Politecnico di Milano
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IEC 61850 Standard and Its Capabilities in Protection Systems

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Acronyms

ACSI	Abstract Communication Service Interface
CB	Circuit Breaker
DER	Distributed Energy Resources
DG	Distributed Generation
FRT	Fault Ride Through
GOOSE	Generic Object Oriented Substation Events
GPS	Global Positioning System
ICD	IED Capability Description
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Devices
IOs	Input/Outputs
IP	Internet Protocol
IRIG	Inter-Range Instrumentation Group
LAN	Local Area Network

LD	Logical Device
LNs	Logical Nodes
MMS	Manufacturing Messaging Specification
MU	Merging Unit
NTP	Network Time Protocol
OSI	Open System Interconnection
PD	Physical Device
PPS	Pulse Per Second
SAM	Substation Automation and Monitoring System
SAU	Substation Automation Unit
SCADA	Supervisory Control and Data Acquisition systems
SCL	Substation Configuration Language
SS	Substation
SV	Sampled Values
TCP	Transmission Control Protocol
WAM	Wide Area Monitoring
WAMPAC	Wide Area Monitoring, Protection And Control
WAN	Wide Area Network

Dedication

Dedicate my master thesis to my dear parents for their support during my life

Life is too short, I hope everyone can experience its beauties

Acknowledgments

GREAT thanks to everybody I have ever met and helped me to write this thesis especially my professor Mr. Gabrielle D'Antona, my tutor Mr. Davide Della Giustina and my colleagues Mr. Alessio Dede, Mr. Massa Giovanni and Mr. Antimo Barbato whom without their patience and cooperation it was hard to achieve my goal

Abstract

TODAY, with the increasing need for energy it is so much needed to find new sources of energy. With the integration of new sources and increasing amount of data to be communicated, the demand for better communication infrastructure is undeniable. Smart grid is created to fulfill this desire. With it, new standards and protocols to house the information and increase the interoperability came up. IEC 61850 as a new standard which can fulfill the desire for a standard communication service for substation automation was built and is deployed by many vendors. IEC 61850 family of standards talk about every part of the system which is needed for sending the data. It talks about sensors in the process level, Ethernet switches for communication up to upper part of the network including station level and Control Center. This project talks about the smart grid and its background information, then it gives further explanation about the information model of IEC 61850 which the Intelligent Electronic devices (IEDs) compatible to this standard obey. In the third part, it talks about the smart grid section and the implementation of IEC 61850 in UnaReti SPA company- A distribution company which has the electrical grid of two big cities namely, Milan and Brescia in Italy. The project as a whole gives the necessary information about the IEC 61850 and the devices which are deployed in smart grid which is the future in Electric industry.

Summary

THIS dissertation is about the IEC 61850 standard and its capabilities in terms of the protection systems. In the first chapter an introduction about the electrical grid is discussed and general architecture of the grid is explained. Then, the Wide Area Network is introduced which contains all the steps from the generation up to distribution and consumption. Later, a very general overview of the IEC 61850 which is the substation automation standard is given to give the reader the hint of what the reader will encounter in this dissertation.

In the second chapter, the information which is considered to be necessary to follow the dissertation is explained.Communication systems and the most common data model-OSI model- is explained since communication is the baseline of the protection systems and is the most important section to meet the time critical data.

Later,in the 3rd chapter, different aspects of the IEC 61850 are introduced and discussed since this dissertation is based on this standard.

The 4th chapter discusses the real situation of today's grid and introduces the assets of the protection and how the protection systems are implemented in the grids. This chapter is referenced to the grids in UnaReti distribution company where the writer has worked for his dissertation. Dur-

ing this period, the writer has worked with serial comunication protocols and compared them with Ethernet which is the dominant protocol in IEC 61850. It is belived that Ethernet has the capacity for real time communication as is suitable in case of faults in the network. [9] This assumption is tested during this dissertation and is referenced also to some papers for more information. Also IEC 61850 is to be expected to be fully suitable and ready to be implemented in the grid. From IEC 61850 stnadards and the papers about it, one may believe that all the devices capable of understanding IEC 61850 data model, are able to communicate with one another without any problem. Also, this protocol is expected to reduce the wiring of the devices so much since it is possible to use the bandwidth of the station LAN for GOOSE and GSSE signals. In the end, IEC 61850 was belived to be fully known by the vendors and the distribution companies but later it is proved that this assumption is not true since electrical grids are expensive assets and one should be totally sure about changes in the protocols and standards since a small mistake will result in great disaster. This is why in many networks, legacy protocols are still in use.

CHAPTER 1

Introduction

1.1 Introduction

Today the electric power grid is a huge system which supports electricity generation, transmission and distribution operations. It has experienced dramatic change since the 20th century to accommodate growing needs of today industrial world. Today it is composed of centralized and decentralized (distributed) generation plants.

Contrary to the previous distribution grid, today electricity flows not only from the power plants but thanks to the Renewable Energy Sources (RES), customers also contribute to the generation of electricity and so it flows in both directions. However, this situation leads to a more complex grid which arises the need to have a harmonic network structure in which all the parts of the grid can communicate each other to exchange the data to be more reliable than ever.

1.2 Smart Grid communication

Today, the electric power grid is undergoing a significant transition into an intelligent, reliable and fully automatic grid which is called smart grid. Substation Automation is one of the services derived from the smart grid and can be achieved by incorporation state of the art information technologies with the power system. The key to smart grid is the communication network which serves as the fundamental information structure to provide bidirectional end-to-end communication in the smart grid. Although a myriad of existing communication technologies can be applied to the smart grid, new communication protocols and enhancement of existing protocols are an indispensable part of the smart grid.

1.3 Network Architecture

In the smart grid there are 3 types of network namely:

- Premises Network
  - Home Area Network (HAN)
  - Building Area Network (BAN)
  - industrial Area Network (IAN)
- Neighborhood area Network(NAN)/Field Area Network(FAN)
- Wide Area Network(WAN)

However, the main focus of this thesis is on the Wide Area Network.

1.4 Wide Area Network

The WAN is at the utility's end of the network architecture. Substations(SSs) are commonly connected together in WAN using optical fiber, which can provide high capacity communications with low latency. In terms of the

Data Rate and Range of the WAN, between 100 Mbps- 10 Gbps are transferred in a distance between 10 km to 100 km. The WAN is interconnected to the public internet using secure communications which enables third parties to participate in the smart grid services.

In the WAN, the main service is to transport the smart grid data to large distances, thus, the network devices are mainly switches and routers to transport the data at a lower layer to reduce costs. Utilities have been operating WANs for various applications such as SCADA, grid monitoring and control and communications with power plants. These WANs have incorporated a variety of communication technologies over optical fibers, power lines and wireless channels.

1.5 IEC 61850 general overview

Over the last decade, Utilities, industries and even residential customers are moving toward a digital world. Therefore, it is expected that every piece of the equipment possess some kind of setting, monitoring and control. In order to be able for the devices to communicate with each other, a new communication model is needed to improve the interoperability and interchangeability between the devices. That model has been developed and standardized in International Electrotechnical Commission(IEC) 61850 - Utilities Communication Networks and Systems in substations. [17] [18] [19]

The IEC 61850 family of substation communication systems standards were released in the early 2000s. These standards include Ethernet [25] based process-level connections between switchyards and control rooms; however, since they are very new in electricity industry, their in-service performance should be tested thoroughly to make sure it works properly as the electrical network is very sensitive and grid owners will lose millioins of dollars in case of a wrong implementation. Some people wrongly think that IEC 61850 is another communication protocol. The truth is this standard is a well-structured and consistent series of publications that defines a set of system requirements. Since the power system is very sensitive and costs a lot of money, it is very important to previously predict the actual behavior of any change in it then put it into action. However, because of many benefits of IEC 61850 for utilities and ease of use in substation, multinational vendors like ABB, Siemens or Schneider Electric and so on, are moving toward standardization of their products with respect to this standard. IEC 61850 compatible devices, contrary to legacy protocols, are able to work with each other so if a substation is equipped with ABB protection devices, in case one of the them needs maintenance, it can be replaced with the protection device from Siemense.Therefore, there is no need to replace a device with same brand anymore. [23]

CHAPTER 2

Electrical Grids: background and technological context

2.1 Background Information

Classical Supervisory Control and Data Acquisition systems(SCADA) typically were envisioned for measurement rate of several seconds or even minutes which means between two measurements, power system needs to be assumed stable and in steady state condition. Wide Area Monitoring, Protection And Control(WAMPAC) extends the time resolution of classical SCADA systems down to sub seconds making it possible to monitor and react to dynamic instabilities in the grid. The information provided by a wide area Monitoring (WAM) system simply aims at providing information, in most cases in real time, about the stability issues in the system, whereas a wide-area control and protection system aims at real-time control of such instabilities and to protect the power system against possible consequent blackouts.

The core idea of the WAMPAC system is the centralized processing of the data collected from various locations of a power system, aiming at the evaluation of the actual power system operation conditions with respect to its stability limits. The switchgear and grid connections in a substation are organized in so-called bays, which contain all the equipment connecting the substation, for example, to a single power line or generator.

The Intelligent Electronic Devices(IEDs) of different bays are connected by a Local Area Network (LAN) to the Substation Automation and Monitoring Systems (SAMSs). The SAMSs typically also included gateway functionality to allow remote control actions to be accepted from, and to transmit status and measurement data to the SCADA over a Wide Area Network (WAN). On the network level operator workstations are present for wide area monitoring control and protection as well as SCADA. [2] [11]

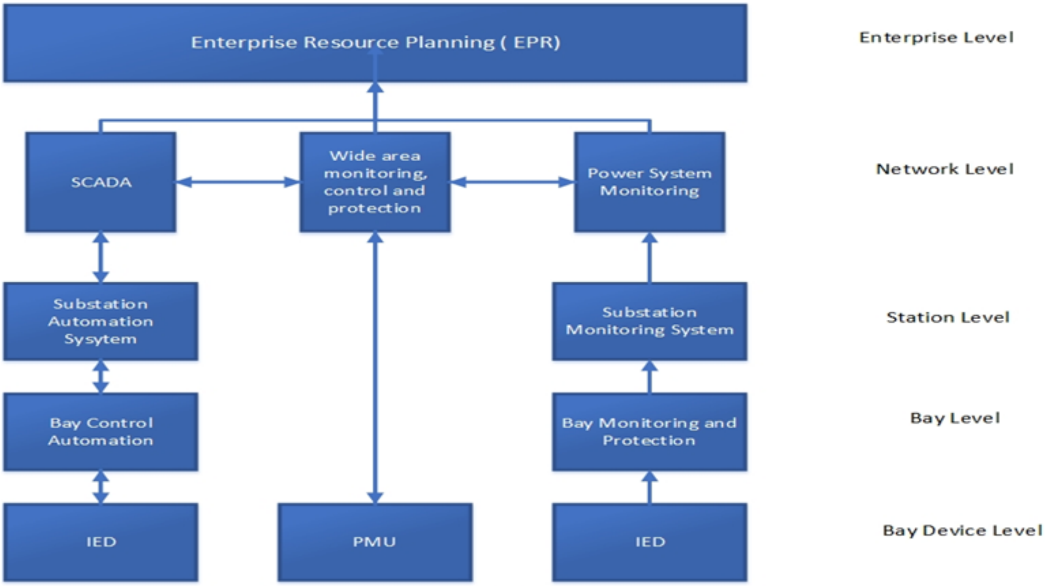

Figure 2.1: *WAMPAC and its connections to other control and monitoring systems in the power Network*

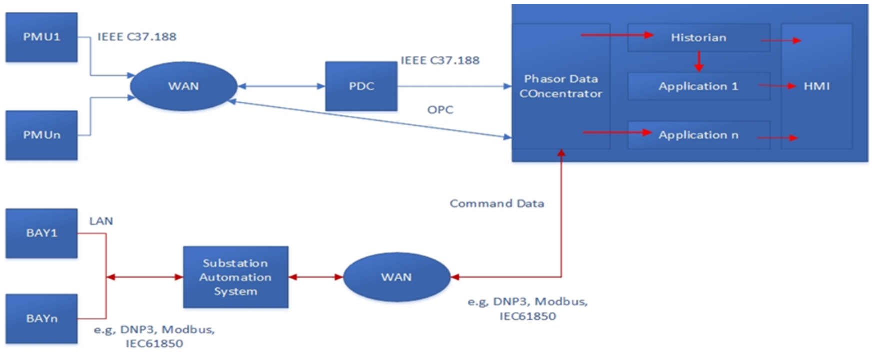

Figure 2.2: *Measurement and Command data flows in a WAMPAC system*

2.2 OSI Model

The reference model mentioned earlier is based on OSI(Open System Interconnection) [10] Model which is slicing the communication process up into seven parts called "layers" that pile up in a vertical direction to conform a data transmission management structure configured as shown in Figure. [30]

Figure 2.3: *different data layers in OSI model*

These layers represent the resources in terms of functionalities and services that communication devices exhibit to collaborate in order to get efficient communication. Each layer must provide the specific services needed to make data communication successful. The services provided by each layer are performed by "entities" conceivable as abstract devices, like programs and functions that implement the particular service. The means to offer such services are based on hardware and/or software depending on the position of the layer, in such a way that lower layers do their job through hardware or firmware (software that runs on specific piece of hardware) while higher position layers do their work using software. The reason for the vertical piling is to indicate that each layer interfaces with another for exchanging capabilities and support in such manner that services available on higher layers are the summation of all services provided by the lower layers. The elements and purposes of each layer are the following:

- Layer 1 (The Physical Layer)

The physical layer is a hardware interface with communication media, with respect to physical, electrical and functional definitions.

- Layer 2 (The Data Link Layer) The data link layer deals with the task of sending packages of data (structured streams of bits) from one place to another ensuring an error free message at the destination device. Networking devices that operate at the data link layer include:
  - Switches
  - Bridges
  - Modems

- Layer 3 (The Network Layer)

The network layer is responsible for traffic control into the network, based mainly on the application of a logical addressing system further to other artifices such as the fragmentation of large data packages. The most common networking device that operates at the network layer for communicating separate networks is the Router.

- Layer 4 (The Transport Layer) The transport layer offers the service of the overall management of communication between two specific devices, independent of possible Constraints imposed by layers 1 to 3. This is made through the execution of various tasks like the following
  - Identification of interacting devices
  - Confirmation of the message integrity
  - Segmentation of large data packages
  - Data traffic control

The most common networking resource that works at the transport layer is the Transmission Control Protocol (TCP).

- Layer 5 (The Session Layer) The session layer provides the set of services needed to establish a dialog between networked devices. The associated tasks to this layer include:
  - Relationship between application programs
  - Data flow control
  - Driving of dialog means
  - Tracking of transferred data

- Layer 6 (The Presentation Layer)

The presentation layer deals with treatment of messages for security or for transferring efficiency, such as message encryption or message compression.

- Layer 7 (The Application Layer)

The application layer is responsible for providing interactive interfaces with human operators of networked devices.

2.3 Smart Grid sensing, Automation And control protocols

When controlling a power grid it is necessary to know the state of the power grid, for example, how much current is on a power line or whether a breaker is open or closed. In order to automatically or manually control the power grid, it is essential to have sensors sensing the state of the grid as well as actors like breakers, changing the state of the grid.

Handling smart grid requires sensing various applications like power generation, substation automation and transmission and distribution systems, but also sensing end costumer behavior via smart meters or sensing data for weather forecasts.

2.4 Communication

The base to communicate is to provide a physical connection between two systems. Ther are common communication mechanisms like the electricity and in terms of the automation systems the range is 4-20mA or optical signalling which is getting more popular. There are many communication protocols nowadays and one of them is the Ethernet-based communication which is independent of the physical layer (wired or wireless). Ethernet is a technology and the physical mean can be even cable (twisted pair; 2 for sending and 2 for receiving)or can be fiber optic.

Systems communicating over Ethernet divide a stream of data into shorter pieces called frames. Each frame contains source and destination addresses, and error-checking data so that damaged frames can be detected and discarded; most often, higher-layer protocols trigger re-transmission of lost frames. As per the OSI model, Ethernet provides services up to and including the data link layer.

2.5 Communication Models

Having the base connection established, there are different communication models. In General, there are Unicast, Multicast and Broadcast.

- Unicast

is used in client-server architectures or peer-to-peer networks where one communication partner is connected to only one other partner

- Multicast

is used in a publisher-subscriber model where the publisher provides information and sends it to all subscribers that have subscribed to the data like Generic Object Oriented Substation Events(GOOSE) messages which will be described later.

- Broadcast

is used when the information is sent to everyone in the network

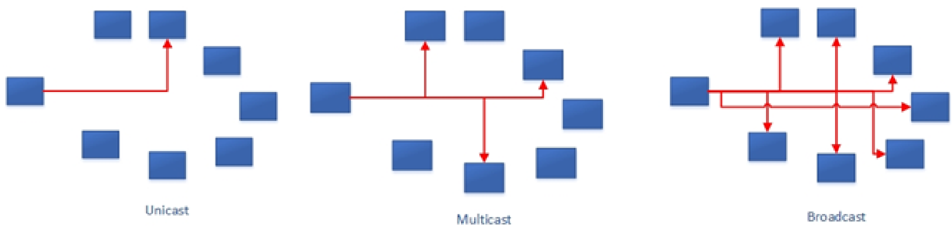

Figure 2.4: *Communication Models:1- Unicast 2- Multicast 3- Broadcast*

2.6 Data Type

Different protocols use different communication models and they differ in the type of data exchanged. In sensing, automation and control typically current data are exchanged, like measurements coming from a sensor or operator data like changing a set point or opening/closing a breaker. In addition, configuration data can be transferred, to populate a graphic display as well as configuring the measurement unit of a sensor.

More advanced applications allow the exchange of Meta data, meaning data describing the measurements, for example, by identifying the type of device used to generate the measurement.

Besides current data, which are typically provided per time interval, alarms and events provide infrequent information, for example, when a device fails. Finally, there are historical data, allowing one to display or to analyze the trend of measurement values (numerical logs) as well as exposing the sequence of events that had happened in the past.

2.7 Information Model

The purpose of an information model is to bring semantic understanding to the data and thus exchange information rather than by data. Standardizing information models brings interoperability to the next level, providing not only a standardized data exchange but an information exchange with standardized semantic.

CHAPTER 3

IEC 61850

3.1 IEC61850

IEC 61850 (communication networks and systems in substations) was developed to provide interoperability between intelligent electronic devices (IEDs) for protection, monitoring, control and automation in substations[5]. IEC 61850 not only addresses communication but also information modeling, tailored to the needs of the electrical power industry. In addition, it defines an XML-based configuration language standardizing the engineering/configuration of substation automation devices. Although IEC 61850 originally addresses substation automation, there are already additional information models defined based on the IEC 61850 model for other domains like wind turbines in IEC 61400-25 or hydroelectric power plants in IEC 61850-7.

The IEC 61850 consists of several parts addressing different issues. The different parts are summarized in the Next figure. Parts 1 to 5 give an overview and define requirements, including requirements on hardware (part 3) and engineering (Part4).

Part #	Title
1	Introduction and Overview
2	Glossary of terms
3	General Requirements
4	System and Project Management
5	Communication Requirements for Functions and Device Models
6	Configuration Description Language for Communication in Electrical Substations Related to IEDs
7	Basic Communication Structure for Substation and Feeder Equipment
7.1	- Principles and Models
7.2	- Abstract Communication Service Interface (ACSI)
7.3	- Common Data Classes (CDC)
7.4	- Compatible logical node classes and data classes
8	Specific Communication Service Mapping (SCSM)
8.1	- Mappings to MMS (ISO/IEC 9506 – Part 1 and Part 2) and to ISO/IEC 8802-3
9	Specific Communication Service Mapping (SCSM)
9.1	- Sampled Values over Serial Unidirectional Multidrop Point-to-Point Link
9.2	- Sampled Values over ISO/IEC 8802-3
10	Conformance Testing

Figure 3.1: *IEC 61850 standards different parts*

The Meta model of IEC 61850 with concepts like Logical Nodes(LNs) and data classes is defined in parts 7-1 and 7-2. The Substation Configuration Language (SCL) defined in part6 is used to configure data sources as well as receive information on the data sources in order to access them. The technology mapping from the abstract services to a concrete technology is given in 8-1 as well as 9-1 and 9-2. The first one defines a mapping to Manufacturing Messaging Specification (MMS) and Ethernet for GOOSE. Part 9-1 defines a mapping of sampled values to a serial connection and 9-2 to Ethernet.

On these three pillars

- communication infrastructure
- Meta model
- configuration language

the Abstract Communication Service Interface (ACSI) is built. The abstract interfaces provide the possibility to add or exchange existing technology mappings of the communication infrastructure.

The base model defined in part 7-3 defines common data classes for status information, measured information, analog settings, and so on. On top of these common data classes domain-specific information models are defined in terms of logical nodes and data classes.

In 7-4 the domain of substation automation is addressed with logical nodes for switchgear, power transformers and so on. The information model of a device can be accessed online by using appropriate services to browse and read the information or offline using SCL of the device. Using the same mechanisms the configuration can be changed. However, it is up to the device what mechanisms it supports.

3.2 Information Model

IEC 61850 provides powerful information modeling capabilities. In IEC 61850, information can be exchanged using ACSI (together with a technology mapping. The IED Capability Description(ICD) file which comes with the protection devices from a specific company, will go through the configuration tool and is converted to scd file. This process is done because icd file can be recognized only with a specific device from a specific brand but once it is converted to a scd file and uploaded in to the IEDs, the different IEDs are able to communicate eachother. The ACSI focuses on concrete data exchange. The Meta model of IEC 61850 that builds the foundation for IEC 61850 information models is summarized in the following figure. This figure only contains those parts that are accessible using the ACSI.

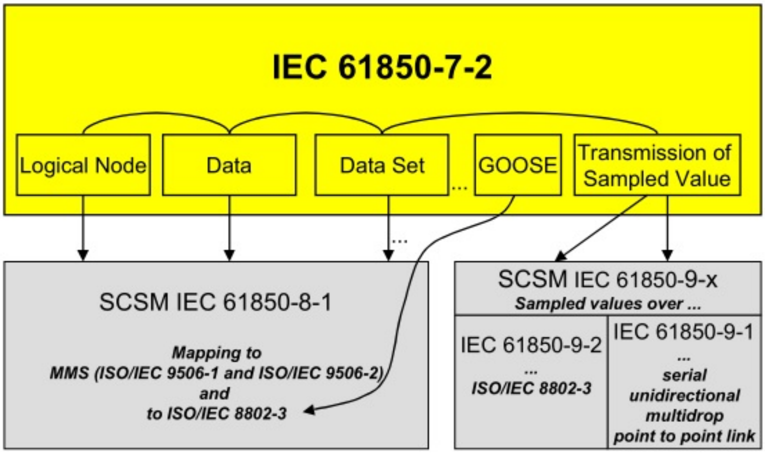

Figure 3.2: *ASCI mappings(conceptual)*

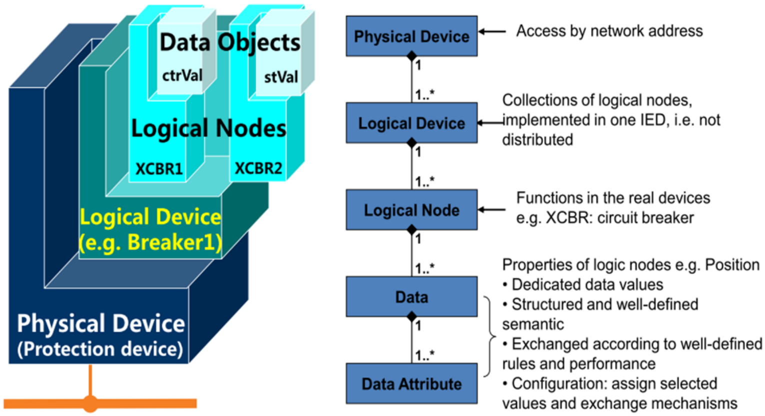

Figure 3.3: *Architecture of data in IEC 61850 model*

The Meta model contains constructs representing the information model (measured value, setpoint, sequence of events) as well as constructs representing the configuration of the communication(called information exchange model in IEC 61850-7-1), like the configuration of a buffered report control block that is used by one client or the associated applications. As it is shown, each data source in IEC 61850 starts with a server having files and logical devices.

Each Physical Device(PD)can represent many Logical Devices . A server must have at least one device but can have many, for example, when representing a whole substation. Each logical device consists of many LNs, having at least a logical node 0 containing some general purpose information like the name plate of the logical device.

The logical node is based on a logical node class. However, the logical node class is only referenced by name. The logical node classes are defined in the information model standards for IEC 61850 like 7-4, 7-410 and 7-420. Logical node classes define the semantic and can be very generic like GGIO just representing generic Input/Outputs(IOs) or more specific like XCBR representing Circuit Breaker capabilities of a switch. Further details are given in 3.2.1 part(types of logical nodes)

The LNs contains several constructs of the information exchange model and in addition at least one data object. The allowed data object of a logical node and whether they are mandatory, optional, or constrained are defined by the logical node class.

Data objects are defined by the common data classes, either defined in 7-3 for the general applicable common data classes, or in the parts defining the logical node classes if a new or very specific data class needs to be defined. Like the logical node class, the common data classes are only referenced by name.

Common data classes are defined for various thing like integer status, measured values or analog settings. They do not define a very strong semantic; this is done for the data objects in the context of their logical nodes defined by their logical node classes. For example, the OpCnt data object of the logical node class XCBR (Circuit Breaker) represents the operation count of the circuit breaker. OpCnt uses the integer status data object class.

For simplicity, the name of the data object actually represents the semantic and thus the OpCnt is used by several logical node classes needing an operation count. The data objects finally contain data attributes and may contain other data objects. Data attributes have a type that can be simple like an integer or Boolean but can also be complex and built from simple data types.

XCBR class				
Data object name	**Common data class**	**Explanation**	**T**	**M/O/C**
LNName		The name shall be composed of the class name, the LN-Prefix and LN-Instance-ID according to IEC 61850-7-2, Clause 22.		
Data objects				
Descriptions				
EEName	DPL	External equipment name plate		O
Status information				
EEHealth	ENS	External equipment health		O
LocKey	SPS	Local or remote key (local means without substation automation communication, hardwired direct control)		O
Loc	SPS	Local control behaviour		M
OpCnt	INS	Operation counter		M
CBOpCap	ENS	Circuit breaker operating capability		O
POWCap	ENS	Point on wave switching capability		O
MaxOpCap	INS	Circuit breaker operating capability when fully charged		O
Dsc	SPS	Discrepancy		O
Measured and metered values				
SumSwARs	BCR	Sum of switched amperes, resettable		O
Controls				
LocSta	SPC	Switching authority at station level		O
Pos	DPC	Switch position		M
BlkOpn	SPC	Block opening		M
BlkCls	SPC	Block closing		M
ChaMotEna	SPC	Charger motor enabled		O
Settings				
CBTmms	ING	Closing time of breaker		O

Figure 3.4: *Anatomy of circuit breaker logical node in IEC 61850-07-4*

In the last column it is stated if the data is M (Mandatory) or O (Optional).

3.2.1 Types of Logical Nodes

There are logical nodes for automatic control the names of which all begin with the letter ”A". There are logical nodes for metering and measurement the names of which all begin with the letter ”M". Likewise there are logical nodes for

- Supervisory Control (C)

- Generic Functions (G)
- Interfacing/Archiving (I)
- System logical nodes (L)
- Protection (P)
- Protection Related (R)
- Sensors (S)
- Instrument Transformers (T)
- Switchgear (X)
- Power Transformers (Y)
- Other Equipment (Z)

Each logical node has an LN-Instance-ID as a suffix to the logical node name. For instance, suppose there were two measurement inputs in a device to measure two 3-phase feeders. The standard name of the logical node for a Measurement Unit for 3-phase power is MMXU. To delineate between the measurements for these 2 feeders the IEC61850 logical node names of MMXU1 and MMXU2 would be used. Each logical node may also use an optional application specific LN-prefix to provide further identification of the purpose of a logical node.

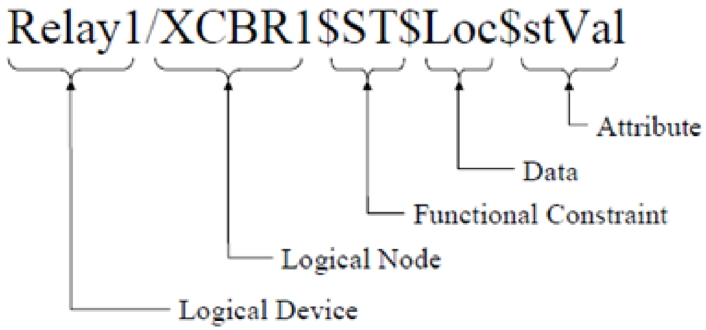

Figure 3.5: *Anatomy of an IEC 61850-8-1 Object Name*

3.3 Communication in IEC 61850

IEC 61850 provides different technology mappings for communication. The mapping to serial connection will not more play an important role so only the mapping to Ethernet is considered. The sampled values(SVs) provide very fast cyclic communication, like 4000 samples per second. [15] [16] As IEC 61850 is based on Ethernet without any specific support for real-time behavior, It does not support deterministic real time behavior but can be considered to be very fast and provides real-time related data on a high accuracy time-synchronized basis between different data sources. [6] SVs can be provided by multicast, allowing several receivers to access the same data only put once on the wire or by unicast only sending the data to one receiver.

GOOSE message is a very fast communication mechanisms and is sent when an event occurs like different types of faults.

MMS uses a client-server model In addition, it supports reporting capabilities (buffered and unbuffered) and access to logs containing historical data. In chapter 4 it will be talked about GOOSE messages, MMS and sampled values in detail. [14]

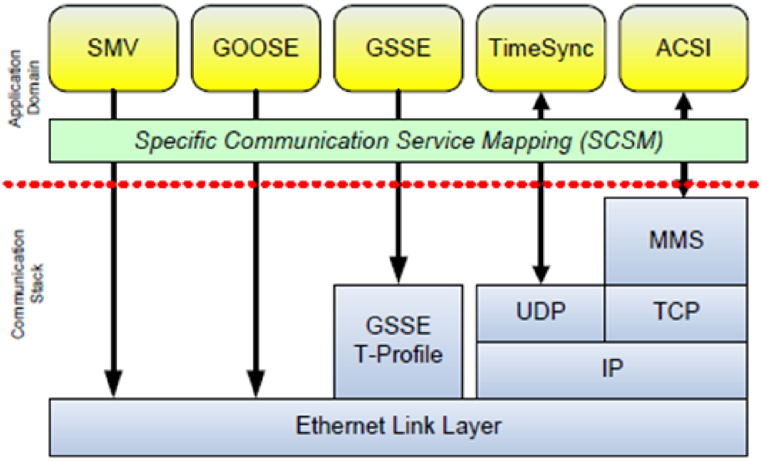

Figure 3.6: *IEC 61850 Communication mapping*

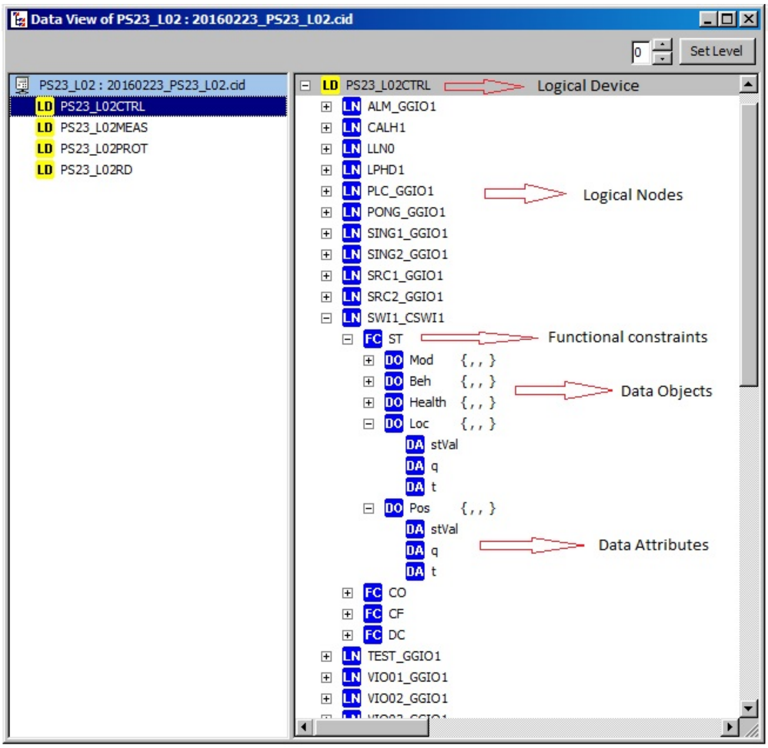

Figure 3.7: *IEC 61850 data accessing model*

In Figure 3.7 the model of accessing data in IEC61850 is described. The data source contains data organized in logical nodes, data objects and data attributes. Those data can be directly read or written using MMS. On top of the data, different data sets can be defined, referencing parts of the data. For example, Dataset1 can reference Dataobject2 of the LogicalNode1 and Dataattr1 of the DataObject1 in LogicalNode2. [28]

When a DataObject is referenced all its Data Attributes are included. Thus, data sets group the data into new categories and data can be contained in several data sets. Data sets can be preconfigured using SCL or dynamically defined using an MMS service. By using MMS, the data sets can be used to read and write data. However, the more important role of data sets is to use them as the data source for different reporting mechanisms. A log control block uses the data of a data set to store the history of the data in a log. Clients can query the log using MMS. Using buffered or unbuffered report control blocks, servers send out data to a client. Here also MMS is used as a protocol.

The difference between buffered and unbuffered is that in the first case the server buffers the data for the preconfigured client so that the client can receive the data later, even if it is not connected when the data should be sent. However, in the unbuffered case any client can subscribe to reports dynamically, but the changes that occur while the client is not connected will get lost. Buffered and unbuffered control blocks reference a data set to define what data they report.

A data set can be used by several control blocks. The report control block configuration specifies when a report shall be triggered and can be set for quality changes, data changes, data updates, integrity, or general interrogation. The latter two are triggered outside the data to receive the current state from time to time (integrity) or request the state by the client (general interrogation), for example, when reconnecting.

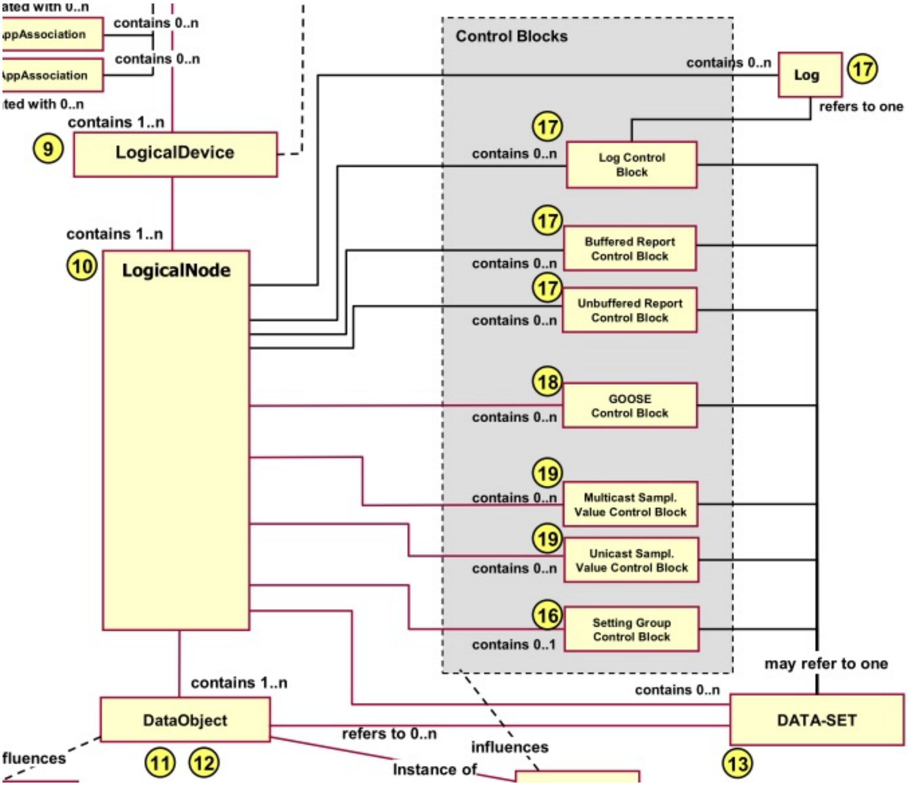

Figure 3.8: *Buffered and Unbuffered control blocks*

When changes trigger the report, only changed values of a data set are returned. Thus, it makes a difference whether a dataset contains a data object or all attributes of a data set individually. In the first case all the attributes are returned if one value changes, whereas in the second case only the changed one is returned. As the attributes can represent, for example, value, quality and time-stamp, it is important to select the data object if quality and time-stamp should be received as well.

A GOOSE control block specifies what data set a GOOSE message should be referring. It can be enabled or disabled. When enable, it sends all data of the referenced data set using the Ethernet-bases GOOSE communication. In the future it will be talked about GOOSE messages more.

The unicast and multicast sample control blocks define what data should be sent by the server in a periodic way (Cyclic communication). When a control block references a dataset all data will be sent even if they have not changed. The sampling rate defines how often the data should be sent. In the case of unicast, the control block also contains information about the client to which the data should be sent. In addition to the above-mentioned access of the data, the MMS mapping also supports browsing capabilities to access the structure of the data (logical devices, logical nodes, data objects, etc.) and the configuration (data sets, control blocks, etc.) and to read and write files in the IEC 61850 server.

3.4 Architecture of the communication system

In previous time copper wiring was used to connect the Circuit Breakers, disconnectors, CTs and VTs to the control room and therefore maintenance and cost were very high. Today, wireless technology and Fiber optic are very popular and common and instead of bunches of copper cable, one fiber optic cable is used. Nowadays, Non-conventional instrument transformers (NCIT) are used such as capacitive voltage sensors and optical current transformers which are safer also. Digital transmission of voltage and current also reduces the amount of the cabling required. Wide spread use of NCIT has been under question since there was no standard interface for multi-vendor interoperability. This is changing with increasing implementation of IEC 61850-9-2 sampled values for the digital interface between NCITs and protection relays.

”Interfaces" are defined in IEC 61850 to link the process, bay and station levels of a substation. Information modelling defines the services, data objects, attributes that enable information to be readily exchanged. totally there are 11 interfaces between the different levels of a substation. these are shown in figure 3.7. For Example, Interface IF4 and IF5 are summarized belowe. IF4 and IF5 together are be considered to be the process bus.

- IF4: Analog data exchange between process and bay level(samples from CT and VT)

- IF5: Control data exchange between process and bay level

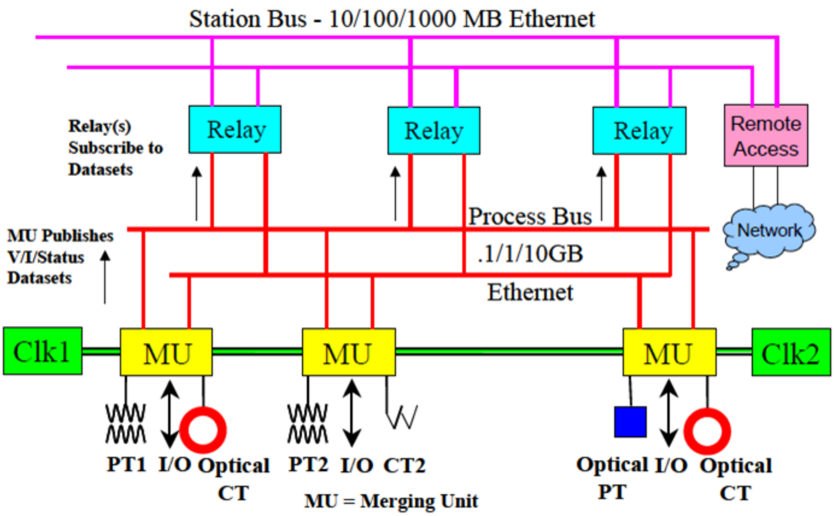

Figure 3.9: *IEC 61850 Substation model*

Substation automation devices that are compliant with IEC 61850 are interoperable but not necessarily interchangeable through the use of common logical nodes and interfaces. [5] The communication infrastructure in a substation consists of 3 levels, namely Process Bus level, Bay level and Station level. In the following each of them are described in detail. [26]

The architecture and topology of process bus networks is an area of active research with the reliability of these networks a particular focus. Sampled value process bus Ethernet topologies can be classified as either point to point links or switched networks. The point to point topology replicates the layout of analogue CT and VT secondary cabling, albeit with a fiber optic network, and is the approach taken by the General Electric "HardFiber" system. Network capacity is not a concern in a point to point process bus as each link is limited to two devices.

Some process bus devices, capable of being used in a switched network, are used in point to point configurations to address specific needs. One such example is Powerlink Queensland's Loganlea substation, where multiple point to point links are used to avoid the need for centralized time synchronization.

Horizontal communication in substations is the communication between protection relays (inter-tripping) or within a bay (process connections)."Vertical communication" is the control of substation equipment through a local operator interface, or from a remote control center. Horizontal communication is generally more time-sensitive and uses a publisher-subscriber model, while vertical communication is more focused on reliability and a client-server model is most commonly used.

To understand the communications between the devices in a grid, the network is divided into some parts for the sake of simplicity. In the following these sections are introduced and explained(WRT the figure 3.6)

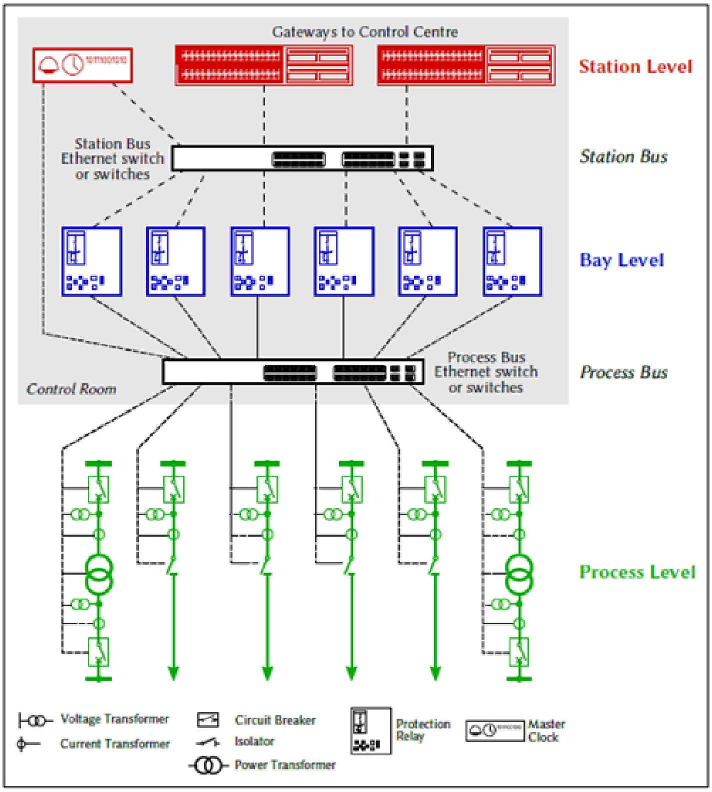

Figure 3.10: *Communication between Process, Bay and Station levels*

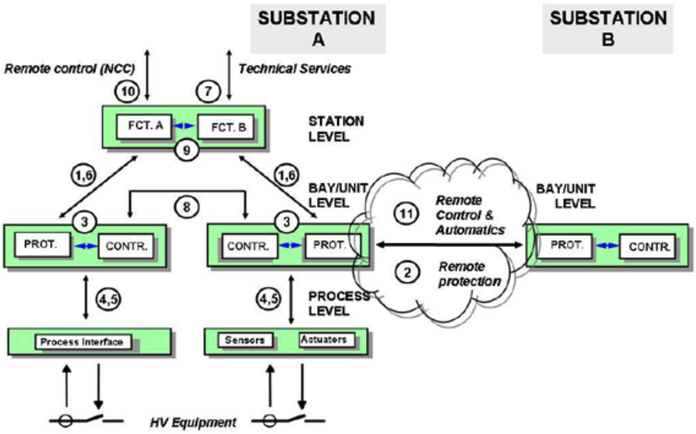

Figure 3.11: *IEC 61850 interfaces model in substations*

- Process level

It consists of all the functions interacting to the process and are basically binary and analog IOs like data acquisition (like sampling) and issuing of commands. The instruments in this level are Current transformer, Voltage transformer, power transformer, isolator and circuit breaker. They are actually the primary apparatus of the power grid which through the interfaces and process bus Ethernet switch send the data to the related IEDs in the Bay level. The process level functions mostly are implemented in the bay level IEDs otherwise these functions are included in the process level IEDs.

- Process bus

Process bus is mainly an Ethernet switch which through it the states and the SVs taken from the process level equipment are sent to the Bay level IEDs and according to the software configuration of the IEDs the commands are issued which again will pass through process bus to the process level equipment to implement the required function. The capacity of the process bus is yet an open issue and lots of research is being done about it.

- Bay Level

It consists of the functions within a bay. A bay is a subpart of a substation like a switchgear or line feeder. Bay level IEDs with respect to the software configuration inside them, decide about the actions that should be done when receiving the data from the process level equipment.

- Station Bus

Is the Ethernet Switch which receives the data from the process level and IEDs in bay level and send them to a Remote Control Center like SCADA or other supervisory programs through Gateway and receives the commands from the operator in Control Center to configure the network the way it is required

- Station Level

It consists of the monitoring part of the network and also sends commands to the IEDs for the desired network configuration.

- Gateway

They are devices that has the function of changing the protocols to enable communicating between the devices. Commonly, SCADA systems use the DNP3 protocol and IEDs in the by level or process level have the IEC 61850 standard. In order to understand for the SCADA and IEDs the structure of the information they communicate, a change of the protocol is needed. However, there is an effort to change the protocol of SCADA to IEC 61850.

- Synchronization Timer

  Devices which are compatible with IEC 61850 need to use a common format for the time since it is required to compare the sequence of events happening in the grid. Also, it is important to keep track of time with an acceptable accuracy for taking samples from the current and voltage for the purpose of protection. Otherwise, if the samples are not synchronized when they reach the IEDs, a phase error and then a malfunction in the protection system is undeniable. Later it will be more talked about the different time synchronization protocols with respect to the accuracy needed by the system. The two famous synchronization timers are:

  – Network Time Protocol(NTP)

is a networking protocol for clock synchronization between computer systems. It is able to synchronize all the operating computers within a few milliseconds of Coordinated Universal Time. This protocol is usually described in terms of a client-server model but also can be used in peer-to-peer connections.

– Precision Time Protocol(PTP)

The primary source of time in a PTP system [20] is the ”grandmaster" clock that usually includes a GPS(Global Positioning System) receiver, providing a common time reference between PTP systems. The end-users are ”slave clocks" that are either embedded in another device or are stand-alone”protocol converters" that re-generate a local 1-PPS(Pulse Per Second) [13] or IRIG-B. [21] Substation Automation Systems generally use IRIG-B and Network Time Protocol (NTP) for distribution of absolute time. The one pulse per second (1-PPS) signals defined in IEC 60044-8 provide a straightforward means of synchronizing events but do not include time of day information (also referred to as ”absolute time"). IRIG-B and 1-PPS are unidirectional and do not compensate for propagation delay while NTP and PTP are bidirectional network based systems that do compensate for network delays [13]

CHAPTER 4

Protection systems in UnaReti

4.1 General Overview

Today's Electric Networks are considered as strategic assets of each country. With increasing the world population, demand for energy and in particular Electric Energy has rocketed since years ago. Therefore, continuity of services and maintenance are becoming more and more important as two critical issues which should be fulfilled.

Distribution System Operators as the owner of the distribution networks and the last in the delivering energy chain to consumers are careful about the electricity outage numbers happening in one year since if it exceeds a certain limit, then they are fined by the related authority.

Having said that, the only way to ensure the continuity of services is heading to a more automated distribution networks which has the selfhealing process in case of a chaos. Electric Networks are always prone to faults like Short Circuits and Over voltages which if not take an action in due time, it is possible to experience a blackout in the system. Thus Protection devices are highly demanded.

4.2 Protection Methods

Among different methods of protecting the grid, two methods are of great importance and used by many utilities namely Logic selectivity and Chronometric selectivity. [7]

1. Logic Selectivity: If a fault occurs at any point in an electrical distribution grid, it is required that the fault be eliminated as soon as possible with minimal outage area. This obvious requirement leads to the necessity of rapidly isolating the detective section. The protecting element- Circuit Breakers- which is placed immediately upstream the fault must operate to eliminate the fault as soon as possible; the other protecting elements- the circuit breakers which act as backup- must not trip.

Conventional selectivity processes (overcurrent and time tag) fulfill these desire to a more or less satisfactory degree. The logic selectivity system makes it possible to attain a total selectivity between all stages of an electrical distribution network from high to low voltage. It also allows the fault to be eliminated very rapidly and independent of the place where the fault occurred. Logic selectivity makes it possible to allow the operation of the CB which the nearest to the fault.[21]

2. Chronometric Selectivity: The chronometric selectivity makes it possible to have a backup protection in case the required CB get stock and cannot break the fault. In this case after a certain amount of time which is set using the IED software, the backup CB will eliminate the fault with the expense that a larger area is affected and lose the electricity.

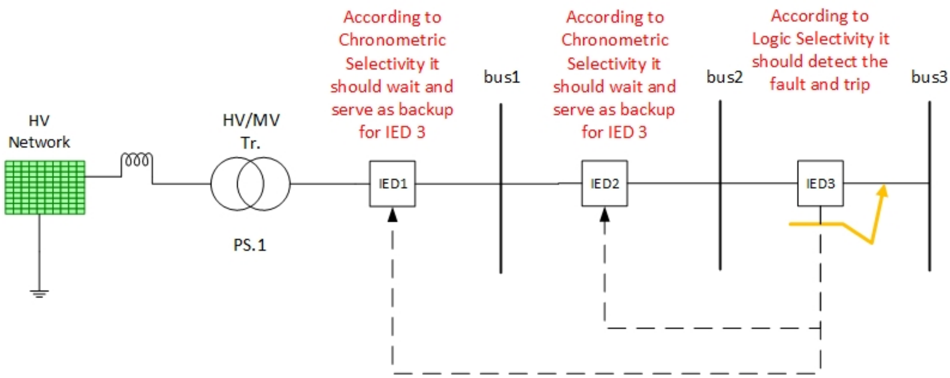

Figure 4.1: *Definition of Logical and Chronometric selectivity*

With respect to the IEC 61850 standard, following there is an example of the list of LN that will integrate the IEC 61850 server in the IEDs controlling reclosers to perform logic selectivity required functions for FLISR solution. The definition of 50P/51P and 67N protection functions are as follows: [12]

- 50P

Phase instantaneous overcurrent elements: It is very fast and by the time the overcurrent happens it will disconnect the circuit.

- 51P

Phase overcurrent protection per time-current curve elements: the disconnection time depends on the current. as much as the current is higher, it will operate sooner.

- 67N

Neutral Directional Overcurrent: Directional overcurrent protection for distribution networks in which the neutral earthing system varies according to the operating mode, based on measured residual current.

Requirement	61850 LN mapping
Time over-current monitoring for ANSI 50P/51P Functions	PTOC -> Time over-current Protection
Directional over-current monitoring for ANSI 67N Function	PTOC -> Time over-current Protection RDIR -> Directional Element PTOV -> Overvoltage Protection
Circuit breaker operation	XCBR -> Circuit Breaker
Recloser operation function	RREC -> Autoreclosing
Breaker Failure Monitorization	RFBR -> Breaker Failure
Logic Selectivity Function (Local Operation)	CLSF -> Logical Selectivity of Faulty MV section management
Logic Selectivity Monitoring (Subscriptions)	ALSM -> Logic Selectivity Monitoring Subscriptions

Figure 4.2: *List of logical nodes for controlling reclosers*

4.3 Assets used in Protection with respect to the devices in UnaReti

4.3.1 Protection relay

A relay is a device which is operated by a variation in its electrical or physical conditions to effect the operation of other devices in an electric circuit. A protective relay is a relay, the principal function of which is to protect service from interruption or to prevent or limit damage to apparatus. In electrical engineering, a protective relay is a device designed to trip a circuit breaker when a fault is detected. As an example, The Protection Relays which are used in UNARETI in SCUOLA project [2] are ThyTronic protection devices.

Figure 4.3: *ThyTronic Protection device*

4.3.2 Current & Voltage transformer

VT and CT are the measuring instruments and the main purpose is to measure the circuit condition or parameters. So the connection of the instrument transformers should not influence or alter the original circuit condition. It follows that the CT is desired to have very little impedance (or resistance) across its terminals. So that the CT in series with the line should not result in any significant voltage drop across its terminals. The current flowing in the secondary of the CT does not influence the primary side current. The primary side current is solely determined by the load impedance, source voltage and of course the line parameters.

A voltage transformer is connected between line and ground. It is desired to have very high impedance. A low impedance results in comparatively large current flow in VT primary and can considerably alters the original circuit condition which is not desired. Otherwise we can say that the voltage transformer should have negligible loading effect on the main circuit. An example of the modern measurement devices is the Thysensor made by Thytronic which consists of the CT,VT and the insulator all in one device. [4]

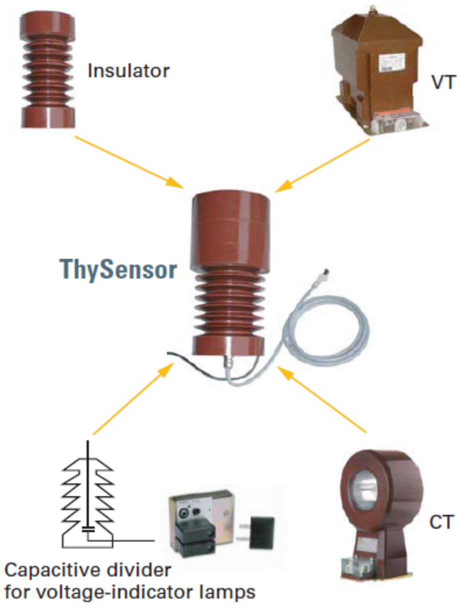

Figure 4.4: *ThySensor*

Figure 4.5: *ThySensor in the ABB Circuit Breaker cabinet*

4.3.3 Circuit Breaker

A circuit breaker is an automatically operated electrical switch designed to protect an electrical circuit from damage caused by overcurrent/overload or short circuit. Its basic function is to interrupt current flow after protective relays detect a fault.

Unlike a fuse, which operates once and then must be replaced, a circuit breaker can be reset (either manually or automatically) to resume normal operation. Circuit breakers are made in varying sizes, from small devices that protect an individual household appliance up to large switchgear designed to protect high voltage circuits feeding an entire city.

Figure 4.6: *ABB Switchgear, the cabinet where the Thysensor and ABB circuit breaker houses*

Circuit breakers are not everlasting devices. Normally they are designed for about 3000 cycles of opening and closing after which their reliability will be very low.

Figure 4.7: *Counter of the number of times the circuit breaker has worked*

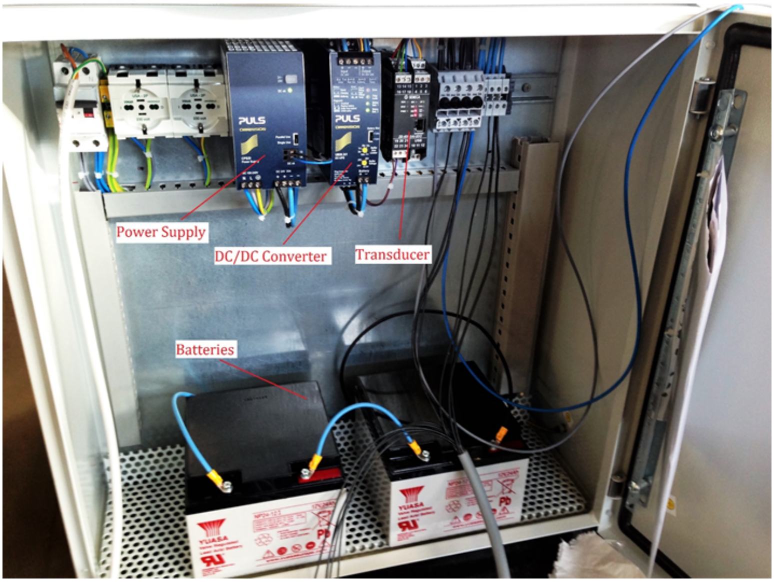

Figure 4.8: *Power supply and other components*

The Circuit Breaker needs the power supply to trip. In order to energize the coil of the breaker a power supply with 2 sets of Battery(in this figure) are used to be sure that power supply is always working . the DC/DC converter is used to change the level of the voltage that the breaker needs to trip.

4.4 IEC 61850 and its capabilities in terms of Protection

In order to be able for the devices to communicate with each other, a new communication model is needed to improve the interoperability and interchangeability between the devices. That model has been developed and standardized in IEC 61850-These standards include Ethernet based process-level connections between switchyards and control rooms. IEC 61850(communication networks and systems in substations) was developed to provide interoperability between intelligent electronic devices (IEDs) for protection, monitoring, control and automation in substations.

4.4.1 GOOSE Message

(Generic Object Oriented Substation Event) It is a very fast communication method to distribute time critical data to several IEDs at the same time [multicast] such as the switchgear status indications, control commands and blocking signals. The methods is based on the publisher/subscriber communication principle in which both IEDs, sender and receiver (one in the process level and the other one in bay level), use a local buffer to handle the process of data exchange. [24]

Since there is no acknowledge by the receivers of the GOOSE messages, they are sent several times in a high frequency after the change. Different data items in an IED can be configured as one Dataset and one GOOSE can accommodate several datasets. Any change in the data attributes of these data sets will generate an event and send GOOSE message to the subscribed IEDs repetitively. Therefore it is very important to configure the datasets. For subscribing it is very important to know the upstream and downstream CB. The GOOSE message normally is sent in a periodic way even when there is not any fault but when a fault is detected, the frequency of the GOOSE message in increased[11]. In the following is a list of the main parameters should be configured.

- GOOSE ID
- Multicast MAC Address
- VLAN priority

- VLAN ID (according to Ethernet switch configuration)
- Application ID
- Configuration revision
- Dataset Name
- Time to live (timeallowedtolive) for GOOSE message in milliseconds.

After Configuring the IED I/O s and the GOOSE dataset, it is important how to manage the GOOSE message using system configuration tool. Different IEDs from different vendors have their own ICD (IED configuration description) file which these ICD files will be sent to the System Configuration Tool and the SCD (System Configuration Description) will be generated which will be again sent back to configure the individual IED.

4.4.2 SVs

This communication service, considered in the standard for transmit data that comes from instrument transformers, uses the publisher/subscriber principle for communication in such a way that the publisher device (merging unit-MU) records the acquired value in an internal buffer and the subscriber device (IED) reads the value and transfers it to its own buffer. A time stamp is added to each acquired value in order to allow the subscriber device to follow the right value sequence.

4.4.3 MMS

This communication service is used to transmit medium priority information.It is used to browse, read, and write the information of the data source. As was defined by the Standard ISO 9506 some years ago, this communication method works under the client/server concept providing features for information exchange between nodes on a communication network with the advantages of interoperability among IEDs supplied by different vendors, independent of the type of application and with significant efficiency of obtaining and distributing the required information. MMS is based on TCP/IP

(Internet Protocol) and while not as fast as GOOSE and SVs, it is still fast and provide real-time-related data.Using Ethernet SVs and GOOSE are limited to an Ethernet segment, whereas MMS uses TCP/IP and can pass through routers and so on. However, there is already Ethernet-hardware available for passing GOOSE messages to other segments (like for substation to substation communication).

4.5 An example for the protection methods:

In this diagram, there are 4 IEDs which are compatible with IEC 61850. These four IEDs are connected together via an Ethernet switch. These 4 IEDs are capable of measuring faults like phase over voltage or phase to ground fault. Also they have the capabilities to perform the auto reclosing function (79 relay). Considering a fault happens downstream the CB4. The process of the protection function is summarized below:

If the IEDs have coordination and setting for logic and chronometric selectivity; IED4 will detect the fault first and will send a block signal to all of the IEDs upstream the CB4. According to a predefined time which is set in the IEDs, all of the IEDs wait to receive the block message which is called in IEC 61850, a GOOSE. The GOOSE message is sent to all of the IEDs upstream via the Ethernet Switch. If the CB4 is stocked or for any other reason cannot perform its required function, the upstream circuit breaker which is CB3 will distinguish the fault with the expense that the outage area will be larger.

The way the IEDs will detect the fault is by using the transformers (CT, VT) and if needed by using sample values and merging unit which will send the associated signal to the IEDs so they will send the specific signal to the Circuit breakers to open (or close in case of auto reclosing) the circuit.

GOOSE messages and Sample Values because of their importance do not go beyond the second layer in the OSI model and so they are very fast. In a complex grid, there are many IEDs and Circuit breakers. Therefore, understanding that the GOOSE message should be sent to which IEDs are very important. This is done by subscribing the IEDs to the GOOSE message via the MAC Address. Since the MAC layer is the second layer and IP address cannot be used, therefore all the IEDs which are subscribed to the GOOSE messages belong to the same LAN (Local Area Network).

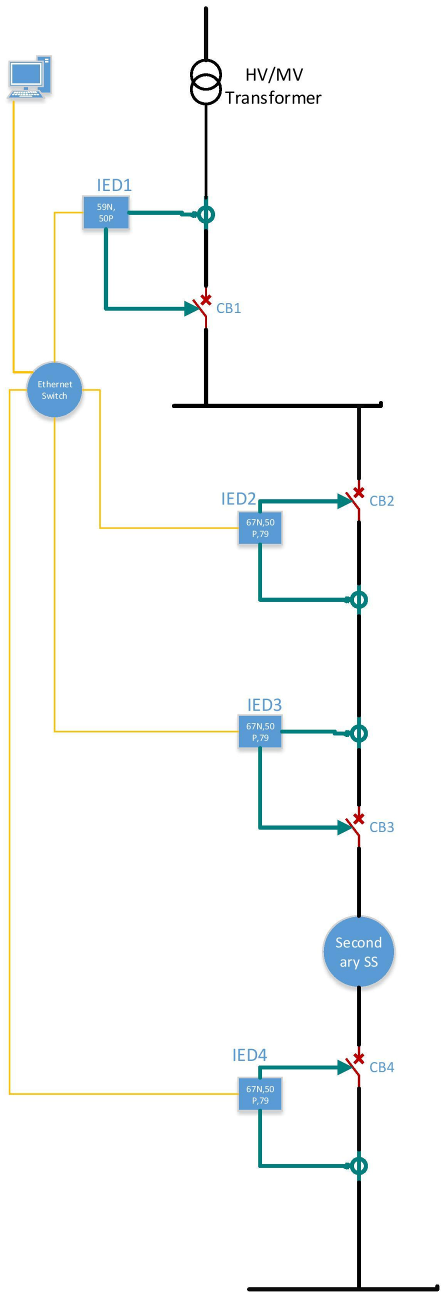

Figure 4.9: *Protection devices in the primary and secondary substations*

4.6 Architecture of the primary and secondary substations in UnaReti

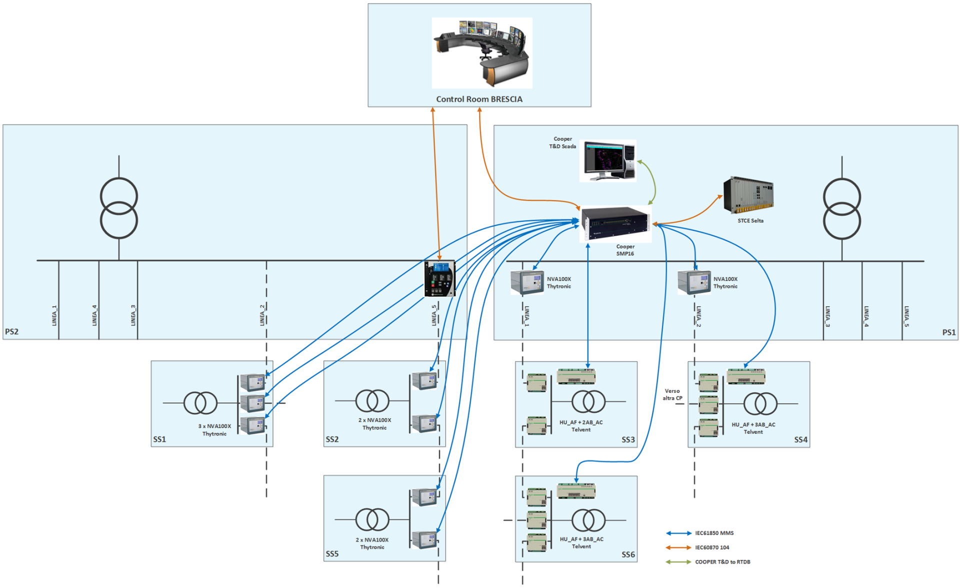

Figure 4.10: *Architecture of the primary substations and secondary substations in UnaReti*

This figure is part of the architecture of the distribution system in UnaReti Group which is one of the partners of the IDE4L project. the aim of this project to create a single concept for distribution network companies to implement active distribution network today based on existing technology, solutions and future requirements.IDE4L develops the entire system of distribution network automation, IT systems and functions for active network management.

- Fault location , isolation and supply restoration
- Congestion management
- Interactions between distribution and transmission network companies

Automation systems and management solutions will be tested in laboratories to ensure the functioning of the complete system. Real-time digital simulators and micro-grid installed in laboratories with real devices are utilized in testing.

UnaReti Reti Electtriche Spa, Ostkraft Holding A/S and Union Fenosa Distribucion, S.A. will demonstrate the developed system and functionalities in their networks including actual customers. Already there are PV, wind power, heat pumps and EVs connected in urban and rural networks. [5]

4.6.1 What is going to be done

The goal is to move the SCADA system from STCE Selta located in the primary substation to control center which is located in Brescia. Both the systems use the IEC 60870-5-104 protocol. Also, the investigation of communicating between the General electric protection device located in one of the primary stations with the Thytronic protection devices located in the secondary substations is tested.

4.6.2 Configuration of RTUs in UnaReti

RTUs are set of devices which have been specifically designed for real-time control and automation Applications. They are placed in primary and secondary substations and are connected via needed communication infrastructure. In this section the RTU's configuration structure is explained with respect to the model used in UnaReti company for the IDE4L project.

Types of Modules

The platform consists of the following core elements:

- Control Unit or Head Unit (HU)

CPU module with built-in (serial, Ethernet) communication ports. There are two types of head units available: an advanced and a basic version, the model we used here was the Advanced Head Unit with Acquisition(HU_AF).

- Serial Communication Module (AB_SER)

This module enables multiple RS-232/485/422 serial channels to be added. This module can be used only with an advanced head unit (HU_A or HU_AF) and with a maximum of four AB_SER for each HU.

- Acquisition Blocks (AB)

  I/O modules which are connected to the HU and perform data acquisition and, in certain circumstances, pre-process signals, control and execute commands to field devices. The features include:

  - digital inputs (AB_DI)
  - digital outputs (AB_DO)
  - analog inputs (AB_AI)
  - ”transducerless" direct AC analog inputs (AB_AC)
  - digital inputs and outputs (AB_DIDO) and multiple inputs and outputs (AB_MIO)

- Complementary Module

These modules have no data processing function, but are indispensable for the ITB architecture. They perform the termination (TU and BT) and the bus expansion (XU) functions, among others

- Data Acquisition Bus

An internal bus is used to connect the head unit to the acquisition blocks. The bus contains power supply, data, and control and synchronization lines. The bus is expanded to the following ITB rows by using a cable which connects the DB15 pins available in the TU and XU Modules Intelligent Terminal Block (ITB) An ITB consists of one HU, a set of ABs, together with all required building elements (termination module, expansion module, flat cables, etc.)

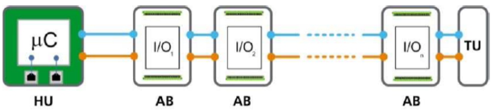

Figure 4.11: *How the acquisition blocks are connected to the head unit*

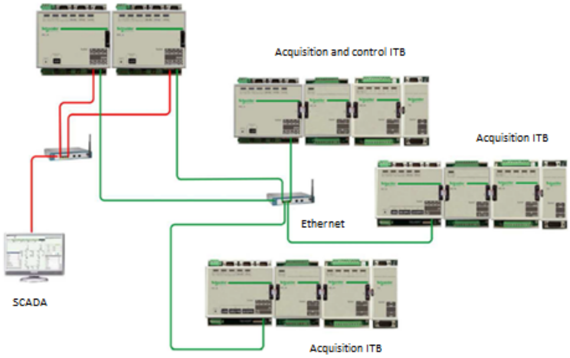

Figure 4.12: *Large RTU/Distributed acquisition with processing redundancy*

The advanced head units HU_A and HU_AF have double Ethernet ports to connect to two different buses; the first one is a data bus to communicate with the acquisition ITBs and the second one is a processing bus to communicate with the other processing units in the system.

As shown in the figure above, there are multiple ITBs acquiring and sending field data by means of an Ethernet bus to a control unit made up of two redundant HU_A modules. This control unit communicates with a switch using the second Ethernet bus.

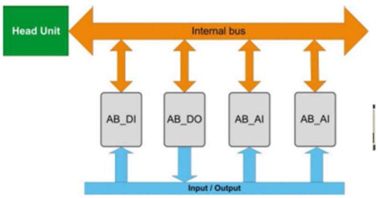

Figure 4.13: *Communication between Head Unit and AB*

Applications of RTUs for the Electrical Market

Currently, the following applications are available:

- Basic application

Basic Application

The implementation of this functionality is as follows:

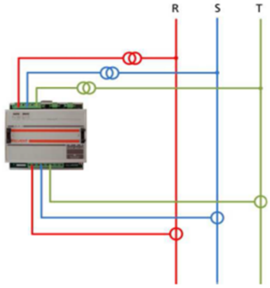

Figure 4.14: *AB-AC basic application*

The calculation of electrical measurements (voltage, current, power and energy meters)

- Synchro check

This application monitors and controls the status of a switch based on certain conditions of synchronism.

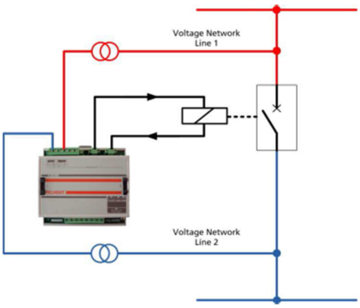

Figure 4.15: *Status checking application*

In the Basic Application the measurements provided are:

Measurement	Description
VR_{RMS}	R-Phase instantaneous true RMS voltage.
VS_{RMS}	S-Phase instantaneous true RMS voltage.
VT_{RMS}	T-Phase instantaneous true RMS voltage.
IR_{RMS}	R-Phase instantaneous true RMS current.
IS_{RMS}	S-Phase instantaneous true RMS current.
IT_{RMS}	T-Phase, instantaneous true RMS current.
AR	R-Phase instantaneous apparent power.
PR	R-Phase instantaneous active power.
QR	R-Phase instantaneous reactive power.
AS	S-Phase instantaneous apparent power.
PS	S-Phase instantaneous active power.
QS	S-Phase, instantaneous reactive power.
AT	T-Phase instantaneous apparent power.
PT	T-Phase instantaneous active power.
QT	T-Phase instantaneous reactive power.
A3phase	Three-phase apparent power.
P3phase	Three-phase active power.
Q3phase	Three-phase reactive power.
VRS	R-S (L-L) voltage.
VRT	R-T (L-L) voltage.
VST	S-T (L-L) voltage.
VR3	R_{SQRT}(3) phase voltage.
VS3	S_{SQRT}(3) phase voltage.
VT3	T_{SQRT}(3) phase voltage.
Freq	Network frequency.
PFR	R-phase power factor.
PFS	S-phase Power factor.
PFT	T-phase power factor.
VN_{RMS}	Neutral instantaneous effective voltage.
IN_{RMS}	Neutral instantaneous effective current.
VR_{Phase}	Voltage R-phase displacement.
VS_{Phase}	Voltage S-phase displacement.
VT_{Phase}	Voltage T-phase displacement.
VN_{Phase}	Voltage Neutral displacement.

Figure 4.16: *AB-AC Measurements*

Measurement	Description
IR_{Phase}	Current R-phase displacement.
IS_{Phase}	Current S-phase displacement.
IT_{Phase}	Current T-phase displacement.
IN_{Phase}	Current Neutral displacement.
VR_{SEC}	R-phase secondary instantaneous effective voltage.
VS_{SEC}	S-phase secondary instantaneous effective voltage.
VT_{SEC}	T-phase secondary instantaneous effective voltage.
VN_{SEC}	Neutral secondary instantaneous effective voltage.
IR_{SEC}	R-phase secondary instantaneous effective current.
IS_{SEC}	S-phase secondary instantaneous effective current.
IT_{SEC}	T-phase secondary instantaneous effective current.
IN_{SEC}	Neutral secondary instantaneous effective current.
Erin	R-Phase active energy demand.
ERout	R-Phase active energy supply.
ERL	R-Phase inductive energy.
ERC	R-Phase capacitive energy.
ESin	S-Phase active energy demand.
ESout	S-Phase active energy supply.
ESL	S-Phase inductive energy.
ESC	S-Phase capacitive energy.
ETin	T-Phase active energy demand.
ETout	T-Phase active energy supply.
ETL	T-Phase inductive energy.
ETC	T-Phase capacitive energy.
Ein3phase	Three-phase active energy demand.
Eout3phase	Three-phase active energy supply.
EL3phase	Three-phase inductive energy.
EC3phase	Three-phase capacitive energy.

Figure 4.17: *AB-AC Measurements*

An Example of the configuration of RTUs in Primary and Secondary Substations

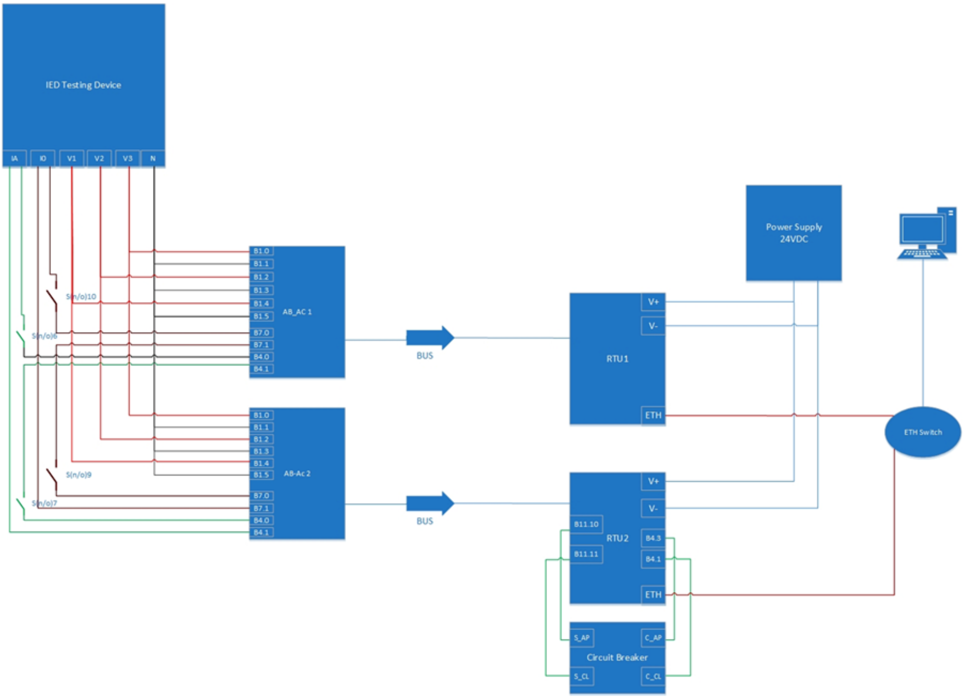

Figure 4.18: *Configuration of RTUs in UnaReti system for protection*

In this configuration, one of the RTUs is considered to be installed in the primary substation and the other one in the secondary substation to communicate via an Ethernet Switch.

4.6.3 SMP

SMP: Short for Symmetric Multiprocessing, a computer architecture that provides fast performance by making multiple CPUs available to complete. Individual processes simultaneously (multiprocessing). Unlike asymmetrical processing, any idle processor can be assigned any task, and additional CPUs can be added to improve performance and handle increased loads. A variety of specialized operating systems and hardware arrangements are available to support SMP. Specific applications can benefit from SMP if the code allows multithreading.

In UnaReti the brand of the SMP is cooper and it is able to convert the IEC 61850 to 104 protocol which is understandable for SCADA System. [32] All the protection devices and the RTU with acquisition blocks send the data to the SMP. This SMP is a multiprotocol system which can communicate with the SCADA 104, 61850 protection devices and the control room which is located in Brescia. The SMP is located in primary station.

Here in the primary substations , there exist two lines(L01 and the L02) and in these primary substations the General Electric protection devices are installed. Also there are some secondary substations-SS- that they have the Thytronic protection devices installed.

By using 61850 model, we would like these devices to speak with each other and exchange GOOSE messages. SCADA system which is in the file (email:23.02.2016) has the 61850 model. We try to change the 104 to 61850 for the SCADA but it still needs to be defined.

Every substation- either primary or secondary- has the data which is divided in 4 logical devices (LD)

- Protection(PROT)
- Control(CTRL)
- Measurement(MEAS)
- disturbance recorder (RD)

In each LD there are the logical nodes related to that function(for example in section PROT there are the logical nodes like

- LLN0
- PVPH
- PTTR
- PTOC

etc. The logical node 0- LLN0- contains the reports-either buffered or unbuffered- and it is possible to subscribe the report to a dataset. Some protection logical nodes have some thresholds which is shown by >,»,»>(with refer to Thyvisor software from Thytronic). About the reports, ALARM is a buffered report. From the SCADA interface it is possible to press a button and enter the SMP interface. Also from the SMP, we are able to enter the cabinet(Substation) interface.

Here in this picture the master protocols are the STCE Selta based on 104 protocol and the Thytronic protection devices in line 1&2 which are based on 61850 protocol. The slave device is the control center which is based on the IEC 60870-5-104 protocol.

The mapping from the 61850 to 104 protocol is done via the Gateway (SMP)

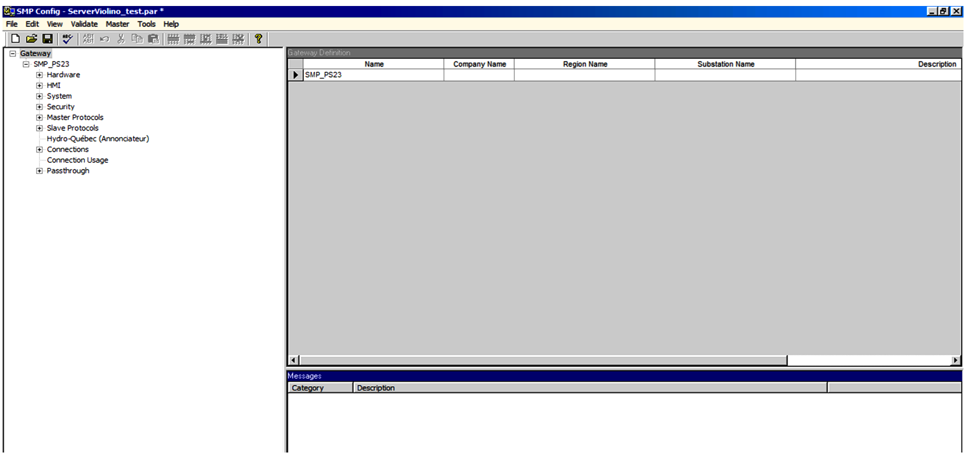

Figure 4.19: *1- Screen shot from the SMP manager software*

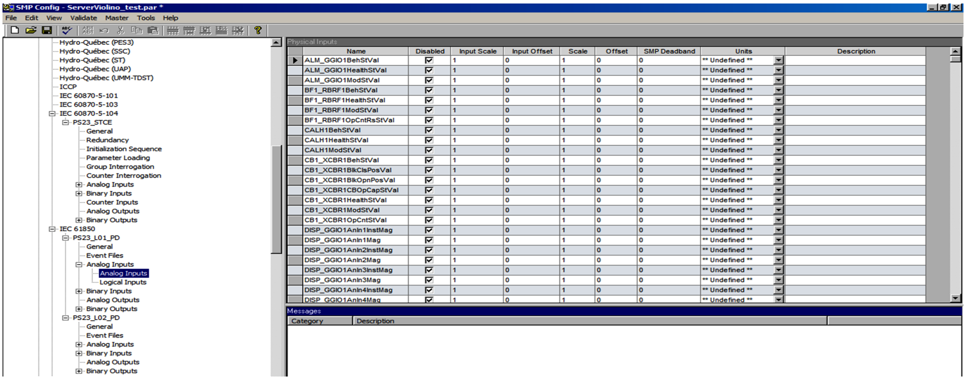

Figure 4.20: *1- Screen shot from the SMP manager software- Master protocols*

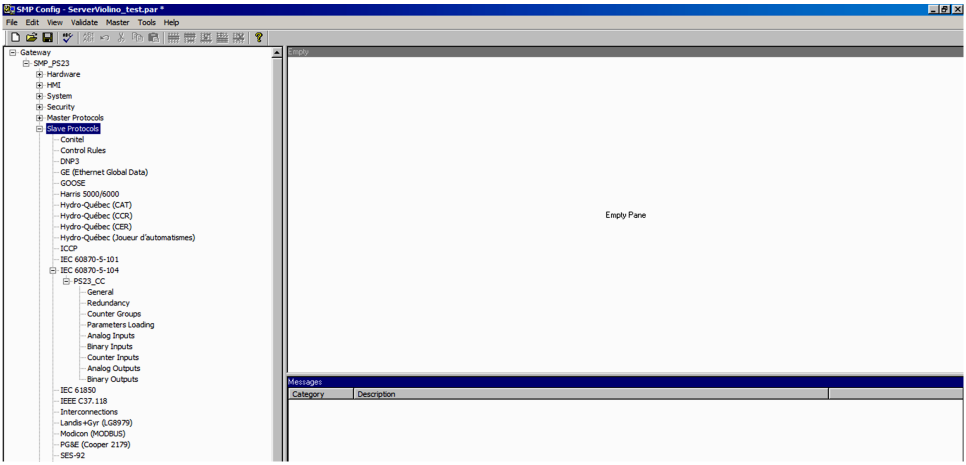

Figure 4.21: *1- Screen shot from the SMP manager software- Slave protocol*

While DNP3 dominant in NA, Latin, South Africa and Australia, the IEC60870-5 protocols dominant in Europe, Middle east and Asia Pacific. There are 3 divisions of IEC 60870-5 namely, IEC 60870-5-101 for serial communication, IEC 60870-5-103 for Protection relays and IEC 60870-5-104 for Ethernet Implementation.

DNP3 is primarily used for communications between a master station and IEDs or RTUs. It is optimizes for the SCADA communications and is supported by a substantial number of SCADA equipment manufacturers [32]

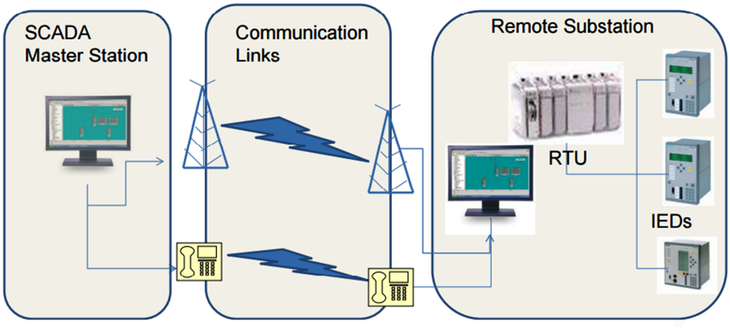

Figure 4.22: *Communication between SCADA and the Remote Substation*

4.7 Simplified Version of a Real Network

The figure shows the simplified version of a network which consists of 2 primary substations. From which one of them is connected and the other one is disconnected and serves as the backup and will be connected in case of a fault which may or may not results in disconnecting the PS1.

Overall there are 11 secondary substations from which only 3 of them are equipped with protection devices (PD) and circuit breakers since they are very expensive compared to the disconnectors with no capability of clearing the short circuit fault. Therefore, these protection devices are just put in strategic points in the network.

In this figure SS4, SS7, SS9 are equipped with the protection devices. Faults are the perturbations which causes abnormal behavior of the grid. These faults should be cleared as soon as possible to reconfigure the grid in a way to energize the healthy sections as many as possible.

Relays are responsible to Clear the faults in the grid. There are many different kinds of relays which they should be used in the grid according to the needs and functionality. For example, 79 is the AutoReclosing relay and is used wherever the automatic reclosing of the circuit breakers is needed. Another example is the 50/51 relay which is the overcurrent relay and responsible for operating in case of overcurrent.

Regarding the protection, it is very important to have backup protection in some strategic parts of the grid since there is a possibility of circuit breaker getting stuck and cannot be opened, although the probability is low with today high technology advancements but still is needed since assets of electrical grid like high voltage transformers are much more expensive compared to a circuit breaker.

Consider a fault happens between the 2 secondary substations namely SS5 and SS6. The process will be explained in the following.

Since the Protection Devices(PDs) are directional and sensitive to the direction of the fault current, R3 will detect the fault and will send a block message (Goose message) to the R1 which serves as the backup protection for R3. This block message is sent to upstream relays otherwise by the time the detect the fault, may operate and a greater section of the grid will be de-energized.

With a very short delay, R3 will send a force trip signal to the R4 to trip in order to reduce the outage area and so the rest of the network can work properly. But since the whole network was energized by the PS1 and now the R3 is open, R4 will send a close command to the R8 (PS2) to close the circuit breaker so the network can be energized from the other side(in this case from the right side). Also almost at the same time a backup block signal is sent to the R6 which works as a backup for R4.

Hence, in this approach only the section between the R3 and R4 of the network is de-energized and the rest of the network can work without any problem. Figure 2, shows the types of the signals which are sent. Figure 3 shows the time domain of the signals.

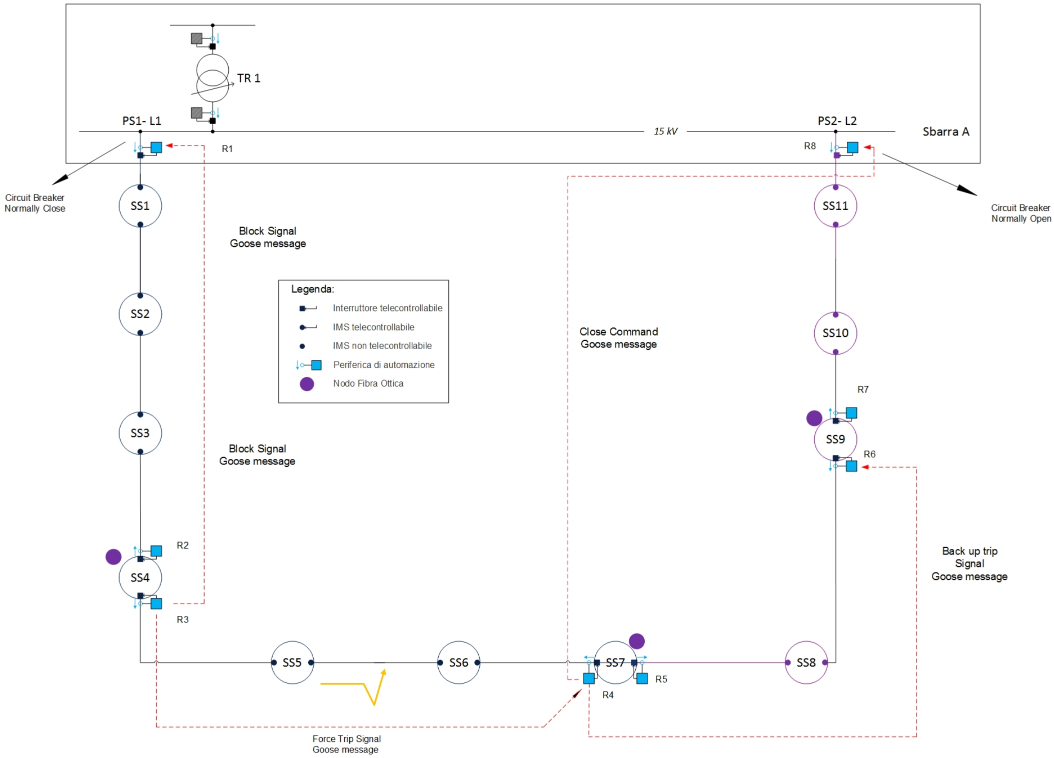

Figure 4.23: *Electrical Grid with the GOOSE messages with fault happening*

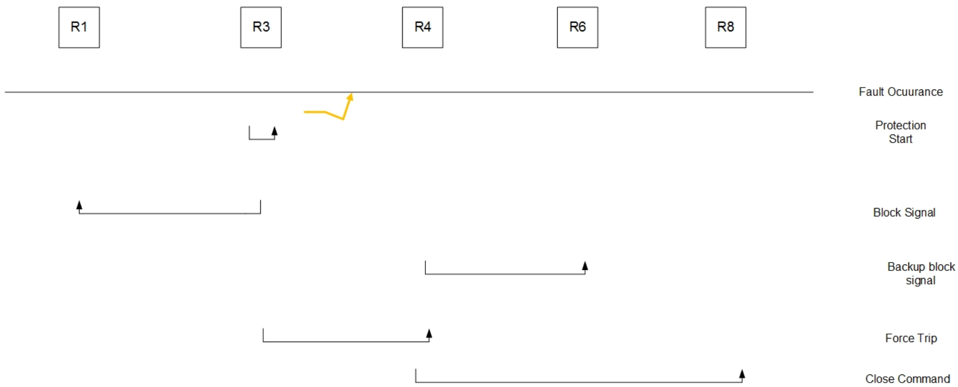

Figure 4.24: *distributed signals from protection devices*

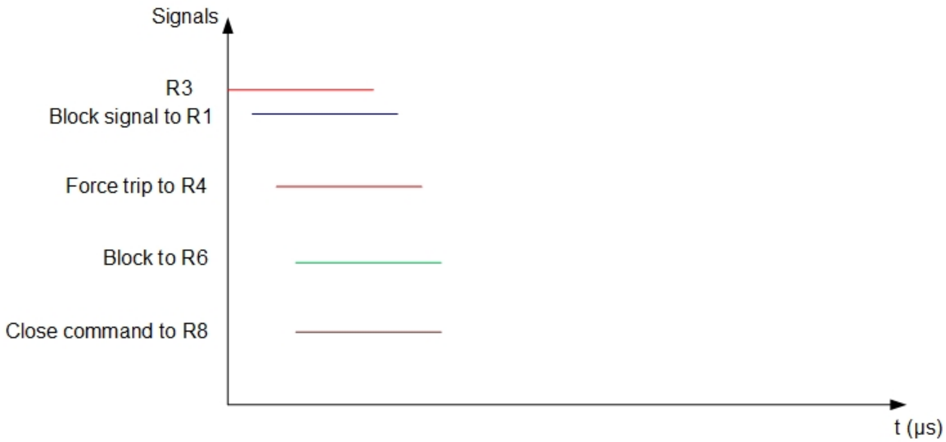

Figure 4.25: *Signals time domain*

In the figure 4.25 the order of the signals which are published are shown. As it is obvious, R3 will generate a signal whhen it detecs the faul. Then with a defined time delay will send the block signal to R1 and a force trip signal to R4. With a time delay again a signal will be sent to the R6 and R8 to perform their functions.

In the figure 4.26 network description, the fault happens between the SS9 and SS8. Because of the logic selectivity, R5 will detect the fault since it is the nearest protection device to the fault. As it detects the fault, it sends a block signal to the upstream PD which is R3. Also, it sends another blocking signal to the second upstream PD-R1-which serves as the backup protection for R3. R5, then send a force trip signal to the R6 to reduce the outage area. When R6 receives the force trip signal, it sends a close command to the R8 to close the circuit breaker and energize the other side of the network from PS2.

The difference between this configuration and the previous one is that if here, R6 get stuck there is no backup PD so the whole right part of the network should remain de-energized but in the previous figure, R4 had the backup which was R5. In the real networks like these, always there is a trade off between the number of the protection devices and the area which will be de-energized in case of a fault, also taking into account the cost of such a solution.

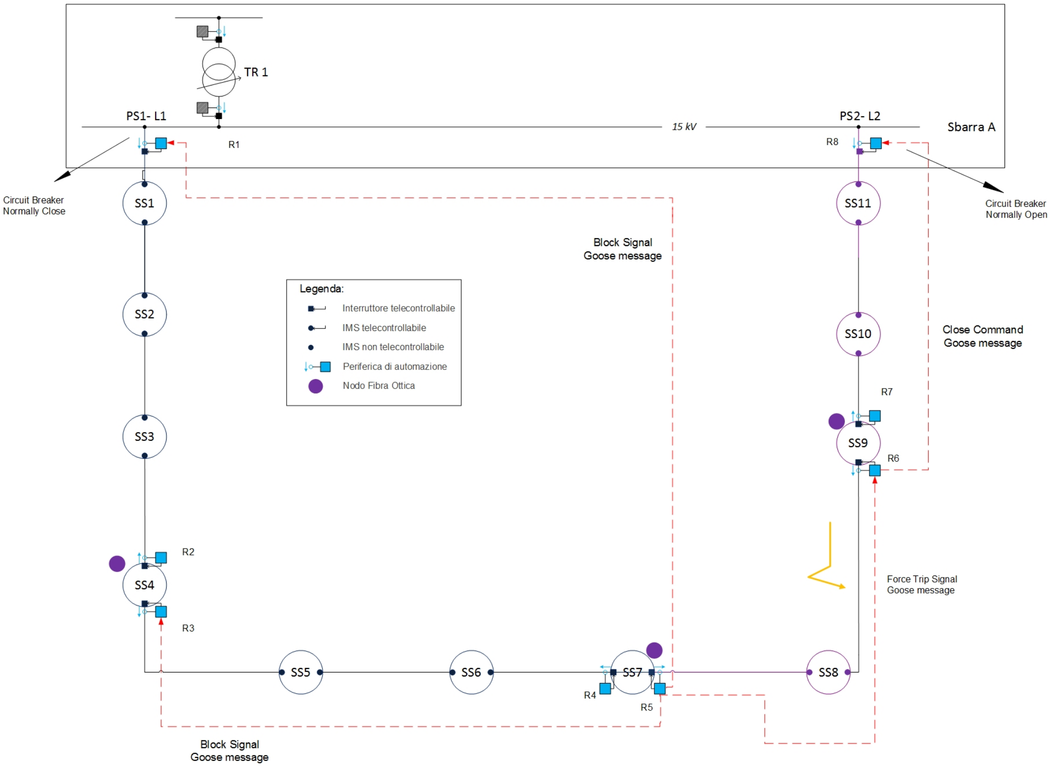

Figure 4.26: *Electrical Grid with the GOOSE messages abd fault happening*

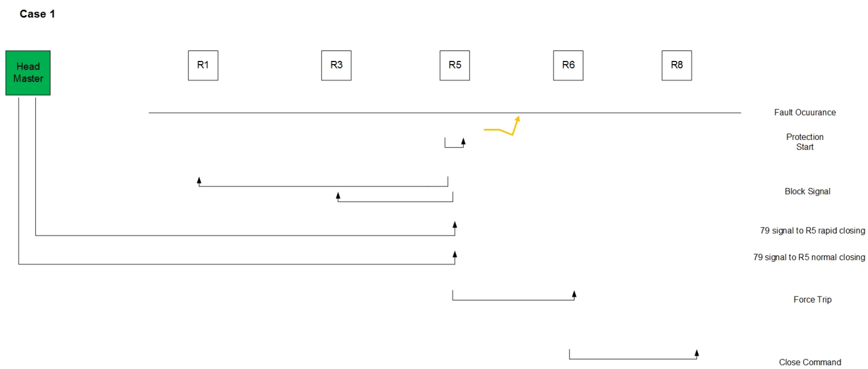

Figure 4.27: *case1-distributed signals from protection devices*

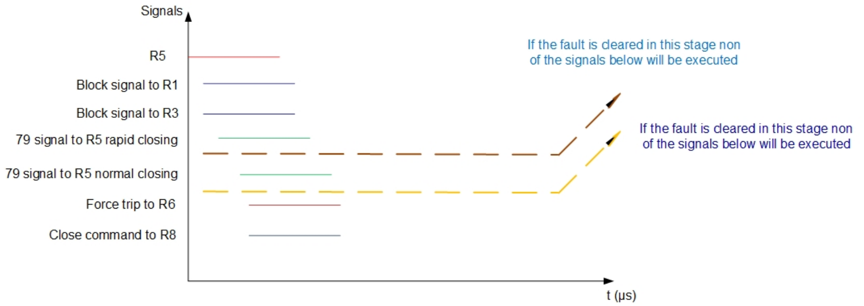

Figure 4.28: *case1-Signals time domain*

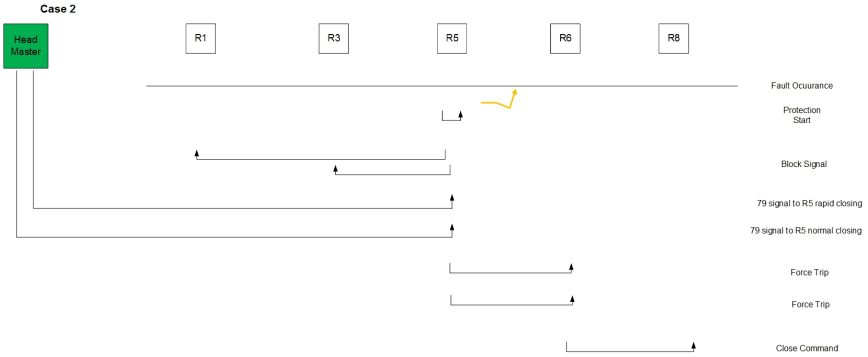

Figure 4.29: *case2-distributed signals from protection devices*

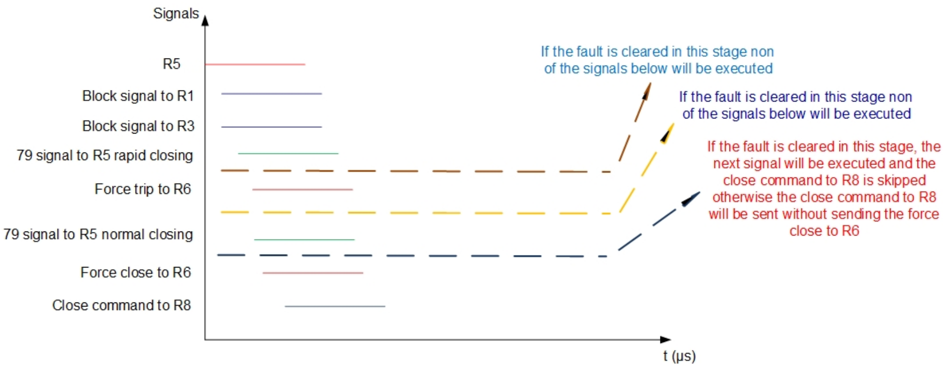

Figure 4.30: *case2-Signals time domain*

It should be stated that IEDs should be provided with the logic to send the close commands or force trip signals because they don't inherently have this option and this logic should be asked from the vendor to be put in the protection devices.

To improve automation, a "substation automation unit"-SAU- solution has been developed. Its main idea is to integrate smart metering data using them to realize network management functions at substations. In case of primaru substaion it is called PSAU and in case of secondaru substation it is called SSAU. This automation unit can be implemented in an open and standard-based manner. SAU is an upper high level device which is capable of receiving all the signals needed to know the current status of the network and also the changes in the configuration of the network which may happen because of a fault.

Furthermore, it should be able to coordinate all the protection devices in the network for exchanging the signals.

In the second case, when the fault happens between the R5 & R6, considering the Autoreclosure function-79 enable-there are different possibility to set the reclosure function. For 79 relay, 2 stages for reclosing are assumed here, namely,

- Rapid reclosing
- normal reclosing

In the Rapid reclosing, as the breaker is open, it will close in μs to see if the fault was temporary. If it was so, then it will remain close and the system continues normally. But, if after closing, the fault still exists then it will open again suddenly and waits a little bit more time. Then, the second stage of autoreclosing(Normal Reclosing) will start to see if this time the fault is eliminated. If so, it will remain close otherwise it will be open until it is closed manually or via a close signal from the Primary Substation Automation Unit (PSAU).

During the time of reclosing it is possible to assume to different cases depending on the type of signals which can be sent to the IEDs. Below is the description of these 2 cases.

- Case 1

In rapid reclosing function, while R6 stays closed, R5 will be open and closed. If the fault has been cleared then R5 will stay closed. Otherwise, the second stage of the reclosing which is normal reclosing will take place while R6 stays close. If in the second stage of reclosing the fault still exists, R5 will open and send the force trip signal to R6.

- Case 2

In rapid reclosing function, while R6 stays closed, R5 will be open and then closed. If the fault has been cleared then R5 will stay closed. Otherwise, R5 will open and sends a force trip signal to R6. But R6 will wait a little bit more time compared to before (which means with no 79 relay) to send the close command to the R8. In the normal reclosing, R5 will close while R6 is open. if the fault is cleared then R5 will send a signal to R6 to close. Otherwise they will open and the close command is sent to R8 for closing the breaker.

4.7.1 How to subscribe the GOOSE message to the IEDs

To subscribe the Goose messages to different IEDs, first the IED which is assumed to send the goose messages and the protection function which is intended to the protection, should be added to the dataset. Here, as an example, relay 67N is considered. By opening the branch of the IED R3, logical device PROT, Logical node PTOC 67N, it is possible to add this logical node to the dataset. So, whenever there is a change in the dataset related to this logical node, it can be programmed to send the goose message to the related IED. Then, by going to the dataset and creating a goose, R3 will be defined as a publisher of the Goose. Now, looking at the window of the Publishers, R3 is shown as a publisher but the subscriber is not defined yet. To subscribe and IED to this Goose message- here in his example R1- the branch of R1 should be open and LN-PTOC from the LD-PROT should be selected. By going to PTOC 67N it is possible to add an input to it and define this input as R3 goose message. Now, by looking at the subscriptions window, R3 is defined as the publisher and R1 as the subscriber

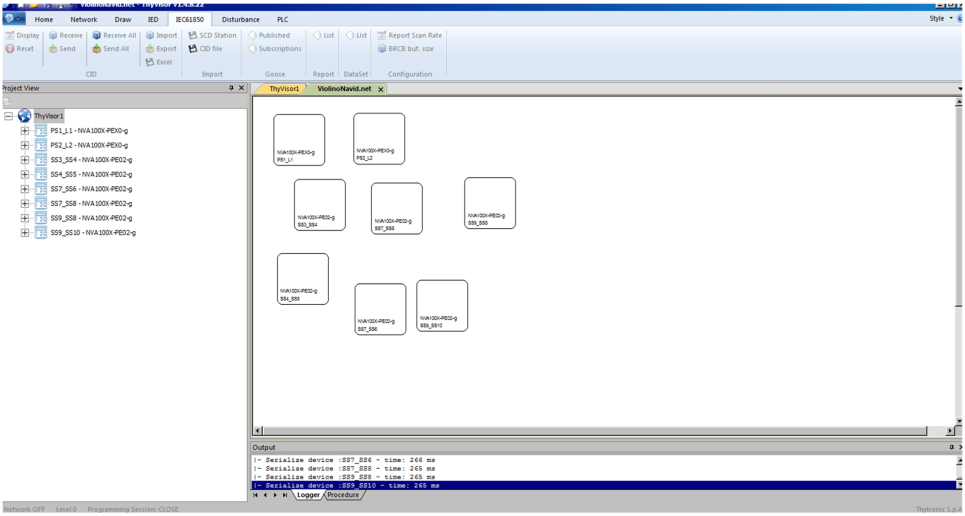

Figure 4.31: *Screenshot of the software of Thyvisor*

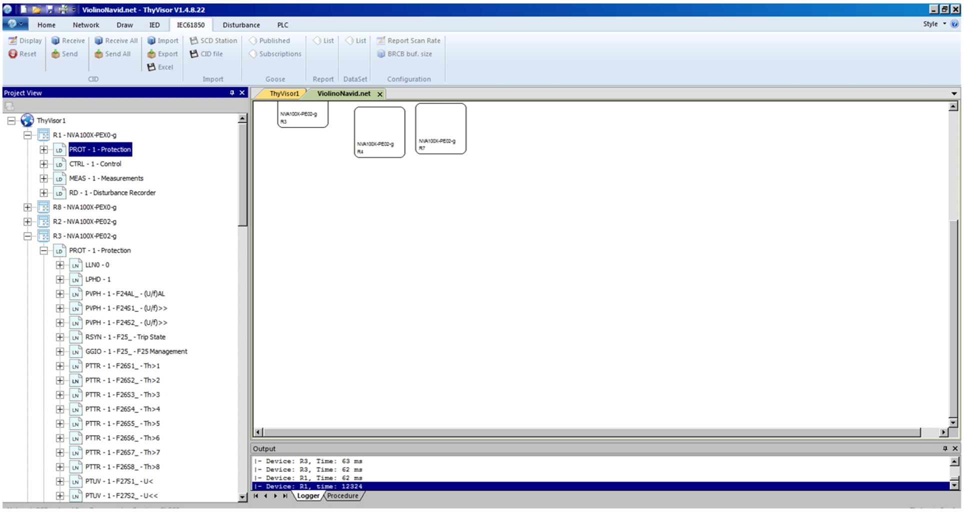

Figure 4.32: *Screenshot of the software of Thyvisor*

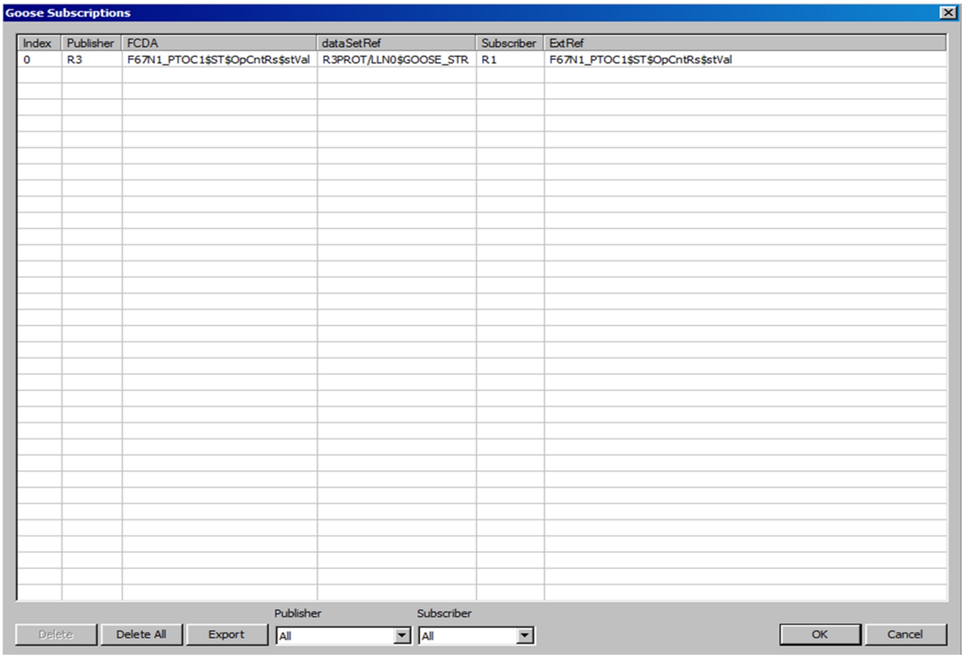

Figure 4.33: *Screenshot of the software of Thyvisor- subscription of the protection devices R3*

4.8 An Innovative Solution

Key Words-Logic Selectivity, chronometric selectivity, distributed Generators, islanding, protection devices, intelligent electronic devices

Abstract: With the integration of Distributed Energy Resources, the need for a more coordinated and complex protection setting arises. Faults in the Electrical grids should be distinguished and be cleared as soon as possible with the minimum outage area. Logic selectivity and Chronometric selectivity as the two common protection methods are used. One of the threats that Variable Energy Resources (VER) poses to the power systems is the islanding which results in great danger not only financially but also will put staff life in danger. This paper is addressed to a theory envisioned for protection purposes. A new possible approach toward setting the protection devices is introduced to cover all the area of the grid beneficially.

The capability of IEC 61850 as a communication standard for substations is used for this protection settings since it is beoming the dominant standard in the Substation Automation. Following the protection scheme, the need to keep the Distributed Generations(DG) connected to the grid and the Pros& Cons of the DG are discussed. Furthermore, a possible islanding condition is created and discussed and the possible solution for removing islanding is proposed.

Distribution systems are mostly radial. one of the major drawback of the radial networks is that in case of any feeder failure, the associated consumers would not get any power as there was no alternative path to feed the transformer. In case of transformer failure also, the power supply is interrupted. In other words the consumer in the radial electrical distribution system would be in darkness until the feeder or transformer was rectified. This is why in the radial systems the switches are introduced to let the power flow in different directions and supply a feeder in case the main supplier is disconnected.Another reason is to avoid the rings in the distribution networks.

4.8.1 Network Function Explanation

In the following radial system, in each line segment there are 2 circuit breakers which protect the line with the help of IEDs. The protection devices are the overcurrent direction protection devices(relays number 50/51,67)so they can measure the current just in one direction. [29] Hence the protection devices on the other side of the line segment have the protection functions of the overcurrent which flows from on the opposite side.

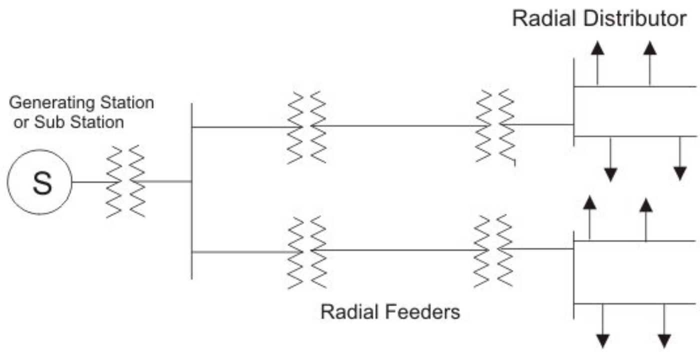

Figure 4.34: *A typical radial system*

After a fault happens in a system, with the help of the logic selectivity [22] [8] the nearest CB will distinguish the fault and send the block signal to the upstream circuit breakers to maintain their normal operation until a pre-defined time. If the nearest CB could not clear the fault, the upstream CB which acts as a backup will clear the fault. Also at the same time a trip signal is sent to the other circuit breaker of the line section to open it and reduce the outage area.

To accomplish this function, first of all it should be defined which IED are upstream and downstream the fault since it is needed to send the block and the trip signals to the other devices in the network. It is possible to use the system of sending a signal to all the other IEDs in the neighborhood and receiving the returned signals. [31] The last signal which comes to the protection device will define which IEDS are upstream and which one is the downstream so the block signals can be send accordingly in the desired direction.

Since the DSOs ask the DG producers to disconnect from the grid in case of a fault, the DG producers will not be willing to invest in DG production. But with the benefits [1] they bring to the netwrok, goverments are willing to invest on them although hey impose some issues [3] like stability on the network. the producers will be motivated to generate energy since they do not accept to lose their production in case of any simple fault. In the grid, the DERs should be disconnected if they are downstream the fault but the DGs upstream the fault will use the Fault Ride Through (FRT) so remain connected to the grid.

Usually every DG unit connected to a distribution network is protected by a great variety of protective relays, Among them voltage and frequency, overcurrent and the interconnection relay seem to play the most important role regarding coordination issues with the line protection. To have a good protection coordination, one should know the rated short circuit current in different situations in case of different types of faults like single phase to ground, double line and double line to ground and 3 phase fault. The overall protection system should be coordinated with the interface protection of the Distributed Generations also.

Another very important issue in the protection coordination is the communication infrastructure between the different IEDs and their latencies and delays. [9] The total delay time to transmit a block and trip signals to the other circuit breakers IEDs should be less than the set time for the backup IEDs. Otherwise selectivity won't be accomplished. [27] The recloser function is very important also to reduce the outage area and to return the network to its initial state if the fault is cleared since many faults in the distribution system are temporary faults which may happen(because of a falling tree or a bird on the overhead lines which may create double line faults or single phase line to ground faults).

The protection systems mostly consists of CBs, IEDs, CTs and VTs.Also there are fuses in the feeders but here they are not the main focus. Although the devices locations in the grid are different but they should be coordinated to ensure the protection.

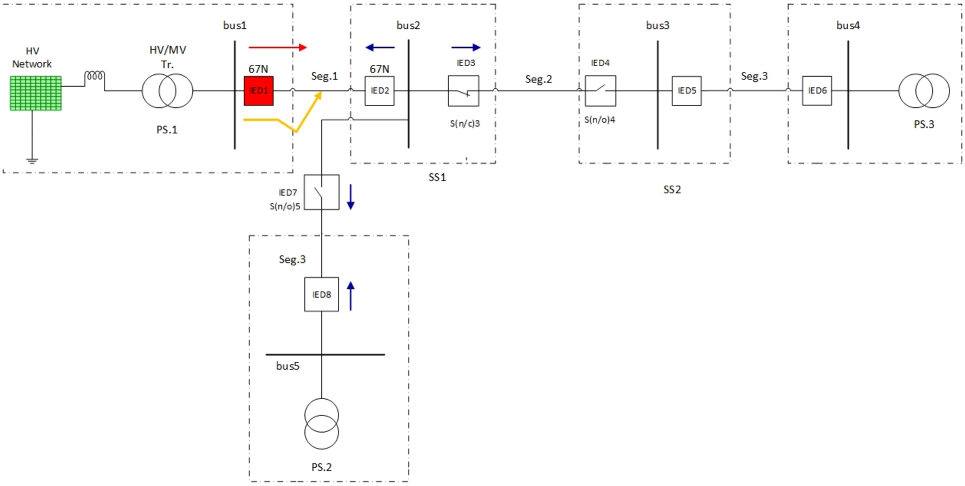

Figure 4.35: *Network Configuration with a fault on Bus1*

4.8.2 Problems definition

Assume a fault happens at seg.1 of the line of the figure 4.34

Since the closest PD is the IED1, it will detect the fault and will open and sends a force trip signal to IED2 to trip it. Also, at the same time a sends a NNG (New Network Configuration) signal to IED3 to choose another upstream PD since now IED1 which was the upstream PD for IED3 before the fault, is open.

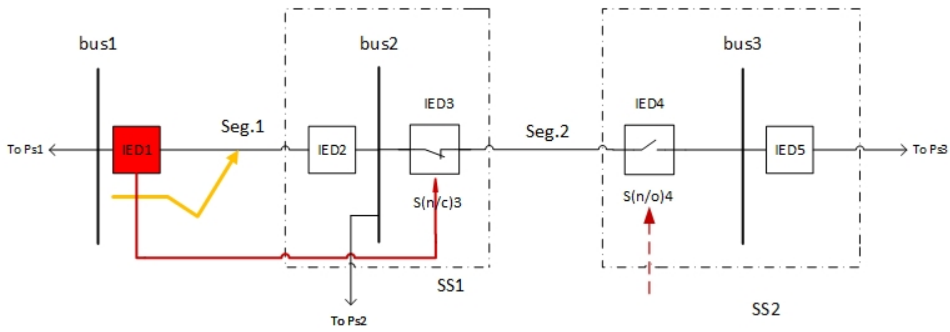

Figure 4.36: *IED1 sending out signals*

According to the logic implemented, IED3 will send the NNG signals to all IEDs 1,5,8 which have the same direction as IED3. Then, they will reply to IED3 except the IED1 since it was open. The last signals which reach the IED3 will be defined the IEDs which should be set as the upstreams (Here in our example: IEDs 5,8).

It is necessary to state that when the fault happens, the contact which was normally open, will receive the command to close to let the part of the system which became de-energize due to the fault now, to energize again. The process of sending and receiving signals are illustrated in the following figures.

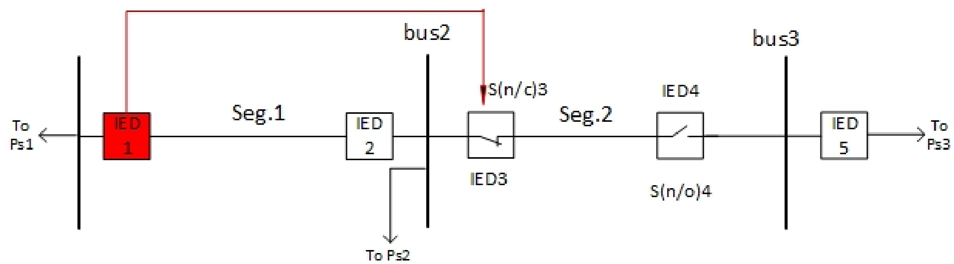

Figure 4.37: *IED3 receiving NNG signal*

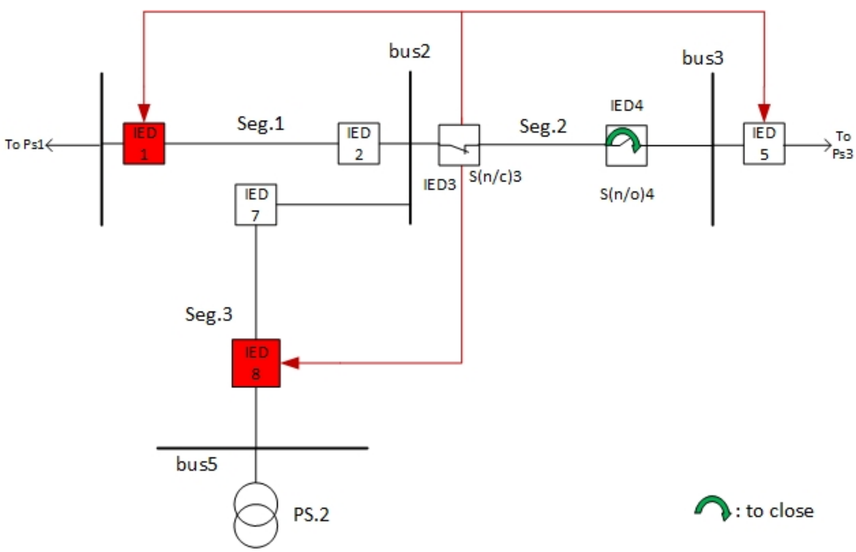

Figure 4.38: *IED3 sending out signals*

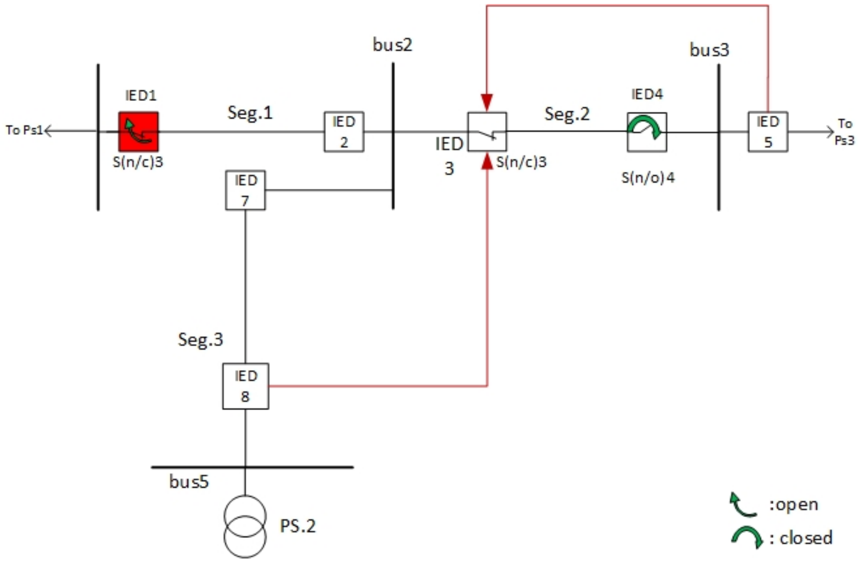

Figure 4.39: *IED3 receiving signals*

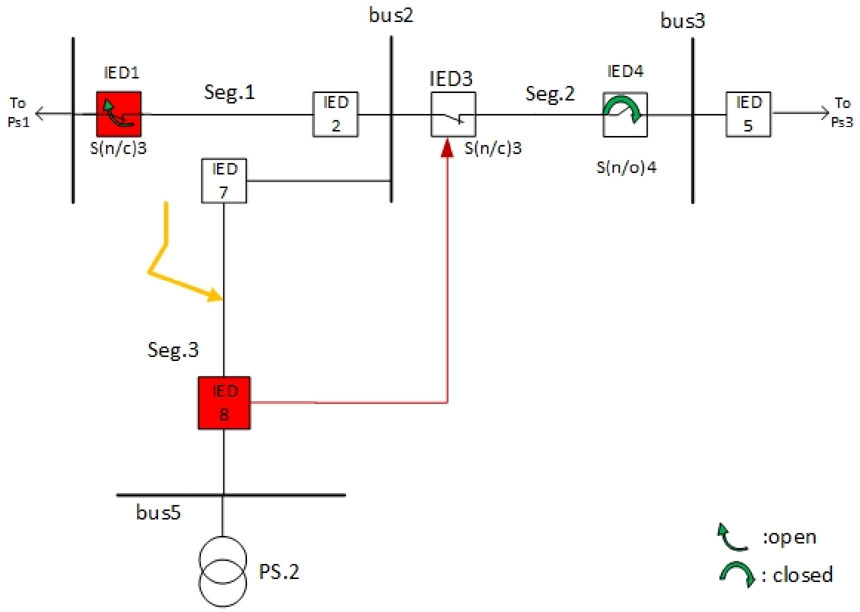

Figure 4.40: *Another fault on seg.3 and the sending out signals from IED8*

Now, assume there happens another fault at seg.3 of figure 4.39

It results that IED8 be open to clear the fault. Hence, it will send a NNG signal to IED3 to update itself according to the latest network configuration.IED again sends the NNG signals to IED9,5 and receives their replies. Therefore at this stage, only the IED 5 will be chosen as the upstream PD for IED3.

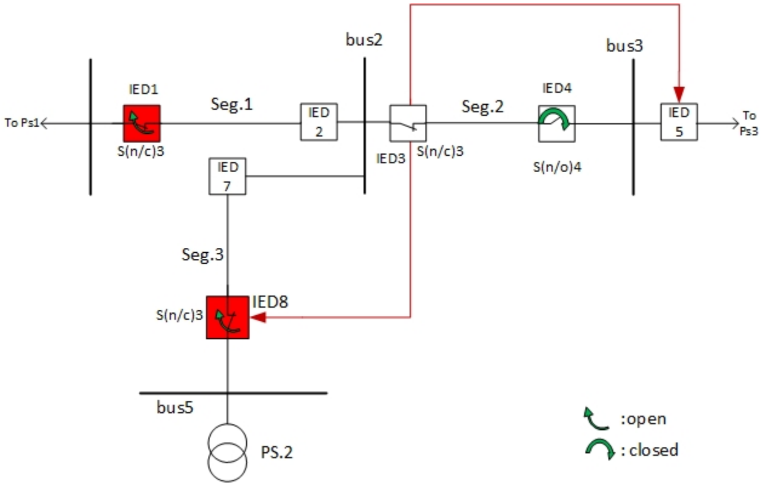

Figure 4.41: *IED3 sending out signals*

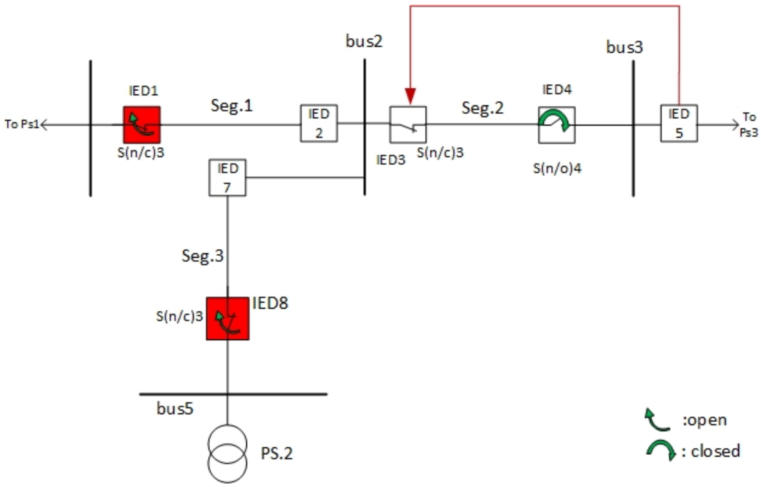

Figure 4.42: *IED3 receiving signals*

In the next figure, assume there are 2 DGs on buses 2 and 3 respectively.

Normally there are many DGs which are distributed in the network but here we consider only 2 DGs as an example.

The network is intact. If a fault happens in seg.3 the IED6 will detect the fault and will open since it is directional protection device and the supply of current is from right to left(IED4 is normally open). Then it sends the NNG and the force trip signals according to the descriptions given in the previous section. The IED 5& 6 are open to clear the fault so the contact of IED4 will be closed to let the system be energized also from the left.

Also, take into consideration that before opening the mentioned contact, DG2 will be disconnected via interface protection to avoid islanding since it is downstream the fault and could be able to contribute to the fault. But when the IED4 contact is closed the DG2 will be again connected to the network. Here if another fault happens at seg.2(now both the contacts are closed), DG2 will be disconnected again since it is again downstream the fault but DG1 will remain closed and uses the FRT.the IED 3,4 will distinguish the fault as it happens in line seg.2.

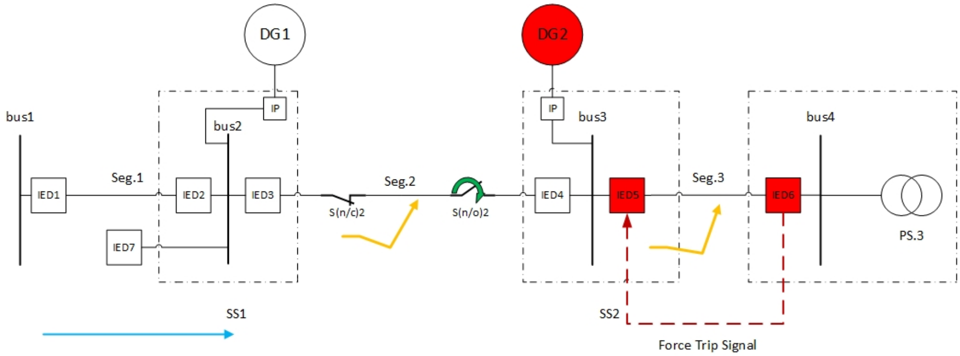

Figure 4.43: *Faults in case of presence of DGs*

Conclusion

THIS chapter will summary all the topics which are discussed in this thesis. In the Introduction chapter, a general description about the Electrical grid and the meaning of Smart grid communication is described. Later, the Electrical grid communication is divided into Premises Network Neighborhood area network Wide area network Then the premises network is subdivided to

- Home Area Network (HAN)
- Building Area Network (BAN)
- industrial Area Network (IAN)

The Wide Area Network is described briefly in this chapter to give an overview about the network which is the main focus of this thesis. The chapter will end with a short description about the IEC 61850 and the history of it. The reasons why these family of standards came to exist also are mentioned briefly.

The second chapter "Electrical Grid: Background and Technological context", in the first part gives an overview about the WAMPAC systems and the classical supervisory control systems like SCADA. Also, the measurement and command data flows in a WAMPAC system are illustrated with the help of a figure. Later on, the OSI data model as the basis of the data is introduced and the different layers associated to this model are described. Communication as the base of transferring information is depicted and the different communication models and their differences are will illustrated. The chapter ends with describing the meaning of information with respect to data and why the information model is used.

The 3rd chapter which is the main purpose of this thesis, is about the IEC 61850. Here the IEC 61850 as the standard for the communication networks and systems in substations are well described. At first the different parts of this standard are given in a table. Following this, the Meta model of IEC 61850 and its information model are given. The information model of this standard is divided into PD, LD, LN, DO, DA for the simplicity to understand the data. Echa type of logical nodes start with a letter with is driven from the first letter of the function it is designed for. For example, the logical node of Measurement starts with M and it is MMXU. Later on in this chapter, the communication in the IEC 61850 is discussed and the GOOSE messages, MMS protocol and the SVs are described briefly to be completed later in the 4th chapter. Following this part, the Architecture of the network is given and the network topology is described. A well-illustrated figure is given which divided the network into Process, Bay and Station levels and talks about the communication between these parts. The synchronization timer as one of the most important parts for time stamping is introduced and the most important protocols are discussed as much as needed.

In the 4th chapter, The work I have done on IEC 61850 with respect to the protection devices has been reported thoroughly. There are enough examples for the reader to get familiar with what has been explained during the whole thesis. It is proved that although there are other technologis like Wifi and 3G for signal communication in real time situations, but Ethernet is still very comfortable for this purposes since it has been tested for many years. At the starting, it was believed that IEC 61850 is totally complete and conforms to the recent years needs but it was found out that still there are any issues with should be confronted like different time stamps which sometimes are needed to be introduced although the standard is violated. All of these issues bear the testimony that IEC 61850, although is very important and has many benefits, but still it has to be edited to be totally suitable for the electrical grids. Another assumption is violated during working with devices of different vendors that despite the fact that all of the devices are based on IEC 61850, one can not put them in the network without having tested that they are able to communicate with eachother-an assumption that I had at the first glance- but interoperability was proved between the protection devices of different vendors after some tests. As it was expected, IEC 61850 enables devices to quickly exchange data and status using GOOSE and GSSE over the station LAN without having to wire separate links for each relay. This significantly reduces wiring costs by more fully utilizing the station LAN bandwidth for these signals and construction costs by reducing the need for trenching, ducts, conduit,etc which were an indispensable part of the legacy protocols and grids.

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