVTR, TCTR) and for the circuit breaker (XCBR) the process bus with dedicated IED2 and IED3 in addition to IED1 (Figure 35), all these three

IEDs shall be synchronized by PTP. For this use case also interoperability shall be provided since all IEDs may come from different suppliers.

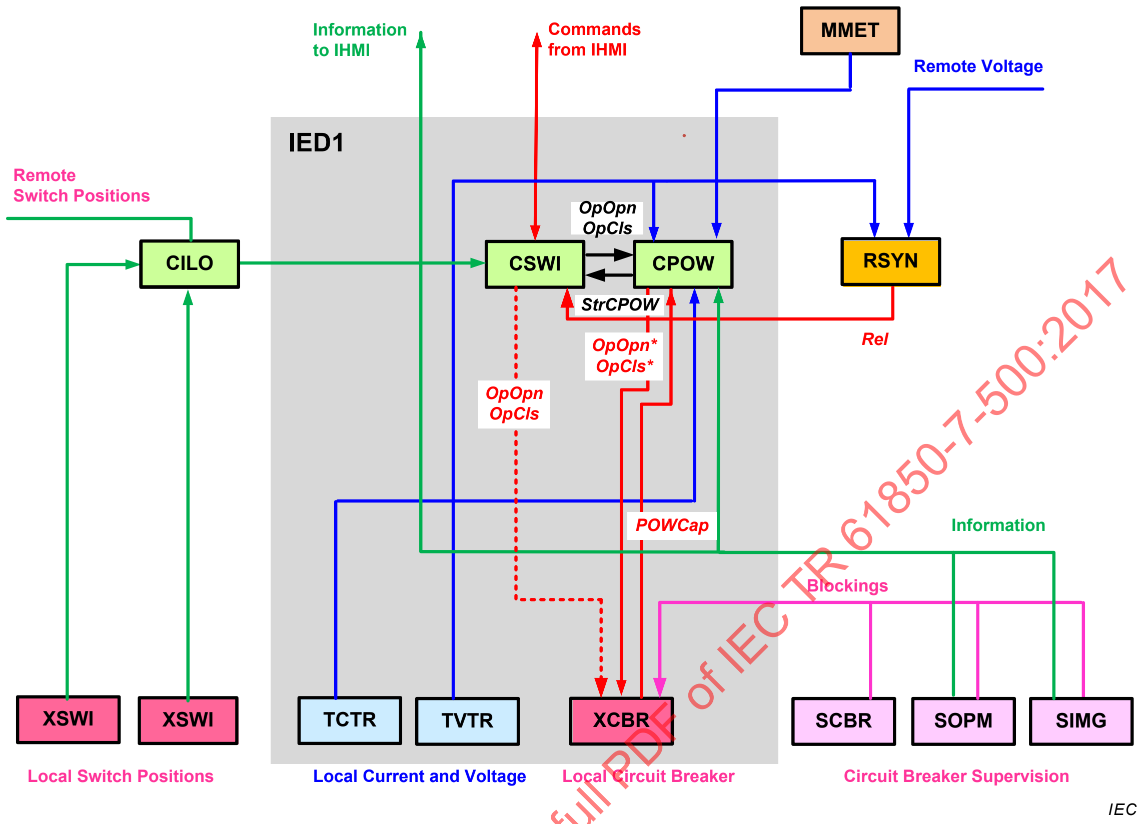


Figure 33 – Point-on-wave switching with all LNs needed in one IED (IED1)

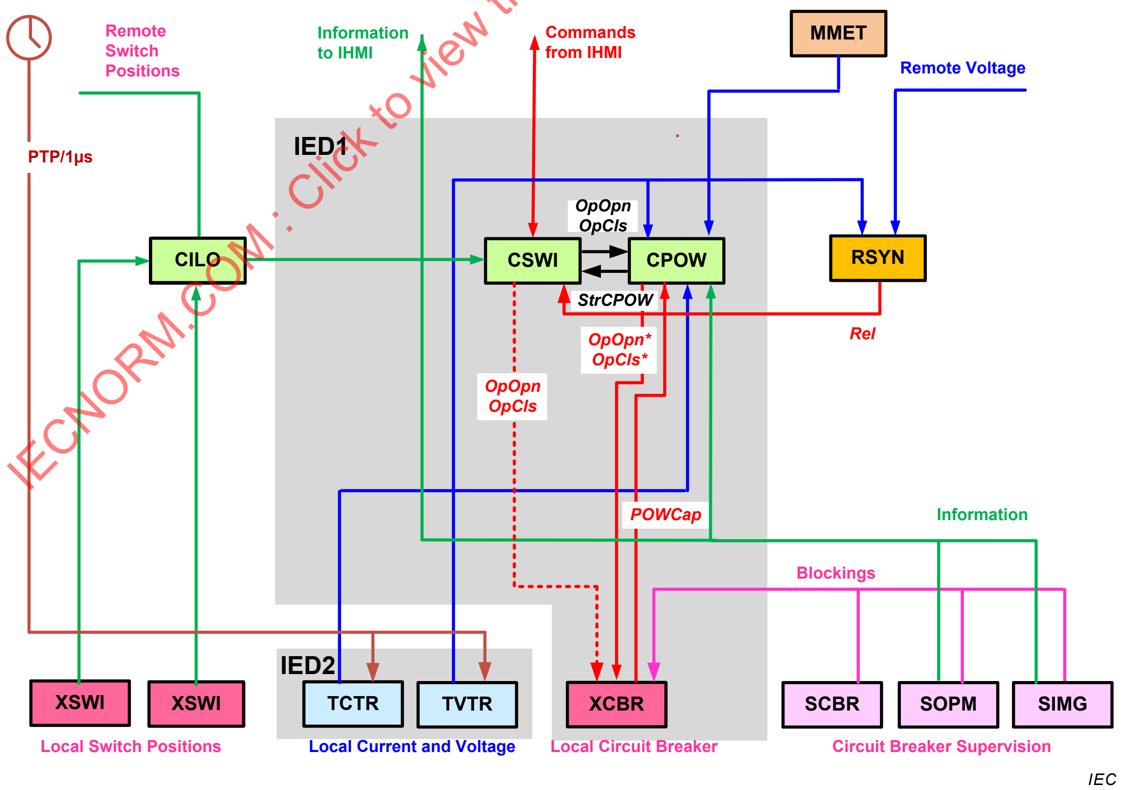


Figure 34 – Point-on-wave switching with Merging Unit (MU) in IED2

For precise point-on-wave switching the “waveforms” of voltages or currents (TVTR, TCRT) for all three phases have to be measured respectively synchronous sampled with an accuracy of about 1 µs requesting PTP in case of using the process bus. For the calculation of the correct start of the breaker drive the appropriate supervision data from all three phases of the breaker have to be provided (XCBR, SCBR, SOPM, SIMG). Depending on the CPOW algorithm not all data may be used respectively subscribed. It should be noted that the sensor information (Sxxx) may be used for direct blocking of the XCBR but also for the CPOW for calculations if applicable. Note that missing data may be added by new DOs in the existing LNs or by new Sxxx LNs in future versions of IEC 61850-7-4. Last not least the actual point-on-wave switching capability of the circuit breaker (XCBR.POWCap = 1"None"/2"Close"/3"Open"/4"Close and Open") has to be known. The Supervision LNs may also be implemented with the XCBR in IED3 as indicated in Figure 35.

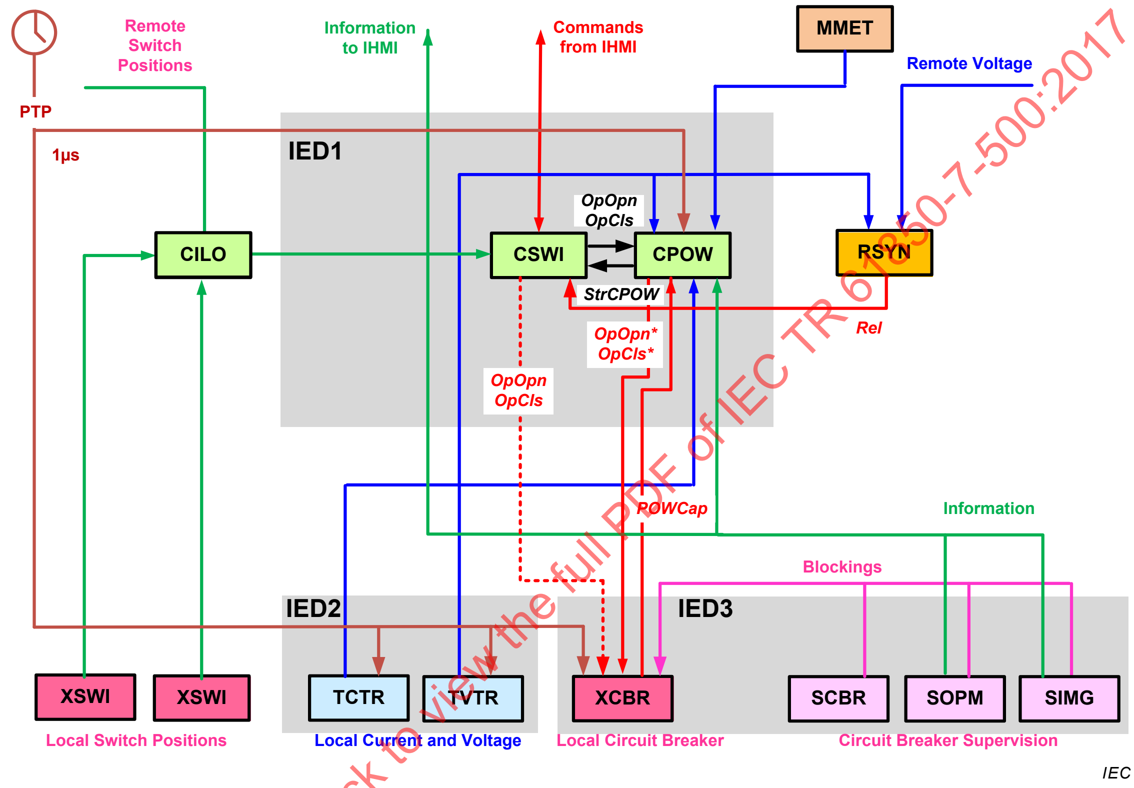


Figure 35 – Point-on-wave switching with process bus and time synchronization

The select command is issued by the operator (IHMI) and sent to the CSWI where the interlocking and other conditions applicable are checked. If released by the checks CSWI shall send SelOpn or SelCls to CPOW. If the CPOW is not active between the operations, its start is confirmed by StrPOW. If the CPOW function is continuously running a "ready" signal from CPOW informs CSWI that point-on-wave switching is possible. StrPOW may also contain the ready information if no dedicated "ready" is available. Then CSWI confirms the selection. Otherwise, the operator gets a negative acknowledgement with an appropriate AddCause. Then the operate command is issued by the operator (IHMI) and sent to the CSWI where the interlocking and synchrocheck is re-checked. If released the operate command from the IHMI is forwarded to CPOW and performed there and sent directly to the circuit breaker XCBR. If there is an issue during the processing by CPOW it will send a "block" to CSWI.

To perform an operation at the requested point on wave, the operation shall be initiated at an absolute time calculated by CPOW based on the time used for synchronized samples. Therefore, PTP shall be provided by the master clock not only for IED2 (TVTR and TCTR) but also for IED1 (CPOW) and IED3 (XCBR).

Such a facility with a command for predefined time is provided by the service "time activated operate" but the use of this service requests a client-server connection between CPOW and XCBR. The "time activated operate" service may be extended by GOOSE messages over the process bus similar to the non-time activated one. The OpOpns and OpCls issued by CPOW both of CDC ACT shall be sent by a GOOSE message with the optional DAs operTmPhsA, operTmPhsB and operTmPhsC (activation times) of time stamp format.

15.3 Breaker failure protection

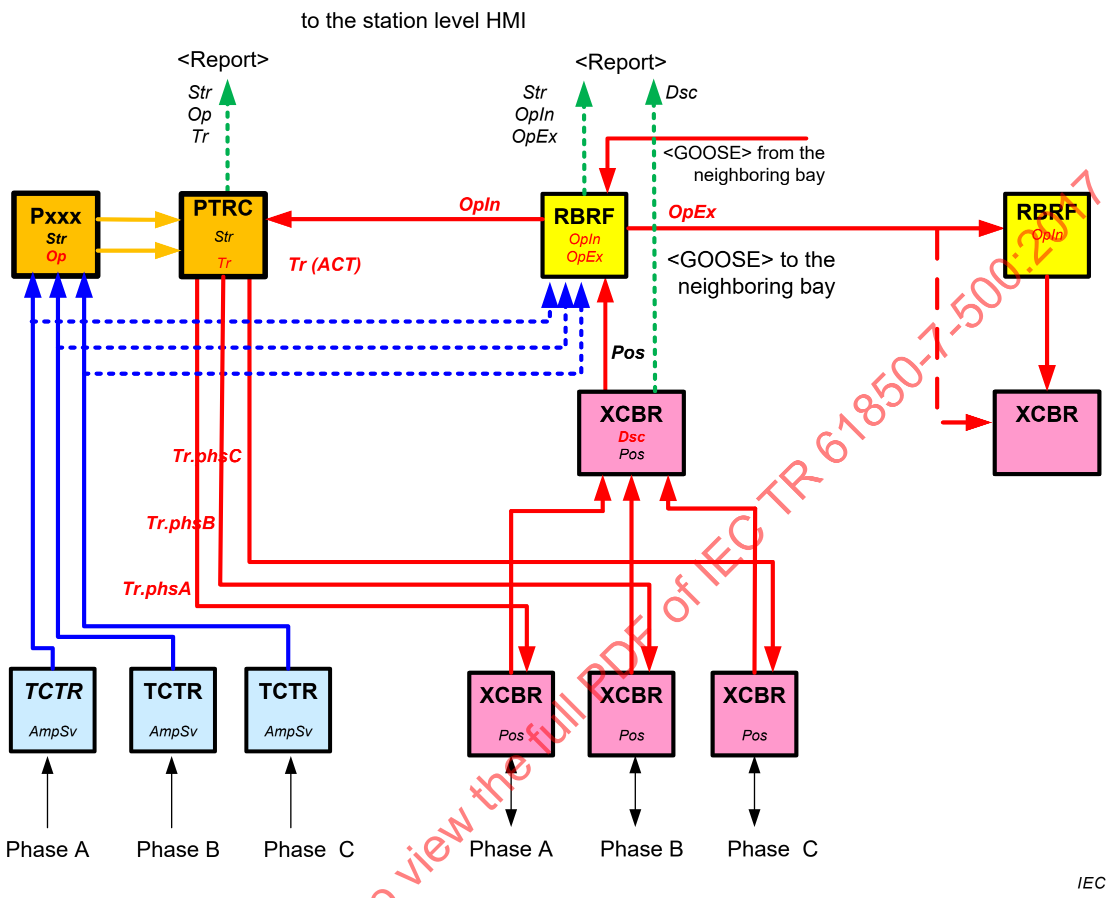


Figure 36 – Single and three-phase tripping and breaker failure protection

Since also in three-phase breakers differences in the pole positions per phase may happen, the modeling of supervision requests three instances of XCBR. The common XCBR reports the phase discrepancy if any. The trip may be performed for all three phases (three-phase trip) or per phase (single phase tripping), which is very common at higher voltage levels e.g. to keep the power system synchronization.

If the Pxxx and PTRC are together with the XCBRs implemented in one IED, a virtual link between the common XCBR and the XCBRs per phase may be programmed and a three-phase trip may be performed via the common XCBR. In case of an intermediate process bus GOOSE messages have to be used. All three phase-related XCBRs shall subscribe the GOOSE message for the general trip with the following attributes if applicable:

PTRC.Tr.general = TRUE

For a trip per phase the “general” is replaced by the phase designation i.e. PTRC.Tr.phA = TRUE or PTRC.Tr.phB = TRUE or PTRC.Tr.phC = TRUE shall be used.

The breaker failure protection RBRF is started by a protection trip and supervises if the breaker really trips. This can be done by several means depending on the implementation:

- supervision of XCBR.Pos
- supervision of (fault) current

- other DOs from XCBR (EEHealth.stVal = Good, BlkOpn.stVal = FALSE, etc.)
- information from other supervising LNs like SOPM, SCBR, SIMG, etc.

If it detects a breaker failure, it first tries a bay local retrip via its data object OpIn, which might use the existing PTRC (if in the same IED as protection), but also go directly to the XCBR respective another XCBR instance belonging to the same circuit breaker.

In case the local retrip was also not successful, the RBRF.OpEx is used to trip all other breakers in the same zone. To get a fast and reliable external trip, this signal shall be distributed with GOOSE messages according to the related performance class in IEC 61850-5. The principle data flow is also shown in Figure 36. The OpEx may go directly to the neighboring XCBRs, however to have an easier implementation of zone concatenation in systems with process bus, it is recommended to handle the OpEx in the RBRF of the neighboring circuit breaker producing a OpIn in the related neighboring XCBRs

Note that for the zone determination the state of the busbar disconnectors needs to be known. The detailed algorithms and architectures here are implementation dependent. In case of a line protection, the OpEx might also be sent to the other side of the line, or be used to trigger the teleprotection direct trip.

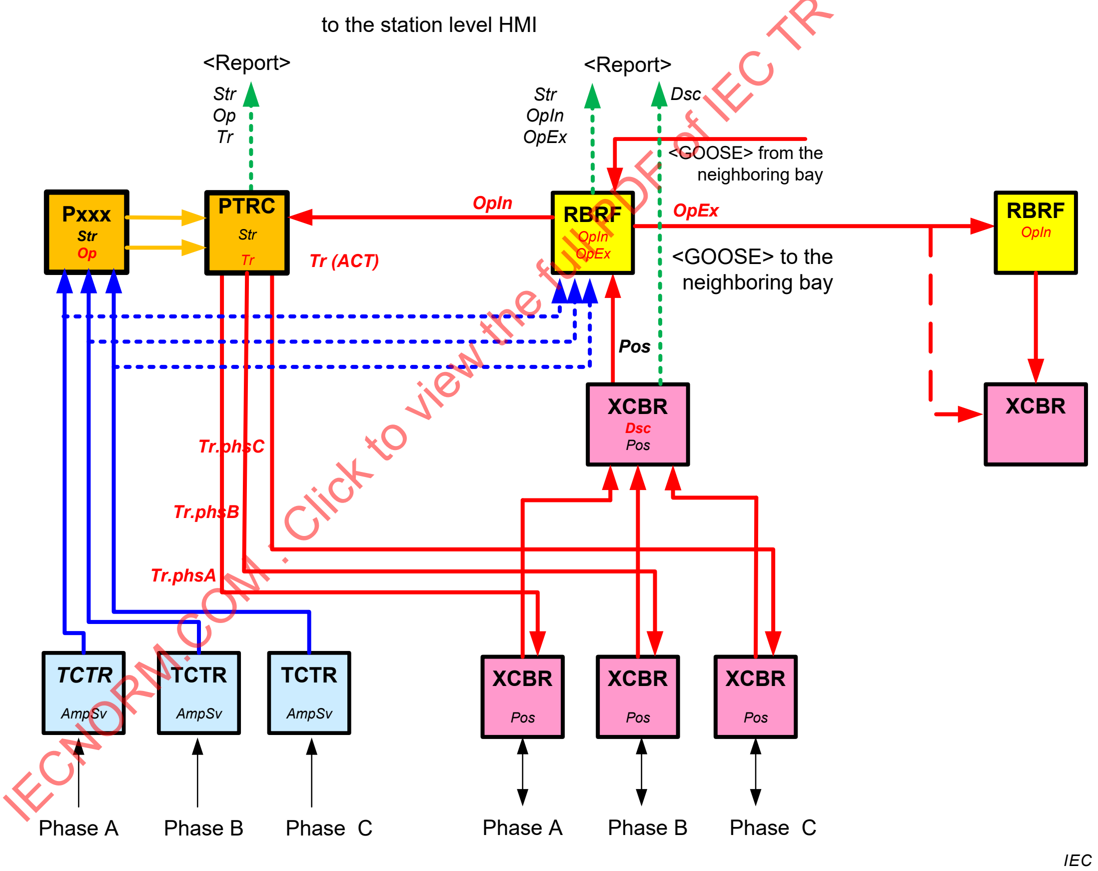


Figure 37 – Single phase tripping and breaker failure protection in a double tripping coil application

For highest reliability in HV substations, protection functions are either combined or more often separated in different devices (Main 1, Main 2, Backup) along with the user preference. Two sets of tripping coils are used, together with Single phase operated CB.

In the above use case Main 1 and Main 2 protection functions are assumed to be combined in one device, acting through PTRC1 and PTRC2 onto separate tripping coils of the same CB. XCBR11, XCBR12, XCBR13 and a common XCBR1 is the phase segregated modeling for the first set of coils, whereas XCBR2x models the CB as referring to the second set of coils.

Control and position monitoring of the CB from the station level HMI is done through a single CSWI1. The naming convention of the LN instances as shown here is an example only for better understanding the modeling.

Further CB outside of the actual HV bay (e.g. the downstream CB in a transformer application) are tripped through electrical contacts of the Main 1 IED. Here a CB is modeled as XCBR3, its tripping is conditioned in PTRC3.

For a better understanding a single breaker failure protection RBRF1 is shown; in reality Main 2 protection is equipped with an RBRF2.

After a trip initiated by the Main 1 protection, PTRC1 triggers the breaker failure protection RBRF1 which supervises the correct operation of the CB opening using an undercurrent element and/or the position indication (depending on the related protection function). If it detects a breaker failure, it first tries a bay local retrip by activation of the second set of trip coils via its data object OpIn directly on XCBR2.

As for Figure 37, in case the local retrip was also not successful, the RBRF.OpEx is used to trip all other breakers in the same zone by GOOSE messaging. In addition, OpEx is causing a direct trip of a downstream XCBR3 to prevent damaging of the protected object by a power-up from the MV side.

15.4 Line differential protection

The current differential protection (LN PDIF, one instance per phase) checks that the currents on both or more sides of the protected object are the same disregarding the sign, i.e. under no fault conditions the sum of the currents is zero according to the Kirchhoff law. The use case shown in Figure 38 refers to a three end or T-type line. However if there is a fault some current may be drained off and the sum is not anymore equal zero. Since this is a direct comparison of measured values, the current differential protection is very sensitive and fast,and the trip happens without delay i.e. there is no start but only a PDIF.Op, respectively a PTRC.Tr. Since the measurement is made on the border of the object i.e. the line for line differential protection, this protection is very selective. The measurement and fault detection is made per phase. All current *samples* are transmitted and compared per phase. Regarding the communication delay it means that the samples shall come from the same instant in time i.e. as result of synchronized sampling typically supported today by GPS clocks. The legacy solution is a hand-shake mechanism synchronizing the ends. Instead of samples phasors may also be calculated and transmitted out of some set of samples which needs less bandwidth but reduces also the performance. The data sent to the other side are defined by the LN RMXU. The teleprotection interface represented by the LN ITPC allows besides supervision the sending of the content of the SV or phasor stream message also over an existing channel. The modelling approach was described in [4] and is integrated in the second editions of the IEC 61850 series.