

Kristian Soleng Evjen

# Functional Testing of Protective Relays in Digital Substations

Master's thesis in Energy and Environmental Engineering  
Supervisor: Hans Kristian Høidalen  
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Faculty of Information Technology and Electrical Engineering  
Department of Electric Power Engineering

 **NTNU**  
Norwegian University of  
Science and Technology



# Preface

We live in a world where digitalization is increasingly present, and substation technology is no exception. I have always been fascinated by electrical engineering and digital communication, and when the opportunity for a master thesis that combines both areas came along, I grabbed it with both hands.

This report is the result of my master thesis at Norwegian University of Science and Technology (NTNU), Department of Electric Power Engineering, performed in the spring semester of 2019. The basis of this master thesis is a project work where digital substation technologies, communication, and multi-vendor possibilities are described through a literature study [1].

I want to thank my supervisor Hans Kristian Høidalen, for guidance and support through the scientific jungle of writing this thesis, as well as Maciej Grebla, who has been supportive of my laboratory work. I also wish to thank Statnett, represented by my point of contact Nils Arild Ringheim, for being open to support me through my work and share valuable knowledge and experience from the industry.

Trondheim, 11th of June 2019

Kristian Soleng Evjen



# Project Description

A large joint research project (ProSmart) at NTNU departments of Electrical Engineering and Telecommunication addresses relay protection solution in a smartgrid perspective where communication of data becomes possible over a wide area. This student project will explore the digital substation possibilities based on the relay protection laboratory that has recently been established. The installed laboratory is equipped with modern ABB 670 relays, OMICRON relay testers, OPAL-RT real-time simulators with hardware-in-the-loop capabilities, all communicating on a process bus over the IEC 61850 protocol.

Digital substations introduce fundamental changes to substation communication, and protective relay testing procedures have to be changed accordingly. The purpose of this master thesis is to analyze how testing of protective relay functionality can be performed in IEC 61850 digital substations, and how this differs from testing conventional substations. A laboratory setup that can be used to perform relay functionality testing in a digital substation environment is to be established. This is the first master thesis to cover digital substation testing using the NTNU relay laboratory and works as a first step into this topic. Hence, an essential part of the thesis is to provide description and documentation of the utilized laboratory equipment, setup, and configuration. The established laboratory setup should then be utilized for performing basic functionality testing of an isolated relay to see how this may be performed in a digital substation environment. IEC 61850 testing tools are needed to perform isolated relay testing in a full digital substation, and these should be covered both in theory and in practice using the laboratory setup.

The aim of the report is to be achieved by performing the following main tasks.

- Give an introduction to relevant conventional and digital substation technologies and principles as well as protective relaying theory.
- Describe existing substation testing principles, as well as new testing tools introduced for digital substations.
- Establish a laboratory setup that can be utilized to show basic principles of testing relay functionality in a digital substation environment, and provide documentation of how this can be done.
- Establish and perform a series of laboratory experiments for relay functionality testing in a digital substation environment.
- Perform laboratory experiments that explore IEC 61850 testing tools and possibilities, and analyze how these can be used to isolate relays in full substations.

- Describe how the laboratory setup and experiments may be generalized and in principle transferred to full digital substations.



# Abstract

In modern society, people are becoming increasingly dependent upon power supply from electricity. Substations are a vital part of electrical power grid operation, as they allow for transformation between voltage levels and house protective relays that prevent damage to power grid components during faulty grid situations. In recent years, a transition from conventional to digital substations has been introduced by making the communication between process and bay level equipment digital over optical communication networks rather than analog over point-to-point copper cables. Digital substations introduce fundamental changes to critical substation operations, including test procedures for protective relays. To facilitate this process, the IEC 61850 standard has been introduced to give standardization of digital substation communication, as well as providing tools that can be utilized for testing purposes in digital substations.

While digital substation technology has been widely accepted in theory within the industry, few power utilities have hands-on experience with this, and even fewer have developed efficient testing procedures for relays in digital substations. The primary purpose of this thesis is to contribute towards filling this gap by analyzing how functional testing of protective relays may be performed in a digital substation environment. A digital substation laboratory setup is successfully established, and its equipment and configuration are described to provide documentation of how this can be done. The setup includes a test set that can simulate and inject both GOOSE and SV messages over a process bus, to which a relay with digital communication capabilities is connected. The relay algorithm is able to process digital messages and publish GOOSE trip messages accordingly.

A set of laboratory experiments are performed to verify this communication, as well as verifying fundamental relay requirements like stability at load situations and external faults, and successful clearing of internal faults. IEC 61850 testing tools are also described and put into practice in the laboratory setup, but this introduces some problems. While it is possible to generate GOOSE and SV messages from the test set, a lack of IED test mode as described in IEC 61850 is shown for the relays installed in the NTNU relay laboratory.

It is wanted to generalize the established laboratory setup to allow for replacing the utilized relay with relays from different vendors, and further translate the laboratory setup into full digital substations. This is in general possible by utilizing SCL files defined in IEC 61850, where CID files are critical for this purpose. These give a standardized description of IED configuration, which allows for transferring the parameters needed to configure GOOSE and SV communication, as well as IED functionalities and data modeling, between relays and test sets.



# Sammendrag

*This is a short summary of the thesis written in Norwegian, the rest of the thesis is written in English.*

I det moderne samfunn blir folk stadig mer avhengige av strømforsyning fra det elektriske kraftnettet. Transformatorstasjoner (*engelsk: substations*) er en sentral del av kraftnettet, da de tillater transformering mellom spenningsnivåer og er installert med relévern som forhindrer skade på kritiske komponenter under feilsituasjoner. De siste årene har man sett starten på en overgang fra konvensjonelle til digitale transformatorstasjoner, der analog kommunikasjon gjennom parallelle kobberkabler erstattes med digital kommunikasjon over en optisk kommunikasjonskanal. Digitale transformatorstasjoner innfører grunnleggende endringer i noen sentrale momenter ved transformatorstasjoner, blant annet hvordan testprosedyrer for relévern kan utføres. For å hjelpe denne overgangen har IEC 61850-standarden blitt innført for å gi standardisering av den digitale kommunikasjonen i slike transformatorstasjoner, samt en del verktøy som kan brukes til testing av disse.

Selv om teorien bak digitale transformatorstasjoner og deres teknologi har blitt allment akseptert innen industrien, er det fortsatt få som har praktisk erfaring med bruk av disse. Enda færre har utviklet effektive testprosedyrer for relévern i digitale transformatorstasjoner. Hovedformålet med denne oppgaven er å bidra til å fylle dette gapet ved å analysere hvordan testing av relévernsfunksjonalitet kan utføres i en digital transformatorstasjon. Et småskala digitalt transformatorstasjons-miljø har blitt satt opp, og oppsett og konfigurering av dette er beskrevet for å gi dokumentasjon på hvordan dette kan gjøres i NTNU sitt relévernlaboratorium. Dette inkluderer et testsett for relévern som kan simulere og publisere både GOOSE- og SV-meldinger over en optisk kommunikasjonskanal, samt et relévern med støtte for digital kommunikasjon. Relévernet er i stand til å bearbeide digitale måleverdier og publisere resulterende GOOSE-meldinger.

Et sett med laboratorieforsøk utføres for å verifisere den digitale kommunikasjonen, samt å verifisere grunnleggende krav for relévern som stabilitet ved normale lastsituasjoner og eksterne feil, og vellykket håndtering av interne feil. Testverktøyene innført i IEC 61850 er beskrevet og vist i praksis i laboratorieoppsettet, men dette introduserer noen problemer. Det er mulig å generere GOOSE- og SV-meldinger fra testsettet, men det vises en mangel på IED-testmodus som beskrevet i IEC 61850 for relévernene som er installert i NTNU sitt relévernlaboratorium.

Det er ønsket å generalisere det etablerte laboratorieoppsettet for å kunne erstatte det benyttede relévernet med relévern fra andre leverandører, noe som videre kan brukes for å overføre laboratorieoppsettet til praktiske digitale transformatorstasjoner. Dette er

generelt mulig ved å bruke SCL-filer som definert i IEC 61580, der CID-filer er kritiske for dette formålet. Disse gir en standardisert beskrivelse av konfigurasjonen for hvert digitale relévern i stasjonen, noe som gjør det mulig å overføre parameterne som trengs for å konfigurere GOOSE- og SV-kommunikasjon, samt IED-funksjoner og datamodellering, mellom relévern og testsett.

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# Nomenclature

## Communication

GOOSE	Generic Object-Oriented Substation Event
LAN	Local Area Network
RTU	Remote Terminal Unit
SV	Sampled Value
VLAN	Virtual Local Area Network

## Substation Components

CB	Circuit Breaker
CT	Current Transformer
IT	Instrument Transformer
MU	Merging Unit
NCIT	Non-Conventional Instrument Transformer
VT	Voltage Transformer

## General

FAT	Factory Acceptance Test
HMI	Human-Machine Interface
HV	High Voltage
IEC	International Electrotechnical Committee
IED	Intelligent Electronic Device
LV	Low Voltage
SAS	Substation Automation System
SAT	Site Acceptance Test
SCADA	Supervisory Control And Data Acquisition
SLG	Single Phase to Ground

## IEC 61850 Data Modeling

DA	Data Attribute
DO	Data Object

LD	Logical Device
LN	Logical Node

### **SCL Files and IEC 61850 Engineering Tools**

CID	Configured IED Description
ICD	IED Capability Description
ICT	IED Configuration Tool
IID	Instantiated IED Description
ISD	IED Specification Description
SCD	Substation Configuration Description
SCL	System Configuration description Language
SED	System Exchange Description
SSD	Substation System Description

# Chapter 1

## Introduction

### 1.1 Motivation

For centuries, communication within electric power grid substations has relied on analog and hardwired equipment. However, the trend in recent years has been a transition towards an increased implementation of digital equipment, utilizing digital communication over optical communication networks rather than hardwired point-to-point copper cables. This fundamental change in substation communication means that its operation must be adjusted accordingly. Correct operation of protective relays is a vital part of a well-functioning power grid, and protect vulnerable substation equipment during faulty situations. Besides, it is important that relays do not operate more often than they are supposed to since this increases the amount of power grid outages. Thorough testing procedures of protective relay functionalities have to be performed to make sure that they operate as expected at all times. Testing procedures are often applied both after production and after delivery to a customer, as well as regular maintenance testing after being put into normal operation.

Most power utilities have developed efficient procedures for testing relay functionality in conventional substations, utilizing hardwired test plugs and injection of analog secondary current and voltage signals. However, this is not possible in a digital substation since it relies on digital communication, and there are no input or output ports to which analog equipment can be connected. While digital substation technologies and the IEC 61850 standard has been accepted within the industry in theory, it is rarely implemented in practice today. This means that very few power utilities have developed test procedures for testing relay functionality in digital substation environments, making this an exciting area of research.

Conventional substation testing procedures may be converted into digital substation environments by changing only relevant communication paths, but this is far from an optimal solution. IEC 61850 introduces a range of new tools and functionalities that can be used to create more efficient testing procedures in the transition from conventional to digital substations, but this requires full knowledge of these tools. Digital substations also offer the significant advantage of having a flexible form of communication rather than relying on point-to-point connections, which can be utilized to create automated testing proce-

dures where no physical reconnections are needed throughout the testing procedure. Also, this may allow remote testing of digital substations by connecting to its communication system through the Internet.

## 1.2 Research Questions

In order to fulfill the project description and reach the main goals of this thesis, the following research questions are to be answered.

- What are the main differences between conventional and digital substations, and how does this transition affect relay testing?
- Is it possible to establish a laboratory setup in the NTNU relay laboratory that allows for testing relay functionality in a digital substation environment?
- How can the established laboratory setup be generalized, for example, by replacing the utilized relay with one from a different vendor?
- How can the established laboratory setup and configuration be transferred into a practical digital substation?
- How does testing procedures that may be performed in the laboratory setup transfer to practical digital substation test procedures?
- Which possibilities for the future development of substation testing procedures do digital substation technology offer?

In addition, a set of research questions are to be answered using the NTNU relay laboratory equipped with OMICRON test sets and ABB relays, all with IEC 61850 communication compatibility.

- Is it possible to publish GOOSE and SV messages from the test set and make the relay successfully respond to these?
- Is it possible to publish GOOSE messages from the relay and make the test set subscribe to these?
- Is it possible to use the laboratory setup to perform experiments that illustrate fundamental principles about relay functionality testing in a digital substation environment?
- Is it possible to utilize IEC 61850 testing tools in practice to separate normal operation from operation related to testing purposes?
- Is Wireshark a suitable tool for analyzing process bus network traffic?

## 1.3 Limitations

Digital substations and relay testing are two broad topics, meaning that limitations are needed to restrict workload and complexity to a feasible level for a master thesis. It is



assumed that all communication between ITs and relays of the substation is digital, which may not always be the case. In a transition period, some substation operators may choose to upgrade only parts of the substation, giving a hybrid substation with elements from both conventional and digital substation technology. Hence, it might be necessary to take conventional testing procedures into account and combine these with new test procedures to fully test a substation.

It should also be noted that the complexity of the laboratory experiments is somewhat limited, as more complex test procedures demand a more complex setup, involving several relays that all have to be configured. Besides, most protective relays in full substations have implemented more advanced functionalities such as breaker failure protection and reclosing that would have to be implemented in the relay configuration to test these. This means that the complexity of the necessary relay configuration needed to perform such procedures is beyond the scope of this report, and is therefore omitted. Hence, the basic test procedures that are implemented through the laboratory experiments of this thesis are too simple to have any significant meaning for practical substations, but they show essential fundamental principles in practice.

There are additional limitations in the laboratory setup, as only an OMICRON test set and ABB relay is utilized. Components from different vendors may have different interpretations of the IEC 61850 standard, which could cause unknown problems if test procedures are to be implemented in a substation with a wide range of protective relays. However, OMICRON and ABB are well established vendors within the industry, and the fundamental principles remain between components from different vendors.

## 1.4 Approach

The project description of this thesis is to be fulfilled through three main steps. The first step is to give an introduction to the theory that digital substations, protective relaying, and relay testing is based upon, which is done through a literature study. The next step is to establish a laboratory setup that can be used to implement the theory described in the literature study in a practical digital substation environment. Finally, a set of laboratory experiments is to be defined and conducted in the established laboratory setup to put the relay testing theory into practice and verify that the relay setup works as expected.

## 1.5 Report Structure

The report is structured as follows. Chapter 2 gives an introduction to fundamental definitions and modeling used in substations. A description of conventional and digital substation technologies is given, as well as an in-depth analysis of IEC 61850 data modeling and tools for digital substations. An introduction to transmission grid faults and protective relay technology is given in Chapter 3, including details on distance protection relays as this will be used in later laboratory experiments. Chapter 4 describes the theory and principles of substation test procedures, focusing mainly on relay functionality testing and how this differs between conventional and digital substations.

Chapter 5 gives an introduction of the established laboratory setup by describing the testing equipment and protective relay to be utilized, as well as how these are interconnected and controlled through software. In-depth documentation of the configuration of this laboratory setup and implementation of necessary functionalities is given in Chapter 6. Hence, chapters 5 and 6 provide documentation of a possible way to establish a digital substation environment using the NTNU relay laboratory. Chapter 7 describes a series of laboratory experiments for testing relay functionality within the laboratory setup, while Chapter 8 provides the results of all laboratory experiments. Analysis and discussion of the laboratory experiment results are given in Chapter 9. A discussion of the laboratory setup and experiments as well as how this can be transferred to a full digital substation is included in Chapter 10, before conclusions and suggestions for further work based on this thesis is given in Chapter 11.

# Chapter 2

## Substations

A brief introduction of various generations of electrical substations is given in this chapter to lay the fundament for the thesis. The inclusion of previous substation configurations is needed since some of their fundamental principles are similar to digital substations. Principles like substation automation systems and substation communication are covered, as these illustrate the main differences between conventional and digital substations. A description of digital substation principles and technologies is also given, with a particular focus on communication and data modeling.

### 2.1 Definitions

The main difference between various generations of substations is related to how the internal communication within substations is performed, which is best illustrated using the substation automation system (SAS) model described in Section 2.2. Up until recent decades, substation control relied solely on hardwired electronic components, and communication between process and bay level as well as bay and station level went through analog signals carried by copper cables [13]. These substations are denoted as *legacy substations* in this report. With the introduction of intelligent electronic devices and remote terminal units (RTUs), the analog communication between station and bay level was gradually replaced by digital communication [14]. This type of substations are called *conventional substations*. The final type of substations to be covered are *digital substations*, where also the communication between bay and process level equipment is digital [15], [16], [17].

An *intelligent electronic device* (IED) is a digital microprocessor-based unit that can be used to house and control power system functionalities. Typical IEDs include digital protective relays as well as station and bay controller units. Note that the terms IED and relay may be used interchangeably in this report, as all digital protective relays are IEDs.

A substation is often physically divided into two main areas; a control room and a switchyard [13]. The substation *switchyard* is often an outdoor area if its equipment relies on air for electrical insulation, but may be made more compact in an indoor environment by using  $SF_6$  gas for insulation [13]. Within the switchyard, incoming and outgoing transmission lines are terminated to a *busbar*. The substation *control room* houses most low

voltage components like IEDs that are used for substation automation and control. In large substations, smaller local control rooms may also exist to control parts of the substation [13]. The transmission lines directing power from a substation towards the power grid customers are known as *feeders* [13]. A *bay* is a grouping of substation equipment whose functionalities logically belong together, and typically consist of circuit breakers, disconnectors and instrument transformers between the busbar and a given feeder.

Substation apparatus can be divided into two main categories; primary and secondary equipment. *Primary equipment* refers to the high voltage (HV) equipment that is located within the substation switchyard. A typical characteristic of primary equipment is that their physical size is strongly dependent upon their nominal voltage level. Examples of primary equipment are circuit breakers, disconnectors and instrument transformers [13]. *Secondary equipment* includes the low voltage (LV) components that typically are located within the substation control room. These are often electrically isolated from the HV system and include components like IEDs [13].

## 2.2 Substation Automation Systems

With the implementation of digital equipment like IEDs, substation automation systems (SAs) was implemented to simplify the control of substations. This is implemented as software within these secondary side components and offers a set of functionalities that can be utilized for efficient substation operation [13]. As illustrated in Figure 2.1, these systems can be modeled as three interacting levels; station, bay, and process level.

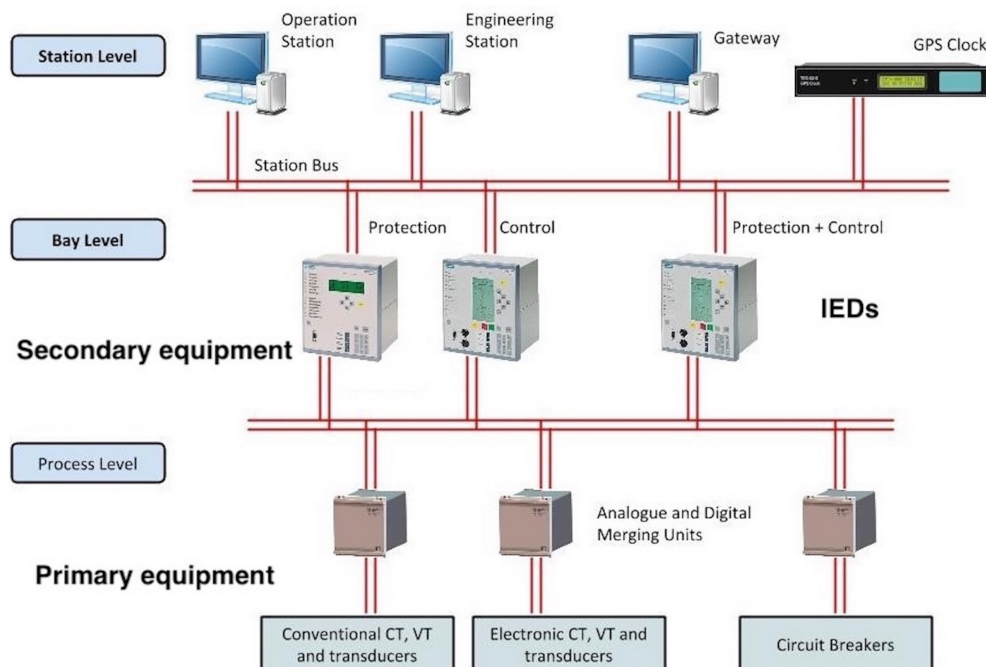


Figure 2.1: Substation automation system model for a digital substation

Source: [2] - McFayden (2014). Modified

### 2.2.1 Station Level

The station level handles functionalities regarding the entire substation. This includes communicating with a supervisory control and data acquisition (SCADA) system, as well as coordinating the operation of the other levels [13], [18]. The station level typically consists of a centralized station controller equipped with a human-machine interface (HMI). In general, an HMI is a terminal that allows substation personnel to read information about the system, as well as making direct changes to its configuration [19].

### 2.2.2 Bay Level

The bay level is divided into groups of one or more substation bays and is used for individual control of each group [13]. A dedicated bay controller unit typically controls the relays and circuit breakers on its bay. This means that protective functionalities are distributed within the substation and allows for efficient operation and control. All bay controllers are coordinated by a station controller located at the station level [19]. Secondary equipment like protective relays is typically modeled at the bay level.

### 2.2.3 Process Level

The last part of the SAS model is the process level, which is the interface to the primary equipment on the HV side of a substation [13]. The process level is used for gathering measurement data from the HV power grid that is processed at the bay level, which may respond with operation messages back to switchgear at the process level [18]. Examples of process level equipment include circuit breakers (CBs) that are used to connect and disconnect power flow through transmission lines, and instrument transformers (ITs). ITs are necessary to transform down voltages and currents in the power grid from primary to secondary side values, which gives magnitudes that can be handled by fragile secondary side equipment at the bay level. There are two main types of instrument transformers; current transformers (CTs) and voltage transformers (VTs). Knowing the CT and VT transformation ratios, protective relays can monitor current and voltage in transmission lines and determine whether these indicate healthy or faulty grid situations.

## 2.3 Conventional Substations

Traditionally, communication between SAS components has relied on point-to-point copper cables carrying analog measurement and control signals. However, the trend in recent years has been a transition towards an increased implementation of digital equipment in substation operations, utilizing optical communication channels for digital communication. In 1964 the International Electrotechnical Committee (IEC) Technical Committee 57 was initiated to provide international standards for communication related to power system control [17]. With the increased implementation of microprocessor-based equipment like IEDs at the station and bay level in the 1980s, substations started to implement

digital communication between the bay and station level through a station communication bus [13], [17].

### 2.3.1 Station Bus

The station bus is a digital communication path that resides between the station and bay level in the SAS model. This allows for vertical communication between station and bay level components, as well as horizontal communication between components within the same level [19]. Most new substations have been installed with station bus communication, replacing hardwired communication through point-to-point copper cabling across the substation control room [19]. Client/server messages are typically used for vertical communication, while GOOSE messages may be used for blocking or interlocking signals between IEDs. A further description of these communication protocols are given in Section 2.5.2. A station bus is typically implemented as a common Ethernet network to which all relevant station and bay level equipment is connected.

### 2.3.2 Bay-Process Communication

In a conventional substation, the communication between process and bay level components remains hardwired. This means that a large number of parallel point-to-point copper cables are connected from each IT located in the switchyard to appropriate IEDs within the control room to carry analog current and voltage signals [13]. Similarly, parallel copper cables are directed from the IEDs back into the switchyard CBs to carry binary control signals, and these connections are typically called trip circuits. This configuration requires a large number of copper cables, which gives a high system cost as well as long installation and commissioning time. There are also safety concerns with this configuration, as live copper cables have to be installed across the control room in which substation personnel is operating.

## 2.4 IEC 61850 Standard

A key part of the transition towards digital substations is the introduction of IEC 61850, a standard that defines substation communication, engineering, and data modeling [4], [11], [20], [21]. The main goal of IEC 61850 is to provide an abstract standardized description of digital substation operation and component requirements, with the aim of achieving full vendor-interoperability for digital substation equipment [20]. Edition 1 of the standard was first released in 2004, with the main focus on communication and data modeling. An improved second edition of the standard was published in 2011, providing a more comprehensive approach to substation engineering as well as further specifications of how its features should be implemented in practice [20]. Rather than being seen as just another communication protocol, IEC 61850 is a collection of protocols and standards that provide a comprehensive approach to digital substation operation. An overview of the main content and structure of IEC 61850 Edition 2 is given in Table 2.1.

Part	Content
1	Introduction and overview
2	Glossary and definitions
3	General requirements
4	System and project management
5	Communication requirements for functions and devices models
6	Configuration description language for IED communication
7	Basic communication structure
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
7-410	Hydroelectric power plants - Communication for monitoring and control
7-420	Distributed energy resources logical nodes
8	Specific communication service mapping
8-1	Mappings to MMS and ISO
9	Specific communication service mapping
9-1	Sampled values over point-to-point link
9-2	Sampled values over ISO
10	Conformance and Performance Testing

Table 2.1: IEC 61850 Edition 2 structure

**Source:** [11] - ABB (2014). Modified

## 2.5 Digital Substations

To fully utilize digital communication in substations, the communication between bay and process level components can be based on an optical Ethernet process bus, rather than parallel hardwired copper cables [13]. This results in a fully digital substation, with little implementation of hardwired copper cables for measurement and control [19].

### 2.5.1 Process Bus

An optical communication bus can be implemented to utilize digital communication in a substation [19]. In a conventional substation, only a station bus is implemented, while a digital substation is installed with both station and process bus. A communication bus can be implemented as an Ethernet local area network (LAN), similar to the network within a house with Internet connection [22]. By utilizing Ethernet adapters, optical cables, and switches, a local digital communication network can be created within the substation. By adding a router to this system, communication with other substations or control centers may be achieved [22]. Ethernet is a broadcast medium where digital messages are sent as light beams over optical cables, which means that every component connected to a communication bus can detect all messages transmitted through the network.

Analog measurements from conventional ITs can be converted to digital messages by utilizing merging units (MUs) before being sent to the process bus. In a digital substation, it is wanted to do this as close to the source as possible, meaning within the switchyard. In recent years, the introduction of non-conventional ITs (NCITs) has improved IT performance and allowed for direct conversion to digital signals, as analyzed in the following NTNU master thesis [23]. A digital substation may have individual communication networks for the process and station bus or have one single physical communication system that interconnects all levels [17], [19].

When implementing a substation process bus, the operational security of the substation should remain at least as good as the existing conventional alternatives. Previous configurations based on hardwired copper cables provide excellent operational safety, but optical cables are more fragile than copper. Besides, Ethernet switches introduce added complexity and possible points of failure to the communication system. However, the operational security can be improved by introducing redundancy to the process bus network, which is usually done using parallel redundancy protocol or high-availability seamless redundancy, as defined in IEC 62439-3 [24], [25].

## 2.5.2 Communication Protocols

Communication in a digital substation environment relies on two main types of communication; publisher/subscriber, and client/server communication [20], [26]. Publisher/subscriber communication includes two communication protocols; generic object-oriented substation event (GOOSE) and sampled value (SV) messages. The abstract data modeling and communication description given in IEC 61850 is not directly applicable in practice. To achieve this, the data has to be mapped onto a specific communication transport protocol [22]. Mapping can be defined as the process of creating an intermediate layer that connects an abstract model or structure into a practical interpretation [22]. As illustrated in Table 2.1, mapping of substation communication protocols is defined in part 8 and 9 of the IEC 61850 standard.

Both GOOSE and SV messages are mapped directly onto the Ethernet system, as illustrated in Figure 2.2 [3], [20]. Ethernet offers low time delay at the cost of few additional features. GOOSE and SV messages are continuously being sent onto the Ethernet network and may be seen by all units connected to the network, and components can be configured to receive certain types of messages by subscribing to them. The last major communication protocol utilized in substations is client/server communication, which is mainly used for monitoring and control messages across the station bus. Client/server communication is mapped onto MMS and TCP/IP, similar to traditional Internet communication [26].



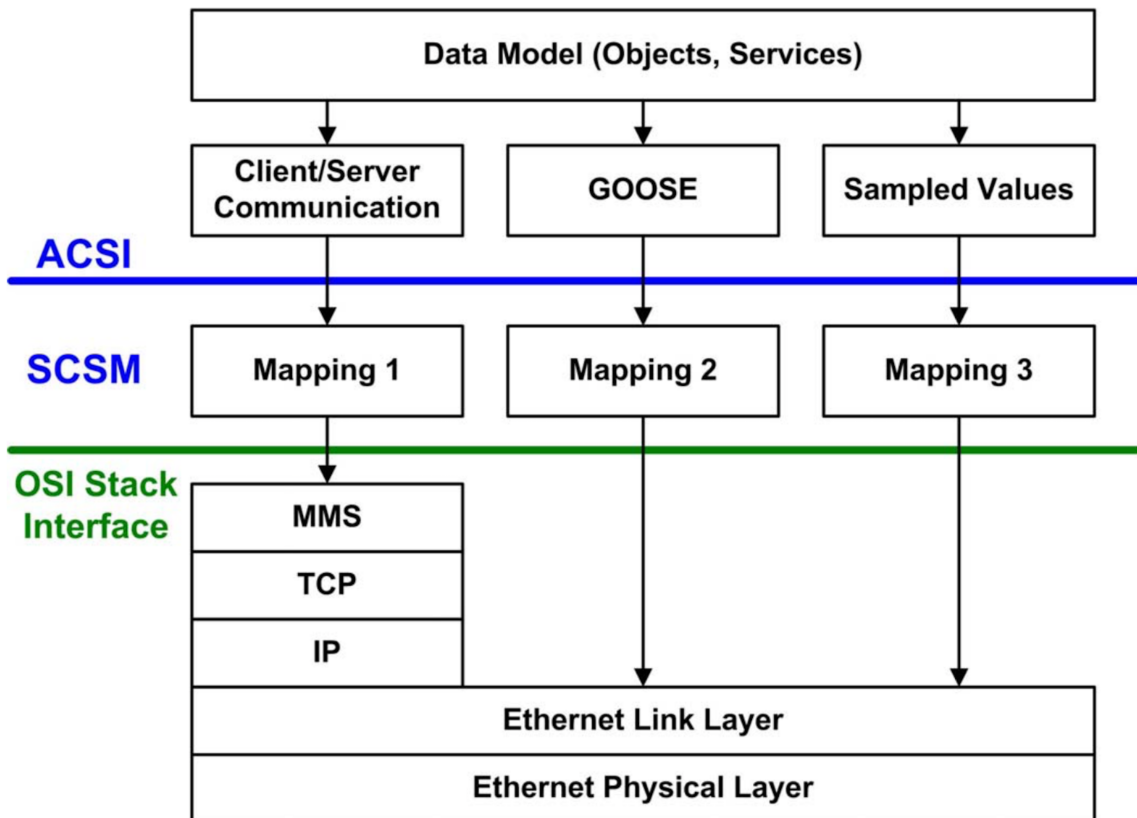


Figure 2.2: Mapping onto communication transport protocols

Source: [3] - Mohagheghi (2011)

### 2.5.3 GOOSE

GOOSE is an important part of digital substation communication, and is often used for transmitting time-critical control functions [20], [27], [28]. The fact that GOOSE is a publisher/subscriber form of communication means that rather than having physical or logically dedicated paths between the sender and receivers of a message, this is solved in a more flexible manner. A publisher sends GOOSE messages to the Ethernet network as configured in its settings, without knowing which equipment will receive and utilize these. Every component in the network will detect all published messages, and a component can be configured to subscribe to appropriate messages from certain components. If a component detects a message that it is configured to subscribe to, it will receive the message and process its contents. Otherwise, the message is discarded.

A key feature of GOOSE messages is that they are event-triggered, meaning that they are transmitted as a reaction to an event that has occurred within the substation [20]. This means that messages can be sent at an irregular time interval, depending on the substation operation. A maximum retransmission interval is specified for each GOOSE configuration, and if no new events have occurred after this interval, the previous GOOSE message is retransmitted. This increases the operational security of the GOOSE transmission scheme, as Ethernet alone is a quick but unreliable form of communication. GOOSE messages are typically used in substations to carry trip signals from relays to switchgear,

interlocking, auto-reclosing of switchgear, or to exchange information regarding breaker failure protection [27], [28]. A vital requirement of these functionalities is that they depend on a minimal time delay, in the range of milliseconds.

### 2.5.4 Sampled Values

SV is a form of communication that is typically used for sending digital measurement messages from MUs or NCITs to protective relays, i.e., between the bay and process level of the SAS model [19]. Unlike GOOSE messages, SV messages are not event-based. Instead, a constant stream of digital messages is transmitted, depending on the measurement frequency specified in the system configuration. As shown in Table 2.1, SV message transmission is defined in part 9-2 of IEC 61850 Edition 2. This specifies that SV messages to be utilized for protection purposes should have a sample rate of 80 samples per cycle, giving 4000 samples per second for a 50 Hz power system. Hence, SV messages may generate a substantial amount of network traffic, which has to be considered to prevent network overloading.

SV messages are typically found in the process bus of a digital substation communication system, but may also appear in the station bus in individual cases [19]. It should also be noted that SV messages typically contain primary side current and voltage measurements that are appropriately scaled by the MU before being sent to the relay. This means that the relay receives digital primary side values in a digital substation, unlike conventional substations where relays receive secondary side analog values. An SV data message consists of a header with information about its publisher and a data part that contains current and voltage measurements from all three phases of a transmission system.

### 2.5.5 Client/Server Communication

The last type of digital substation communication is client/server communication, which is often used for communication between the station and bay level. This is a connection based form of communication where virtual paths are defined between the sender and a recipient before data is transmitted [22]. This is typically used for communication with a SCADA system, where the substation IEDs acts as servers that send information and respond on control signals from a SCADA client [7]. Client/server communication was first introduced in conventional substations but is also used for similar applications in digital substations. While client/server communication offers increased reliability and security through its mapping, as shown in Figure 2.2, these mechanisms add time delay to the communication and make it unfeasible for use in time-critical purposes.

### 2.5.6 Plug and Play Functionality

An important feature of IEC 61850 is an explicit, standardized description of communication within substation control and automation systems. This means that it, in theory, is possible to replace an IEC 61850 compatible IED with another IED from a different manufacturer without loss of operational security [29]. The configuration of an IED to

be replaced can be transferred to a new IED using SCL files defined in the IEC 61850 standard, which will be covered further in Section 2.8. This is called plug and play functionality since it allows for seamless interchanging of components as long as they are IEC 61850 compatible and the system communication is standardized. While different components may handle similar problems differently internally, this does not affect the system functionality as long as their input and output values are standardized [29].

## 2.6 IEC 61850 Data Modeling

A key element of the IEC 61850 standard is the introduction of vendor-independent modeling of substation data, as defined in part 7 of IEC 61850 Edition 2 seen in Table 2.1. This includes a set of rules that uniquely identify data elements in a standardized format, where data elements are organized into groups based on their functions and logical associations [17]. This results in the following hierarchy of data building blocks for IEC 61850 substation data, presented from top to bottom, which will be described in this section.

1. IEC 61850 physical device
2. Logical device (LD)
3. Logical node (LN)
4. Data object (DO)
5. Data attribute (DA)
6. Data

### 2.6.1 IEC 61850 Physical Device

An IEC 61850 physical device is a microprocessor unit that processes measurement data related to monitoring and control functions. This is typically IEDs or IEC 61850 servers located in a digital substation environment. Each physical device has a unique network address that is used for the identification of every single component [3]. Figure 2.3 illustrates a typical IEC 61850 data structure, where the physical device is indicated by the outermost box.

### 2.6.2 Logical Device

A logical device (LD) is a virtual unit that exists within a physical device and defines a set of monitoring and control functionalities that forms a protective relay. Each LD can be seen as an individual IED in terms of functionality, even though they are contained within one physical unit. In this way, a physical device can perform several monitoring and control tasks simultaneously by containing various LDs [3]. Figure 2.3 contains one LD, indicated in purple.

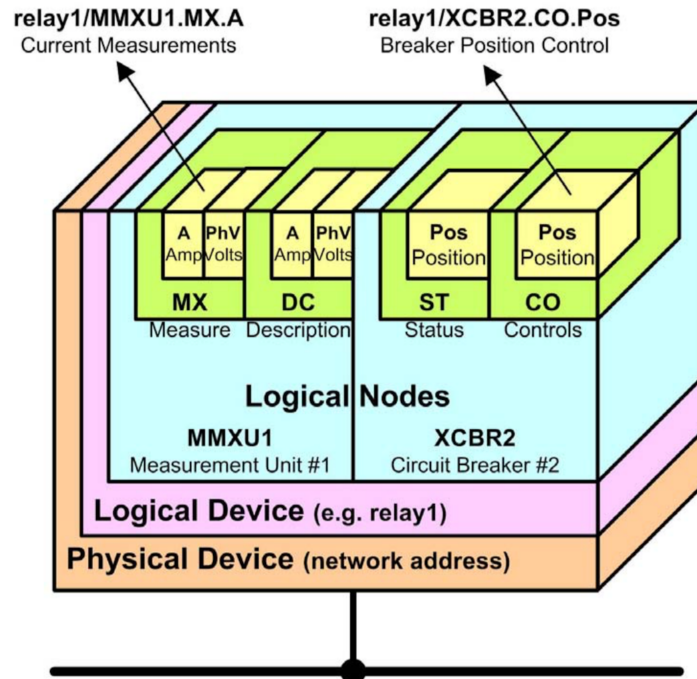


Figure 2.3: IEC 61850 semantic data structure  
**Source:** [3] - Mohagheghi (2011)

### 2.6.3 Logical Node

The protection and control functions of an IEC 61850 substation consists of data units called logical nodes (LNs). These are virtual groupings of information that logically represent functional elements, and may represent information of primary or secondary equipment in a standardized format [3], [30]. Examples of LNs include XCBR that contain all information that can be obtained from an IEC 61580 CB, and PDIS that gathers the data that can be specified in an IEC 61850 distance relay. IEC 61850 defines about 100 different LNs for digital substations and allows for creating new LNs in a standardized format [31]. In Figure 2.3, the LNs of an IT and a CB are included and indicated in blue.

### 2.6.4 Data Objects

An LN is a collection of smaller data objects (DOs) that logically belong together, and each DO specify a standardized format of storing information regarding a substation unit [3]. For example, the LN XCBR contains a DO that indicates whether the CB is open or closed. Some DOs are mandatory for a given LN, often because they represent basic information that is needed in all substations. Other DOs are optional and are only included when additional functionalities are supported by the given physical device [17]. The green boxes in Figure 2.3 indicates that two DOs are specified within each LN.

### 2.6.5 Data Attributes

Each of the data fields in a DO is called data attributes (DAs), which are containers in which data can be stored. For example, the DO "measure" shown in Figure 2.3 contains two DAs indicated in yellow, one containing information of measured current and one for measured voltage.

### 2.6.6 Data

The data itself represents the bottom level of the IEC 61850 abstract data structure. A piece of data must be stored within a DA, and can have a basic type like integer or boolean values, or contain data structures like vectors or complex numbers [17].

## 2.7 IEC 61850 Data Names

To make use of the abstract data modeling defined in Section 2.6 in the communication protocols introduced in Section 2.5.2, unique identification of each data element within a substation is needed [4]. IEC 61850 introduces a solution to this concern by creating standardized object names in which the LD, LN, DA, and data is included. The anatomy of an example IEC 61850 object name is illustrated in Figure 2.4, from which one could see that the LD "Relay1" contains information about the CB "XCBR1", and the mode of operation of this CB is set to "Loc", indicating settings for local control. The DA is of type "stVal", which describes that the data is of a static value type. Note that it is important that each LD has a unique name within each substation, as this means that every piece of data has a unique identification using this name construction method.

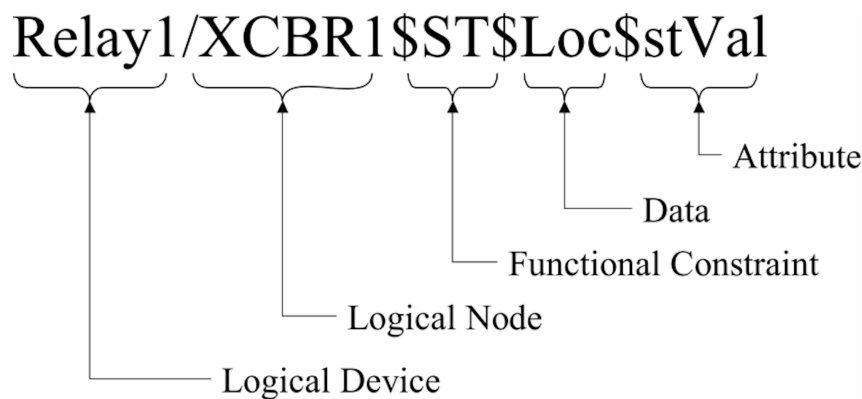


Figure 2.4: IEC 61850 object name anatomy

Source: [4] - Mackiewicz (2006)

## 2.8 IEC 61850 Engineering and SCL

To facilitate interoperability and plug and play functionality between digital substation components, part 6 of the IEC 61850 standard defines a System Configuration description Language (SCL) as shown in Table 2.1 [32]. This can be utilized to give an abstract definition of substation design, communication, and components, that is independent of the vendors and internal details of each component. SCL defines seven types of files that each describe various levels of a substation, and all should be utilized throughout the engineering process when creating new digital substation systems [5], [32]. This may also be used to transfer configuration files between IEDs, as the standardized descriptions following the IEC 61850 data modeling should be interpreted equally by all IEC 61850 compatible IEDs.

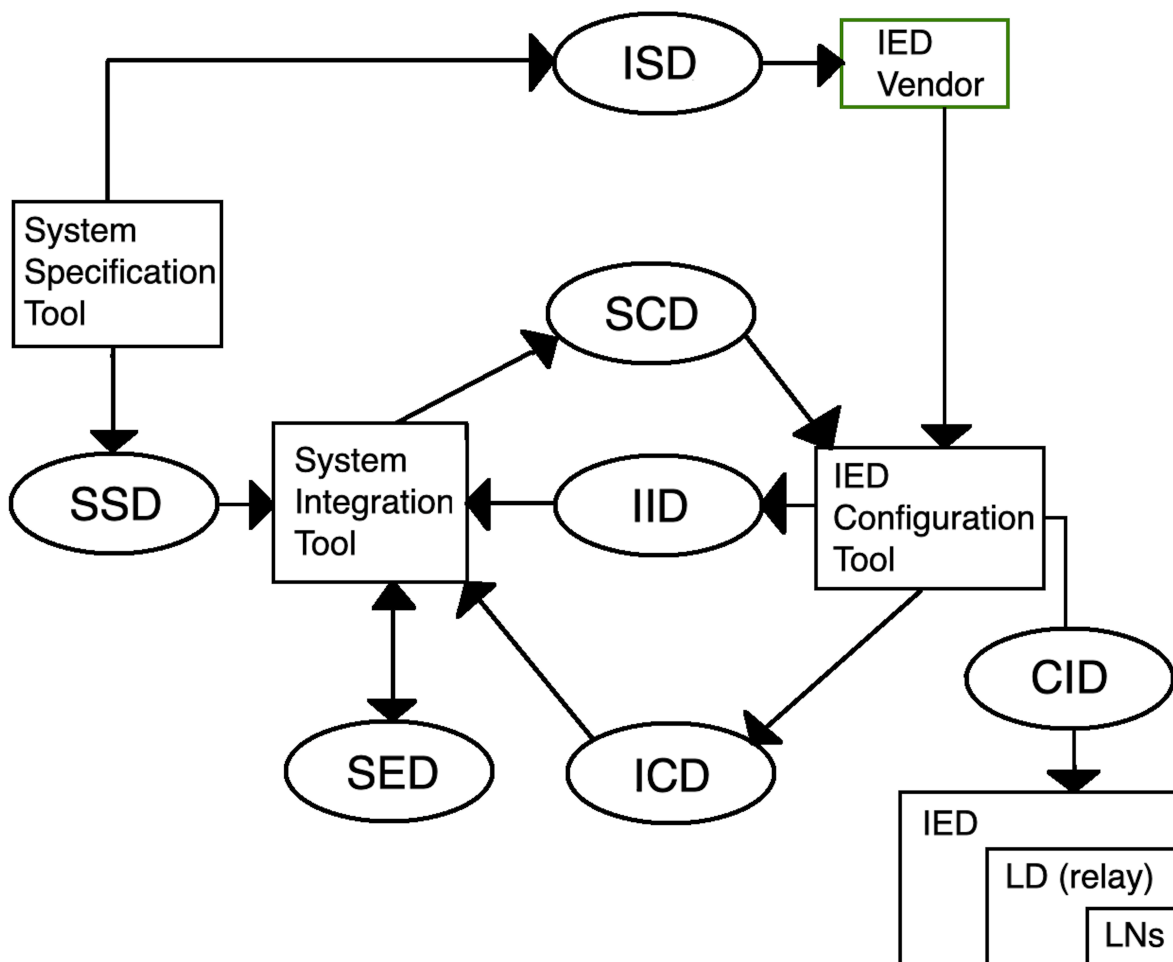


Figure 2.5: IEC 61850 engineering process  
 Source: [5] - OMICRON Energy (2018). Modified

When designing and creating new digital substations, thorough engineering processes are required [33]. This typically involves defining the system specifications and design, along with the system configuration and documentation of the entire substation setup. IEC 61850 defines a set of engineering tools that makes this process streamlined by standard-

izing the engineering data contents and tools [33]. An idealized version of an IEC 61850 engineering process is shown in Figure 2.5. Each of the circles in the figure indicates a standardized IEC 61850 file format that is written in the SCL language. The rectangles represent IEC 61850 engineering tools, vendors, or physical components, while the arrows between objects represent the flow of communication through the process. Ideally, these engineering processes should start at the top left corner with the system specification tool, and end with the implementation of IEDs in the bottom right corner. A description of essential tools and SCL files are given in the following sections.

### 2.8.1 System Specification Tool

The system specification tool is used provide a high-level description of IEC 61850 digital substations and may be used by power utilities to create system specifications that are sent to the vendors that produce and deliver the full system [33]. This results in a substation system description (SSD) file that describes the substation topology, often in the form of single line diagrams. Besides, an IED specification description (ISD) file is created, containing a description of the IED functionalities that are to be included in the substation [5]. The ISD file may be sent to IED vendors to describe the requirements of the IEDs to be produced.

### 2.8.2 System Integration Tool

SSD files are used as input to the system integration tool to implement the system specifications and make sure that these are within the system boundaries. IED capability description (ICD) files are also used as input to this tool, containing information about the functionalities available in each IED. The purpose of this is to align the system configuration tool with the IED functionalities that are installed in the system. The last input to this tool is system exchange description (SED) files that may be used to transfer information between various substation projects to synchronize their configuration and allow for communication between them when completed [5].

### 2.8.3 IED Configuration Tool

The system integration tool results in substation configuration description (SCD) files, which is the main result of the engineering process, describing the complete substation configuration [33]. However, these engineering processes will in practice often have to be performed iteratively until the final SCD file of the substation is obtained [33]. This is shown by the instantiated IED description (IID) part of the figure. If the functionalities and capabilities of the IEDs implemented in the substation are not compatible with the SCD file used as an input to the system integration tool, appropriate changes have to be made to the SCD file. After making these changes, for example, related to the LNs or IED communication, a new ICD file is created. This is sent back as an input to the system integration tool, resulting in an updated SCD file. This iterative process continues until all functionalities match between the SCD files and IED capabilities [5]. Once the final

SCD file is obtained from this process, the IED configuration tool generates a configured IED description (CID) file, containing a description of the substation IEDs. In the CID file, all information needed to configure each IED is included, so this may be imported into any IEC 61850 compatible IED to make this operate as specified through the engineering process [33]. Note that this means that the IED configuration is independent of specific internal details about the vendor and hardware of each relay.



# Chapter 3

## Protective Relaying

Protective relaying is a crucial part of this thesis, and fundamental theory about this is needed to work with relay test procedures in the following chapters. As introduced in Section 2.2, protective relays are a type of IEDs that is located at the bay level of the SAS model, with the primary purpose of detecting and taking actions towards clearing faulty situations in the electric power grid [6], [34], [35]. There are several types of protective relays, for example, overcurrent and differential relays. However, the main topic of this chapter is distance relays, also known as impedance relays, as these are utilized in the laboratory experiments of this thesis.

### 3.1 Fundamental Principles

A protective relay takes in information about the state of the power grid through measurements from ITs at the process level. This information is then processed and compared to the relay configuration to determine whether the grid is operating in healthy or faulty conditions. If the measured values violate the configurations, a trip signal is sent to corresponding CBs and disconnectors. This signal opens the CBs and isolates faulty components from the power grid. Various protective relays are typically coordinated in a protective scheme in order to protect an entire power grid as good as possible. The main goal when creating protective schemes for a substation is that all faults are detected and cleared, but that as small parts as possible are disconnected from the grid during faults. This can be achieved by following four main principles that must be taken into account when creating protective relay schemes for a substation [34].

1. **Security:** the relay does not operate when it is not supposed to. This means that if no fault has occurred within the area to be protected, the protective system should not operate.
2. **Dependability:** the relay operates correctly when it is supposed to. If a fault occurs within the primary protection zone of a relay, the relay should trip every single time. Note that both security and dependability is needed for a fully functioning protective scheme.

3. **Stability:** after a fault and subsequent relay tripping of CBs, as much of the healthy system as possible should remain operative.
4. **Selectivity:** only faulty parts should be isolated from the system when clearing faulty situations. Hence, selectivity and stability imply that a faulty situation ideally should be successfully cleared by disconnecting as few components from the system as possible.

Protective relays are configured to operate within a primary protection zone. If a fault occurs within this area, the relay is supposed to detect, handle, and successfully clear the fault within a short time [34]. Besides, a relay can be configured to detect faults outside its primary zone, in which case it is said to operate as backup protection. However, since most parts of the power grid are covered by a primary zone of protection and system selectivity is to be achieved, a time delay must be added to the backup protection to allow the primary protection to operate first to obtain selectivity [34]. All four principles of protective relaying have to be taken into account when coordinating various zones of protection into an optimal protection scheme,

## 3.2 Distance Protection

Distance protection relays are typically the most important components for the protection of long HV transmission lines in the power grid [6], [35]. Hence, a distance relay is to be utilized in the laboratory experiments later in this thesis, and an overview of its principles and configuration is given in this section. The setting of primary and backup zones of protection for distance relays is also described.

### 3.2.1 Principles

The fundamental principle of distance protection relays is that current and voltage are measured for a component that is to be protected and used as input signals for the relay. An impedance  $Z = \frac{V}{I}$  can be calculated using these values, which is called the impedance that is seen by the relay [6]. In a numerical relay, a protection algorithm is implemented and configured to make decisions about which measurements indicate healthy and faulty grid situations. A distance protection relay has six different measurement circuits; between each pair of phases and between each phase and ground. By analyzing the current and voltage characteristics of each circuit, it is possible to detect which of the eleven possible fault types, as described in Section 3.4, that has occurred in the grid [35].

Since the total impedance of a transmission line is typically proportional to its length, the relay can be set to cover a given length of a line. If a fault occurs in the transmission line, the voltage typically decreases while the current increases, giving reduced impedance seen by the relay. The relay can be configured to interpret this as a fault and give a trip signal to appropriate CBs [6]. The distance of a transmission line that is covered by a relay is called the reach of the relay. The ITs of a distance relay are typically installed at one end of a transmission line, with a defined forward direction towards the line to be

protected. This means that a fault occurring on the line results in a positive impedance due to the polarity of measured voltages and currents.

### 3.2.2 Zones of Protection

A distance relay can be configured to have various zones of protection. In the primary protection zone, often called zone 1, a relay should typically trip as fast as possible if faults are detected. Rather than covering the entire length of a transmission line, zone 1 typically covers about 80-90% of a transmission line [6]. This is done to prevent zone 1 from tripping for faults occurring at the component at which the line is terminated, as this often should be cleared by another primary protection zone to increase the selectivity of the protective scheme. There are some inaccuracies and uncertainties both in IT measurements and the parameters being used to configure relay settings, so a safety margin has to be taken into account to prevent such unwanted tripping scenarios. A fault occurring within zone 1 of a distance relay may be called internal faults, while faults occurring beyond this primary protection zone are called external faults.

A key feature of distance relays is that they can detect faults occurring far away in the grid, and thereby act as backup protection for large parts of the power grid [6]. This allows for the configuration of a number of backup protection zones. For instance, zone 2 can be configured to cover an entire transmission line, as well as the subsequent busbar and parts of the next transmission line. A time delay, typically about 0.3 seconds, must be added for this zone to allow appropriate primary protection zones to operate and maintain the system selectivity. However, if the primary protection fails to operate within the specified time delay, the backup protection takes action to clear the fault [6]. Similarly, several additional backup zones can be configured, each covering bigger parts of the system and having increased time delay. Backup zones may also be configured to cover faults occurring in the backward direction of the relay to cover parts of the grid that are located behind the relay, referred to its forward direction [35].

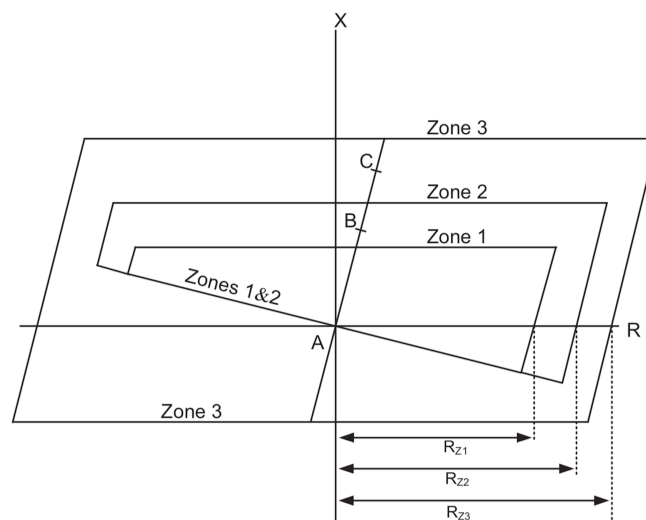


Figure 3.1: RX diagram for a numerical relay of quadrilateral type  
**Source:** [6] - Alstom Network Protection & Automation Guide (2014)

The configuration of distance relay zones of protection is best illustrated through an RX diagram, as shown in Figure 3.1, where the impedance seen by the relay is given by its imaginary (vertical axis) and resistive (horizontal axis) components [6]. It is assumed that the relay and its ITs are located at terminal A, looking into a transmission line towards terminals B and C in its forward direction. Zone 1 covers most of the transmission line between A and B, zone 2 covers both terminals A and B as well as a part of the following transmission line, while zone 3 covers an even bigger part of the system including the backward direction [34].

Since transmission lines in the HV power grid are mainly inductive, the reactive component of a zone setting mainly determines how large portions of the grid are covered by the zone. The resistive reach of each zone is typically exaggerated since most fault situations involve a mainly resistive object creating short circuits, which shifts the fault situation in the resistive direction [34]. Note that a relay should not trip for normal load conditions. Since loads connected to the grid are typically mainly resistive and have a magnitude far greater than the impedance of a transmission line, a normal load situation is typically located far out to the right in the RX diagram [6]. However, an increased load will reduce the load impedance, which means that the point of operation moves towards the protection zones. Hence, when configuring protective zones of a distance relay, heavy load situations must often be taken into account to prevent tripping due to overload.

### 3.3 Pilot Protection

The performance of protective relay schemes may be improved by adding pilot protection functionalities [34]. Pilot protection allows relays and IEDs to communicate trip information with each other horizontally, and the most important signals are permissive and blocking signals [36]. Blocking signals can be utilized to improve the security of a protective scheme. As discussed in the previous section, a protective relay scheme utilizing distance relays typically contains several backup protection zones that overlap its primary protection zones. If a relay detects a fault within its primary zone of protection, it may be configured to send blocking signals to other relays to make sure that other relays do not trip for this fault [36]. This means that even though other relays might want to trip due to inaccuracies or errors in the configuration or abnormal grid situations, they receive a block signal that prevents them from tripping. In a digital substation, this horizontal communication may be implemented using GOOSE messages between relays. This improves the security of other relays, as well as the selectivity of the protective scheme.

Permissive trip signals may be sent in order to allow for high-speed tripping and hence reduce the trip time of a relay. A transmission line is typically protected by placing a distance relay at each end of a transmission line, both looking into the line from their side [36]. As discussed in the previous section, there are uncertainties in the primary zone settings of a distance relay, which means that a relay is typically set to cover only 80-90% of transmission lines with an instantaneous trip. If a fault occurs close to the end of a transmission line, this is seen as a fault in zone 1 of the closest relay, while the remote relay at the other end of the transmission line may see this in its zone 2, resulting in a time-delayed trip [36]. However, if a pilot protection scheme is implemented, the relay

closest to the fault can be configured to send a permissive trip signal to the remote relay once it detects a fault that occurs on the transmission line, which allows the remote relay to trip without additional time delay.

## 3.4 Transmission Grid Faults

Faults in the transmission power grid typically refer to unwanted short circuits, occurring either between phases or between phases and ground [36]. Faulty grid situations typically result in fault currents and voltage drop in the grid, as well as a range of AC phenomena like changed frequency, phase angles, and harmonic components. Protective relays can be configured to detect these changes in measured power grid parameters and interpret them as certain types of faults [36]. Using the notation  $L1$ ,  $L2$ ,  $L3$  for each of the three phases and  $E$  for ground, there are a total of 11 possible fault situations that may occur in a 3-phase transmission grid, all listed below.

- **Single phase to ground (SLG):** short circuit between one of the three phases and ground ( $L1-E$ ,  $L2-E$  and  $L3-E$ ).
- **Phase to phase:** short circuit between two phases ( $L1-L2$ ,  $L2-L3$  and  $L1-L3$ ).
- **Phase to phase to ground:** short circuit between two phases and ground ( $L1-L2-E$ ,  $L2-L3-E$  and  $L1-L3-E$ ).
- **3-phase faults:** short circuit between all three phases, possibly to ground ( $L1-L2-L3$  and  $L1-L2-L3-E$ ).

The different fault types give different fault characteristics and may have different causes. In a 3-phase overhead transmission line, SLG faults are the most common fault type, typically contributing to around 90 % of the total faults [37]. This is typically due to objects close to the transmission line coming into contact with one of the phases, for example, nearby trees moving in the wind or falling on the line. 3-phase to ground faults typically occur in more comprehensive fault conditions, for example, if a storm damages an entire transmission line segment. As shown in the yearly power grid interruption statistics in Norway produced by Statnett, most power grid interruptions are related to faults in transmission lines, and most of these occur due to interactions from the surrounding environment [37].



# Chapter 4

## Relay Functionality Testing

An overview of relevant theory related to relay testing is given in this chapter to provide the background needed to discuss and perform relay functionality testing in later chapters. A description of test types and methods of relay functionality testing is given, and the differences between testing relays in conventional and digital substation environments are studied. Digital substation test tools introduced by IEC 61850 are also introduced, along with an overview of some utility testing experiences from digital substation pilot projects.

### 4.1 Testing Procedures

A wide range of testing procedures are needed through the life span of a substation [8], [38]. To verify the correct operation of newly installed or modified substation components, they have to be thoroughly tested before being put into normal operation. After production, a new relay is typically type tested by its manufacturer to provide documentation of its functionality and interfaces [8]. When installing new substation components, factory acceptance testing (FAT) is performed by the manufacturer to verify proper operation on the factory. After delivery to the operation site, a site acceptance test (SAT) is often performed to confirm correct operation in the conditions in which the relay is going to operate [8], [38]. In addition, interoperability testing may be performed to make sure that different IEDs are compatible to communicate with each other [8]. After being put into operation, regular maintenance testing is required to ensure maintained operational security over time.

#### 4.1.1 Types of Relay Testing

Several factors must be taken into account when testing substation components and their operation. Thus, different types of testing are needed, and the main types of substation testing are given below.

- Conformance testing: verifying that a digital substation component communicates and behave according to the IEC 61850 standard, and assuring full IEC 61850 compatibility [12]. As seen in Table 2.1, this is covered in part 10 of IEC 61850 Edition

2 where methods and abstract test cases are specified. The result of a conformance test may be a certificate that specifies the component capability according to IEC 61850 [12].

- Performance testing: verifying that components perform their specified functionalities within given time limits, even during periods with heavy communication network load [12]. Typically, the maximum end-to-end time delay from a message is sent until an appropriate recipient receives it is measured. Part 10 of IEC 61850 provides methods for correct measurement procedures and statistical methods that should be taken into account when performing performance testing [12].
- Functional testing: verifying the correct behavior of digital substation components. This may be performed on individual components, for a selection of components, or a full-scale system [12]. Functional testing is typically performed during FAT, SAT, and routine testing. For a protective relay, it is wanted to test all of its utilized functionalities both individually and in combination with other functionalities.

The main focus of this report is functional testing of protective relays, which means that performance and conformance testing are not an essential part of the laboratory experiments. Note that all three types of testing should be included in a complete relay testing procedure for digital substations. The IEC 61850 standard has a primary focus on conformance and performance testing, while functional testing is not specified as detailed [12]. However, IEC 61850 defines a range of tools that can be used for functional testing of relays in digital substation environments, which is discussed in the following sections.

## 4.2 Functional Testing of Protective Relays

Testing the functionality of protective relays is a key part of substation test procedures. Failure to handle faulty situations correctly may cause damage to critical components, potentially resulting in huge economic losses. Similarly, operation for faults that occur outside the zones of protection causes unwanted interruption of the power supply, which may cause big economic losses, particularly for industrial customers [8]. This means that thorough testing procedures are needed, both for individual relays and the entire protective system [8]. Seen in correlation to the protective relaying principles introduced in Section 3.1, testing procedures for an isolated relay should typically include the following main considerations.

- Verifying stability at normal operating conditions, meaning that the relay should not trip during healthy load situations [8].
- Verifying stability for external faults, meaning that the relay should not trip for faults occurring outside its zones of protection [8].
- Verifying high-speed clearing of faults within the zones of protection [8]. This means that a successful trip is executed within specified time limits to clear faulty situations.
- Additional special cases may also be tested, for example, CT saturation and breaker failure conditions.



There are two main approaches for testing relay functionality, depending on how measurement signals are applied to the relay; primary and secondary injection [38]. Primary injection means that current and voltage is applied at the HV side of the system, which is converted to secondary values through ITs and sent to an associated relay. In a secondary injection procedure, secondary side currents and voltages are simulated and injected directly into the relay without going through ITs [38]. Test methods may also be divided by the nature of the measurement signals that are applied to the relay, as listed below.

- **Steady state testing:** injecting purely sinusoidal current and voltage signals with constant magnitude and phase angle.
- **Dynamic state testing:** injecting purely sinusoidal current and voltage signals with time-varying magnitude and phase angle.
- **Transient testing:** injecting current and voltage signals with time-varying magnitude and phase angle, including transient signal components.

#### 4.2.1 Conventional Substation Relay Functional Testing

Testing procedures and their practical implementation are different for conventional and digital substations, meaning that new tools and methods have to be introduced [7]. The main difference between testing relay functionality in conventional and digital substations is related to the differences in communication between ITs and relays, which can be shown by illustrating how secondary injection tests are performed for either configuration.

In a conventional substation, a test set is typically connected directly to a relay through hardwired point-to-point test plugs from the front panel outputs of the test set [39]. Secondary side values are simulated and injected into the relay, and the response is detected by connecting hardwired binary trip circuits directly from the relay to the test set [7]. A typical configuration is illustrated in Figure 4.1. This procedure follows the communication principle between bay and process level equipment in conventional substations introduced in Section 2.3.2, with point-to-point hardwired copper cables carrying analog signals.

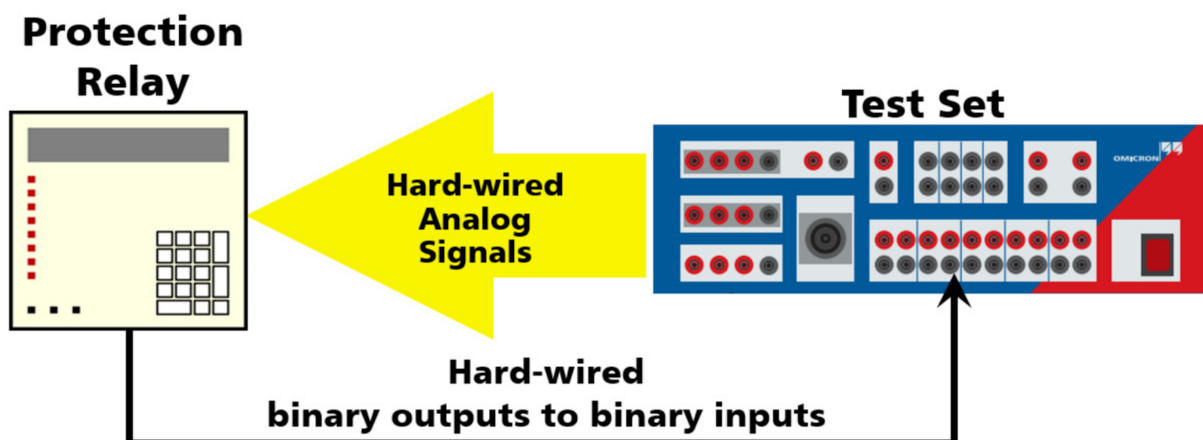


Figure 4.1: Conventional test set configuration  
Source: [7] - Carvalho (2014)

## 4.2.2 Digital Substation Relay Functional Testing

Relay functionality testing in a digital substation is somewhat similar to the procedures used in conventional substations, but the test set communication is digital rather than analog. Also, the test set does not have any direct point-to-point connections to the relay [7]. A digital test set may generate a stream of SV messages that are published to the substation process bus to which the relay is connected. The relay to be tested can be configured to subscribe to these SV messages and interpret them as measurements from an IT. If a trip signal is activated, the relay will publish this as GOOSE messages to the substation network. The test set has to be configured to subscribe to these messages and interpret them correctly to detect that the relay tripped [7]. An illustration of such a configuration is given in Figure 4.2. It is also possible to make the test set simulate GOOSE messages for testing more complex configurations. For example, it is possible to simulate breaker positions, interlocking, or communication from other IEDs using the test set. Note that none of the front panel ports of the test set are used, but that a single Ethernet cable connected to the back panel of the test set provides the only connection to the substation process bus.

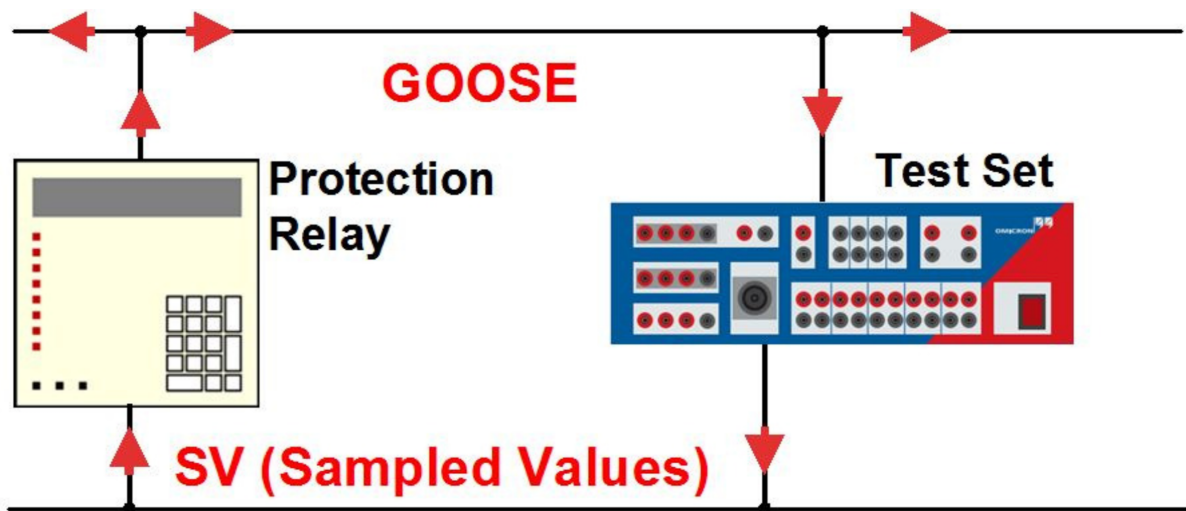


Figure 4.2: Digital test set configuration  
Source: [7] - Carvalho (2014)

## 4.3 Testing Communication Paths

In a conventional substation, testing the physical communication paths between bay and process level equipment is a fairly simple process, but may be time-consuming due to the large number of paths to be tested [7]. The input and output ports of each relay are tested, and continuity of the cable between two ports may be tested using a multimeter [7].

Software tools are needed to test and analyze the communication within a digital substation [7]. By connecting to the process bus, the multicast nature of the Ethernet network can be utilized to check all messages. For instance, one could verify that an IED is correctly producing GOOSE messages by subscribing to these messages. It is also possible

to verify that another IED is correctly receiving GOOSE messages by analyzing an LN within the IEC 61850 data modeling that shows GOOSE subscriptions [7]. A network sniffing tool like Wireshark can be used to capture all data traffic that flows on a substation communication bus. This tool can be used to inspect and analyze all GOOSE and SV messages being published to the network, as well as client/server communication.

## 4.4 IEC 61850 Testing Tools

When transitioning from conventional to digital substations, the operational security should at least be maintained, and if possible, improved. This means that new methods and tools are needed to ensure sufficient operational security, while also utilizing the possibilities provided by IEC 61850 [7], [12], [39], [40]. IEC 61850 Edition 1 introduced four important features that can be utilized for testing purposes in digital substations [40]. More detailed specifications on how to fully utilize these, as well as the addition of other features, are given in Edition 2 of the standard [8]. This includes LN test modes, test messages, mirroring of control information, as well as possibilities for isolating and testing a device in a system [39], [40].

### 4.4.1 Test Mode

Each LN has a DO called *Mod*, which can be used to configure the LN to operate in one of five possible test modes [40]. It is possible to change the mode of each LN individually, or make modifications to all LNs related to a protective functionality by changing the *Mod* of their LD [39]. The resulting behavior of an LN is stored in a DO called *Beh*. The value of this *Beh* parameter depends on the combination of the *Mod* of the LN and the *Mod* parameter of the LD that it is operating within [12]. *Mod* and *Beh* can have one of the following five values.

1. **ON:** used for relays in normal operation. In this mode, the relay only responds to normal operational messages, while test messages are ignored.
2. **ON/BLOCKED:** similar to the ON mode, but IEDs do not give output signals for tripping CBs, even if the protection algorithm indicates tripping.
3. **TEST:** used for testing purposes. In this mode, the relay will only respond to test messages and ignore normal operational messages.
4. **TEST/BLOCKED:** similar to the TEST mode, but no CB tripping signals can be produced. This may be useful for performing testing in energized and fully operating substations, to prevent unwanted CB tripping during test procedures.
5. **OFF:** the relay does not respond to any messages.

If the *Mod* of an LN and its LD are different, the largest of these values according to the enumeration given above will give the resulting *Beh* parameter. For example, if a LD has mode ON (LLN0.Mod.stVal = ON = 1) and one of its CB LNs has mode

TEST/BLOCKED (XCBR.Mod.stVal = TEST/BLOCKED = 4), the resulting LN behavior will be TEST/BLOCKED (XCBR.Beh.stVal = TEST/BLOCKED = 4) [12]. A full overview of LN and LD *Mod* combinations and resulting *Beh* parameters is given in Appendix A.

#### 4.4.2 Test Messages

To distinguish normal operational messages from messages being sent for test purposes, a test flag is included in the header of every GOOSE message [40]. SV messages can also be marked as test messages in a similar manner. An LD that is operating in TEST mode will publish GOOSE messages with the test flag activated. For example, if an LD is put in test mode by setting *Mod* = TEST and it receives SV messages with the test flag "True", it will process to the SV messages and output resulting GOOSE messages with the test flag "True" [39]. This can be used to separate normal operational messages from messages sent for test purposes [40].

#### 4.4.3 Mirroring of Control Information

A problem related to the BLOCKED test modes and test messages is that it is not possible to verify correct relay and breaker operation by external inspection since CBs are blocked from operating even in trip conditions. To solve this, a mirroring of control information is included in IEC 61850 Edition 2, meaning that there are two separate data sets indicating control information in each LN; *opRcvd* and *opOk* [40]. This is illustrated by example in Figure 4.3. Once a control message is received, the data object *opRcvd* is immediately activated and updated, meaning that information regarding the IED behavior is stored even if no output is given [8]. This data can be studied to detect whether a relay indicated trip, even though its LD was in a BLOCKED mode and hence did not output any trip signals. After the control message has been processed through the IED, the parameter *opOk* as well as a time stamp *tOpOk* will be activated and updated to indicate the subsequent action taken by the IED. [8].

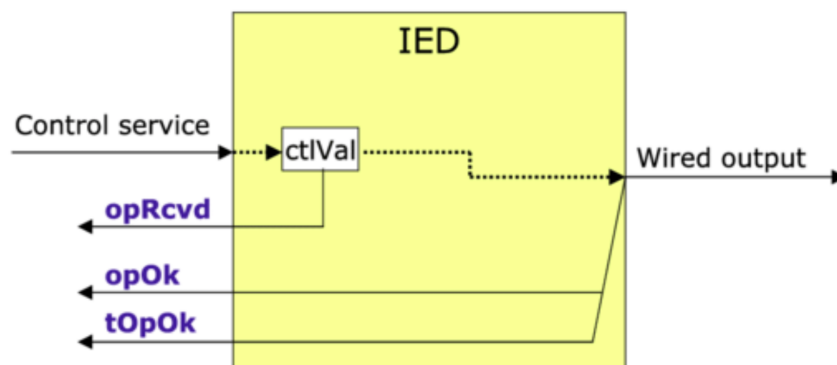


Figure 4.3: Mirroring of control information principle

Source: [8] - Apostolov (2018)

#### 4.4.4 Isolating Devices

In testing procedures for relay functionality in a complete substation, it is often wanted to isolate relevant components from the system to test individual components [8]. This can be done in a conventional substation using a hardwired test switch that allows the relay to be physically isolated from the substation environment, as individual current, voltage, and binary signals may be measured and applied [41]. By connecting test plugs from a test set to appropriate ports of the test switch, it is possible to isolate and test individual relays in conventional substations [41]. Similar possibilities for isolating devices is necessary for digital substations, but physical isolation is unpractical since disconnecting the Ethernet cable through which the relay is communicating will interrupt all of its communication. However, virtual isolation can be achieved by utilizing appropriate combinations of the IEC 61850 testing tools introduced above, with IED test mode and GOOSE and SV test messages as the main tools [8], [40].

### 4.5 Utility Testing Experiences

While the theory behind substation testing has been covered in this chapter, it is also useful to look at how utilities have experienced digital substation testing in practice. In theory, the IEC 61850 standard provides a lot of neat testing solutions, but it is not given that everything works as expected at this relatively early stage of digital substation development.

#### 4.5.1 Norway - Statnett Digital Substation Testing

Statnett, the transmission system operator in Norway, has installed a digital substation with process bus as a pilot project, intending to gain hands-on experience with these systems. Through this project, they have gained some experiences regarding testing of digital substations using IEC 61850, as described in the following paper [42]. By implementing protection and control equipment from three different vendors, it was detected that each vendor had a different implementation of test related messages at the point of testing. One vendor did not support SV test messages, another did not support GOOSE test messages, while the last vendor accepted both [42]. It was also discovered challenges related to the level of independence when testing various protective functionalities within a single physical component. It was shown that only one of the vendors allowed for setting the individual LDs of a physical IED independently in test mode, while the other two vendors only supported putting the entire physical device in test mode [42].

Another essential experience was related to the definition of GOOSE messages, which is typically performed during the engineering phase of the substation construction, as introduced in Section 2.8 [42]. During relay functionality testing, it may be necessary to utilize GOOSE messages that are used to control functionalities that are not used during normal operation. For example, it may be necessary to use an "Overcurrent start" GOOSE message to verify that relays are configured with correct thresholds, even though such a message may not be needed in normal operation. If a GOOSE message is not

defined during the substation engineering, it is not possible to utilize its corresponding functionality during later test procedures. Hence, it may be beneficial to consider testing operations already in the substation engineering phase [42].

### 4.5.2 France - Digital Substation Testing Experiences

”Postes Intelligents” is a French smart grid project where six utilities contribute to create a full IEC 61850 digital substation and gain experience on these systems [43]. All internal communication within the substation goes through a digital process and station bus, and no hardwired backup connections are added. The IEC 61850 Edition 2 test features described in this chapter were used for testing specific relay functionalities both during FAT and maintenance testing [43]. During the SAT testing phase, it was experienced that more work had to be done in the substation switchyard than in conventional test procedures, which introduces a few challenges. This requires coordination between engineers performing tests on outdoor cubicles in the switchyard and the personnel operating the station controller within the main control building [43]. Besides, the outdoor work is subject to weather conditions, which was solved using tent-like shelters around the control cubicles during testing.

### 4.5.3 Russia - Hydropower Process Bus

One of the generator-transformer units of the hydropower plant Nizhegorodskaya in Russia has been installed with an IEC 61850 process bus as a pilot project [44]. During the FAT procedures, testing of relay functionality was performed using a real-time digital simulator along with an OMICRON CMC 256 Plus relay test set. Through these tests, it was found that in busy situations with heavy network load, the transmission delay within the process bus became infeasible. The solution to this is to create virtual local area networks within the process bus network to separate the network load. Using this solution it is, for example, possible to separate GOOSE and SV messages into different networks to reduce the traffic on each component [44]. Loss of process bus time synchronization was also found to be a potential problem since this resulted in total inoperability of the protective relays. A solution to this is to have a strict focus on assuring redundancy in time synchronization equipment [44].

# Chapter 5

## Laboratory Equipment, Setup and Software

A vital part of this thesis is to provide documentation of how a digital substation environment may be established in the NTNU relay laboratory. Hence, this chapter provides an overview of the laboratory equipment to be used along with its associated software, while details about the configuration of each component are given in Chapter 6. Also, an overview of the laboratory Ethernet connections is given in this chapter. Well-established equipment like an OMICRON relay test set and ABB distance relay is to be used, and these can be utilized to illustrate fundamental digital substation testing principles in a practical manner. A more in-depth description of the NTNU relay laboratory as installed with conventional equipment in 2014 is given in the following former NTNU master thesis [45].

### 5.1 Relay Test Set



Figure 5.1: OMICRON CMC 356 relay test set  
Source: [9] - OMICRON (2013)

An OMICRON CMC 356 relay test set with IEC 61850 compatibility, as shown in Figure 5.1, is utilized to inject secondary side currents and voltages, thereby simulating primary side operating conditions for testing purposes. The test set can be used for both conventional and digital substation testing, and its digital communication does not affect the conventional methods for protection testing [10]. The front panel is seen in Figure 5.1 where the input and output ports can be used to transmit analog signals for conventional testing. However, for the generation of GOOSE and SV messages, one of two Ethernet ports, called ETH1 and ETH2, on the back panel is utilized. The OMICRON test set is also used as the master clock for time synchronization in the laboratory setup, meaning that the time settings of the relay are controlled by the test set clock.

### 5.1.1 OMICRON Tools and Modules

To fully utilize a CMC test set, OMICRON provides a set of software tools that adds a range of necessary functionalities. The main software is called OMICRON Test Universe and is operating in a laboratory computer that is connected to the test set through an Ethernet connection [46]. Within Test Universe, a wide range of modules and tools are provided to facilitate relay testing, and the main digital substation configuration modules include the following.

- **Test Object Module:** used to define test objects and their nominal values [47].
- **Hardware Configuration Module:** can be used for mapping physical of ports in the test set to the logical test set functionalities [47].
- **GOOSE Configuration Module:** a tool that is used to configure GOOSE subscription by creating mappings between received GOOSE messages and test set functionalities [12]. Mappings for output GOOSE messages published by the test set can also be created using this tool.
- **Sampled Values Configuration Module:** used for configuring SV messages to be published from a test set, from which a total of three simultaneous SV streams can be produced [12].

A conventional test set utilizes binary input and output ports to send and receive control and status information. The test set works in the same way for GOOSE messages, but the binary inputs are mapped to GOOSE messages through the GOOSE Configuration Module [10]. The mapping principle is similar to the ones described in Section 2.5.2, creating a logical bridge between analog and digital signals and allowing other OMICRON test modules to operate in the same way for conventional and digital substations [10].

Similarly, OMICRON has provided a logical connection between conventional and digital injection of current and voltage samples, as configured using the SV Configuration Module. The test set produces analog and digital outputs simultaneously when SV streams are active, and the other test modules are not aware of whether digital messages are produced or not. This means that analog output signals are available through the front panel ports in addition to the published SV stream, which allows for testing conventional and digital substation components simultaneously.



### 5.1.2 Protection Testing With Subscribed GOOSE Messages

Figure 5.2 shows the logical flow of an operation where an IED is sending GOOSE messages that are mapped to the binary input ports of an OMICRON test set. It is assumed that a test set has sent measurement data to an IED, and is waiting for responding GOOSE control messages [10]. The box to the left shows a physical IED, containing an LD called "PROT" that contains its protective functionalities. An LN "PTRC1" that contains start and trip information is given, containing data "Tr.General" for tripping, and "Str.General" for starting functions. This information is gathered in a GOOSE message that is published to a substation Ethernet communication bus. This is received by a test set that is configured to subscribe to this message. When the IED receives the GOOSE message, its information is mapped onto binary analog signals, one for starting and one for tripping. This is sent to the test modules applied from OMICRON Test Universe in the laboratory computer for further assessment of the received information [10].

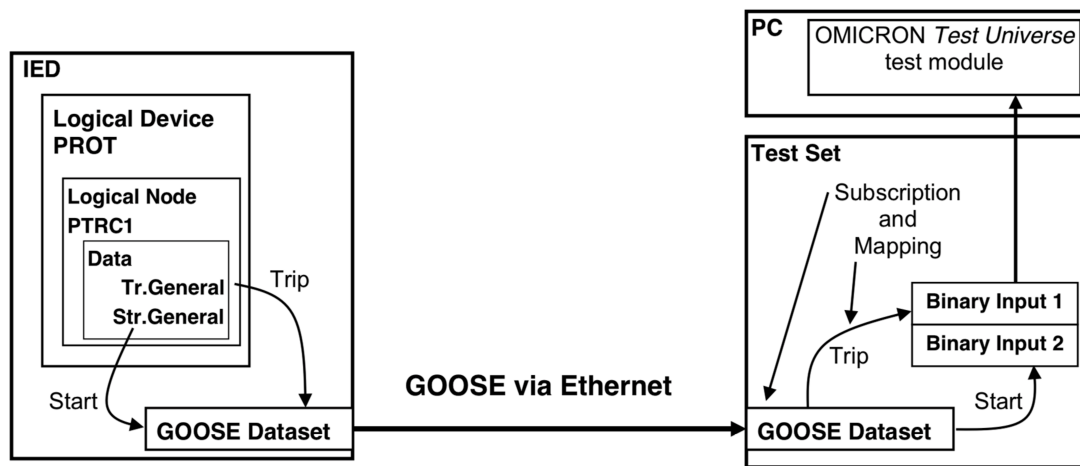


Figure 5.2: GOOSE mapping for test set input

Source: [10] - OMICRON (2014)

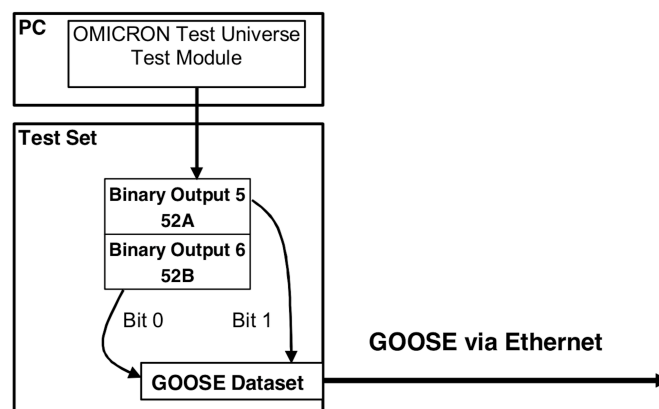


Figure 5.3: GOOSE mapping for test set output

Source: [10] - OMICRON (2014)

An opposite mapping is needed if a test set is used for simulating an IED response by

inject GOOSE messages to the network, and this is illustrated in Figure 5.3. Knowing the configuration of the test set and what the binary signals from each output port represents, as well as the structure of the GOOSE dataset, the analog output from the test set can be configured to activate appropriate bits in a GOOSE message for correct mapping [10].

### 5.1.3 Test Set GOOSE Subscriptions

A key part of using a relay test set effectively in a digital substation environment is the correct configuration of GOOSE subscriptions [10]. There are several ways of achieving this, and the four most used methods are illustrated in Figure 5.4. Note that the enumeration in the arrows of the figure corresponds to the method descriptions given below. The IEC 61850 engineering tools defined in Section 2.8 facilitates the process of configuring GOOSE subscriptions, as SCL files may contain information about all configured IEDs and GOOSE messages within the substation [28].

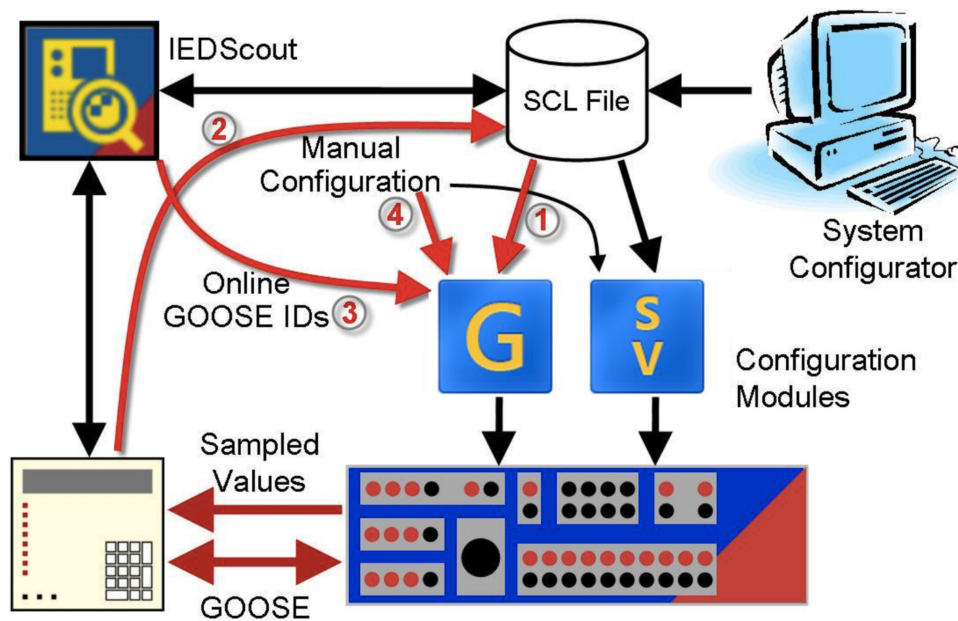


Figure 5.4: GOOSE configuration, four methods

Source: [10] - OMICRON (2014)

1. **Using SCL file from the IEDs self-description:** if no SCD files are available for a substation, OMICRON IEDScout is a tool that can be used to extract CID files from IED. By connecting to the IED, IEDScout can extract the self-description CID file that is put into the IED by its vendors and shows its configuration according to its capabilities and available functionalities [10]. This CID file may be imported into the OMICRON GOOSE Configuration Module to configure the test set GOOSE subscriptions.
2. **GOOSE sniffing on the process bus:** IEDScout can also be used to detect GOOSE messages flowing in an Ethernet bus, which is useful if no SCL files are available. As the IEDScout detects GOOSE messages within the network, they

appear in the GOOSE Configuration Module, which allows for configuring a subscription to these messages [10].

3. **Manual subscription configuration:** this is the most basic method, and is often time-consuming and demands insight into the details of how GOOSE communication works. A GOOSE message can be configured from scratch by manually typing both its header parameters and dataset structure, and if this is done identically to the GOOSE messages published by an IED, this can be used to set up a subscription to its GOOSE messages [10].
4. **Using SCL files from the substation description:** this is often the preferred method for full substations. As discussed in Section 2.8, SCD files describing the entire substation should be created during the substation engineering process. These SCD files can be imported into OMICRON Test Universe, which makes information about all configured GOOSE messages available for the test set [10]. This can be used by OMICRON Configuration Module to set up GOOSE subscriptions in the test set.

### 5.1.4 Performing Test Procedures in OMICRON

Secondary side injection may be performed using an OMICRON test set by utilizing the various test modules provided by the Test Universe software [48]. A range of modules may be included in a single test document to simplify the testing process, from which they may be stored, monitored, and controlled. After a test procedure has been performed using these test modules, the test set automatically generates a test report with an overview of the applied testing conditions and observed results. This includes both the input values applied by the OMICRON and the response detected from the relay. The test modules to be used in later laboratory experiments are described in this section.

#### QuickCMC Test Module

QuickCMC is the most basic test module found in Test Universe and allows for control of the front panel outputs of the test set [49]. This includes independent simultaneous control of each current and voltage output, as well as all binary output ports. The results of QuickCMC tests are given in an automatically generated test report.

#### Advanced Distance Protection Test Module

Advanced Distance Protection is a test module within Test Universe that is specialized for applying fault situations aimed at testing test distance relays, and allows for generating different fault types at specified points in the impedance plane [50]. This is typically done by defining a series of test shots in the impedance plane, which are translated into current and voltages and automatically injected by the test set as the module is activated. After the tests are finished, a report of the results is automatically provided by this test module [50]. The zones of protection defined in the OMICRON Test Object Tool are indicated in the impedance plane, which makes it easy to define test shots at various parts of each zone of protection.

## State Sequencer

State Sequencer is a flexible test module that can be used to define a range of steady-state situations along with conditions for the transition from one state to the next [47]. It is also possible to activate latching binary outputs, where the binary output persists after the test module has been closed. This is utilized in the laboratory experiments to inject binary output signals from the test set while simultaneously injecting current and voltage measurements using the Advanced Distance Module.

## 5.2 Relay

In the laboratory experiments, an ABB RED 670 line differential and distance protection relay is to be used for testing purposes. This IED is able to receive SV messages sent over a process bus according to part 9-2 of the IEC 61850 standard, as well as GOOSE messages [9]. The relay may be configured either using PCM 600 software from the laboratory computer and transferring the settings through Ethernet or by using the local HMI directly on the relay front panel [51]. The relay HMI with its buttons and functionalities is illustrated in Figure 5.5.

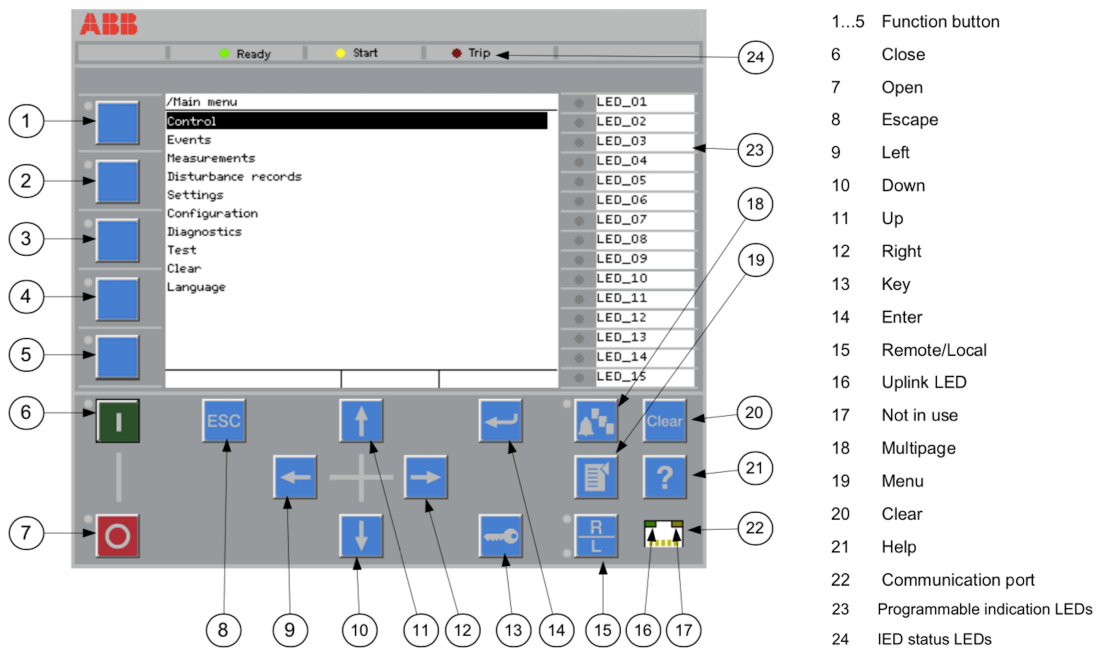


Figure 5.5: ABB RED 670 relay front panel and HMI

Source: [9] - ABB (2016)

Communication between the laboratory computer and relay for configuration through PCM 600 goes through the Ethernet port in the front panel of the relay [51]. However, the communication to the process bus goes through the two fiber ports located on the back panel of the relay; ports AB and CD. Both port AB and CD support GOOSE communication as described in IEC 61850-8-1, but only port CD can be used for SV

communication as described in IEC 61850-9-2 [51]. For a more in-depth description of the relay, please refer to the RED 670 application and commissioning manuals [9], [51].

### 5.2.1 PCM 600 Relay Configuration

Digital ABB relays are typically configured using PCM 600 to create a CID file that describes the specified relay configuration, as introduced in Section 2.8, which is transferred to the IED over Ethernet. PCM 600 projects are organized in a tree-structure, where various substations, voltage levels, and bays may be defined. IEDs can be added to each bay, and configuration of each IED may be performed in "Online" mode if an Ethernet connection is established between the computer and the relay front port. Note that the IP address of the relay front port is needed in order to connect to a relay and activate online configuration, which can be found by navigating in the relay HMI as described in Figure 5.5 (*Configuration* → *Communication* → *Ethernet Configuration* → *FRONT:1*). PCM 600 is then able to read the available relay capabilities, which allows for a simplified configuration process. The configuration tools for an online IED in PCM 600 can be found by right-clicking on the IED, and the main tools are described below.

- **IED Configuration:** the main tool for configuring each IED, containing some important sub-tools.
  - **Hardware Configuration:** used for viewing and modifying the hardware input and output modules located on the relay front panel [52]. Note that both OMICRON Test Universe and ABB PCM 600 have a Hardware Configuration Tool, but these are different and independent tools.
  - **Communication:** can be used to modify the Ethernet communication ports of the relay, as well as to activate GOOSE publishing.
- **Application Configuration:** a graphical tool that is used to configure the functionality of a relay [52]. This is done by adding functional blocks available in the IED library as well as input and output channels as defined in the Hardware Configuration and creating logical connections between them.
- **Parameter Setting:** used to inspect and modify the parameters of each individual IED functionality [52].
- **Signal Matrix:** used to create logical connections between source and target objects in the IED Configuration, for example, between physical ports and function blocks [52]. This includes binary inputs and outputs, analog inputs, and received GOOSE messages.
- **IEC 61850 Configuration:** may be used to establish the IEC 61850 configuration of a relay by creating GOOSE data sets, configuring GOOSE subscriptions within the project IEDs, and viewing GOOSE inputs.

After the PCM 600 configuration is finished, the configuration can be sent to the relay by right-clicking on the IED in the PCM 600 project and activating "Write to IED". It is also possible to do the reverse communication by activating "Read from IED" if it is wanted to obtain the configuration from a relay to the PCM 600 tool.

## 5.3 Laboratory Computer

A laboratory computer is needed to operate the OMICRON Test Universe software for test set configuration, as well as PCM 600 for relay configuration. Also, Wireshark or similar software should be installed if process bus network traffic is to be analyzed. A standard Dell OptiPlex 7050 computer is used in the laboratory setup of this thesis, installed with the software mentioned above. Communication between the laboratory computer and both the test set and relay configuration goes through an Ethernet cable connection.

### 5.3.1 Wireshark

Wireshark is a network traffic analysis tool that can be used to analyze the traffic of an Ethernet network by intercepting all messages passing through the network and displaying it in a readable format, a process that is called packet sniffing [22], [53]. Hence, before a test procedure is started, Wireshark may be applied if the subsequent network traffic is to be analyzed. This can be used to ensure that GOOSE and SV messages are published correctly on the network, and to detect whether messages are lost during transmission [38]. Wireshark is installed in the laboratory computer, and an Ethernet connection between the computer and the process bus allows for analysis of the process bus traffic.

### 5.3.2 SV Message Analysis in Wireshark

```

▼ IEC61850 Sampled Values
  APPID: 0x4000
  Length: 108
  Reserved 1: 0x0000 (0)
  Reserved 2: 0x0000 (0)
  ▼ savPdu
    noASDU: 1
    ▼ seqASDU: 1 item
      ▼ ASDU
        svID: ABB_MU0101
        smpCnt: 209
        confRef: 1
        smpSynch: none (0)
        seqData: 00000000000000000000000000000000

```

Figure 5.6: SV message as seen by Wireshark

Wireshark can be used to detect individual GOOSE and SV messages and study their content, and an SV message as seen by Wireshark is shown in Figure 5.6. An important part of the SV header is the parameter *APPID* that indicates the application type of the SV message. Note that SV messages have no test flag, as introduced in Section 4.4.2, that is directly visible in Wireshark. However, the parameter *Reserved 1* can be inspected to see whether the message has its test flag activated or not [54], [55]. This is a quality flag

with a fixed length of two bytes and has the value 0x0000 if the SV message is in normal operation mode. However, if the most significant byte of the *Reserved 1* parameter is set to 1, this indicates that the SV message has been sent from a test device [55]. This corresponds to the bits 1000000000000000, which translates into the hexadecimal number 0x8000 or the decimal number 32 768. Hence, the test flag activation of an SV message can be observed in Wireshark if the value of *Reserved 1* is 0x8000.

The section *savPdu* shows the contents of a SV message, where *svID* is a unique identifier of each SV message and is the main parameter used to distinguish SV messages from each other and configure SV subscription. The parameter *smpCnt* is a counter of each SV message and is incremented for each message until being reset cyclically. All data described until this point are referred to as the header of the SV message, describing its overall information. The parameter *seqData* contains the current and voltage measurement data contained in the SV message in a standardized format. This is called the payload of the SV message. Note that this is all zeros if the publishing of SV messages from OMICRON has been activated, but no test module has been applied.

### 5.3.3 GOOSE Message Analysis in Wireshark

No.	Time	Source	Destination	Protocol	Length
4	5.502446	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	229
8	8.880663	AbbAutom_1a:66:80	Iec-Tc57_01:00:00	GOOSE	274
14	15.502737	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	229
19	18.880787	AbbAutom_1a:66:80	Iec-Tc57_01:00:00	GOOSE	274
24	25.502517	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	229
27	28.880569	AbbAutom_1a:66:80	Iec-Tc57_01:00:00	GOOSE	274
32	35.502603	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	229
36	38.880660	AbbAutom_1a:66:80	Iec-Tc57_01:00:00	GOOSE	274
40	45.502683	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	229
47	48.880695	AbbAutom_1a:66:80	Iec-Tc57_01:00:00	GOOSE	274

```

> Frame 4: 229 bytes on wire (1832 bits), 229 bytes captured (1832 bits) on interface 0
> Ethernet II, Src: AbbAutom_1a:66:80 (00:00:23:1a:66:80), Dst: Iec-Tc57_01:00:03 (01:0c:cd:01:00:03)
  GOOSE
    APPID: 0x0004 (4)
    Length: 215
    Reserved 1: 0x0000 (0)
    Reserved 2: 0x0000 (0)
    gosePdu
      gocbRef: AA1J1Bay1A1LD0/LLN0$G0$gcbTrip
      timeAllowedtoLive: 11000
      datSet: AA1J1Bay1A1LD0/LLN0$Trip
      goID: AA1J1Bay1A1LD0/LLN0.gcbTrip
      t: Jun 9, 2018 13:31:43.767260611 UTC
      stNum: 1327
      sqNum: 1083
      test: False
      confRev: 100
      ndsCom: False
      numDatSetEntries: 18
    allData: 18 items
      Data: boolean (3)
        boolean: False
      Data: boolean (3)
  
```

Figure 5.7: GOOSE message as seen by Wireshark

A GOOSE trip message as defined in Section 6.2.1 is shown in Figure 5.7, showing how Wireshark interprets this. In the top window of the figure, all messages detected on the process bus are listed. A filter "goose" has been added in order to filter out SV messages and show GOOSE messages only. From here, the packet number, timestamp of when the packet was received, as well as source and destination of each package is shown. By clicking on a message, its details are given as seen in the lower window of the figure.

The details of the GOOSE message shows that it contains the parameters *APPID* and *Reserved 1*, both with the same purpose as for SV messages. The *goosePdu* section shows information about the GOOSE message, located in the header of the GOOSE message [56]. The *allData* section shows the data contained within the payload of the GOOSE message, and its contents can be opened and analyzed further. The GOOSE payload has no fixed structure like SV messages, but rather corresponds to the GOOSE dataset defined for each message. Note that it is possible to detect whether or not the test flag of a GOOSE message is activated, as discussed in Section 4.4.2, by inspecting the *test* parameter in *goosePdu*.

## 5.4 Process Bus

The laboratory process bus consists of a Siemens RUGGEDCOM RSG 2200 Ethernet switch (NTNU number: P08-0608), which is the main component of the laboratory communication. The switch has four high-speed fiber ports and seven traditional Ethernet ports for external communication. The OMICRON test set applies SV and GOOSE messages to this process bus through Ethernet cables, while the relay is connected through high-speed fiber. Besides, Wireshark has an Ethernet connection between the laboratory computer and process bus to detect all network traffic flowing through the process bus. Note that all GOOSE and SV messages are available on all ports of the Ethernet switch, as they utilize the Ethernet broadcast mechanism introduced in Section 2.5.1.

## 5.5 Laboratory Ethernet Connections

All Ethernet connections for communication between the laboratory equipment are logically illustrated in Figure 5.8. Traditional Ethernet cables are illustrated with red lines, while the green lines illustrate high-speed fiber cables. The fiber ports AB and CB of the relay are connected to the process bus fiber ports to transfer SV and GOOSE messages between the process bus and the relay. In addition, an Ethernet connection between its front port and the laboratory computer allows for transferring configuration files between PCM 600 and the relay. The laboratory computer has a connection to the process bus, where Wireshark is applied to sniff network traffic. A connection from the computer to the OMICRON test set allows for controlling the test set using the Test Universe software. The test set is also connected to the process bus to inject GOOSE and SV messages to the process bus, as well as receiving GOOSE messages.



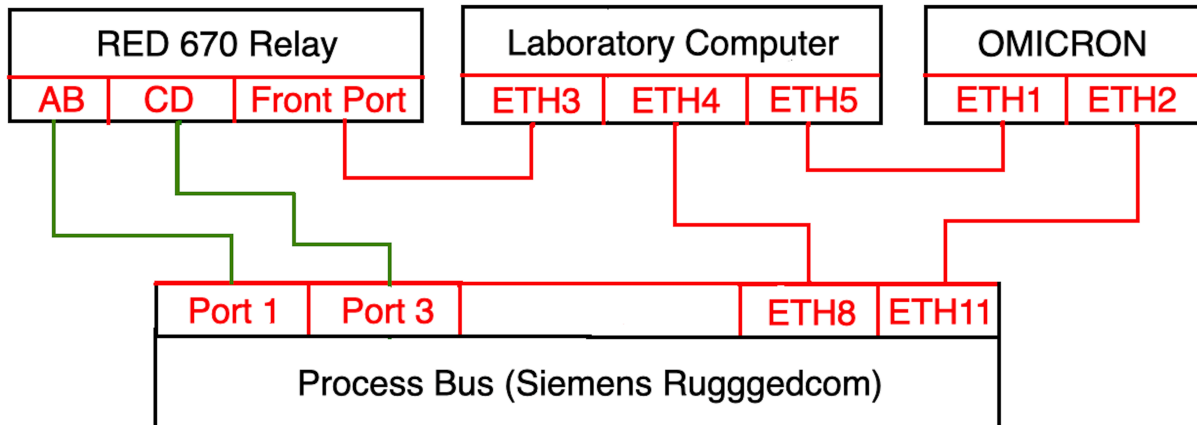


Figure 5.8: Laboratory Ethernet connections

Note that for a direct Ethernet connection between the laboratory computer and the relay to work, it is necessary that they have similar IP addresses. The IP address of the relay front port can be found using the relay HMI (*Configuration* → *Communication* → *Ethernet Configuration* → *FRONT:1*). The Ethernet adapter in the computer used for this connection has to be configured to have an IP address according to the IP address and subnet mask in the relay front port. For example, if the relay front port has IP address 192.168.10.16 and subnet mask 255.255.255.0, the PC Ethernet adapter must be configured to have a fixed IP address of 192.168.10.X and subnet mask 255.255.255.0. Note that X may be any number between 0 and 255, but not equal to any other IP addresses in the network. The computer Ethernet adapter settings can be found in the computer settings (*Computer Settings* → *Network and Internet* → *Change adapter options* → *Right click on the Ethernet adapter connected to the relay front port* → *Properties* → *Internet Protocol Version 4 (TCP/IPv4)* → *Use the following IP address:*).



# Chapter 6

## Laboratory Configuration

This chapter describes suggested configurations of the laboratory equipment introduced in the previous chapter, and is to be used in the laboratory experiments in following chapters. These configurations show some of the fundamental principles introduced in previous chapters in practice and provides the communication needed for relay testing as introduced in Figure 4.2. An illustration of the general logic behind the laboratory setup is given in Figure 6.1.

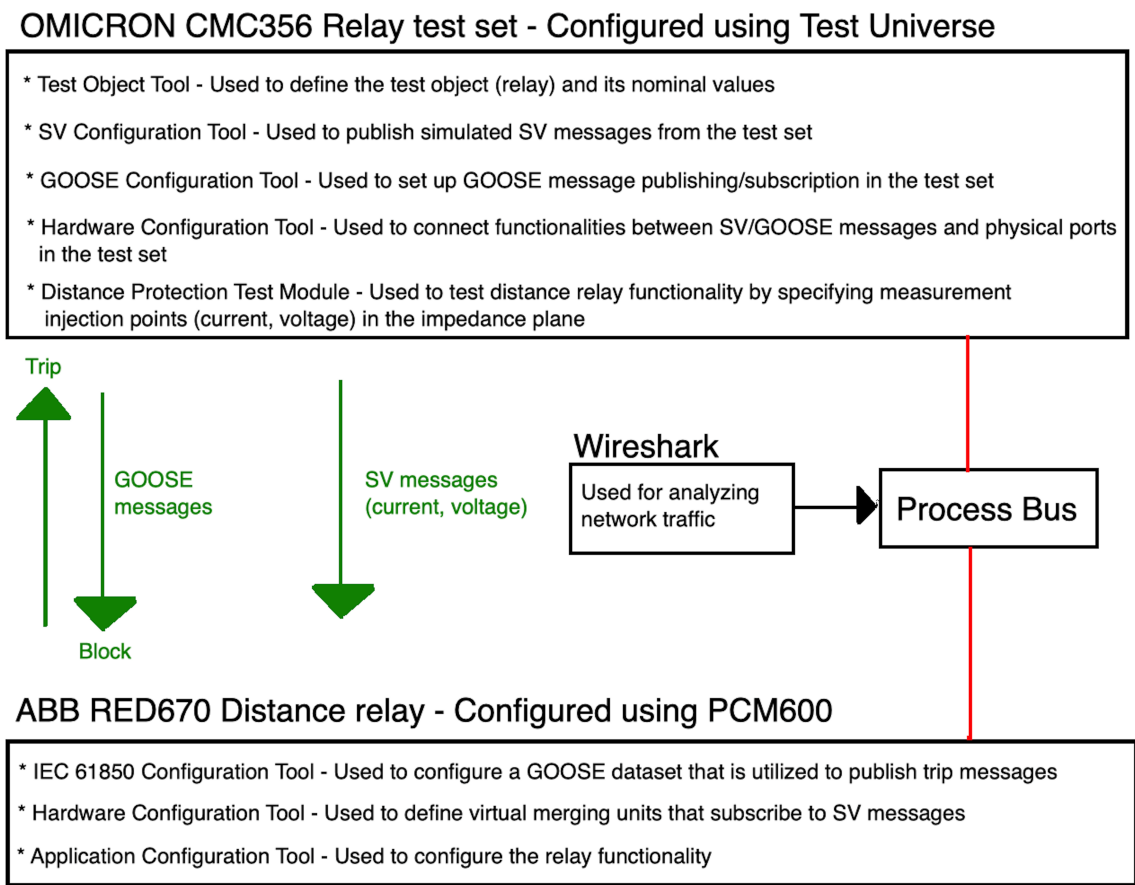


Figure 6.1: Principle illustration of the laboratory setup

The OMICRON CMC 356 relay test set is to be configured using the OMICRON Test Universe software as described in Section 5.1.1, while the ABB RED 670 distance relay is to be configured using PCM 600 as described in Section 5.2.1. The communication between the test set and the relay goes through an Ethernet network, as described in Section 5.5. Wireshark is connected to the router in order to monitor all network traffic. SV messages are going to be sent from the test set to the relay, while GOOSE messages flow in both directions, as trip messages are sent from the relay to the test set and blocking messages are simulated from the test set and sent to the relay. In-depth descriptions of each of the utilized configuration tools are given in the following sections.

## 6.1 Test Object Tool

The image shows two side-by-side configuration windows from the Test Object Tool. The left window is titled 'Device Settings' and contains the following fields:

- Device:** Name/description: RED670, Manufacturer: ABB, Device type: Distance Relay, Device address: (empty), Serial/model number: (empty), Additional information 1: (empty), Additional information 2: (empty).
- Nominal Values:** Number of phases: 3 (selected), f nom: 50,000 Hz, V nom (secondary): 264,000 V (L-L), 152,420 V (L-N), V primary: 132,000 kV (L-L), 76,210 kV (L-N), I nom (secondary): 1,000 A, I primary: 1,000 kA.
- Substation:** Name: Substation, Address: (empty).
- Bay:** Name: Bay, Address: (empty).
- Overload Detection Sensitivity:** High, Custom (0,0000 s), Low, Off (selected).
- Residual Voltage/Current Factors:** VLN/ VN: 1,732, IN / I nom: 1,000.
- Limits:** V max: 1,000 kV (L-L), I max: 100,000 A.
- Debounce/Deglitch Filters:** Debounce time: 3,000 ms, Deglitch time: 0,000 s.

The right window is titled 'Distance protection parameters' and contains the following fields:

- System Parameters:** Line length: 15,30  $\Omega$ , Line angle: 78,69  $^\circ$ , PT connection: at line, CT starpoint: Dir. line.
- Tolerances:** Tol. T rel.: 5,000 %, Tol. T abs. +: 50,00 ms, Tol. T abs. -: 0,000 s, Tol. Z rel.: 5,000 %, Tol. Z abs.: 50,00 m $\Omega$ .
- Grounding Factor:** Mode: kL, kL magnitude: 1,000, kL angle: 0,00  $^\circ$ . Checkboxes for 'Calc. with RE/RL and XE/XL' and 'Separate arc resistance' are present.

Figure 6.2: Test Object configuration

To configure general parameters of the object to be tested using OMICRON, the Test Object Tool found within Test Universe is used. The most important parameters include system frequency and the number of phases in the system. Besides, primary and secondary side current and voltage are specified, which gives the VT and CT ratio of the system. This specifies the relation between the secondary side values applied by OMICRON test modules and the primary side measurement values that are sent to the relay as SV messages. The Test Object settings used in this laboratory setup is shown in the left window in Figure 6.2, specifying a CT ratio of 1000/1 and VT ratio of 500/1. Proper configuration of the distance relay settings is also needed for the distance protection test module, as seen to the right in Figure 6.2. The line length in ohms (secondary side value)

and line angle is specified, along with tolerances and grounding factors. The relay zones of protection are also specified using a geometric tool in the "Zone Settings" tab.

## 6.2 Sampled Value Configuration

To simulate and apply current and voltage measurements in a digital substation environment, the test set must be configured to publish streams of SV messages, as introduced in Section 2.5.4. The SV messages may then be received by the relay by making it subscribe to them, which allows for the processing of the measurements through the relay protection algorithm.

### 6.2.1 Publisher - Test Set

The OMICRON is configured to publish SV messages using its Sampled Value Configuration Module [48]. As seen in Section 2.4, SV services are defined in part 7-2 of the IEC 61850 standard, and their transmission over Ethernet networks is defined in part 9-2. Since no SCD file is available for the laboratory setup, a manual configuration of SV messages is necessary, which can be done by setting the following parameters.

- **Sampled value ID:** this is used for unique identification of an SV stream, and must be equal to the identifier used in the relay configuration for correct publisher/subscriber connection.
- **Multicast MAC address:** a unique MAC address is needed to publish SV messages onto the Ethernet network successfully.
- **Application ID:** an identifier that is used to determine the application of each SV message.
- **VLAN ID:** larger digital substation communication networks are typically divided into various virtual networks (VLANs). This identifier is used to make sure that the SV messages are published on the correct VLAN [48].
- **VLAN priority:** this can be used to define how the published SV messages should be prioritized within the network compared to other messages.
- **Simulation flag:** this activates the test flag in the published SV messages, as discussed in section 4.4.2.
- **Ethernet port:** the OMICRON CMC 356 test set is installed with two Ethernet ports, ETH1 and ETH2, and one of these has to be selected to output the generated SV messages. Note that this setting is found in the "General" tab [48].

The SV configuration used in this laboratory setup is given in Figure 6.3. Once these parameters have been set, the configuration can be applied to the OMICRON test set for application by pressing "Apply Configuration". When this is done, the test set immediately starts to publish digital SV messages. If no test module has been started to inject current and voltage signals, empty SV messages are produced and published to

the process bus. Note that the simulation flag is set to "Normal" in the main laboratory configuration, but is set to "Simulated" using the drop-down menu in later experiments to explore SV test messages. It is possible to publish up to three simultaneous SV streams, which may be done by enabling simulation from each of the three SV tabs.

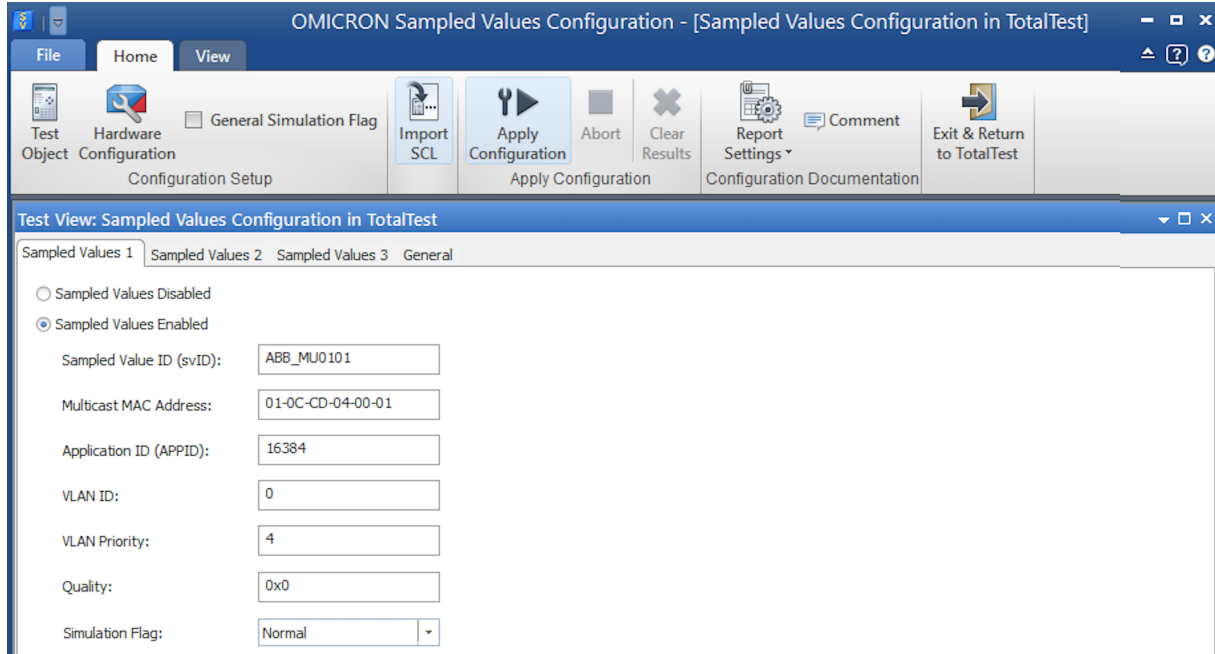


Figure 6.3: Test set SV configuration

Appropriate settings of the analog output signals in OMICRON Hardware Configuration is needed to complete the publishing of SV messages. This is used to configure the output current and voltage signals that are to be mapped to SV messages and make sure that these correspond to phase voltage and line current for each phase, as illustrated in Figure 6.4.

Global Hardware Configuration													
General		Analog Outputs				Binary / Analog Inputs		Binary Outputs		DC Analog Inputs		Time Source	
Display Name	Connection Terminal	CMC356 V A				CMC356 I A							
		1	2	3	N	1	2	3	N				
VL1-E		X											
VL2-E			X										
VL3-E				X									
<b>IL1</b>						X							
IL2							X						
IL3								X					

Figure 6.4: OMICRON analog output Hardware Configuration

### 6.2.2 Subscriber - Relay

IEDs have to be configured to subscribe to appropriate SV messages to make sure that they receive SV messages generated by the test set. This can be done using the PCM 600 Hardware Configuration Tool, where the relay can be configured to receive SV streams by assigning virtual merging units, as introduced in Section 2.5.1, to its software slots (s921-s924) [9]. This assigns a virtual MU to the relay, which means that the relay interprets the SV messages received from the test set as if they were produced by a physical MU in a substation. The laboratory configuration is given in Figure 6.5, where two merging units are defined; MU1 4I + 4U and MU2 4I + 4U.

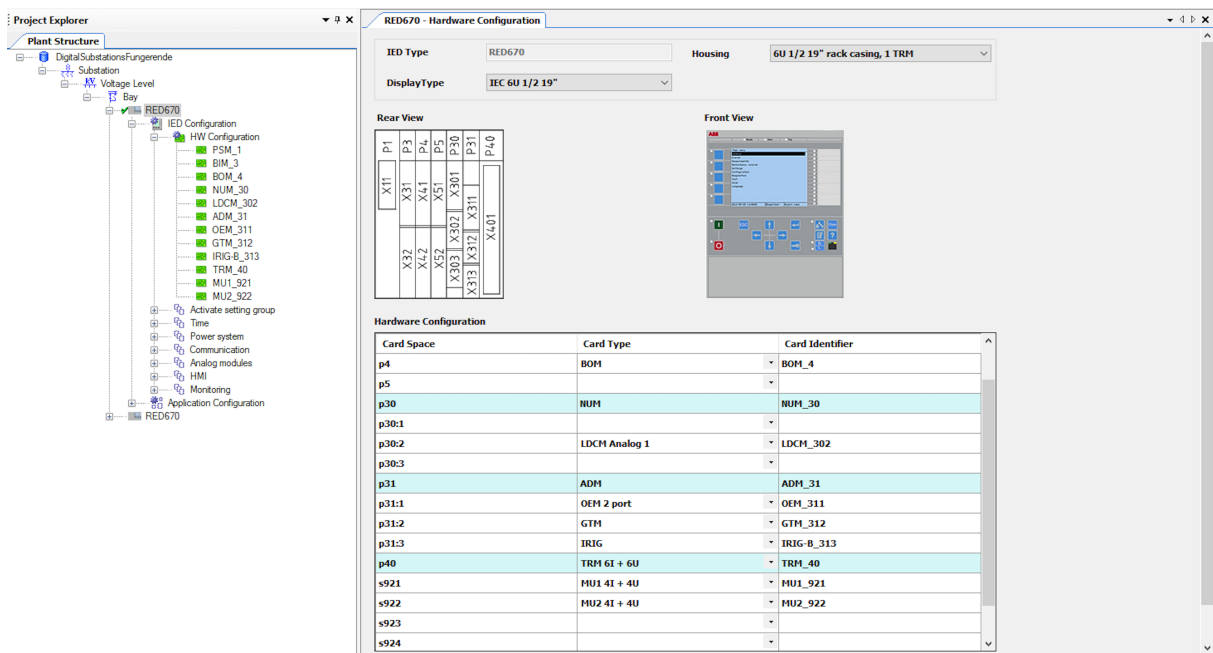


Figure 6.5: Relay Hardware Configuration

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
✓ MU1_921					
✓ SVId		ABB_MU0101		10	34 characters
✓ SmplGrp		0		0	65535
✓ NAMEI1		11			13 characters
✓ CTStarPoint1		ToObject			
✓ NAMEI2		12			13 characters
✓ CTStarPoint2		ToObject			
✓ NAMEI3		13			13 characters
✓ CTStarPoint3		ToObject			
✓ NAMEI4		14			13 characters
✓ CTStarPoint4		ToObject			

Figure 6.6: Merging unit Parameter Setting

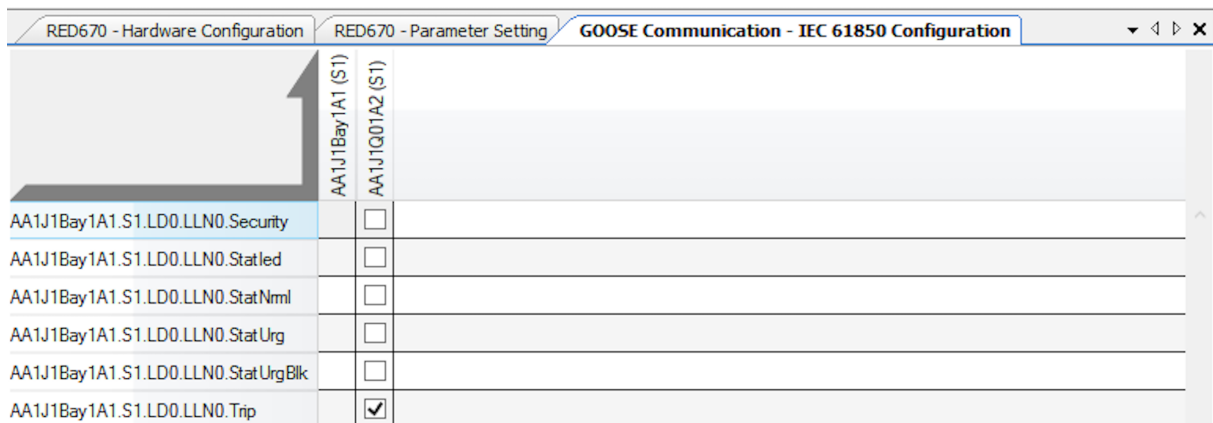
The next step is to modify the Parameter Setting of each of the defined MUs, as illustrated in Figure 6.6. The most critical parameter is the *SVID*, which has to be identical to the sampled value ID of the SV stream published by the test set if the relay is to subscribe to its generated measurement signals.

## 6.3 GOOSE Configuration of Trip Messages

Once the SV publisher/subscriber communication has been configured, it is possible to apply current and voltage measurements from the test set to the relay. The next step in the communication configuration is to allow the test set to respond with GOOSE trip messages, which the test set may subscribe to determine the relay response.

### 6.3.1 Publisher - Relay

The relay can be configured to send GOOSE messages, as described in Section 2.5.3, using the PCM 600 IEC 61850 Configuration Tool. This gives an overview of the available GOOSE datasets, as shown in Figure 6.7, where a trip message has been created in addition to the standard GOOSE datasets in the relay.



	AA1J1Bay1A1 (S1)	AA1J1Q01A2 (S1)
AA1J1Bay1A1.S1.LD0.LLN0.Security	<input type="checkbox"/>	
AA1J1Bay1A1.S1.LD0.LLN0.StatIed	<input type="checkbox"/>	
AA1J1Bay1A1.S1.LD0.LLN0.StatNml	<input type="checkbox"/>	
AA1J1Bay1A1.S1.LD0.LLN0.StatUrg	<input type="checkbox"/>	
AA1J1Bay1A1.S1.LD0.LLN0.StatUrgBlk	<input type="checkbox"/>	
AA1J1Bay1A1.S1.LD0.LLN0.Trip	<input checked="" type="checkbox"/>	

Figure 6.7: GOOSE dataset overview

A new dataset can be created by right-clicking in the dataset menu. A name must be given to the dataset, as well as a location in the dataset structure of the substation as described in Section 2.6. The trip message used in the laboratory setup is created, as shown in Figure 6.8, with the name "Trip" and located in the LN "LLN0" of the relay. This gives a full GOOSE message name that includes its substation, bay, LD and LN location, as well as the defined GOOSE message name. Hence, the GOOSE name structure is identical to the principles introduced in Section 2.7.



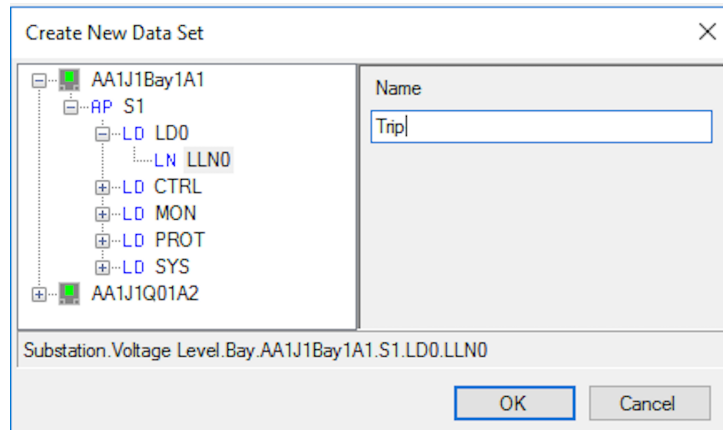


Figure 6.8: Creating a new trip GOOSE dataset

The new GOOSE dataset is empty at first, and can be filled by right-clicking on the dataset and clicking "Details". This unveils the data structure of all available substation components and allows for creation of customized GOOSE messages. Figure 6.9 shows how the laboratory GOOSE trip message is created by including all operational data attributes related to the relay protection functionality. The GOOSE message now contains a general trip signal, trip signals for each phase, a quality bit and a timestamp for each of the three zones of protection.

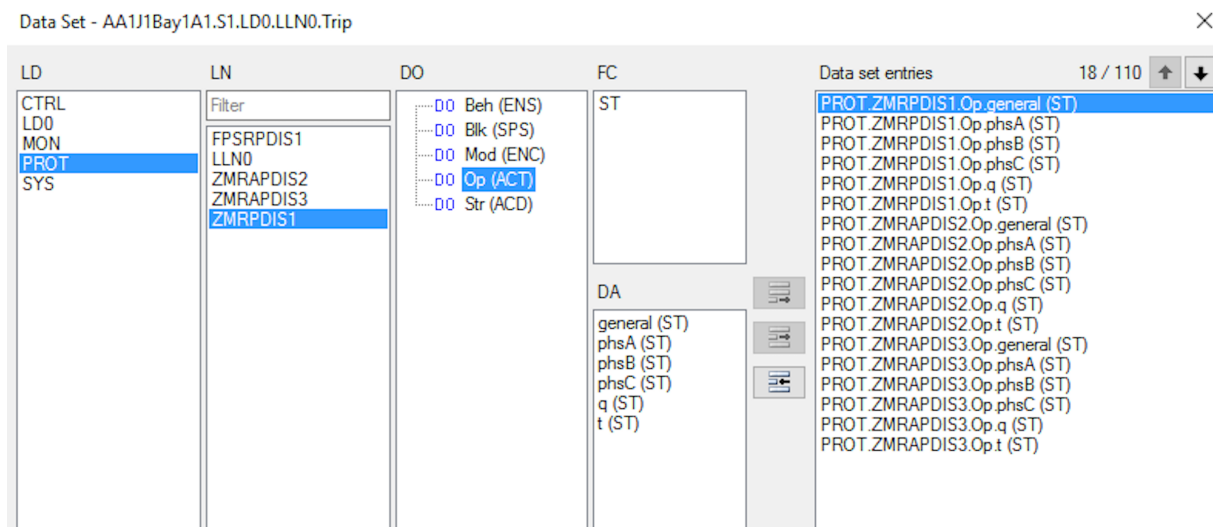


Figure 6.9: Modifying GOOSE dataset contents

Note that the data object names are structured as discussed in Section 2.7 and that the protection functionality LNs added to the GOOSE message corresponds to the functional blocks that are to be defined in Section 6.5. This also shows the IEC 61850 data modeling as introduced in Section 2.6, where each protective functionality has a LN (*ZMRPDIS1*), which has DOs (*Op*) that contain operational data. The DOs are further structured into DAs (*general*), which contains the actual data in a standardized way. Each DA belongs to a functional constraint (*FC*), and the data used in the figure are status attributes of type ST.

The IEC 61850 Configuration Tool is used to finalize the GOOSE trip message publishing and is accessed by right-clicking on the appropriate relay in the PCM 600 project structure. By selecting the "GOOSE Controls" tab in this tool, GOOSE message subscription within a substation may be configured. All GOOSE datasets from the previous dataset tab appear in this menu, where GOOSE subscriptions can be viewed and modified. A problem that was experienced during the laboratory experiment was that the relay did not publish GOOSE messages unless another IED was configured to subscribe to this message. This was solved by creating an additional IED in the PCM 600 project structure and making it subscribe to the GOOSE trip message, as shown in Figure 6.10. Note that the additional IED is just included in the configuration file, no additional physical IEDs are connected. Available GOOSE messages are listed in the left bar, available IEDs are listed in the top bar, and each IED can be configured to subscribe to GOOSE messages by checking corresponding boxes. In this example, the additional IED (*AA1J1Q01A2*) is set to subscribe to the trip message defined in the previous section (*AA1J1Bay1A1.S1.LD0.LLN0.gcbTrip*).



Figure 6.10: GOOSE subscription configuration

### 6.3.2 Subscriber - Test Set

When the GOOSE trip message publishing is established, the test set must be configured to subscribe to these messages to finish the trip circuit communication. The general methods for doing this in an OMICRON test set was introduced in Section 5.1.3 and the fourth of these methods are to be used for the laboratory configuration, using SCL files from the substation description. After GOOSE datasets have been created in PCM 600, it is possible to export them as a CID file. This gives a description of the IED configuration, including GOOSE and SV messages as well as data structures, in a standardized format as discussed in Section 2.8. This is done by right-clicking the substation in the PCM 600 project structure and selecting "Export", which exports all IED data from the project in the SCL format. This CID file may then be imported into Test Universe and used to configure test set GOOSE subscriptions. In GOOSE Configuration Tool, this is done by clicking "File" and "Import SCL", and selecting the CID file exported from PCM 600.

Figure 6.11 shows the GOOSE Configuration Tool after importing the CID file for the GOOSE dataset created in the previous section. This gives a list of GOOSE datasets that can be selected to view their contents. Note that the content of the imported GOOSE trip message corresponds to the trip message defined in Figure 6.9. The left window shows a list of the binary input ports in the OMICRON test set. By clicking on an input port from this list and a data attribute of a GOOSE dataset to the right and activating the lower left button, a mapping is created between them, as introduced in Section 5.1.2 [10]. For example, this means that if the data attribute that indicates general trip in zone

1 (*ZMRPDIS1.Op.general*) is mapped to binary input 1 ("Bin. In. 1"), an activation of *ZMRPDIS1.Op.general* in the subscribed GOOSE message is interpreted as if binary input 1 received an analog signal.

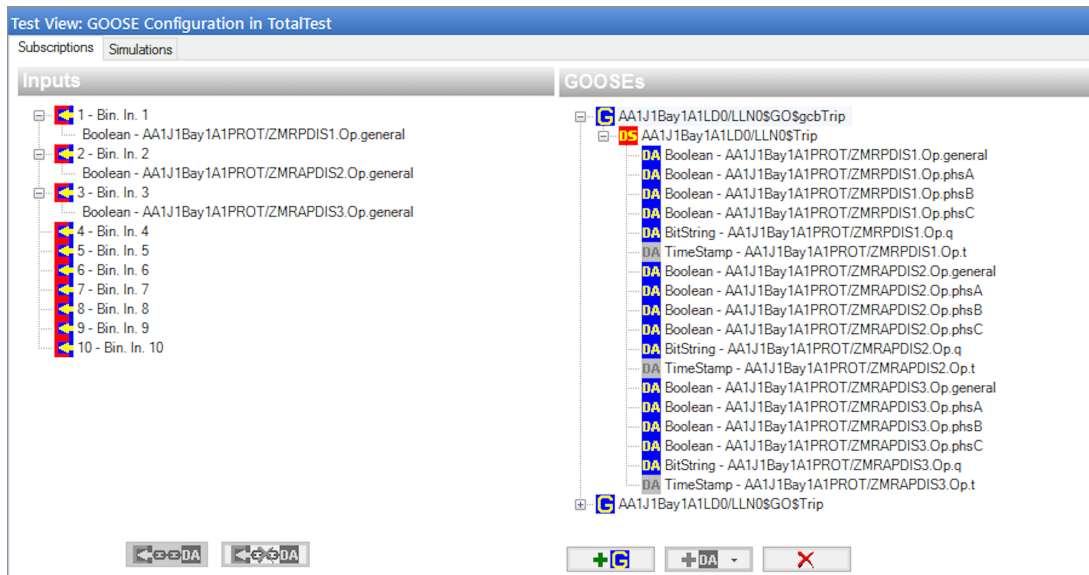


Figure 6.11: GOOSE Configuration Tool for test set GOOSE subscription and mapping

Three data objects are mapped to binary inputs in this configuration, one general trip signal for each zone of protection implemented in the relay. This means that the activation of binary input 1 corresponds to a trip signal from zone 1, binary input 2 corresponds to trip in zone 2 and binary input 3 to trip in zone 3.

The next step of the GOOSE trip message subscription is to map the binary inputs in Figure 6.11 using OMICRON Hardware Configuration, which is illustrated in Figure 6.17. This allows the OMICRON to implement the various binary input signals correctly, as these are activated through the GOOSE message mapping.

Global Hardware Configuration

General Analog Outputs Binary / Analog Inputs Binary Outputs DC Analog Inputs Time Source

Function		Binary	Binary	Binary	Binary	Binary					
Potential Free		<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>					
Nominal Range											
Clamp Ratio											
Threshold											
Display Name	Connection Terminal	1+	1-	2+	2-	3+	3-	4+	4-	5+	5-
<b>Bin. in 1</b>		X									
Bin. in 2				X							
Bin. in 3						X					

Figure 6.12: OMICRON binary input Hardware Configuration

The binary inputs activated by the GOOSE trip messages must be correctly interpreted

by the test set modules to finalize the GOOSE trip message configuration. This can be done in the "Trigger" bar that is found in each test module, as seen in Figure 6.13 for the Advanced Distance Module. Note that the available binary inputs correspond to the ones being defined in the Hardware Configuration. By including all three binary inputs and utilizing the trigger logic "Or", a general trip signal from one of the zones of protection is interpreted by the test module as a trip. This is considered the standard trigger logic configuration for this setup and is used for most of the laboratory experiments. By checking the time delay of each trip, it is possible to identify which zone tripped.

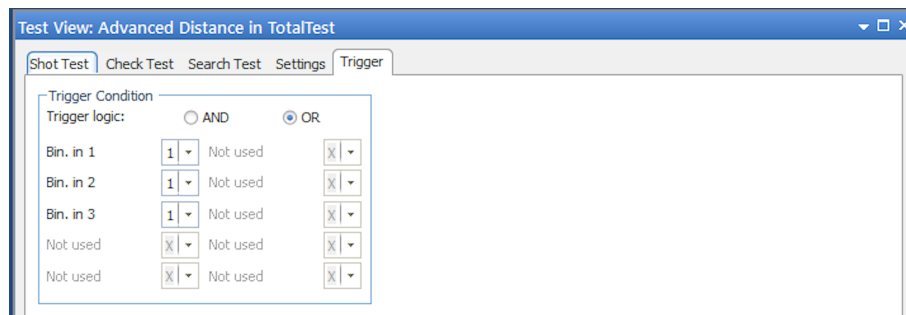


Figure 6.13: OMICRON trigger logic for all test modules

## 6.4 GOOSE Configuration of Blocking Messages

It is also possible to send GOOSE messages in the opposite direction by simulating and publishing GOOSE messages from the test set and making the relay subscribe to them. For example, it is possible to make the test set simulate pilot protection blocking signals, as introduced in Section 3.3 and send it to the relay over the process bus. If properly configured, the relay interprets these GOOSE messages as being sent from another IED.

### 6.4.1 Creating GOOSE Dataset in PCM 600

The first step towards GOOSE simulation is to create a GOOSE dataset, which can be done using PCM 600 as in Section 6.3.1. From here, the additional virtual relay created in Section 6.3.1 can be utilized to create a GOOSE dataset through the PCM 600 IEC 61850 Configuration Tool. This dataset is shown in the top half of Figure 6.14 named "Interlocking" and is created similarly to the trip message in the previous section. A function block *DPGAPC1* (generic communication function for double point indication) is added to the Application Configuration of the additional relay, as this includes a data object *stVal* that can be used to contain blocking indication in the GOOSE message. Note that this GOOSE message is not a message that would be used in practice for a digital substation, but it can be used to send blocking messages if properly configured in both the subscriber and publisher. The RED 670 can be configured to subscribe to these GOOSE messages, as illustrated in the bottom half of Figure 6.14. Once the GOOSE dataset is created, it can be exported as a CID file using the same procedure as in Section 6.3.2.

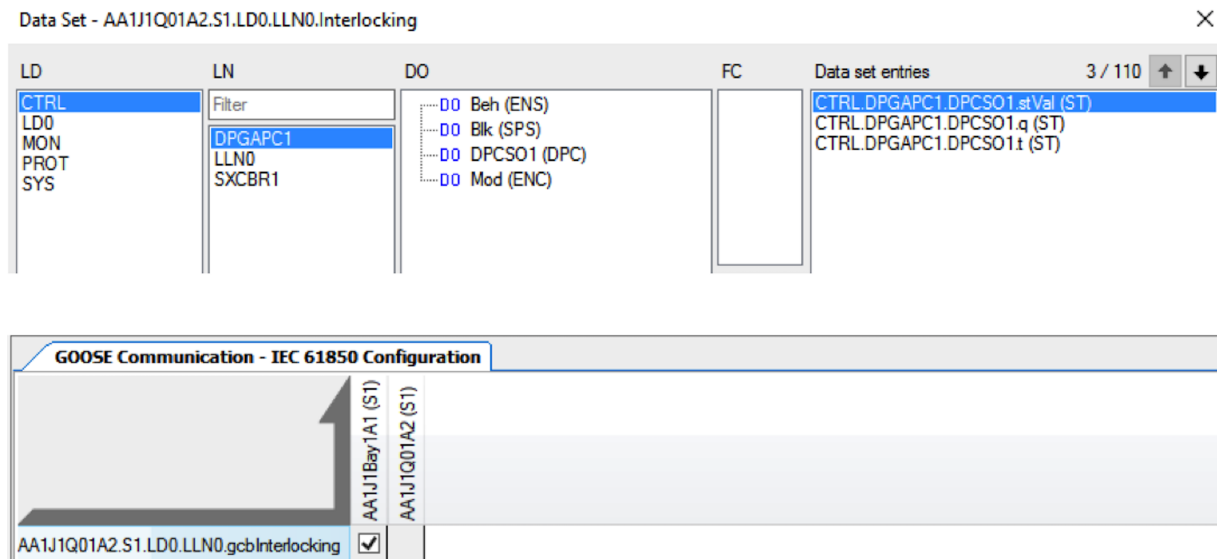


Figure 6.14: GOOSE blocking message creation (top) and relay subscription (bottom)

## 6.4.2 Publisher - Test Set

Once the GOOSE dataset is created, it is wanted to make the test set publish equivalent GOOSE messages to simulate signals from other IEDs. As discussed in Section 5.1.2, the GOOSE Configuration Module is used to create mappings between the analog OMICRON ports and its digital messages. By importing the CID file created in PCM 600, the GOOSE dataset appears in the simulation tab of GOOSE Configuration Module, as shown in Figure 6.15. This uses the same mapping principles between GOOSE data objects and binary terminals on the test set as the GOOSE subscription procedure described in Section 6.3.2.

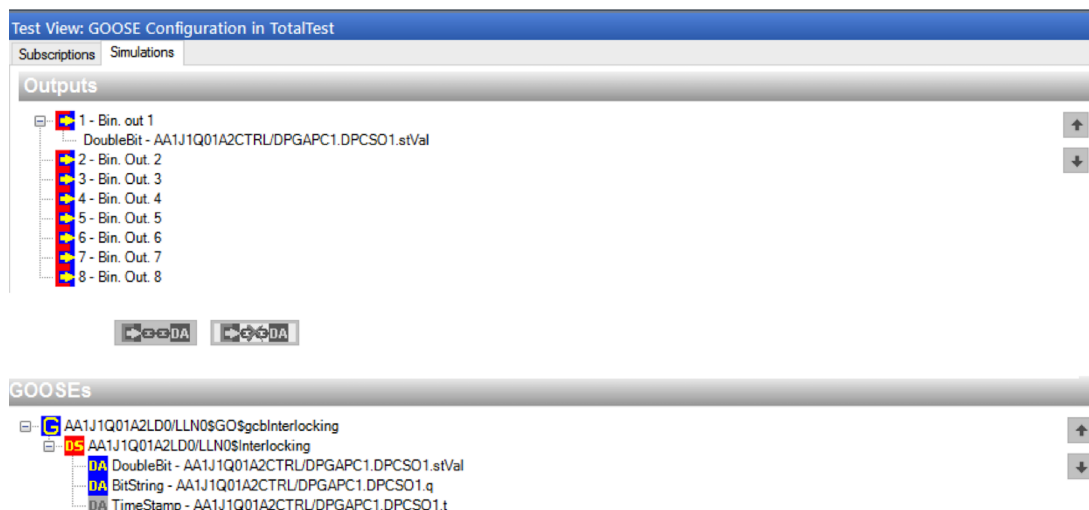


Figure 6.15: OMICRON GOOSE message simulation

The details of the GOOSE message may be viewed by left-clicking on it, as seen in Figure

6.16. Note that the *Simulation Flag* parameter can be set to "Simulated" to activate the GOOSE test flag, as discussed in Section 4.4.2. Also, the parameter *Enabled* must be set to "True" in order to enable this functionality.

AA1J1Q01A2LD0/LLN0\$GOS\$gcbInterlocking	
GOOSE control reference	AA1J1Q01A2LD0/LLN0\$GOS\$gcbInterlocking
GOOSE ID	AA1J1Q01A2LD0/LLN0.gcbInterlocking
Application ID	2 (0x0002)
MAC Address	01-0C-CD-01-00-01
Configuration revision	100
> Repetition	{10000. 4. 2}
> VLAN	{4. 0}
Simulation Flag	Normal
Enabled	True

Figure 6.16: OMICRON GOOSE message details

Figure 6.15 shows that the previously defined data object *stVal* is mapped to binary output 1 of the test set. After this has been applied, it is possible to control the content of the GOOSE messages published by the test set by activating and deactivating binary output 1 using OMICRON test modules, for example, QuickCMC or State Sequencer. This generates corresponding GOOSE messages, and the RED 670 relay reacts to these messages as it has been configured to subscribe to them. The Hardware Configuration in Figure 6.17 shows the mapping for the created blocking message.

Global Hardware Configuration									
General		Analog Outputs		Binary / Analog Inputs		Binary Outputs		DC Analog Inputs	
Display Name	Connection Terminal	1+	1-	2+	2-	3+	3-		
Bin. out 1		X							

Figure 6.17: OMICRON binary output Hardware Configuration

### 6.4.3 Subscriber - Relay

The final step of the GOOSE simulation is to make the relay interpret the GOOSE messages correctly. This is achieved by adding a functional block *GOOSEDPRCV* (GOOSE double point receive) to the Application Configuration of the RED 670 relay. This allows for using information from GOOSE messages as input to the relay functionality. The subscribed GOOSE message may be connected to this functional block using the "GOOSE receive" tab in the PCM 600 Signal Matrix Tool, as seen in Figure 6.18. This shows that the *stVal* data of the LN *DPGAPC1* defined as the GOOSE message content is mapped to the functional block *GOOSEDPRCV*.


GOOSE Communication - IEC 61850 Configuration		RED670 - Signal Matrix	RED670 - Application Configuration				
IED, Logical Device : 	AA1J1Q01A2, CTRL Data Object: Data Attribute:	AA1J1Q01A2, CTRL	AA1J1Q01A2, SYS - AA1J1Q01A2, SYS				
		DPGAPC1					
		DPCSO1 stVal		AcsCtlFail addInfo	AcsCtlFail addr	AcsCtlFail cnt	AcsCtlFail sev
- GOOSEPRCV:1							
GOOSEPRCV:1	DPOUT	X					

Figure 6.18: PCM 600 Signal Matrix Tool, showing the "GOOSE receive" tab

## 6.5 Relay Functionality Configuration

An example setup with typical configuration is used for testing relay functionality in this thesis, which is to be described in Section 7.1. Hence, relay functionality for the RED 670 relay must be configured using PCM 600 Application Configuration [9]. While relay configuration is not a key part of this thesis, a short overview of the configuration of relay functionality is included for the sake of completeness.

The Application Configuration of this setup is divided into two pages; input and protection. Figure 6.19 shows the input page, where current and voltage signals for each phase from the virtual MUs defined in Section 6.2.2 are used as inputs. These are sent through *SMAI* (signal matrices for analog input) function blocks that gathers measurement signals from each of the three phases into one signal. The terminals of the *SMAI* blocks are connected to the virtual MU signals by right-clicking on each terminal and selecting "Connect" and "Analog Hardware Channel". The current and voltage signals are set as output variables I3P and V3P to simplify the configuration, allowing to use these values as input in other parts of the Application Configuration Tool.

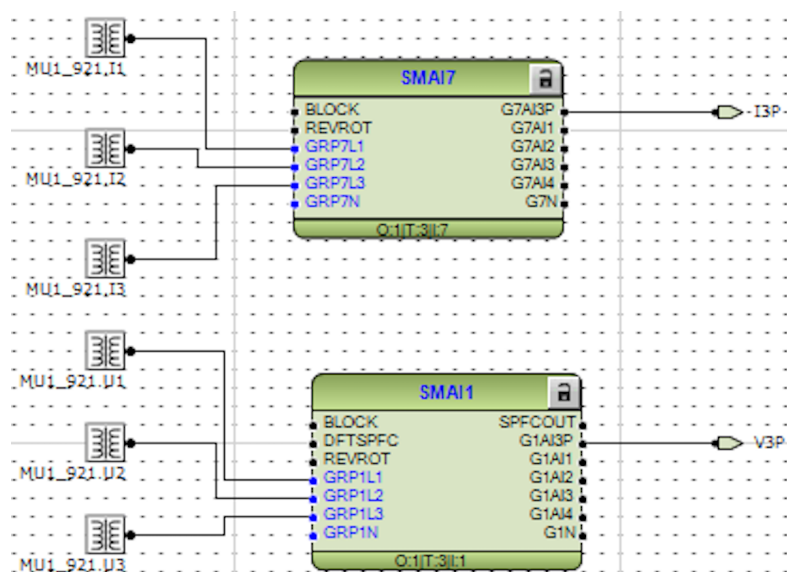


Figure 6.19: Relay inputs, current and voltage for each phase from virtual MU

The next step is to use the input signals to perform protective functionalities in the protection page, as shown in Figure 6.20. The following protective functional blocks are used.

- *ZDRDIR* (directional impedance quadrilateral) is used to determine the direction to the fault [9]. The inputs are 3-phase current and voltage measurements, while the output is used as an external directional condition (*DIRCND*) for the impedance relay functions.
- *FRSPDIS* (phase selection, quadrilateral characteristic with fixed angle) is used as a starting zone for the protective relay functions [9]. The inputs are 3-phase current and voltage measurements, while the output is used as an external starting condition (*STCND*) for the zones of protection.
- *ZMRPDIS* is used for the primary zone of protection, while functional blocks *ZMRAPDIS* are used to provide additional zones of impedance protection [9]. If the primary zone trips, both backup zones are blocked, and if zone 2 trips, zone 3 should be blocked. Start and trip signals from each zone are connected to LED indicators 1 to 6 on the relay front panel through functional blocks *GRP1\_LED*.

As discussed in Section 3.2, a distance relay is typically configured with 3 different zones of protection with increasing reach and time delay. Each protective zone has to be configured using the Parameter Setting Tool, according to the discussion of protective zones in Section 3.2.2. The full relay parameter settings are given in Appendix B, corresponding to the zone settings defined in the example model in Section 7.1. Note that each functional block has a specified "cycle time", which specifies how often values are processed through each functional block when calculations are performed. The cycle time can be determined when creating a functional block, and it is important that interconnected functional blocks have identical cycle time to ensure proper operation. It was experienced that by using different cycle times for the input *SMAI* blocks and the protective blocks, the protective functionalities of the relay did not operate at all.

In addition to the protection configuration, the functional block *GOOSEDPRCV* is added to use GOOSE blocking messages as input, as introduced in Section 6.4.3. This is sent through a block *POS\_EVAL* that decomposes this double point value into two components "OPENPOS" and "CLOSEDPOS". The component "CLOSEDPOS" is further connected to the "BLOCK" input of the starting zone of the distance protection. This means that when the GOOSE message dataset indicates activation of the blocking functionality, all protective functions are blocked. The two states are also connected to LED 7 of the relay front panel, which means that this indicates green when the blocking functionality is deactivated and red when it is activated.



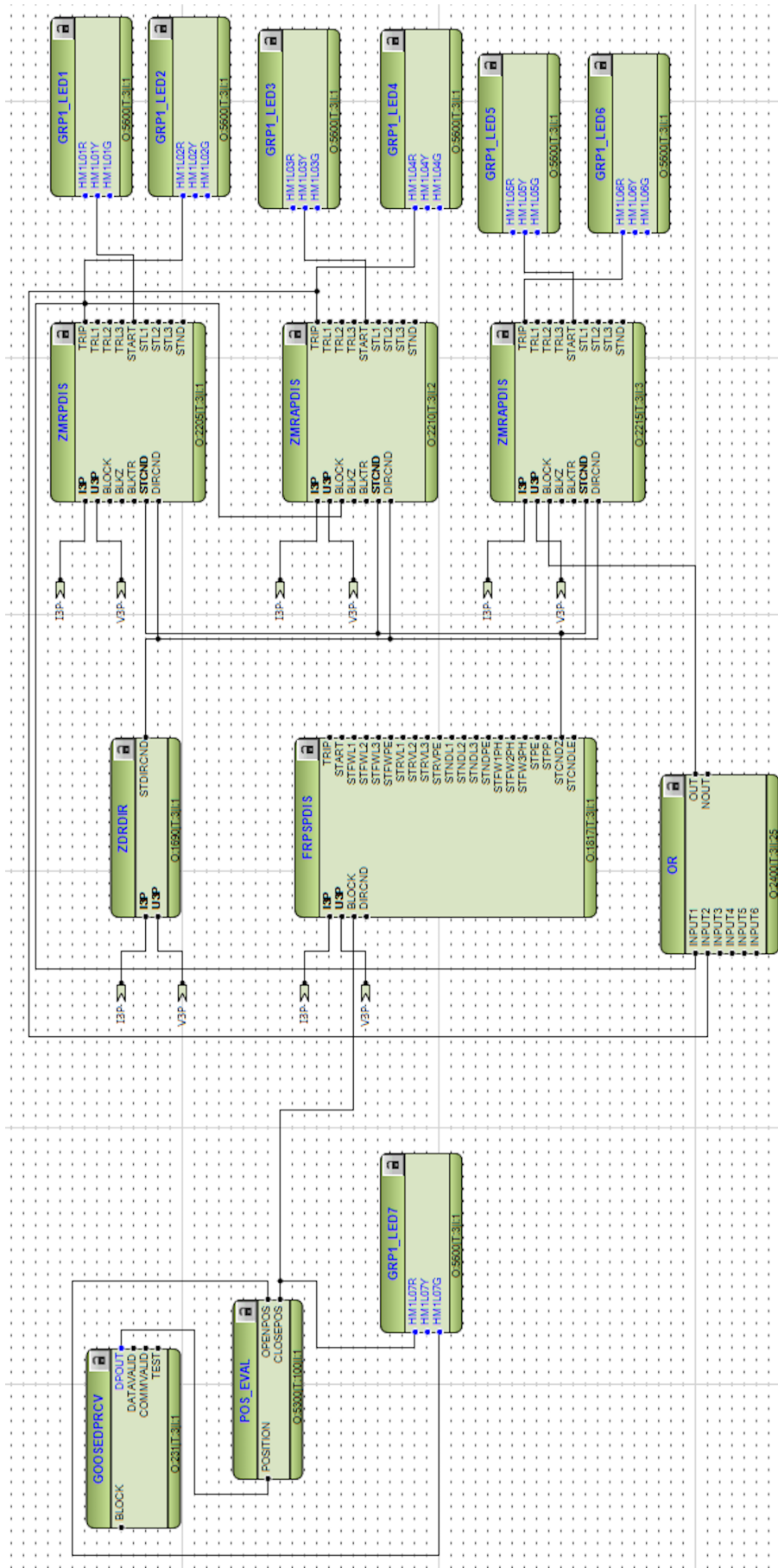


Figure 6.20: Relay protective functions, defined from scratch in PCM 600 Application Configuration



# Chapter 7

## Laboratory Experiment Methods

A series of experiments related to relay functionality testing in a digital substation environment is to be performed using the laboratory setup and configuration established in Chapters 5 and 6. A description and overview of these experiments and the methods to be used are described in this chapter. Note that most details of the configuration and setup of the methods are covered in Chapter 5 and 6, and these are referred to in this chapter.

### 7.1 Example Model

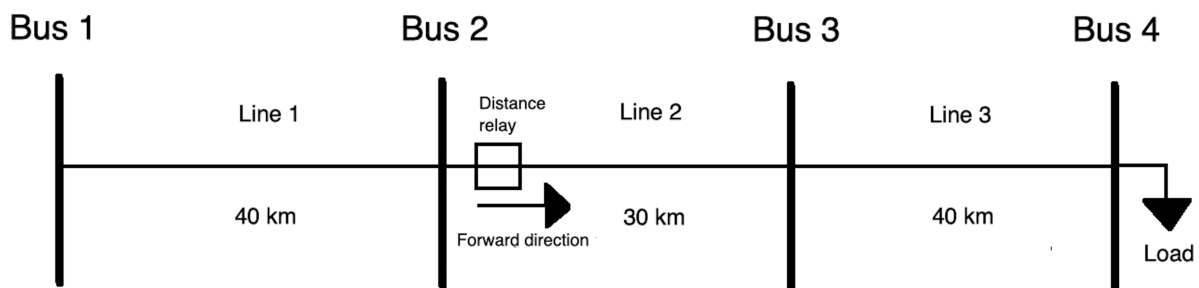


Figure 7.1: Example network model

An example network model is created and used to conduct all laboratory experiments. The network model to be used is a simple 4-bus radial network, as shown in Figure 7.1, where only transmission lines and a single load is taken into account. A full overview of the network parameters is given in Table 7.1. The RED 670 distance relay is placed at the start of line 2 to protect the system against faults while providing stability for normal load situations. The relay has a defined forward direction, as introduced in Section 3.2.1. Note that all transmission lines have equal specific parameters but may have different absolute parameters due to having different lengths. The zone settings of the relay are set according to the discussion in Section 3.2.2 and implemented into the relay using the process described in Section 6.5. Zone 1 is set to cover 80 % of line 2 in the forward

direction, while zone 2 has increased reach and covers entire line 2 as well as 20 % of line 3 in the forward direction. Zone 3 is used for backup protection for line 1, covering 50 % of line 1 in the backward direction only.

Parameter	Value
Frequency	50 Hz
Voltage level	132 kV
Specific line resistance	0.1 $\Omega/km$
Specific line reactance	0.5 $\Omega/km$
Line phase angle	78.69°
Load	50 MW + j10 MVar
Zone 1 resistive reach	2.4 $\Omega$ (forwards)
Zone 1 reactive reach	12 $\Omega$ (forwards)
Zone 1 intentional time delay	0.0 s
Zone 2 resistive reach	3.8 $\Omega$ (forwards)
Zone 2 reactive reach	19 $\Omega$ (forwards)
Zone 2 intentional time delay	0.3 s
Zone 3 resistive reach	2 $\Omega$ (backwards)
Zone 3 reactive reach	10 $\Omega$ (backwards)
Zone 3 intentional time delay	0.6 s
CT ratio	1000/1 A
VT ratio	500/1 V

Table 7.1: Example network model parameters

The current seen by the relay for the given 3-phase load in this transmission system is calculated in Appendix C, giving a secondary side load current of  $I = 0.90256/-24.33^\circ$  A. By assuming a stiff voltage of 132 kV on Bus 2, the VT ratio of 500/1 gives a secondary side voltage of 264 V at these load conditions. The laboratory experiments are divided into three main parts, and a description of these is given in the following sections. Note that none of the IEC 61850 test tools will be utilized for part 1 or part 2 of the experiment, as these will be investigated in part 3.

## 7.2 Part 1: Testing Communication Paths

The first part of the laboratory experiments is to verify that the communication between the test set and the relay works as expected through SV messages as well as trip and blocking GOOSE messages over the process bus. This is equivalent to the communication path testing introduced in Section 4.3. This is typically not the main part of relay functionality testing procedures in full substations but is necessary for these laboratory experiments to verify that the communication configuration from Chapter 5 and 6 is successfully established.

This includes making sure that SV messages are correctly generated and published by the test set through secondary side injection, and that the relay receives these correctly.

As introduced in section 2.5.4, relay inputs are secondary side values for conventional substations, while SV messages in a digital substation typically carry primary side values. This means that the OMICRON test modules apply secondary side values, which are converted to primary side values using the CT and VT ratios defined in Test Object before being mapped into SV messages. Hence, it must be verified that the values being published by the test set are properly scaled and received by the relay. This is done by applying current and voltage signals from the test set and verifying that the relay is receiving equivalent measurements. The values measured by the relay can be seen using the relay HMI as described in Figure 5.5 (*Measurements* → *Analog primary values* → *MU1:s921*).

In addition, GOOSE trip and blocking messages are to be tested. The GOOSE trip messages are automatically published from the relay, while the blocking message publishing must be activated in the test set. It should be verified that the trip messages change from indicating "No trip" to "Trip" when applying faulty situations using QuickCMC and that the relay correctly interprets these GOOSE messages as trip signals. It should also be verified that the test set is publishing GOOSE blocking messages and that the content of these messages change once QuickCMC is used to activate the blocking functionality. A full step-by-step description of the test procedures to be implemented is given below.

- Activate SV publishing from the test set by applying SV Configuration Tool as configured in Section 6.2.1.
- Activate GOOSE blocking message publishing from the test set by applying GOOSE Configuration Tool as configured in Section 6.4.2.
- **Part 1.1: Verify SV communication**
  1. Verify that SV messages are being published to the process bus by checking that SV messages with the same sampled value ID as published by the test set (*ABB\_MU0101*) appear in Wireshark.
  2. Apply secondary side currents and voltages utilizing QuickCMC, as shown in Figure 7.2.
  3. Verify that the relay receives primary side values that are scaled according to the CT and VT ratios defined in Test Object (1000/1 A and 500/1 V)

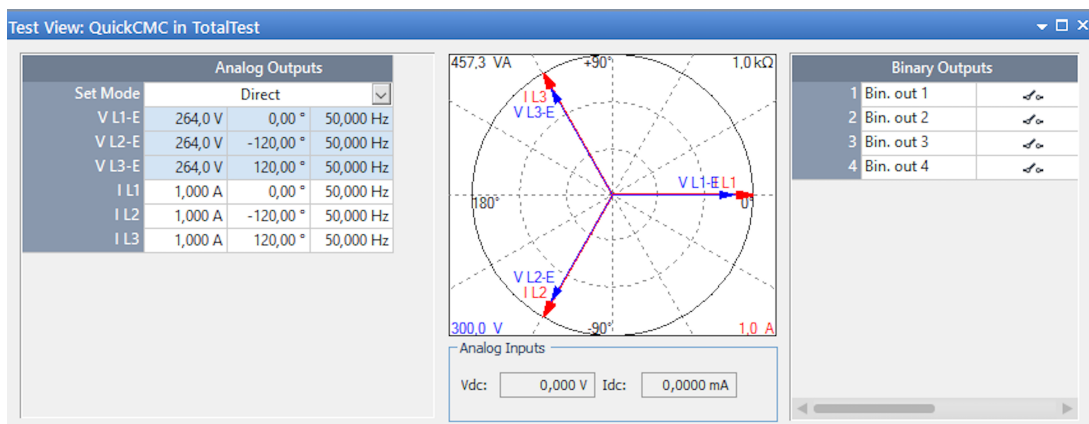
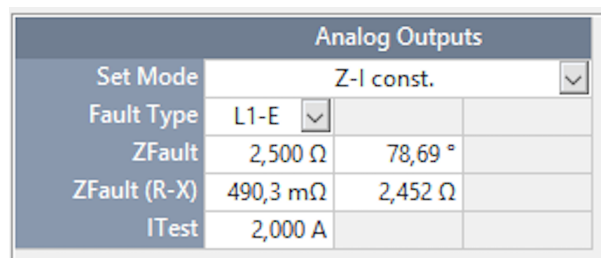


Figure 7.2: QuickCMC test for verifying communication and CT/VT ratios

- **Part 1.2: Verify GOOSE trip message communication**

1. Verify that trip messages are being published from the relay using Wireshark.
2. Use QuickCMC to apply a fault in zone 1 of the distance relay, as shown in Figure 7.3.
3. Verify that the relay indicates a trip by inspecting the relay LED indicators 1-6.
4. Verify that QuickCMC interprets the GOOSE trip message as a successful trip.
5. Use Wireshark to verify that the contents of the GOOSE message change to indicate trip.



Analog Outputs				
Set Mode	Z-I const. <input type="button" value="v"/>			
Fault Type	L1-E <input type="button" value="v"/>			
ZFault	2,500 Ω	78,69 °		
ZFault (R-X)	490,3 mΩ	2,452 Ω		
ITest	2,000 A			

Figure 7.3: Applying fault in zone 1 using QuickCMC

- **Part 1.3: Verify GOOSE blocking message communication**

1. Use Wireshark to verify that the test set is publishing GOOSE blocking messages with the blocking functionality deactivated.
2. Activate binary output 1 from the test set using QuickCMC to activate the blocking functionality. This is done by activating "Bin. out 1" in the top right corner of Figure 7.2.
3. Verify that the blocking functionality is correctly applied and interpreted in the relay functionality by inspecting the relay LED indicator 7.
4. Use Wireshark to verify that the GOOSE blocking messages indicates that the blocking functionality has been successfully activated.

## 7.3 Part 2: Testing Relay Functionality

The second part of the laboratory experiment implements basic relay functionality test procedures for the isolated RED 670 relay, as introduced in Section 4.2. This is performed by utilizing dynamic state testing, where a series of measurement signals are applied from the test set using QuickCMC and Advanced Distance Module. The three main considerations for protective relaying described in Section 4.2 are to be tested through these procedures. First, it is necessary to verify that the relay does not trip during healthy load situations, which is done by injecting calculated load currents using QuickCMC. A series of test shots are then to be injected using Advanced Distance Module to verify

that the relay does not trip for faults occurring outside each of its configured zones of protection.

The next step is to verify that the relay protection algorithm successfully clears faults occurring within the zones of protection. This is done by injecting a series of test shots of various types indicating internal faults using the Advanced Distance Module. The final step is to verify that the blocking message defined in Section 6.4 works as expected, by simulating and publishing it to the relay and verifying that the relay does not trip for the internal fault situations applied in the previous step. Note that for all Advanced Distance Module fault simulations, three types of faults as discussed in Section 3.4 are included; *L1-E*, *L1-L2* and *L1-L2-L3*. Assuming symmetry between each of the phases, this tests all major fault situations and tests the relay algorithm at each of their unique fault characteristics. Note faults occurring within a zone of protection for the distance relay are referred to as internal faults, while external faults mean faults that occur outside zones of protection, as introduced in Section 3.2.2.

- Activate SV publishing from the test set by applying SV Configuration Tool as configured in Section 6.2.1.
- **Part 2.1: Verify stability at normal load conditions.**
  1. Apply calculated load conditions using QuickCMC, as shown in Figure 7.4.

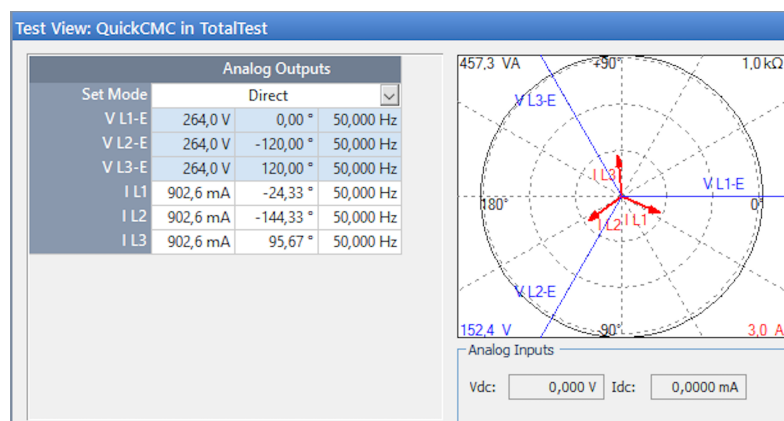


Figure 7.4: QuickCMC test for verifying relay stability at load conditions

2. Verify that none of the distance protection zones indicates a trip by inspecting the relay LED indicators 1-6 as configured in Section 6.5.
  3. Verify that none of the distance protection zones tripped by inspecting the QuickCMC test report.
- **Part 2.2: Verify stability for external faults.**
    1. Apply a series of test shots outside the configured zones of protection 2 and 3 using Advanced Distance Module, as shown in Figure 7.5.
    2. Verify that none of the zones tripped for any of the applied fault situations by inspecting the relay LED indicators 1-6.

3. Verify that none of the zones tripped for any of the applied fault situations by inspecting the Advanced Distance test report.
4. Deactivate trip from zone 2 to test zone 1 for stability at external faults without tripping zone 2. This is done using the trigger menu as shown in Figure 6.13 and setting "Bin. in 2" to 0, meaning that the GOOSE message indicating trip in zone 2 and activating binary input 2 in the test set is not taken into account in the test module trip logic.
5. Apply test shots similar to the ones in Figure 7.5, but with  $|Z| = 15\Omega$  for each of the three fault types.
6. Verify that none of the zones tripped for any of the applied fault situations by inspecting the relay LED indicators 1-6.
7. Verify that none of the zones tripped for any of the applied fault situations by inspecting the Advanced Distance test report.

State	$ Z $	Phi	%	% of	t nom	t act.	Dev.	t min	t max	I <sub>Test</sub>
1 ●	25,00 $\Omega$	78,69 °	n/a		no trip	n/a		no trip	no trip	2,000 A
2 ●	-15,00 $\Omega$	78,69 °	n/a		no trip	n/a		no trip	no trip	2,000 A

Figure 7.5: Applying external faults using Advanced Distance Module

- **Part 2.3: Verify dependability for internal faults.**

1. Apply a series of test shots within the configured zones of protection using Advanced Distance Module, as seen in Figure 7.6.
2. Verify that appropriate distance protection zones indicate a trip by inspecting the relay LED indicators 1-6 throughout the testing procedure.
3. Verify that appropriate distance protection zones tripped by inspecting the Advanced Distance test report.

State	$ Z $	Phi	%	% of	t nom	t act.	Dev.	t min	t max	I <sub>Test</sub>
1 ●	5,000 $\Omega$	78,69 °	n/a		no trip	n/a		no trip	no trip	2,000 A
2 ●	15,00 $\Omega$	78,69 °	n/a		no trip	n/a		no trip	no trip	2,000 A
3 ●	-5,000 $\Omega$	78,69 °	n/a		no trip	n/a		no trip	no trip	2,000 A

Figure 7.6: Applying internal faults using Advanced Distance Module

- **Part 2.4: Verify that the blocking message prevents relay tripping.**

1. Activate GOOSE blocking message publishing from the test set by applying GOOSE Configuration Tool simulation as configured in Section 6.4.
2. Activate binary output 1 from the test set using "latching outputs" in State Sequencer Module, as seen in Figure 7.7. This activates the blocking functionality by adjusting the data content of the GOOSE message.



3. Use Wireshark to analyze the GOOSE messages published from the test set to verify that its content change as the blocking message is activated.
4. Apply the same simulated internal fault situations as in the previous step using Advanced Distance Module.
5. Verify that none of the zones tripped for any of the applied fault situations by inspecting the relay LEDs indicators 1-6.
6. Verify that none of the zones tripped for any of the applied fault situations by inspecting the Advanced Distance test report.

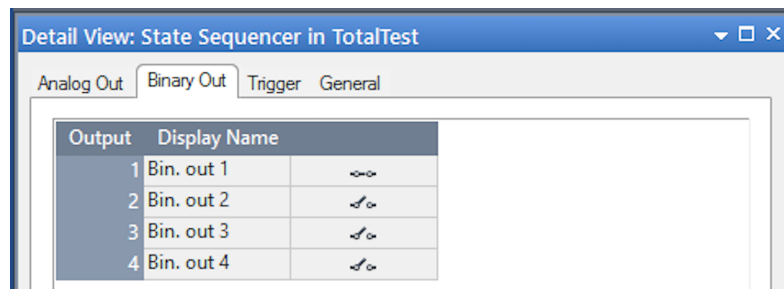


Figure 7.7: State Sequencer Module for applying binary outputs

## 7.4 Part 3: IEC 61850 Testing Tools in Practice

To implement isolated test procedures as described in part 1 and 2 of the laboratory experiments in a practical substation, the IEC 61850 testing tools described in Section 4.4 must be utilized appropriately. Hence, these testing tools and capabilities within the described laboratory setup are explored in this part of the laboratory experiments.

### 7.4.1 Test Messages

First, test messages generated from the test set are to be verified. This is done by activating GOOSE and SV messages injection from the test set with the test flag active and using Wireshark to verify that their test flags have been successfully activated.

- **Part 3.1: Verify SV and GOOSE test message simulation**

1. Use the SV Configuration Tool to inject SV messages from the test set. This is done as shown in Figure 6.3, but selecting *Simulation Flag* = "Simulated" from the dropdown menu.
2. Use GOOSE Configuration Tool to inject GOOSE blocking messages from the test set with the test flag activated. This is done as described in Section 6.4.2, but selecting *Simulation Flag* = "Simulated" from the dropdown menu as seen in Figure 6.16.

3. Use Wireshark to verify that the test flags have been successfully activated for both GOOSE and SV messages from the test set, as described in Section 5.3.1. Compare the messages to messages with the test flag deactivated.

## 7.4.2 Relay Test Mode

When test message injection has been verified, the next step is to put the relay in test mode to check that it reacts as expected to test messages. The RED 670 relay has a test mode, as introduced in Section 4.4.1, that can be activated through the relay HMI (*Test* → *IED Test Mode* → *TESTMODE:1* → *IEDTestMode* = "On"). Once this has been activated, the "Start" LED will flash yellow to indicate that the relay is in test mode. Besides, it must be verified that the GOOSE trip messages published by the relay in test mode has the test flag activated, which can be analyzed using Wireshark.

- Activate SV generation with *Simulation flag* = "Simulated", as described in Part 3.1.
- **Part 3.2: Verify Dependability for Test Messages when in Test Mode**
  1. Set relay in test mode using its HMI, as described above.
  2. Use the SV Configuration Tool to inject SV test messages from the test set, as described in Part 3.1.
  3. Apply the same current and voltage signals as in Part 2.3 using Advanced Distance Module, indicating various internal fault situations.
  4. Verify that the relay trips correctly by inspecting the relay LED indicators 1-6.
  5. Verify that the relay trips correctly by inspecting the Advanced Distance test report.
  6. Use Wireshark to verify that the GOOSE trip messages sent from the relay have the test flag activated.
- **Part 3.3: Verify stability for test messages when in normal mode**
  1. Set the relay in normal mode as described above but setting the parameter *IEDTestMode* = "Off".
  2. Apply the same current and voltage signals as in Part 2.3 using Advanced Distance Module.
  3. Verify that the relay does not trip by inspecting the relay LED indicators 1-6.
  4. Verify that the relay did not trip by inspecting the Advanced Distance test report.

# Chapter 8

## Laboratory Experiment Results

The main results of the laboratory experiments are presented in this chapter. The structure used in Chapter 7 is maintained, dividing the experiments into Part 1.1 to 1.3, Part 2.1 to 2.4, and Part 3.1 to 3.3. The main documentation of the results are the test reports generated by OMICRON, and the full short-form test reports of all experiments in Part 2 and 3 are given in Appendix D. The most valuable content from the test reports is presented in this chapter, along with relevant Wireshark traces and HMI measurements.

### 8.1 Part 1: Testing Communication Paths

#### Part 1.1: Verify SV Communication

The resulting process bus traffic from publishing sampled values from the test set is shown in Figure 8.1 as a Wireshark trace after SV simulation has been applied. Secondary side current and voltage signals were then applied from the test set using QuickCMC, and the resulting primary side currents and voltages received by the relay are shown in Table 8.1.

Parameter	Applied value from test set	IT ratio	Measured value in relay HMI
I1	1 A	1000	1000.007 A
I2	1 A	1000	1000.006 A
I3	1 A	1000	1000.006 A
V1	264 V	500	132.001 kV
V2	264 V	500	132.001 kV
V3	264 V	500	132.001 kV

Table 8.1: Relay HMI measurements, confirming correct SV messages received and IT ratios

No.	Time	Source	Destination	Protocol	Length	Info
1	0.000000	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
2	0.000198	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
3	0.000491	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
4	0.000689	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
5	0.000999	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
6	0.001197	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
7	0.001491	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
8	0.001689	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
9	0.002005	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
10	0.002192	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
11	0.002503	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
12	0.002688	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
13	0.003013	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
14	0.003199	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
15	0.003493	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	
16	0.003691	OmicronE_00:59:6e	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122	

```

> Frame 1: 122 bytes on wire (976 bits), 122 bytes captured (976 bits) on interface 0
> Ethernet II, Src: OmicronE_00:59:6e (20:b7:c0:00:59:6e), Dst: Iec-Tc57_04:00:01 (01:0c:cd:04:00:01)
▼ IEC61850 Sampled Values
  APPID: 0x4000
  Length: 108
  Reserved 1: 0x0000 (0)
  Reserved 2: 0x0000 (0)
  ▼ savPdu
    noASDU: 1
    ▼ seqASDU: 1 item
      ▼ ASDU
        svID: ABB_MU0101
        smpCnt: 713
        confRef: 1
        smpSynch: none (0)
        seqData: 000afbee0000000000a97bf00000000ffea6c4600000000...

```

Figure 8.1: Wireshark trace, confirming correct SV publishing

## Part 1.2: Verify GOOSE Trip Message Communication

Figure 8.2 shows a Wireshark trace of the process bus GOOSE traffic from the relay. After a fault in zone 1 was applied, it was observed from the relay LEDs that the relay indicated trip in zone 1. Figure 8.3 shows that this is correctly interpreted as a trip signal, with a total time delay of 78.1 ms. Figure 8.4 shows Wireshark traces of the GOOSE trip messages before and after the trip was applied. Note that not all of the GOOSE message data is included, as some unchanged data has been omitted.

No.	Time	Source	Destination	Protocol	Length
6505	1.624932	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
46517	11.624922	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
86527	21.624929	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
126544	31.624921	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
166554	41.624898	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
206564	51.624892	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
246583	61.624939	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
286594	71.624900	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
326604	81.624920	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228
366625	91.624886	AbbAutom_1a:66:80	Iec-Tc57_01:00:03	GOOSE	228

Figure 8.2: Wireshark trace showing GOOSE trip message publishing

Binary Inputs / Trigger				
Bin. in 1	<input type="radio"/>	<input checked="" type="checkbox"/>		78,10 ms
Bin. in 2	<input type="radio"/>	<input type="checkbox"/>		n/a
Overload	<input type="radio"/>	<input type="checkbox"/>		n/a

Figure 8.3: QuickCMC trip indication

▼ GOOSE

APPID: 0x0004 (4)  
Length: 213  
Reserved 1: 0x0000 (0)  
Reserved 2: 0x0000 (0)

▼ goosePdu

gocbRef: AA1J1Bay1A1LD0/LLN0\$GO\$gcbTrip  
timeAllowedtoLive: 11000  
datSet: AA1J1Bay1A1LD0/LLN0\$Trip  
goID: AA1J1Bay1A1LD0/LLN0.gcbTrip  
t: Jun 8, 2018 08:00:33.159471571 UTC  
stNum: 71  
sqNum: 0  
test: False  
confRev: 100  
ndsCom: False  
numDatSetEntries: 18

▼ allData: 18 items

- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: bit-string (4)  
Padding: 3  
bit-string: 0000

(a) Trip deactivated

▼ GOOSE

APPID: 0x0004 (4)  
Length: 213  
Reserved 1: 0x0000 (0)  
Reserved 2: 0x0000 (0)

▼ goosePdu

gocbRef: AA1J1Bay1A1LD0/LLN0\$GO\$gcbTrip  
timeAllowedtoLive: 11000  
datSet: AA1J1Bay1A1LD0/LLN0\$Trip  
goID: AA1J1Bay1A1LD0/LLN0.gcbTrip  
t: Jun 8, 2018 08:00:33.162599682 UTC  
stNum: 74  
sqNum: 1  
test: False  
confRev: 100  
ndsCom: False  
numDatSetEntries: 18

▼ allData: 18 items

- ▼ Data: boolean (3)  
boolean: True
- ▼ Data: boolean (3)  
boolean: True
- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: boolean (3)  
boolean: False
- ▼ Data: bit-string (4)  
Padding: 3  
bit-string: 0000

(b) Trip activated

Figure 8.4: GOOSE trip messages published by the relay before and after trip

### Part 1.3: Verify GOOSE Blocking Message Communication

A Wireshark trace of the process bus GOOSE traffic from the test set after activating GOOSE Configuration Module is given in Figure 8.5. After applying binary output 1 of the test set using QuickCMC, LED number 7 changed color from green to red. Figure 8.6 shows a Wireshark trace of the GOOSE blocking message before and after the blocking functionality is activated.

No.	Time	Source	Destination	Protocol	Length
9113...	223.962934	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
8705...	213.962002	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
8299...	203.961056	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
7891...	193.960122	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
7485...	183.960179	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
7078...	173.959231	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
6671...	163.958290	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
6264...	153.957360	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
5857...	143.956418	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186
5450...	133.955445	OmicronE_00:59:6d	Iec-Tc57_01:00:01	GOOSE	186

Figure 8.5: Wireshark trace showing GOOSE blocking message publishing

▼ GOOSE

APPID: 0x0002 (2)  
Length: 172  
Reserved 1: 0x0000 (0)  
Reserved 2: 0x0000 (0)

▼ goosePdu

gocbRef: AA1J1Q01A2LD0/LLN0\$G0\$gcbInterlocking  
timeAllowedtoLive: 20000  
datSet: AA1J1Q01A2LD0/LLN0\$Interlocking  
goID: AA1J1Q01A2LD0/LLN0.gcbInterlocking  
t: May 28, 2019 08:46:19.135020494 UTC  
stNum: 1  
sqNum: 121  
test: False  
confRev: 100  
ndsCom: False  
numDatSetEntries: 3

▼ allData: 3 items

▼ Data: bit-string (4)  
Padding: 6  
bit-string: 40

▼ Data: bit-string (4)  
Padding: 3  
bit-string: 0000

(a) Block deactivated

▼ GOOSE

APPID: 0x0002 (2)  
Length: 171  
Reserved 1: 0x0000 (0)  
Reserved 2: 0x0000 (0)

▼ goosePdu

gocbRef: AA1J1Q01A2LD0/LLN0\$G0\$gcbInterlocking  
timeAllowedtoLive: 8  
datSet: AA1J1Q01A2LD0/LLN0\$Interlocking  
goID: AA1J1Q01A2LD0/LLN0.gcbInterlocking  
t: May 28, 2019 09:06:12.226835548 UTC  
stNum: 2  
sqNum: 0  
test: False  
confRev: 100  
ndsCom: False  
numDatSetEntries: 3

▼ allData: 3 items

▼ Data: bit-string (4)  
Padding: 6  
bit-string: 80

▼ Data: bit-string (4)  
Padding: 3  
bit-string: 0000

(b) Block activated

Figure 8.6: GOOSE block messages published by the relay before and after activation

## 8.2 Part 2: Testing Relay Functionality

### Part 2.1: Verify Stability at Normal Load Conditions

The applied conditions and resulting relay actions are presented in Table 8.2. It was observed that none of the relay LED indicators indicated trip signals for the applied load conditions. The full test report is given in Appendix D.

Conditions	
Applied values	Load conditions
Blocked	No
Test mode activated	No
Expected result	No trip
Results	
LED indication	No trip
Test report result	No trip

Table 8.2: Applied conditions and resulting relay actions

## Part 2.2: Verify Stability for External Faults

It was observed that none of the relay LED indicators indicated trip for applied external fault conditions for testing zones 2 and 3. However, the LEDs indicated trip in zone 2 for faults occurring beyond zone 1. The full test reports for both tests are given in Appendix D. A summary of the applied faults and main results from the test report is given in Table 8.3 and 8.4, where the column "Observed trip" indicates the trip time observed by the test set.

Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Beyond Zone 2	L1-E	No trip	No trip	No trip
Beyond Zone 2	L1-L2	No trip	No trip	No trip
Beyond Zone 2	L1-L2-L3	No trip	No trip	No trip
Beyond Zone 3	L1-E	No trip	No trip	No trip
Beyond Zone 3	L1-L2	No trip	No trip	No trip
Beyond Zone 3	L1-L2-L3	No trip	No trip	No trip

Table 8.3: Applied external faults and resulting trip times for zone 2 and 3

Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Beyond Zone 1	L1-E	Trip Zone 2	No trip	No trip
Beyond Zone 1	L1-L2	Trip Zone 2	No trip	No trip
Beyond Zone 1	L1-L2-L3	Trip Zone 2	No trip	No trip

Table 8.4: Applied external faults and resulting trip times for zone 1, trip from zone 2 deactivated

## Part 2.3: Verify Dependability for Internal Faults

The relay LEDs indicated start and trip for appropriate zones of protection through the testing procedure of applying internal faults. The applied faults and main results are given in Table 8.5, while the full test report is given in Appendix D.

Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Zone 1	L1-E	Trip Zone 1	0 ms	35.5 ms
Zone 1	L1-L2	Trip Zone 1	0 ms	25.8 ms
Zone 1	L1-L2-L3	Trip Zone 1	0 ms	19.0 ms
Zone 2	L1-E	Trip Zone 2	300 ms	335.0 ms
Zone 2	L1-L2	Trip Zone 2	300 ms	329.9 ms
Zone 2	L1-L2-L3	Trip Zone 2	300 ms	320.8 ms
Zone 3	L1-E	Trip Zone 3	600 ms	622.2 ms
Zone 3	L1-L2	Trip Zone 3	600 ms	623.3 ms
Zone 3	L1-L2-L3	Trip Zone 3	600 ms	622.9 ms

Table 8.5: Applied internal faults and resulting trip times

## Part 2.4: Verify that the Blocking Message Prevents Relay Tripping

Figure 8.7a shows a Wireshark trace of the block GOOSE message after test set GOOSE simulation has been activated, but before the block functionality is activated. Figure 8.7b shows a similar Wireshark trace after the block functionality has been activated. The State Sequencer test report used to apply binary output 1 and activating blocking functionality is shown in Part 2.4a of Appendix D. The test report from the subsequent Advanced Distance testing is given in Part 2.4b of the appendix. Table 8.6 gives a summary of the applied fault situations and resulting trip actions from the relay.

```

> Ethernet II, Src: OmicronE_00:59:6e (20:b7:c0:00:59:6e),
  GOOSE
  APPID: 0x0002 (2)
  Length: 172
  Reserved 1: 0x0000 (0)
  Reserved 2: 0x0000 (0)
  goosePdu
    gocbRef: AA1J1Q01A2LD0/LLN0$G0$gcbInterlocking
    timeAllowedtoLive: 20000
    datSet: AA1J1Q01A2LD0/LLN0$Interlocking
    goID: AA1J1Q01A2LD0/LLN0.gcbInterlocking
    t: May 14, 2019 09:17:09.111633598 UTC
    stNum: 3
    sqNum: 12
    test: False
    confRev: 100
    ndsCom: False
    numDatSetEntries: 3
    allData: 3 items
      Data: bit-string (4)
        Padding: 6
        bit-string: 40
      Data: bit-string (4)
        Padding: 3
        bit-string: 0000
      Data: utc-time (17)
        utc-time: Jan 1, 1970 00:00:00.000000000 UTC

> Ethernet II, Src: OmicronE_00:59:6e (20:b7:c0:00:59:6e),
  GOOSE
  APPID: 0x0002 (2)
  Length: 172
  Reserved 1: 0x0000 (0)
  Reserved 2: 0x0000 (0)
  goosePdu
    gocbRef: AA1J1Q01A2LD0/LLN0$G0$gcbInterlocking
    timeAllowedtoLive: 20000
    datSet: AA1J1Q01A2LD0/LLN0$Interlocking
    goID: AA1J1Q01A2LD0/LLN0.gcbInterlocking
    t: May 14, 2019 09:13:45.023955941 UTC
    stNum: 2
    sqNum: 28
    test: False
    confRev: 100
    ndsCom: False
    numDatSetEntries: 3
    allData: 3 items
      Data: bit-string (4)
        Padding: 6
        bit-string: 80
      Data: bit-string (4)
        Padding: 3
        bit-string: 0000
      Data: utc-time (17)
        utc-time: Jan 1, 1970 00:00:00.000000000 UTC
  
```

(a) Block deactivated

(b) Block activated

Figure 8.7: GOOSE blocking messages simulated and published by the test set



Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Zone 1	L1-E	No trip	No trip	No trip
Zone 1	L1-L2	No trip	No trip	No trip
Zone 1	L1-L2-L3	No trip	No trip	No trip
Zone 2	L1-E	No trip	No trip	No trip
Zone 2	L1-L2	No trip	No trip	No trip
Zone 2	L1-L2-L3	No trip	No trip	No trip
Zone 3	L1-E	No trip	No trip	No trip
Zone 3	L1-L2	No trip	No trip	No trip
Zone 3	L1-L2-L3	No trip	No trip	No trip

Table 8.6: Applied internal faults with blocked relay functionality and resulting trip times

### 8.3 Part 3: IEC 61850 Testing Tools in Practice

#### Part 3.1: Verify SV and GOOSE Test Message Simulation

Figure 8.8a shows a Wireshark trace of a GOOSE blocking message with the test flag deactivated, while Figure 8.8b shows the GOOSE message after the test flag has been activated. Similarly, a Wireshark trace of an SV message with the test flag deactivated is shown in Figure 8.9a, while Figure 8.9b shows the same type of SV message after the test flag has been activated.

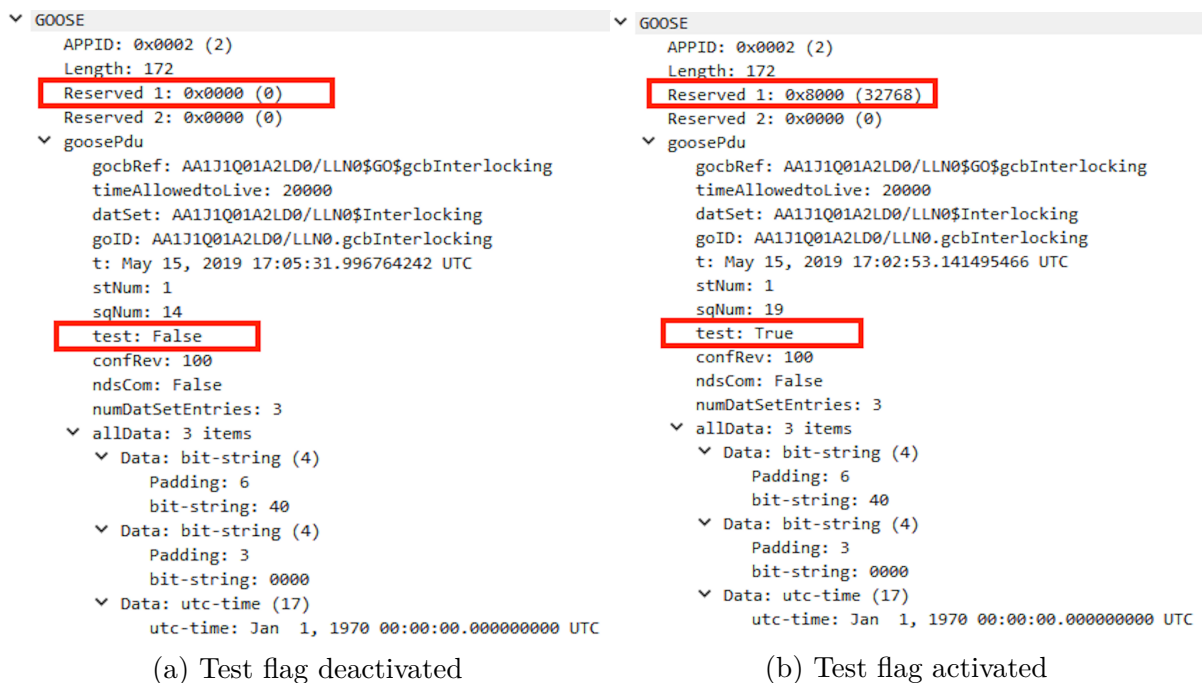


Figure 8.8: GOOSE test message verification using blocking message from OMICRON

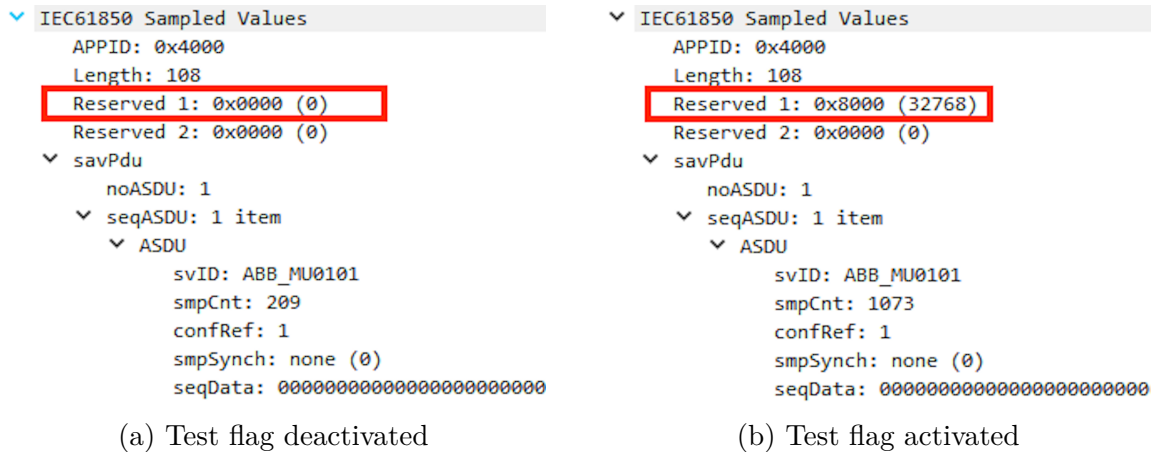


Figure 8.9: SV test message verification using SV message from OMICRON

### Part 3.2: Verify Dependability for Test Messages when in Test Mode

It was observed that the relay LEDs indicated trip signals as expected through the testing procedure of applying internal fault SV messages to the relay in test mode. The Advanced Distance test report is given in Appendix D, and its main results are presented in Table 8.7. A Wireshark trace of a GOOSE trip message published by the test set during the testing procedure is given in Figure 8.10.

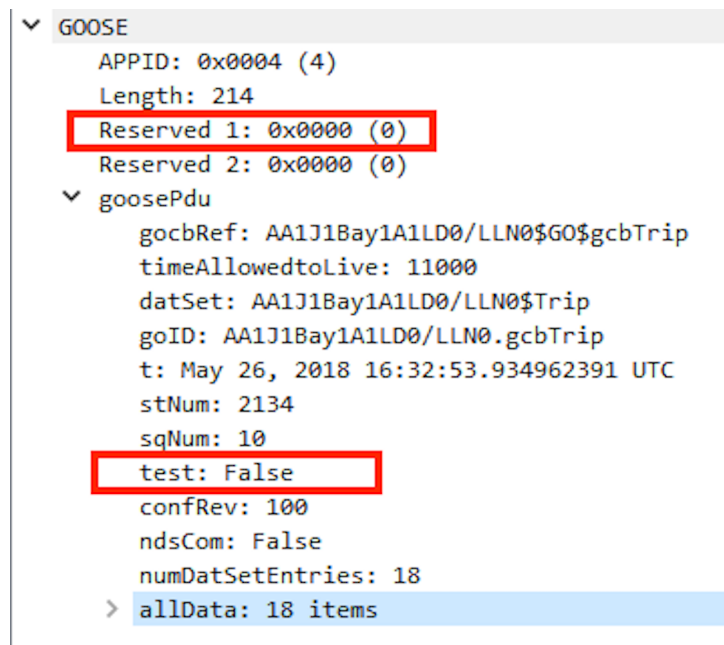


Figure 8.10: GOOSE test message verification using trip message from relay in test mode

Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Zone 1	L1-E	Trip Zone 1	0 ms	No trip
Zone 1	L1-L2	Trip Zone 1	0 ms	No trip
Zone 1	L1-L2-L3	Trip Zone 1	0 ms	No trip
Zone 2	L1-E	Trip Zone 2	300 ms	No trip
Zone 2	L1-L2	Trip Zone 2	300 ms	No trip
Zone 2	L1-L2-L3	Trip Zone 2	300 ms	No trip
Zone 3	L1-E	Trip Zone 3	600 ms	No trip
Zone 3	L1-L2	Trip Zone 3	600 ms	No trip
Zone 3	L1-L2-L3	Trip Zone 3	600 ms	No trip

Table 8.7: Internal faults and resulting trip times, test messages applied to relay in test mode

### Part 3.3: Verify Stability for Test Messages when in Normal Mode

Table 8.8 shows the main results of applying test messages indicating internal faults for the relay in normal operation. The full test report is given in Appendix D. The relay LEDs indicated trip throughout the testing procedure.

Fault location	Fault type	LED indication	Theoretical trip	Observed trip
Zone 1	L1-E	Trip Zone 1	No trip	32.7 ms
Zone 1	L1-L2	Trip Zone 1	No trip	24.5 ms
Zone 1	L1-L2-L3	Trip Zone 1	No trip	21.1 ms
Zone 2	L1-E	Trip Zone 2	No trip	334.5 ms
Zone 2	L1-L2	Trip Zone 2	No trip	323.2 ms
Zone 2	L1-L2-L3	Trip Zone 2	No trip	322.6 ms
Zone 3	L1-E	Trip Zone 3	No trip	621.3 ms
Zone 3	L1-L2	Trip Zone 3	No trip	622.4 ms
Zone 3	L1-L2-L3	Trip Zone 3	No trip	621.4 ms

Table 8.8: Applied internal faults and resulting trip times, test messages applied to relay in normal mode



# Chapter 9

## Laboratory Experiment Analysis and Discussion

An analysis and discussion of the results from the laboratory experiments are given in this chapter, making use of the theory described earlier in the report. The laboratory experiment results from Chapter 8 are analyzed using the same structure as in the method and result chapters. Verification of correct SV and GOOSE communication are given in Part 1, while Part 2 shows that the functionality tests worked as expected. In Part 3, there were problems related to the IEC 61850 test mode of the relay, and an analysis of this is given.

### 9.1 Part 1: Testing Communication Paths

#### Part 1.1: Verify SV Communication

The first part of the laboratory experiment was to verify that the SV publishing from the test set to the relay was configured correctly. Figure 8.1 shows that a constant stream of SV messages is being published to the process bus from the OMICRON, marked with the source "OmicronE.00:59:6e". This gives a clear indication that the SV messages originate from the test set, and is correctly published. In addition, the SV ID (*svID* = "ABB\_MU0101") is equal to the one being configured in Section 6.2.1. As introduced in Section 5.3.2 this is the main parameter to identify SV messages uniquely, so it is verified that SV messages are successfully published from the test set to the process bus.

Figure 8.1 does also indicate the amount of SV messages produced, as well as the time interval between each message. It is seen that 16 messages are detected over a period of 0.003691 seconds, which translates to 4335 messages per second. A more detailed analysis of this can be performed using the Wireshark trace in Figure 9.1, where it is shown that Wireshark detected a total of 120 132 packets during 30.000159 seconds, corresponding to 4004.4 messages per second. Note that the total amount of packets also takes into account regular communication messages from the process bus Ethernet switch, which means that the amount of SV messages is slightly lower than this number. As introduced in Section

2.5.4, IEC 61850 part 9-2 describes a transmission rate of 4000 messages per second for SV measurements in a 50 Hz system. Hence, it is verified that the test set produces SV messages at a rate that is in line with the IEC 61850 standard.

No.	Time	Source	Destination	Protocol	Length
120124	29.998160	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120125	29.998346	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120126	29.998661	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120127	29.998847	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120128	29.999159	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120129	29.999345	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120130	29.999654	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120131	29.999851	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122
120132	30.000159	OmicronE_00:59:6d	Iec-Tc57_04:00:01	IEC61850 Sampled Values	122

Figure 9.1: SV messages recorded in Wireshark in 30 seconds

The next step is to verify correct scaling of current and voltage measurements from secondary side values applied by the test set through its test modules to the primary side values published as SV messages, as introduced in Section 2.5.4. Table 8.1 shows that both the current and voltage magnitudes per phase received by the relay correspond with the secondary side values applied from QuickCMC, scaled by the CT and VT ratios defined in Section 6.1. Hence, the SV communication between the test set and relay as well as correct CT/VT ratios has been successfully tested and verified.

## Part 1.2: Verify GOOSE Trip Message Communication

The Wireshark trace in Figure 8.2 shows that a constant stream of GOOSE messages is being published from the relay, as configured in Section 6.3.1, sent at a regular interval of 10 seconds. This interval corresponds to the maximum retransmission time interval defined in the relay settings, as introduced in Section 2.5.3. This means that the contents of the GOOSE trip message have not changed between each message, which is as expected for a situation where the relay does not produce signals. Hence, it is verified that no changes occur in the trip message data before faults are applied.

After applying a fault in zone 1, the relay LEDs indicated a trip in zone 1 at the relay front panel, and Figure 8.3 confirms that binary input 1 of the test set was activated 78.1 ms after the fault was applied. In Section 6.3.2, binary input 1 of the test set was mapped to the general trip signal in zone 1 of the GOOSE message, which means that the GOOSE message was correctly received and interpreted by the test set. Note that the relay configuration in Section 6.5 said that no intentional time delay was to be added for faults occurring in zone 1 of the relay. However, there is a range of time delays that are introduced in the practical setup that in total results in the observed time delay, which is discussed further in Section 9.4.

A comparison of the GOOSE message content before and after tripping is given in Figure 8.4, which shows that the contents of the GOOSE message have changed after the relay tripped. The GOOSE dataset creation in Section 6.3.1 included 6 data items for each of the three zones of protection, giving a total of 18 items in the dataset; *General trip*,

*Trip phase A, Trip phase B, Trip phase C, Quality bit and Timestamp.* The figure shows that the boolean information in the first two items has changed, which corresponds to a general trip in zone 1 and trip for phase A in zone 1. This is exactly as expected when applying an SLG fault at *L1* in zone 1, so the GOOSE trip message communication has been successfully verified.

### Part 1.3: Verify GOOSE Blocking Message Communication

After applying GOOSE blocking message simulation, Figure 8.5 shows that a single stream of GOOSE messages is being published from the test set, each with a time interval of 10 seconds. This corresponds to the maximum retransmission time interval defined for the GOOSE blocking message in Section 6.4.1, which means that no changes in GOOSE data have occurred during this time interval. This is as expected before activating the blocking functionality.

After applying binary output 1, the fact that the LED switched from green to red indicates that the blocking functionality in the GOOSE messages is activated, as this was configured in Section 6.5. The comparison of GOOSE messages before and after this activation in Figure 8.6 shows that the data of the messages has changed. As configured in Section 6.4.1, the GOOSE dataset consist of three items; *stVal*, *Quality bit* and *Timestamp*. The bit string of the *stVal* parameter that is utilized to activate the trip functionality has changed from "40" to "80", which is interpreted as activation of the blocking functionality by the relay based on its LED indication.

## 9.2 Part 2: Testing Relay Functionality

### Part 2.1: Verify Stability at Normal Load Conditions

The results in Table 8.2 show that the relay did not indicate a trip in its front port LEDs when applying load conditions, and the test set did not receive GOOSE messages that were interpreted as trip signals. If the load conditions had entered zone 2 of the relay protection algorithm, this would be detected as a time-delayed trip of 300 ms. Hence, the relay has been correctly configured in terms of the load situation, even without using load encroachment. This means that the relay has been tested and verified at stability for normal load situations, which was specified as an important relay characteristic in Section 3.2.2. Hence, the test was passed.

### Part 2.2: Verify Stability for External Faults

Table 8.3 shows that the relay LEDs did not indicate relay algorithm trip for any of the applied external faults outside zone 2 and 3 and that the test set received no active trip signals. This is as expected when applying faults are outside the zones of protection, according to the description of distance protection zones in Section 3.2.2. When applying

faults just outside zone 1, i.e., within zone 2 of the relay algorithm, the relay LEDs indicated trip in zone 2. In addition, binary input 2 of the relay was activated. This is as expected, as the fault is seen as an internal fault in zone 2, which trips the relay algorithm. This changes the GOOSE trip message dataset, meaning that GOOSE trip messages are sent to the test set. Hence, this would have resulted in a time-delayed trip if this input had not been removed from the test set trigger logic when testing zone 1. The full test report for Part 2.2 in Appendix D confirms that the test set did not expect the tests to result in trip, and no trip was observed. This means that stability at external faults has been verified, and the test was passed.

### Part 2.3: Verify Dependability for Internal Faults

The results in Table 8.5 show that the relay tripped as expected for all applied internal faults. An average time delay of 26.04 ms between the theoretical and actual trip time was observed, which is discussed further in Section 9.4. In the full test report in Appendix D, the column "t nom" shows the expected trip time for each of the applied faults, while "t act" shows the time delay observed by the test set between applying measurements and receiving trip signals. The resulting deviation between these two values is automatically calculated in the column "Dev". All results show that the relay tripped as expected, which means that the test was passed.

### Part 2.4: Verify that the Blocking Message Prevents Relay Tripping

In this part of the laboratory experiment, the same internal faults as in Part 2.3 were applied, and the same relay configuration is used. The only difference is that a blocking message is simulated and applied from the test set, which will give different results if working correctly. Figure 8.7 shows that the contents of the GOOSE data change from *bit-string* = "40" to *bit-string* = "80" after the block functionality has been activated, which was found in Part 1.3 to give correct activation of the blocking functionality. The resulting test report shows that the relay did not trip for any of the internal fault situations from Part 2.3 that previously gave trip signals, which verifies that the blocking functionality worked as expected. Hence, the test was passed.

## 9.3 Part 3: IEC 61850 Testing Tools in Practice

### Part 3.1: Verify SV and GOOSE Test Message Simulation

The GOOSE message comparison in Figure 8.8 shows that the *test* parameter of the simulated GOOSE messages has changed from "False" to "True" after activating the test flag. This indicates that the test flag is successfully activated, in line with the GOOSE test flag discussion in Section 6.4.2. Besides, the *Reserved 1* parameter has changed from 0x0000 to 0x8000, which indicates that the GOOSE message has been sent for test



purposes, as introduced in Section 5.3.3. Hence, a GOOSE message marked for test purposes has been successfully simulated.

Figure 8.9 gives a similar comparison of SV messages before and after the test flag was activated in the test set simulation. From this, it can be seen that the parameter *Reserved 1* changed value from 0x0000 to 0x8000 as the test mode is activated. As described in Section 5.3.2, this is how SV messages are marked as being sent for test purposes, so simulation of SV messages with the test flag activated has been successfully established.

### Part 3.2: Verify Dependability for Test Messages when in Test Mode

The results in Table 8.7 show that the test set did not receive trip signals for any of the applied internal faults, meaning that the test was failed. However, the front panel LEDs indicated relay algorithm tripping throughout the test procedure, identical to what was observed in Part 2.3 when applying internal faults and not using test messages and test modes. Hence, the relay did not operate as expected in test mode when applying test messages. By analyzing the transmission interval between the GOOSE trip messages in Figure 8.10, it is evident that the relay did not publish GOOSE messages as a result of relay trip, but rather due to the retransmission system of GOOSE messages as introduced in Section 2.5.3. The *Reserved 1* parameter is 0x0000 and the parameter *test* is "False", even though this was sent from an IED in test mode. Hence, the relay did not respond with GOOSE trip messages with the test flag active, which it should according to the description in Section 4.4.4 when operating in test mode.

From this, it is clear that the relay test mode does not operate according to the IEC 61850 standard definition of IED test mode, as introduced in Section 4.4.1. A further analysis of the relay operation can be found through the relay HMI (*Test* → *Function Test Modes*). From here, the LN of each protective functionality has three parameters that may be modified; *Mod*, *Blocked* and *EvDisable*.

- ***Mod***: the *Mod* parameter of each LN may be changed independently from the *Mod* of the LD, as introduced in Section 4.4.1. However, when the IED test mode is activated, this value remains ON for all protective LNs. The interface allows for changing this to any of the five values defines in IEC 61850 Edition 2, but only ON and OFF seem to work. When trying the other values; TEST, TEST/BLOCKED and ON/BLOCKED, an error message "Value not supported in current IEC 61850 Edition" appears.
- ***Blocked***: this parameter is automatically set to "Yes" when the IED test mode is activated. This shows that rather than having support for the BLOCKED values of the *Mod* parameter, this is implemented as a separate parameter.
- ***EvDisable***: used to disable the reporting of events to components at the station level.

From this, it is clear that the IED test mode sets *Mod* = ON and *Blocked* = "Yes" for every protective functionality LN, which means that the relay algorithm operates but no output signals are produced from the protective functionalities. This explains why the

relay LEDs indicated trip signals, but no active GOOSE trip messages were produced. This means that the relay test mode is suited for testing each protective functionality individually, by blocking the other functionalities from operating. However, a significant weakness to this solution is that once the physical relay is put into test mode, all protective functionalities are automatically blocked, which is not suited for performing testing on relays in operating substations. It is wanted to keep most protective functionalities in a relay in normal operation while putting the LN of the functionalities to be tested in test mode by setting  $Mod = TEST$  for these LNs. This separates their traffic from normal operational traffic through test messages, but this is not possible with the test mode of this relay. This problem is similar to the problems described by utility experiences from Statnett in Section 4.5.1. This described that IEDs only from one out of the three utilized vendors allowed for setting individual LNs in test mode, while the other two only were able to put the entire device in test mode. However, the problem with the relay used in the laboratory experiments is that in addition to only being able to put the entire IED in test mode, this test mode did not operate as expected.

Another problem with the relay test mode is that it does not work according to the discussion of LN and LD  $Mod$  parameters and resulting LN behavior  $Beh$  in Section 4.4.1. In the above discussion, it was found that the LD of the relay could be configured to the mode  $Mod = TEST$ , and the LN of each protective functionality was automatically set to  $Mod = ON$ . According to the described theory and looking at the table in Appendix A, this combination should give a resulting LN behavior  $Beh = TEST$ . However, it seems like this is not the case for the relay used in the laboratory setup.

The relay used in the laboratory experiments is an ABB RED 670 of version 2.0.0 and utilizes IEC 61850 Edition 2.0. ABB has been contacted about this issue, and lack of full IEC 61850 test mode is a known matter for this generation of ABB relays. Different vendors seem to have different interpretations of each version of the IEC 61850 standard, and the standard is continuously under development. Hence, it is likely that ABB considered the IED test mode description in IEC 61850 as incomplete at the time of making this generation of relays, which is an explanation of why the relay test mode did not operate as expected. From the relay HMI, it was shown that it was possible to put each LN in test mode, but that this resulted in an error message. This shows that they had this functionality in mind while developing the relay. ABB has also stated that their newer generation of relays fully supports IEC 61850 test mode and that this should be implemented in the NTNU relay laboratory as soon as possible.

### **Part 3.3: Verify Stability for Test Messages when in Normal Mode**

The results in Table 8.8 show that the relay tripped for all of the applied internal faults, which was not expected for this laboratory experiment, meaning that the test was failed. The relay LEDs indicated that the relay algorithm resulted in trip signals as in Part 3.2, but now there was also generated active GOOSE trip messages. Similarly to Part 3.2, these GOOSE trip messages did not have the test flag activated. By comparing the results in Table 8.8 with the ones obtained in Part 2.3 when applying the same faults but without activating the SV test flag, these tests gave almost identical results, only with

slight differences in trip time. This means that the relay operated the same way to applied internal fault SV messages with the test flag active and inactive. Since it was shown in Part 3.2 that the relay test mode did not operate completely according to the IEC 61850 standard, these results might have been expected. It seems like rather than taking SV test flags into account, this is neglected by the relay and its response is independent of SV test flags.

## 9.4 Observed Trip Time Delay

The resulting trip times from Part 1.2, 2.3, and 3.3 all show that an unintentional time delay was observed between applying faults and receiving trip signals. The total time delay is measured in the test set as the time from faults are applied by activating a test module until a binary input is interpreted as an active trip signal. In the practical laboratory setup, this delay may be caused by all parts of the communication loop, as well as the mapping of GOOSE and SV messages. There are delays when mapping analog signals from the OMICRON test module into SV messages and when publishing GOOSE messages from the relay, as well as a transmission delay across the process bus network in both directions. Besides, the relay algorithm has an operational time, and the mapping of trip GOOSE messages into the binary input of the test set introduces a time delay.

The unintended time delay of 78.1 ms observed in Part 1.2 is unfeasible for most protection purposes in practical substations. This would typically be unveiled in relay performance testing of full substations, as introduced in Section 4.1.1, rather than functional testing. However, it is shown in Table 8.5 that time delays in the range of 19.0 to 35.5 ms were observed when applying test shots using Advanced Distance Module in Part 2.3 of the laboratory experiments. Similarly, Part 3.3 showed time delays in the range of 21.1 to 33.4 ms, with an average unintended delay of 24.86 ms. These delays are at a magnitude closer to what would be expected in full substations.

This shows that the time delay related to SV and GOOSE mapping, process bus transmission, and relay algorithm does not make up the most significant part of the 78.1 ms time delay in Part 1.2. Hence, this time delay is most likely due to the test module that is ramping up the analog currents and voltages that are mapped to SV messages. QuickCMC was used in Part 1.2, which applies steady state values instead of the direct test shots utilized by Advanced Distance Module in Part 2.3 and 3.3. In addition, no pre-fault conditions were applied in Part 1.2 of the experiment, which means that the currents and voltages would have to be ramped up from zero in the analog outputs and then converted into SV messages. By applying pre-fault conditions before applying the fault in QuickCMC, this time delay may have been reduced.



# Chapter 10

## Discussion

This chapter provides discussions of the main topics and research question of this thesis, starting with a discussion of the transition from conventional to digital substations and how this affects substation test procedures. The established laboratory setup is discussed, as well as how this may be developed and improved. A discussion of how this setup can be generalized is also presented, as well as how this translates into a full digital substation environment. The test procedures utilized in the laboratory experiments and how they translate into practical substation test procedures are also covered. The use of Wireshark as a tool for analyzing process bus GOOSE and SV traffic is also discussed before possibilities for the future development of digital substation testing are explored.

### 10.1 Transition from Conventional to Digital Substations

As seen in Chapter 2, the transition from conventional to digital substations means that analog communication through parallel copper cables between process and bay level equipment is replaced with digital communication over a process bus. This means that rather than installing miles of parallel copper cables between process and bay level equipment, a single optical Ethernet bus may be installed.

#### 10.1.1 Advantages

Digital substations reduce the environmental impact of substations due to the large reduction in copper cabling, and may also simplify installation and commissioning processes. The power grid of the future is likely to contain increased amounts of renewable energy sources like wind turbines and solar panels, introducing a more time-varying and demanding operation of the grid. Digital substations are more suited to this change than conventional substations since it is easier to perform system reconfiguration or implementing adaptive protection settings using GOOSE messages between IEDs.

The plug and play features introduced by IEC 61850, as described in Section 2.5.6, means that rather than having each vendor going their own direction with substation component development, this is likely to be gathered more towards common goals through the IEC 61850 standard. This may give faster development of substation technology, as solutions from different vendors may build on top of each other rather than each vendor having different tailor-made solutions. The fact that customers can choose freely between vendors when purchasing digital substation components also gives increased customer flexibility and demands more streamlined processes for vendors to compete in this market.

### 10.1.2 Challenges and Limitations

A challenge with digital substations is that while full interoperability and plug and play functionality work in theory, this does not always work as easily in practice. As experienced in Part 3.2 of the laboratory experiments, the relay used for testing was shown not to support the full IEC 61850 test mode. This was also seen in the utility experiences in Section 4.5.1, where only one out of three vendors allowed for setting individual LNs in test mode. This can potentially cause major issues when performing relay testing in digital substations, so it is critical that thorough conformance testing is performed to make sure that all components support all necessary IEC 61850 features. This also requires a personnel that has an in-depth understanding of this technology. Section 4.5.2 showed that utilities had experienced practical challenges related to digital substation testing, showing that more experience is needed to make these processes more efficient.

The transition towards digital substations does also introduce new challenges like time synchronization between substation equipment and network load on the process bus, as seen in the utility experiences in Section 4.5.3. This introduces additional possible points of failure to substations, which have to be handled with great caution. Large network load may result in loss of time-critical GOOSE messages, potentially giving increased CB trip time or loss of interlocking conditions. Time synchronization was not an essential part of the laboratory setup in this thesis, since using the OMICRON as the master clock was sufficient for the laboratory experiments. However, loss of time synchronization may potentially mean that IEDs stop working as expected, so this has to be taken into account and developed in the future. No problems related to network load were experienced during the laboratory work, but this may have been tested by publishing several streams of parallel SV messages from the test set.

In a transition period, some vendors may choose to implement digital substation technology with process bus and MUs only in some parts of a substation. This may increase the difficulty of relay test procedures, as principles from both conventional and digital substation testing have to be utilized simultaneously. However, the OMICRON CMC 356 test set used in the laboratory experiments generates both analog and digital signals simultaneously, as described in Section 5.1. This means that even though substations may have components from both conventional and digital substation technology, this test set can be used for testing both. Besides, the fact that OMICRON has implemented digital communication to the test set through a direct mapping between digital messages and the analog ports of the relay, all test modules may be used in the same way as with conventional substations. This means that the transition requires little adaptation from

the test set operating personnel, as only the additional GOOSE and SV configuration tools are new.

## 10.2 Laboratory Setup and Configuration

An essential goal of this thesis was to establish a laboratory setup with fully functional process bus communication between a relay and a test set. The setup and configuration of this equipment were shown in Chapter 5 and 6, and was proven to work through Part 1 of the laboratory experiments. While the setup is limited to a single ABB relay and an OMICRON test set connected by a process bus, the configuration of these components was suitable to show key principles of GOOSE and SV communication over an IEC 61850 process bus in practice. Also, the fact that the components from well-established and market leading vendors were utilized means that this might be relevant elsewhere.

### 10.2.1 Possible Areas of Improvement

While the laboratory setup was successfully used to show fundamental principles in practice, its simplicity does offer much room for development and improvement. For once, the fact that the relays did not fully support IED test modes as described in IEC 61850 Edition 2 could have been discovered at an earlier stage, which may have allowed for finding a way around this. The laboratory setup could also have been improved by implementing relays from different vendors to get better conditions for studying a generalization of the laboratory setup. However, the only available relays with IEC 61850 compatibility were other ABB relays of the same generation. Hence, the configuration of these relays would not offer any new experiences as they would follow the same procedures as described in Chapter 6.

Another possible area of improvement is to implement more than one single relay into the setup. This was one of the possible ways that were considered to expand the laboratory setup considered in this thesis if time and work restrictions allowed it. For example, this could have been used to show how the IEC 61850 testing tools allowed for a separation of normal and test related operation, by having one relay in test mode and the others in normal mode. However, since the test mode of the available IEDs was found not to work as expected, this would not have been possible to put into practice. Hence, a setup with additional relays was not established.

In addition to the laboratory setup itself, the publishing of GOOSE messages may also have been made more relevant for practical substations. While trip messages from relays is a very typical use of GOOSE messages, the pilot protection blocking messages configured in Section 6.4 are not included in all existing substations. With a more complex laboratory setup, it may have been possible to simulate more typical messages for horizontal communication between IEDs in substations, for example, messages related to interlocking between switchgear. However, the blocking message illustrates the creation of GOOSE datasets and test set GOOSE publishing nicely.

## 10.3 Generalization of the Laboratory Configuration

The laboratory setup and configuration up until this point have illustrated how the communication paths between a relay and a test set can be established in a digital substation environment using the NTNU relay laboratory. However, the research questions also stated that it is wanted to generalize this process to allow the utilized ABB relay to be changed with other relays from different vendors. When testing relay functionality in practical digital substations, this often includes performing test procedures on a variety of relays from different vendors. For this discussion, it is assumed that the test set is fixed, as relay testing typically involves test sets from the same vendor. Since one of the motivations behind upgrading from conventional to digital substations is reduced testing time, it is wanted that the process of establishing a test setup is as seamless as possible. If large parts of the configuration and setup have to be tailored for each relay, this will increase the workload and time demand of testing processes. The way to solve this is to utilize the SCL files and engineering tools introduced by IEC 61850, as described in Section 2.8, that allows for structuring and communicating substation information in an abstract standardized way.

### 10.3.1 SV Subscription in Relays

Section 6.2 showed that the configuration of SV subscriptions for the ABB relay meant that the SV ID of the virtual MUs of the relay had to be identical to the SV IED of the messages generated by the test set. This process can be generalized by utilizing SCL files to transfer the configuration from the test set to the relay configuration tool. After the OMICRON SV Configuration Tool has been used to generate SV streams from the test set, it is possible to export this in a CID format. This file includes all parameters that are needed to set up a subscription to these SV messages, as described in Section 6.2.1, in a standardized format that can be interpreted by all relays with full IEC 61850 compatibility. This means that even if relays from other vendors require other SV parameters in addition to the SV ID, all SV parameters are easily available. By importing this file into the relay configuration, the relay can be configured to subscribe to these in a streamlined process. Note that even if several SV streams are published by the relay simultaneously, every parameter of all streams is included in this file.

### 10.3.2 GOOSE Publishing from Test Set

SCL files may also be used to transfer GOOSE datasets between relays and test sets, which may help the configuration of GOOSE simulation from a test set. However, this is not as straight-forward as with SV messages, as it is critical that the GOOSE dataset published by the test set is equivalent to the ones defined in the relay configuration. While Section 6.2.2 showed that SV messages only need the header information to be equivalent, Section 6.4.2 showed that GOOSE messages also need the payload structure of the message to be equivalent for the GOOSE message to be applicable in the receiving relay. This means that the most sensible way to do this is to create a GOOSE dataset from the relay, which



may then be exported as a CID file that contains all GOOSE datasets available in a substation. This can then be imported into the test set, and GOOSE publishing may be configured using the same procedure as in Section 6.4.2.

### **10.3.3 GOOSE Publishing from Relays**

If a relay is configured to publish GOOSE messages, this may easily be transferred to the test set if the relay is fully IEC 61850 compatible. This process is equivalent to the one described in Section 6.3.2, where the dataset of the published GOOSE message has to be exported from the relay as a CID file and imported into the test set to configure a subscription to these messages. After this, the contents of the GOOSE dataset has to be mapped to the functionalities of the test set to be appropriately interpreted.

## **10.4 Transferring Laboratory Experiments to Full Substations**

To make use of the principles used for testing an isolated relay in a digital substation environment in the laboratory in practice, this must be transferred to a full digital substation. While problems related to the IED test mode was experienced in Part 3.2 and 3.3 of the laboratory experiments, it is for the rest of this discussion assumed that these work as specified in IEC 61850 Edition 2 and described in Section 4.4.

### **10.4.1 Configuring Test Set SV Communication**

When applying test sets to a practical digital substation, the substation IEDs are typically already configured to subscribe to SV messages from a given MU. The test set can be configured to publish SV messages with header information that is equivalent to the messages sent from a given source to simulate messages from this source. As long as the header information is equivalent, the relay reacts to these messages as if they were published from its original source. Hence, this allows for injecting current and voltage measurements from the test set that are interpreted as normal operational messages by the relays that are configured to subscribe to SV streams from the simulated MU.

### **10.4.2 Configuring Test Set GOOSE Communication**

An essential element of the engineering process of new digital substations is to create a set of SCL files that describes the substation in a standardized way, as introduced in Section 2.8. This means that for practical substations, all GOOSE datasets defined in the substation are given in SCD files, which can be used to configure GOOSE communication to the test set. By importing this into OMICRON GOOSE Configuration Module, publishing and subscription of relevant GOOSE messages to and from the test set may be configured using the same procedures as described in Section 6.3.2 and 6.4.2

### 10.4.3 Utilizing IEC 61850 Test Tools in Full Substations

The IEC 61850 testing tools described in Section 4.4 must be utilized properly to transfer the laboratory experiments of performing relay functionality testing for an isolated relay into a full digital substation. This allows for virtual isolation of the relay functionalities that are to be tested, giving a similar scenario to the laboratory setup. Using these tools in practice was one of the research questions of this thesis, but this turned out to be problematic due to the lack of IED test mode for the utilized relays. However, these issues are likely to be eliminated as the digital substation technology matures.

A description of how virtual isolation may be achieved in full substations using IEC 61850 test tools is best given by an example. Suppose that some protective functionalities within a relay are to be tested, while all other protective functionalities in the substation are in normal operation. First, the LNs of the relay functionalities to be tested should be set to test mode by setting the DO *Mod* = TEST, while the LN of the corresponding CBs should be set to *Mod* = TEST/BLOCKED. Note that the LD of the relay should remain *Mod* = ON, as setting this to TEST results in behavior *Beh* = TEST for all its protective functionality LNs, as seen in Appendix A.

A test set can inject SV messages to the appropriate relay as described above, with the SV test flag activated. The relay will then process these values, and if they violate the relay protection algorithm, a GOOSE trip message with the test flag activated will be sent to the associated CBs. The CBs will receive the message, but they will not trip since they are in TEST/BLOCKED mode. After such testing procedures are performed, the resulting relay actions may be analyzed by inspecting the DOs *opRcvd* and *opOK* as introduced in Section 4.4.3, even if no physical trip can be seen by inspection. This separation of normal and test operation allows for testing relay functionalities in an operating substation, without reducing the operational safety of the system during the test procedure. Note that this requires that the protective tasks of the LNs that are set to *Mod* = TEST will have to be covered by other protective functionalities that are in normal operation, at least temporarily.

## 10.5 Transferring Laboratory Experiments to Practical Test Procedures

The primary purpose of Part 2 of the laboratory experiments was to illustrate the main principles related to relay functionality testing in practice. However, they are not directly applicable for test procedures in practical substations as these are far more complex, consisting of more steps and testing more functionalities. An attempt was made to translate a conventional substation test procedure from Statnett into a digital substation test procedure to retain the details of existing well-established test procedures. However, this was proven to be unfeasible for this thesis, as this requires an implementation of a more complex laboratory setup with additional relay functionalities like breaker failure protection and reclosing of CBs. Hence, the purpose of this section is to describe how this translates in theory.

### 10.5.1 Fundamental Principles

As introduced in Section 3.1, four fundamental principles have to be taken into account in protective relaying schemes; security, dependability, stability, and selectivity. For this to be achieved, it is important to verify that the protective functionalities of each relay work as expected through relay functionality test procedures. Part 2 of the laboratory experiments cover the testing of stability at healthy load situations, stability for external faults, and dependability for internal faults for an isolated relay. Hence, the main principles for performing distance relay protection testing are covered.

### 10.5.2 Relay Testing

The performed testing procedures have the main focus of verifying that the zones of protection are configured correctly and that the relay operates according to the configured zones. This type of test procedure for isolated relays are typically performed by the relay vendor after production in the relay FAT, as introduced in Section 4.1. In addition to this, conformance testing is typically performed after production, which in the case of relays for digital substations verifies relay compatibility with the IEC 61850 standard. Through these conformance tests, the problems related to lack of IED test mode experienced in Part 3.2 of the laboratory experiments would have been discovered at an early stage. Performance testing of each relay would have to be performed to check that the relay operated within given time limits, which would have detected the fairly long trip time that was discovered in Part 1.2 of the laboratory experiments.

After delivery to the substation side, a SAT is typically performed for each bay. This typically includes testing of features surrounding the relay, like switchgear operation and communication with other parts of the system. The testing of pilot protection blocking signals in Part 2.4 scratches the surface of this type of testing. The relay themselves are typically tested with a focus of functionalities related to features like reclosing and breaker failure protection (trip repeat), which are not included in the performed experiments. Towards the end of SAT testing, the bay is typically energized, and it is verified that the relays are correctly receiving currents and voltages, similar to the principles explored in Part 1.1 of the laboratory experiments. It is often also verified that the relays have stability at normal load situations, as tested in Part 2.1 of the experiments.

## 10.6 Using Wireshark to Analyze Process Bus Traffic

When installing digital substation components in the NTNU relay laboratory, a decision had to be made about how to analyze process bus traffic. One possibility was to do this from the OMICRON test set utilizing the Test Universe module IEDScout, as introduced in Section 5.1.3. The test set used in the laboratory setup has full support of this module, but is not used as the license for this tool has not been purchased. The chosen solution was to use Wireshark, a free network traffic analysis tool introduced in Section 5.3.1.

### 10.6.1 Wireshark

Through the laboratory experiments, Wireshark has shown to provide everything necessary to analyze GOOSE and SV process bus traffic. Both SV and GOOSE messages were analyzed, and all main parameters related to the message header and the most important metadata is easily available. However, one limitation is that it is not straight-forward to perform a detailed analysis of the payload of SV messages and thereby determine the current and voltage measurements of each phase. For example, the Wireshark trace of an SV message in Figure 8.1 shows how its current and voltage contents are presented in the parameter *seqData*. This is structured as a string of hexadecimal numbers of a standardized format, which means that it is possible to dissect this data into currents and voltages for each phase and convert their values from hexadecimal values to decimal numbers. This is a tedious process, which means that Wireshark is not suitable for analyzing the payload of SV messages. This may, for example, be needed if the relay receives measurements that are not as expected based on the injected signals, where one could analyze the SV messages to see whether the issue lies within the relay or in the test set. However, it is easy to see whether SV messages carry measurements or not, since the *seqData* is all zeros if all of its currents and voltages are zero. This can be used to determine whether injected measurements are correctly mapped to SV messages or not.

### 10.6.2 Alternative: IEDScout

While Wireshark is a solid network traffic analysis tool, IEDScout has the advantage of additional functionalities and features. While Wireshark is a general tool that is more often used in computer network engineering than in digital substations, IEDScout is tailor-made for digital substations. As seen in Section 5.1.3, IEDScout may simplify the process of configuring test set GOOSE subscriptions, especially if no SCL file is available for a substation. For example, the second configuration method described in Section 5.1.3 shows that IEDScout is capable of detecting previously unknown GOOSE messages on the process bus and directly implement them into the GOOSE Configuration Module. Besides, IEDScout offers features for simulating entire IEDs based on their CID file, as well as tools for viewing and modifying SCL files. Hence, IEDScout may be useful for performing more complex laboratory experiments than the ones implemented in this thesis.

## 10.7 Future Development in Digital Substation Testing

The transition towards digital substations introduces a wide range of possibilities for creating more efficient relay test procedures in the future. As seen in the laboratory experiments and Section 4.2.2, the broadcast nature of digital communication over Ethernet networks means that no physical reconnections are needed during relay test procedures in digital substations. Besides, test sets purely based on digital communication are likely to be cheaper than conventional test sets, or hybrid test sets like the one used in the

laboratory experiments, since no analog electrical equipment is needed. This may make it economically feasible to install permanent test sets within each digital substation, which may be controlled remotely. This means that it would be possible to perform remote testing of substation components, without having to send personnel to the substation. This would reduce operational costs related to testing and allow for more frequent maintenance testing of components.

This may be taken a step further by implementing automatic test procedures in digital substations. The standardized step-by-step nature of testing procedures can be implemented into digital systems, resulting in test procedures that are at least partly automated. The test results may be analyzed automatically or sent to remote substation personnel for analysis.



# Chapter 11

## Conclusions and Further Work

The main conclusions and takeouts from the thesis are given in this chapter, along with answers to the research questions stated in Chapter 1. In addition, some suggestions for possible further work within the topic of digital substation testing are presented.

### 11.1 Summary and Conclusions

#### 11.1.1 Transition Towards Digital Substations

Correct operation of substations is an important part of a well-functioning power grid, and a transition from conventional to digital substations has started in recent years. In Chapter 2, it is shown that the main difference between conventional and digital substations is that the communication between process and bay level equipment has changed. Conventional substations utilize hardwired point-to-point copper cables carrying analog signals for this communication, while digital substations replace this with an IEC 61850 digital process bus.

Chapter 4 shows that this transition has significant impacts on how relay functionality testing may be performed. Conventional substation components are typically tested using hardwired point-to-point test plugs to inject current and voltage measurements from a test set to a relay, but this is not possible in digital substations since its relays have no analog terminals. Instead, the test set must simulate digital GOOSE and SV messages that the relay is configured to subscribe to, as well as subscribing to responding GOOSE messages from the relay. To facilitate digital substation testing, IEC 61850 defines a set of testing tools, with IED test mode and GOOSE and SV test messages as the main features. By using these tools appropriately, it is possible to separate normal operational traffic from test relayed traffic, which can be used to obtain virtual isolation of protective functions to be tested.

### 11.1.2 Laboratory Setup

A laboratory setup implementing a digital substation environment is successfully established in the NTNU relay laboratory, as described in Chapter 5. This consists of an ABB distance relay and an OMICRON relay test set, communicating over a process bus. GOOSE and SV communication was successfully configured in Chapter 6, which allows for performing a series of relay functionality tests for an isolated relay as described in Chapter 7.

### 11.1.3 Laboratory Experiments and Wireshark

In total, the results from Part 1 of the laboratory experiments show that the setup and configuration loop between the test set and the relay is working as expected. Hence, it is possible to establish both GOOSE and SV communication using the available laboratory equipment. Part 1.1 verifies that it is possible to publish SV messages from the test set that are correctly received and interpreted by the relay. Part 1.2 shows that the relay is able to publish GOOSE trip messages, which was shown to be appropriately interpreted as trip signals in the test set. In Part 1.3, it is shown that the test set is able to publish GOOSE messages, which are correctly received and implemented in the relay functionality.

The results from Part 2 show that it is possible to use the established laboratory setup to perform a series of experiments that illustrate the fundamental principles of relay functionality testing in practice. Part 2.1 verifies relay stability at load conditions, while Part 2.2 successfully tests stability against external faults. In Part 2.3, it is confirmed that the relay operates as expected to clear internal faults, before a pilot protection GOOSE blocking message simulated from the test set is shown to operate appropriately in Part 2.4. In Part 3, some problems related to IEC 61850 testing tools are discovered. Part 3.1 shows that the OMICRON is able to publish both GOOSE and SV messages with the test flag activated, meaning that test message simulation is successful.

In Part 3.2, some shortcomings are discovered in the laboratory setup, as it is shown that the relay does not fully support IED test mode as described in IEC 61850 Edition 2. When putting the relay in test mode, all protective functionalities are blocked. While it is possible to put the entire IED in test mode, it is not possible to change the *Mod* parameters of each LN to any other values than ON and OFF. This means that the relay does not support a separation of normal operational traffic from test related traffic, which is confirmed by the fact that the relay is shown to ignore SV test flags. Through the laboratory experiments, it is also experienced that Wireshark provides everything that is needed for analyzing process bus traffic in this thesis, including GOOSE and SV message details. However, for more complex configurations it may be useful to use more advanced tools like IEDScout to simulate IEDs and analyze network traffic in an easier way.



### 11.1.4 Transferring Laboratory Setup and Tests to Practical Substations

The established laboratory setup may be generalized to make its configuration applicable across various relays from different vendors. The key to achieve this is to utilize SCL files as introduced in IEC 61850, which may be used to import and export GOOSE and SV information between relays and test sets in a standardized way. This may also be utilized to transfer the laboratory setup and configuration principles into full digital substation environments. SCL defines CID files that give a standardized, abstract description of the IED configurations within a digital substation, and these should be created through the engineering process of IEC 61850 digital substations. All information related to GOOSE publishing and subscription as well as SV subscriptions for the IED is given in this file. Hence, the CID files of the relays to be tested can be imported into test sets to configure GOOSE publishing and subscription and SV simulation from the test set.

While the relay functionality testing performed in the laboratory experiments were shown to be too simple for full substations, their fundamental principles are still applicable in practice. The test procedures in Part 2.2 and 2.3 of the laboratory experiments are similar to the FAT testing typically performed by relay vendors after production, while Part 2.1 is similar to substation energizing testing typically performed at the end of SAT procedures. However, for complete testing of a full substation, both conformance and performance testing of relays are necessary in addition to functional testing.

### 11.1.5 Future Development of Digital Substation Testing

The future of substation testing shines bright in the light of digital substation technology. As the technology matures and vendors get more coordinated and in line with the development of the IEC 61850 standard, it is realistic to expect possibilities for performing remote testing in the future. It is also very likely that automated, or at least partially automated, test procedures will be implemented in digital substations over time.

## 11.2 Suggestions for Further Work

This thesis has scratched the surface of digital substations and relay testing procedures within such environments, which has uncovered a lot of exciting possibilities for further work. One possibility is to expand the established laboratory setup with additional relays from different vendors, to explore the interoperability between these components. In theory, this should be a straight-forward process through the plug and play features of IEC 61850, but this has shown to be more problematic in practice.

It is also possible to build on this thesis by introducing more complex relay functionalities like breaker failure protection and reclosing. This increases the complexity of the laboratory setup and allows for implementing more complete test procedures. If this is successfully established, it may be possible to analyze a well-established relay functionality testing procedure for a relay in an existing substation and convert this into a digital

substation environment which may then be performed in the laboratory. This would allow for performing laboratory experiments that are closer to practical testing procedures than the ones used in this thesis.

Another possibility is to make a more in-depth analysis of IEC 61850 test tools, that were shown not to work entirely as expected with the equipment used in the laboratory setup of this thesis. I have given feedback on the fact that the relays installed in the NTNU relay laboratory do not fully support these features, which is known by the vendors. I have received indications that the relays in the lab will be replaced with newer ABB relays that have support for all the newest IEC 61850 functionalities. This can be used to utilize the IEC 61850 testing tools in practice, hopefully working according to the standard. This will allow for performing further analysis of IEC 61850 test tools in the laboratory. For example, one could add several relays to the laboratory setup where some are operating in test mode, and others are operating in normal mode, and see whether or not it is possible to utilize this to create virtual isolation of individual relays.

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# Appendices





# Appendix A

## LN Behavior

LD Setting ( <i>Mod</i> )	LN Setting ( <i>Mod</i> )	Resulting LN Behavior ( <i>Beh</i> )
ON	ON	ON
ON	ON/BLOCKED	ON/BLOCKED
ON	TEST	TEST
ON	TEST/BLOCKED	TEST/BLOCKED
ON	OFF	OFF
ON/BLOCKED	ON	ON/BLOCKED
ON/BLOCKED	ON/BLOCKED	ON/BLOCKED
ON/BLOCKED	TEST	TEST/BLOCKED
ON/BLOCKED	TEST/BLOCKED	TEST/BLOCKED
ON/BLOCKED	OFF	OFF
TEST	ON	TEST
TEST	ON/BLOCKED	TEST/BLOCKED
TEST	TEST	TEST
TEST	TEST/BLOCKED	TEST/BLOCKED
TEST	OFF	OFF
TEST/BLOCKED	ON	TEST/BLOCKED
TEST/BLOCKED	ON/BLOCKED	TEST/BLOCKED
TEST/BLOCKED	TEST	TEST/BLOCKED
TEST/BLOCKED	TEST/BLOCKED	TEST/BLOCKED
TEST/BLOCKED	OFF	OFF
OFF	ON	OFF
OFF	ON/BLOCKED	OFF
OFF	TEST	OFF
OFF	TEST/BLOCKED	OFF
OFF	OFF	OFF

Table A.1: Combinations of LN and LD *Mod* values and resulting *Beh* values  
**Source:** [12] - OMICRON (2019). Modified



# Appendix B

## Relay Parameter Settings

Group / Parameter Name	IED Value	PC Value	Unit	Min	Max
✓ Application Configuration					
✓ ANALOG_INPUTS					
✓ Analog modules					
✓ 3 phase analog group					
✓ SMAI1: 1					
✓ AI1NAME		GRP1L1			13 characters
✓ AI2NAME		GRP1L2			13 characters
✓ AI3NAME		GRP1L3			13 characters
✓ AI4NAME		GRP1N			13 characters
✓ GlobalBaseSel		1		1	12
✓ DFTRefExtOut		InternalDFTRef			
✓ DFTRefence		InternalDFTRef			
✓ ConnectionType		Ph-N			
✓ AnalogInputType		Voltage			
✓ SMAI7: 7					
✓ AI1NAME		GRP7L1			13 characters
✓ AI2NAME		GRP7L2			13 characters
✓ AI3NAME		GRP7L3			13 characters
✓ AI4NAME		GRP7N			13 characters
✓ GlobalBaseSel		1		1	12
✓ DFTRefence		InternalDFTRef			
✓ ConnectionType		Ph-N			
✓ AnalogInputType		Current			

## APPENDIX B. RELAY PARAMETER SETTINGS

✓	PROTECTION				
✓	Impedance protection				
✓	DistanceZones(21.Z<)				
✓	ZMRPDIS: 1				
✓	GlobalBaseSel	1		1	12
✓	Setting Group1		<input checked="" type="checkbox"/>		
✓	Operation	On			
✓	OperationDir	Forward			
✓	X1PP	7,00	Ohm/p	0,10	3000,00
✓	R1PP	1,50	Ohm/p	0,01	1000,00
✓	RFPP	10,00	Ohm/l	0,10	3000,00
✓	X1PE	12,00	Ohm/p	0,10	3000,00
✓	R1PE	2,40	Ohm/p	0,01	1000,00
✓	X0PE	1,00	Ohm/p	0,10	9000,00
✓	R0PE	0,10	Ohm/p	0,01	3000,00
✓	RFPE	10,00	Ohm/l	0,10	9000,00
✓	OperationPP	On			
✓	OpModetPP	On			
✓	tPP	0,000	s	0,000	60,000
✓	OperationPE	On			
✓	OpModetPE	On			
✓	tPE	0,000	s	0,000	60,000
✓	IMinOpPP	10	%IB	10	1000
✓	IMinOpPE	10	%IB	10	1000
✓	IMinOpIN	5	%IB	5	1000
✓	ZMRAPDIS: 2				
✓	GlobalBaseSel	1		1	12
✓	Setting Group1		<input checked="" type="checkbox"/>		
✓	Operation	On			
✓	OperationDir	Forward			
✓	X1PP	15,00	Ohm/p	0,10	3000,00
✓	R1PP	2,80	Ohm/p	0,01	1000,00
✓	RFPP	10,00	Ohm/l	0,10	3000,00
✓	X1PE	19,00	Ohm/p	0,10	3000,00
✓	R1PE	3,80	Ohm/p	0,01	1000,00
✓	X0PE	1,00	Ohm/p	0,10	9000,00
✓	R0PE	0,10	Ohm/p	0,01	3000,00
✓	RFPE	10,00	Ohm/l	0,10	9000,00
✓	OperationPP	On			
✓	OpModetPP	On			
✓	tPP	0,300	s	0,000	60,000
✓	OperationPE	On			
✓	OpModetPE	On			
✓	tPE	0,300	s	0,000	60,000
✓	IMinOpPP	10	%IB	10	1000
✓	IMinOpPE	10	%IB	10	1000

✓	ZMRAPDIS: 3				
✓	GlobalBaseSel	1		1	12
✓	Setting Group1				
✓	Operation	On			
✓	OperationDir	Reverse			
✓	X1PP	15,00	Ohm/p	0,10	3000,00
✓	R1PP	3,00	Ohm/p	0,01	1000,00
✓	RFPP	10,00	Ohm/l	0,10	3000,00
✓	X1PE	10,00	Ohm/p	0,10	3000,00
✓	R1PE	2,00	Ohm/p	0,01	1000,00
✓	X0PE	1,00	Ohm/p	0,10	9000,00
✓	R0PE	0,10	Ohm/p	0,01	3000,00
✓	RFPE	10,00	Ohm/l	0,10	9000,00
✓	OperationPP	On			
✓	OpModetPP	On			
✓	tPP	0,600	s	0,000	60,000
✓	OperationPE	On			
✓	OpModetPE	On			
✓	tPE	0,600	s	0,000	60,000
✓	IMinOpPP	10	%IB	10	1000
✓	IMinOpPE	10	%IB	10	1000
✓	DirectionalImpedance(21D.Z<				
✓	ZDRDIR: 1				
✓	GlobalBaseSel	1		1	12
✓	Setting Group1				
✓	IMinOpPP	5	%IB	5	30
✓	IMinOpPE	5	%IB	5	30
✓	ArgNegRes	115	Deg	90	175
✓	ArgDir	15	Deg	5	45
✓	PhaseSelection(21)				
✓	FRSPDIS: 1				
✓	GlobalBaseSel	1		1	12
✓	Setting Group1				
✓	INBlockPP	100	%IPh	10	100
✓	INReleasePE	10	%IPh	10	100
✓	RLdFw	120,00	Ohm/p	1,00	3000,00
✓	RLdRv	120,00	Ohm/p	1,00	3000,00
✓	ArgLd	20	Deg	5	70
✓	X1	120,00	Ohm/p	0,50	3000,00
✓	R1PP	100,00	Ohm/p	0,10	1000,00
✓	R1PE	100,00	Ohm/p	0,10	1000,00
✓	X0	120,00	Ohm/p	0,50	9000,00
✓	R0PE	5,00	Ohm/p	0,50	3000,00
✓	RFFwPP	100,00	Ohm/l	0,50	3000,00
✓	RFRvPP	100,00	Ohm/l	0,50	3000,00
✓	RFFwPE	100,00	Ohm/l	1,00	9000,00
✓	RFRvPE	100,00	Ohm/l	1,00	9000,00
✓	IMinOpPP	5	%IB	5	500
✓	IMinOpPE	5	%IB	5	500



# Appendix C

## Load Current Calculations

A three-phase load is given for a transmission system, and it is wanted to calculate this into a load current per phase.

- Three-phase load:  $S_{3phase} = 50MW + j10MVAr$
- Per phase:  $S_{1phase} = \frac{1}{3}S_{3phase} = 16.67MW + j3.33MVAr$

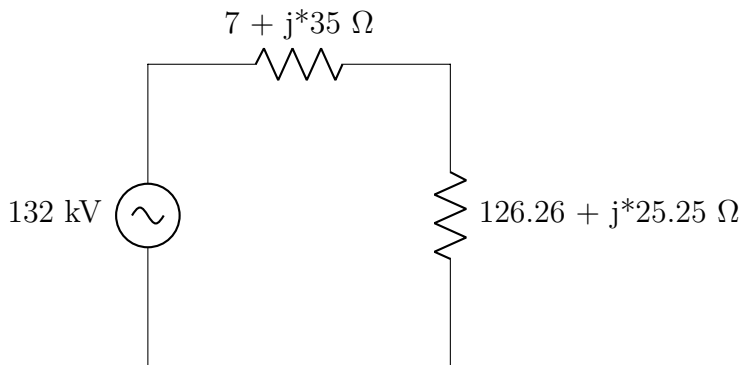
Assuming a flat voltage profile of 132 kV, the equivalent load impedance per phase will be:

$$\bullet Z_{load} = \frac{S_{1phase}}{V} = \frac{16.67MW + j*3.33MVAr}{132kV} = 126.26 + j25.25\Omega$$

In addition, the line impedance up until the load has to be calculated.

- Line length between the relay and load:  $L = 70km$
- Specific line impedance:  $Z_{line}^* = 0.1 + j0.5\Omega/km$
- Resulting line impedance per phase:  $Z_{line} = 7 + j35\Omega$

This will give the following equivalent circuit per phase:



Total equivalent impedance =  $Z_{eq} = 133.26 + j60.25\Omega$

Primary side load current per phase:  $I = \frac{132kV}{Z_{eq}} = \frac{132kV}{133.26 + j60.25\Omega} = 902.56 / -24.33^\circ$ .

**Resulting secondary side current:**  $I = 0.90256 / -24.33^\circ$





# Appendix D

## Laboratory Experiment Test Reports

### Part 2.1) Load Situation - QuickCMC:

<b>Test Module</b>				
Name:	OMICRON QuickCMC	Version:	3.20	
Test Start:	14-mai-2019 10:31:13	Test End:	14-mai-2019 10:31:18	
User Name:		Manager:		
Company:				

### Test Results

<b>Title: Load situation</b>				
<b>Fault Calculator:</b>				
<b>Table Inputmode</b>		<b>Parameters (All values are secondary)</b>		
<b>Direct</b>	V L1-E	264,0 V	0,00 °	50,000 Hz
	V L2-E	264,0 V	-120,00 °	50,000 Hz
	V L3-E	264,0 V	120,00 °	50,000 Hz
	I L1	902,6 mA	-24,33 °	50,000 Hz
	I L2	902,6 mA	-144,33 °	50,000 Hz
	I L3	902,6 mA	95,67 °	50,000 Hz
<b>Generator Settings</b>				
V L1-E	264,000V	0,00°		
V L2-E	264,000V	-120,00°		
V L3-E	264,000V	120,00°		
I L1	0,903A	-24,33°		
I L2	0,903A	-144,33°		
I L3	0,903A	95,67°		
<b>Binary Inputs</b>				
<b>Name</b>	<b>Slope</b>		<b>Time</b>	
Bin. in 1	0			
Bin. in 2	0			
Overload	0			
<b>Summary</b>				
		1 tests passed, 0 tests failed, 0 tests not assessed		100,00% passed
		<b>Test passed</b>		

## Part 2.2a) Testing Zone 2 and 3 for External Fault Stability:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	14-mai-2019 10:31:43	Test End:	14-mai-2019 10:32:31	

### Test Results

#### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
25,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

#### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
25,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

#### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
25,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

<b>Test State:</b> <b>Test passed</b>
---------------------------------------

## Part 2.2b) Testing Zone 1 for External Fault Stability, Zone 2 Deactivated:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	14-mai-2019 10:33:41	Test End:	14-mai-2019 10:34:06	

### Test Results

#### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

#### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

#### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

<b>Test State:</b> <b>Test passed</b>
---------------------------------------

## Part 2.3) Testing Trip for Internal Faults - Advanced Distance:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	31-mai-2019 10:45:20	Test End:	31-mai-2019 10:45:40	
User Name:		Manager:		
Company:				

### Test Results

#### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		0,000 s	35,50 ms	35,50 ms	2,000 A	Passed
15,00 Ω	78,69 °	n/a		300,0 ms	335,0 ms	11,67 %	2,000 A	Passed
-5,000 Ω	78,69 °	n/a		600,0 ms	622,2 ms	3,7 %	2,000 A	Passed

#### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		0,000 s	25,80 ms	25,80 ms	2,000 A	Passed
15,00 Ω	78,69 °	n/a		300,0 ms	329,9 ms	9,967 %	2,000 A	Passed
-5,000 Ω	78,69 °	n/a		600,0 ms	623,3 ms	3,883 %	2,000 A	Passed

#### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		0,000 s	19,00 ms	19,00 ms	2,000 A	Passed
15,00 Ω	78,69 °	n/a		300,0 ms	320,8 ms	6,933 %	2,000 A	Passed
-5,000 Ω	78,69 °	n/a		600,0 ms	622,9 ms	3,817 %	2,000 A	Passed

<b>Test State:</b>	
	<b>Test passed</b>

## Part 2.4a) Block Message Generation:

<b>Test Settings</b>				
<b>State</b>		<b>State 1</b>		
Bin. out 1		1		
<b>Test Module</b>				
Name:	OMICRON State Sequencer	Version:	3.20	
Test Start:	14-mai-2019 14:13:03	Test End:		
User Name:		Manager:		
Company:				

## Test Results

<b>Test State:</b> <b>Test passed</b>
---------------------------------------

## Part 2.4b) Block Message Test - Advanced Distance:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	14-mai-2019 11:12:18	Test End:	14-mai-2019 11:13:29	
User Name:		Manager:		
Company:				

## Test Results

### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
12,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I Test	Result
5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
15,00 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed
-5,000 Ω	78,69 °	n/a		no trip	no trip		2,000 A	Passed

<b>Test State:</b> <b>Test passed</b>
---------------------------------------

## Part 3.2) Test Messages Applied to Relay in Test Mode - Advanced Distance:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	31-mai-2019 10:48:25	Test End:	31-mai-2019 10:49:36	
User Name:		Manager:		
Company:				

### Test Results

#### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		0,000 s	no trip		2,000 A	failed
15,00 Ω	78,69 °	n/a		300,0 ms	no trip		2,000 A	failed
-5,000 Ω	78,69 °	n/a		600,0 ms	no trip		2,000 A	failed

#### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		0,000 s	no trip		2,000 A	failed
15,00 Ω	78,69 °	n/a		300,0 ms	no trip		2,000 A	failed
-5,000 Ω	78,69 °	n/a		600,0 ms	no trip		2,000 A	failed

#### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		0,000 s	no trip		2,000 A	failed
15,00 Ω	78,69 °	n/a		300,0 ms	no trip		2,000 A	failed
-5,000 Ω	78,69 °	n/a		600,0 ms	no trip		2,000 A	failed

<b>Test State:</b>	
	<b>Test failed</b>

### Part 3.3) Test Messages Applied to Relay in Normal Mode - Advanced Distance:

<b>Test Module</b>				
Name:	OMICRON Advanced Distance	Version:	3.20	
Test Start:	29-mai-2019 16:21:39	Test End:	29-mai-2019 16:22:00	
User Name:		Manager:		
Company:				

### Test Results

#### Shot Test: Fault Type L1-E

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		no trip	32,70 ms		2,000 A	failed
15,00 Ω	78,69 °	n/a		no trip	334,5 ms		2,000 A	failed
-5,000 Ω	78,69 °	n/a		no trip	621,3 ms		2,000 A	failed

#### Shot Test: Fault Type L1-L2

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		no trip	24,50 ms		2,000 A	failed
15,00 Ω	78,69 °	n/a		no trip	323,2 ms		2,000 A	failed
-5,000 Ω	78,69 °	n/a		no trip	622,4 ms		2,000 A	failed

#### Shot Test: Fault Type L1-L2-L3

Z	Phi	%	% of	t nom	t act.	Dev.	I <sub>Test</sub>	Result
5,000 Ω	78,69 °	n/a		no trip	21,10 ms		2,000 A	failed
15,00 Ω	78,69 °	n/a		no trip	322,6 ms		2,000 A	failed
-5,000 Ω	78,69 °	n/a		no trip	621,4 ms		2,000 A	failed

<b>Test State:</b>	
	<b>Test failed</b>

