TAMPEREEN TEKNILLINEN YLIOPISTO

JUKKA PIIRAINEN

APPLICATIONS OF HORIZONTAL COMMUNICATION IN INDUSTRIAL POWER NETWORKS

Master of Science Thesis

Examiner: professor Pekka Verho
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ABSTRACT

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The amount of information generated in substation automation systems has grown exponentially since the introduction of Intelligent Electrical Devices (IED). Until recent years substation communication between IEDs was realized with proprietary protocols. This led to communication problems in systems with IEDs from different vendors. The IEC 61850 standard was introduced in order to harmonize substation communication and gain interoperability.

The IEC 61850 is an international standard defining communication networks and systems in substations. The standard defines substation functions, communication services and communication between devices as independent units. Thus the standard provides an opportunity for redefinition if technology in one area develops. The standard divides substation communication into three levels. This study focuses on horizontal GOOSE communication between IEDs in bay level and its applications. Horizontal communication has conventionally been solved by hardwiring required information between devices. GOOSE communication enables the transmission of these signals via Ethernet network, therefore creating a system that is more easily expandable and reducing the need of hardwiring.

The purpose of this work is to provide information for ABB Process Industry Plc concerning IEC 61850 and GOOSE. The substance of IEC 61850 and horizontal communication are presented in the theory chapters. The applications of GOOSE were examined in order to get more practical results. The applications were selected based on the capabilities of recently introduced REF615 IED. Each application is first described in general, followed by an example solution with REF615 IEDs. A fault arc protection application was selected for further testing based on an upcoming customer project. This application was configured between two REF615 IEDs and the functionality of the application was confirmed before the customer project was initiated.

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Sähköasemien tuottaman informaation määrä on kasvanut merkittävästi älykkäiden toimilaitteiden (IED) tultua markkinoille. Viime vuosiin asti sähköaseman laitteiden kommunikointi on toteutettu valmistajakohtaisia protokollia käyttäen, jolloin eri laitevalmistajien laitteiden välinen kommunikointi on ollut hankalaa toteuttaa. Tiedonsiirron yhdenmukaistamiseksi ja eri valmistajien laitteiden yhteentoimivuuden saavuttamiseksi esiteltiin IEC 61850 standardi.

Kansainvälinen IEC 61850 standardi määrittelee tiedonsiirtoverkot ja -järjestelmät sähköasemilla. Standardissa sähköaseman toiminnot, kommunikaatiopalvelut ja laitteiden välinen kommunikaatio on määritelty kukin erillisenä kokonaisuutena. Täten standardi tarjoaa mahdollisuuden uudelleenmäärittelyyn, mikäli teknologia jollakin osa-alueella kehittyy. Sähköaseman kommunikaatio on standardissa jaettu kolmeen tasoon. Tämä diplomityö keskittyy kenttätason horisontaaliseen GOOSE kommunikaatioon ja sen sovelluksiin. Perinteisesti horisontaalinen tiedonsiirto on ratkaistu johdottamalla tarvittavat tiedot laitteiden välillä. GOOSE kommunikaatio mahdollistaa tilatietojen siirtämisen Ethernet-verkkoa pitkin, jolloin johdotuksen tarve vähenee ja järjestelmää pystytään tarvittaessa helpommin laajentamaan.

Työn tarkoituksena on tuottaa ABB Prosessiteollisuudelle tietoa IEC 61850 standardista ja horisontaalista kommunikaatiosta. Standardin ja horisontaalisen kommunikaation keskeiset ajatukset on esitetty teoriakappaleissa. Hyödynnettäviä tuloksia varten myös GOOSE kommunikoinnin sovelluksia tutkittiin. Tutkittavat sovellukset valittiin äskettäin julkaistun REF615 IED:n toiminnallisuuden perusteella. Kukin sovellus kuvataan ensin yleisesti, jonka jälkeen esitetään esimerkkitoteutus REF615 releitä käyttäen. Lähestyvän asiakasprojektin perusteella tarkempaan testaukseen valittiin valokaarisuojaukseen liittyvä sovellus. Sovellus konfiguroitiin kahden REF615 releen välille, jotta sen toimivuus voitiin todentaa ennen asiakasprojektin käynnistymistä.

PREFACE

This master's thesis was written for ABB Process Industry Plc as a part of a development project concerning the IEC 61850 standard. It is written specially for professionals familiar with substation automation, but who have minor knowledge about the IEC 68150 and GOOSE communication. I hope this study provides valuable information to future projects implementing applications based on GOOSE communication.

During the study the support and guidance from the project team was essential. Thus I wish to show my acknowledgements to Timo Haapalainen, Timo Peltoniemi and Toni Korpi-Halkola. Other important sources of information include Janne Starck and Juha Willman, who familiarized the author with GOOSE communication and process industry electrification. I also wish to thank Katja Rajaniemi for the chance to work for ABB Process Industry Plc and professor Pekka Verho for examining this study.

The greatest gratitude during my studies belongs to my family Heikki, Sinikka, Elina and Antti-Juhani for their endless support. Equally important are all my friends, to whom I would like to show my acknowledgements.

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CONTENTS

ABBREVIATIONS AND NOTATION

ABB	Asea Brown Boveri
ACSI	Abstract Communication Service Interface
AIS	Air-Insulated Switchgear
APPID	Application Identification Number
BIO	Binary Inputs and Outputs
CCT	Communication Configuration Tool
CDC	Common Data Class
CID	Configured IED Description
CMD	Command Interpreter
EMI	Electromagnetic Interference
EPRI	Electric Power Research Institute
FAT	Factory Acceptance Test
FC	Functional Constrain
GIS	Gas-Insulated Switchgear
GOOSE	Generic Object Oriented Substation Event
GOCB	Goose Control Block
GSE	Generic Substation Event
HMI	Human Machine Interface
HV	High Voltage
ICD	IED Capability Description
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
IEEE	Institute of Electrical and Electronics Engineers
IGMP	Internet Grouping Message Protocol
IP	Inter-networking Protocol
ITT	Integrated Testing Toolbox
LAN	Local Area Network
LD	Logical Device
LN	Logical Node
LV	Low Voltage
MAC	Media Access Control
MBPS	Megabytes Per Second
MMS	Manufacturing Message Specification
MTBF	Meat Time Between Failures
MV	Medium Voltage
OSI	Open Systems Interconnection
PD	Physical Device
PDC	Power Distribution Control
RSTP	Rapid Spanning Tree Protocol
SAS	Substation Automation System

SAT	Site Acceptance Test
SC	Synchronism Check
SCADA	System Control and Data Acquisition
SCD	Substation Configuration Description
SCL	Substation Configuration Description Language
SMT	Signal Matrix Tool
SNMP	Simple Network Management Protocol
SPS	Single Point Status
SSD	Substation Specific Description
SV	Sampled Values
TCP	Transport Control Protocol
TPAA	Two Party Application Association
UCA	Utility Communications Architecture
VLAN	Virtual Local Area Network
VT	Voltage Transformer
XML	Extensible Markup Language

1. INTRODUCTION

In this chapter the purpose and background of this study are presented, followed by a short history of the IEC 61850 standard. Finally the scope of this study and an outline of the chapters are presented.

1.1. Purpose

This master's thesis was initiated by ABB Oy Process Industry Electrification, Instrumentation and Composite Plants business unit as a part of a development project. The project focuses on standardization of power distribution control based on the IEC 61850 standard, presented by the International Electrotechnical Commission (IEC). The IEC 61850 describes communication networks and systems in substations. The focus of this master's thesis is to investigate the possible applications of horizontal communication between Intelligent Electronic Devices (IEDs). The communication is described by IEC 61850 as Generic Object Oriented Substation Event (GOOSE). [1] This master's thesis provides information about the technological aspects of GOOSE communication.

1.2. Background

Substation is described as a number of switchgear controlled, supervised and protected by a Substation Automation System (SAS). Substation can be divided into three levels, which are called station level, bay level and process level. [2] From the perspective of process industry, an SAS is essential in order to provide distribution of electricity for various types of equipment. Substation automation provides the means for effective, reliable and safe distribution of electric energy.

In recent years the development of substation automation systems has been rapid due to the introduction of microprocessor relays. These relays are capable of executing several protection and control functions to different devices in the substation. Modern relays can also perform, for example, auto-reclosing and self-monitoring functions, thus they are called IEDs. [3]

Due to the rapid development of IEDs, a vast amount of information is now available within a substation and the requirements for communication technology are increasing. Up till recent years, vendors have used different communication protocols to exchange information inside a substation. This has lead to vendor-specific communication solutions, leaving customers depending on the products of the selected vendor. Due to vendor-specific communication, interoperability between products from different vendors has been either cumbersome or impossible. This problem was acknowledged by major vendors in the industry as well as international organizations.

In order to gain genuine interoperability and standardize the communication of an SAS, IEC published the 61850 standard between 2002 and 2005. The key aspect of the standard is to describe communication of an SAS in a way that supports interoperability and future solutions in communication and substation automation. The standard presents a uniform way to describe data generated in an SAS by decomposing it into smallest possible entities that can exchange data. By defining these data models, the transferring services and communication protocols, a substation automation system can be described uniformly. The principles for these data models, transferring services and protocols are presented in this study.

One of the services for data exchange is horizontal GOOSE communication, which can be best described as fast peer-to-peer communication between IEDs. The possible applications of this communication can replace present solutions of protection and control realized by hardwired schemes. The principles of the most relevant applications for the target company's needs are presented within this study. One of these applications is described in detail by configuring the required parameters to IEDs and testing the GOOSE solution.

1.3. Scope of the Study

Due to the publication of the IEC 61850 standard, ABB released a new series of IEDs with native support to IEC 61850 communication. The aim of this study is to investigate the possible applications of horizontal GOOSE communication for one IED from the new Relion® series. The selected IED is REF615, which is designed for feeder protection in low and medium voltage switchgear. The REF615 is commonly used for industrial power systems protection, and thus the applications based on GOOSE communication provide profitable information for ABB Process Industry. The examination of more versatile REF630 IED and its applications was also suggested. However, the REF630 was not yet available at the beginning of this study. Therefore it was not included in this study.

The outline of this study is as follows. The first chapter provides background information for the reader to understand the rationale behind the initiation of this master’s thesis. Chapter 2 describes the objective, workflow and information sources used in this study. Chapter 3 presents the basis for understanding how substation data is described according to the standard. The required communication infrastructure for horizontal communication is also presented. In Chapter 4 possible applications are first described generally, and then with an example solution with ABB’s REF615 IEDs. Information regarding reliability, testing and documentation of GOOSE based solutions is also presented. Chapter 5 presents a detailed description of GOOSE implementation to ABB IEDs. The required engineering and configuration with software tools, as well as the performance of GOOSE communication, are presented. Finally in Chapter 6 the outcome of this master’s thesis is presented with proposals to future topics for investigation.

2. RESEARCH METHODS

In this chapter the objective of this study is defined, followed by a presentation of the workflow of this study. In the final chapter the information sources and research methods used in this study are presented.

2.1. Objective

This master's thesis is a part of a development project which focuses on standardization of power distribution control (PDC) systems. The focus of this study is on horizontal communication between IEDs and its possible applications. The technological benefits of the applications compared to conventional solutions are presented based on the feedback received from the project team. Important aspects, such as reliability, redundancy and security, are presented in order to evaluate the reliability of GOOSE solutions compared to conventional solutions. The purpose of this work is to present information about the new concept of horizontal communication based on IEC 61850 standard. Equal importance is given to producing the most suitable applications for REF615 IED's on the framework of Process Industry's target business markets.

2.2. Workflow

At the beginning of the study a project team was appointed to investigate the possibilities to standardize practices used in PDC systems. One part of this project was to investigate possible applications of horizontal GOOSE communication, which is the subject of this study. After the goals and milestones of this study were specified with ABB and approved by Tampere University of Technology, the investigation was initiated.

The investigation of the subject started with collecting reference material about the IEC 61850 standard and horizontal communication. The content of this study was enunciated after the author had familiarized himself with the standard and discussed with the project team. When the requirements for horizontal communication were internalized, ABB provided the author with training about the configuration of IEDs including implementation of GOOSE communication. After the required training a number of REF615 IEDs were acquired by the project team in order to test and demonstrate the implementation of GOOSE communication. The most relevant applications for REF615 IEDs were selected to be presented in this study. This was achieved by studying reference material and discussing with project engineers. The application of transferred arc protection trip was further on selected to be configured and tested. The author acquired the knowledge and skills required for application tests by investigating the standard, product manuals, and by participating to relevant ABB's courses. This was followed by an application test, where the transferred arc protection trip application was tested and also the performance of GOOSE communication was noticed. The setting up of the test equipment, the configuration work and the actual testing were done in ABB Process Industry's facilities. After the tests, the principles and signals required for all the selected applications were discovered by investigating the product manuals and the IEC 61850 standard. The major tasks and workflow of this study are depicted in Figure 1.

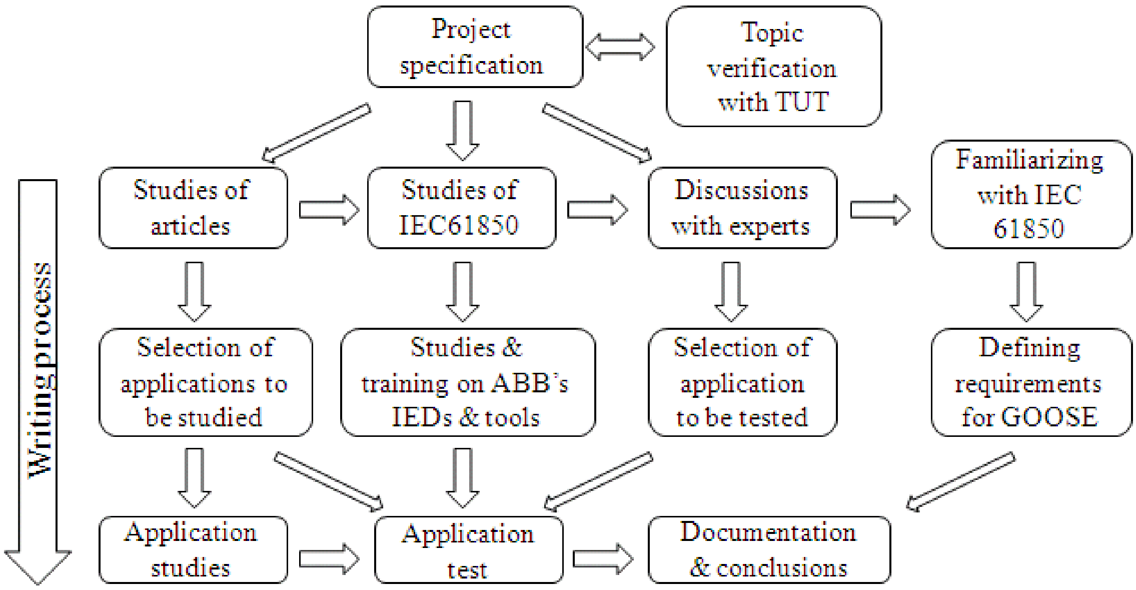


Figure 1. Workflow of the study.

After the author had done enough research on IEC 61850, the contents of this study were enunciated and the writing process begun. After all selected applications were introduced and the test completed, the findings of this study were documented for ABB. Finally the conclusions of this study were written.

2.3. Methods and Sources

Because the IEC 61850 was published between 2003 and 2009, the reference material available is vast. Naturally the standard itself is a major source of information, along with a number of publications written by experts and scientists worldwide. Most of the material was acquired from internet based databases of international organizations, such as the Institute of Electrical and Electronics Engineers (IEEE). The fact that ABB has access rights to major scientific databases concerning electrical engineering was a notable contribution. Articles concerning IEC 61850 published in Praxis Profiline were very useful at the initial phase of study. Master's of Science thesis with relevant topics were also used as a reference.

After the author had familiarized himself enough with the subject, the actual process of investigating and writing begun. During this phase the colleagues working at the PDC development project were an important source of information. Interviews with specialists in the fields of substation automation and process industry electrification were also arranged. This provided important perspective and experience to the study.

3. IEC 61850 STANDARD

The purpose of this chapter is to introduce the theoretical background and network requirements for GOOSE based applications. At the beginning, an overview of the IEC 61850 is given, followed by a description of the purpose and objective of the standard. The information structure defined by IEC 61850 is presented by introducing the object model and data mapping. The services for information exchange are described in chapter 3.3.3, followed by a presentation of the substation description language. The requirements for network infrastructure are introduced by presenting network topologies and component features. The data transfer medium and information security are described in the final chapters.

3.1. Overview

The history of IEC 61850 began in 1990, when Electric Power Research Institute (EPRI) and the IEEE started a project on Utility Communications Architecture (UCA). The aim of the UCA-project was to develop both the communication between control centers and the communication from substation to control center. The outcome of the project was a standard called IEC 60870-6-TASE.2. In 1994 both EPRI and IEEE started working on new standard called UCA2, which focused on the station bus communication. In 1996 IEC Technical Committee 57 began working with IEC 61850, a standard defining station bus. These two working groups with similar tasks joined their forces in 1997, with a goal to create one single standard for station bus communication. The result of the combined work is the new international IEC 61850 standard series, whose latest part was published in 2009. [3; 4]

The IEC 61850 standard currently consists of fourteen parts, which are presented in Appendix 1. Together these parts constitute all the requirements that a substation automation system has to fulfill. From the perspective of horizontal communication, the IEC 68150-8-1 is the most relevant part in the standard. Due to the vast amount of pages and information within the standard, a special reading guide has been composed. This guide is meant to point out the relevant parts of the standard to a specific professional. The reading guide is presented in Appendix 2. Horizontal communication between IEDs and its applications are relevant to both application and communication engineering. Therefore, all the parts mentioned in the reading guide are relevant in this context. [5]

3.2. Purpose and Objective of the Standard

The implementation of IEDs has become prevailing in substation automation. Intelligent electronic devices are performing all necessary functions inside a modern substation. This requires efficient communications among the IEDs, which requires the use of communications protocols. Before the IEC 61850 standard was released, different vendor-specific communication protocols were used to exchange information among the IEDs. This means that if different vendors were used, the information would have to be converted to the protocol in question. Protocol converters cause delay and increase the possibility of errors to the communication process. As the amount of information grows, this can potentially create problems within the substation. [3; 6]

The purpose of the IEC 61850 series is to solve the problems related to different communication protocols by introducing a standardized communication protocol. The key objectives of the standard are interoperability of IEDs, supporting the operation functions and performance requirements of the substation, and supporting future technological development. The object of the IEC 61850 is not to standardize the functions inside a substation. The functions simply have to be defined in order to determine their requirements for the communication. The standard does not define how different functions should be allocated in the system. It only specifies the structure and communication interface of the functions. Therefore, the standard does not confine the development of IEDs or substation automation, and vendors can continue developing functionality in their products. [3; 6; 7]

3.3. Information Structure in IEC 61850

Horizontal GOOSE communication between IEDs is based on the IEC 61850 standard. Consequently, the reader must understand how data generated in the IEDs is being modeled in the standard. The following chapters present the models for information and data used in the standard. [8]

According to IEC 61850, an SAS can be presented as a combination of three levels: station level, bay level and process level. These levels and the possible interfaces between them are presented in Figure 2. The numbers within Figure 2 present the interfaces of data exchange between different parts of an SAS, which are listed below [6]:

1. Protection data exchange between bay and station level.
2. Protection data exchange between bay level and remote protection (beyond the scope of IEC 61850).
3. Data exchange within bay level.
4. Current transformer and voltage transformer instantaneous data exchange between process and bay level.
5. Control-data exchange between process and bay level.
6. Control-data exchange between bay and station level.

7. Data exchange between substation and a remote engineer’s workplace.
8. Direct data exchange between the bays especially for fast functions such as interlocking.
9. Data exchange within station level.
10. Control-data exchange between substation and remote control centre (beyond the scope of IEC 61850).

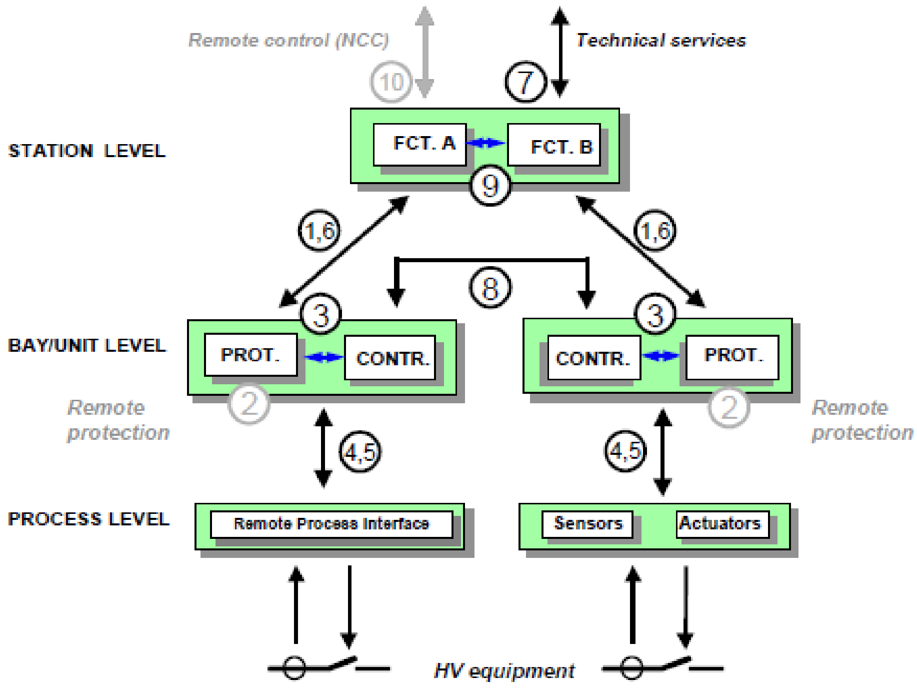


Figure 2. A Substation Automation System according to IEC 61850. [6]

This study focuses on horizontal communication, which is referred to by number 8 in Figure 2. The purpose of horizontal communication is to provide means for IEDs to communicate with each other in order to perform, for instance, fast interlocking protection schemes within substation. This requires fast and reliable communication, also between IEDs from different vendors.

The IEC 61850 series defines communication by using the OSI-model (Open Systems Interconnection). The OSI-model is an internationally standardized (ISO/IEC 7498-1) model that uses the concept of layering the communication functions. The model contains seven layers each of which have defined functional requirements in order to create a robust communication system. The OSI-model does not specify which protocols should be used in order to achieve the functionality, nor does it restrict the solution to a single set of protocols. Therefore, by using the OSI-model the IEC 61850 series preserves the possibility to change the chosen protocols if technology develops in that particular area. [7; 9] The OSI-model is illustrated in Figure 3.

OSI Layer	Protocol		Profile
Layer 7: Application	Application level protocols; MMS, FTP, SMTP, HTTP		Application profile
Layer 6 :Presentation			
Layer 5: Session			
Layer 4: Transport	TCP	UDP	Transmission profile
Layer 3: Network	IP		
Layer 2: DataLink	IEEE 802.3 (Ethernet, Fast Ethernet,...)		
Layer 1: Physical			

Figure 3. Communication stack of OSI-model [3; 8]

The actual communication inside an SAS can be divided into three separate parts: [10]

- Data of the applications
- Services for transferring this data
- Real communication protocols

In order to make the communication possible, all of these parts have to be defined. In most standards used today these parts are defined together, which creates a unique syntax for the messages being transmitted. This makes the data and the services dependent from the protocol and also the protocol dependent from the communication technology. In IEC 61850 series these parts are all defined separately. If technology in one of these parts develops considerably, it is only required to redefine this part to meet the state-of-the-art technology. Therefore, the requirement for supporting future technology can be achieved.

Data of the applications is described by an object model. The idea of the object model is to decompose data of the substation functions into smallest possible entities, which are then used to exchange information. The structure of the object model is described in Chapter 3.3.1. For transferring services an object-oriented concept called Abstract Communication Service Interface (ACSI) is used. To achieve actual communication, the abstract objects and services need to be mapped to real communication protocols. These protocols should be practical to implement and should operate in common computing environment of the power industry. The actual implementation to real protocols is achieved through Specific Communication Service Mappings (SCSM) which is defined in parts 61850-8-1, 61850-9-1 and 61850-9-2 of the standard. The information exchange services and mappings to real protocols are presented in Chapter 3.3.2. [11]

3.3.1. Object Model

Information exchange requires specific data models for data generated in the IEDs. The IEC 61850 series uses the concept of virtualization in order to create these data models.

Virtualization provides a view of those aspects of a real device that are of interest for the information exchange with other devices. In the IEC 61850 series only the relevant details that are required to provide interoperability are defined. These definitions are created by using an object model, which decomposes the functionalities of a real device into the smallest possible entities. A good illustration of the object model can be achieved by imagining an IED as a container, which is presented in Figure 4. [12]

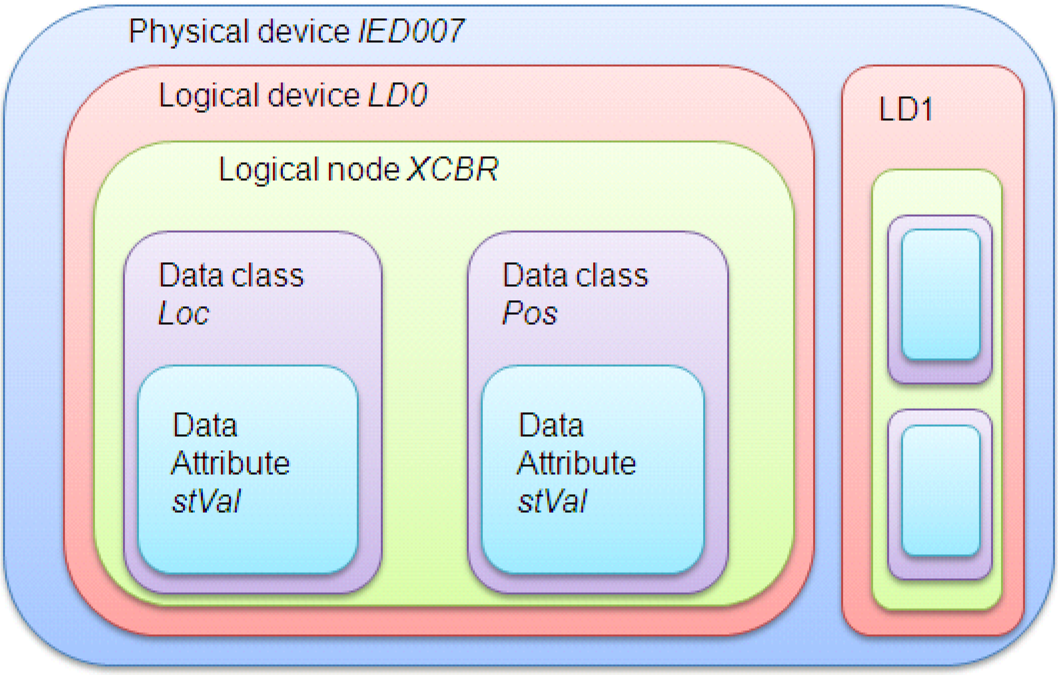


Figure 4. Object model of IEC 61850 [12]

In the IEC 61850 series object model begins with a physical device (PD). These devices are capable of connecting to the network, and are therefore defined by a network address. Each PD has to have a unique IP-address in order to ensure the functionality of the network. A physical device, for instance an IED, consists of one or several logical devices (LDs). A logical device is a compound of logical nodes (LNs), and each of these logical nodes is related to a specific function inside a substation. At least three logical nodes must be within a logical device, namely two LNs related to common issues for the logical device (LLN0 and LPHD), and at least one LN performing some functionality. A logical node is a grouping of data and services related to certain substation function. Therefore, all data generated from the substation can be assigned to a certain logical node. A complete list of logical nodes is defined in the IEC 61850-7-4 and is presented in Appendix 3. In the standard a logical node is specified as the smallest entity that can exchange information. Logical nodes are combined into groups based on their functionality. These groups and the number of nodes in a group are presented in Table 1. At the moment a total of 92 logical nodes are defined in the standard. [11; 12]

Table 1. Logical node groups [5]

Symbol	Logical node group	Number of LNs
A	Automatic control	4
C	Supervisory control	5
G	Generic references	3
I	Interfacing and archiving	4
L	System logical nodes	3
M	Metering and measurement	8
P	Protection functions	28
R	Protection related functions	10
S	Sensors and monitoring	4
T	Instrument transformer	2
X	Switchgear	2
Y	Power transformer	4
Z	Further power system equipment	15
Total		92

Each logical node contains one or more elements of data. These data elements are named according to the standard and are related to a specific purpose in the substation. An example of one logical node is given in Table 2.

Table 2. A logical node for circuit breaker; XCBR [13]

XCBR class				
Attribute Name	**Attr. Type**	**Explanation**	**T**	**M/O**
LNName		Shall be inherited from Logical-Node Class (see IEC 61850-7-2)		
Data				
Common Logical Node Information				
		LN shall inherit all Mandatory Data from Common Logical Node Class		M
Loc	SPS	Local operation (local means without substation automation communication, hardwired direct control)		M
EEHealth	INS	External equipment health		O
EEName	DPL	External equipment name plate		O
OpCnt	INS	Operation counter		M
Controls				
Pos	DPC	Switch position		M
BlkOpn	SPC	Block opening		M
BlkCls	SPC	Block closing		M
ChaMotEna	SPC	Charger motor enabled		O
Metered Values				
SumSwARs	BCR	Sum of Switched Amperes, resetable		O
Status Information				
CBOpCap	INS	Circuit breaker operating capability		M
POWCap	INS	Point On Wave switching capability		O
MaxOpCap	INS	Circuit breaker operating capability when fully charged		O

The *XCBR* logical node is a model of a circuit breaker and it contains several elements of data. The first column describes the name of the data. This name is unique and defined by the standard. The second column describes the Common Data Class (CDC) to which the data belongs. Part 61850-7-3 of the standard presents all CDCs, which are 29 in total. The *Explanation* column presents a short description of the data class in question. If there is a letter *T* marked in the next column, this informs the transient nature of the data class. The last column informs whether the data class is mandatory (*M*) or optional (*O*) for the logical node in question. For instance, *XCBR* logical node has a data class *Loc*, which belongs to a single point status (SPS) common data class, is non-transient, and is mandatory. [12; 13]

The elements of data within a logical node have to conform to the specification of a Common Data Class (CDC), as stated above. A common data class is a description of the type and structure of the data within a logical node. Each CDC has a defined name and a set of attributes, which in turn have a defined name, a defined type and a specific purpose. For illustration an anatomy of Single Point Status (SPS) common data class is presented in Table 3.

Table 3. The anatomy of Single Point Status (SPS) common data class. [14]

SPS class					
Attribute Name	**Attribute Type**	**FC**	**TrgOp**	**Value/Value Range**	**M/O/C**
DataName	Inherited from Data Class (see IEC 61850-7-2)				
DataAttribute					
			status		
stVal	BOOLEAN	ST	dchg	TRUE | FALSE	M
q	Quality	ST	qchg		M
t	TimeStamp	ST			M
			substitution		
subEna	BOOLEAN	SV			PICS_SUBST
subVal	BOOLEAN	SV		TRUE | FALSE	PICS_SUBST
subQ	Quality	SV			PICS_SUBST
subID	VISIBLE STRING64	SV			PICS_SUBST
			configuration, description and extension		
d	VISIBLE STRING255	DC		Text	O
dU	UNICODE STRING255	DC			O
cdcNs	VISIBLE STRING255	EX			AC_DLNDA_M
cdcName	VISIBLE STRING255	EX			AC_DLNDA_M
dataNs	VISIBLE STRING255	EX			AC_DLN_M
Services					
As defined in Table 13					

The table lists all data attributes that belong to common data class SPS. The first and second column describe the name and type of the data attribute, respectively. The individual attributes of a common data class are grouped into categories by functional constrains (*FC*). The functional constrain of a data attribute is told in the third column. The trigger option column (*TrgOp*) defines when for instance reporting or reading of the data will occur. The fourth column describes the predefined values or value range for the data attribute. The last column (*M/O/C*) refers to whether the data attribute is mandatory, optional or conditional. For instance the first data attribute in Table 3 is named *stVal*, the type of data is *BOOLEAN* and it belongs to a functional constrains for status attributes (*ST*). The trigger option for *stVal* is data-change (*dchg*), and it is mandatory (*M*) for single point status CDC. [3; 11; 12; 14]

The anatomy of an object name according to IEC 61850 can be easily understood by following the data model described in this chapter. An example of such name is presented in Figure 5, with explanations. The parts of the object name marked with an asterisk (*) are defined by the standard, other parts can be freely allocated according to the vendor. According to IEC 61850 the object name can contain 62 marks including separation points. The name of the logical node can contain 11 marks including both a prefix and a suffix. [3; 8]

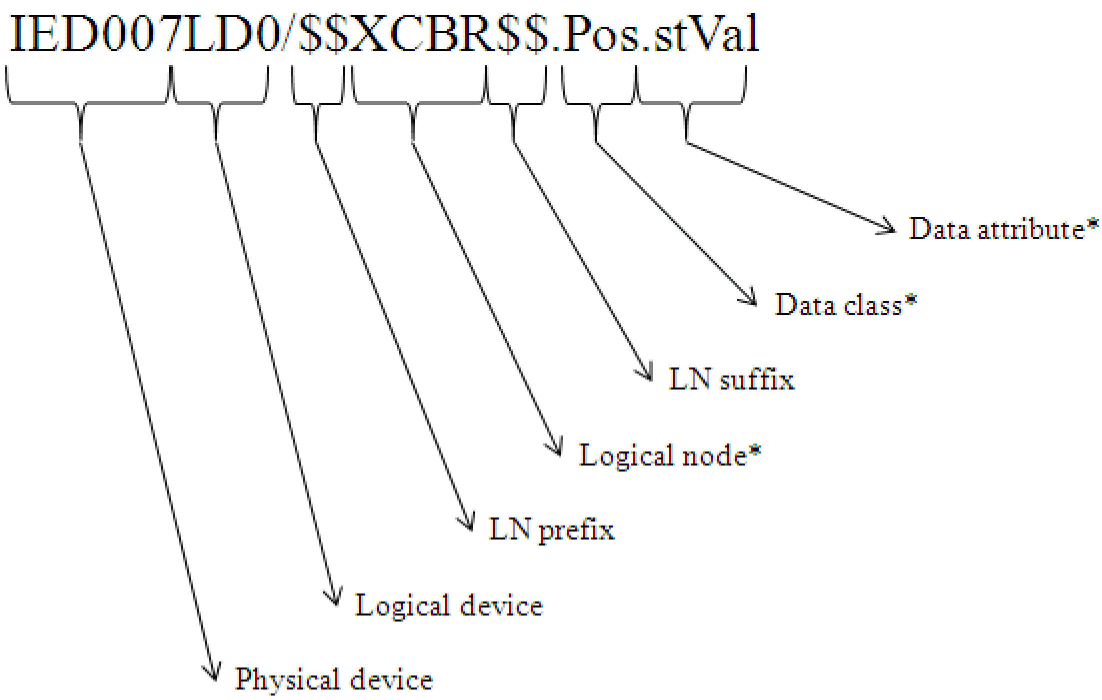


Figure 5. The anatomy of an object name according to IEC 61850-8-1 [8]

In order to group chosen data attributes or object references of data, the IEC 61850 defines the concept of a dataset. A dataset is a single collection of object references, including data or data attributes organized as a dataset for communication. Because IEC 61850 defines the object references, the communicating partners shall both acknowledge them, therefore only the values and the name of the dataset need to be transmitted. Datasets are divided into two types, persistent and non-persistent, which relate to the visibility of the datasets. The persistent datasets are visible to any clients of Two Party Application Association (TPAA). These include the pre-configured datasets, which are also permanent. The non-persistent datasets are visible only to the defined client that of the dataset in question. Non-persistent datasets are vital to the functionality of GOOSE communication. The chosen data attributes of a GOOSE message have to be grouped into a dataset, in order to perform the required function within the substation. This is described in Chapter 3.3.3. [12; 15]

3.3.2. Data Mapping

The object model describes all data generated by an IED in an abstract way, preserving the direct relation with the functions from which the data is originated. In order to transfer this uniformly constructed data, information exchange services have to be defined. The IEC 61850 series uses an object-oriented concept called Abstract Communication Service Interface (ACSI). The ACSI is very useful, because the services are independent of the information content and the communication protocol. This service enables all IEDs to behave identically from the perspective of a communication network. This way also the services for transferring data are described independently. Therefore, the object models and services can be mapped to any protocol.

In the ACSI model there are two groups of communication services. The first group uses client-server model, for example to get data values from IEDs. The second group is a peer-to-peer model with Generic Substation Event (GSE) services, which are used for fast communication between IEDs and periodic sampled value transmissions. These services comprise the communication services described by the IEC 61850 series, which are listed below: [7; 12]

- Client-Server Communication
- Time-critical Sampled Values
- Time-critical GOOSE Messages

Client-Server communication works as a service where the client requests data from a server which offers it. The server contains the content of logical device, the association model, time synchronization and file transfer, which are defined as accessible and visible from the communication network. [12] In the SAS a Client-Server communication is used for transferring relatively large amounts of information, which is not time-critical. This means, for instance, transferring configuration data to IEDs. When time-critical information has to be moved, the standard describes two types of communication services. These are Sampled Values (SV) for metering information and GOOSE messages for fast peer-to-peer communication between IEDs.

Sampled Values are messages related to instrumentation and measurement. Therefore, they are transferred between bay and process levels, as illustrated by number 4 in Figure 2. The SV messages are time critical and they need to be in chronological order. Possible loss of messages also has to be detected. These messages can be sent as unicast to one receiver or as multicast for several receivers. [7] The SV messages are beyond the scope of this study, and therefore are not described in detail. However, it is worth mentioning that as technology migrates to next generation, digital information exchange between IEDs and process level devices becomes possible. For instance, current transformers can send values digitally via IEC 61850 network. This need has been taken into account by defining transmission of SV messages. [11]

Time-critical GOOSE messages have been defined for fast horizontal communication between IEDs. They are used to transfer state and control information between IEDs, for instance trip or locking commands in order to achieve designed control and protection schemes. GOOSE messages are transmitted as a multicast over Local Area Network (LAN), from which all IEDs configured to receive the message can subscribe it. The demand for fast transmission is obvious, as most protection and control schemes depend on fast action of devices. Different message types are presented in Table 4. For SV and GOOSE messages this demand can be achieved by a different mapping to real protocols, which are presented next. [7]

Table 4. Types of messages according to IEC 61580 [16]

Type	Name	Example
1a	Fast messages – trips	Trips
1b	Fast messages – others	Commands, simple messages
2	Medium speed messages	Measurement values
3	Low speed messages	Parameters
4	Raw data messages	Output data from transducers and instrument transformers
5	File transfer functions	Large files
6a	Time synchronization messages a	Time synchronization, station bus
6b	Time synchronization messages b	Time synchronization, process bus
7	Command messages with access control	Commands from station HMI

In order to communicate by using the OSI-model, communication services have to be mapped to real communication protocols by using different communication profiles. The profiles used in IEC 61850 are presented in Figure 6.

Basically, in the upper three layers of the OSI-model, the IEC 61850 uses two application profiles, the Connection Oriented OSI and Connectionless OSI. For the four lower layers of the OSI-model three types of transmission profiles are used, Connection Oriented TCP, Connection Oriented OSI and Connectionless OSI. The actual communication profiles can be divided into MMS (Manufacturing Message Specification) and non-MMS profiles according to IEC 61850-8-1. [8]

For client-server communication MMS is used. This protocol was originally designed for manufacturing, but it was chosen because it has proven to support the complex naming and service models of IEC 61850. [11] MMS is an internationally standardized messaging system for exchanging real-time data and supervisory control information between networked devices and computer applications. [12] MMS covers the application profile of the OSI-model, and the transfer and network layers are covered either by TCP/IP or ISO. In the perspective of GOOSE messages, client-server communication is used only to transfer GOOSE Control Block information during the configuration phase of IED engineering. [8] Because client-server communication cannot fulfill the real-time demands of GOOSE-messaging, different communication profiles have to be used for time-critical messages. [8; 11; 12;]

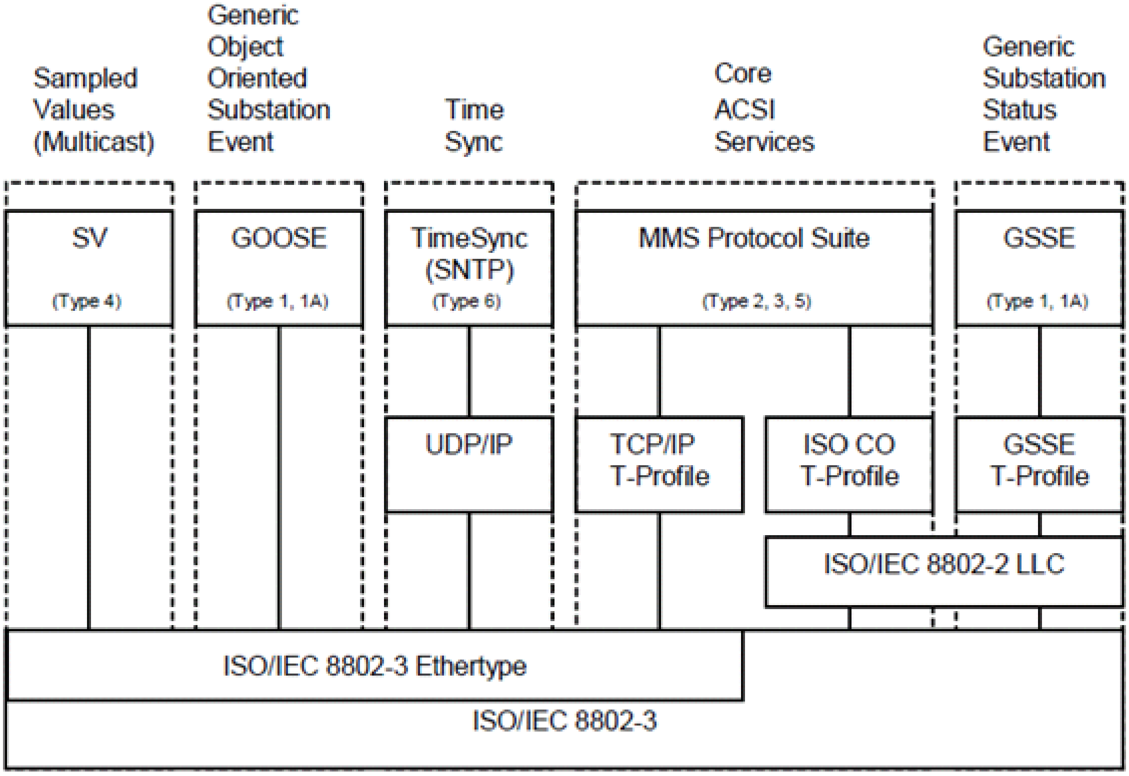


Figure 6. An overview of functionality and profiles in IEC 61850 [8]

For GOOSE communication Connectionless OSI and non-MMS profiles are used. This means that the connection between IEDs prior to sending is not confirmed. The GOOSE message is simply sent to the network. This is needed in order to meet the time-critical demand of GOOSE communication. As depicted in Figure 6, GOOSE messages are mapped directly into the Ethernet data frame in order to eliminate processing time of the middle layers. The communication profiles for GOOSE services and GSE management are described in part 61850-8-1 Clause 6.3. The protocols and services for OSI application profile according to IEC 61850-8-1 are shown in Table 5.

Table 5. Application profile for GOOSE messages and GSE management. [8]

OSI model layer	Specification			m/o
	Name	Service specification	Protocol specification	
Application	GSE/GOOSE protocol	See Annex A		m
Presentation	Abstract Syntax	NULL		m
Session				

As presented in Table 5, the specific GSE/GOOSE protocol is presented in Annex A of IEC 61850-8-1, and the Basic Encoding Rules for presentation layer are described in ISO/IEC 8824-1 and ISO/IEC 8825-1. The protocols used for OSI transmission profile are illustrated in Table 6. The chosen protocols assure that GOOSE communication can meet the strict real-time demands of peer-to-peer communication of IEDs. These protocols among others related to the performance of the network are described in Chapter 3.4.2 of this study.

Table 6. Transmission profile for GOOSE messages and GSE-management. [8]

OSI model layer	Specification			m/o
	Name	Service specification	Protocol specification	
Transport				
Network				
DataLink	Priority Tagging/ VLAN	IEEE 802.1Q		m
	Carrier Sense Multiple Access with collision detection (CSMA/CD).	ISO/IEC 8802-3:2001		m
Physical (option 1)	10Base-T/100Base-T	ISO/IEC 8802-3:2001		c1
	Interface connector and contact assignments for ISDN Basic Access Interface. [a]	ISO/IEC 8877:1992		
Physical (option 2)	Fibre optic transmission system 100Base-FX	ISO/IEC 8802-3:2001		c1
	Basic Optical Fibre Connector. [b]	IEC 60874-10-1, IEC 60874-10-2 and IEC 60874-10-3		

[a] This is the specification for the 10BaseT connector.

[b] This is the specification for the ST connector.

c1 It is recommended to implement at least one of the two physical interfaces. Additional or future technologies may be used.

In addition to services described earlier, time synchronization and Generic Substation Status Event (GSSE) are depicted in Figure 6. Time synchronization provides a reference clock for the entire network, which is used, for instance, to have sampled values in chronological order. It uses the Simple Network Time Protocol (SNTP), which is mapped to the ISO/IEC 8802-3 Ethernet frame via UDP/IP protocols. The GSSE provides similar status information as GOOSE, but is merely a list of information compared to configurable datasets of GOOSE. [8]

3.3.3. Information Exchange

The information exchange with GOOSE messages is established by using a specific Generic Substation Event (GSE) model. This model provides the possibility of fast and reliable system-wide information exchange of input and output data values. The GSE model presents an efficient method for simultaneous delivery of the same generic substation information for more than one physical device through the use of multicast services. According to the standard, the GSE model applies to the exchange of values of a collection of data attributes. There are two different message types defined in the standard that use the GSE model. The Generic Substation State Event (GSSE) message type is able to transfer state change information, which means bit pairs. The GOOSE message type can convey a wide range of data attributes organized in a dataset. The major difference between these two message types is that GSSE provides a simple list of status information, whereas GOOSE provides a flexible combination of information organized into a dataset. Therefore, in GOOSE the information that needs to be exchanged can be specified. The actual information exchange is based on a publisher/subscriber mechanism. This mechanism along with services is presented in Figure 7.

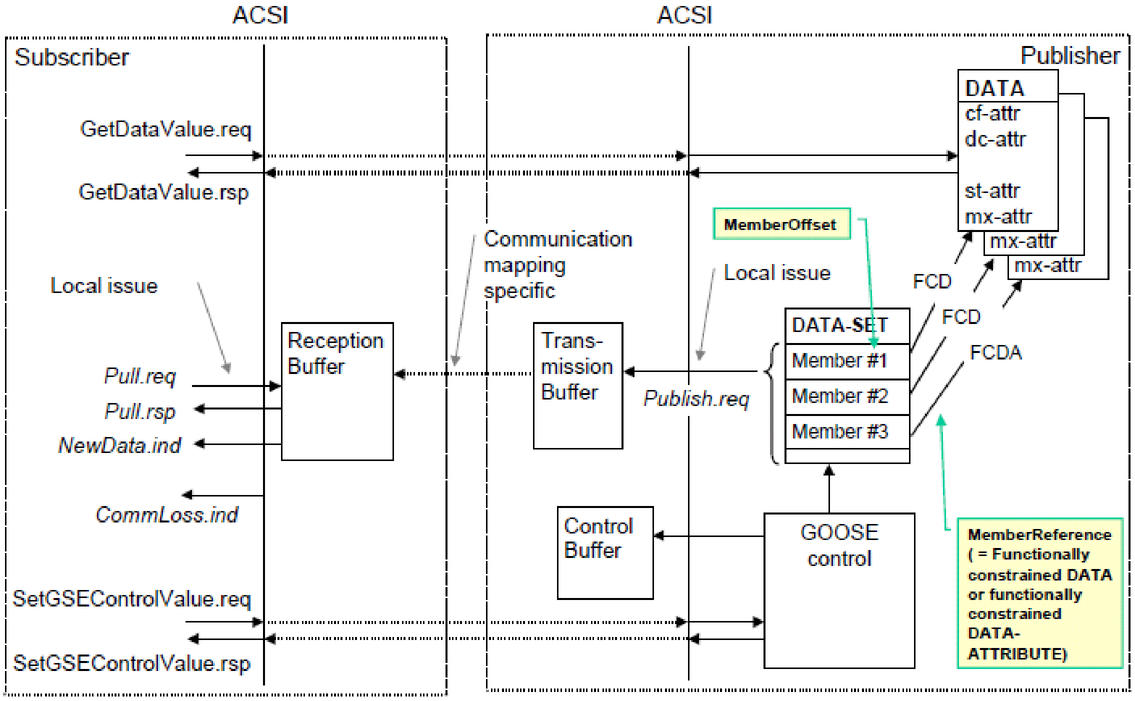


Figure 7. An overview of the classes and services of the GOOSE model. [15]

As illustrated in Figure 7, within a dataset there is a group of data attributes with specific functional constrain, for instance *st-attr* for status. Each of these data attributes within a dataset is called *Member* of the dataset, with a *MemberReference*-numbering starting at one. If any of these data attributes change, the publisher will write the changed values to a transmission buffer. The values are transferred as a GOOSE message to the subscriber with a local service *Publish.req*. Communication mapping specific services will transfer the values to a *Reception buffer* in the subscriber, from which they are signaled further on, for instance to perform the application in question. [15]

In a practical perspective, this means that a specific GOOSE control block (GOCB) has to be configured for each GOOSE message. This control block includes the information which a dataset needs for transmission. The GOOSE control block specifies the MAC addresses (Media Access Control) for both the destination and source of the GOOSE message. The actual addressing of GOOSE messages is done via MAC addresses. The destination address of a GOOSE message contains a multicast MAC address, whereas the source address of a GOOSE message contains a unicast MAC address. The recommended definitions and limitations of MAC addresses are depicted in Table 7. The first three octets are defined by IEEE, and are *01-0C-CD* for GOOSE and GSSE messages. The fourth octet in the MAC address defines the type of the message. Value *01* is used for GOOSE messages. Finally, the last two octets are used for individual addressing of different messages types. The recommended range for addressing is presented in Table 7. Recommended MAC address range for GOOSE and GSSE messages. [8]

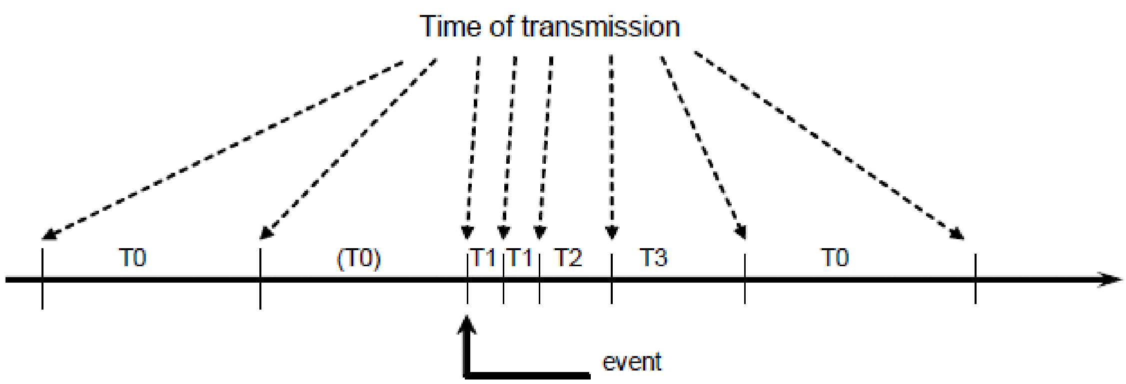
Table 7. Recommended MAC address range for GOOSE and GSSE messages. [8]

Service	Recommended address range assignments	
	Starting address (hexadecimal)	Ending address (hexadecimal)
GOOSE	01-0C-CD-01-00-00	01-0C-CD-01-01-FF
GSSE	01-0C-CD-02-00-00	01-0C-CD-02-01-FF

A specific three digit hexadecimal virtual local area network (VLAN) identification number is also a part of the GOCB with the range of 000 to FFF. This is used to identify which VLAN the GOOSE message is been transmitted to. The priority of the GOOSE message can be determined by a specific VLAN priority number, which is a decimal value with a range from 1 to 7. Messages with a priority from 1 to 3 are considered low priority messages, and messages with a priority from 4 to 7 high priority messages.

Also an application identity number (APPID) has to be part of the GOCB. That is a unique hexadecimal value for sending the GOCB within the network. It identifies the dataset and GOOSE message. APPID has a hexadecimal range of 0000 to 3FFF.

In order to ensure the arrival of the GOOSE message, it is sent multiple times on fast intervals. The multiple transmissions are depicted in Figure 8, where vertical lines present GOOSE messages send by the publisher.



T0	retransmission in stable conditions (no event for a long time).
(T0)	retransmission in stable conditions may be shortened by an event.
T1	shortest retransmission time after the event.
T2, T3	retransmission times until achieving the stable conditions time.

Figure 8. Transmission of GOOSE messages. [8]

When no data change occurs, the GOOSE message is transmitted periodically according to set MaxTime. Periodic transmissions enable the monitoring of GOOSE communication. When one or several of the data attributes within the GOOSE dataset change, the first transmission with the updated data values is send within the configured MinTime. After the first transmission the same GOOSE message is retransmitted a number of times until the stable condition time is achieved. This enables the supervision of GOOSE communication, which was not possible with hardwired solutions. The receiver can detect communication losses if the periodically sent message disappears. The actual detection of communication loss is detected according to a parameter called TimeAllowedToLive. The relation between this parameter and MaxTime is not defined in the standard, and is therefore manufacturer and product specific. MinTime and MaxTime are defined in the GOCB. Values for MinTime and MaxTime are application specific, for example 10 and 1000 milliseconds respectively. [8]

3.3.4. Substation Description Language

A substation automation system is typically project specific, and the introduction of IEDs has generated a need for propriety software tools for configuration of the IEDs. If interoperability has to be maintained, a standardized format for configuration data of both substations and IEDs is essential. Therefore, for describing and configuring an SAS, a specific Substation Configuration Description Language (SCL) has been defined in IEC 61850-6. The actual syntax of SCL is defined with Extensible Markup Language (XML). The XML-schema enables to automatically check the data contained in the different configuration files described below.

An illustration of the engineering process of an IEC 61850 based SAS is presented in Figure 9. As depicted in the figure, the engineering process needs different software tools in order to define the specification of a substation, the characteristics of an IED and the complete SAS including data and communication models. These programs produce different kind of files, each using SCL as an interface providing basis for continuous engineering. There are four separate file types in the IEC 61850 series, which are described next.

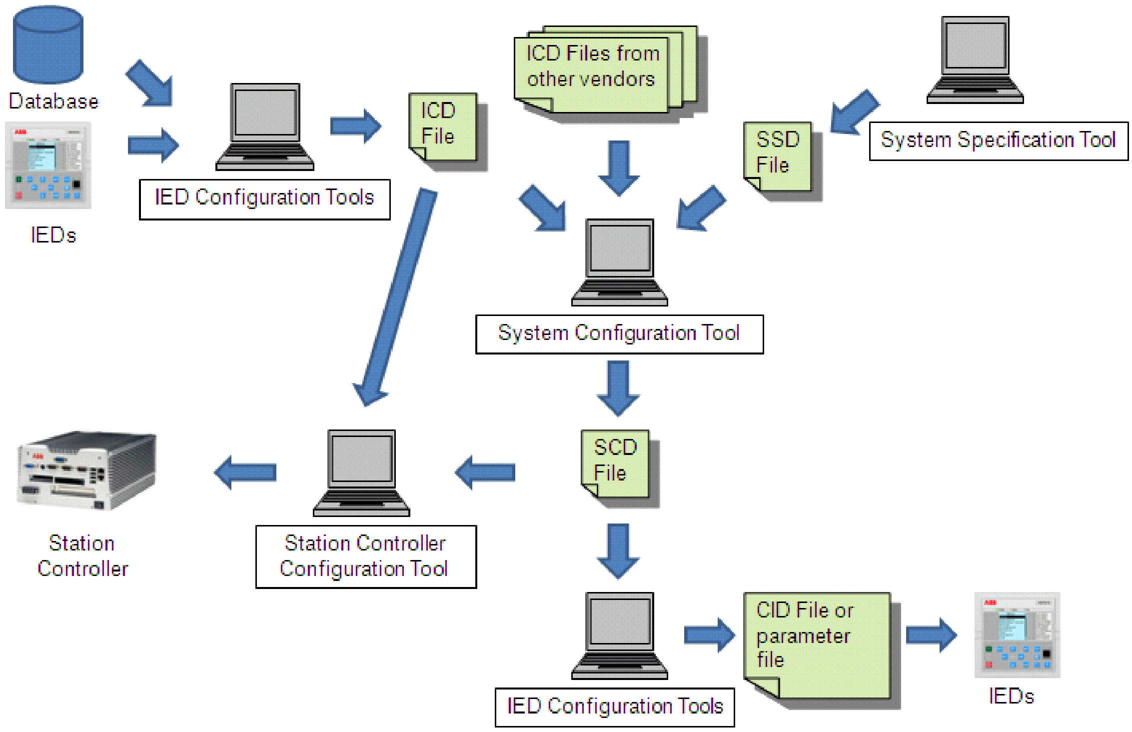


Figure 9. Engineering process of an IEC 615850 based SAS. [17]

The Substation Specific Description (SSD) is a file used to specify the structure of the electrical switchyard. This type of file is needed when data has to be exchanged from a system specification tool to a system configuration tool. The file contains all required logical nodes and describes a single line diagram of the substation. Also, all the needed data type templates and the logical node type definitions are contained in the file.

The IED Capability Description (ICD) describes data model and communication services of an IED in question. This information is exchanged from an IED configuration tool to the system configuration tool, and it contains the information and communication facilities available in the IED. With an ICD-file the system engineer can parameterize communication messages between IEDs.

For a complete description of an SAS, including data and communication models, the Substation Configuration Description (SCD) is needed. This type of file is required for data exchange from the system configuration tool to the IED configuration tool. The SCD file contains all IEDs, substation description section and communication configuration defining properties for the sending and receiving devices.

Finally, for the data exchange from the IED configuration tool to the actual IED within a project, the Configured IED Description (CID) is required. This file is dedicated to a project specific IED, containing all configuration data for fluent operation of the IED. [18; 19]

3.4. Network

In order to establish a communication network for an SAS described in the IEC 61850 series, certain issues concerning the network have to be decided. The standard defines qualities required for the performance of the network. Other issues not defined by the standard include network topology, cyber security and reliability of the network. The issues related to the network are presented next, as they are as important for the functionality of the SAS as the definitions of data modeling and communication services within an IED.

3.4.1. Network Topologies

A communication network can be established by using different network topologies. There are three basic topologies, namely bus, star and ring. In reality these topologies can be implemented with numerous variations and hybrids of the three. Different topologies offer different redundancy and performance for the network. In this chapter basic network topologies and few common variations suitable for substation LAN are presented.

In the bus topology each switch is connected to the previous or next switch via one of its ports, often referred to as uplink ports. These ports are usually operating at higher speed than the ports connected to the IEDs. An example of bus topology is illustrated in Figure 10. Although the bus topology is cost effective, it has two major disadvantages. When the number of switches connected to the bus increases, the delay between the first

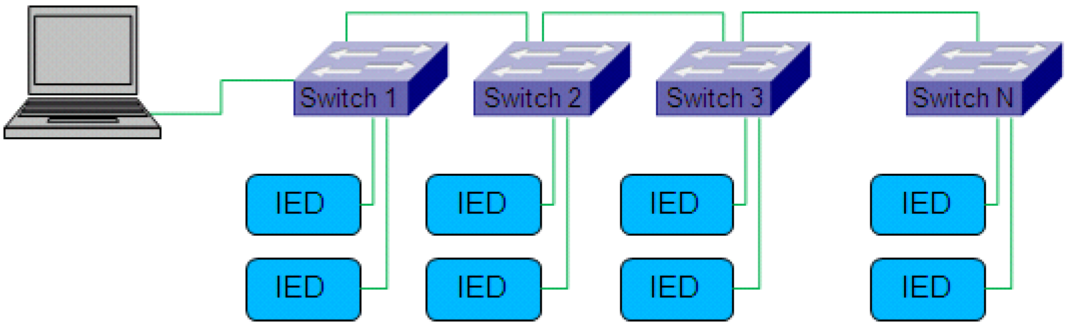


Figure 10. An example of bus topology. [20]

and last switch increases as well. The worst case delay, also referred as latency, should always be considered. The latency of the bus topology can make it not suitable for time-critical applications, for instance GOOSE messages. Another disadvantage is that bus topology has no redundancy. If one of the connections between switches is lost, communication to every IED downstream from that connection is also lost. [20]

The ring topology offers more redundancy compared to bus, as the last switch is connected back to the first, as pictured in Figure 11. The ring topology forms a loop in the network, which requires the use of managed switches. The switches should support Rapid Spanning Tree Protocol, which is depicted in Chapter 3.4.2. In ring topology one of the switches is configured as backup switch, which breaks the loop in the network. If one of the connections between switches is lost, the backup switch will establish connection via another route. This way some redundancy can be achieved. However, if one of the switches is lost, the communication to all IEDs connected to that switch is also lost. The advantage of ring topology is improved redundancy in a cost effective way. It still has the same disadvantage with latency as the bus topology. The added complexity and cost of managed switches can also be seen as a disadvantage. However, in the context of this study this is irrelevant, as all switches within the IEC 61850 communication network have to be managed, as depicted later on. [20]

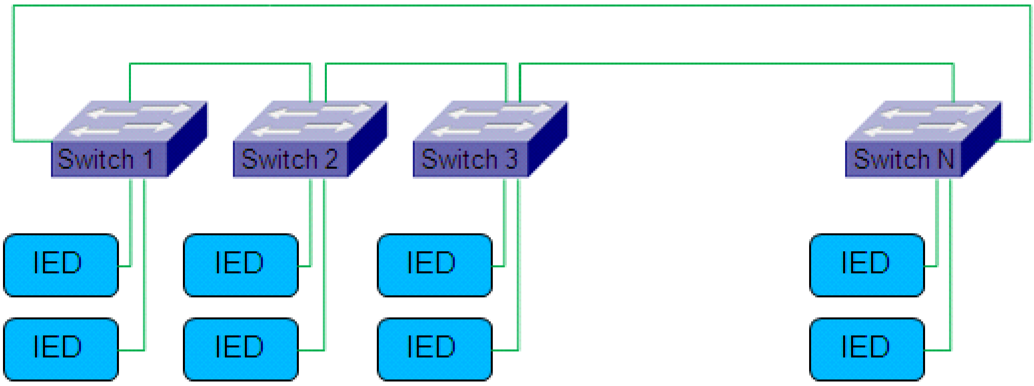


Figure 11. An example of ring topology. [20]

In the star topology all switches are connected to a backbone switch, thus forming a star configuration as illustrated in Figure 12. This topology offers the best latency compared to others, since communication between any two IEDs can be established via the backbone switch. However, it has no redundancy. If one of the switches fails the communication to IEDs connected to that switch is lost, or if the backbone switch fails, all the switches are isolated. [20]

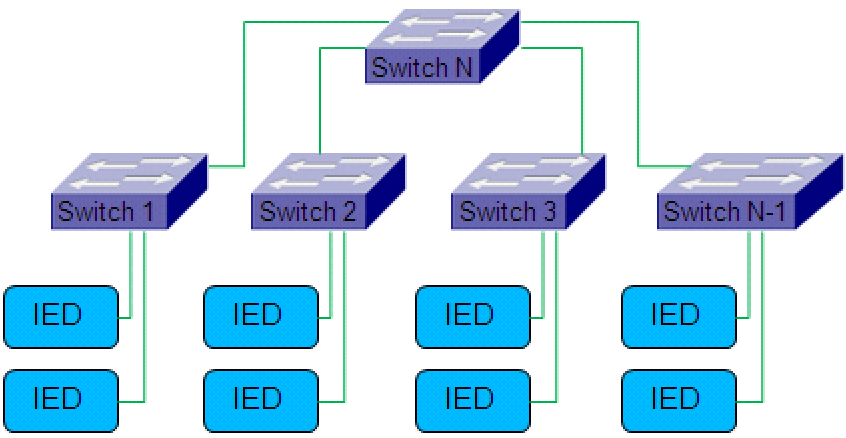


Figure 12. An example of star topology. [20]

In order to improve redundancy and latency the basic topologies can be merged. Basically any combination of topologies can be applied, but in this study two possible combinations to improve redundancy are presented. A fault tolerant hybrid topology, as illustrated in Figure 13, can offer enhanced redundancy by implementing two parallel star topologies connected to form a ring. [20]

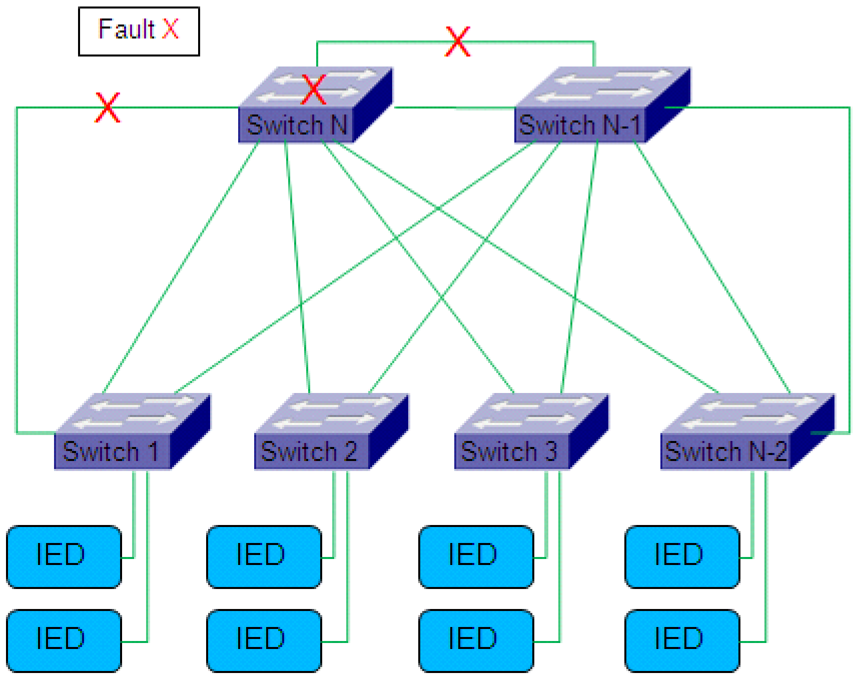


Figure 13. An example of fault tolerant hybrid topology. [20]

This kind of hybrid topology can tolerate certain faults, as depicted on Figure 13. Nevertheless, switches connected to IEDs are not redundant, thus communication faults can affect the performance of an SAS. By duplicating each switch and connection in the network a high redundancy can be achieved. This requires dual Ethernet ports in the

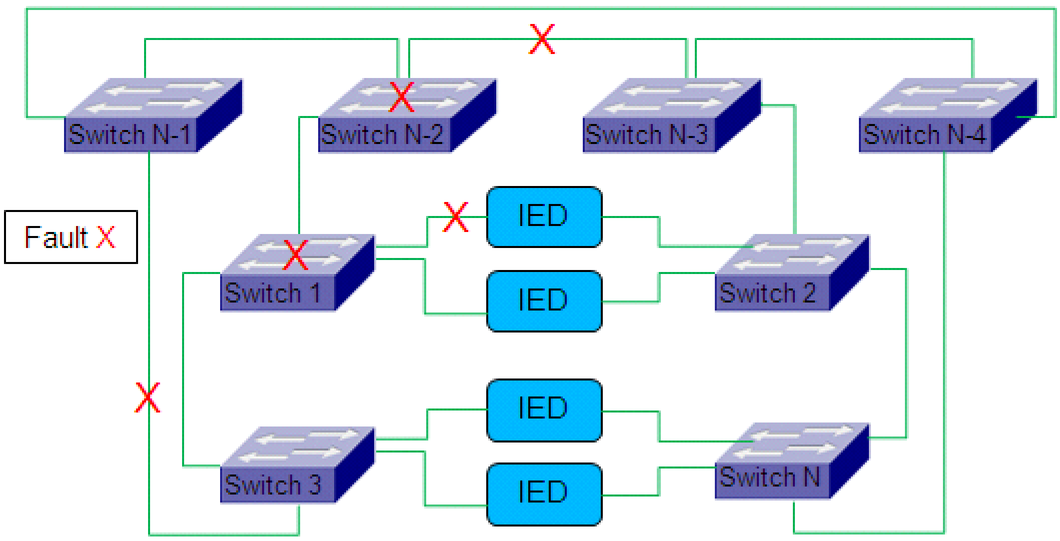


Figure 14. An example of duplicated high redundancy topology. [20]

IEDs, as each IED is connected via two separate links to the network. This kind of topology can tolerate any fault related to network equipment, as illustrated in Figure 14. Only the failure of an IED will isolate that particular IED from the network. Of course in critical applications this kind of failure has to be taken into account in the application itself, for instance by backup protection. [20]

3.4.2. Component Features

The IEC 61850 defines Ethernet as the physical layer of the OSI-model. The use of Ethernet requires that all IEDs are physically connected to an Ethernet switch. These connections form a Local Area Network (LAN), which the IEC 61850 uses for communication. Ethernet is based on frames of information, which can be sent to the LAN at any time. In order to meet the real-time control requirements of an SAS, Ethernet switches need to conform to certain features. These features offer advanced functions for layers 2 and 3 of the OSI model.

The IEEE 802.3x Full-Duplex operation on all ports makes sure that no collisions appear between the transmitted frames. This is achieved by a store and forward process within the Ethernet switch. The received packets are first buffered in the memory of the switch, placed in a queue, and then transmitted one by one as they reach the front of the queue. This makes Ethernet much more deterministic than the previous methods used for collision detection. The Full-Duplex operation can be found in unmanaged switches. However, for all other features required of the switches a managed switch is required. Therefore, only managed switches should be used with IEC 61850. [20; 21]

In order to ensure that time-critical information can pass through the switches without additional delay due to store and forward process, the IEEE 802.1p Priority Queuing has to be implemented within the switches. This feature allows frames to be tagged with different priority levels, allowing the frames with the highest priority to bypass the buffered memory of the switch, therefore eliminating additional delay. This means that priority tagged GOOSE messages are placed in front of the store and forward queue. The transmission of any frame is not interrupted when a priority tagged frame arrives in front of the queue. The priority tagged frame is just simply transmitted next. [20; 21]

The VLAN defined in IEEE 820.1Q allows to logically separate network to virtual LANs. This means that the same physical network sharing cabling and infrastructure can contain several VLANs. The different VLANs are indentified by the switches with a tag header on the Ethernet frame. Each VLAN has its own broadcast domain, which means that Ethernet frames from one VLAN will not be transmitted onto another VLAN. Different communication traffic of the IEC 61850 substation network can be segregated into separate VLANs. These separate VLANs could be used for instance to substation LAN management, MMS communication, GOOSE messages and sampled values in IEC 61850 network. The advantages of VLANs concerning GOOSE include restricted access to VLAN for GOOSE, and preserving free bandwidth as only GOOSE messages are allowed to use the specific VLAN. The use of VLANs in GOOSE communication is not mandatory, and is thus decided by the designer. It can be enabled by configuring the specified VLAN identification in the GOOSE control block, and by configuring same VLAN to switches in the network. [20; 21]

To achieve network redundancy some form of ring topology has to be applied. However, if a physical loop occurred in an Ethernet network, the first broadcasted frame would consume all available bandwidth by circulating endlessly in the loop. This is prevented by Rapid Spanning Tree Protocol (RSTP), defined in IEEE 802.1w. The RSTP puts certain links in the network into a backup state, which means that no traffic is allowed to flow across the link. This way any physical loops in the network are disconnected. The RSTP enables this by forming a logical tree network including all switches in the network. If network problems occur, the backup links are re-enabled in order to restore communication of all devices. This happens automatically within milliseconds and it works on any network topology. The RSTP also supports interoperability. Therefore, switches from different vendors can be implemented in the network. The RSTP has been enhanced by proprietary protocols. However, as they are not standardized solutions, they are not presented in this study. [20; 21]

The Internet Grouping Message Protocol (IGMP) Snooping/Multicast filtering allows the sending of multicast frames in the network, which are then filtered and assigned to those IED’s which request them. In IEC 61850 station bus GOOSE messages are sent as multicast frames, hence the requirement for IGMP is justified. [12; 15]

An important protocol related to redundancy is called Simple Network Management Protocol (SNMP). This protocol enables to verify the redundancy of the network in regular intervals. Therefore, any faults related to the network can be detected and recovered in order to maintain the redundancy of the network. [2]

3.4.3. Data Transfer Medium

The IEC 61850 defines Ethernet as a standard medium for the communication. Ethernet supports both widespread CAT5/RJ45 copper cabling and fiber optics. However, IEC 61850 does not specify whether copper or fiber optics should be used. This creates a technological and economical dilemma, as fiber optics has technical advantages but also a higher cost compared to copper cabling. Fiber optic cabling is immune to electromagnetic interference (EMI), which makes it well suitable for substation environment. Other advantages of fiber optics include ability to span long distances and maintain extensive bandwidth. The problem between copper and fiber cabling can be solved by a compromise. Copper interconnections between IEDs and Ethernet switches can be used for instance between bays and to use fiber to connect switches between switchgears. This compromise can be justified by the fact that IEDs within a bay are usually located inside the switchgear where connections are relatively short, therefore inducting less EMI to copper cabling. In the field of process industry electrification IEDs and Ethernet switches are usually located in metal enclosed cabinets. This creates a Faraday shield which removes EMI within the cabinet. The use of copper cabling in such cases is therefore further justified. However, the designer of the network should always compare between costs saved versus reliability and criticality of the electrical system.

Fiber optics has two basic types available in the market. These are multi-mode and single-mode fiber. A multi-mode fiber requires less expensive light source, but has limitations regarding distance and bandwidth. It can reliably carry signal over a distance of two kilometers at bandwidth of 100 Megabytes Per Second (MBPS) or 300 meters at 1000 MBPS. The single-mode fiber is more expensive as it requires a high quality laser light source. Its advantage is that it allows nearly infinite bandwidth with distances exceeding 100 kilometers. [21]

3.4.4. Information Security

When communication is performed via network, information security has to be considered. Generally information security of an SAS has been achieved by physically isolating the communication network from Wide Area Networks (WANs). Together with restricted access to the substation facility the isolation provides effective means to implement a required security level, as only authorized personnel are allowed to gain access to the network components. Access to network components should be restricted also within the substation, in order to avoid unintentional access to networks with critical tasks, such as networks used for IEC 61850-communication. In electrification of process industry, this means that the IEC 61850 network is situated in the same facilities as the switchgear equipment. However, interconnections to WANs might be required, for instance to provide customer support via internet. Usually this is done by a controllable switch, so that the owner of the switchgear can decide whether external communication is allowed or denied. If such interconnections are allowed, the substation LAN becomes vulnerable for attacks.

The IEC 61850 standard does not define information security, although it uses common protocols, such as Ethernet and TCP/IP, for data transmission. The IEC TC 57 recognized a need for another standard to specify security issues that would encompass the IEC 61850 series. This led to the development of IEC 62351, which covers security issues for IEC 60870-5, IEC 60870-6 and IEC 61850 series. Security for IEC 61850 is presented in part 6 of the IEC 62351 standard. For security issues concerning GOOSE the standard states that applications requiring multicast addressing and 4ms response times should not be encrypted. Instead, a communication path selection process should be used, which means that GOOSE messages should be restricted to a logical substation LAN. [22; 23]

Substation LAN should be designed as a private network, however, interconnections to WANs might be required, thus making the substation LAN vulnerable for attacks. The interconnections to WANs are enabled via a gateway. The gateway should provide security by using a firewall and an encrypted Virtual Private Network (VPN). However, it should be stated that because GOOSE does not use TCP/IP protocol, it is not possible to send GOOSE messages trough a gateway. Therefore, possible harm to GOOSE communication via a gateway can only be produced by reducing available bandwidth. This problem can be resolved by using encrypted VLANs, which secure configured bandwidth for each VLAN. [22; 23]

Information security can be further improved via layered security. Managed switches offer several means to implement this. By using VLANs, critical applications can be isolated in the same physical network. Switches can also have so called managed security by means of SSL/SSH. Independent port security and IEEE 802.1x can be deployed to deny physical access to the network. This means that only recognized computers can be connected to the network. The IEC 62351 working group is exploring more methods for making IEC 61850 and GOOSE messages more secure. [21]

4. APPLICATIONS OF GOOSE

Horizontal communication has a variety of possible applications in substation automation. Based on the input from the project team, only the most relevant applications for ABB Process Industry's PDC-solutions are considered. This input consists of prior experience and solutions used in customer projects. The selection of applications was also affected by the fact that the implementation should be possible with ABB's REF615 IEDs.

4.1. Process Industry Electrification

Process industry in general refers to metal-, petrochemical- and forest industry. ABB Process Industry is specialized in electrification and instrumentation of pulp and paper factories. The variety of completed customer projects is large, including both greenfield and renovation sites. From the perspective of electrification, each project is unique and the scale varies substantially. An overview of process industry electrification equipment is presented in Figure 15.

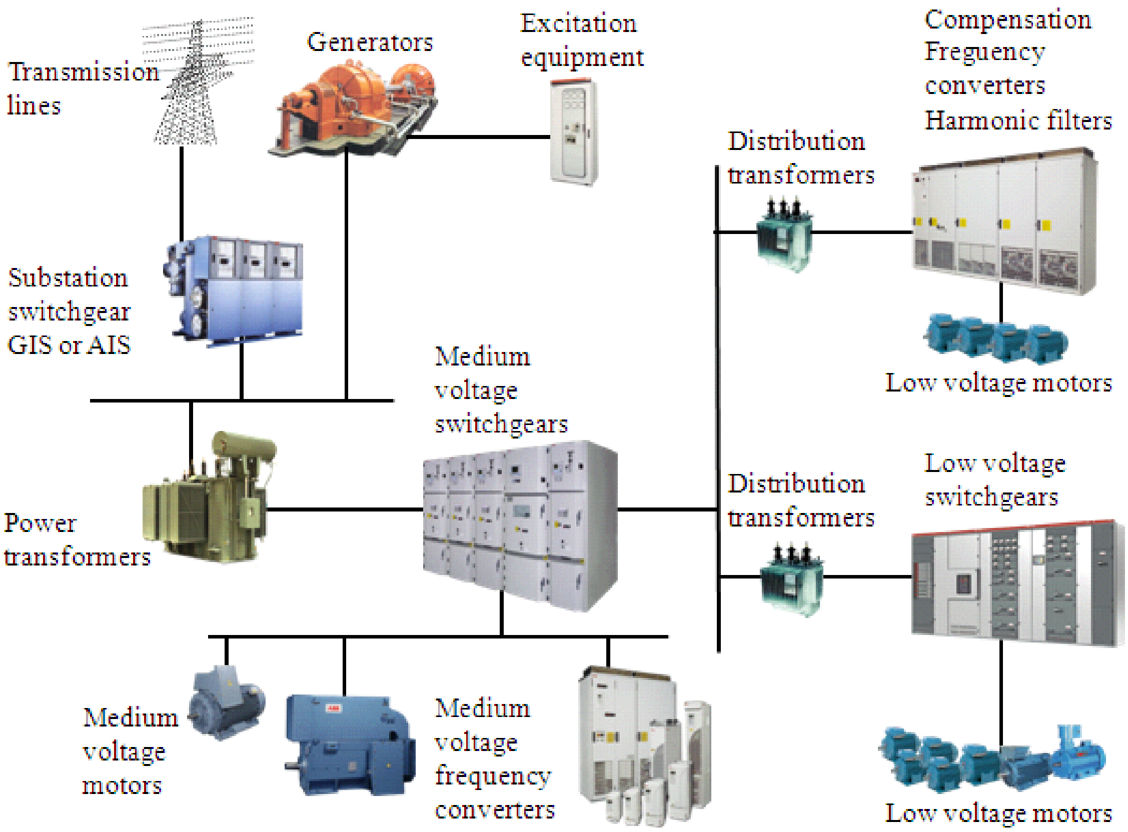


Figure 15. A general overview of process industry electrification.

Typically industrial power systems have relatively high short-circuit currents and the power density of the system is high. Most of the load consists of electric motors with a majority of asynchronous motors. This can create disturbances in the power system if adequate filtering is not implemented. In order to ensure the persistence of the industrial process different control and data acquisition systems need to be implemented. These include systems for power distribution control and process automation. [24]

In complete electrification of a pulp and paper factory the scope of the project is vast. Electrification starts with the energy production, which can be done either locally or via a distribution network. If the required energy is produced locally by generators, they require adequate protection. Energy can also be transferred from power plants via transmission lines, which requires substation with either Air-Insulated Switchgear (AIS) or Gas-Insulated Switchgear (GIS). In the transmission level reactive power compensation might also be required by local distribution company. Electrical energy is transferred from the generators or switchgear trough transformers to Medium Voltage (MV) switchgears. The MV switchgear supplies power to MV motors and possibly to MV frequency converters. Adequate protection for motors is required, and the use of frequency converters usually demands harmonic filtering. From the MV switchgear power is further supplied to Low Voltage (LV) switchgear via distribution transformers. The LV switchgears provide power to LV motors and other process equipment, for instance instrumentation devices. Instrumentation and its requirements are beyond the scope of this study.

Trough the complete chain of power distribution, adequate protection and control of the equipment must be provided. This means that the power system is safe to use and it can isolate faults preferably without interrupting critical processes. The designing of a dependable power system is always a task of economical optimizing. This means that a certain amount of interruptions must be tolerated, because a totally dependable system would be too expensive. In process industry electrification even short interruptions in power distribution can cause substantially long or expensive interruptions in the industrial process. [24]

The presented power system requires a control and monitoring system, possibly with an interface to local power company’s control system. An interface with process automation control system is often required as well. This creates challenges for the engineering of communication, as different control systems need to be able to exchange information.

4.2. Conventional Solution

Information exchange between bay level devices is conventionally realized by hardwiring. This means that any information which should be transferred to another IED is assigned to an output contact. The terminals of this output contact are then wired to an input in the receiving IED. The functions of the inputs are configured in the receiving IED by using proprietary configuration software. The principle of hardwiring is to use specific wiring for every transferred signal. As a number of inputs and outputs are needed to interact with the circuit breakers, disconnectors and earth switches, the use of hardwiring is limited to the available number of inputs and outputs of a given IED.

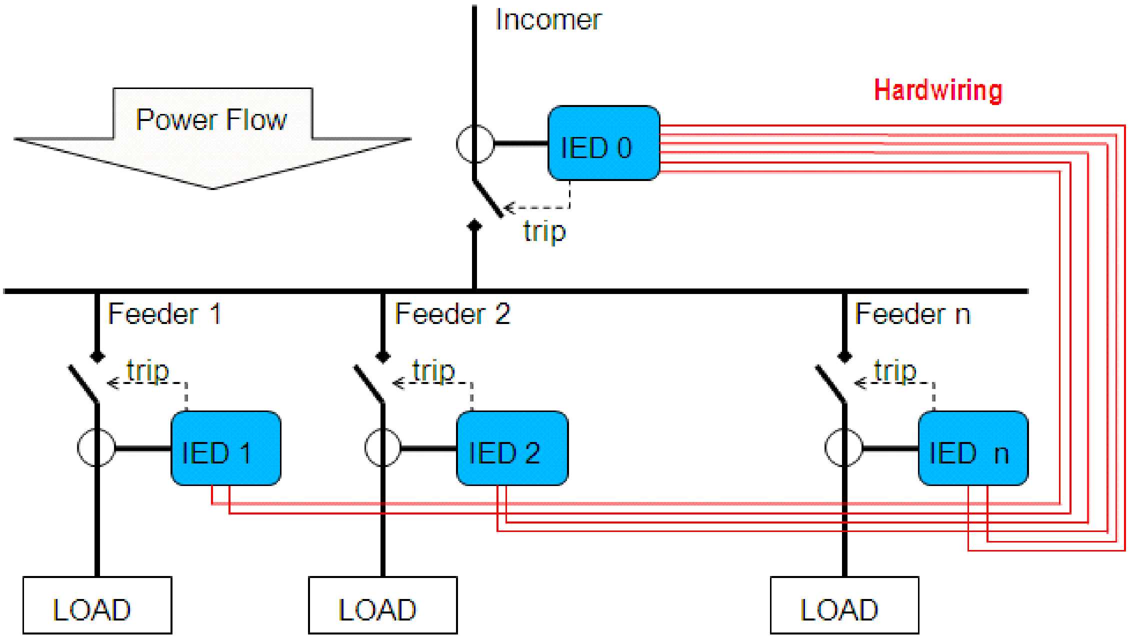


Figure 16. An example of horizontal communication via hardwiring.

An example of a hardwired solution can be illustrated by a simple blocking scheme, which is presented in Figure 16. If any of the feeder IEDs, for example IED 1 detects an overcurrent situation, the start signal of overcurrent protection is transferred upstream to IED 0 via hardwiring marked with red lines. This signal can then be used to block the fast stage overcurrent protection in the incomer IED 0, allowing the feeder IED 1 enough time to send a trip signal for clearing the fault. Without the blocking scheme, the upstream IED 0 would detect the overcurrent and send a trip signal, which would interrupt power flow for all feeder IEDs. Therefore, blocking can reduce the size of the affected area in fault situations. However, in order for the blocking application to work, the overcurrent start signal will have to be hardwired from all feeder IEDs, therefore resulting in a lot of assembly work and wiring.

When the number of IEDs increases, the number of individual wires becomes excessive due to the information exchange required between all relays taking part in the blocking application. Within an SAS there can be a number of other applications, which require horizontal communication between IEDs. Typical signals between switchgear bays include breaker, disconnector and earth switch status signals, service and interlocking position information, and protection start signals. Hardwiring is also used for signaling to and from external systems, for example Remote Terminal Units (RTU) or other automation systems. As well as the signals between bays, current, voltage and power measurements are transferred. This is often the case in process industry electrification, where process automation and SAS have interfaces.

4.3. GOOSE Solution

The purpose of GOOSE messages is to replace hardwired signals by unambiguously naming all elements of data and then transferring this data via Ethernet network station bus. This is illustrated in Figure 17 with a similar scheme as presented in the previous chapter. The use of GOOSE can be achieved by using the object model of substation information, which is described in IEC 61850-7-4. When the object oriented data model is used, each data attribute will have a unique name in the whole substation, and thus the subscriber and publisher of this data will know where it originated. Required data for certain application can be organized and transferred as GOOSE message.

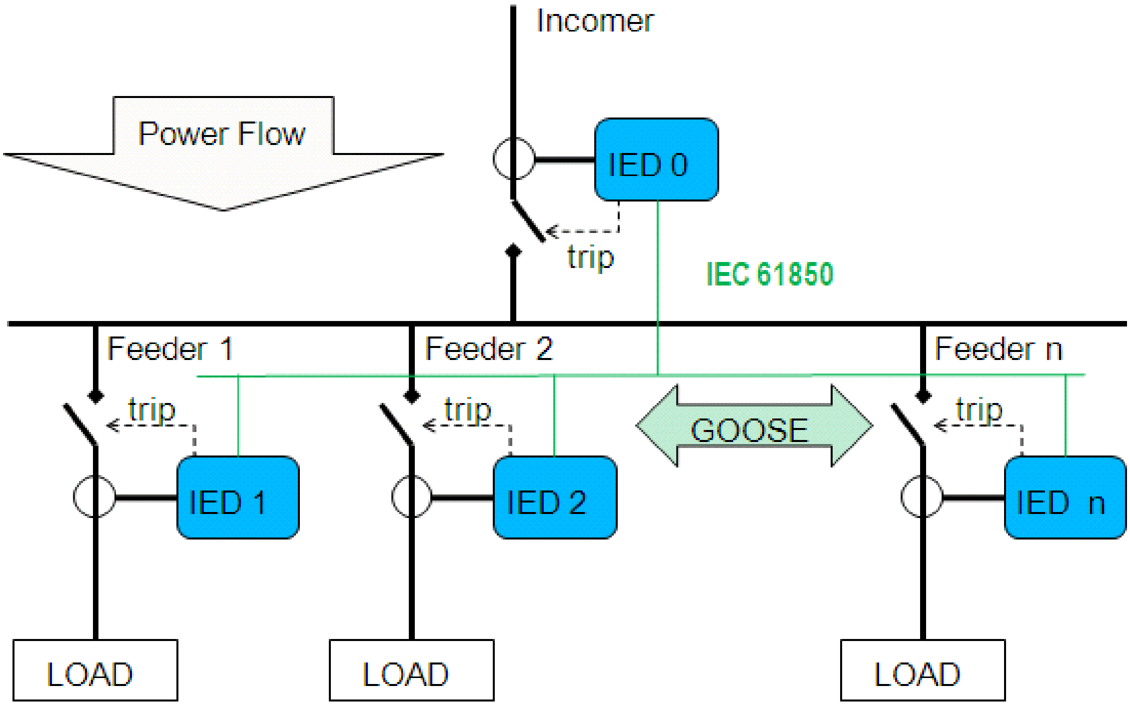


Figure 17. An example of horizontal communication via GOOSE

The configuration of GOOSE messages is done by using proprietary software tools. The desired data attributes are attached into a dataset, and this dataset is then configured to be sent as a GOOSE message. The sending of a dataset via GOOSE needs specific GOOSE Control Block, where essential information regarding GOOSE traffic is presented. Detailed description of GOCB is presented in Chapter 3.3.3. The subscribers of the GOOSE message are also defined in the configuration process. Information sent via GOOSE needs to be configured in the receiving IEDs to perform the desired function. This is done by virtually connecting the signals inside the IED and configuring them to perform desired application. After the configuration is done, the information of the SCD file is uploaded separately into IEDs. All IEDs within the substation need to get this information, therefore the proprietary software tools must be able to import the SCD file into the IEDs via network. Finally the physical connections have to be established by implementing Ethernet switches and cabling between substation IEDs. The requirements for network components are described further in Chapter 3.4.2.

4.4. Benefits of GOOSE

Extensive hardwiring of signals creates significant cost in switchgear installations. The amount of hardwiring required for typical 10-bay medium voltage switchgear installation is pictured in Table 8. When the amount of hardwiring needed is so vast, it becomes apparent that the use of GOOSE communication can significantly reduce costs in switchgear installations. [25]

Table 8. I/O wiring in conventional hardwired medium voltage switchgear. [25]

Number of IO wires	Between protection and control devices	Between other devices	Total
Inter-bay signaling	104	116	220
Automation system	85	47	132
Other external systems	383	252	635
Total	572	415	987

An important characteristic of GOOSE is that communication is monitored. As presented in Chapter 3.3.3 GOOSE messages are sent periodically even if no data change occurs. If these periodically sent messages disappear, the loss of horizontal communication can be detected. In conventional solutions, failure in the communication can be detected either in regular testing, or when an application fails to work. The period for regular tests is from one to three years depending on the customer. Thus in practice the communication is not monitored at all in hardwired solutions. In GOOSE based solutions communication failures can be detected within seconds, depending on the IEDs.

Other benefits of GOOSE include the expandability of the SAS without additional hardwiring between IEDs. New hardwiring is only required between process equipment and the implemented IEDs. Similarly, new applications or modifications to existing applications can be implemented without incremental hardwiring, as required data can be transferred via GOOSE.

4.5. GOOSE Applications

Different protection and control applications, which can be realized by using GOOSE communication, are presented in the following chapters. Each application is first described in general, and then the functions and signals required for GOOSE solution are presented. The functions and signals are defined according the IEC 61850 standard. The signals are presented in tables, for example Table 9. These tables state the name of the GOOSE publisher IED and the name of the GOOSE subscriber including the function block input where the GOOSE signals needs to be connected. On the third column a general description of the signals is given followed by an example of the required data attributes for ABB's REF615 IED's. The underlined parts of the name path are defined by the standard, whereas other parts can be chosen by the vendor, in this case ABB. The data attributes for each signal were found by investigating the appropriate LN for the application from the IEC 61850. Manuals for REF615 IEDs were also used as a source in order to create examples of the applications. By examining the list of data classes defined for that LN the correct data objects were selected. Similarly, the data classes have defined tables of data attributes, from which the proper attributes for each signal could be selected. Because the names of the LNs, data classes and data attributes are defined by the standard, they were easy to locate in the IED communication configuration software.

Table 9. An exemplary table of the application signals.

Publisher	Subscriber	Signal description	Data attributes for REF615
Publisher IED's name	Subscriber IED's name *Function Block Input*	General description	LD.$$LN$$.DataClass.DataAttribute

The REF615, which was selected for this study by the project team, is a dedicated feeder IED. It is designed for protection, control, measurement and supervision of utility substations and industrial power systems. The REF615 is designed according to IEC 61850, therefore it fully supports GOOSE communication. The REF615 can be ordered in six different variants from A to F, which all include a different standard configuration. The GOOSE communication is application specific, and therefore it has to be individually configured to IEDs depending on the application. In the following chapters selected applications for this study are presented, and the possible implementation with REF615 IEDs is given as an example.

4.5.1. Bay Interlocking

Switchgear interlocking is used to prevent switchgear operation, which could lead to malfunction or damage of primary switching equipment. This is achieved by comparing switch positions in related switches or disconnectors, and determining the individual interlocking conditions to switches according to logical rules. Based on the logical rules between switch positions, interlocking can either prevent or allows switching execution. The conditions for interlocking depend on the station configuration. In bay interlocking only the switch positions in the same bay are evaluated, as presented in the following example.

In order to provide safe working conditions for assembly or maintenance work in switchgear certain conditions have to be met. The switchgear must be isolated from the power system and it must be grounded. Generally, this means using two types of bay interlocking. When the disconnector is closed, the closing of the earth switch circuit breaker is locked. Another type of interlocking must be used when earth switch is closed, and the work in the switchgear is in progress. In this case all disconnectors of lines capable of power feed to the line in question must be locked to open position. Therefore, the closing of related circuit breakers has to be locked. The status values of disconnectors and earth switches are conventionally hardwired in order to implement this type of interlocking applications. These values can be transmitted via GOOSE by using the signals provided in the logical node XSWI. These signals are presented in Table 10 with descriptions.

Table 10. Signals for bay interlocking example.

Publisher	Subscriber	Signal description	Data attributes
Infeed IED 0	Feeder IED 1 *CBXCBR1* *BLK_CLOSE*	Disconnector position Position closed Position ok	 CTRL.DCSXSWI1.PosCls.stVal CTRL.DCSXSWI1.PosOk.stVal
Feeder IED 1	Infeed IED 0 *CBXCBR1* *BLK_CLOSE*	Earth switch position Position closed Position ok	 CTRL.ESSXSWI1.PosCls.stVal CTRL.ESSXSWI1.PosOk.stVal

An example of bay interlocking is pictured in Figure 18. For simplicity, only one disconnector and one earth switch are presented. If the disconnector is closed, the Feeder IED1 controlling the earth switch needs the *position closed* and *position ok* signals from the Incomer IED0, which are depicted in blue color in Figure 18. The *position ok* signal means that the disconnector is not between positions, in other words the information is valid. If either of the signals equals true, the closing of the related circuit breaker is locked. In the case of REF615 this is done by virtually connecting signals via a logical OR gate to CBXCBR1 function BLK_CLOSE input. Similarly, in the opposite case, when the earth switch is closed, the Infeed IED0 needs the signals stating that the earth switch position is *closed* and *ok*. These signals are virtually connected via OR gate to the locking input of CBXCBR1.

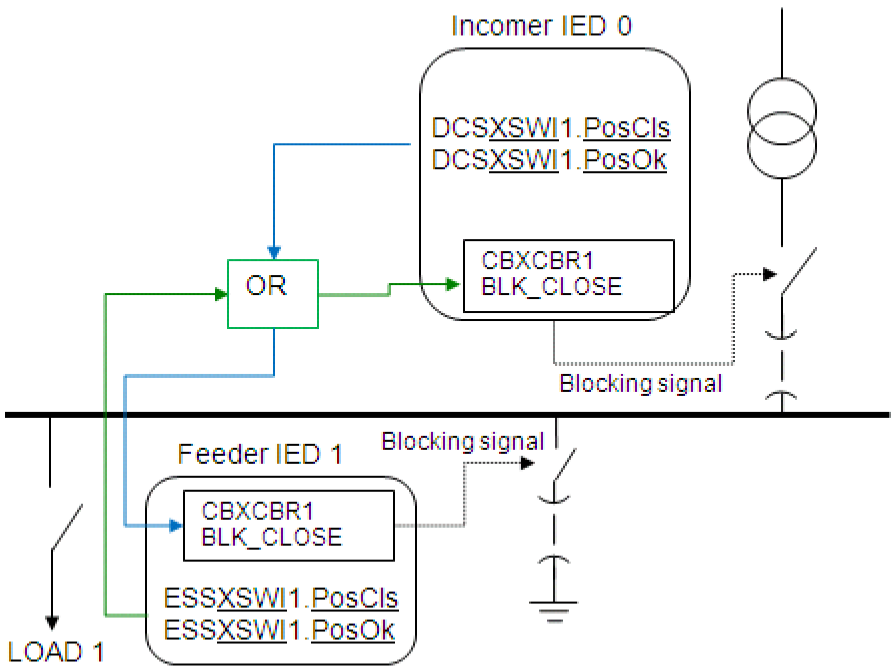


Figure 18. Example of bay interlocking application.

The control functions providing these signals are included in variants B, D, E and F of REF615. There are three functions for disconnectors and one for earth switch indicator. In the given example only one disconnector function is applied, the other two functions are separated by increasing the number after the LN.

4.5.2. Inter-Bay Interlocking

In interlocking schemes, where switch positions in other bays need to be taken into account the applications are referred to as inter-bay interlocking. Conventionally, an SAS is used for inter-bay interlocking schemes. In these schemes all feeder and bay controllers report the switch positions to a station controller, which then evaluates and defines interlocking conditions. In conventional designs, this leads to a vast amount of hardwiring.

When similar schemes are realized by using GOOSE, the switch positions can be transmitted directly between bay controllers, as presented in Figure 19. The evaluation and definition of interlocking conditions can be done directly in the IEDs instead of the station controller. When switch positions are transferred as GOOSE messages, only the signals controlling the disconnectors remain hardwired. Therefore, the need of hardwiring is reduced. As interlocking schemes depend on station configuration, an overall description of transmitted signals is not possible. However, interlocking applications can be represented by the example depicted in Figure 19. In the example, interlocking is used to enable or interlock the circuit breaker QA1, which connects the two busbars.

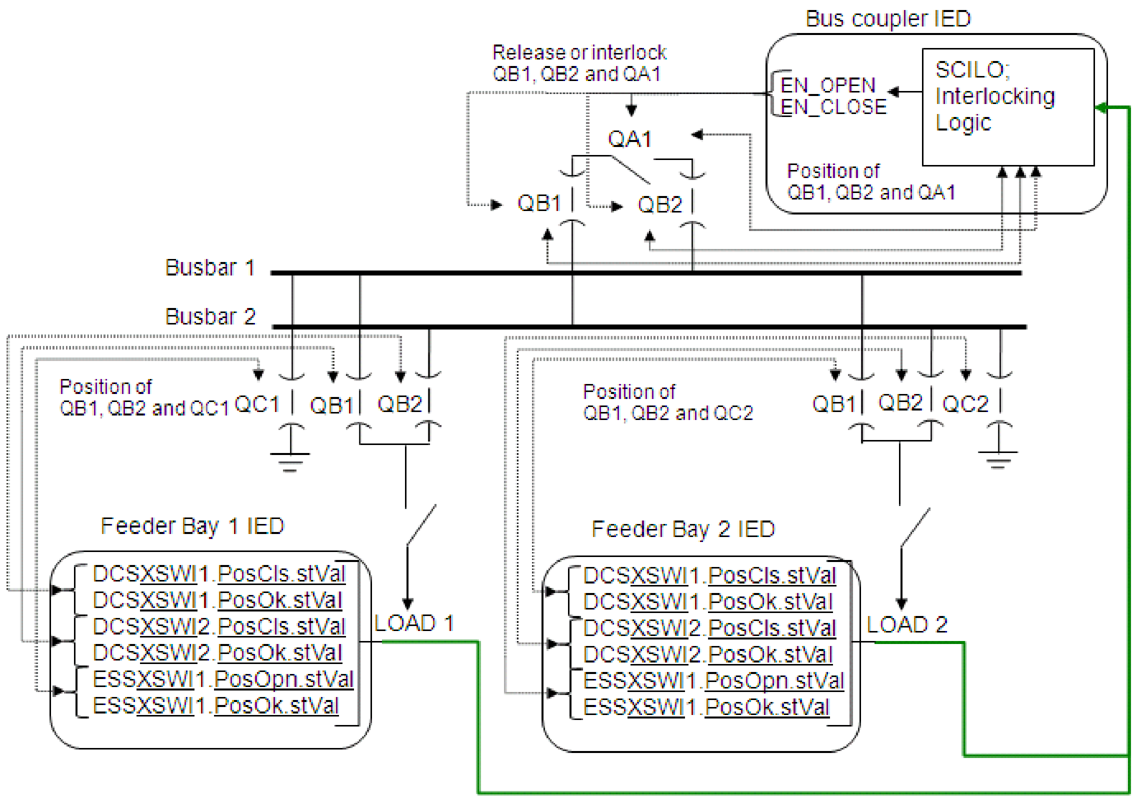


Figure 19. An example of inter-bay interlocking application.

In the IEC 61850 a logical node called SCILO is defined for interlocking purposes. However, this LN is not included in the REF615 IEDs and therefore they can only be used to send required information for interlocking function located in the bus coupler IED. The configuration of the interlocking logic to the SCILO LN is beyond the scope of this study. Instead, exemplary switching conditions for bus coupling disconnectors and circuit breaker are given in Table 11.

Table 11. Switching conditions for bus coupler bay.

Switch and direction	Interlocking conditions
QA1 open	not allowed if: ((feeder 1A: QB1 = closed) AND (feeder 1A: QB2 = closed)) OR ((feeder 2A: QB1 = closed) AND (feeder 2A: QB2 = closed))
QA1 close	allowed if: the disconnectors of the bay are not between positions AND earthing switches QC1 and QC2 are open
QB1 open / close	allowed if: QA1 = open
QB2 open / close	allowed if: QA1 = open

For the given exemplary switching conditions, the signals presented in Table 12 should be transmitted via GOOSE, in order to transfer required information for the interlocking scheme. Both feeder IEDs publish the status information of their disconnectors and earthing switches. As stated in Table 11, the opening of circuit breaker QA1 is not allowed if both disconnectors in either bay 1 or bay 2 are closed. Therefore, the data attributes *CTRL.DCSXSWI1.PosCls.stVal* and *CTRL.DCSXSWI2.PosCls.stVal* are included in the GOOSE message. In order to verify that disconnectors are not between positions the *PosOk.stVal* attributes are transferred. Similar attributes indicate that earthing switches are open and not between positions. Thus, all required information for this exemplary interlocking function is transferred via GOOSE.

Table 12. Signals for inter-bay interlocking example.

Publisher	Subscriber	Signal description	Data attributes
Feeder bay 1	Bus coupler	Disconnectors QB1 and QB2 in bay 1 are closed and not between stages, and earthing switch QC1 is open.	CTRL.DCSXSWI1.PosCls.stVal CTRL.DCSXSWI1.PosOk.stVal CTRL.DCSXSWI2.PosCls.stVal CTRL.DCSXSWI2.PosOk.stVal CTRL.ESSXSWI1.PosOpn.stVal CTRL.ESSXSWI1.PosOk.stVal
Feeder bay 2	Bus coupler	Disconnectors QB1 and QB2 in bay 2 are closed and not between stages, and earthing switch QC2 is open.	CTRL.DCSXSWI1.PosCls.stVal CTRL.DCSXSWI1.PosOk.stVal CTRL.DCSXSWI2.PosCls.stVal CTRL.DCSXSWI2.PosOk.stVal CTRL.ESSXSWI1.PosOpn.stVal CTRL.ESSXSWI1.PosOk.stVal

In real interlocking applications the number of required position signals is often vast. For simplicity, the number of signals was kept low in this example. The REF615 IEDs do not have the required logical node SCILO for creating interlocking logic. However, standard configurations B, D, E and F have the required control functions for transferring disconnector and earth switch positions. For the actual implementation of sophisticated interlocking schemes more complex IEDs, for instance RE_630, RE_650 or RE_670 are required.

4.5.3. Reverse Blocking

Blocking applications are used to restrict a fault in the power system to a smaller area. One typical application is reverse blocking, which is used for high speed busbar protection. In reverse blocking the instantaneous overcurrent protection stage of an upstream incomer IED is blocked by a downstream feeder IED, which operates and isolates the fault. By blocking the fast operation of the incomer IED, the influence of the fault can be limited to the feeding line where the fault occurred. If the feeder IED cannot isolate the fault, the incomer IED will clear the fault after the predefined delay of low stage overcurrent protection. The blocking signal is transferred in reverse direction compared to power flow, hence the name reverse blocking. Conventionally, this application needs hardwiring for each blocking signal from the feeder IEDs to the incomer IED. If the same application is realized with GOOSE, the blocking signals can be transmitted via GOOSE messages. In IEC 61850 the logical node PTOC is defined for time overcurrent protection. Depending on proprietary solutions, the PTOC LN can have more than one function with different operation time characteristics. For example, in ABB's REF615 IEDs, there are four PTOC functions for non-directional overcurrent protection. These are named PHLPTOC1, PHHPTOC1, PHHPTOC2 and PHIPTOC1 for low, high and instantaneous stages respectively, including two instances for high stage. The following example uses these function blocks in order to demonstrate a reverse blocking application, as depicted in Figure 20.

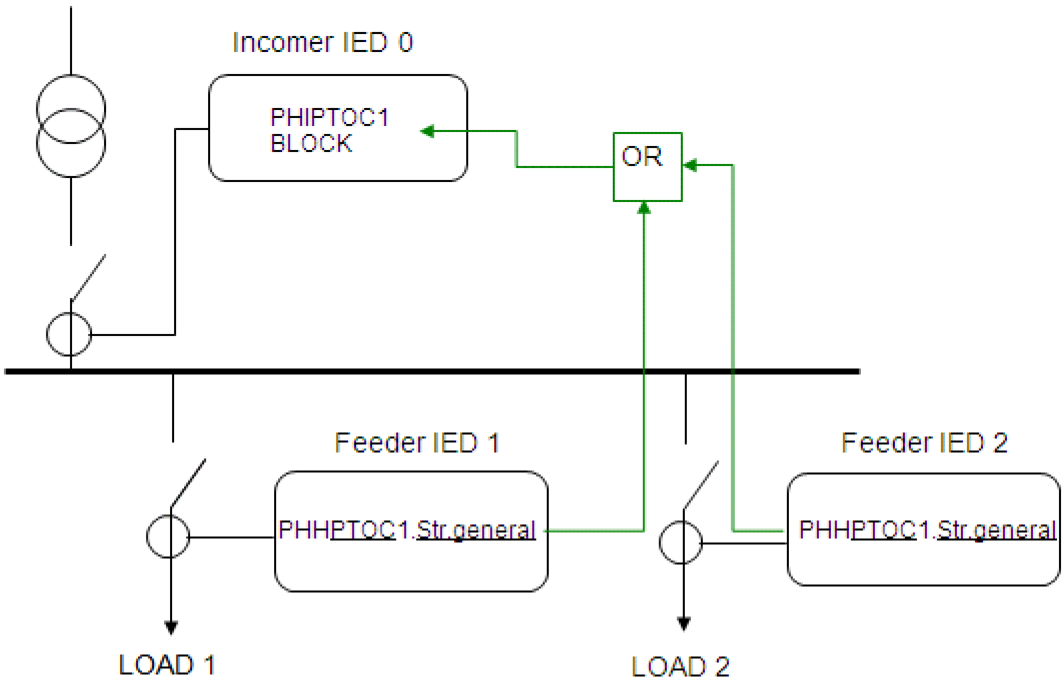


Figure 20. Example of reverse blocking application.

When one of the feeder IEDs high stage overcurrent protection function detects a fault, the start signal is sent via GOOSE to incomer IED 0. This start signal is configured to block the instantaneous stage overcurrent protection in IED 0, and therefore the feeder IED has a chance to clear the fault by tripping related circuit breaker. If this does not clear the fault, the high stage overcurrent protection of the incomer IED will operate, and clear the fault after the configured delay time. The use of reverse blocking can thus potentially minimize the impact of a fault.

Table 13. Signals for reverse blocking example.

Publisher	Subscriber	Signal description	Data attributes
Feeder 1	Incomer IED *PHIPTOC1 BLOCK*	Start signal of high stage non-directional overcurrent protection	LD0.PHHPTOC1.Str.general
Feeder 2	Incomer IED *PHIPTOC1 BLOCK*	Start signal of high stage non-directional overcurrent protection	LD0.PHHPTOC1.Str.general

The signals required for the presented example are listed in Table 13. The required function of non-directional overcurrent protection is available in standard configurations A to E of REF615 IEDs.

4.5.4. Breaker Failure Protection

When an IED detects a fault in the power system, it will operate and send a trip signal to the circuit breaker. Under normal conditions the circuit breaker will open and isolate the fault from the power system. Thus the operation of a circuit breaker is essential for the protection function to perform as desired. If the circuit breaker fails to operate, the fault can cause further damage or threat the stability of the power system. In order to avoid this, a breaker failure protection can be implemented. This is achieved by monitoring the time delay between the trip signal and the actual opening of the circuit breaker. If the fault current has not been interrupted within a set time delay from the circuit breaker trip, the breaker failure protection is initiated. This is realized by sending a trip signal to adjacent circuit breakers in order to ensure that the fault is isolated. This trip signal can be sent via GOOSE communication.

Table 14. Signals for circuit breaker failure example.

Publisher	Subscriber	Signal description	Data attributes
Feeder 1	Incomer IED *TRPPTRC1:1 TRIP*	Signal for external backup trip	LD0.CCBRBRF1.OpEx.general
Feeder 2	Incomer IED *TRPPTRC1:1 TRIP*	Signal for external backup trip	LD0.CCBRBRF1.OpEx.general

In ABB's REF615 there is a specific function for circuit breaker failure protection, the CCBRBRF, which is based on the RBRF logical node defined in IEC 61850. The function is available in all standard configurations of REF615. This function has two independent timers for re-tripping. One timer is for internal re-trip of its own breaker and another for external back-up trip. The required signals for external upstream trips are listed in Table 14. This signal can be configured in the receiving IED to perform tripping of related circuit breaker. An illustration of the example is given in Figure 21.

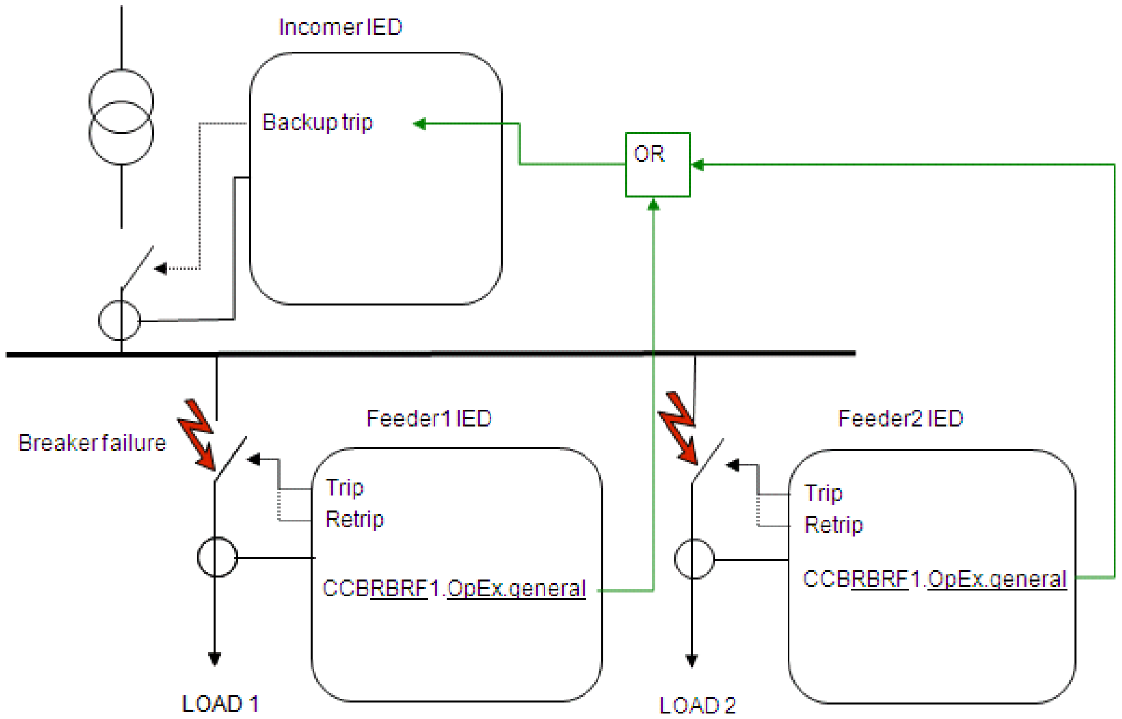


Figure 21. An example of circuit breaker failure protection.

In the presented example both feeder IEDs have circuit breaker failure function. In case of breaker failure, the function will try to re-trip the circuit breaker after the initial trip signal has failed. If the re-trip signal cannot isolate the fault, the function will send back-up trip signal to upstream incomer IED. This signal is configured in the incomer IED to trip the related circuit breaker. The breaker failure protection is useful for achieving the n-1 criterion, which means that the fault is cleared from the system even if one component fails to clear the fault.

4.5.5. Fault Arc Protection

Fault arc protection is used to detect arc situations in air insulated metal-clad switchgear, which can be caused by insulation breakdown during operation or human errors during maintenance. According to IEC 61850, the arc protection is realized by protection logical node SARC. This LN is used as a function, which monitors phase and residual currents and can detect light either locally or remotely in order to make accurate decisions on ongoing arc situations. When an arc situation is detected, the function sends trip signal to the related circuit breaker. However, if the arc is located upstream in relation to power flow direction, the circuit breaker cannot isolate the fault. This can also be the case if the arc is located within the circuit breaker compartment. In these cases, the arc protection IED can send fault arc detection signal to upstream IED which can isolate the fault by opening the related circuit breaker. This signal can be sent by using GOOSE. The upstream IED is also equipped with SARC function and the arc fault detection can be used as an input in remote light detection. In order to avoid unnecessary tripping, it is convenient if the arc protection IED has different light sensors. These sensors can be installed, for example, in the busbar compartment, the breaker compartment or the cable compartment of the switchgear.

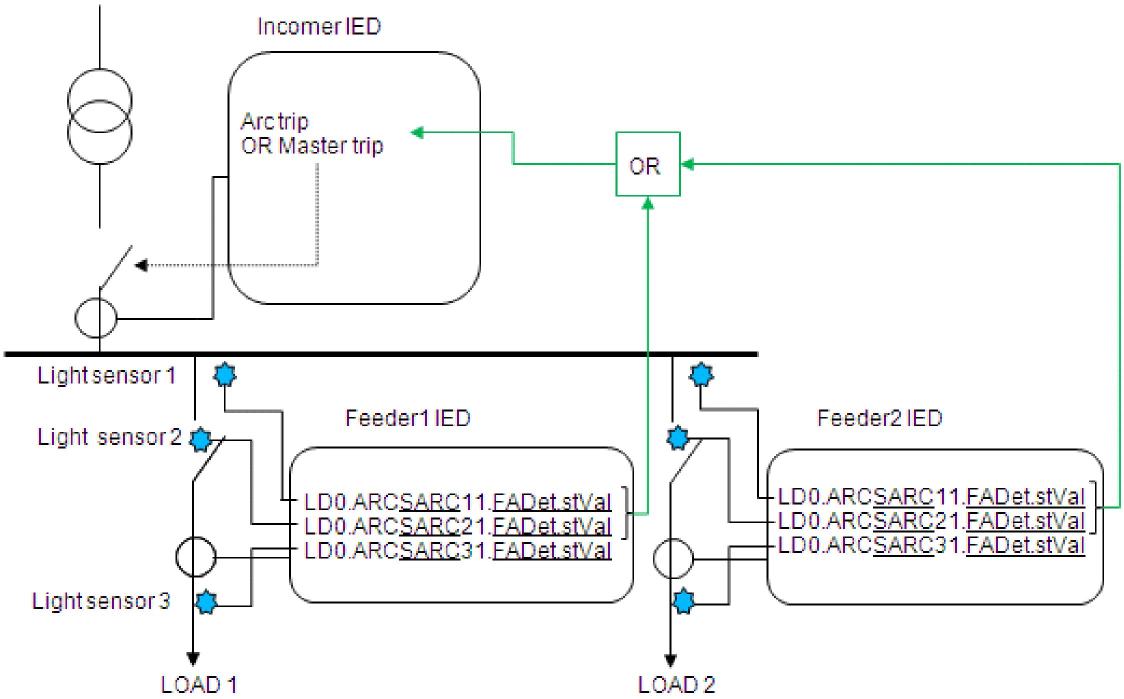


Figure 22. Example of fault arc protection application.

In the REF615s the fault arc protection is available as an optional function in all standard configurations. As depicted in Figure 22, the REF615 has three different light sensors for the fault arc detection. In the given example the sensors are placed in the cable compartment, the circuit breaker compartment and the busbar compartment. If one of the feeder IEDs detects an ongoing arching situation in either sensor 1 or 2, the IED sends a GOOSE message to the upstream incomer IED. Because the sensors one and two are in the busbar and the circuit breaker compartment, the feeder IED cannot isolate the fault. The fault arc detection signal is transferred to incomer IED, where it is virtually connected to the related ARCSARC function as remotely detected arc fault. Together with phase current values the function concludes that there is an arching situation, and opens the circuit breaker. The result is the same whether the light is detected with sensor 1 or sensor 2.

Table 15. Signals for fault arc protection.

Publisher	Subscriber	Signal description	Data attributes
Feeder 1	Incomer IED	Fault arc detected:	
	ARCSARC1 REM_FLT_ARC	Light sensor 1	LD0.ARCSARC11.FADet.stVal
	ARCSARC2 REM_FLT_ARC	Light sensor 2	LD0.ARCSARC21.FADet.stVal
Feeder 2	Incomer IED	Fault arc detected:	
	ARCSARC1 REM_FLT_ARC	Light sensor 1	LD0.ARCSARC11.FADet.stVal
	ARCSARC2 REM_FLT_ARC	Light sensor 2	LD0.ARCSARC21.FADet.stVal

The required signals for this example are listed in Table 15. Arc fault protection was selected by the project team as the application that would be demonstrated and tested as a part of this study. Therefore, detailed description of the configuration and testing of transferred arc protection trip is presented in Chapter 5.

4.5.6. Triggering of Disturbance Recording

When a fault occurs in a power system, a disturbance record from a time period including values prior and after the fault can be very useful on order to analyze why the fault occurred. In IEC 61850 a dedicated LN is defined for disturbance recording, which is named RDRE. This LN describes basic functions of the disturbance recorder. For consistent modeling, the disturbance recorder function is decomposed into one LN class for analogue channels and one LN class for binary channels, named RADR and RBDR respectively.

In IEDs the triggering of disturbance recording can be configured to happen automatically, for example when a trip signal is commenced. In some cases it would be useful to have disturbance records from other parts of the power system as well, in order to see how the fault has affected them. The triggering of these recordings can be achieved by GOOSE communication. For instance, the trip signal of an IED can be send via GOOSE to adjacent IEDs, and this signal can be used as a trigger of disturbance recording.

In the example pictured in Figure 23 the start signals of overcurrent protection are being used to trigger the disturbance recorder in the incomer IED. The standard defines PTOC function for non-directional time overcurrent protection. In REF615 IED’s there are low stage, high stage instance 1, high stage instance 2 and instantaneous stage functions for non-directional time overcurrent protection. The functions are named PHLPTOC1, PHHPTOC1, PHHPTOC2 and PHIPTOC1 respectively. The non-directional overcurrent protection functions are available in standard configurations A to E. In standard configuration F overcurrent protection is directional, and its functions are named DPHLPDOC1, DPHLPDOC2 and DPHHPDOC1, with two instances for low stage. The instantaneous stage remains non-directional, therefore the PHIPTOC1 function is used. These functions have similar data attributes for GOOSE communication, thus only non-directional functions are presented in this example.

Start signals of all three stages are transferred via GOOSE to the upstream IED as pictured in Figure 23. If the disturbance records are required only from actual fault situations, the operate signal of the protection functions can also be used. In this case the last two parts of the transferred data attribute's name would be changed to *Op.general*.

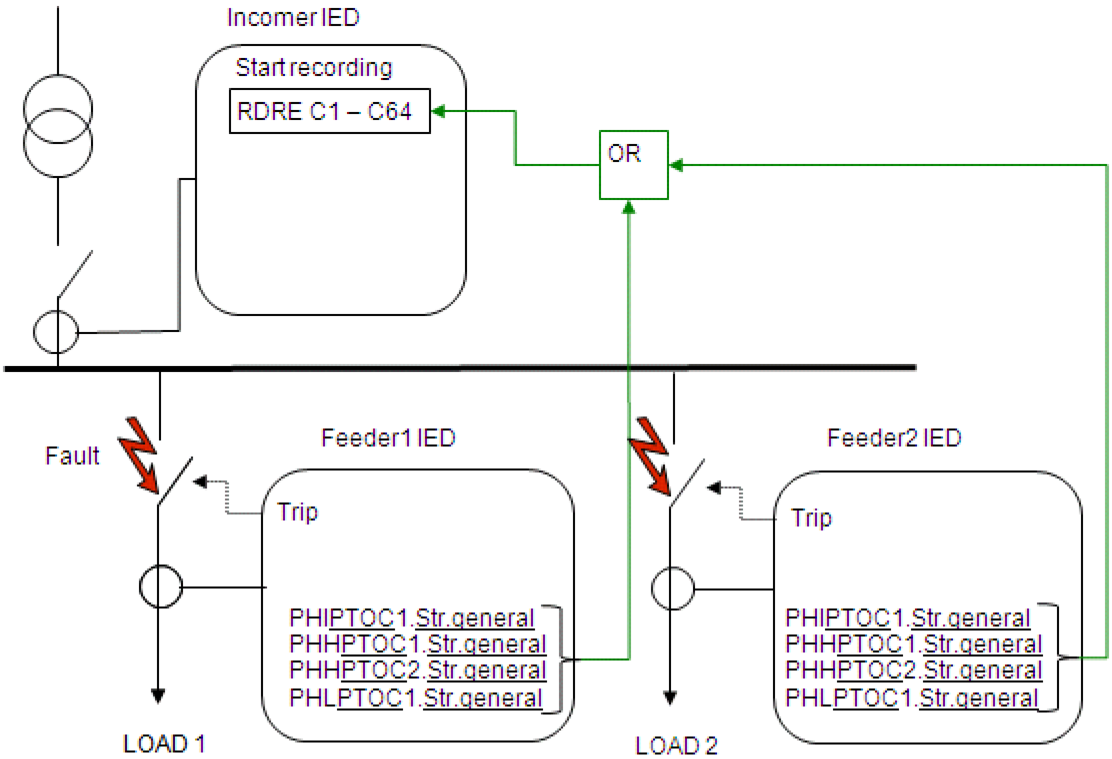


Figure 23. Example of disturbance recorder triggering.

In REF615 IEDs the disturbance recorder has up to 12 analog and 64 binary signal channels. This function is available in all standard configurations. The triggering of these channels can be done in several ways. The analog channels can be triggered on limit violations, and the binary channels on state changes. Both channel types can also be triggered periodically or manually. The manual triggering can be done via a parameter called trig recording. The trig recording can be configured to start via local human machine interface (HMI) or GOOSE communication. If GOOSE communication is used, the incoming signal is virtually connected to one binary input, which triggers the recording for all configured channels. It would be convenient to use one binary input for all trigger signals transferred via GOOSE. In this example channel one is chosen, as depicted by C1 in Figure 23.

Table 16. Signals for triggering of disturbance recorder.

Publisher	Subscriber	Signal description	Data attributes
Feeder 1	Incomer IED *RDRE:1 C1*	Time overcurrent protection star signal: Instantaneous stage, High stage instance1, High stage instance2, Low stage	LD0.PHIPTOC1.Str.general LD0.PHHPTOC1.Str.general LD0.PHHPTOC2.Str.general LD0.PHLPTOC1.Str.general
Feeder 2	Incomer IED *RDRE:1 C1*	Time overcurrent protection star signal: Instantaneous stage, High stage instance1, High stage instance2, Low stage	LD0.PHIPTOC1.Str.general LD0.PHHPTOC1.Str.general LD0.PHHPTOC2.Str.general LD0.PHLPTOC1.Str.general

Table 16 presents exemplary signals for disturbance recorder triggering. In this example the start signals of time overcurrent protection are used. The start signals of all four instances are transferred via GOOSE to the incomer IED. These signals are then virtually connected through a logical OR gate to RDRE:1 channel C1. Thus any of the signals will trigger the disturbance recorder.

4.5.7. Future Applications

The use of IEDs supporting IEC 61850 enables the implementation of several protection and control applications via GOOSE. The applications presented in this study were selected because they are relevant for ABB Process Industry, and can be realized with ABB's REF615 IEDs. However, with more sophisticated IEDs the possibilities of GOOSE based applications increase. Two possible applications for future research are shortly presented below.

When two circuits with different power sources are connected through impedance, a Synchronism Check (SC) is required. In IEC 61850 a specific logical node, RSYN, is defined to perform as an SC function. The RSYN function monitors the conditions on both sides of a breaker, and verifies that conditions are safe before closing the breaker. The verification of synchronism is done by comparing the voltages on both sides of the breaker. The difference in magnitude, phase angle and frequency has to be within certain limits, in order to maintain the stability of the power system and minimize possible internal damages. The IED which compares the voltages requires magnitude, phase angle and time stamp of all phase voltages, as pictured in Figure 24.

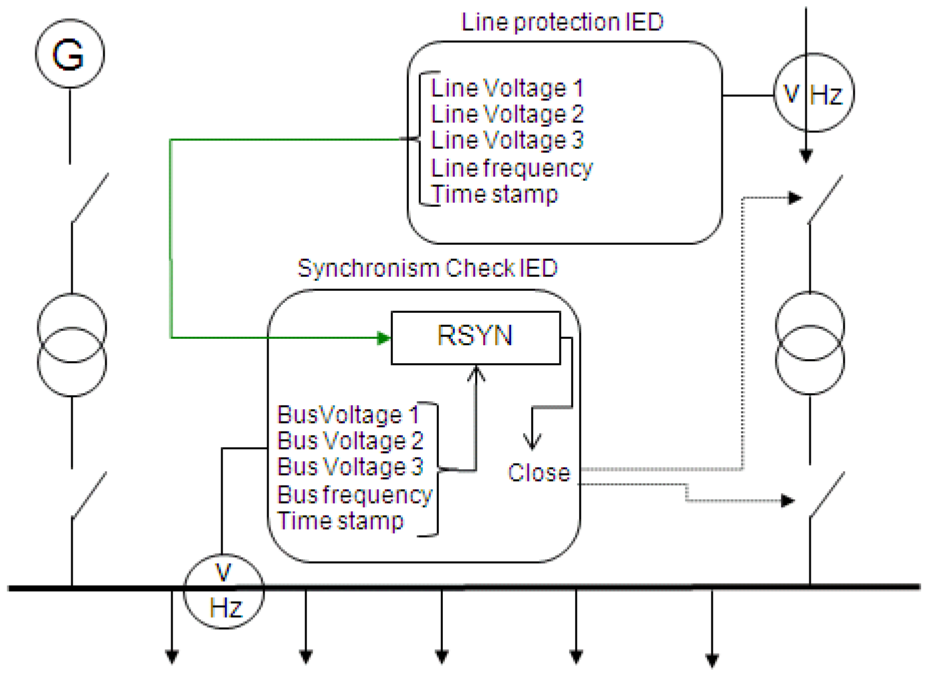


Figure 24. An example of synchronism check

In the presented example bus has two possible feeders, a generator or transmission line. When the generator is, for instance, under maintenance and the power feed needs to be transferred to transmission line, a synchronism check is required. The SC IED subscribes the line voltages from the line protection IED as an analogue GOOSE message. The challenge of analogue GOOSE messages is the time synchronization of the network. In order to provide accurate information, the time difference in the network should be less than one microsecond. [27] The bus voltages are transferred straight from a bus VT via conventional hardwiring. The RSYN function compares the difference of the values, and decides whether the closing of the circuit breakers is safe or not. However, this application requires the use of more complex IEDs including the RSYN function, and is not presented in detail in this study.

Another application where GOOSE could be implemented is transformer differential protection. According to IEC 61850, a logical node PDIF is defined for differential protection. In this scheme differential protection IED requires three phase currents from the High Voltage (HV) and LV sides of the transformer. Depending on the grounding method the residual current of the transformer might also be needed. Based on this information the differential protection IED can decide whether a fault is inside its protection zone or not. The currents from LV side and residual current of the transformer can be transferred to the differential protection IED via GOOSE as presented in Figure 25. The LV side protection IED publishes three phase current values as GOOSE message and the differential protection IED subscribes it. If a neutral point earth-fault IED is required, it publishes residual current as GOOSE message and the differential protection IED subscribes it.

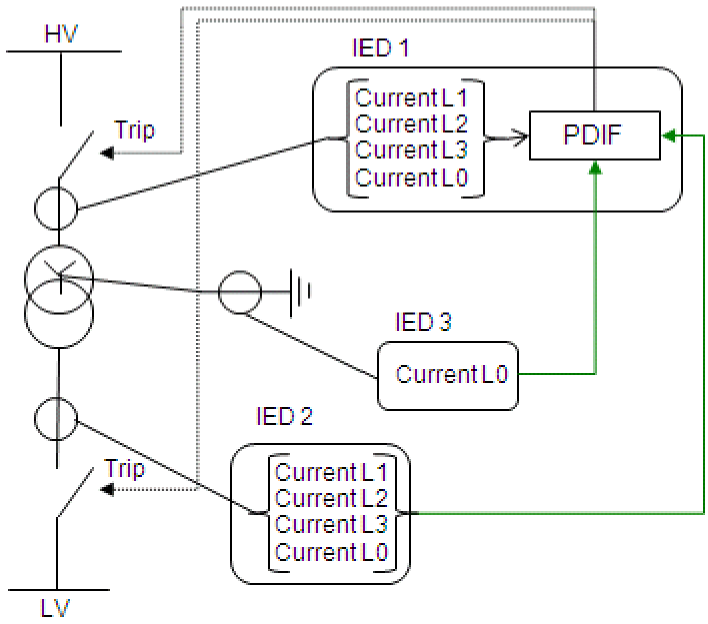


Figure 25. An example of differential transformer protection.

Both of the presented future applications extend the use of GOOSE to transfer measurement values. In the IEC 61850 standard sampled values are defined for this purpose. However, the sampled values are defined to originate straight from the process equipment, i.e. current and voltage transformers with native IEC 61850 support. Because such instruments are not yet available in the market, the presented schemes can only be implemented by using either GOOSE or hardwiring to transfer measurement values. According to ABB experts, applications utilizing GOOSE for transferring measurement values are currently being evaluated. Similarly, the performance of presented schemes should be tested before actual implementation.

4.6. Reliability and Redundancy

The requirements for the reliability of an SAS are described in IEC 61850-3 Clause 4. These requirements refer to IEC 60870-4, which specifies performance requirements for a telecontrol system. In IEC 60870-4 different properties, which influence the performance of a system, are defined and classified. These properties include concepts of reliability, availability, maintainability, security and integrity. According to IEC 61850-3, any single point of failure should not cause the substation to be inoperable. [26] This means that all components, including those used only for communication, should be reliable enough to meet this demand.

The concept of reliability is defined as the measure of a system to perform its intended function under specified conditions for a specified period of time. The reliability can be described by Mean Time Between Failures (MTBF), which means the statistical period of time in hours between any component failure in the system. From MTBF values of a component a failure rate can be calculated by dividing the number of failures with the time taken into consideration. If no valid data is available, failure rate can be estimated as inverse MTBF, as shown in Formula 1. [27]

$$Fr = \frac{1}{MTBF} \tag{1}$$

For a complete system the failure rate can be calculated from the individual components. If the components are in series, the total failure rate is the sum of the components' failure rates. If the components are parallel the MTBF values can be added together, resulting to smaller failure rate. The total failure rate and total MTBF of a system can be calculated according to these rules. Other indicators of redundancy can be calculated with these values.

The concept of availability is defined as the ability of a unit of a system to perform its function on a given instant. The availability is a probability figure, which concerns operation on a given instant, whereas reliability concerns operation over a given time period. Availability A can be calculated if the uptime and the downtime of the system are known, as presented in Formula 2.

$$A = \frac{uptime}{(uptime + downtime)} \cdot 100\% \tag{2}$$

According to IEC 60870-4, the Formula 2 is applicable if there are statistics from a period of twelve months regarding the equipment and six months regarding the system. If these times are not known, the predicted availability Ap can be calculated by using the MTBF and Mean Time To Repair (MTTR). The predicted availability can be calculated with Formula 3. [27]

$$Ap = \frac{MTBF}{(MTBF + MTTR)} \cdot 100\% \tag{3}$$

The concept of maintainability is described as the ability of a system to restore its operation and maintain it under normal working operations after detection of a fault. Maintainability is expressed in hours by Mean Time To Restoration (MTTR), which means the sum of different tasks required to restore the operation of the system.

In this context the concept of security means that any single component failure should not result in a critical failure in the system. In GOOSE communication this can be achieved by applying redundant network topologies, as described in Chapter 3.4.1. Solutions concerning information security are presented in Chapter 3.4.4. [27]

The term data integrity is defined as the unchangeability of information between a source and a destination. Data integrity with GOOSE is guaranteed by sending the message several times, as presented in Figure 8 earlier in this study. With the GOOSE message a specific quality bit is also published, thus the subscriber can detect whether the information in the GOOSE message is valid or not.

The most relevant meters for redundancy and reliability are MTBF and availability values. During this study reliability information concerning GOOSE communication was acquired. An Excel template, which calculates the reliability, availability and MTBF of the whole system, was created based on the MTBF values and number of components. The template was excluded from this report, as it is only valid to components used by ABB Process Industry. In order to improve redundancy in GOOSE applications, the best practices are redundant network topologies and redundant components.

4.7. Testing

In order to assure the functionality of horizontal communication, both the products and implementation regarding GOOSE communication should be tested. The general classifications of quality tests are defined in IEC 61850-4. A more detailed presentation of conformance testing is presented in Part 10 of the standard. In the IEC 61850-10 specific test cases for GOOSE communication are introduced. Products with native IEC 61850 should pass all these tests, in order to show conformance to IEC 61850. However, the conformance testing of individual products is out of the scope of this study. Hence the focus is in the testing of functionality of applications, which are project specific. The IEC 61850-4 states that when a new SAS is introduced, the system integrator is responsible for testing all functions. The term system integrator refers to a turnkey deliverer of an SAS. The testing is carried out by the representatives of the system integrator and the customer in optional Factory Acceptance Test (FAT) and mandatory Site Acceptance Test (SAT). The FAT is described as the functional tests of an SAS manufactured according to customer specification. This means that the parameters of the SAS are set according to the planned applications. The FAT can be carried out in the facilities of the manufacturer or other agreed location by using process simulating test equipment. When the actual installation of the SAS is completed, further testing of the functionality of the SAS is accomplished trough mandatory SAT. The SAT is defined as the verification of each data and control point and the correct functionality within the SAS and also between the SAS and its operating environment. The SAT is carried out in the whole installed plant by using the final parameters as defined in the customer specification. [28; 29]

4.7.1. Testing Software

In GOOSE applications it is possible to send messages by using dedicated software which use the configuration files of the IEDs. Thus the simulation of substation events is not mandatory. Naturally for the testing of overall performance of the SAS the simulation is essential. However, if only GOOSE needs to be tested, dedicated software is sufficient.

For this purpose there are vendor based programs available, such as Omicron’s IEDScout and ABB’s Integrated Testing Toolbox (ITT). The configuration files of the IEDs can be loaded into these programs either from database or straight from the IEDs. The programs can then create virtual IEDs based on the configuration files and send related GOOSE messages to the network. The functionality of these messages in the receivers can then be verified. A detailed description of the functionality and use of these programs is beyond the scope of this study.

4.7.2. Testing Method

The GOOSE applications presented in this study have to be tested in FAT and SAT tests before actual operation. This can be achieved by simulating the related process events and verifying the desired operation of the SAS. This should be done similarly as when testing hardwired solutions. First the connections to process level equipment in all IEDs are verified. This means the hardwired connections to voltage and current transformers, as well as connections to circuit breaker trip coils.

The performance of applications utilizing horizontal communication is tested by the following method. The required output of IED's function block is manually activated by using IED's local HMI. The output signals from a function are transferred via GOOSE or hardwire. The transferred signals are connected to function blocks in the receiving IEDs, where they should activate certain outputs. The receiving function blocks are accessed via local HMI and the required outputs verified. This procedure is repeated to all applications. As all connections to process equipment were verified at the beginning, the performance of applications utilizing horizontal communication is also verified. By using this procedure, the configuration of GOOSE in the sending IEDs is verified by activating the correct function block. The connection to receiving IEDs is verified. And finally the configuration of receiving IEDs is verified.

4.8. Documentation

A substation automation system forms a complex entity with vast amount of equipment, wiring and signals. Therefore, a detailed documentation of specific definitions of the SAS is required. The IEC 61850 defines references for SAS documentation in part 61850-4. According to the standard, required SAS documentation can be divided into two separate groups, hardware documentation and parameter documentation. The hardware documentation includes circuit diagrams, signal lists and function diagrams for external equipment. The circuit diagrams should describe links between SAS components and their connections with the primary process equipment. The parameter documentation consists of configuration list, signal lists and parameter lists. Graphical displays and operation menu sequences as well as function diagrams for internal features such as IED internal function blocks should be included in the parameter documentation. The interfaces between hardware and parameter documentation are the signal lists, which should have identical identifiers in both documentations. [29]

4.8.1. Relevant Documentation

A complete description of SAS documentation is beyond the scope of this study, but documentation concerning GOOSE is an essential part of GOOSE based applications. The hardware documentation should include all equipment related to GOOSE. In circuit diagrams this means all IEDs, Ethernet switches and related wiring needed to establish GOOSE communication. All relevant documentation concerning this equipment should also be included in the hardware documentation, in other words manuals and technical information about the equipment. Hardware documentation does not require much additional work compared to hardwired solutions. The role of parameter documentation becomes essential when GOOSE based solutions are applied in an SAS. Primarily, all information regarding GOOSE is stored in the SCD files of the SAS. Thus updated backup SCD files are an essential part of the documentation.

4.8.2. Signal Lists

In order to provide readable documentation about GOOSE, specific signal lists with functional descriptions should be provided. These lists should present the publishers and subscribers of GOOSE messages with reference to parameter and configuration lists. An example of such a list is given in Table 17.

Table 17. An example of GOOSE message signal list.

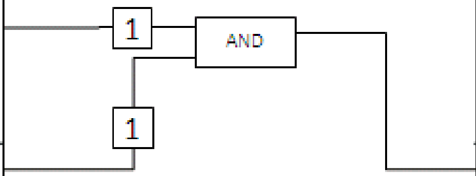
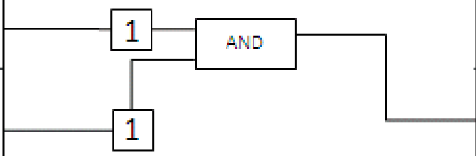
Publisher	Signal description	Data attributes	GOOSE APPID	Function block input	Subscribers
Name of the publisher IED	General description of the data being transferred	Complete names of the attributes in the data set	The unique application ID of the GOOSE message	The function block and the name of the input where the message is connected	Names of the subscriber IEDs
Example publisher	Example signal description	Example data attributes	Example GOOSE APPID	Example function block input	Example subscribers
REF615_26	Arc light detection signal, sensor 1	LD0. ARCSARC11. FADet.stVal	0001	ARCSARC1. REM_FLT_DET	REF615_25

Table 17 provides all the information regarding GOOSE communication that is necessary for the person responsible for GOOSE configuration. When the configuration is done, more detailed information can be found in the backup SCD files.

4.8.3. Logical Diagrams

The documentation should also provide description of the applications within the SAS. With applications utilizing GOOSE this can be achieved, for instance, by logical diagrams as pictured in Table 18. The functionality of the application is presented with logical operators, presenting an overview of the logic and signals required for the applications. As the GOOSE APPID is unique within the system, it links the logical diagram to the signal lists. A logical diagram presents the overall functionality of the application more illustratively than mere signal lists.

Table 18. An example of GOOSE message logical diagram.

Description	Input signal to the application	Logical diagram of the application	Output signal to the application	Description
General description of the input signal	IED name; GOOSE APPID number or binary input number			
General description of the input signal	IED name; GOOSE APPID number or binary input number		IED name; Binary output number	General description of the output signal
Example description	**Example input signals**	**Example logical diagram**	**Example output signals**	**Example description**
Arc light detected, sensor 1	REF615_26; GOOSE 0001			
Overcurrent protection start	REF615_25; BI6, BI7		REF615_25; BO1; BO2	Trip circuit breaker

Documentation of horizontal communication is needed in the engineering, configuration and testing phases of an SAS project. Further on, documentation is assigned to the customer during commissioning. The presented examples of signal lists and logical diagrams have all necessary information regarding GOOSE based solutions. However, ABB Process Industry suggested that when GOOSE is implemented in interlocking applications the relevant information regarding GOOSE should be documented in interlocking diagrams. Similarly, when GOOSE is used in protection applications, GOOSE documentation should be implemented in protection diagrams. Thus the information regarding GOOSE would be documented where it is most likely needed. However, this is a vendor specific solution, and therefore it is not presented in this study.

5. APPLICATION TEST

In the following chapters an example case of GOOSE based application is given. First the general idea of the selected fault arc protection is described. The equipment used in the test is presented, followed by a detailed description of the configuration process with ABB's products. Finally, the operation of the application is presented.

5.1. Application Tested

The fault arc protection was chosen as the application to be tested on the basis of an upcoming customer project, which requires applying of GOOSE communication to fault arc protection scheme. The purpose of the test is to describe how fault arc protection with two IEDs can be realized with ABB's products and software tools. The idea of the application is similar to the example presented in Chapter 4.5.5, and is pictured in Figure 26.

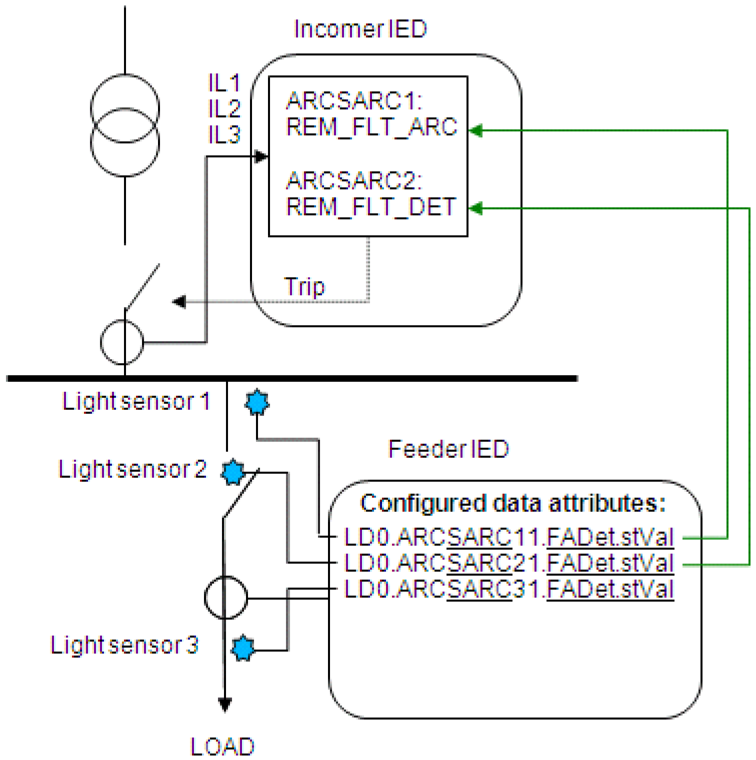


Figure 26. Tested fault arc protection application.

When the downstream *Feeder IED* detects an ongoing fault arc situation in the busbar compartment it cannot isolate the fault. If the arc is detected in the breaker compartment, the breaker might be damaged and the isolation of the fault is not possible. Therefore, the detection of arc fault in these two compartments is transferred to upstream *Incomer IED*, which can isolate the faults by operating the related breaker. The *Incomer IED* sends the trip signal based on the externally detected light signal and locally sensed overcurrent. In this test the load is assumed to be capable of injecting short-circuit current to the arc fault location. Therefore, both of the IEDs are designed to send trip signals if arc fault is detected in busbar or breaker compartment.

In real cases there would be more loads and more feeder IEDs to protect them. However, the configured signals for similar arc protection scheme would be the same, therefore using only one feeder IED is justified.

5.2. Test Equipment

The application test was conducted with two ABB's REF615 relays, equipped with optional arc protection. The arc protection includes three light sensors, which are able to detect ongoing arc situations. In order to establish GOOSE communication, an Ethernet network was created. The test equipment with IP addresses is illustrated in Figure 27. The network equipment included one managed Ethernet switch, three RJ-45 LAN cables and a configuration computer. The required programs for configuring ABB products were included in the laptop that ABB provided for the testing.

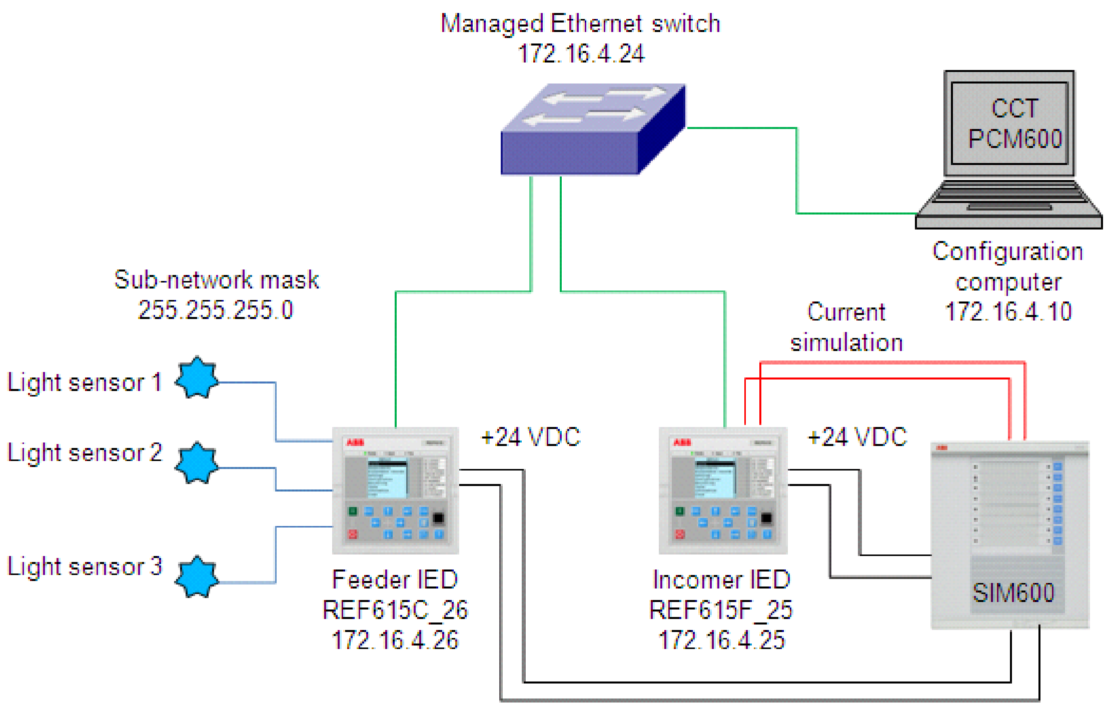


Figure 27. Test equipment for fault arc protection.

Programs include the PCM600, which is a configuration software designed for substation automation. In the PCM600 the layout of the substation is defined by creating required voltage levels and bays. Required IEDs are created in the PCM600 project, and the correct parameters and settings for the IEDs are defined. Also, the required connections of incoming and outgoing signals between the IEDs function blocks are defined by using a specific Signal Matrix Tool (SMT).

Another program called Communication Configuration Tool (CCT) is needed for defining horizontal communication. The required datasets and GOOSE control blocks are created in the CCT, as well as the subscribers of the GOOSE messages.

In order to power up the IEDs and simulate current to incomer IED, a simulation device SIM600 was introduced. The SIM600 supplied direct current for the IEDs. A powerful flashlight was also required to simulate the arc flash of fault arc situation.

5.3. Configuration Description

In order to create a test network, the IP-addresses for the REF615 IEDs were manually configured via local HMI. The IP-address and the sub-network mask of the configuration computer were also changed in order to create a functional LAN. After this the IEDs and computer were connected to the Ethernet switch by using a star topology. The connections were verified by using the command interpreter (CMD) in the configuration computer. It can be launched by choosing *Start* > *Run* and typing *cmd* to the *Run*-window. The communication settings of the computer can be printed to the CMD by typing *ipconfig*. The IP-address and sub-network mask of the computer were printed as shown in Figure 28.

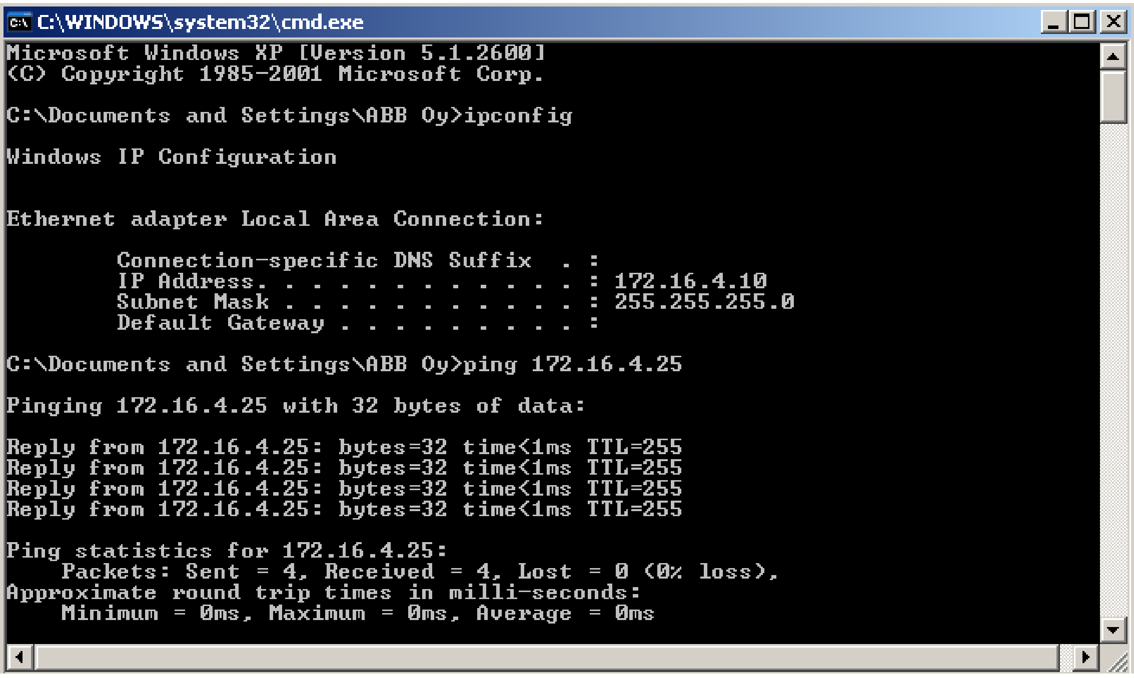


Figure 28. Screenshot from CMD.

The connections between the computer and the IEDs can be verified with *ping*-command. For instance, by typing *ping 172.16.4.25* the connection between the computer and the incomer IED can be tested. Similarly, all connections within the same network can be tested when the IP-addresses are known. This testing is based on Internet Control Message Protocol (ICMP) echo request tool, which uses TCP/IP. The tool sends ICMP packages to the target IP-address, and monitors the replies to these packages. If all four reply packages return from the target IP-address, the connection is functional, as shown in Figure 28.

5.3.1. Configuration in the PCM600

The configuration of an SAS project begins by defining the layout of the substation in the PCM600. The engineering starts by creating a new project in the PCM600. For this test a project called *Arc_Test_PCM* was created. After this, required substations, voltage levels, bays and IEDs can be created. A new substation can be added in the *Project Explorer* – window by right clicking over the project name and choosing *New* > *General* > *Substation*. The voltage levels are added similarly by right clicking over *Substation* and choosing *New* > *General* > *Voltage level*. After this bays are added in similar fashion under *Voltage Level*. Finally, the IEDs are added with a right click over *Bay* and choosing *New* > *Feeder IEDs* > *REF615*.

For the purpose of this test a simple layout was created including one substation and one voltage level. Two bays were created within the voltage level, each containing one REF615 IED. When an IED is created in the PCM600, it can be configured online or offline. In online configuration the PCM600 will retrieve the order code of the IED and automatically generate functions for the IED. This is done with the help of a wizard window, which only requires the IP-address of the IED. When the functions have been generated, the IED is ready for application specific configuration. Similar procedure has to be repeated in order to create another REF615 IED to the substation. The final plant structure of the PCM600 project is depicted in Appendix 4.

5.3.2. Configuration in the CCT

The configuration of GOOSE communication for ABB's IEDs is done in separate software called CCT. The project created in PCM600 has to be exported and then imported to CCT. The file being exported is an SCD file, it contains all information regarding the substation description and IEDs. In CCT the imported SCD file shows the data structure of the substation as a logical tree. The GOOSE configuration is done in the IED section of CCT. There all IEDs described in the SCD file are presented by their technical keys, which are unambiguous within the project. Technical keys used in the test are pictured in Figure 27, *REF615C_26* for the sending IED and *REF615F_25* for the receiving IED.

The GOOSE configuration is done first for the sending IED. By navigating to the logical device *LD0* and logical node *LLNO*, the actual GOOSE configuration can be done in the *IEC61850 Data Engineering* window. The specific dataset is first created in the *Dataset Engineering* tab by clicking *New Dataset*. In this test the dataset was named *Arc_DS*. All required data attributes are then added to the created dataset by choosing them from the *Data Model* column and clicking *Add*. In this case, the data attributes are the arc detection signals, which are listed in Table 19. The created dataset is presented in Appendix 5.

Table 19. Configured data attributes.

Publisher	Subscriber	Signal description	Data attributes
Feeder IED	Incomer IED	Fault arc detected	
REF615C 26	REF615F 25	Light sensor 1	LD0.ARCSARC11.FADet.stVal
		Light sensor 2	LD0.ARCSARC21.FADet.stVal
		Light sensor 3	LD0.ARCSARC31.FADet.stVal

When the required data attributes are added, the dataset needs a GOOSE control block. This is done in the *Goose Control Engineering* tab. By clicking *GSE Control*, a new GOCB can be configured. First the GOCB was named *Arc_GOCB* and the correct dataset selected. By clicking *Address Definition* CCT automatically creates all other required information, which is confirmed in a pop-up window. The values used in this test are pictured in Figure 29.

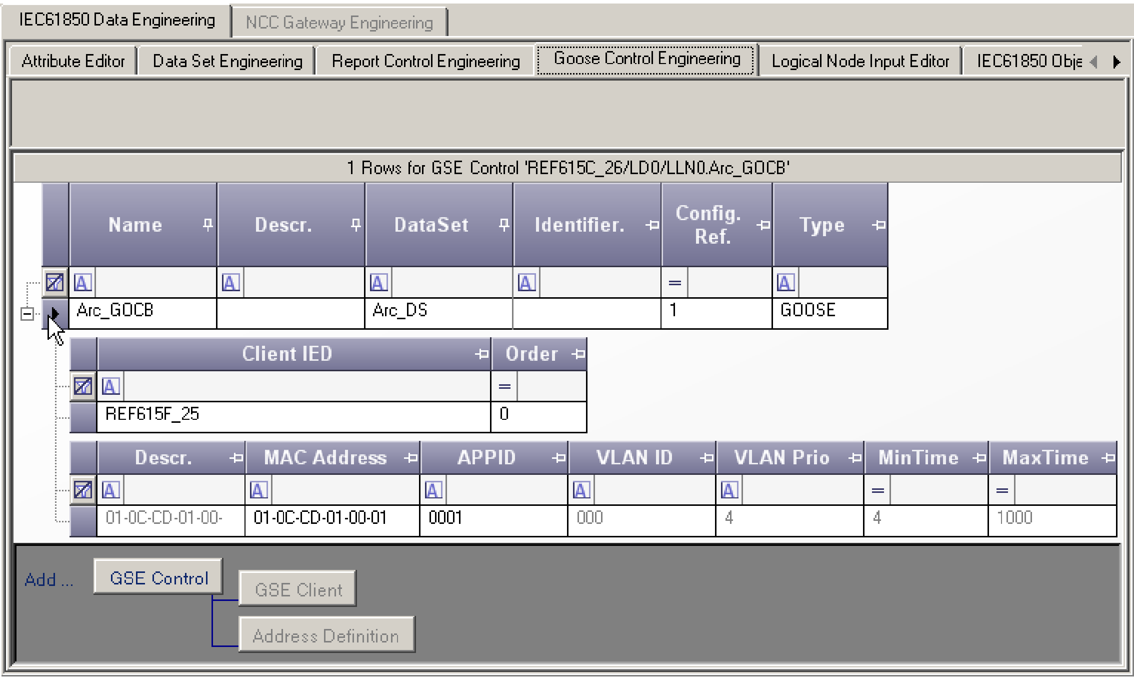


Figure 29. Values for GOCB.

The GOCB for this GOOSE message is now defined. The subscriber of the message is added by dragging it from the *Project Navigator* window to the upper right corner of the GOCB, which is depicted by the cursor arrow in Figure 29. If more than one subscriber is required, they can be added similarly by using drag-and-drop. The subscribers are show in Figure 29 under *Client IED* heading.

Now all required information for the GOOSE message is defined. The created information has to be updated to the SCD file. This is done by choosing *Tools* > *IEC61850 Data Flow Engineering* > *Update dataflow.* After the update, the created GOOSE message and the related data attributes are visible in the subscriber IED's logical node LLNO as inputs. The CCT project should be saved at this point.

5.3.3. Parameterization and Uploading

Before the application is operative, certain parameters have to be defined and the configuration loaded to IEDs. This is done in the PCM600 program, thus the SCD file must be exported from the CCT back to PCM600. This is done by choosing *Tools* > *SCL Import/Export* > *Export SCL File*. The exported file is imported to the PCM600 by right clicking over *Substation* and selecting *Import*. After importing the SCD file with GOOSE configuration, it is available for further configuration.

The created GOOSE message has to be connected to desired functions in the subscriber IED. This is done in SMT, which is opened by right clicking over the subscriber IED and selecting *Signal Matrix Tool*. The SMT shows all binary inputs, binary outputs and functions of the IED in spreadsheets. All connections between the inputs, outputs and functions are made virtually in these spreadsheets. The created GOOSE message is visible in the *Binary Inputs* tab. Each data attribute appears as one binary input, and each of them can be connected to a desired function. In the arc protection test, the fault detection signals from sensors 1 and 2 are designed to result in a trip in the incomer IED. Therefore signals *ARCSARC11.FADet.stVal* and *ARCSARC21.FADet.stVal* are virtually connected to the *ARCSARC1 REM_FLT_DET* and *ARCSARC2 REM_FLT_DET* as pictured in Appendix 4. The remotely detected light signals operate as inputs of the incomer IED's arc protection function.

In order to easily notice whether a GOOSE signal is received in the subscribing IED all three signals are configured to turn on a led in the front cover of *REF615C_25*. Configuration is done in SMT by first connecting signals to a generic timer function called TPGAPC4:4 via logical OR gate. The timer function is then connected to the led number 11 on the binary outputs tab. Every time the configured GOOSE message is received, the led number 11 will lit according to the default time set in the TPGAP4:4. When the configuration in the SMT is done, the changes made are automatically saved to the configuration file by closing the SMT.

The parameterization of the IEDs is also done in the PCM600. Parameterization means the configuration of application specific values and settings, for example the start level of overcurrent protection. Parameterization is done by browsing to the correct function in the *Project Explorer*. The arc protection functions for the Feeder IED are found with the following path, *REF615C_26* > *Application Configuration* > *Settings* > *Other Protection* > *ARCSARC11* and *ARCSARC21*. The parameter settings can be opened by a right click over the correct function. For this test example it was merely checked that the operation mode for functions *ARCSARC11* and *ARCSARC21* was *Light + Current* and the start value was 2.5 times the nominal current. In this mode the arc protection function needs both light and overcurrent signals in order to send a trip signal to circuit breaker. The light signal can either come from IED's own sensors or as remotely detected light, as in this example. When the *Parameter Settings* window is closed, the changes are automatically saved to the configuration file.

Finally, the completed configuration needs to be written to IEDs. This is done separately for each IED by right-clicking over them in the *Project Explorer* and selecting *Write to IED*. When the new configuration is uploaded to IEDs, they will automatically reboot in order for the new settings to come into operation. After rebooting the IEDs are operative including the created GOOSE communication.

5.4. Test

In order to test the created application and GOOSE communication, an overcurrent signal was simulated with SIM600 and the light sensors were simulated with flashlight. The light sensors for arc detection are equipped with automatically compensated reference level in order to prevent unfounded operation. The light sensors are covered with black dust caps, thus each sensor could be tested separately. When overcurrent and light flash in front of light sensor one were simulated, the outcome was tripping of both IEDs, as designed. Similar results were achieved by simulating light sensor two. The flashes were so fast that the configured led only flashed quickly, unless the light in front of the sensors was left on. Because the fault detection signal of light sensor three was not connected to trip function in the Incomer IED, the simulation of sensor three only lit the led number 11 as configured. In the Feeder IED the simulation resulted in tripping, as designed.

The performance of GOOSE communication was not subjected to study because ABB has tested the performance of REF615 IEDs with KEMA. The conclusion of these tests is that REF615 complies with performance class P1 for type 1A – Fast messages. This means that the total transmission time of the GOOSE message is below 10 milliseconds, as defined in IEC 61850-5. [16; 30]

5.5. Problems in the Configuration

During the testing process several problems with configuration were encountered. Most of them were human errors caused by lack of experience. However, the use of two different programs for GOOSE configuration was found cumbersome by all members of the project team. The team members found importing and exporting the SCD file between programs confusing. Therefore, the integration of PCM600 and CCT would rationalize the configuration process.

Some problems could be traced as actual software bugs, which were reported further on. One of the bugs discovered in CCT was related to a parameter called *Config.Ref*, which is included in every GOCB. The configuration reference is automatically increased, if any changes are made to the GOOSE message. The *Config.Ref* has to be same in the sending and receiving IEDs, otherwise the GOOSE message will be ignored. When the dataset was changed, and the configuration file written to both IEDs, the *Config.Ref* parameter in the subscribing IEDs was not changed automatically. Thus the subscribers did not accept the incoming GOOSE message, as the *Config.Ref* parameters did not mach. This problem could be avoided by deleting the GOCB and creating it again. However, it should be possible to make changes to an existing GOOSE message. The problem was reported further on, and will be taken into account in the next version of CCT.

Another problem related to configuration files was found in other IED's. If the configuration file was uploaded straight from the IED, it did not include the GOOSE configuration. Therefore, if any changes to the configuration are required, they should be done to the original file, and uploaded to IED. Otherwise the configured GOOSE messages are lost.

The problems found indicate that the usability of the programs and IEDs requires development. The bugs that were found will be fixed in the next versions of the programs. However, all these problems can be avoided, if the configuration process is familiar and the bugs known. Therefore, adequate training and practice is essential in engineering of GOOSE based applications.

6. CONCLUSIONS

The purpose of this study was to investigate possible applications of GOOSE communication for ABB Process Industry's electrification solutions. The customers have not yet requested GOOSE based applications, but a few pilot projects including GOOSE have been realized. As the IEC 61850 becomes more common in the field of substation automation, it is highly likely that the standard will become a prominent solution for process industry customers.

The selected applications were presented with example signals for ABB's REF615 IEDs. Because the logical nodes are named according to IEC 61850, the presented applications can be implemented similarly with other ABB IEDs equipped with required functions. Applications can be implemented with other vendor products, although the complete signals names might change.

Interviews with process industry specialists showed general interest concerning the possibilities of GOOSE communication. The IEC 61850 is seen as the standard defining communication in substations and beyond. The next editions of the standard will include more specifications concerning reliability of the communication and extending the scope of the standard to hydro and wind power generation. However, with GOOSE based applications most experts are still waiting for more reference cases in order to be convinced of its performance. It can therefore be suggested, that GOOSE communication is first implemented to less time critical applications, such as interlocking. With the experience gained from these pilot projects, the use of GOOSE can be further extended. If the IEDs conform to IEC 61850, and the requirements of the standard are taken into account in the network structure, GOOSE can be implemented to more demanding and critical applications as well.

As mentioned above several problems were encountered during the configuration of GOOSE based application. This indicates that the configuration programs need to be developed in order to provide more user friendly programs in the future. Compared to conventional hardwired schemes, GOOSE based applications require new type of configuration work. Unfortunately, not a lot of experience has been gained in this area so far. One of the advantages of GOOSE is the cost saved by using less labor intensive hardwiring. Initially the use of GOOSE might be more expensive if the costs related to training and learning are taken into account. In the long run the use of GOOSE is more cost effective, as the configuration process becomes part of the engineering. Further benefits can be achieved via expandability of GOOSE based applications. New IEDs can be added or replaced without additional hardwiring. Instead the required signals can be added to each IEDs configuration files. The challenges of GOOSE based solutions are related to redundancy, security and documentation of the applications. In order to provide reliable communication the network structure has to be designed with proper components, topology and required features. In the next edition of the IEC 61850 these matters will be taken into account in detail. The documentation of GOOSE applications requires new type of documents, as the signals between IEDs cannot be read from circuit diagrams. The configuration files need to have backups that are up to date with the system. GOOSE based applications require new type of training for service personnel, as horizontal communication is verified with programs instead of conventional metering. Adequate training of GOOSE is required also among engineers and sales personnel, in order to avoid false beliefs and resistance for change.

As technology develops more IEDs with native IEC 61850-communication will become available in the market. With additional functionality in the IEDs more applications can be realized with GOOSE communication. The full potential of IEC 61850 becomes topical when first process level devices with native IEC 61850-communication are introduced to the market. This means that process level devices can transfer measurement values as SV messages via IEC 61850-network. This provides interesting topics for further study, as the process level devices can communicate to IEDs without hardwiring.

Based on the interviews with experts, the common opinion in the industry is that IEC 61850 is the present and future standard for substation communication. This becomes topical in the field of process industry electrification when the customers become aware of the potential of IEC 61850. Therefore, it can be stated that IEC 61850 will play a significant role also in the future of process industry electrification.

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Appendix 1: Parts of the IEC 61850

IEC 61850 - Communication networks and systems in substations	
Part	Title
IEC 61850-1	Introduction and overview
IEC 61850-2	Glossary
IEC 61850-3	General requirements
IEC 61850-4	System and project management
IEC 61850-5	Communication requirements for functions and device models
IEC 61850-6	Configuration description language for communication in electrical substations related to IEDs
IEC 61850-7-1	Basic communication structure for substation and feeder equipment – Principles and models
IEC 61850-7-2	Basic communication structure for substation and feeder equipment – Abstract communication service interface (ACSI)
IEC 61850-7-3	Basic communication structure for substation and feeder equipment – Common data classes (CDC)
IEC 61850-7-4	Basic communication structure for substation and feeder equipment – Compatible logical node classes and data classes
IEC 61850-8-1	Specific communication service mapping (SCSM) – Mappings to MMS (ISO/IEC 9506-1 and ISO/IEC 9506-2) and to ISO/IEC 8802-3
IEC 61850-9-1	Specific communication service mapping (SCSM) – Sampled values over serial unidirectional multi drop point to point link
IEC 61850-9-2	Specific communication service mapping (SCSM) – Sampled values over ISO/IEC 8802-3
IEC 61850-10	Conformance testing

Appendix 2: Guide for the Reader

User		IEC 61850-1	IEC 61850-5	IEC 61850-7-1	IEC 61850-7-4	IEC 61850-7-3	IEC 61850-7-2	IEC 61850-8-x	IEC 61850-9-x
Utility	Manager	x	-	clause 5	-	-	-	-	-
	Engineer	x	x	x	x	x	in extracts	x	-
Vendor	Application engineer	x	x	x	x	x	in extracts	x	in extracts
	Communi-cation engineer	x	x	x	-	-	x	-	x
	Product manager	x	x	x	x	in extracts	in extracts	in extracts	-
	Marketing	x	x	clause 5	in extracts	in extracts	in extracts	in extracts	-
Consultant	Application engineer	x	x	x	x	x	-	x	-
	Communi-cation engineer	x	-	x	-	-	x	x	x
All others		x	x	x	-	-	-	-	-

The “x” means that this part of the IEC 61850 should be read.
The “in extracts” means that extracts of this part of the IEC 61850 series should be read to understand the conceptual approach used.
The “-“ means that this part of the IEC 61850 may be read.

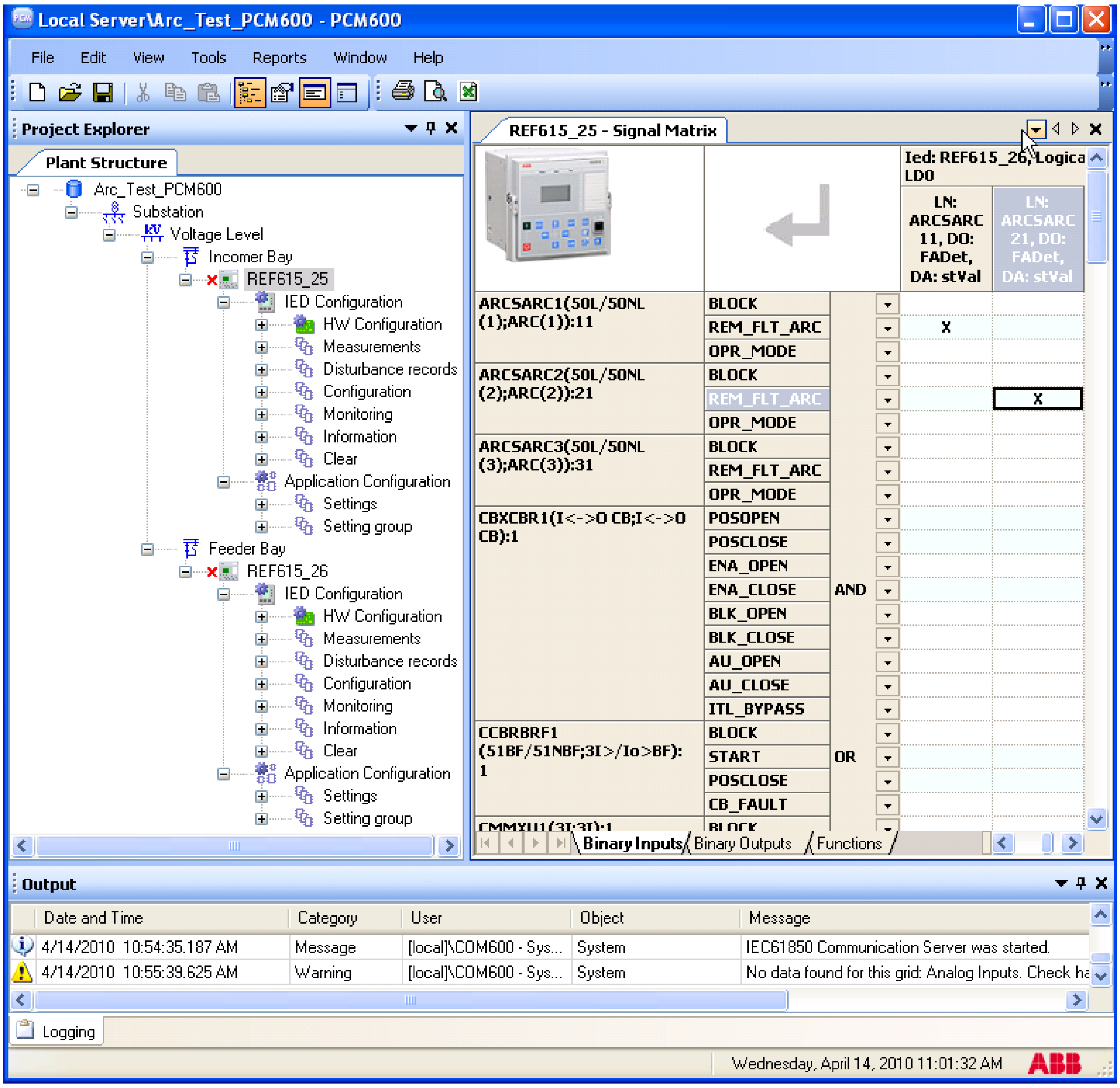
Appendix 3: Table of Logical Nodes

Group A	Automatic control (4)
ANCR	Neutral current regulator
ARCO	Reactive power control
ATCC	Automatic tap changer control
AVCO	Voltage control
Group C	Supervisory control (5)
CALH	Alarm handling
CCGR	Cooling group control
CILO	Interlocking
CPOW	Point-on-wave switching
CSWI	Switch controller
Group G	General references (3)
GAPC	Generic automatic process control
GGIO	Generic process I/O
GSAL	General security application
Group I	Interfacing and archiving (4)
IARC	Archiving
IHMI	Human machine interface
ITCI	Telecontrol interface
ITMI	Telemonitoring interface
Group L	System logical nodes (3)
LPHD	Physical device information
CLN	Common logical node
LLN0	Logical node zero
Group M	Metering and measurement (8)
MDIF	Differential measurements
MHAI	Harmonics or interharmonics
MHAN	Non phase related harmonics or interharmonics
MMTR	Metering
MMXN	Non phase related measurement
MMXU	Measurement
MSQI	Sequence and imbalance
MSTA	Metering statistics
Group P	Protection functions (28)
PDIF	Differential
PDIR	Direction comparison
PDIS	Distance
PDOP	Directional overpower
PDUP	Directional underpower
PFRC	Rate of change of frequency
PHAR	Harmonic restraint

PHIZ	Ground detector
PIOC	Instantaneous overcurrent
PMRI	Motor restart inhibition
PMSS	Motor starting time supervision
POPF	Over power factor
PPAM	Phase angle measuring
PSCH	Protection scheme
PSDE	Sensitive directional earthfault
PTEF	Transient earth fault
PTOC	Time overcurrent
PTOF	Overfrequency
PTOV	Overvoltage
PTRC	Protection trip conditioning
PTTR	Thermal overload
PTUC	Undercurrent
PTUV	Undervoltage
PUPF	Underpower factor
PTUF	Underfrequency
PVOC	Voltage controlled time overcurrent
PVPH	Volts per Hz
PZSU	Zero speed or underspeed
Group R	Protection related functions (10)
RDRE	Disturbance recorder function
RADR	Disturbance recorder channel analogue
RBDR	Disturbance recorder channel binary
RDRS	Disturbance record handling
RBRF	Breaker failure
RDIR	Directional element
RFLO	Fault locator
RPSB	Power swing detection/blocking
RREC	Autoreclosing
RSYN	Synchronism-check or synchronising
Group S	Sensors and monitoring (4)
SARC	Monitoring and diagnostics for arcs
SIMG	Insulation medium supervision (gas)
SIML	Insulation medium supervision (liquid)
SPDC	Monitoring and diagnostics for partial discharges
Group T	Instrument transformer (2)
TCTR	Current transformer
TVTR	Voltage transformer
Group X	Switchgear (2)
XCBR	Circuit breaker
XSWI	Circuit switch
Group Y	Power transformer (4)

YEFN	Earth fault neutralizer (Petersen coil)
YLTC	Tap changer
YPSH	Power shunt
YPTR	Power transformer
Group Z	Further power system equipment (15)
ZAXN	Auxialiry network
ZBAT	Battery
ZBSH	Bushing
ZCAB	Power cable
ZCAP	Capacitor bank
ZCON	Converter
ZGEN	Generator
ZGIL	Gas insulated line
ZLIN	Power overhead line
ZMOT	Motor
ZREA	Reactor
ZRRC	Rotating reactive component
ZSAR	Surge arrestor
ZTCF	Thyristor controlled frequency converter
ZTCR	Thyristor controlled reactive component

Appendix 4: Screenshot from PCM600



Appendix 5: Screenshot from CCT