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THE MULTI-VENDOR BASED TRANSFORMER PROTECTION SCHEME FOR TRANSMISSION NETWORK

by

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DECLARATION

I, Shangase Nichol Ntokozo, declare that the contents of this dissertation represent my own unaided work, and that the dissertation has not previously been submitted for academic examination towards any qualification. Furthermore, it represents my own opinions and not necessarily those of the Cape Peninsula University of Technology.

	11 October 2023
Signed	**Date**

ABSTRACT

The transformer operates under different voltage levels, requiring much better safety. Several faults can occur, such as over-current due to overloads and incipient faults, winding faults, external short circuits, and terminal (internal) faults. There is a need for careful attention to any transformer fault, as some can cause hazardous situations. A transformer protection device offers creative protection, control, and monitoring solutions.

Instrument transformers scale high current or voltage values into small, uniform values that are simple to manage for protective relays and measuring instruments. The instrument transformers usually remain in operation for several years and are replaced only when a mechanical failure occurs or physical life has expired. However, substation protection and control systems have recently changed more frequently, predominantly electronic and computer-based systems. However, incorporating new technologies can introduce challenges, especially when certain IED vendors encounter compatibility issues in their communication capabilities.

There is only one way to solve this issue on the distribution and transmission network systems to deploy new technology, such as one standard that will be able to interface different vendors together, the bay process bus, and Standard Protocol IEC 61850. The standard of the IEC 61850 defined the communication networks in substations that will bring interoperable systems and flexible architectures to the substation automation domain. This research focuses on the transformer's current differential protection scheme and investigates the IEC61850 standard-based communication interoperability between two different IED vendors for transformer protection. It also focuses on improving the transformer's operation speed and increasing the operational flexibility, reliability, and stability of a protection scheme for internal and external faults.

The research will use the modified IEEE Nine-Bus system to develop and implement a method of testing the multi-vendor IED based on Hardware-In-Loop (HIL) configuration with the RTDS. Different software environments were used for developing and implementing a current differential protection scheme, and the performance of various types of faults was analysed. The utilization of the IEC 61850 standard based on the current differential protection scheme is developed to achieve interoperability GOOSE between the IEDs. Speed and reliability can be enhanced by using the standard GOOSE message applications for the Transformer Protection Relay System using the IEC61850 standard.

Keywords: Transformer protection, IEC 61850 standard, Current differential protection scheme, Interoperability, Hardware-In-Loop, GOOSE message, RTDS, IED, and RSCAD.

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DEDICATION

This thesis is dedicated to my parents Nozibele H. Shangase (MaDlamini) and Zwelidumile D. Tshangase. The entire family Nkos'vumile (Brother), Nontle (Sister), the kids Wanda, Azile, and Sinokuhle Shangase.

Further dedication goes to all my great ancestors. Ohh! Shuku, NkomoZabantu, Galela, Sengane, Nonqoma, Mageza ngobisi emvakwendlu kwaMtshakazi, Aaa!! SHANGASE.

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GLOSSARY

Busbar	A power system network substation serves as a shared connection point within the network.
Current Transformer	A device that converts current from one magnitude to another.
Discrimination	The capability of multiple protection systems to determine the appropriate response to a specific fault and subsequently implement corrective measures.
GOOSE	Data of various formats, including status, value, and more, are organized into an IEC61850 dataset and swiftly transmitted within a matter of milliseconds.
IED	The term "digital devices" encompasses a range of protection, control, metering, and monitoring devices that utilize microprocessor-based technology.
Interchangeability	The capability to seamlessly replace an IED with an alternative IED from a different vendor without any adverse effects or disruptions.
Interoperability	Enables two or more IEDs, irrespective of the vendor, to seamlessly exchange information and utilize it for the accurate execution of designated functions.
Numerical relays	A versatile relay that can swiftly capture instantaneous samples of voltages or currents and execute mathematical algorithms for purposes such as control, monitoring, protection, and metering.
Power system stability	Refers to its capacity to recover and maintain stability following disturbances, such as voltage and current variations
Power system reliability	Operational reliability denotes the likelihood of a power system's ability to operate according to the anticipated specific operating conditions.
Protection system	It is a system designed to safeguard electrical power plant equipment by isolating the faulty part from the normal system in the event of a fault.
Security	The sensitivity of a protection scheme refers to its capacity to restrain and prevent inadvertent operations when there is no actual need for intervention.
Selectivity	In the event of a fault, the protection scheme is expected to selectively trip only the necessary circuit breakers to effectively isolate the faulted section.

ABBREVIATIONS/ ACRONYM

AC	:	Alternating Current
ACSI	:	Abstract Communication Service Interface
ANSI	:	American National Standards Institute
ASCII	:	American Standard Code for Information Interchange
BRCB	:	Buffered Report Control Block
CB	:	Circuit Breaker
CDC	:	Common Data Classes
CID	:	Configured IED Description file
CT	:	Current Transformer
DC	:	Direct Current
EHV	:	Extra High Voltage
FLT	:	Fault
FLTDUR	:	Fault Duration
FLTSIG	:	Fault Signal
GOOSE	:	Generic Object-Oriented Substation Events
GoCB	:	GOOSE Control Block
GoEna	:	GOOSE Enable
GSE	:	Generic Substation Event
HIL	:	Hardware-in-the-loop
HV	:	High Voltage
ICD	:	IED Capability Description file
IEC	:	International Electrotechnical Commission
IED	:	Intelligent Electronic Device
IEEE	:	Institute of Electrical and Electronics Engineers
IP	:	Internet Protocol
LAN	:	Local Area Network
LN	:	Logical Node
LV	:	Low-Voltage
MCL	:	MiCOM Configuration Language
MV	:	Medium Voltage
MVA	:	Mega-Volt-Ampere
OS	:	Operating System
PSL	:	Programmable Scheme Logic
RSCAD	:	R (Real-time digital) Simulator Computer-Aided Design
RTDS	:	Real-Time Digital Simulator
SAS	:	Substation Automation System
SCB	:	Section Circuit Breaker
SCD	:	System Configuration Description
SCL	:	Substation Configuration Language
SCSM	:	Specific Communication Service Mapping
SEL	:	Schweitzer Engineering Laboratories
TRF	:	Transformer

CHAPTER ONE

INTRODUCTION

1.1 Introduction

The Power System Environment of today believes in innovation, efficiency, quality of infrastructure, and globalization as the realms of power grid systems converge into a modern paradigm of smart grid (SG) technology. The innovative electrical grid is a grid that incorporates a wide variety of operational and energy-efficient initiatives, including renewable energy resources, energy-efficient services, smart meters, and smart appliances (Borlase, 2013; Leal-Arcas, 2020). Electronic power generation and regulation of the generation and distribution of electricity are critical aspects of the smart grid.

Since the electricity demand keeps on increasing worldwide and because of the effect of global warming, there is a trend to substitute green-renewable fossil fuels, such as solar and wind power. For over a century, the Electric power transmission grid has been increasingly established, from the start of the design of low-voltage (LV) local direct current (DC) grids to three-phase high-voltage (HV) alternating current (AC) networks. And eventually to currently integrated bulk networks of varying voltage levels and numerous complex electrical components(Li et al., 2010).

In the past and currently, several major blackouts have been a challenge since the legacy grid suffers from insufficient automated analysis, slow response to rapidly changing loading, restricted Control, and poor communication between energy produced and power consumed (Sikiru et al., 2011). Therefore, this results in the new modern smart grid as the next iteration of the power distribution infrastructure, which seeks to solve the challenges of the legacy infrastructure. According to the above statement, the transformer's fault on the distribution and transmission network becomes a huge problem, so careful attention is required on any transformer fault. Some can cause hazardous situations, and as we know, many have not met the requirements of the latest standard IEC 61850 communication protocol (Gers & Holmes, 2011).

Power Transformers are vital components of electrical control systems. It is difficult to repair on-site and costly to fix, so they require robust security systems to ensure free operation of the fault and availability. Differential protection schemes are among the most used safety systems for power transformers. In essence, the operating principle of Kirchhoff's first rule is a differential protection scheme considering the equivalent of a power transformer and a node formed between the two winding's primary and secondary. In a fault-free state, the current flowing through the primary circuit should also be equal to the current flowing through the secondary side (Arapoglou & Siderakis, 2016).

Proper transmission network operation relies on protective equipment to detect fault conditions and isolate the malfunctioning equipment. Schemes of protection used in power systems must comply with the requirement of the standard of electrical protection requiring operating speed, security, reliability, stability, and sensitivity, to minimize damage when the fault occurs. Differential protection, differential relays, and overcurrent protection are examples of electrical transformer protection systems. This will be analysed based on compliance with the IEC61850 standard protocol (Reimert, 2006; Mladen Kezunovic, Jinfeng Ren, 2016; Sendin et al., 2016). Transformer protection methods beyond differential and overcurrent are essential because they provide a comprehensive approach to protecting these critical assets. Restricted Earth Fault (REF) protection addresses internal winding faults, backup protection ensures redundancy in case of primary protection failure, and mechanical protection protects against physical stresses. Together, these methods help ensure the reliability, longevity, and safety of transformers in various operational conditions (Krieg & Finn, 2019; Sendin et al., 2016).

Owing to the host of Intelligent Electronic Devices (IEDs) in the Substation Automation System (SAS), various academic studies and analyses on power protection systems have existed for many decades. A proper and well-planned communication system is needed for such data to interconnect and share IEDs. It has described communication technology as a significant contributor to ensuring cost-effective protection, reliability, and unfailing schemes. Developing a secure and reliable Application Communication Protocol becomes a key priority for communication power and protection systems (Hadbah et al., 2014; Mackiewicz, 2006).

The Institute of Electrical and Electronics Engineers (IEEE) and the International Electrotechnical Committee (IEC) have agreed to work together so that it will move forward with existing protocols for SAS communication. The goal was to ensure interoperability and the free configuration of substations in the multi-vendor world. The consequence of this agreement was the adoption in 2004 of the first version of the International Standard IEC61850 (Konig et al., 2010; Hadbah et al., 2014).

The thesis looks at the aim of the research, which is to investigate further the Multi-vendor-based transformer protection scheme for the transmission network. The main focus is to develop a transformer current differential protection scheme, one of the instrument transformer types, and analyse different types of faults. Furthermore, it is to investigate the IEC61850 standard-based interoperability problems between the IEDs produced by other vendors and propose solutions for improving communication between these devices. The development of a current transformer protection scheme complies with the electrical protection standard and fulfils the power system's operational security, reliability, speed, and stability requirements.

1.2 Background and Rationale

1.2.1 Electrical Power Grid

The electrical power grid network can be considered to consist of a transmission network, a generation plant, a sub-transmission system, and a distribution network. In General, Electric power passes through many substations at various voltage levels between the bulk power stations and the final consumers (Turan, 2014).

The main three components of an electrical power grid system are

- Generation: two types are decentralized and centralized.

Decentralized generation is similar to consumption, though a centralized generation is far from consuming.

- Transmission and Distribution

The transmission network is a high-voltage system for transmitting electricity from where it is generated to distribution points, including substations, transformers, and power lines (Mcdonald & Grigsby, 2012). Transmission losses over long distances are reduced when electricity is at high voltages. At the point of generating electricity, it is sent through a transformer voltage which is changed from small to higher (step-up). At the same time, the substations contain transformers that step down the electrical voltage so that it can be transmitted.

- Consumption

Consumers have different requirements, but, in general, electricity offers critical energy resources, such as illumination and fuel/power for appliances. Consumers are industrial, commercial, and residential consumers

1.2.2 Substations

Substations are essential components of the global power network, including energy transmission, generation, and distribution to end-users. The overall role of a substation within the network is to make sure that the voltages are converted from one point to another and provide the switching functions to provide a link between energy sources and the ultimate user that protects the grid and its components (Refaat & Mohamed, 2019; Krieg & Finn, 2019).

1.2.2.1 Transformers

Transformers have become essential for high-voltage power transmission, ensuring that long-distance power transmission is an economically feasible protection scheme. It consists of several relays positioned remotely from each other and other distance protection schemes involving some communication between locations for unit protection. In short, the purpose of instrument transformers is necessary to allow protection tools to respond to faults and provide measurements that are as precise as possible for the current, voltage, reactive, and real power present in the HV circuit. There are two types of transformer instruments which are Voltage and Current Transformers (Krieg & Finn, 2019; Gers & Holmes, 2011).

1.2.2.2 Protection

Protection is essential to make sure that faults are found and discriminatively cleared in a period that is quick enough to ensure the stability of the power network and mitigate plant damage. The widely used specific types of protection systems schemes are Feeders, Transformers, Generators/ Reactors, and Busbars, as shown in Figure 1.1. Individual rights are extended to different equipment products such as rails, transformers or connections, busbars, etc. (R.K.Jena, 2016; Krieg & Finn, 2019).

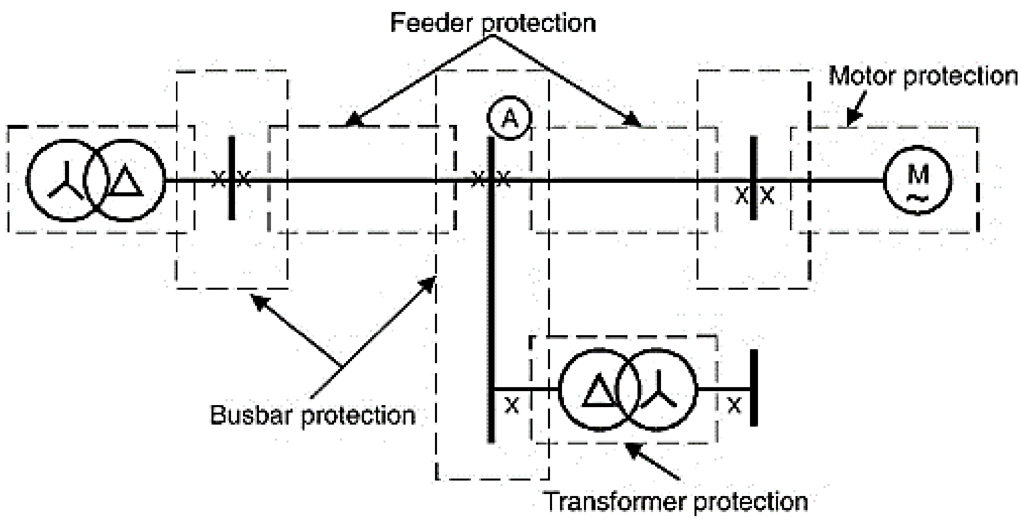


Figure 1.1: **Overall schematic indicating transformer, feeder, motor, and busbar protection (Hewitson et al., 2004)**

There are three primary methods for detecting short circuit faults:

- Current Operated Protection

It is probably the most used type of protection and the most important one. With any current that flows through it beyond its setting value, a current-controlled relay will work irrespective of direction (although overcurrent directional relays are available as well but often require a VT link to establish the directional element) (Krieg & Finn, 2019).

- Impedance Protection

Through using current and voltage measurements, impedance calculation can be done via a relay. Distance protection is used on feeder circuits, the most common form of protection. The protection of distance is a non-unit form of main protection, but a relay at a remote end can be transformed into a protection scheme unit form when provided with a contact channel to another point (Emhemed et al., 2017).

- Differential (unit) protection

The current entering the circuit will be the same as that exiting the circuit, based on Kirchhoff's rule, and when that is not the case, it's got to be a problem with the current flowing out of the covered circuit/zone at some other point. Differential protection schemes can extend to many if not all, equipment or plant products. It is widely used for the protection of feeders (cable and overhead lines), transformers, reactors (and related connections), busbars, etc. Differential protection scheme relays of the traditional transformer will compensate for vector changes on primary and secondary currents. This is because the transformer's vector group is expected by adding the vector party in the relay environments rather than using a different interposing current transformer (I / PCT) which used to be the case (Krieg & Finn, 2019; Arapoglou & Siderakis, 2016).

1.2.3 The IEC 61850 Substation Communications Standard

The IEC 61850 specification was explicitly developed to define the information models used in SAS, naming conventions, protocol standards, and communication service specifications, using intelligent control and monitoring systems based on microprocessors. It has since been extended and added to several sub-standards that join knowledge automation models and communication within and between Hydropower plants and DERs, among others. The main purpose of IEC 61850 Standards is used to describe the common app-level features (data semantics, object models) that authorize various IEDs for effectively interacting and communicating within the SAS. The standard also concerns the classification of the classes of SAS communications services and their importance but not the specifics of implementing a particular protocol stack at a lower level (León et al., 2016; Short et al., 2016).

1.3 The Problem Awareness and Statement

1.3.1 Awareness of the Problem

The substations' automated protection and control systems have been developed and widely adopted in the last three decades. Such structures have brought about a radical change to the theory of technology and service. Currently, these advanced digital technologies are used in 100 percent of the large Medium Voltage (MV)/High Voltage (HV) and Ultra-High Voltage (UHV)/High Voltage (HV)/Extra High Voltage (EHV) substations in growing industrial countries. The substation control technology was secure and remained unaltered from the start of the electricity supply until the 1990s for around 100 years. A large substation wall was lined with electromechanical control and measuring elements illustrating the substation scheme (Buchholz & Styczynski, 2014).

In recent decades, protection technology has evolved from electromechanical relay systems completed on panels to analogue protective cubicles to digital protective devices and IEDs. Figure 1.2 shows the Evolution timeline of protection technologies (Chowdhury, 2015; Gunasekera, 2017). The IEDs have brought about many more features compared to their electromechanical counterparts. The electrical substation IEDs are defined by IEC 61850, an international standard communication protocol. The implementation of IEC 61850 tackled the interoperability problem. Interoperability decreases reliance on a single vendor, and this could also reduce the cost of implementation. The implementation of the IEC 61850 standard in the automation of substations has come with its benefits (Sparks, 2018; Buchholz & Styczynski, 2014).

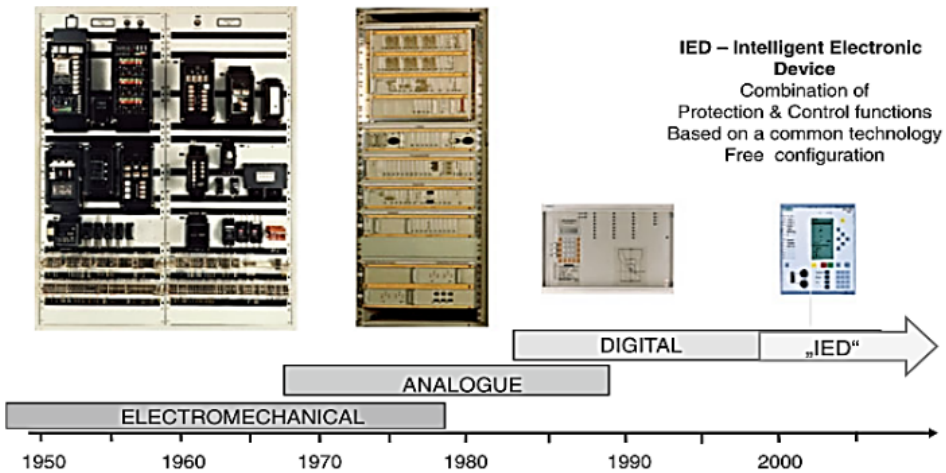


Figure 1.2: **Evolution Timeline of protection technologies (Buchholz & Styczynski, 2014)**

1.3.2 Problem Statement

Proper transmission system operation depends on the protective equipment, which must protect people and machinery within the power system. This protective gear is essential for detecting fault states and promptly disconnecting malfunctioning devices, be it due to equipment failure, injuries, adverse weather conditions, or mal-operation by the personnel involved (Rocha et al., 2018; Verzosa & Lee, 2017; Panteli, 2013). Transformers play a critical role in electrical power systems, operating across various voltage levels. During their service life, they are susceptible to a range of faults, including overload faults, incipient faults, winding issues, external short circuits, and terminal (internal) faults. The consequences of these faults can pose significant risks to both the transformer itself and the broader power system. Therefore, ensuring the paramount protection, control, and monitoring of transformers is crucial (Dekate & Kamdi, 2023; Sahu & Pahariya, 2021; Liu et al., 2021).

Traditional instrument transformers, including current transformers (CTs), are essential for accurate measurement and effective fault response within power systems. These transformers are typically in service for extended periods, being replaced only due to mechanical failure or the end of their physical lifespan. One of the primary challenges faced in this context is the frequent changes in substation protection and control systems.

However, the landscape of protection and control systems for substations has evolved rapidly, with a shift towards electronic and computer-based technologies. This shift necessitates the integration of new technologies and standards to ensure seamless communication, interoperability, and adaptability within substation automation. In this regard, the IEC 61850 standard has emerged as a pivotal protocol for connecting multiple vendors and establishing communication networks that promote interoperable systems and adaptable designs to the substation automation domain. To keep pace with these advancements, there is a pressing need to deploy innovative solutions that offer better control, protection, and monitoring capabilities for transformers (Kumar et al., 2021; I. Ali et al., 2018; Kumar et al., 2023).

This research problem addresses several critical aspects:

- **IEC 61850-Based Communication**: It examines the communication interoperability of Intelligent Electronic Devices (IEDs) from different vendors, specifically focusing on transformer protection mechanisms. Ensuring that these devices can seamlessly communicate and share critical data is crucial for system reliability and safety.

- **Current Differential Protection**: The research places particular emphasis on the current differential protection mechanism employed in transformers. This mechanism is essential for detecting and responding to various types of faults, both internal and external. Enhancing the operational flexibility, dependability, and stability of this protection strategy is a central objective.

- **Testing and Validation**: To address these challenges, the research develops and implements a Hardware-In-Loop (HIL) setup with the Real-Time Digital Simulator (RTDS) using the modified IEEE Nine-Bus system. This setup allows for rigorous testing and validation of multi-vendor IEDs under various fault conditions, helping to ensure the performance and reliability of transformer protection systems.

- **Utilization of GOOSE Messaging**: Additionally, the research explores the use of Generic Object-Oriented Substation Event (GOOSE) messaging applications in conjunction with the IEC 61850 standard. This approach is expected to enhance the speed and reliability of the Transformer Protection Relay System.

In summary, this research addresses the critical problem of ensuring effective communication interoperability between multi-IED vendors for current differential transformer protection, with a specific focus on enhancing protection strategies, flexibility, dependability, and stability in the face of internal and external faults. The study employs advanced simulation techniques and leverages the capabilities of the IEC 61850 standard to tackle these challenges effectively in the context of modern power systems.

Contribution: This research is of significant importance as it centers on parallel transformer differential protection, with a primary focus on exploring and addressing interoperability challenges arising from the utilization of multi-vendor IEC 61850 devices within the context of parallel transformer differential protection schemes. This research underscores the critical role of achieving seamless GOOSE message interoperability, which is paramount for the effective operation and fault detection in parallel transformers. This approach stands in contrast to other related studies that predominantly concentrate on scenarios involving non-parallel transformers.

Lessons learned: In the process of conducting this research, valuable lessons have been acquired, particularly through the design and implementation of a lab-scale HIL system for parallel transformer current protection. Additionally, the development of GOOSE communication in IEC 61850, with a keen eye on interoperability, has been a significant learning experience. The research has yielded unique findings that affirm the compatibility of IEDs from different vendors. Importantly, there was no missing information when the MCL/SCL language of the MiCOM-P645 was imported to SEL-487E, and vice versa. This compelling evidence demonstrates the feasibility of GOOSE message interoperability in a multi-vendor system, a discovery that advances the field.

To substantiate the claims of IEC 61850-based relays operating faster than conventional relays, the research provides empirical evidence. Notably, the use of harmonic restraint or blocking elements has been instrumental, enabling rapid tripping of circuit breakers via GOOSE communication for all parallel transformer faults with minimal delay in energizing a faulty transformer. This innovation also offers the opportunity to enhance certain turn-on conditions while maintaining sensitivity. The observed faster response of the IED GOOSE signal compared to hardwired methods bolsters the research's credibility

.

1.4 Research Aim and Objectives

The primary objective of this research is to develop a transformer current differential protection scheme while simultaneously delving into the challenges surrounding interoperability according to the IEC61850 standard, particularly among IEDs from various vendors (Multi-Vendor). In doing so, we aim to propose viable solutions that enhance communication between these devices. Furthermore, this research also places a significant emphasis on investigating and rectifying the critical issue of communication interoperability among various IED vendors, with a specific focus on transformer protection mechanisms. The overarching goal of this study is to improve the operational flexibility, dependability, and stability of protection strategies for both internal and external failures in transformers.

The aim mentioned above is achieved by fulfilling the following objectives:

- Conduct a comprehensive literature review encompassing parallel transformer protection schemes, the challenges associated with the IEC61850 standard, and the identification of solutions for achieving interoperability among Multi-vendor IEDs.
- Provide an in-depth overview of the theoretical foundations underpinning the development of transformer protection schemes and communication protocols.
- Develop a comprehensive RSCAD model of the transmission network, utilizing it as a case study for analysis and experimentation.
- Implement and create a current differential protection system within the RTDS environment software, subsequently investigating the outcomes of various fault scenarios.
- Development of a hardware-in-the-loop (HIL) protection scheme, integrating IEDs sourced from different vendors, and exploring the potential for interoperability between these devices while developing improvement solutions.
- Thoroughly analysis the test results obtained and evaluate the effectiveness of the proposed solutions during their implementation phase.

1.5 Delimitation of the Research

The research aims to investigate and provide comprehensive methods for achieving IEC 61850 standard-based interoperability problems in transformer current differential protection schemes between Intelligent Electronic Devices (IED) produced by different vendors. The scope of the investigations is restricted by the IEC 61850 standard, specified on the IEDs to be used, thus identifying and executing several test cases.

Therefore, this thesis project will be focused on the following:

- Transformer current differential protection scheme.
- Testing of protection performance and Performance of various types of faults.
- RTDS and RSCAD transmission network real-time software to simulate the performance of various types of faults and case studies.

1.6 Hypothesis

There is a possibility of developing a reliable protection scheme for a current differential transformer protection scheme based on different secure and effective vendors for any power distribution network by performing a thorough protection audit, developing an algorithm based on the IEC61850 device specifications, and organizing protection studies. By strictly implementing the IEC 61850 standard, the digital transformer protection for transmission will be intelligent, reliable, and cost-effective.

1.7 Research Motivation

The transformer differential protection scheme must run very quickly for internal faults. Therefore, a proper investigation of the IEC61850 standard-based interoperability problems between the Intelligent Electronic Devices produced by different vendors will be conducted to achieve this.

The research investigation will provide a solution to the following:

- Show the reliability of multi-vendor substation automation systems applications.
- Vendor-independent interoperability solutions.
- To advance the previous research on interoperability, vendor intervention is required for seamless system integration utilizing the IEC 61850 standard.
- Possibility of interoperability between the IEDs and the development of improvement solutions.
- Results of the software simulation based on RSCAD and RTDS.

1.8 Assumptions

The RSCAD software environments examine the existing problems of the transformer's current differential protection scheme and seek a solution to the problem of designing. They are enforcing the IEC61850 standard-based interoperability problems between the Intelligent Electronic Devices developed by different vendors and suggesting solutions to improve communications between these devices.

The following conclusions are made based on the work carried out in the field until now:

- The replacement of old relays, such as electromagnetic, static, and statics relays, with microprocessor-based relays.
- The enhanced operational speed in comparison to traditional relays. And the ongoing development modification of the software that had some problems.
- Modern electrical substation control room's physical devices have largely been replaced with modern IEDs, which are software-based logical devices, and these IEDs are implemented according to IEC 61850 standard protocol.
- Necessary tools and test equipment are available for investigation.
- Throughout the testing time, the standard IEC 61850 has not changed yet.
- The vendors have met all the minimum specifications throughout the test up until now.

1.9 Significance of the Study

Transformers have become essential for high-voltage power transmission, ensuring that long-distance power transmission is economically feasible protection schemes consisting of several relays remotely located from one another. Certain schemes for distance protection involve some form of contact to achieve a unit protection function between each location (Padilla, 2016). The above statement makes this research more important as it will investigate the IEC61850 standard-based interoperability problems between the Intelligent Electronic Devices produced by different vendors and propose solutions for improving communication between these devices. Many industrial companies and communities will benefit from this as the transformer's current differential protection scheme fault will be identified as quickly as possible.

1.10 Expected Outcomes of the Research

The main outcome of this research is intended to provide a simulated transformer current differential protection scheme using the software mentioned above and the improvement solution of the possibility of interoperability between the IEDs.

- Hardware in-the-loop protection scheme using IEDs from different vendor solutions.
- Conference paper and research articles.
- To produce complete documentation of the master’s degree.

1.11 Practical Literature Review

The transformer differential protection scheme must run very quickly for internal faults. Therefore, to achieve this, a proper investigation of the IEC61850 standard-based interoperability problems between the Intelligent Electronic Devices produced by different vendors will be conducted and practical. The following are the research methodologies that will be employed to achieve the aims of the project:

1.11.1 Model development

Models for the studied framework are to be built and implemented in RSCAD and RTDs based on the preliminary review and interpretation of the previous work and the applicable information gained from the research of the related fields as described above. RSCAD is the proprietary simulation program for RTDS Technologies, explicitly designed to communicate with the RTDS Simulator hardware. The RTDS Simulator uses highly specialized proprietary hardware and software developed by RTDS Technologies specifically to simulate real-time power systems.

1.11.2 System simulation and performance analysis

Several simulation cases will be conducted focusing on the transformer current differential protection scheme and the IEC61850 standard-based interoperability problems between the IED produced by different vendors. This study makes use of a modified IEEE Nine-bus power system network. Simulation software is used to evaluate the current differential protection transformer's scheme to simulate all protection components. The model examined includes the power system architecture to be covered, and the selection of the type of IEDs used to execute the functions and communication within the other protection scheme.

Making use of the new digital relay technology has made it possible to use many alternative methods to secure, capture, store, and distribute information about the power system effectively and economically. The software packages used for simulation and protection performance analysis settings are RSCAD and RTDs.

1.11.3 Data collection

Simulation results were performed to gather practical protection data for the transformer current differential protection scheme and to investigate the IEC61850 standard-based interoperability between the Intelligent Electronic Devices produced by multi-vendors. A comparison will be drawn between the data of the two aforementioned schemes data is concluded different configuration tools, test tools, and test methods will be shown.

1.11.4 Test Bench Setup

Physical industrial-grade IEDs provided by different vendors are used during simulation and testing. A Hardware-In-the-Loop (HIL) test is carried out in the laboratory with the assistance of a specially designed test bench. The physical protective IED device(s) interfaced with the RTDS devices are included on the test bench for testing the proposed protection scheme. When faults are introduced on the simulation network using hardwire and GOOSE for interoperability, protection IEDs are tested.

1.12 Thesis Organization

Related principles, architecture, simulation results, and interpretation are discussed in this thesis. The Research investigative report is broken down as follows:

- **Chapter One:**
  This chapter provides the research topic's background, motivation, and objectives. The problem statement, research objectives, motivation for undertaking the research work, hypothesis, delimitation of the research, assumptions, research methodology, Significance of the Study, and expected outcomes of the research are described. It also discusses the practical literature review and outline of the thesis with a glance at each chapter.

- **Chapter Two:**
  In this chapter, a comprehensive literature review is presented, covering various aspects of the protection of transformer substation automation, control, and monitoring. Furthermore, the discussion includes an exploration of the IEC61850 standard for substation communication. In addition, the functions of IEDs, current differential protection, an overview of the IEC61850 standard-related theory, and various papers and articles related to my research thesis are also discussed.

- **Chapter Three:**
  The chapter discusses the transformer theory on the power system, parallel transformer, protection of the transformer, requirements for the operation of the differential protection, and typical Transformer Differential Configuration. This chapter also discusses the theory of IEC61850 Standards communication for Monitoring, Control, and Protection Functions for the IED.

- **Chapter Four:**
  This chapter offers a summary of the design technique procedure, hardware selection, and test facility construction.

- **Chapter Five:**
  In this chapter, simulation, and modeling studies are conducted to explore the implementation of the developed protection scheme within an RTDS Hardware-In-The-Loop (HIL) environment.

- **Chapter Six:**
  In this chapter, the analysis focuses on the simulation results obtained from the developed models in Chapter Four and Chapter Five.

- **Chapter Seven:**
  This chapter demonstrates the development of an advanced protection scheme using the communication standard IEC 61850 and its generic substation event (GSE) control model GOOSE. The interoperability between two different IEDs is proven through this approach.

- **Chapter Eight:**
  This chapter is the thesis's concluding chapter. Deliverables, conclusions, and recommendations.

- **Chapter Nine:**
  This chapter provides a comprehensive list of references, including books and journal articles that have been utilized throughout the research work.

- **Chapter Ten (**APPENDICES**):**
  This appendix includes the original IEEE 9-Bus system, an overview of different parts of the IEC 61850 communication Standard, and the original Logic Control Diagram Design for circuit breakers and fault control.

1.13 Conclusion

This chapter's thesis and discussion of the research statement and its background to the problem were introduced. Provides a comprehensive overview of the research significance, goals, and objectives of the study. It also outlines the methodology employed and includes a practical review along with an overview of the subsequent chapters. The following chapter is dedicated to the literature review, specifically focusing on transformer protection and interoperability, with an emphasis on the IEC61850 standard.

CHAPTER TWO
REVIEW OF THE LITERATURE

2.1 Introduction

The growing demand for a safe and reliable supply of electrical energy is an important factor from the point of view of consumers and energy suppliers. Therefore, avoiding power transformer failures, especially those resulting in transformer failure, is critical when harnessing electrical power. Faults can damage the transformer and result in costly maintenance and repairs. The transformer badly damaged by a fault has to be replaced with a new one, which is very expensive in the power grid. Also, this can block the power supply and reduce its reliability. After the privatization and restructuring of energy systems in recent years, the transformer has played an increasingly important role (Faiz & Heydarabadi, 2014).

A power transformer is a critical piece of equipment in electrical systems. As a result, the continuity of transformer operation is critical in maintaining power supply reliability. Any unscheduled repair work, particularly replacing a faulty transformer, is costly and time-consuming. As a result, it should be protected by fast and accurate relays to prevent subsequent transformer damage caused by internal faults. One of the most common approaches for transformer protection is low-impedance differential protection (Moravej & Bagheri, 2016).

Power transformers' safe and stable operation is critical to the stability of the power system and related equipment. Because any fault in a power transformer affects the relevant power system, precise fault diagnosis and immediate disconnect of the faulty power transformer from the rest of the power system are critical to reduce damages caused by high fault current and prevent power system instability (Wang et al., 2021).

This chapter focuses on the history of the challenges related to transformer protection and power system stability and reliability. The literature review will focus on differential transformer protection based on IEC 61850 and Substation Automation control. It also examines the literature review research focusing on the interoperability of GOOSE messages. It explores the compatibility of multi-vendor Intelligent Electronic Devices (IEDs) based on the IEC 61850 standard. And also the literature review of the parallel transformer’s protection schemes is also reviewed in this chapter.

2.2 Overview of the Substation Automation System

For over a century, substation automation has relied on hardware components. Since the 1980s, the integration of information from Remote Terminal Units (RTUs) at generating stations and substations has been facilitated through the implementation of supervisory control and data acquisition (SCADA) systems. This gave operators the system-wide information required to plan and operate the power system. Substation automation refers to the use of data from IEDs, substation control and automation features, and remote user control commands to monitor power system equipment. They are used in over-current protection and SCADA. Current IEDs are complex and have several configurations and functions (Gurusinghe et al., 2018; Mouftah et al., 2019).

To be able to use them, one must understand the features of their application and the performance properties very well. Using various digital simulators will help check and assess the IEDs and make more informed decisions. The selection of new IEDs and their integration into one substation automation system can offer a range of advantages. To ensure that the advantages are completely explored, new functions need to be considered that can add value to the solutions for substation automation. Current IED assessment methods and new feature requirements are highly restricted and need to be updated to meet emerging market needs within the industry. The new IEDs must be selected to enhance the security and reliability of the operation of power systems, as well as the productivity of the operator and the decision-making process (Hernández et al., 2020; Aftab et al., 2020).

2.3 Literature on the Transformer Protection scheme

Because of the numerous benefits of smart grids and technology today, it is necessary to change the criteria of protective schemes with self-healing features. All parameters must be analyzed to improve the overall monitoring and protection of the transformer. Transformer protection demonstrates its significance due to its self-importance and complexity as a result of nonlinear magnetizing core characteristics with different voltage levels. According to transformer failure statistics, the most common causes are winding failure and tap changer failure (Bo et al., 2016; Farkhani et al., 2020).

2.3.1 Requirements towards the operation of the transformer protection

When applying for transformer protection, careful attention must be given to the selection and performance of current transformer ratios. Unique characteristics of transformers, such as winding ratios, magnetizing inrush current, and the presence of winding taps or load tap changers, pose challenges in designing a dependable and secure transformer protection scheme (Fofana & Hadjadj, 2018). Faults can potentially affect both the transformer itself and its corresponding protection scheme. The fault currents' severity, frequency, and duration can damage mechanical transformers, though the transformer impedance somewhat restricts the fault. Operating currents through faults for differential protection could result from current transformer mismatch and saturation. When choosing a protection scheme, it is essential to consider factors such as current transformer ratio, relay sensitivity, and operating time (Lin et al., 2015; Patil & Singh, 2019).

The authors (Kazemi & Labuschagne, 2012) examine the adverse conditions to which a power transformer might be subjected and provide a solution in the protection scheme for each operating condition. The authors discuss transformer overload, through-fault, and over-excitation protection. They also examine the effects of these operating conditions on the power transformer and provide solutions to mitigate them. The authors investigate the adverse conditions to which a power transformer may be subjected and discover that power transformers play an important role in power system delivery. The proper application of relay elements that monitor the thermal state of a transformer and through-faults can provide short- and long-term benefits.

The authors (Sun et al., 2016) aim to provide a solution for the safe operation of power transformers by analyzing the various faults that can occur in power transformers and proposing a protection scheme for each operating condition. The authors discuss the importance of power transformers in electrical power systems and how they are susceptible to various faults such as overload faults, incipient faults, winding issues, external short circuits, and terminal (internal) faults. The authors propose a protection scheme that includes the use of current transformers (CTs) and voltage transformers (VTs) to detect fault states and promptly disconnect malfunctioning devices. The paper also examines the effects of these operating conditions on the power transformer and provides solutions to mitigate them. The paper also states that safe operation plays a systematic and technical assurance role in ensuring stable power transformers and protective devices. To ensure the safe and stable operation of the power system and prevent accidents, it is necessary to install high-quality and technologically advanced protection devices based on scientific principles.

The authors (Cheng & Yu, 2018) delve into the systematic exploration of intelligent approaches applied in fault diagnosis and decision-making for large oil-immersed power transformers utilizing dissolved gas analysis (DGA), proposing a protection scheme involving current transformers (CTs) and voltage transformers (VTs) to detect and isolate malfunctioning devices while offering solutions to mitigate adverse operating conditions. Furthermore, the paper provides a comprehensive survey of the current landscape of intelligent methods for fault diagnosis in oil-immersed power transformers based on DGA, encompassing expert systems (EPS), artificial neural networks (ANN), fuzzy theory, rough sets theory (RST), grey system theory (GST), swarm intelligence (SI) algorithms, data mining technology, machine learning (ML), and other intelligent methods, collectively contributing to high-precision transformer fault diagnosis.

2.3.2 Differential Protection scheme

In terms of selectivity, sensitivity, and operational speed, the differential protection principle is widely regarded as superior to directional comparison, phase comparison, or stepped distance schemes. It functions as a unit protection with its zone delineated by the location of current transformers. A conventional differential function reacts to the combined total of all currents within its protection zone. Except for internal faults, this sum should ideally equal zero (Ali et al., 2019; Niranjane & Majumdar, 2021). In practice, measurement errors and shunt elements within the zone can produce a spurious differential signal, necessitating appropriate countermeasures. With advancements in the field of differential protection, these countermeasures became more sophisticated, progressing from adding an intentional time delay, percentage restraint, and harmonic restraints to sophisticated fault detection algorithms and adaptive restraining techniques (Lwana et al., 2021; Ngema et al., 2022).

The authors (Gajić, 2014), introduce differential protection schemes specifically designed for Converter Transformers. These transformers are frequently employed to supply power to medium-voltage drives, power electronic devices, and FACTS devices. Nonetheless, when applying numerical differential protection designed for standard three-phase power transformers to the differential protection of converter transformers, it becomes challenging to compensate for additional phase angle shifts caused by unconventional winding connections. Consequently, this would lead to a persistent false differential current. The paper details the process of developing these differential schemes and provides real-world installation examples with captured current waveforms from differential relays (DRs).

The authors (Stanbury & Djekic, 2014), guided scheme behaviour, this work investigated the impact of CT saturation on transformer differential relays. It was discovered that CT saturation causes harmonic blocking. Harmonic blocking is shown to provide effective protection against nuisance trips caused by CT saturation. The results of injecting 46 simulated faults into three relays show how modern transformer differential relays behave when CT saturation occurs.

The authors (Andreev et al., 2016) address the problem of incorrect relay protection and emergency automation, including differential transformer protection, in this paper. This problem was discovered to be caused by a mismatch between transformer differential protection settings and real-world operation conditions, which was caused primarily by the use of several gross simplifications in the existing method of calculating transformer differential protection settings. Based on the summarized research presented in this paper, it can be concluded that suitable mathematical models consider the unique characteristics of specific implementations and processes in current transformers. And are integrated into appropriate aids, specifically, the program-mathematical modelling of differential transformer protection designed by the article's author, and are effective tools for testing and optimizing transformer differential protection settings.

The authors (E. Ali et al., 2018) present an improved differential power transformer protection scheme. The suggested technique scheme is based on the absolute sum of each phase's primary and secondary currents, supplemented by the absolute difference and sum of each phase's primary and secondary terminal voltages. The suggested method seeks to avoid the mal-operation that might occur with typical three-phase transformer differential protection schemes due to transitory phenomena such as magnetic inrush current, simultaneous inrush with internal fault, and faults with current transformer saturation.

The authors (Afrasiabi et al., 2020), As the most difficult issue in power transformer protection the goal is to propose a fast, reliable, and independent protection scheme for distinguishing inrush currents from internal faults in power transformers. The inrush phenomena is the most difficult issue that can cause differential protection to fail. During the initial energization of a power transformer, the phenomenon of inrush generates a magnetizing inrush current. The results show that it outperforms three different shallow and three state-of-the-art DNN-based techniques in terms of accuracy and reliability. The proposed scheme's adaptability and robustness are assessed by considering the effects of CT saturation, superconducting fault current limiter, and series compensation.

2.3.3 Literature search on RTDS with transformer protection

Power systems that have been accurately modelled and designed for real-world applications should be tested for viability and reliability. Control and protection devices for power systems should also be thoroughly tested before being installed in the system to ensure their compatibility and effectiveness. More importantly, power systems should be tested for various scenarios that could endanger the grid. Real-time simulators have several advantages, including the ability to simulate contingency or test procedures that are difficult to simulate on a real system for training or preventive purposes. Real-time simulators also save time when it comes to simulations involving large amounts of data, such as hours of load forecasts, weather forecasts, and so on (Moravej & Bagheri, 2016; Makwana et al., 2021).

A Real-Time Digital Simulator (RTDS) tests a differential relay and discriminates between magnetizing inrush and internal fault currents in a power transformer. A digital simulator can run a power system model in Real-Time. To evaluate the performance of protection IEDs, they can be connected as HIL to the simulator. This is referred to as hardware-in-the-loop testing (Rigby, 2007; Almas et al., 2012).

The authors (Moravej & Bagheri, 2016) presented the work to demonstrate the use of an RTDS to test differential relay operation in a power transformer protection scheme. The hardware allows for importing and exporting many signals from the simulator to an external actual power transformer and other power system components, allowing for so-called closed-loop testing. The obtained test results demonstrate the utility of the RTDS simulator in determining the actual power transformer behaviour under different power-system conditions. The RTDS software, RSCAD, is used for power transformer and power system model simulation.

(Apostolov, 2016) describes how to use the methods and tools defined in IEC 61850 Edition 2 to support the virtual isolation of the tested functions in a live substation for remote testing. The paper also discusses some of the advantages and disadvantages of using remote testing. Interoperability between engineering tools (including testing tools) is expected to improve, which is desperately needed. New functional and system testing features should make it easier to isolate IEC 61850-based installations. Even though there are some challenges, the benefits of improving testing efficiency are too great to overlook.

The authors (Kong et al., 2016) discussed the creation of a methodology and facility to conduct protection and control coordination studies. These studies involve the use of real-time simulation and HIL testing to evaluate the performance of protective relays and new technologies. The RTDS platform is utilized as part of this process. The primary concerns revolve around two aspects: guaranteeing the precision of real-time simulation specifically for a Flexible AC Transmission System (FACTS) application conducted in a test power network, and minimizing the financial expenses associated with implementing real-time simulation and HIL testing of FACTS protective relays, including the costs related to the acquisition of the RTDS and other necessary hardware resources.

The authors (Murugan et al., 2019) describe testing a power transformer differential relay in a HIL configuration using an RTDS and Digital Signal Processor (DSP) for all possible power transformer operating conditions. The implementation of the Empirical Fourier Transform-based transformer differential relay (EFTDR) algorithm is carried out on the TMS320F28335 DSP, which establishes connectivity with the RTDS through a combination of analogue and digital hardware circuits. Similarly, the proposed relay's response is feedback into the RTDS digital channel. The response of the relay triggers the tripping of the respective circuit breakers within the RSCAD simulation circuit. In this scenario, the effectiveness of the EFTDR algorithm is assessed by conducting HIL testing using the RTDS and DSP. The evaluation includes analyzing the performance of the EFTDR under different conditions such as internal faults, inrush currents, current transformer saturation, and possible combinations of these events in relation to power transformers.

2.4 IEC 61850 interoperability literature search

The research primarily investigates the interoperability of protection systems based on the IEC 61850 standard, with a specific emphasis on the seamless transmission of GOOSE messages, their publication and subscription processes, and the interpretation of these messages by different IEC 61850 compliant devices from various vendors. International Electrotechnical Commission (IEC)-61850-enabled devices are becoming increasingly important in substations. When devices from different manufacturers are used, device compatibility with these standards does not guarantee interoperability. If multivendor device interoperability can be achieved, power utilities will be able to implement multivendor devices in substations (Reda et al., 2021; Bhattacharjee et al., 2022).

The author (Apostolov, 2013), implementing different protection schemes within IEC 61850-based systems offers substantial benefits compared to conventional hard-wired schemes. The continuous transmission of GOOSE messages by the protection and communications devices offers a dependable indication of the interface's status. This is a capability that conventional schemes can only achieve through scheduled testing or when the scheme fails to function. The utilization of communication schemes based on the IEC 61850 standard facilitates the exchange of messages between redundant protection IEDs. This leads to the enhanced reliability of the protection scheme, as it enables interoperability among the devices.

The authors (Kriger et al., 2013), examine the structure of GOOSE messages that becomes necessary when conducting fault diagnosis or designing hardware that complies with the specifications outlined in the IEC 61850 standard. A case study that verifies the structure of the GOOSE message, as defined in IEC 61850-8-1, through both simulation and experimentation using real Intelligent Electronic Devices (IEDs). Initially, the message structure is confirmed by simulating the GOOSE message and capturing it with network protocol analysis software. Subsequently, packet frame analysis is conducted to further validate the structure of the message. The 2nd phase of the case study involves practical experimentation with IEDs to generate a GOOSE message. The generated message is then analyzed using network protocol analysis software to examine its characteristics and behavior. The confirmation of the GOOSE message structure, as outlined in the IEC 61850 standard's section 8-1, involves both simulation and real-world experimentation with physical devices. This comprehensive approach ensures the validation of the GOOSE message structure according to the specified standard requirements.

(Hadbah et al., 2014) demonstrate how to deploy, configure, and manage IEC61850-based Protection IEDs using Omicron's IEDScout software. This provides researchers and professionals with a valuable opportunity to gain practical experience and stay updated with the IEC 61850 standard and its compatible equipment. It enables them to enhance their understanding and proficiency in working with the standard and associated devices. There are numerous vendors and software packages accessible for interacting with relays and performing the required configuration tasks. Future work will explore additional substation automation packages and procedures to provide a comprehensive overview of available options in the field.

(Bhattacharjee et al., 2022) research outlines the development and evaluation of a digital substation test platform that integrates devices sourced from different manufacturers. The intelligent electronic devices (IEDs)' process bus communication and protection operation were tested to validate device interoperability. The testbed was put through its paces for two IED process bus communications, GOOSE, and sampled measured value (SMV). The research conducted on this testbed will provide solutions to the issues connected with a multivendor system. Substation engineers must deal with and advise on multivendor systems. In the future, this system can be expanded by adding more multivendor devices with complicated network architecture and a SCADA system.

2.5 Literature review of the parallel transformer's protection schemes

When connecting transformers in parallel, several important factors must be considered. To begin with, when two units are connected in parallel, the combined impedance will be considerably lower compared to the impedance of each individual unit. It is crucial to ensure that the resultant surge in short-circuit current during faults does not surpass the capacities of the transformer cabling or switchgear capabilities. Furthermore, it is important to have transformers with comparable voltage ratios and maintain consistent phase relationships when connecting them to the HV and LV busbars. Ideally, it is desirable for the transformers to possess identical megavolt-ampere (MVA) and impedance ratings. However, achieving this may not always be feasible (Shah et al., 2018).

When parallel connecting transformers are equipped with on-load tap changers (OLTCs), it is necessary to establish a regulating system that can effectively exchange information between them. For instance, in a master-follower configuration, inter-panel connections are essential to enable a single automatic voltage regulator (AVR) to determine the appropriate tapping decision and govern all the interconnected transformers. Traditionally, this has been accomplished by utilizing panel selector switches and establishing connections between the inputs and outputs of the regulating relays through wiring (Guzmán et al., 2009; Yarza & Cimadevilla, 2013).

On-Load Tap-Changers (OLTC) are either manual or automatic on power transformers. Fluctuations in the load supplied by the power transformer can lead to variations in the secondary voltage level. To accommodate these changes, the voltage ratio on the transformer equipped with an on-load tap changer (OLTC) can be adjusted, allowing for the adjustment of the secondary voltage level (Bugade et al., 2018; Balaji & Ramesh, 2015). By comparing the setpoint voltage with the measured voltage, the voltage regulator manages the on-load tap changer to adjust the tap position either upward or downward. This enables the parallel connection of power transformers. Circulating Current control, Master-Follower control, and Reactance control are the three main methods for controlling parallel transformers (Gajić & Aganović, 2016; Sangeerthana & Priyadharsini, 2020).

The authors (Constantin & Iliescu, 2012), discussed the main characteristics of the master-follower control method and its functionality when integrated into a multifunction protection system (MPS). The paper also includes a case study demonstrating how to control a bus's voltage using the master follower method.

The authors (Adam Patrick Taylor and Larry L. Wright, 2012), present a modified circulating current technique that outlines the design of a load tap changer (LTC) control system suitable for the coordination of up to four parallel transformers. This paper's LTC control was built with programmable logic, math functions, and IEC 61850 communications over fibre-optic Ethernet. Field tests were conducted on three parallel autotransformers operating at 230/115 kV in the Santee Cooper system to evaluate the load tap changer (LTC) control. The newly implemented Ethernet-based LTC control system by Santee Cooper has demonstrated exceptional performance, successfully fulfilling all of the utility's predetermined objectives. It has been accepted as the Santee Cooper system's standard for parallel tap-changing control.

(Yarza & Cimadevilla, 2014) provide a comprehensive description of the two predominant control schemes employed for Automatic Voltage Regulators (AVRs), namely master-follower and circulating current, highlighting their key features and operational principles. By utilizing the IEC 61850 standards, this implementation can support the coordination of up to five parallel-operating power transformers. However, the paper does not mention any experiment or simulation carried out in this manner, nor does it show the results of such experimentation or simulation.

(Sarimuthu et al., 2016) provide an overview of the diverse voltage control schemes employed for on-load tap changer (OLTC) systems, specifically designed to regulate voltage in distribution networks integrated with renewable energy sources. This paper examined the existing OLTC voltage control scheme and new techniques. Furthermore, the article explores the voltage control approach for on-load tap changer (OLTC) transformers connected both in series and parallel. It also delves into the benefits of utilizing the Enhanced Automatic Paralleling Package and SuperTAPP n+ relay schemes, which can enhance voltage control in networks incorporating renewable energy sources at varying levels.

(Gatan, 2017), research suggested an innovative approach for controlling tap changer transformers, which can be implemented in both radial and meshed networks. A special software application shall implement the application technique for AVC& AVRS with SCAD automation system, primarily to precisely ensure the minimum and maximum OLTC control system.

The authors (Igbogidi & Dahunsi, 2020), present a practical detail of enhanced power supply with paralleling of transformers using the same parameters approach on Rivers State University 2 X 15MVA, 33/11kV Injection Substation in Nigeria. The authors collected data from Port Harcourt Electricity Distribution Company and Transmission Company of Nigeria and used appropriate equations to generate relevant data for successful load flow analysis. The data collected in conjunction with relevant data generated served as an input source in Electrical Transient Analyzer Program 12.6 software. The load flow analysis was conducted, and a higher substation power loss was encountered at the first instance. However, substation power loss was reduced from 1004.9 kW to 945.2 kW in the second load flow (New Case) analysis when T1A and T2A were connected in parallel. The New Case showed enhanced power supply with paralleling of transformers using the same parameters approach.

2.6 Real-time Data Network and System Level Testing

Simulation of real-time power networks using devices like the RTDS is a common approach allowing for the evaluation of "hardware-in-the-loop" components of the power system, such as relay control or protection systems with compensator VAR. Without compromising the efficiency of the power system, different power system conditions can be simulated with the device being tested and fed back into the simulation. Hardware RTDS allows direct communication with devices compatible with the standard of IEC 61850 (GOOSE and Sampled Values) so that all connections in the testbed can be connected to Ethernet (Chen, 2016).

The authors (Sidwall & Forsyth, 2020) discuss the evolution of power system behavior and equipment modeling and testing as the power system has undergone an evolution in the types of generator and load deployed on the system, the penetration and capabilities of automation and monitoring systems, and the structure of the energy market. The authors summarize various recent advancements from a particular simulator manufacturer, RTDS Technologies Inc., which have been enabled by growth in the high-performance processing space and the emerging availability of high-end processors for embedded designs. The paper also highlights emerging requirements for real-time simulators when it comes to simulation fidelity, interfacing options, and ease of use.

The authors (Huang et al., 2021) describe a test method and data application method of a physical model for power distribution networks. The authors record the test process during the physical simulation test and design a reasonable test procedure. The test data can be expanded and applied to provide strong support for technical research and analysis of distribution automation.

2.7 Literature review of existing papers related to this research

In this section, the literature review papers will be discussed, most imported the one that is closest to the Multi-Vendor Based Transformer Protection Scheme for Transmission Network. The most important is that this review paper will be more related to the aim of this research project, as discussed in section 1.4.

To find relevant research publications, specific keywords were used. The following are the keywords:

- IEC 61850 Interoperability and IEC 61850 testing.
- Interoperability for multi-vendors and Fast-speed IEDs to communicate with IEDs.
- Development of transformer protection schemes and communication.
- GOOSE message applications and Interoperability framework.
- Communication protocols in substations and standards for substation automation.
- Fault detection and isolation in a power transformer.
- Substation monitoring and control.

Further searches can be performed by mixing and matching keywords, and search results can be filtered as needed. As a result, several research articles relating to the keywords are produced. The papers were surveyed and compared according to the specified criteria.

- Author, year, and title of the paper.
- Aim of the paper
- Method and Model Use
- Used software/ hardware
- Limitations
- Achievements

The papers in Table 2.1 are being compared and contrasted based on their topics regarding transformer and substation automation, protection, monitoring, and control. On top of that, a comparison of papers concerning computer simulations in real-time, real-time testing of protective devices was also recorded in Table 2.2. Which is discussed in section 2.7.1 and section 2.7.2 of this chapter respectively.

2.7.1 Analysis of various papers on transformer protection based on IEC 61850 and Substation Automation control

Table 2.1: Analysis of different papers on transformer protection based on IEC 61850 and Substation Automation control

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
1.	(Hadbah et al., 2014). **Using IEDScout Software for Managing Multivendor IEC61850 IEDs in Substation**	This paper demonstrates how the protection IEDs based on IEC61850 are managed, configured, and deployed through the IEDScout software of Omicron.	Communicating and Connecting with the protected relays in this portable substation are practical techniques.	Omicron IEDScout.	It only uses two vendors SEL and ABB.	It clearly explains the ability to track GOOSE messages and monitor and process data sent in such messages in applications such as EnerLyzer and TransView.
2.	(Ingram et al., 2014). **System-Level Tests of Transformer Differential Protection Using an IEC 61850 Process Bus**	This paper provides an overview of the performance protection for process buses since the behavior of in-service multifunction process buses is largely unknown.	Real-Time Digital Simulation and "actual" automation for substation tools were used to introduce an experimental approach.	RTDS with OMICRON CMC256-6 security test set for relay protection had IEC 61850 and RET670.	It focuses on sampled values, IEC 61850-9-2, and GOOSE message, IEC 61850-8-1.	System tests incorporating simulation of HIL offer proof of overall protection device performance efficiency and whether the grid code specifications are being met. Systematic testing of the protection system described in this paper shows that relays can satisfy performance requirements under extreme conditions.
3.	(Lei et al., 2014). **Reliability Modeling and Analysis of IEC 61850 Based Substation Protection Systems**	This paper sets out a new reliability approach modeling and current substation protection systems analysis.	A novel simulation and analysis technique of protection systems based on IEC 61850 is presented	None	The paper was limited to the theory party only.	None
4.	(Hasan Ali et al., 2014). **Comparisons process-to-bay level peer-to-peer network delay in IEC 61850 substation communication systems**	This paper addresses the implementation of protocol IEC 61850 for data communication systems in the electrical power engineering industry Between sub-stations. This protocol to IEC 61850 presents new challenges for the efficiency of real-time	SAS involved several items for the status of the equipment in the substation, such as protection, alarm, monitoring, control, and live reports.	OPNET Modeler.	It is restricted to a basic simulation of the network level from process to bay model.	Practical applications based on simulation tests are recommended, and packet size must use small packets and avoid sending out non-uniform sources of data to ensure data transmission and reliability in real-time.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
		communication between substation IEDs.				
5.	(Daboul et al., 2015). **Testing Protection Relays Based on IEC 61850 in Substation Automation Systems**	This paper reviews the specifications for traditional safe relay testing (physical devices and software) and performance testing based on IEC 61850 relays.	GOOSE message performance evaluation has an advantage over traditional hardwired testing.	Cap 505 Relays Configuration Software and Test Universe Tool.	It contrasts only two methods outlined by IEC 61850 that can be effectively used without any degradation to replace traditional substation systems for control and protection.	Available research based on IEC 61850 has shown that GOOSE provides a high-priority, highly flexible, and reliable system for interlocking and security purposes for exchanging substation events between IEDs.
6.	(Arnold et al., 2015). **Performance Testing and Assessment of Multi-Vendor Protection Schemes Using Proprietary Protocols and the IEC 61850 Standard**	This paper offers an overview of the performance of IEC 61850 standard devices concerning their scale, protection, and reliability in operation.	Distance security and remote protection systems are supported by connectivity and testbed equipment implemented in the system.	RSCAD and MICOM-P546 IEDs.	It is limited to multi-vendor IEDs, which include the functionality of the distance protection zone.	Standard IEC 61850 offers several advantages for the automation of the substation, and the results indicate that the IEC 61850 specification was implemented as planned.
7.	(Arapoglou & Siderakis, 2016). **Differential Protection Schemes and Techniques for Power Transformers – Educational Aspects**	Differential protection system for the transformer power and also do the simulation. This must understand the energization current and should not send out any tripping action.	The differential protection scheme	MATLAB Simulink	It only covers transformer protection based on the differential scheme.	The results of the simulation show the value of the delta relation, which reduces the degree of asymmetric loading from secondary to primary winding.
8.	(León et al., 2016). **Simulation Models for IEC 61850 Communication in Electrical Substations Using GOOSE and SMV Time-critical Messages**	A suggested model for the simulation of the communication standard IEC 61850, which targets applications using GOOSE and SMV messages, has been proposed in this paper.	Models of this simulation were OMNeT+++/INET installed in compliance with IEEE standards 802.3 and IEEE standards 802.1q.	RTDS with IEDs with the IEC 61850 standard based on GOOSE and SMV.	It focuses on the simulation of the substation architecture for IEC 61850.	The simulation outcomes, which were validated through a comparison with actual equipment, confirm that the fixed-priority scheduling algorithm implemented in the switch is performing as intended, effectively preventing the occurrence of priority inversion.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
9.	(Zhao et al., 2016). A **New Virtual Relay Protection Simulation System of Substation Based on IEC61850 Standard**	This research presents a better IEC61850-based smart virtual protection relay simulation substation that visually displays both the virtual circuit and the protection signals.	The Visual C++ language builds an intelligent substation virtual relay protection simulation framework into the Windows platform.	This framework reads and writes XML files using VC++6.0, primarily by communicating with the programming interfaces.	The system cannot configure protection in two or more protective devices and monitor the adjacent components' situation to protect the backup.	This paper sets out fresh concepts for structural modelling of the simulation systems and Virtual protection system part of the structure. The graphical operating environment is based on an easy and transparent interface and intuitive performance.
10.	(Chen et al., 2016). **Interoperability Performance Assessment of Multivendor IEC61850 Process Bus**	This paper proposes a technique for evaluating the efficiency of the MU when working with IEDs performing a task of distance protection from different manufacturers.	A closed-loop simulator was used solution involving a real-time computer.	RTDS simulator.	The comprehensive interoperability evaluation process was not covered	The results show that IEDs use different schemes to interpret data of SV as one of the IEDs does not interpret, and the other has the same SV stream readings overwritten.
11.	(Song et al., 2017). **Interoperability Test for IEC 61850-9-2 Standard-based Merging Units**	This paper suggests a proactive approach to interoperability tests It focuses mainly on collecting packets and monitoring communications between the system MU or DUT test with IEC 61850 9-2 based MUs.	Model for SV transmission on a mixed stack with direct ISO / IEC 8802-3 connection combined with IEC 61850 8-1.	SVScout, omicron, and Wireshark.	It utilizes only the Sampled Values (SV) IEC 61850-9-2.	As set out above, both commercial vendor MU's passed the interoperability test results. Another problem in the test is that the svID in the configuration file for vendor B MU does not adhere to the LE specification IEC61850-9-2.
12.	(Kuznetsov et al., 2017). **Parallel Operation of Three-Phase Power Transformers with Different Short-Circuit Voltages**	To develop a lab bench that will be used to investigate the parallel operation of three-phase power transformers with varying short-circuit voltages.	Only calculation and theory have been used in this paper.	None	It is limited to theory only.	The investigation has revealed that one of the transformers under examination operates in conversion mode, resulting in a 180° phase shift in its currents. This particular phase shift is identified as the main factor leading to the failure of normal parallel transformer operational conditions.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
13.	(Patrashkin & Andreev, 2017). **IEC-61850 Use in Central Relay Protection and Automation Network Systems**	This paper proposes the use of GOOSE messages to relay measurement results from voltage measurements and current transformers located at remote energy network nodes.	The IEC 61850 specification includes incorporating several logical devices into a single physical structure, allowing to integrate essentially any digital device that supports one of the current data transmission protocols into an IEC 61850.	Wireshark software package	It is limited to the sampled values (SV) of the standard section IEC 61850-9-2 and the GOOSE message IEC 61850-8-1 and Wireshark applications.	This paper shows that data can be distributed similarly using local area networks and the global Internet.
14.	(Verzosa & Lee, 2017). **Testing Microprocessor-based Numerical Transformer Differential Protection.**	The paper aims to review how phase differential protection principles are implemented in numerical technology by different relay models, provide guidance in their application, and guide test personnel in performing their work.	The authors propose test methods for use with modern test systems that can be applied to test all transformer phase differential protection functions easily and effectively.	None.	Testing methodology is designed for microprocessor-based numerical transformer differential protection and may not be applicable to other types of protection schemes or substation configurations	The paper's achievements include reviewing how phase differential protection principles are implemented in numerical technology by different relay models, providing guidance in their application, and proposing test methods for use with modern test systems.
15.	(E. Ali et al., 2018). **Power transformer differential protection using current and voltage ratios**	It presents an improved differential protection scheme Based on the absolute difference ratio and absolute sum of transformer primary and secondary currents.	The proposed differential defense scheme is evaluated using a single-line diagram of the electric power grid.	MATLAB/Simulink	Restricted to the study of the No-Load Energization simulation, External CT saturation fault, Internal fault, and Simultaneously charged energy.	The results indicate that the technique proposed may be measurable. Identify fault cases from 3% of the windings and above the neutral end within a specified time frame, depending on the fault.
16.	(Daboul & Orsagova, 2018). **Interoperability testing for IEC61850 Based Substation Automation System**	This paper describes a method for evaluating the interoperability of IEDs from multiple vendors using the IEC 61850 standard. It also includes the testing's lab results.	A physical connection between the system devices, which include protection IEDs, Ethernet switches, and PCs, clearly describes the interoperability issue. IEDs are from different vendors.	Test universe, PCM600, and Network analyser (GOOSE).	It only uses two different vendors for the simulation.	Some of the IEC 61850 challenges have been discussed. It was discovered that differences in IED configuration tools cause a variety of configuration issues, including import and export errors of a specific SCL type file.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
						It was concluded that GOOSE is faster than traditional wiring.
17.	(Rocha et al., 2018) **Practical approach to testing the transformer differential protection for internal and external faults, CT saturation and inrush transients**	The paper presents a methodology that allows examining the differential protection of power transformers through computational simulations and numerical relay tests.	They implemented a testing system in the laboratory that simulated the power system in ATP (power transformer, CTs, and fault modes) and applied the simulated signals through a programmable test set to a commercial relay to evaluate their response to these events.	The authors used the Alternative Transient Program (ATP) as a computational tool.	Testing methodology is designed for differential protection of power transformers and may not be applicable to other types of protection schemes or substation configurations.	The paper's achievements include presenting a methodology that allows examining the differential protection of power transformers through computational simulations and numerical relay tests. The study intends to guide the development of a robust testing methodology for differential protection of power transformers.
18.	(Salvador & Rodriguez, 2018). **Automatic Multi-Vendor IED Fault Data Collection and Analysis Solution**	The paper discusses the method for automated processing of fault files, focusing on the significance and advantages an organization may achieve from archiving fault file data on the data historian and the non-SCADA info.	A centralized solution for IED management that supports the automatic recovery of data from multi-vendor events. Email update, version control, and archiving of the documents collected.	PowerSYSTEM Centre	It only simulates three vendors from different manufacturers.	The Breaker Analytics section automatically parses the line's name, location of the device, distance to the fault, and length of the fault to make it readily available; this allows operators to isolate the problem and restore customer service.
19.	(Gurusinghe et al., 2018). **Testing of IEC 61850 sampled values based digital substation automation systems**	This research provides a technique for evaluating a completely Digital SAS that uses a simulator for the real-time power network.	Implementation of integrated SAS device testing in a laboratory environment.	System Configuration Tool (SCT) is used to map information and all other configurations provided by IEC 61850 with a real-time simulator to create an SCD file.	It is limited to a real-time simulator for simulation.	None.
20.	(I. Ali et al., 2018). **Communication Modeling for Differential Protection in IEC**	The paper aims to design an IEC-61850-based protection scheme to take care of faults outside the substations.	It presents a communication configuration for line current differential protection schemes applied between two	The authors used MATLAB/Simulink software to simulate the communication configuration	The proposed communication configuration is designed for line current differential protection schemes	The paper's achievements include presenting a communication configuration for line current differential protection schemes applied between two automated

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
	61850 Based Substations		automated substations and evaluates its performance using a network simulator tool.	network between two substations.	applied between two automated substations.	substations and evaluating its performance using a network simulator tool1.
21.	(Chen et al., 2018) **Virtual site acceptance test platform for IEC 61850 based substations with multi-vendor bay solutions.**	The paper aims to develop a virtual site test platform to assess the engineering process and interoperability performance for a fully digital substation with multi-vendor bay solutions. The authors present a data monitoring tool that visualizes data flows in IEC 61850 networks, which can help commissioning engineers intuitively validate signals as they do for conventional schemes.	Case studies are presented to investigate the interoperability of sampled values, generic object-oriented substation events, and manufacturing message specification communication services.	RTDS with IEDs.	Testing methodology is designed for fully digital substations with multi-vendor bay solutions and may not be applicable to other types of protection schemes or substation configurations.	The paper's achievements include developing a virtual site test platform to assess the engineering process and interoperability performance for a fully digital substation with multi-vendor bay solutions, presenting a data monitoring tool that visualizes data flows in IEC 61850 networks, and investigating the interoperability of sampled values, GOOSE, and manufacturing message specification communication services.
22.	(Chang, 2019). **IEC 61850 Based Electrical Protection and Control System for Nuclear Power Plants**	This paper proposes the nuclear power plant electrical protection and control scheme for MV and LV networks based on IEC61850 technology. Current methods are tested, and the methodologies for applying IEC61850 to nuclear are applied.	Component control systems track the incoming circuit breakers for the process components for the switchgear MV and LV and branch feeder circuit breakers. Several vendors include relays, measuring devices, and control devices for nuclear power plant auxiliary power systems.	None	Restricted to theory only and by IEC 61850-based study of MV and LV networks at nuclear power plants.	On the other hand, EPCS based on IEC61850 can use several useful MV and LV network control functions. The EPCS can conduct high-speed bus transfers by coordinating between feeder protection relays.
23.	(Li et al., 2019). **A New Vibration Testing Platform for**	This paper proposes a new ECT vibration testing network with synchronous vibration source status	To examine the modern age of non-conventional instrument	The only signal generator is used to simulate the waveform.	Research is limited to theory and using a signal generator.	The proposed test framework for testing ECT's compliance with international standards is easy to introduce and more

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
	Electronic Current Transformers	under the ECT output signal.	transformers and IEC61850-related optical network communications.			comprehensive than existing industry practices.
24.	(Krishnamurthy & Baningobera, 2019). **IEC61850 standard-based harmonic blocking scheme for power transformers**	The aim is to create a harmonic transformer blocking scheme using a portion (87HB) of the differential transformer relay (SEL487E) to give the harmonic blocking signal IEC61850 GOOSE to the overcurrent backup relay (SEL751A) to avoid tripping under some conditions.	Differential protection and overcurrent protection backup according to standard IEC 61850.	A protective system for transformers on one IED is used, with IEC61850-8-1 used for communication.	Only one vendor, such as SEL, was used for practical simulation.	The simulation results have shown that the standard protection scheme based on IEC61850 is quicker than the hardwired signals. This concludes that the transformer's speed and reliability are enhanced using standard GOOSE-based IEC61850.
25.	(Azizan et al., 2019). **Simulation of differential relay for transformer protection**	Transformers are an important component of the electric power system, and their protection is critical. Due to the potential risk of transformer damage during a fault, there was a need for faster and more targeted protective measures. The differential protection design was used for this purpose.	Simulink/MATLAB was used to simulate and run the power system model. The model utilized in this case consists of an 11/33 kV power system, incorporating a current relay protection scheme located between the transmission line and the transformer.	MATLAB/Simulink	The simulation was done using MATLAB only.	The evaluation was carried out under various fault conditions. Several fault scenarios are analyzed in the research, encompassing double line-to-ground faults, single line-to-ground faults, and line-to-line faults. Simulation studies were carried out, and the performance of the relays under various system parameters and conditions was investigated.
26.	(A. Elbaset et al., 2020). **IEC 61850 Communication Protocol with the Protection and Control Numerical Relays for Optimum Substation Automation System**	The control of the substation automation system for the best automation system, based on the IEC 61850 communications protocol, is discussed in this paper.	Simulation of the substation using multiple vendors, Based on communications standard IEC 61850.	MICOM-P546 multi-function protection relay.	The scope of this study is restricted to simulating communication protocols specifically utilized in substation automation systems, involving the use of various relays for protection applications.	After suffering a loss, the circuit must have zero recovery time to rebound to normal active mode. With the development of IEC 61850, these goals can be accomplished by using the accelerating role of the trip scheme in the IEDs.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
27.	(Makwana et al., 2021). **Enhanced Transformer Differential Protection – Design, Test and Field Experience**	This paper discusses the effect of lowering the 2nd harmonic threshold on differential protection and emphasizes the advantages of waveform recognition algorithms, such as gap detection and CT saturation techniques for unblocking differential protection during internal faults in the presence of harmonics.	The primary focus of this paper is on introducing a novel transient bias technique that enhances stability during through faults. Additionally, it explores a no-gap and CT saturation technique for unblocking differential protection during internal faults, enabling faster clearance even in the presence of harmonics produced during CT saturation.	RTDS	It is limited to testing the internal fault stability.	The adaptive transient bias algorithm improves the stability of the biased differential element during external fault scenarios, according to various field records and RTDS testing. Furthermore, it is evident that the implementation of CT saturation and no-gap waveform recognition techniques effectively decreases the operation time of the biased differential element in internal fault scenarios, particularly when CT saturation generates a second harmonic exceeding the predefined harmonic blocking thresholds.
28.	(Kumar et al., 2021). **Toward a Substation Automation System Based on IEC 61850.**	The paper aims to evaluate the performance of an Ethernet-based network and validate the overall process bus design requirement of a high-voltage non-conventional instrument transformer.	The authors employed an optimized network engineering tool to investigate the impact of communication delay on the substation automation system during peak traffic. The authors used an Ethernet-based network to evaluate the performance of a high-voltage non-conventional instrument transformer.	The OPNET.	Investigation and feasibility studies are still required for the full implementation of non-conventional instrument transformers at a large scale within utilities, industries, smart grids, and digital substations.	Employing an optimized network engineering tool to evaluate the performance of an Ethernet-based network and validate the overall process bus design requirement of a high-voltage non-conventional instrument transformer. The study intends to guide the development of a robust substation automation system with IEC-61850-based communication configuration.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
29.	(Sharma et al., 2021). **Testing IEC-61850 Sampled Values-Based Transformer Differential Protection Scheme.**	The paper aims to discuss the functional testing of Sampled Values (SV)-based protective relays with the help of test equipment that can publish SV streams.	The authors detail how to test through fault conditions, pick-up, slope characteristics, and harmonic restraints on a transformer differential relay that utilizes a process bus to subscribe to current samples.	The COMTRADE.	Testing methodology is designed for SV-based protective relays and may not be applicable to other types of protection schemes or substation configurations	Include discussing the functional testing of SV-based protective relays with the help of test equipment that can publish SV streams and detailing how to test through fault conditions, pick-up, slope characteristics, and harmonic restraints on a transformer differential relay that utilizes process bus to subscribe to current samples.
30.	(Bhattacharjee et al., 2022) **Hardware Development and Interoperability Testing of a Multivendor-IEC-61850-Based Digital Substation.**	The paper aims to develop and test a digital substation test platform that incorporates devices from different manufacturers to validate device interoperability. The authors tested the process bus communication and protection operation of the IEDs to validate device interoperability.	The testbed was tested for two IED process bus communications, generic object-oriented substation event (GOOSE), and sampled measured value (SMV).	Python coding, OPNET simulation software, VUZS simulator, MATLAB, HYPERSIM modulator.	Testing methodology is designed for digital substations with multi-vendor bay solutions and may not be applicable to other types of protection schemes or substation configurations.	The paper's achievements include developing and testing a digital substation test platform that incorporates devices from different manufacturers to validate device interoperability and testing the process bus communication and protection operation of the IEDs to validate device interoperability.
31.	(Kumar et al., 2023) **Review of the Legacy and Future of IEC 61850 Protocols Encompassing Substation Automation System**.	The paper aims to present a comprehensive review of various legacy protocols and highlight the path forward for a new protocol laid down as per the IEC 61850 standard. The authors discuss the challenges of designing a substation automation system that features flexibility, adaptability, interoperability, and high accuracy.	They present the IEC 61850 protocol as a user-friendly solution that employs fiber optics instead of conventional copper wires, facilitates the application of non-conventional instrument transformers, and connects Ethernet wires to multiple intelligent electronic devices.	Wireshark tool and SV Scout tool of Omicronenergy.	Deployment of smart protocols in future substations is not a straightforward process as it requires careful planning, shutdown, and foreseeable issues related to interface with proprietary vendor equipment.	The paper's achievements include presenting a comprehensive review of various legacy protocols and highlighting the path forward for a new protocol laid down as per the IEC 61850 standard. The study intends to guide the development of a robust substation automation system with IEC-61850-based communication configuration.

2.7.2 Analysis of different publications on Real-Time Digital Simulation

Table 2.2: Different types of publications on Real-Time Digital Simulation were analysed

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
1.	(Kuffel et al., 2016). **The Role and Importance of Real Time Digital Simulation in the Development and Testing of Power System Control and Protection Equipment**	This paper aims to explain the concept of real-time digital simulation and its application in facilitating the development and operation of contemporary power systems. The paper focuses on exploring the utilization of this technology in the realms of development, testing, and implementation.	Wide area measurement protection and control is an innovative approach that goes beyond local measurements, providing a broader network perspective. It is a new concept being researched and implemented to enhance traditional protection/control schemes.	EMTP, ATP, PSCAD, and RTDS.	Limited to Hardware In-the Loop (HIL) testing.	The appropriate utilization of real-time simulation in the power industry leads to several benefits, including enhanced system performance, decreased on-site commissioning duration, reduced outage time, improved comprehension of equipment, the capability to debug, enhance, and repair, and an overall boost in confidence.
2.	(Moravej & Bagheri, 2016) **Testing of differential relay operation for power transformers protection using RTDS**	The research conducted in this paper showcases the application of a Real-Time Digital Simulator (RTDS) in a power transformer protection scheme to validate the operation of the differential relay	The controls components library is used to implement a differential relay using an RTDS.	Real-Time Digital Simulation (RTDS)	The paper was limited to Magnetizing Inrush Current and B-H curve flux simulation.	The findings illustrate that the identification of various current types within a power transformer under different operational circumstances is achieved with rapid, precise, selective, and reliable capabilities.
3.	(Iracheta-Cortez & Flores-Guzman, 2017) **Developing automated Hardware-In-the-Loop tests with RTDS for verifying the protective relay performance**	The paper describes the steps for carrying out automated Hardware-In-the-Loop tests on protective relays with the real-time power system simulator RTDS. The main features with such tests are the performance verification of new protective relays, before their commissioning within the electrical substations, and the	The authors built a digital simulation model of a power network as a benchmark case to perform the Hardware-In-the-Loop tests with the distance relay SEL-421. Finally, they analyzed the performance of the distance relay.	The authors used a Real-Time Digital Simulator (RTDS) as a real-time power system simulator for carrying out automated Hardware-In-the-Loop tests on protective relays.	The study only focuses on automated Hardware-In-the-Loop tests for protective relays with RTDS. Therefore, it does not provide any comparison between different simulators or testing methods.	The study describes the steps for carrying out automated Hardware-In-the-Loop tests on protective relays with RTDS. The study shows that such tests are useful for performance verification of new protective relays before their commissioning within electrical substations and for improving power system reliability.

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
		improvement of the power system reliability.				
4.	(Pazdcrin et al., 2018). **Platform for Testing IEC 61850 Control Systems Using REAL-TIME SIMULATOR**	The article outlines the fundamental principles of developing a dynamic simulation platform in real-time, enabling researchers to study the coordinated operation of diverse devices that communicate through IEC 61850 protocols.	The newly established laboratory can test each IED individually and the entire SAS.	Matlab Simulink, Omicron, RETOM, and other systems that use time series recorded in a real-world power system.	The paper was limited to MMS, SV, and GOOSE simulation.	In addition to performing SAS analysis, the proposed modeling platform facilitates a range of investigations aimed at optimizing information processes within the digital substation and improving its technical and economic aspects.
5.	(León et al., 2019). **Real-Time Analysis of Time-Critical Messages in IEC 61850 Electrical Substation Communication Systems**	An in-depth analysis of their timing is needed because of the time-bound nature of SAS applications. This paper presents an empirical model for testing the timing of exchanges of SV and GOOSE messages in an IEC 61850 Process Bus.	The model enables the evaluation of the timing of communication by evaluating the response time for each SAS message stream.	RTDS, OMNeT++, and INET frameworks.	During a simulation, only one relay was used from SEL.	None.
6.	(Pang et al., 2019) **Comparison Between PSCAD and RTDS Hardware In-the-Loop Simulations System in Power Quality**	The paper aims to compare the simulation results of PSCAD and Real-Time Digital Power System Simulator (RTDS) HIL under the same conditions to express their corresponding results for other researchers to reference the differences and choose the suitable testing system.	The authors built a power compensator simulation system in both PSCAD and RTDS. The set-up process is introduced, and their simulation results are analyzed.	PSCAD and RTDS are used as simulation software. Digital Signal Processor (DSP) control is used inside simulation components.	The study only compares the simulation results of PSCAD and RTDS for one power compensator simulation system. Therefore, the results differences produced by RTDS and PSCAD become one important reference for a system or algorithm.	The study shows that RTDS provides a real-time simulation process to get close to real experimental results. Further, RTDS supports HIL and permits DSP control inside simulation components.
7.	(Memon & Kauhaniemi, 2021). **Real-Time Hardware-In-the-Loop Testing of IEC 61850 GOOSE based Logically Selective Adaptive Protection of AC Microgrid**	This paper examines the latest literature on HIL testing methods and applications. Provides a detailed description of a newly developed HIL testing setup. In the case study, real-time HIL testing is employed to assess an	The authors introduced a fault detection and isolation algorithm for grid-side faults that are adaptive and rely on communication, as well as logic-based selectivity.	OPAL-RT simulator platform with MATLAB/Simulink and RT-LAB software. RTDS.	This paper was limited to the fault simulation of opening the Circuit Breakers.	The outcomes are encouraging, with the observed results of the real-time (RT) simulation closely aligning with the initially assumed conditions. To successfully implement the proposed adaptive protection and enable a smooth

	Paper author and year	Aim of the paper	Method and Model Use	Used software/ hardware	Limitations	Achievements
		enhanced version of a previously suggested communication by evaluating the IEC 61850 GOOSE protocol.				transition to the islanded and isolated mode, the use of a dedicated, efficient, and dependable Ethernet link is crucial.
8.	(Nomandela et al., 2023) **Transformer Differential Protection System Testing for Scholarly Benefits Using RTDS Hardware-in-the-Loop Technique**	The paper presents a hardware-in-the-loop (HIL) test for a transformer differential protection system to prove the validity of the settings configuration of the relay. The focus of this study is not limited to the protected transformer, but it also considers the system in which the transformer is employed.	The authors present a step-by-step configuration up to the testing part, which proves and validates the concept of differential calculations.	Real-Time Digital Simulator (RTDS).	The study only focuses on automated Hardware-In-the-Loop tests for protective relays with RTDS. Therefore, it does not provide any comparison between different simulators or testing methods.	The study describes the steps for carrying out automated Hardware-In-the-Loop tests on protective relays with RTDS. The study shows that such tests are useful for performance verification of new protective relays before their commissioning within electrical substations and for improving power system reliability.
9.	(Yadav et al., 2023) **Hardware-in-the-Loop Testing for Protective Relays Using Real Time Digital Simulator (RTDS)**	The paper aims to describe the steps for carrying out automated Hardware-In-the-Loop tests on protective relays with the real-time power system simulator RTDS. The main features with such tests are the performance verification of new protective relays, before their commissioning within the electrical substations, and the improvement of the power system reliability.	The authors built a digital simulation model of a sample distribution system to perform Hardware-In-the-Loop tests with two SEL-351 relays. Proper settings for the relays were calculated for coordination.	AcSELerator Quickset software and Real-Time Digital Simulator (RTDS) were used as a real-time power system simulator for carrying out automated Hardware-In-the-Loop tests to protective relays.	The study only focuses on automated Hardware-In-the-Loop tests for protective relays with RTDS. Therefore, it does not provide any comparison between different simulators or testing methods.	The study describes the steps for carrying out automated Hardware-In-the-Loop tests on protective relays with RTDS. The study shows that such tests are useful for performance verification of new protective relays before their commissioning within electrical substations and for improving power system reliability.

2.8 Observations and Remarks on Studies

The analysis centers on a literature review encompassing various techniques employed in transformer differential protection. The study underscores a significant gap in research about multivendor-based parallel transformer differential protection schemes with interoperability. The review of existing literature reveals a predominant focus among previous researchers on distinct aspects such as digital algorithms for transformer protection schemes and the broader field of protection and control of power transformers. Throughout the examination of the literature, the following observations were noted:

- Lack of Multivendor Interoperability Research: The literature review indicates a notable absence of research endeavors dedicated to the development and evaluation of multivendor-based parallel transformer differential protection schemes. This absence underscores a potential area for innovation and improvement within the field.
- Specialized Focus: Previous research predominantly concentrated on niche topics within transformer protection, such as digital algorithms. While valuable in their own right, these specialized studies may not address the broader challenges associated with the integration and interoperability of protection schemes across different vendors.
- Limited Holistic Approach: The reviewed literature often lacks a comprehensive, holistic approach to transformer protection. Researchers tend to tackle isolated aspects without considering the overarching need for interoperability in complex power systems.
- Opportunity for Integration Research: The absence of research in multivendor-based parallel transformer differential protection with interoperability suggests an opportunity for future studies to bridge this gap. Addressing interoperability challenges is crucial for modern power systems that often involve components from various manufacturers.

(Patil & Singh, 2019) conducted a literature review aiming to provide an overview of traditional and advanced protection schemes for power transformers. They discuss the importance of power transformers in ensuring a stable electricity supply in a power grid network. Additionally, they provide an overview of the various protection schemes used for power transformers, including traditional protection schemes such as overcurrent protection, differential protection, and earth fault protection, as well as advanced protection schemes such as artificial intelligence-based protection schemes.

(Shrirao & Warkad, 2021) provide a literature review that aims to present various methodologies of transformer protection. They discuss the importance of transformer protection in ensuring the continuous operation of transformers, which are the foremost important devices within the power system. The document offers a comprehensive summary of different protection schemes used for transformers, including thermal overload protection, differential protection, and earth fault protection.

Previous researchers have shown that there has not been much work done on parallel transformer protection schemes in terms of communication in multi-vendor IEDs. The majority of researchers primarily focus on introducing innovative methods to enable the control of paralleled load tap changer power transformers. However, others undertake a comparative evaluation of existing paralleling methods and offer optimal operation strategies for substation configurations that are increasingly common in modern power systems.

The communication of power transformer differential protection is also vital, as it involves the exchange of data between IEDs using communication protocols such as IEC 61850 GOOSE communication. Utilizing the IEC 61850 standard, the protection scheme based on it surpasses the speed of hardwired signals, enhancing both the speed and reliability of the transformer scheme through the implementation of IEC 61850 standard-based GOOSE applications. In both modern and legacy substations, IEDs are widely employed for data collection, protection, metering, control, and automation. They have been recognized as critical for the optimal operation and management of contemporary substations in recent years. It is abundantly clear that the configuration of an IEC 61850-based SAS is critical to achieving interoperability, given that IEC 61850 is based on object modeling.

According to the literature review, certain conditions must be met when establishing a SAS for power transformer protection to ensure compatibility. The ultimate issue is how vendors interpret IEC 61850. IEDs must be chosen based on their application functionality when developing interoperable systems. The current research does not reveal how various manufacturers interpret the IEC 61850 standard for communication. Utilities should not compromise their protection principles merely due to their dependence on a single vendor. Utilities should prioritize maintaining their protection philosophy without being constrained by vendor limitations. Despite the application of the IEC 61850 standard to these techniques, there is a lack of prior research papers specifically focusing on the communication aspects and interoperability of a multi-vendor-based parallel transformer differential protection scheme. This research project will shed light on the success of multi-vendor IED interoperability in parallel transformer protection.

The thesis proposes the use of the IEC 61850 interoperability standard-based microprocessor-based multi-IEDs transformer differential protection scheme to implement and investigate interoperability and protection functions for multi-vendor IEDs in power transformer differential protection within a power system grid. The interoperability study aims to assess how various suppliers interpret generic GOOSE messages, particularly in the context of transformer differential protection. Instead of focusing on timing issues, a protection scheme must be established to demonstrate that interoperability is functional within the protection system. Next, an analysis of system configuration tools for various vendor tools is conducted. The communication technique employed provides a high-speed mechanism for exchanging information between Intelligent Electronic Devices (IEDs). The IEC 61850 standard control model GOOSE can be used to enable logical nodes (LNs), facilitating efficient high-speed communication between IEDs while minimizing reliance on traditional hardwiring within the protective system.

Interoperability issues in the context of the proposed research on power transformer differential protection using IEC 61850 standard-based microprocessor-based multi-IEDs can encompass a range of challenges related to the seamless interaction and compatibility of devices and systems from different vendors. Here are some specific areas where interoperability issues might arise: Protocol Compatibility, Message Interpretation, Data Mapping, Timing and Synchronization, Configuration Tools, Cybersecurity, Device Behavior, Firmware and Software Updates, Legacy Equipment, and Testing and Validation.

To address these interoperability challenges, the proposed research will likely involve rigorous testing, validation, and potentially the development of standardized communication profiles or best practices. It may also explore the use of gateways or middleware to facilitate communication between devices from different vendors. Ultimately, the goal is to ensure that the protection scheme functions seamlessly, regardless of the specific vendors' devices involved.

In conclusion, the literature review highlights a significant research gap in the field of multi-vendor-based parallel transformer differential protection schemes that prioritize interoperability. This gap emphasizes the importance of future research endeavors aimed at addressing this crucial aspect of power system protection. The seamless integration of protection technologies from different vendors into complex power networks is essential for enhancing system reliability and ensuring the continued safe and efficient operation of power transformers. As power systems evolve and incorporate equipment from multiple vendors, the need for standardized interoperability solutions becomes increasingly evident, making this an area ripe for exploration and innovation in the field.

2.9 Conclusions

This chapter begins with an overview of the Substation Automation System in electrical power systems. An extensive literature review examines the diverse range of techniques employed in power transformer protection. The literature review focuses on the requirements for the operation of the transformer protection scheme and includes a literature search on RTDS with transformer protection Hardware-in-the-Loop (HIL) testing, enabling the exploration of GOOSE communication utilization during developmental processes. The chapter incorporates a comprehensive review of prior research conducted by different scholars, focusing on the parallel protection system for power transformers. Additionally, this chapter explores the existing literature on the interoperability of GOOSE messages, investigating the compatibility of multi-vendor Intelligent Electronic Devices (IEDs) compliant with the IEC 61850 communication standard.

As mentioned in the preceding sections, this research will focus on the transformer protection scheme. More importantly, it will be based on the newly adopted IEC-61850 communication standards. Most significantly, these chapters provide a short overview summary of the literature review of existing papers related to this research. The observations drawn from the literature's findings have been completed, and the recommended proposed method has been discussed.

Chapter Three provides an in-depth discussion of the theoretical foundations of transformer fundamentals, transformer protection techniques, and the role of protective relays in ensuring transformer safety. It also covers communication in power transformer protection schemes and interprets the IEC 61850 standard communication summary.

CHAPTER THREE

THEORETICAL ASPECTS BASED ON THE TRANSFORMER PROTECTION

3.1 Introduction

Electricity is supplied, transmitted, and consumed by networks of electrical components known as electrical power systems. An electrical grid is a power line system that supplies homes and industries with a large region. Generally, electrical grids are composed of three layers of interconnected networks: generation, transmission, and distribution. An electric-powered grid additionally incorporates a managed software program and related equipment to transmit power from the place of generation to residential, industrial, or commercial users. This is accomplished by transporting electricity from generation buses to distribution substations via transmission buses linked by transmission lines. Transformers are essential tools in the electrical system.

3.2 Overview of the Power Grid System

The power grid is an electric/power grid responsible for the interconnection of a network for supplying energy to customers from producers. This power grid includes generators, transformers, transmission, and individual consumer distribution; as shown in Figure 3.1, the generation is when the power plant generates the electricity and sends it through the transformer. This transformer is responsible for stepping up the voltage since it is on the generating parts. Transformers are important to electrical transmission because they can adjust the voltage of the electrical current, making transmission more reliable, cost-effective, and practical. The transmission system has large High-Voltage (HV) power lines; this line is always present around the country, often close to highways. Sometimes they go underground or under the sea. This system can carry power over long distances, sometimes more than 400 miles. The distribution grid consists of substations and smaller distribution lines with lower voltage, and the substation transformer is responsible for stepping down the voltage and distributing it to customers (Mehta & Mehta, 2006; Brown, 2009).

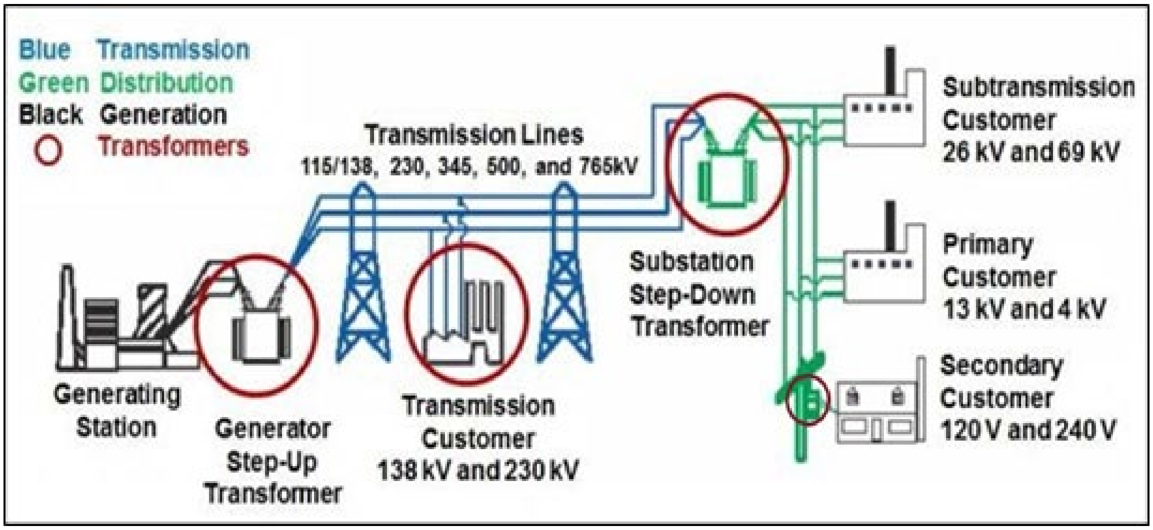


Figure 3.1: **Traditional Power grid transportation (Gilstrap et al., 2015)**

However, the change of the power grid into the new technology grid and interfacing with the IEC61850 standard has brought a lot of challenges to the old system equipment. The SAS protection communication protocol has been greatly influenced by IEC 61850. IEC 61850 was created with the primary goal of achieving seamless interoperability across various vendors' protective devices. IEC 61850 provided a practical solution to the interoperability issue for numerous utilities all over the world (Sendin et al., 2016).

3.3 Transformer Overview

Transformers are used to connect two networks to varying voltage rates. They can change the transmission network voltage to the distribution network or increase the voltage from a generator to a network operator for transmission or distribution. A transformer is a two or more windings static device that converts an alternating voltage and current system by electromagnetic induction into another current and the voltage system, typically at different values and at the same frequency, to transmit electrical power. It is unavoidable that any fault will occur somewhere in the network sooner or later. When any part of the system fails, it must be detected quickly and unconnected from the system (Krieg & Finn, 2019; Machowski et al., 2020).

One of the highly efficient devices used in electrical systems for distribution for converting the voltages generated into convenient transmission and consumption voltages for this purpose is the basic operating theory of the transformer. A transformer is made of two primary and secondary windings coupled with a common magnetic core (Okedu, 2019). Various transformer forms are displayed in Figure 3.2.

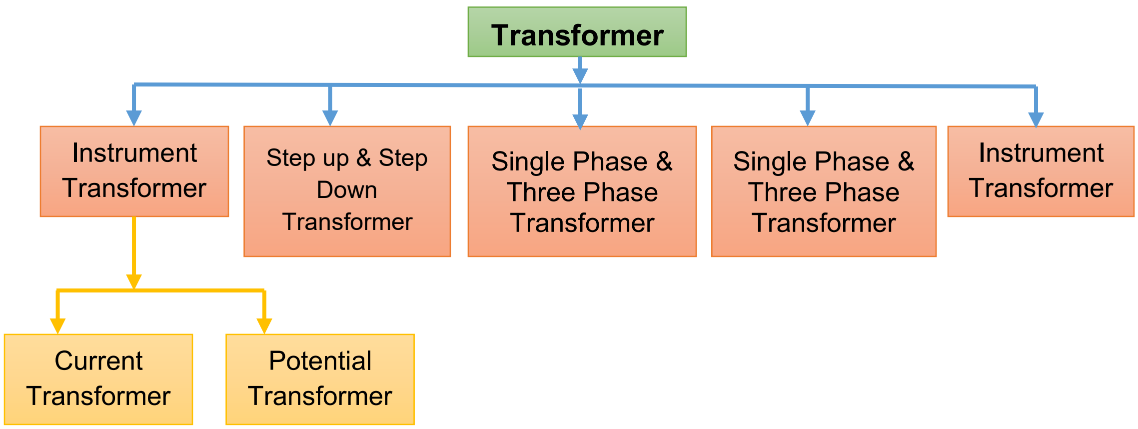


Figure 3.2: Various kinds of transformers

3.3.1 Basic Operation Theory of the Transformer

If the winding primary is attached to a source and the secondary circuit remains open, the transformer functions as an inductor extracted from the source with the restricted current. One voltage at the same time is generated due to the magnetic coupling in the secondary open winding circuit. When a load has been connected through terminals of the secondary, the current flows into the second terminal, which is determined by the open circuit's load impedance and secondary voltage. Through the main winding, a proportionate current is drawn according to the ratio of turns from Primary to Secondary. This concept of transformer operation is used for standardization purposes in converting the current and voltage on the circuit to the appropriate values (John J. Winders, 2002; Glover et al., 2017; Iuravin, 2018).

3.3.2 Transformer Construction

Two inductive windings and a laminated steel core make up a transformer. The coils are both isolated from one another and the steel core. A transformer may comprise a tank, which houses the winding and core assembly, as well as bushings to connect the terminals. It may also incorporate an oil conservator that supplies cooling oil within the transformer tank, along with various other components (Vecchio et al., 2002; Harlow, 2012; Adnanaqeel & Watson, 2018). Figure 3.3 depicts the fundamentals of transformer construction.

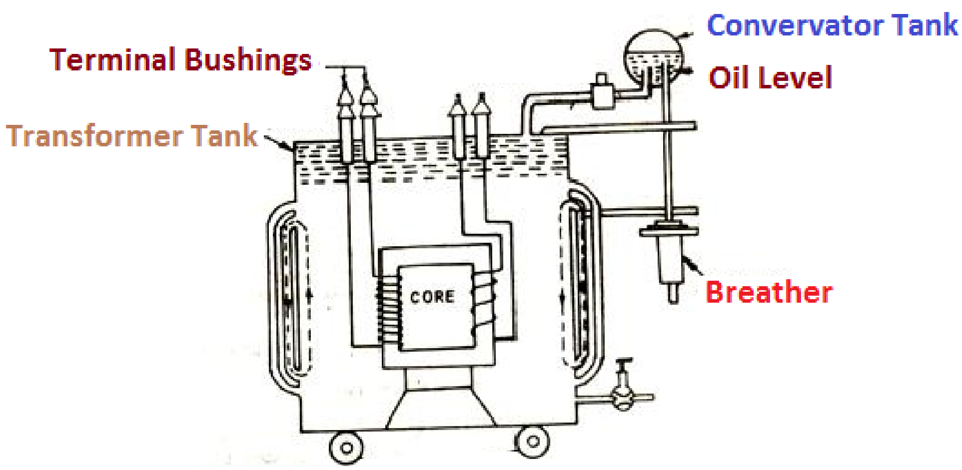


Figure 3.3: Fundamental transformer construction (Adnanaqeel & Watson, 2018)

Due to their construction, transformers can be categorized into two categories: core transformers and shell-type transformers (Heathcote, 2007; Bakshi & Bakshi, 2020), each of which is discussed below.

Table 3.1: Description of transformer Construction type

Construction transformer types	Description of transformer type
Core type	In a core-type transformer, the core limbs are mounted with cylindrical former wound windings. Each layer of the cylindrical coils is insulated from the others and has a different number of layers. Materials like paper, cloth, or mica can be used for insulation. Since they are simpler to insulate, low-voltage windings are positioned closer to the core.
Shell type	The coils in a transformer are wound and arranged in layers, with insulation separating them. A shell-type transformer can exhibit either a simple rectangular shape or a more distributed form.

Every electrical device experiences some power loss, so there are two different types of transformers based on these losses. Transformers that are ideal and practical (Glover et al., 2017), Figure 3.4 shows the ideal and practical transformer.

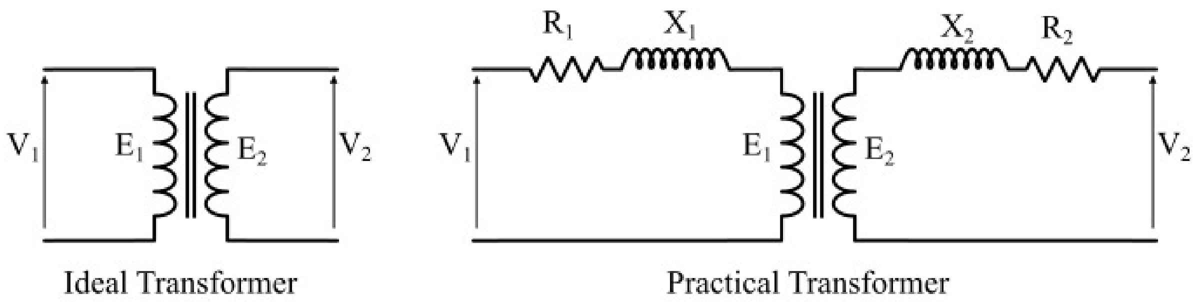


Figure 3.4: **Basic Ideal transformer and practical transformer (Bakshi & Bakshi, 2020)**

3.3.2.1 Ideal Transformer

An ideal transformer is an imaginary transformer with zero energy losses. It is important to note that an ideal transformer does not exist in reality, which means it is hypothetical and cannot be realized practically (Vecchio et al., 2002; Bakshi & Bakshi, 2020). The following are the characteristics of an ideal transformer;

- The primary and secondary windings have very little resistance (or zero).
- There is no leakage flux, implying that the flux is entirely contained within the magnetic circuit.
- Due to the infinite permeability of the magnetic core, establishing flux in the core requires only a small amount of MMF.
- Winding resistance, hysteresis, and eddy currents do not cause any losses. As a result, the efficiency is 100%.

3.3.2.2 Practical Transformer

A practical transformer is one in which, due to its core and winding properties, there are some energy losses within the transformer (Fofana & Hadjadj, 2018). As a result, the practical transformer is represented by the following equation,

$$\mathrm{TRF}_{\mathrm{PRAC}} = \mathrm{TRF}_{\mathrm{IDEAL}} + \text{Energy Losses} \qquad \text{Equation 3.1:}$$

TRF_{PRAC} = Practical Transformer
TRF_{IDEAL} = Ideal Transformer
Energy Losses = Energy Losses

The following are the primary characteristics of a practical transformer;

- The primary and secondary windings possess a finite amount of resistance.
- A leakage flux exists, indicating that not all of the flux is contained within the magnetic circuit.
- The magnetic core has a finite permeability, so a significant amount of MMF is required to build up the flux in the core.
- The transformer suffers losses due to winding resistances, hysteresis, and eddy currents. As a result, a practical transformer's efficiency is less than 100%.

3.4 Parallel Transformers

In parallel operation, the HV and LV of two (or more) transformers are connected to the source and load busbars, respectively. As defined by IEC 60076 - 8, the parallel operation is referred to as a direct terminal-to-terminal connection between transformers in the same installation. The reliability of parallel operation is higher than that of a single larger unit. When two transformers are connected in parallel, the cost of maintaining spares is reduced. It is usually more cost-effective to install another transformer in parallel rather than replace the existing transformer with a single larger unit. In the case of two parallel transformers (of equal rating), the cost of a spare unit is also less than that of a single large transformer. Furthermore, for the sake of reliability, a parallel transformer is preferable (Blackburn & Domin, 2014; Harlow, 2012; Jiguparmar, 2012a; Mohan, 2021).

3.4.1 Need for Parallel Operation of Transformers

In electrical power systems, it is common to use several smaller rated transformers connected in parallel rather than a single larger rated transformer. This is because it is not necessary to disconnect the entire system if one of the transformers fails. Furthermore, system operators can turn off any transformer for maintenance while other transformers handle the load, ensuring a constant electricity supply. The requirement for parallel transformer operation arises. When the transformer rating is exceeded, an additional load must be accommodated. During the design process, the electrical system's efficiency, availability, reliability, and flexibility must be maximized (Heathcote, 2007; Sridhar, 2020; Kaminickas, 2015; Edvard, 2019; Mohan, 2021).

- **Efficiency: T**he maximum efficiency of an electrical power transformer is at full load. If we run a number of transformers in parallel, we can turn on only those that will provide the total demand by operating closer to their full load rating. When the load increases, we can switch no one by connecting another transformer in parallel to meet the total demand. This allows us to run the system as efficiently as possible.
- **Availability:** When one of the transformers is removed for maintenance, the other transformers connected in parallel operation will meet the load demand without causing any service interruption.
- **Reliability:** If any parallel transformers trip due to a fault, the remaining transformers will share the load. As a result, the power supply will not be interrupted if the load demand in that scenario does not overload the transformers.
- **Flexibility:** If future power demand increases, there must be a parallel provision for connecting transformers in the system to meet the extra demand. In the event of a decrease in future demand, the removal of parallel-operating transformers from the system can help maintain a balance between capital investment and its corresponding return.

3.4.2 Conditions for Parallel Operation of Transformer:

Transformer primary windings are connected to source busbars, and secondary windings are connected to load busbars for parallel connections. Several conditions must be met for transformers to operate in parallel successfully; these conditions are as follows (Heathcote, 2007; Edvard, 2019; Jiguparmar, 2012a):

- (The voltage rating for the primary and secondary is the same) identical voltage and turn ratio
- The same X/R Ratio and % impedance.
- Same KVA ratings.
- Identical Position of Tap Changer.
- Angle shift with same phase (Vector group is same).
- Rating for the Same Frequency.
- Same phase sequence and polarity.

It is believed that some of these conditions are convenient, and some are mandatory.

Table 3.2: **Convenient and mandatory conditions for parallel transformer operation**

Conditions	Brief explanation
Convenient	The voltage ratio, turns ratio, % impedance, KVA ratings, and tap changer position are all the same.
Mandatory	These include the same phase shift angle, polarity, phase sequence, and frequency. Parallel operation is possible but not ideal when convenient circumstances are not met.

When two transformers with the same parameters are connected in parallel, the load is shared equally, and there are no circulating currents in the transformer windings. Circulating current can cause protection relays to malfunction.

Other Necessary Conditions for Parallel Operation (Heathcote, 2007; Jiguparmar, 2012b):

- The same network must power all parallel units.
- The secondary cabling connecting the transformers to the point of paralleling is designed to have similar lengths and characteristics.
- The corresponding phases' voltage difference must not exceed 0.4 percent.
- During parallel operation of the transformers, there is a significant increase in fault current on the secondary side.
- On the secondary side of the transformers, directional relays should be installed.
- One transformer's percent impedance must be between 92.5 and 107.5 percent of the others. Otherwise, excessive currents would flow back and forth (circulating currents) between the two transformers.

Some sets will function in Parallel transformers, and there is a Vector group of Transformers that will not work in parallel. However, the table below illustrates the Vector group of Transformers that will operate in parallel.

Table 3.3: **The vector group selection for parallel transformers**

Parallel Operation in Action		
Sr. No	**Transformer 1**	**Transformer 2**
1	Delta-Delta	Delta-Delta or Star-Star
2	Star-Star	Star-Star or Delta-Delta
3	Delta-Star	Delta-Star or Star-Delta
4	Star-Delta	Star-Delta or Delta-Star

The advantages of parallel transformers have been discussed above, and below, the disadvantages of a transformer's Parallel Operation will also be discussed:

- To increase breaker capacity, short-circuit currents must be increased.
- The potential for circulating currents to reduce load capacity and increase losses by flowing from one transformer to another.
- The bus has received high ratings.
- Paralleling transformers significantly reduce transformer impedance, resulting in very slow impedance and high short circuit currents. Consequently, certain measures are necessary to limit the current, including the use of reactors, fuses, high-impedance buses, and similar components.
- Controlling and protecting three units in parallel is more difficult.
- Because Main-tie-Main is so common in this industry, it is not a common practice.

3.4.3 Transformers Tap Changer and its Operations

Transformer tap-changing is used to maintain a constant voltage or to stay within the prescribed limits. Tap-changing involves placing tapings on the coils of a transformer so that the voltage induced can be varied by varying the turn ratio. A tap changer's purpose is to regulate the output voltage of a transformer by changing the number of turns in one winding and thus changing the transformer's turn ratio. This configuration is done externally to the transformer by removing the coil terminals from the transformer tank. Off-Load Tap-Changing Transformers (No load or off circuit) and On-Load Tap-Changing (OLTC) Transformers are the two types of tap-changing transformers. To meet customer requirements, all power transformer designs can accommodate both/either type of tap changers (Jauch et al., 2015; Harlow, 2012; Shoemaker & Mack, 2017; Sridhar, 2020).

3.4.3.1 Off-Load Tap-Changing Transformer (No load or off circuit)

This approach, known as off-load tap changing, entails adjusting the taps on the transformer once the load has been disconnected. Off-load tap changing is commonly employed in low-power, low-voltage transformers, offering a cost-effective means of tap adjustment. The taps are changed manually using the hand wheel provided on the cover. Certain transformers are equipped with mechanisms that allow for tap changes through the operation of mechanical switches. The winding is connected to taps at different locations. Because the taps are located at various points throughout the winding, only one tap can be connected at a time; otherwise, a short circuit will occur. As a result, the selector switch is activated after disconnecting the load. A mechanical lock is provided to prevent the unauthorized operation of an off-load tap changer. Electromechanical latching mechanisms can be utilized to activate circuit breakers and de-energize the transformer promptly when the tap changer handle is manipulated, thus preventing accidental operation (Mehta & Mehta, 2006; Shoemaker & Mack, 2017).

3.4.3.2 On-Load Tap-Changing (OLTC) Transformer

The turn ratio can be changed using on-load tap changers without removing the load. Even when the transformer is delivering the load, tap changing is still possible. On-load tap changers significantly increase the system's efficiency. Nowadays, on-load tap changers are a standard feature on almost all large power transformers. The following are the justifications for OLTC provision in power transformers (Mehta & Mehta, 2006; Harker, 2008):

- The main circuit is unaffected while on-load tap changers are in use.
- Dangerous sparking is avoided. The on-load tap changer switch is housed in an oil-filled compartment that receives the taps from the windings. The tap changer is a type of mechanical selector switch that can be controlled locally or remotely by a motor.

A handle designed to be operated manually in an emergency. A temporary connection between the adjacent taps must be made when the tap changers switch from one tap to another because the selector switch is a make-before-break switch. As a result, the adjacent taps experience a short circuit. A reactor or a resistor must be used to limit the short-circuit current. Therefore, an impedance is included in all types of on-load tap changers to prevent short circuit current during tap-changing operation. Resistance or a centre-tapped reactance could be the impedance. A pair of resistors always perform it in contemporary designs (Mehta & Mehta, 2006; Harker, 2008; Shoemaker & Mack, 2017).

3.4.4 Control Methods for Transformers Parallel Operation

The master/follower protocol, commonly employed, is extensively utilized for parallel control purposes. This is a simple method for keeping several tap changers at the same tap number. Therefore, it is suitable in situations where the transformers exhibit closely similar voltage ratios across all tap positions and possess matched impedance. According to transformer theory, if such transformers are connected in parallel at the same tap, they will share the common load in proportion to their rating, with no circulating current within the paralleled loop. The current circulating or negative reactance method can be used for parallel operating transformers that do not meet these requirements. Coordinating the control of multiple parallel tap changers is essential for achieving master/follower operation. This involves synchronizing the actions of the tap changers in parallel. Tap changer supervisory controllers are used in modern implementations (Sridhar, 2020).

3.5 Types of Transformer Faults

A variety of factors can contribute to the failure of an electrical transformer, with statistics indicating that winding failures are the most frequent cause of faults in transformers. Deterioration of the insulation, often caused by moisture, voltage surges, vibration, overheating, and mechanical stress during a faulted transformer, is a big cause of winding failure. Another type of fault is the voltage-regulating load tap changers and Transformer bushings. Current transformers have triggered other miscellaneous faults, Oil leakage due to unsuitable tank welding, oil contamination from metal particles, overvoltage, and overloads (Grisby, 2012). There are several types of transform protection which are as follows:

- Electrical: This uses fuse, overcurrent protection, differential, and over-excitation.
- Mechanical: There are two methods generally accepted for detecting faults in transformers: accumulated gases and Pressure Relays. Such detection methods include sensitive detection of faults and protection against compliments by differential or overcurrent relays.

3.6 Instrument transformers

The voltage transformers and current transformers continuously monitor an electrical system's voltage and current and are responsible for giving the relay feedback signals to allow the detection of unstable conditions. In modern distribution systems, the value of actual currents ranges from a couple of amperes in homes, small commercial/industrial buildings, and so on to thousands of amperes in power stations, national grids, and so on, often relying on operating voltages. Likewise, the voltages vary from a few hundred volts to many kV in electrical systems. It is, however, impossible to design and manufacture monitoring relays for every distribution system and to match the countless currents and voltages present. Therefore, current transformers and voltage transformers are used to allow all types of distribution systems to use the same types of relays to ensure that the availability and cost of relays are within reasonable ranges (Grisby, 2012;

Mcdonald & Grigsby, 2012; Krieg & Finn, 2019). The principal functions of transformers of instruments are:

- To insulate the primary high voltage relays, meters, and instruments.
- Typically transforming voltages or currents from high is too easy to manage for relays and devices.
- To provide a few nominal currents and voltages with the possibility of standardizing relays and instruments, etc.

Instrument transformers are special transformer versions regarding voltage and current measurements. The theories for instrument transformers, in general, are identical to those for transformers. The instrument transformers consist of a voltage transformer (known as a potential transformer) and a current transformer.

3.6.1 Voltage/Potential Transformer

An open-circuited transformer is a voltage transformer connected with the main winding over the electrical system's regulated main voltage. A comfortable proportionate voltage for monitoring is produced at the secondary. Voltage transformers have two types that are commonly used for the protection of equipment (Krieg & Finn, 2019).

- Electro-magnetic type (commonly known as the VT)
- Capacitor Type (called the CVT).

3.6.2 Current Transformer

The transformer current is used for measuring purposes as well as for protecting and is also used to convert the high current to the appropriate current value given in the circuit if the current is high for direct measuring instrument application. The current transformer's primary winding is connected to the principal circuit, carrying the full operating current of the system directly in series. In its secondary, to obtain an equivalent measure of the main current of the device, the equivalent current is generated that flows through the relay coil. The normal flows are normally 1 ampere and 5 amperes. In construction, all transformer current used in protection is identical to transformer standards. They consist of primary and secondary magnetically coupled windings wound on a common core of iron, the primary winding being linked to the network in series, unlike voltage transformers (Krieg & Finn, 2019).

These must also withstand the latest short-circuit networks, and there are two types of current transformers: primary type Wound and Bar. Protection CTs Under normal conditions, normally, protection relays are not supposed to provide directions for tripping. On the other side, they concern themselves with a wide variety of currents, ranging from appropriate fault settings to maximum fault currents, which are often normal (Hewitson et al., 2004). The combined primary current in a current transformer is determined by the vector sum of the excitation current. The current can be calculated by multiplying the turn ratio with the secondary current reversal. The primary current is shown in Equation 3.2.

$$\mathbf{I_p} = \mathbf{I_0} + \frac{\mathbf{I_S}}{\mathbf{K_T}} \qquad \text{Equation 3.2:}$$

Where,

Is – secondary or reversal current
I_p – primary current
K_T – turn ratio
I_0 – excitation current

3.6.2.1 Application of current transformers

Current transformers are used to resolve the limitations faced by series trip coils so strong primary currents are reduced to manageable rates that protective equipment can handle comfortably. These use current transformers that must be used beyond certain limits, i.e., excessively high current rating and breakage capacity. Overcurrent and ground fault are basic schemes (Mcdonald & Grigsby, 2012).

3.7 Transformer Protection System

Protection is an engineering electrical power branch that protects electrical power networks from faults by disconnecting faulty parts from the rest of the electrical grid. The transformer protection scheme's purpose is to maintain a stable system power only by isolating the faulty components while leaving as much of the system network already in service as possible. Therefore, the protection schemes must apply a realistic and negative approach to the fault clearance framework. The types of equipment used to protect the power supply system’s failures are known as protection devices (CBs, VTs, CTs, etc.) (Mcdonald & Grigsby, 2012; Machowski et al., 2020).

Protection systems generally consist of five components:

- Voltage and current transformers are designed to lower the electric power system's high voltages and currents to manageable rates for handling relays.
- Protective relays for sensing the fault and initiating a trip.
- Circuit breakers opening/closing a relay and auto recloser-based system
- Batteries for supplying power when power is disconnected in the system
- Channels of communication to enable current and voltage analysis at a line's remote terminals and to allow remote equipment tripping.

Protection is expected to be done to avoid the following:

- Prevents any supply disruption
- The electrical equipment is costly, and any damage to the equipment should be avoided.
- The power system should always be functioning safely.
- As well we build electrical equipment, fault on the power system may occur
- The fault could pose a danger to life and property.

Transformer Protection generally develops rare faults as static, completely enclosed, and immersed in oil, but if these faults are sustained, the results could be dangerous if the transformer is not disconnected. Transformer protection is generally classified based on a transformer's operating voltage and volt-ampere range. For protection, power transformers are generally classified into three types which are Small power transformers with ratings up to 500 kVA, Medium power transformers with ratings ranging from 500 kVA to 5 MVA, and Power transformers with ratings greater than 5 MVA are considered large (Patel & Chothani, 2020).

According to transformer failure statistics, the most common causes of transformer failure are winding failure and tap changer failure. Transformer protection is classified into electrical and non-electrical (Patel & Chothani, 2020). The transformer faults usually occurring can be divided as:

- Faults in the transformer's auxiliary equipment.
- Faults in winding and connections to the transformer.
- Overloads and short circuits external.

As power grids grow bigger and hold more electricity, the need for fast, reliable disconnection becomes more urgent when faults occur. Protective relay equipment is intended to detect fault states and breakers of the trip circuits. Today's manufacturing models, hardware, and communication relays are becoming standardized to a point where only the software included differs. The network's protection and control functionality can be used to deliver optimum performance and reduce the lifetime cost of capital, thereby improving supply quality, disturbance recording, and substation monitoring (Eberhard, 2011). Personal injuries and damage can occur when a fault is not fixed early.

3.7.1 Protective relays

This device provides instructions for disconnecting a defective section component and ensuring that power is still fed to the remaining system. It is often used to monitor system parameters. Where appropriate, it can be instructed to function quickly (dependability) and should not function incorrectly (discrimination, stability). In the past, relay technology has changed from electromechanical to static, digital, and numerical relays with time. Each of these has brought a size reduction and improved functionality (Das, 2018; Das & Kanabar, 2015). Table 3.4 displays a comparison of protection relay technology features and is followed by a brief history of the different types of relay development.

3.7.1.1 Numerical relays

Due to technological advances, numerical relays are the evolution of digital relays. One or more digital signal processors (DSPs) are designed to process signals in real-time, using mathematical algorithms for protective functions with appropriate software and microprocessors. This enabled higher speeds due to the higher sampling rate. Different manufacturers produced all the relays that were discussed. Therefore, numerical relays also have different manufacturers. This implies that individual software and hardware components were dedicated to each protection relay function (Eberhard, 2011).

Several signs of progress have been made, including moving the same protection functions to a single platform to give common software and then moving on to universal software for a certain manufacturer for all types of relays. Universal hardware is still being developed, and each vendor has developed its communication protocol. Then there was the issue of combining the many protocols collected to complete a new development. There was discussion on the need for a single standard with a universal communication protocol.

The International Electrotechnical Commission (IEC) developed a committee to standardize protocols that facilitate communication among relays, creating a unified environment for relay communication. A new IEC 61850 standard was established; with IEC 61850, utility communication within and between substations will be used for substation automation and protection purposes. In comparison to the conventional relay, This led to modern devices being known as Intelligent Electronic Devices (IEDs), as protective IEDs perform automation, communication, and control functions In addition to the traditional functions of protection (Krieg & Finn, 2019). Table 3.5 briefly describes the evolution of protection relays over the years for Figure 3.5.

Table 3.4: **Comparing the characteristics of protective relay technology (Giraneza, 2018)**

TYPE OF RELAY			
Characteristics	Electromechanical	Solid-state	Digital
Sensitivity and accuracy	Good	Very good	Excellent
Reliability	High	Good	Moderate
Discrimination	Low level	Good	Excellent
Multifunction	No		Yes
Range of settings	Limited	Wide	Very Wide
Self-monitoring	No	No	Yes
Speed of response	Slow	Fast	Very fast
Metering	No	No	Yes
Disturbance immunity	High	Low	Very low
Lifetime	Long	Short	Short
Parameter settings	Difficult	Easy	Very easy
Remote operation	No	No	Yes
Visual indication	Targets, Flags	LED	LCD
Event log	No	No	Yes
Relay Size	Bulky	Small	Compact
SCADA capability	No	No	Yes
Maintenance	Frequent	Low	Low

Table 3.5: Description of Figure 3.5

Block	Description of the Block
1	Includes solid-state and electromechanical relay.
2	These add communication with a Data Concentrator or RTU (A station level system that gathers all Bay level relays / IEDS information), the start of an automation substation system.
3	It uses protocols such as DNP3 (IEEE 1815) and Modbus to display communication: more recently, using GOOSE (IEC61850) to present peer-to-peer communication.
4	This is responsible for the direct conversion of digitized analogue values from merging units (MU) to IEDs using IEC61850-9-2.

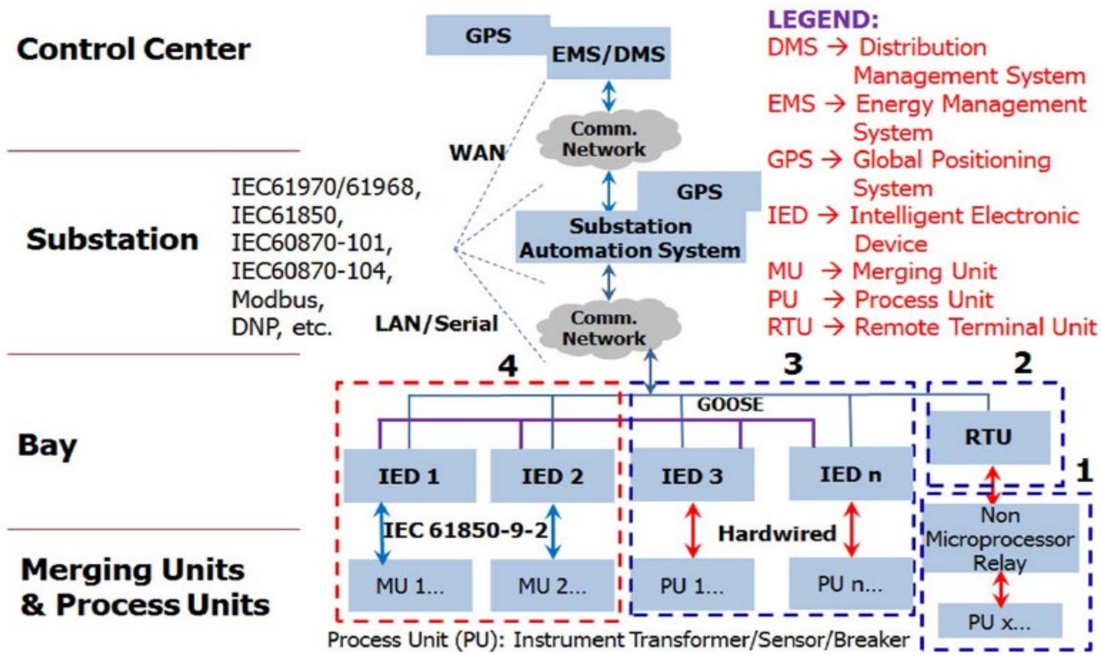


Figure 3.5: Clear overview of the evolution protection relays (Das & Kanabar, 2015)

3.8 Transformer protective relays Protection

The various types of protection for transformer components are listed in Table 3.6. These tables explain the causes and consequences of the faults commonly found in power system transformers. Besides, it also mentions the Protection schemes necessary to protect against such faults. However, this research will focus on differential protection only (Leelaruji & Vanfretti, 2011).

Table 3.6: **Transformer protective relays Protection** (Patel & Chothani, 2020)

Important Individual Protection Units					
Units	**Type of Protection**	**ANSI Codes**	**Causes**	**Effect**	**Protection Scheme**
Transformer	Protection against overload Over-current	58	The increased power of the transformer on the secondary side	Transformer Overheating	Thermal picture relay (with temperature tracking)/overcurrent relay
	Over-current protection Earth	50/51	Phase and ground faults Poor	Overcurrent can cause damage to windings	Over-current relays
	Protection against earth faults (Stator & Rotor)	50N/51N	Poor insulation, its connection is direct to the earth	Causes current imbalances in the system	Neutral relays with over-current module
	Differential Protection	87	Faults inside the protected zone	Internal faults may be short circuits or overloads that can affect the winding of transformers or earth faults.	Differential protection at each side of the transformer with CTs (Unit Protection)
	Directional (Phase and Neutral) protection	67/67N	Fault in the nearby (parallel) feeder/bay, which causes healthier tripping feeder/bay due to poor selectivity of the relay	Tripping extra feeders, driving the system into greater outages	Directional Over-current relay detects the direction of the current in and out of the protected unit flows-in. If the direction of the flow-out and flow-in current is not the same, the breaker will receive a trip signal
	Protection Failure Breaker	50 BF	Malfunctioning breaker	Due to tripping failures, it is impossible to isolate faulty equipment (Longer presence of fault currents and potentially greater damage to equipment)	Breaker relay failure that works with its algorithm to attempt to open the breaker, then it sends a trip order to the nearby breakers to isolate the failed equipment to prevent the flow of fault currents from being fed.

3.8.1 Differential Protection Scheme

As the name suggests, differential protection compares the currents entering and leaving the protected and operating zone if the difference between those currents is greater than the specified magnitude. It is possible to split this form of protection into two forms: balanced voltage and current. However, differential protection is achieved numerically nowadays. Analysing the ubiquitous electromechanical relay is useful for understanding the principles of differential protection (Rajput, 2006; Gers & Holmes, 2011). Figure 3.6 shows a simple protection scheme for differentials.

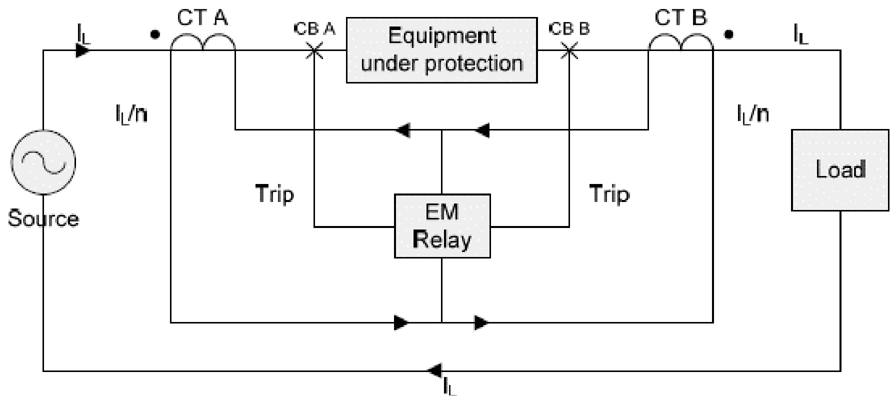


Figure 3.6: **Simple Protection Scheme for differential (Bergstrom, 2010)**

From the above Figure 3.6, we can conclude that the current entering the equipment under protection under normal operating conditions is equal to the leaving current. An overcurrent relay is operated under protection by a circuit breaker on either side of the equipment. Current transformers of the same type and turn ratio are mounted on either side of the equipment. These current transformers produce similar secondary currents with the same primary currents and turn ratio. Therefore, on the above diagram, no-spill current flows through the relay under these circumstances, and therefore no trip signals will be produced (Bergstrom, 2010; Gers & Holmes, 2011).

However, if the internal fault happens to the equipment under the protection of the large current is going to flow through the fault, leading to a rapid reduction of the current entering the equipment; this results in a reduced secondary CT B current. This will allow the current through the relay to pass, which would be of sufficient magnitude to trip through the circuit breakers. The current leaving the equipment is the same as the current entering in the event of an external fault, so the relay does not move/trip. It is just as we want it, as faults outside the equipment are in another protection zone and are contained by another scheme (Bergstrom, 2010).

The current in the current transformers in modern IEDs does not directly control the operating coil that passes through the circuit breakers, so the connection is not as seen in this example. Current transformer currents are inserted into the IED, where they are sampled and digitized. The differential procedure is then done by software for the IED.

- Through-fault Stability in Differential Protection: This requires the protection to operate only for faults within the protection zone. Therefore, due to the low-current faults associated with the equipment inside the protection region, we need this protection to be effective.

3.8.1.1 Differential Transformer Protection

To effectively detect ground faults in proximity to the Earth, transformers are commonly protected against winding faults using a combination of differential protection and Restricted Earth Fault (REF) protection. This ensures heightened sensitivity and reliable protection. Each transformer device may have differential protection against relays. The protection concept for this relay is a comparison of current inputs on the transformer's high and low-voltage sides. Under ideal conditions, there is no current flow inside a relay unless the protected device has a defect (Leelaruji & Vanfretti, 2011).

For protection schemes, for transformer components, the relay type that is used is Differential Relay based on the ANSI Code 87, with the Input parameters currents from the primary ($I_{\mathbf{primary}}$) and secondary ($I_{\mathbf{secondary}}$) side with the output parameters current (I) (Leelaruji & Vanfretti, 2011). Its operating principle is as follows

- Protects the transformer against faults from internal by taking current inputs from both the transformer's primary and secondary aspects.
- In normal conditions or external faults, the sum of these currents (considering the transformer turns ratio) is zero but not zero in the event of fault conditions.
- In case of a fault, the signal trips from the differential relay transformer (87) to the transformer protection breaker circuit.

3.8.1.2 Differential Relay

A differential relay is a suitably linked overcurrent relay that functions when a predetermined value exceeds the phasor difference of currents at the two ends of a zone that is protected. There are three fundamental systems of differential or balanced protection voltage, current, and biased beam/ percentage differential relay (Renoald, 2015; Rajput, 2006). The current differential Relay Advantage and Disadvantage are shown in Table 3.7. However, the disadvantages of the differential relay in biased beam relays are largely overcome (Mehta & Mehta, 2006).

Table 3.7: **The current differential Relay Advantage and Disadvantage**

Advantage	Disadvantage
▪ ONLY Due to an effective 16-bit A / D conversion technique, complete digital signal handling with a powerful 16-microprocessor and high measurement precision in all setting areas. ▪ With a versatile signal grouping matrix in the relay, easily adaptable to different substations and alarm networks.	▪ Cable impedance from the secondary CT to the remote relay panel may have a chance of mismatching. ▪ The capacitance of pilot cables causes the relay to work improperly when a wide by-fault occurs outside the equipment. ▪ Accurate matching of current transformer characteristics cannot be done; therefore, under normal operating conditions, a spill of current could flow through the relay.

- Biased Beam Relay

The biased beam relay (also called Differential Relay Percentage) is constructed in terms of its fractional relationship to a current that flows through the protected zone to respond to the differential current. Essentially it is a balanced overcurrent relay beam with an additional restraining coil. The restraining coil generates a biasing torque to the operating torque in the opposite direction. Under normal conditions and due to fault, torque restriction is more than the operation of torque. Relay, therefore, remains inoperative. If the fault occurs internally, the force of operation exceeds the force of bias, and thus the relay is worked. Varying the number of turns on the restraining coil can adjust the bias force (U.A.Bakshi & M.V.Bakshi, 2006; Mehta & Mehta, 2006). The schematic structure for a biased beam relay is shown in Figure 3.7, and Figure 3.8 shows the equivalent circuit.

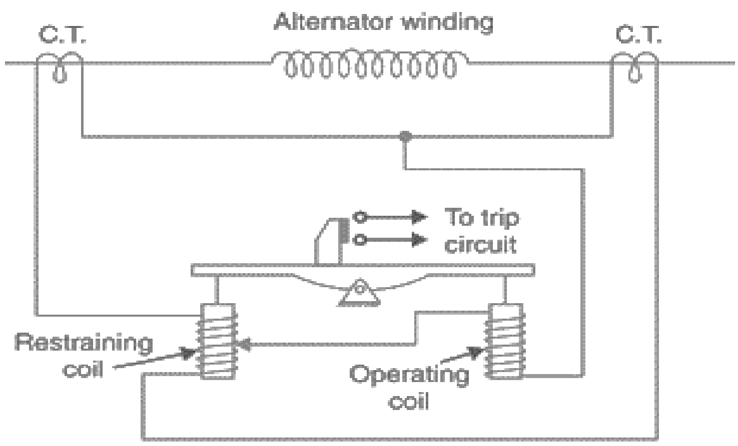


Figure 3.7: **Schematic diagram of a biased beam relay (Mehta & Mehta, 2006)**

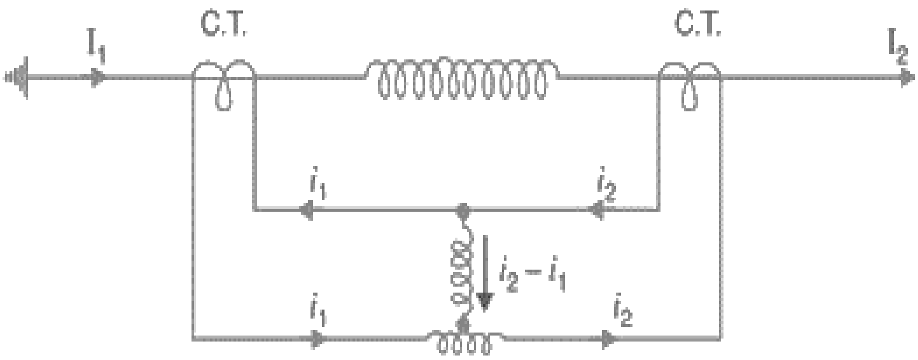


Figure 3.8: The equivalent circuit (Mehta & Mehta, 2006)

3.8.2 Problems Encountered in Differential Protection

The differential scheme described suffers from the following drawbacks (U.A.Bakshi & M.V.Bakshi, 2006):

- **The difference in lengths of pilot wires:** Because of the different lengths of the pilot wires on both sides can result in unbalanced conditions. Relay on either side by attaching adjustable resistors to pilot wires to obtain equipment points on the wires of the pilot is overcome.
- **The difference in CT ratio error:** Differences in the high values of the short circuit currents make the relay work even for external or protection operations. This is overcome by introducing a biased Beam Relay coil.
- **Tap changing alters:** the voltage-current ratio between the HV and LV sides, and the relay senses this and acts. This equipment adjusts the turn ratio effectively. This causes both sides to unbalance, so to compensate for this effect, tapings can also be given on CTs which are to be varied similarly to the main transformer, but this method is not feasible. A biased Beam Relay coil will solve that.
- **Magnetizing inrush current:** this happens while the transformer is being energized, generating harmonics on its primary side. The secondary is not showing a present. CTs like the circuit do not have the load. The operation of the differential relay is dependent on the variation in current between different points. The relay is supplemented with a harmonic restraining device that will block it when the transformer is energized.

3.8.3 Requirements for the operation of the differential protection

While manufacturers of relays dedicated to differential protection impose the secondary CT characteristics needed for proper operation, having minimum knowledge of this protection is useful for understanding and avoiding errors. The area limited by CTs that measure incoming and outgoing currents is controlled by differential protection. If the outgoing currents are not aligned with the incoming currents, this is typical because, in the protected area, there has been a fault (U.A.Bakshi & M.V.Bakshi, 2006).

3.8.4 Typical Transformer Differential Configuration

An example of the typical transformer differential connection with the label is shown in Figure 3.9. The various connections of the transformer may be delta to star, delta to delta, star to delta, and star to star. We need to consider the System's Current Transformer (CT) configurations with the CT, CT Mismatch, CT Saturation, CT Polarity, and CT Star Stage.

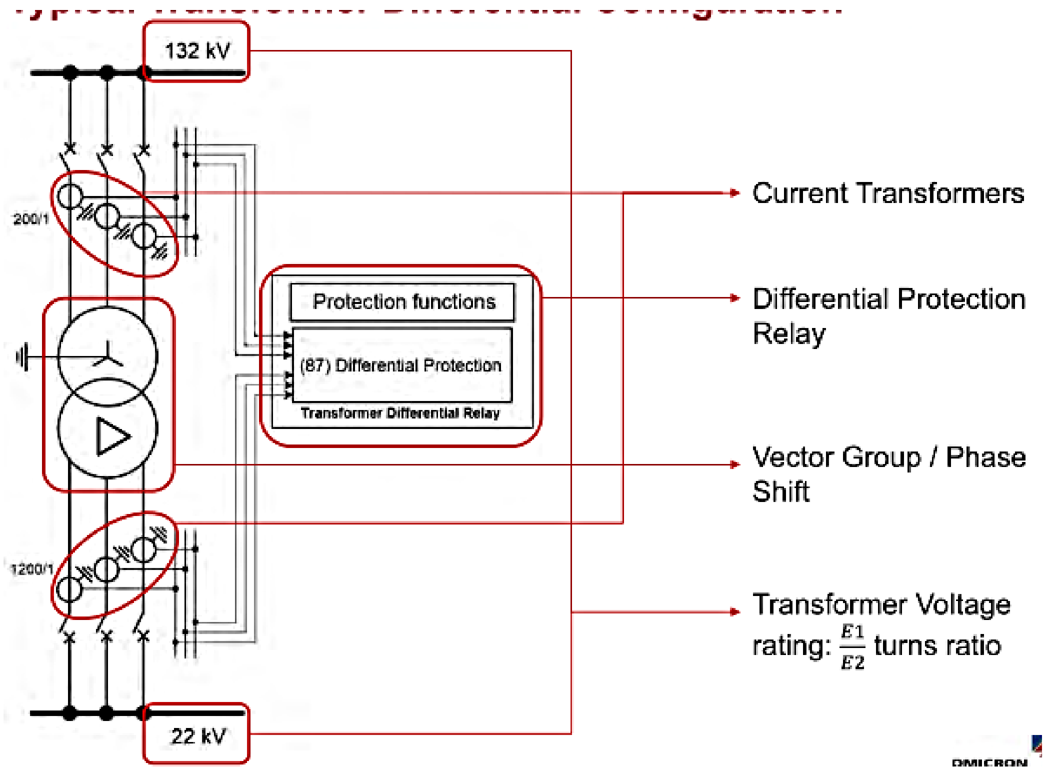


Figure 3.9: Typical Differential Configuration Transformer (Louw, 2020)

3.8.5 Zero Sequence Elimination in Differential Protection

Zero-sequence filtering is a concept used in Transformer Differential Protection to remove the zero-sequence current component from the current transformer's secondary current. This definition is useful in Transformers having earthed Star winding (Bergstrom, 2010; Blackburn & Domin, 2014). For a better understanding, let us consider the delta-to-star transformer voltage ratio of 1:1, as shown in Figure 3.10. For the sake of convenience, a voltage ratio of 1:1 was considered.

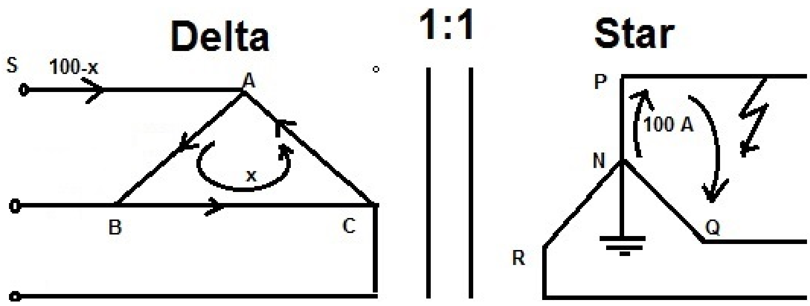


Figure 3.10: The 1:1 voltage ratio of a Delta Star Transformer (Electrical Baba, 2017)

In the Transformer PN phase, assume a single line to ground fault occurs. The flow of fault current through the R phase, consisting of Zero Sequence I_0, positive sequence I_1, and negative sequence current I_2, will result in this ground fault. While the Zero Sequence current I_0 will flow from the earthed star side of the Transformer, this current portion will not flow on the Delta side as a Delta winding but will circulate in the Delta winding. Therefore, no zero-sequence current will be present in the transformer's delta-side line current. This will generate a differential imbalance current, which can lead to the activation of a differential relay even in the case of a fault.

Notice that Differential Protection is a protection unit that only operates if a fault is defined inside the protection zone. However, because of the zero-sequence current being applied under a fault condition, even in a fault condition, the differential relay will run, which is certainly not desirable. Therefore, zero sequence filtering is necessary on the star side in Delta to Star or Star to Delta Transformer differential protection to stabilize the differential relay under a fault condition. It may or may not require this filtering in the Star-to-Star transformer, but it is recommended to allow it (Electrical Baba, 2017).

3.9 Harmonic Fundamental Frequency

A fundamental waveform refers to a sinusoidal waveform that represents the base frequency of a complex waveform. The fundamental frequency is the lowest frequency at which the complex waveform is constructed, and the duration of the complex waveform corresponds to the period of the fundamental frequency.

Harmonics are currents or voltages that act at the same frequency as the integral (total number) frequency. Given a 50Hz fundamental waveform, this means that 100Hz (with 2x50Hz) would be the second harmonic frequency, 150Hz (with 2x50Hz) would be the third harmonic, and so on. Similarly, the 2nd harmonic frequencies will be at 120Hz, given a 60Hz fundamental waveform. We assume that the harmonics are multiples of basic frequency and thus can be expressed as $2f$, $3f$, $4f$, and so on (Ribeiro et al., 2014).

The harmonic study is how the dimensions and phases of fundamental and high-order harmonics of periodic waveforms are measured. According to Fourier's theorem, each non-sinusoidal periodic wave can be decomposed as the number of sine waves using the Fourier series.

3.10 Factors affecting the harmonic sources of false differential currents or differential protection for transformers

The over-excitation or inrush of a transformer condition creates false differential currents that might cause differential relay maloperation. Both conditions generate distorted differential currents because they are linked to the core saturation of the transformer. The distorted waveforms issue data that helps to distinguish between internal faults from over-excitation and inrush conditions. However, other distortion sources, such as CT saturation, resonant conditions in equipment, or nonlinear fault resistance, may complicate this discrimination (Blackburn & Domin, 2014). Possible causes of false differential currents in applications of power transformers are (Blackburn & Domin, 2006; Blackburn & Domin, 2014):

- A mismatch between the transformers' CTs on both ends.
- A tap changer triggered the power transformer variable ratio.
- Because of vector group connections, phase shifts between primary and secondary power transformer currents.
- Inrush currents for magnetization.
- Over-excitation transformer.
- Current transformer (CT) saturation.

The percentage restraint characteristic of the relay typically addresses the first two sources of error mentioned. A correct CT link or emulation in a digital relay resolves the phase shift issue. It is a very complex problem to differentiate internal fault currents from false differential currents induced by over-excitation and magnetizing inrush transformers (Blackburn & Domin, 2014).

3.10.1 Magnetizing Inrush, Over-excitation, and CT Saturation

A power transformer's inrush or over-excitation conditions generate false differential currents that could cause incorrect operation of the relay. As they are related to the core saturation of transformers, both conditions create distorted currents. Distorted waveforms provide data that helps differentiate against internal faults in the conditions of inrush and over-excitation. However, other causes of distortion, such as device resonant nonlinear fault resistance or CT saturation conditions, may complicate this discrimination (Harlow, 2012; Blackburn & Domin, 2014).

3.10.1.1 Magnetizing Inrush Currents

Inrush current is a phenomenon that happens when the magnetic field in the transformer is exposed to sudden changes in a transformer. Since the inrush current is a temporary phenomenon induced by the transformer's magnetization, it only flows into the transformer and not on the other hand. Because of this, it creates a differential current that can induce differential protection. Only the inrush of a single transformer due to initial energization will be examined to limit the reach of this study (Blackburn & Domin, 2014). This excludes the sympathetic inrush series and parallel, where the inrush current is partly drawn from and from other transformers. Pseudo inrush, where the inrush is triggered by a fault being cleared, where the voltage comes back to normal, is also omitted. The explanation for this specification is that the inrush is observed and operated on in the same way (Blackburn & Domin, 2014; Patel & Chothani, 2020).

When a transformer is energized with a system voltage that does not align with the intended steady-state flux, it results in the occurrence of a transient current called magnetizing inrush current. For a transformer with no residual flux, Figure 3.11 illustrates this phenomenon. For best performance, transformers typically run close to saturation, so flux values greater than average result in a great exciting current and extreme saturation (Blackburn & Domin, 2014).

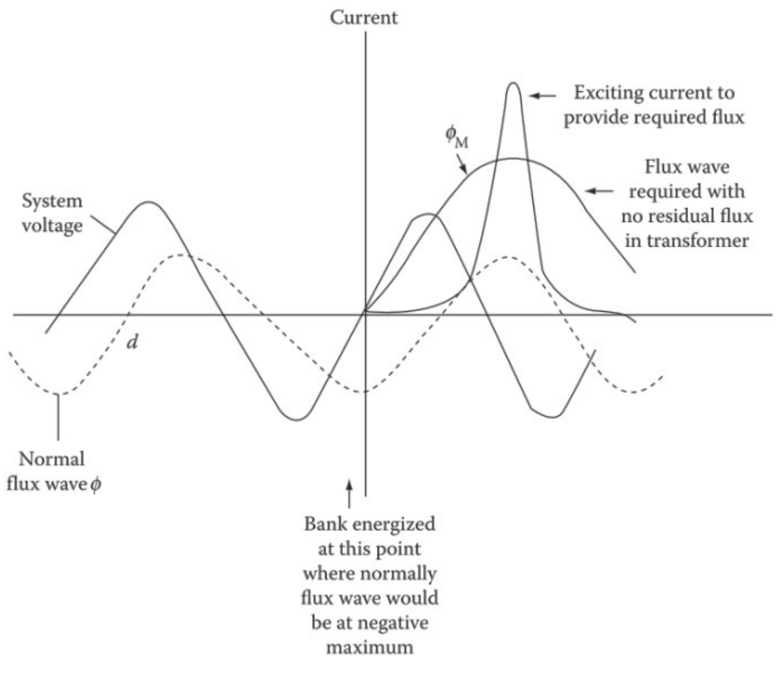


Figure 3.11: **Magnetizing phenomenon of inrush current (no residual flow initially in the transformer) (Blackburn & Domin, 2014)**

A common phenomenon where the magnetizing inrush current is an issue is transformer energization. As the transformer is energized, the voltage of excitation on one transformer winding is raised from 0V to the full voltage. With the saturation amount determined configuration of the transformer, the residual flux in the core, the impedance of the unit, and the point on the voltage wave, the core of the transformers are usually saturated. The amount of current needed to supply this flux could be up to forty times the transformer's maximum load rating (Blackburn & Domin, 2014).

If residual flux polarity and magnitude are not compatible with the polarity and magnitude of the ideal instantaneous value of steady-state flux, the magnetizing inrush occurs in a transformer. Inrush currents are a typical cause of transformer energization, but any transient can generate these currents in the circuit of the transformer. Other triggers include voltage recovery after an external fault is cleared or a transformer is energized in parallel with a transformer already running. Inrush current waveforms and magnitude depend on a multitude of variables and are almost impossible to predict. The key properties of inrush currents are described below (Harlow, 2012; Blackburn & Domin, 2014; Patel & Chothani, 2020):

- DC offset, odd, and even harmonics are usually included.
- They usually consist of bipolar or unipolar pulses divided by low current range intervals.
- Peak values decrease very slowly for unipolar inrush pulses. The time constant is usually considerably longer than the exponentially decaying DC offset of the fault currents.
- 2^{nd} harmonic material begins with a low value and increases as the current of the inrush decreases.

Some inrush can often occur in one or two phases in a three-phase circuit and usually all three phases, with the voltages splitting at 120 °, but in one of the phases, it may or may not be maximum or zero. When either the wye or delta-linked terminals are energized from a transformer bank, Figure 3.15 demonstrates a typical magnetizing inrush current trace.

During the inrush, 2^{nd} and 4^{th} harmonics are quite present in the scenario; Figure 3.12 shows when we look in terms of the transformer on the flux compared to the magnetizing current, it gives us an indication of what happened during the inrush when the inrush conditions take place the flux is displaced. This means that the waveforms are typically expected to be something like, as shown in Figure 3.13, and its magnetizing currents spike quite high. It displaced because upon energization, the voltage is at 0V, and there is no flux because the voltage was at 0. It only starts to stabilize after a couple of milliseconds, so this means what will happen when you start to energize the transformer is the waveforms will be as shown in Figure 3.14. The flux in Figure 3.12 is a little bit offset, which will give you the characteristics indicated on the left side of it in blue. After a while, it will stabilize and give the characteristics shown in blue in Figure 3.14. This will result in Figure 3.15, where the current will increase its spikes, and this increasing current will have a lot of 2nd and 4th harmonics, and after a while, it will stabilize (Harlow, 2012; Blackburn & Domin, 2014; Patel & Chothani, 2020; Louw, 2020).

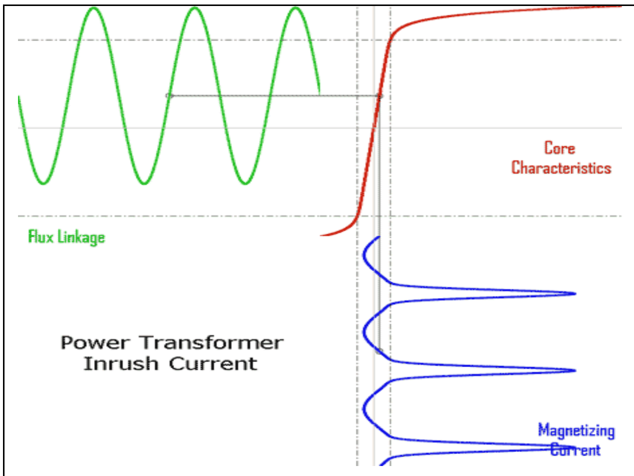


Figure 3.12: Power transformer inrush current on the flux compared to the magnetizing current (Patel & Chothani, 2020)

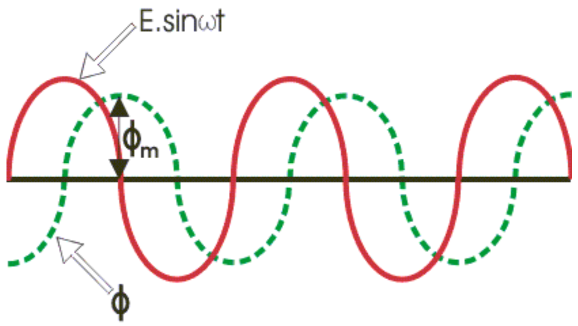


Figure 3.13: Inrush expected Voltage flux waveform (Louw, 2020; Gopika & Sankar, 2016)

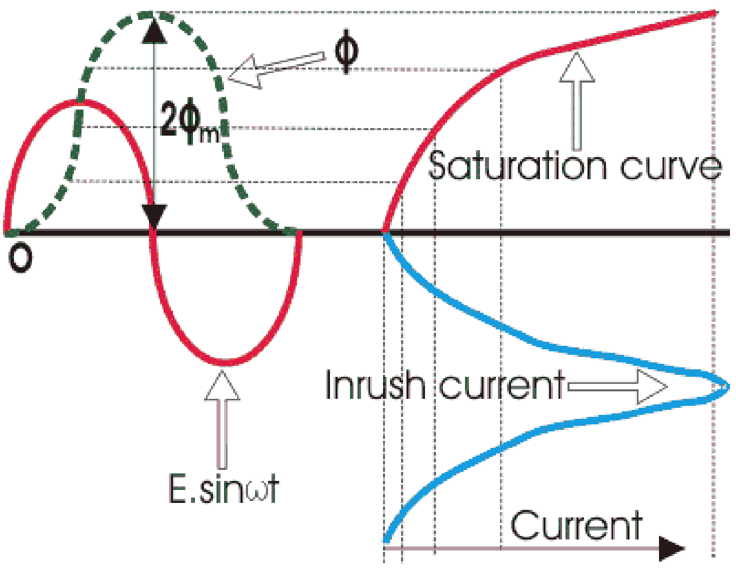


Figure 3.14: Transformer inrush current or magnetizing inrush current of the transformer (Moon & Dhatrak, 2014)

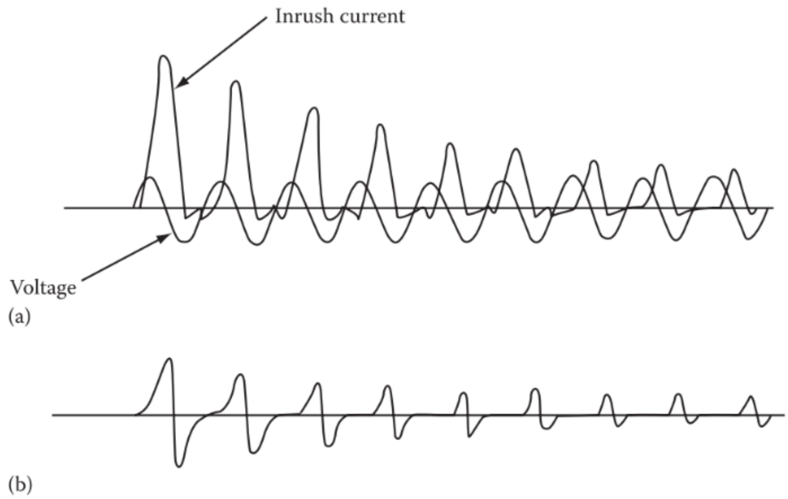


Figure 3.15: **Typical magnetizing transformer inrush current: (a) the current of a phase into wye windings connection; (b) the current of a phase into the windings connected by delta (Blackburn & Domin, 2014)**

3.10.1.2 Transformer Over-excitation

In the inside core of the transformer, the magnetic flux is inversely proportional to the system's frequency and directly proportional to the applied voltage. The transformer core becomes saturated when conditions of over-excitation that are above the limits design of the transformer arise, resulting in a heat accumulation with subsequent damage to the transformer. The harmonic quality of the transformer's excitation current is mainly unusual, odd harmonic. Flux levels that saturate the transformer's core can be generated by under-frequency or overvoltage conditions. In any part of the power system, these irregular working conditions may occur so that any transformer may be subjected to over-excitation. In addition, a power transformer's over-excitation is a common cause of A.C. Core saturation that generates odd harmonics in the exciting current (Harlow, 2012).

The 3rd harmonic is ideally suitable for the identification of over-excitation, but this harmonic is either the CTs Delta connection or the differential relay filters' delta connection compensation. The current has a high 5th harmonic percentage portion of I_{5th} during over-excitation. However, for detecting over-excitation situations, a reliable quantity is always a 5th harmonic (Harlow, 2012). Transformer over-excitation induces transformer heating and enhances exciting current, vibration, and noise. To avoid damage to the transformer, a severely overexcited transformer should be removed. Since the amount of over-excitation a transformer can withstand is difficult to monitor with differential protection, for over-excitation, difference protection of a transformer tripping is not desirable. Instead, a separate transformer, such as a V / Hz element, which response to the voltage/frequency ratio, may be used over the excitation element (Blackburn & Domin, 2014).

As a percentage of the fundamental part, harmonics are expressed. The 3rd harmonic is of utmost importance for identifying over-excitation conditions. Still, this harmonic is either compensated by the delta connection of the CTs or by the delta connection compensation of the differential relay filters. However, the 5th harmonic, for detecting over-excitation conditions, is still a reliable quantity.

The first one to consider using the fifth harmonic to restrain the transformer's differential relay was (Einvall & Linders, 1975); they suggested setting this restriction function concerning the fundamental at 35% of the 5th harmonic.

A current of harmonics on the over-excitation 5th is more prominent and visible; its waveform is similar to the inrush, except it happens when the transformer is already stabilized. In this case, the flux is not displaced. Still, it has increased, as we can see the magnetizing current changes its waveform fully, as shown in Figure 3.16, and the waveform of the flux is supposed to be as shown in Figure 3.17. Still, it ends with the waveform as shown in Figure 3.18, where the currents have not displaced or changed in its waveform compared to what was expected to do (Blackburn & Domin, 2014). Over-excitation state of the power transformer due to decreased frequency; magnetic characteristics of flux (green), iron core (red), and magnetizing current (blue).

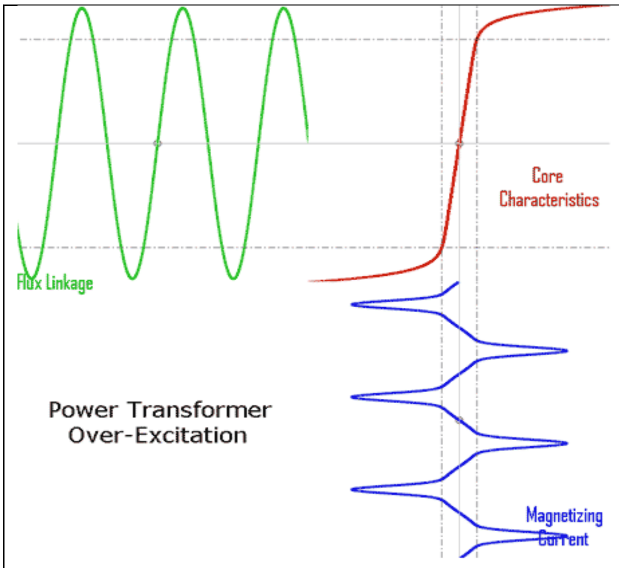


Figure 3.16: Power transformer over-excitation current on the flux compared to the magnetizing current (Louw, 2020)

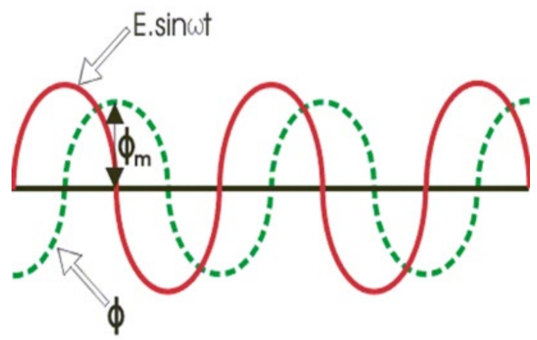


Figure 3.17: Over-excitation expected Voltage flux waveform (Gopika & Sankar, 2016; Louw, 2020)

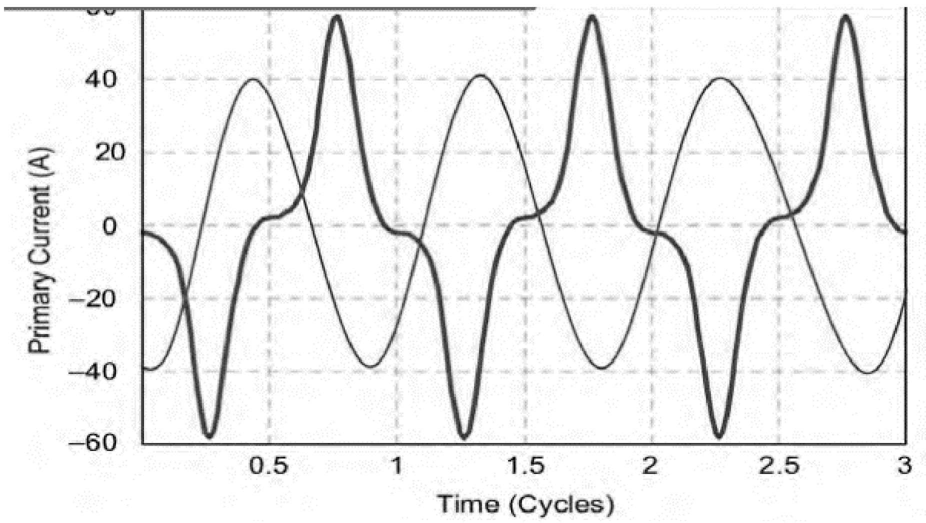


Figure 3.18: Currents have not displaced or changed in their waveform (Harlow, 2012)

3.10.1.3 Current transformer saturation

Considerable attention has been given to CT saturation and its effect on protective relays during faults. The CT saturation associated with differential transformer relaying raises many problems with such relaying (Patel & Chothani, 2020):

- Due to the presence of distorted secondary current waveforms during certain conditions, operational current can cause current transformer (CT) saturation during external faults, leading to incorrect operation of differential relays.
- The harmonics found on a current transformer's saturated secondary currents may delay the operation of the differential transformer relay on the internal faults of the transformer.

CT saturation has a double-edged impact on the protection of the transformer differential. The false current differential results can lead to the misoperation of external failure relays. This false current differential is resolved in some instances by the percentage restraint in the relay. The CT harmonics could delay the work of differential relays with harmonic restraint or blocking if internal errors occur. The main features of CT saturation are as follows (Patel & Chothani, 2020):

- For a certain period after the inception of a fault, CTs faithfully replicate the primary current. The period to saturation of CT depends on many variables but generally is one cycle or longer.
- DC component is responsible for the worst saturation of the CT element of the primary current. In the course of this DC saturation duration, the secondary current can include DC Offset, even harmonics, and odd harmonics.

- The CT-only AC Saturation has when DC offset falls out; the differential relays work well for external fault, so long as the CTs properly replicate the primary currents, which are characterized by odd secondary current harmonics. If one of the CTs is saturated or both are saturated at various amounts, the differential relay occurs with the incorrect operating current, which could cause relay misoperation. Certain differential relays incorporate the utilization of harmonic components resulting from current transformer (CT) saturation to introduce additional restraint and ensure proper functioning.

According to (Stanbury & Djekic, 2014), the high slope 2 (characteristic of the Dual-Slope) is mostly redundant anywhere harmonic blocking is permitted during CT saturation through-faults.

3.11 Inrush and Over-excitation Approaches to Discriminate Internal Faults

Inrush currents and conditions of over-excitation often cause unwanted operating currents that can endanger the differential protection elements. Internal faults are distinguished from over-excitation, inrush conditions, and external CT saturation faults by the harmonic portion of the differential present. It is possible to use a harmonics transformer to either block or restrain. The early differential relay designs used time-delayed or temporary desensitizing for the relay to avoid the inrush current. Alternative configurations employed a supplementary voltage signal to either block or restrain the operation of the relay's differential function. Both concepts have struggled to tension between effective and rapid internal fault detection and protection against external fault tripping, over-excitation, and magnetizing inrush. Modern percentage differential current relays resolve this conflict in one of two ways: using wave shape detection or harmonics to restrain or block (Harlow, 2012).

To block or restrain the relay, the harmonic contents of differential current can be used to distinguish between internal failures and over-excitation or inrush situations. The differences between harmonic blocking and harmonic restraint are historically different, commonly interchangeable using both, but have not been clearly defined in the technical literature on this subject. To restrain or block the relay, the differential current harmonic material may be used to provide a means of differentiating between inrush or over-excitation internal faults and conditions (Harlow, 2012).

3.11.1 Harmonic Restraint

In early electro-mechanical relays, harmonic restraint was used and could still be used in relays for microprocessors. The restraint current includes all harmonics in the method except basic but including DC. The current flow in the restraint coil tends to prevent the operation process from the current flow in the operating coil, which includes only the basic frequency. The classic way to limit tripping is harmonic restraint control. This method has many variants. All these strategies are based on the assumption of a high second harmonic current level with magnetizing inrush current. The internal transformer fault current normally has an extremely low 2nd harmonic value. The most basic form of harmonic restraint involves comparing the magnitude of the 2nd harmonic in the differential current to the magnitude of the fundamental frequency component. If the ratio between these two values exceeds a user-defined threshold, the tripping of the differential element is blocked (Grisby, 2012; Blackburn & Domin, 2014).

All harmonics were utilized to provide restraint functionality with the original harmonic-restricted differential relays. Internal faults with CT saturation were protected from inrush conditions by the high degree of harmonic restraint that resulted, although at the cost of operating reliability and speed. In modern relays, with slight modifications, this principle has been carried forward to provide restraint through the use of selected harmonics rather than all harmonics. By providing extra current differential restraint from the specified harmonic content of the various winding current inputs, the harmonic restraint theory employs the current percentage restraint principle (Grisby, 2012; Blackburn & Domin, 2014)

3.11.2 Harmonic Blocking

In several modern microprocessor relays, the Harmonic Blocking method has been implemented. With harmonic blocking, the second harmonic part is typically used (some relay manufacturers use the fourth harmonic). The inrush condition is declared, and the differential operation is blocked when the ratio is greater than the other harmonic setting point of the second harmonic variable to the fundamental compound. The logically dependent harmonic component blocks the differential element when the ratio of the second harmonic component to the basic component of the differential current is above the pre-set threshold. Another harmonic may be chosen to induce blocking in addition to the second harmonic. A choice in the middle of the 3rd harmonic and the 5th harmonic can be made. However the fifth harmonic is used more commonly as the third harmonic (for example, by delta winding) is often removed in power transformers (Grisby, 2012; Blackburn & Domin, 2014).

The protection is completely operational even when, for example, the transformer is shifted to a single-phase fault since the restraint harmonic works independently per phase, by which inrush currents in one of the safe phases can be present. The protection can also be defined to restrict the phase with inrush current presenting harmonic material exceeding the permissible value and the other phases of the differential phase (called 'cross-block function'), which is blocked. The selectable length of this cross-block may be reduced. In an independent harmonic blocking operating mode, the differential element uses the magnitude of the fifth harmonic part of the differential current to block its transformer activity under excitation conditions. To avoid undesired operation during over-excitation, differential relays can also use fifth-harmonic blocking (Grisby, 2012; Blackburn & Domin, 2014).

3.11.3 Differential protection harmonics blocking that is not used

The section will clarify why other harmonic blocking, such as the 3rd harmonic, is not used in practice. The only explanation for blocking third harmonics is if the high harmonic content wrongly enables differential protection. But then you have a costly differential relay often switched off by the load currents. And when an off-normal, non-destructive condition is briefly present and could trigger a false differential trip, would you want to block it. Blocking the differential protection for detecting 2nd or 5th harmonic material has grown based on the need to avoid relay failure for non-fault events. The 3rd harmonic is similar to the zero-sequence current that occurs during earth failures, and we do not want to block the protection (Grisby, 2012; Blackburn & Domin, 2014).

That being said, the delta lets the reflected zero sequence currents from the star side (for earth defects on the star side) flow inside the delta while the transformer is delta-connected on one side. Therefore, currents that come to the relay on the star side by CTs do not appear in CTs on the delta side. This is discussed in the relay settings by choosing the zero-sequence filtering properly (so that the zero-sequence currents are filtered out on the star side as well).

3.11.4 Differential Operating Characteristic

Figure 3.19 shows an Operating characteristic of a transformer differential protection system. Small differential currents are also possible under health conditions due to transformer magnetization, tap change/leakage, and saturation effects. The sum addition of all these effects represents the maximum differential current that is possible under health conditions. The differential characteristics are an approximation to all these effects, and out of these characteristics, we have a restrain/blocking region and trip region. In most cases, the characteristics start at the lower set value ($\mathrm{I}_{\mathrm{diff>}}$) which is 0.25X the nominal current value and it rises to 6X set value ($\mathrm{I}_{\mathrm{diff}\gg}$) above this value, the relay will trip independently of the stabilizing current (Louw, 2020; Anderson et al., 2022).

The characteristics have two slopes which have the following functions:

- Slope 1: This is a more sensitive operation or operating slope.

- Slope 2: This is the less sensitive characteristic and is a basic de-sensitized to accommodate or consider the following effects on a transformer, magnetization, tap change/leakage, and saturation.

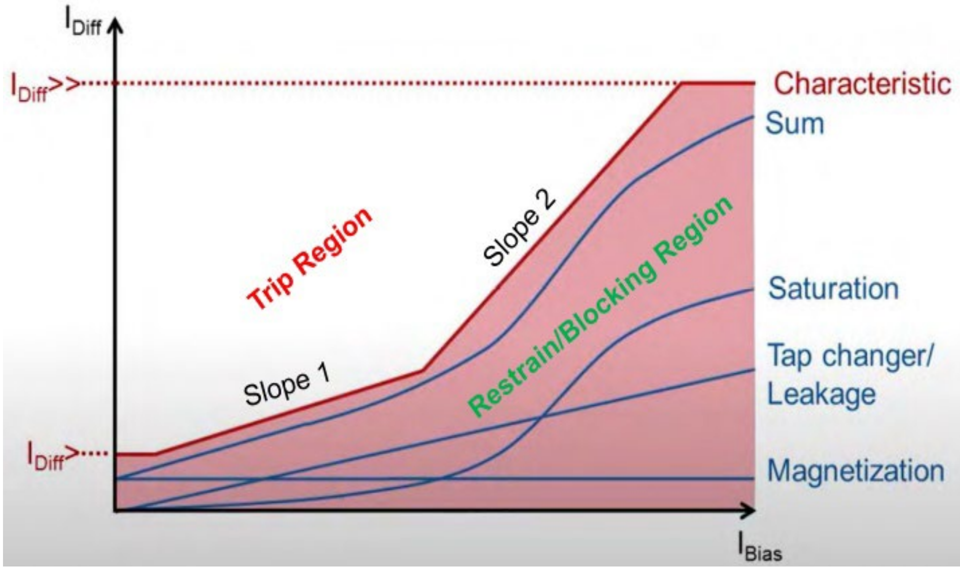


Figure 3.19: **Transformer Differential protection device Operating Characteristic (Louw, 2020)**

3.12 Communications on the protection of power systems

Communication on the power grid is very critical because this includes channels of communication, a receiver, and a transmitter. Media type and topology of networks in communication offer various opportunities for advancing protection relays speed, safety, reliability, and sensitivity. Every kind of communication media has advantages and disadvantages in operation (both digital and analogue) and numerous topologies networks. Communication protocols are a collection of rules enabling communication through the network. Protocols on communications must allow and regulate communication networks. Protocols lay down rules for data representation, communications signalling, error detection, and network computer device authentication. Protocols comprise a set of guidelines that must be followed to fulfil requirements for the communication of various vendor products. Communication protocols can be divided into two categories, physical protocols and layered protocols (Leelaruji & Vanfretti, 2011).

3.13 Overview of power system stability and reliability

Stability refers to the power system's ability to counteract and overcome disturbances by generating forces that restore equilibrium. The examination of power system dynamics during disturbances is an integral part of studying power system stability. A power system's stability is defined as its capacity to return to normal, stable operation after experiencing some sort of disturbance. Disturbances can be minor (incremental changes in load and generation) or significant (Loss of a large generator or load and Faults on transmission lines). The following are the classifications of power system stability (Grigsby, 2007; Das, 2018; Kundur et al., 2004; Machowski et al., 2020)

- Rotor Angle Stability
  The ability to maintain synchronism after being disrupted.
  Synchronous machine torque balance.
- Voltage Stability
  A power system can maintain stable voltage levels at all nodes within the system both during normal operation and following a disturbance.
  Reactive power balance.

Power system stability issues are typically classified as either steady state or transient. Steady-state stability, also known as small or slow disturbance stability, pertains to the power system's capacity to restore synchronism following gradual changes, such as incremental power variations. It characterizes the system's ability to maintain stable operation in the long term despite minor fluctuations. Dynamic stability is an extension of steady-state stability. With the inclusion of automatic control devices, dynamic stability concerns small disturbances that last a long time. Transient stability is concerned with the effects of large, sudden disturbances such as fault occurrence, line outage, and sudden application or removal of loads (Kundur & Malik, 2022; Okedu, 2019).

3.14 IEC 61850 Standard Communication

The IEC61850 is focused on using a sophisticated model of abstract objects to achieve interoperability among various vendor IEDs, and the definition of the IEC61850 is defined above. The model data can be compared to Protocol IEC 61850 and may also be mapped to various protocols, such as GOOSE, which allows for digital and analogue peer-to-peer data sharing. These protocols contain time tags and even asynchronously exchangeable messages. The transition rate, on average, is 12 milliseconds. This standard of IEC 61850 offers a very wide advantage compared to other protocols, for example, programming independently of cable, performance higher with the greater exchange of data, or multiple data transmission to avoid missing information (Bansal, 2019).

The IEC 61850 standard provides communication models that facilitate the seamless exchange of information among various components of power utility automation systems. These models include the Client/Server communication service model, as well as protocols such as GOOSE, SV, and GSSE. They enable efficient and compatible communication within the automation system, ensuring reliable and coordinated operations. As defined in Appendix B Sections 8-1 and 9-2 of the IEC 61850 standards for SV and GOOSE, abstract services and objects are mapped within the SCSM (Bansal, 2019; Eriksson, 2017; Joshi, 2020).

3.14.1 IEC 61850 standard benefits

After the launch of the standard for IEC 61850, several electrical infrastructures were impressed by the benefits that the standard offers. The greatest advantage is that it gives interoperability to the automation of the substation over complete control, protection, and measuring schemes (Hogan, 2014). A worldwide industry requires universal standards, where each product demands power to be incorporated with its global operating concept into every framework. Global thinking means reducing costs by equalizing rivals and their roles and standardizing the management and operating procedures (Borlase, 2013).

In utility applications, IEC 61850 is an integral standard for all functions of communication. This technology is non-proprietary with numerous vendors and offers interoperability through standardized data models and information exchange between devices and application functions. This makes the design of communication networks extremely scalable and can significantly simplify the design of automation substations, optimize system curtain collection implementation, and increase performance. It fulfills the needs of utilities to add products from different manufacturers for long-term equipment exchangeability and expandability of systems (Borlase, 2013; Hirschmann, 2012).

IEC 61850 offers different advantages, which are listed below (Anombem, 2012):

- A dedicated connection between that IED and one other IED would have been necessary before an IED could communicate with two other IEDs. The link may be connected to different IEDs with IEC 61850 IEDs, a single Local Area Network (LAN). It decreases those connections' difficulty and the installation costs associated with cabling, ducting, and trenching.

Some of the major standard IEC 61850 features and capabilities to be explored in this research project include:

- Interoperability with multiple vendors. This enables selecting the best product for a specified task, irrespective of its vendor.
- Data object names are standardized in predefined descriptive strings for each element of the IEC 61850 standard. And it cannot change these elements as an additional safety measure.

3.14.2 IEC 61850 Architecture of substation automation system

SAS involved several items to the state of the substation equipment, such as monitoring, control, live reporting, alarm, and protection. The aims involve the development of a single protocol for maximum distribution of power network, taking into account the modelling of the various data needed and the description of basic services necessary for the potential mapping of data evidence. Sub-functions may identify logical nodes as the main feature, and the logical nodes reside in logical devices such as IEDs. Traditionally, process equipment was connected via copper cabling to devices at the bay level. Ever since the adoption of the IEC 61850 standard process bus, connecting process equipment by a digital interface with the rest of the network (IEDs). IEC 61850-8-1 and IEC 61850-9-2 are specified as the GOOSE and the SVM's (Das, 2018; Bansal, 2019; Padilla, 2016) IEC 61850 substation is split into three parts: station level, bay level, and process level, as shown in Figure 3.20.

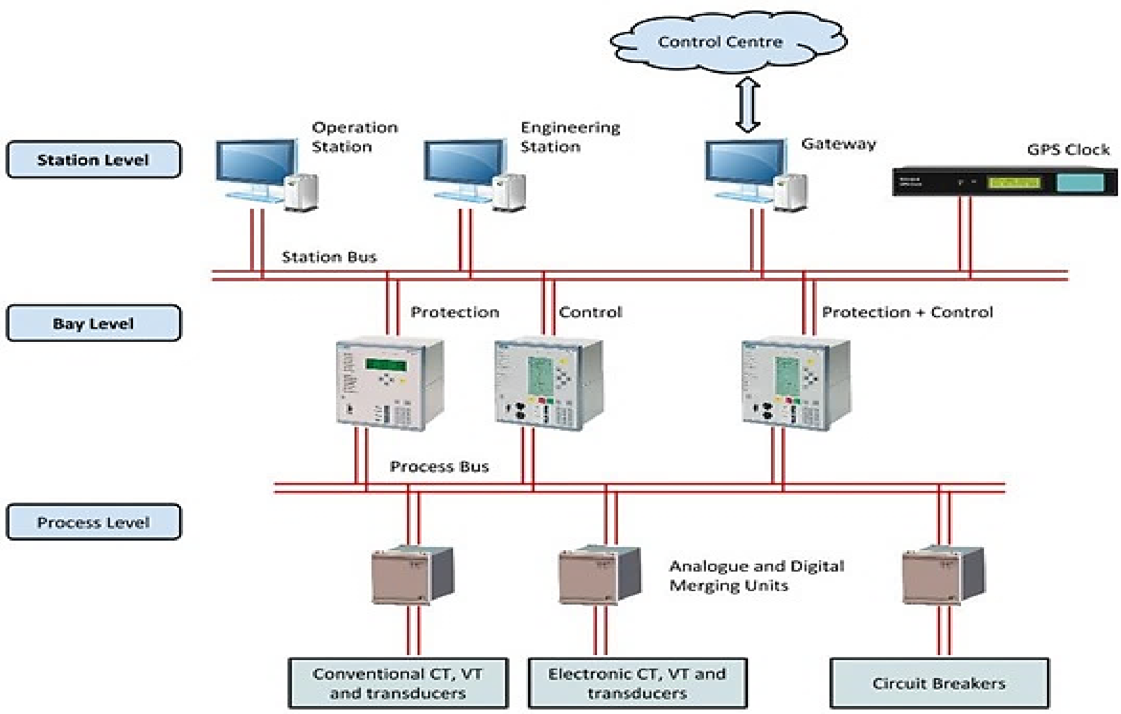


Figure 3.20: Digital Substation Architecture (Skoff, 2020)

The communication of the various SAS logical interfaces is established in IEC 61850-5, as seen in Figure 3.21. For convenience, the necessary logical structure of the SAS is reproduced in Figure 3.20. The interfaces (IFs) are shown as numbers in Figure 3.21 (Bansal, 2019; Kariyawasam, 2016):

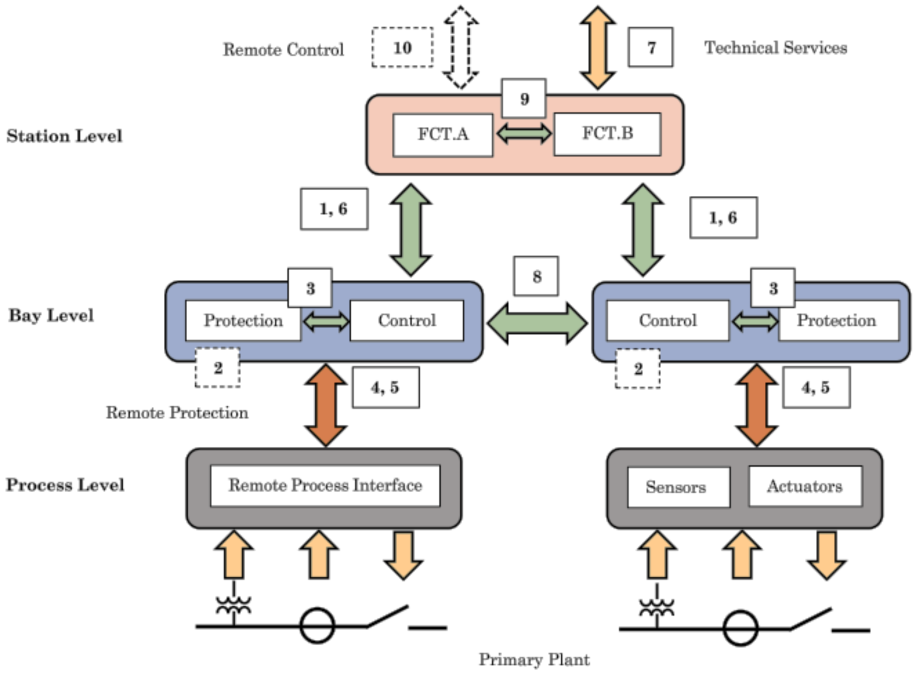


Figure 3.21: Logical substation communications interfaces in IEC 61850 (Kariyawasam, 2016)

Two important LANs (or bus systems) are recognizable using the logical interfaces provided in Figure 3.21. IEC 61850-5 specifies that the combination of interfaces IF 1, IF 6, IF 3, IF 9, and IF 8 can be described as the Station Bus, while interfaces IF 4 and IF 5 can be described as the Process Bus. However, in a separate building, the physical equipment may be installed. This logical architecture and the physical device configuration have no clear connection. These logical interfaces can be realized through different physical interfaces, or multiple logical interfaces can be consolidated into a single physical interface. For example, certain process and bay-level functions may be integrated within the same physical structure. Furthermore, one or more of these physical interfaces could be merged into a single LAN. The availability of systems, performance criteria, costs, geography, and other constraints play a role in this physical architecture (Kariyawasam, 2016).

Merging units (MUs) on the IEC 61850 specified another application category of devices related to the functions of protective or non-protective. The instrument transformer interface (non-conventional and conventional) with various types of substation monitoring, control, protection, and recording equipment is via a MU system. The MU samples analogue VT and CT signals send the sampled signals to the IED(s) with the process bus in a standardized format.

3.14.3 Digital relays based on the IEC 61850 standard

The IEC61850 solution is widely regarded as the optimal standard since it fulfills all the communication requirements of protective IEDs. It is considered the most suitable standard due to its comprehensive coverage of communication needs in the context of protective IEDs. IEC 61850 greatly influenced the protection of the automation system for the substation Protocol of communication. The main purpose of the IEC61850 standard, developed in the first place, has been discussed in the above sections. The main objective of the IEC61850 specification is to promote the interoperability of different vendors' IEDs (Padilla, 2016). The IEC 61850 standard scope was the communication inside a substation and the definition of different aspects of substation communication, which are outlined and will address the primary sections of IEC 61850's core features as follows (Krieg & Finn, 2019; Hirschmann, 2012).

- It converts everything in the actual substation information into knowledge models in the form of common naming conventions, frameworks, and formats to manage information easily.
- It offers the Abstract Communication Service Interface (ACSI) and allows for entire databases and applications with improvements in protocols and media of communication.
- A Substation Configuration Description Language (SCL) is standardized in a structure to define the topology of the substations, process linking, communication, information models, the flow of data, etc. SCL is used to share information and software on the communication configuration of an IED from various fabricators.

This is achieved using a structured data model, abstract system communication facilities, and SCL. Those characteristics include Serial transmission of sample value, peer-to-peer Communication of High-speed by GOOSE, Standardized Data Model Protection System, benefits of the IEC61850 standard, and its basic architecture (Padilla, 2016).

3.14.4 Substation Configuration Language (SCL)

Protocol to IEC 61850 specifies that engineers and vendors use an SCL that has been created to configure the settings and format functions within a specific IED. SCL is a vernacular configuration description that is based on the XML (eXtensible Markup Language) as specified in IEC 61850-6-1 to define configurations. Additionally, it entails assigning Logical Nodes (LNs) to each IED that is connected to the relevant equipment. The intent of these SCL files might be different, but the arrangement of these files is the same (Gers & Holmes, 2011; Buchholz & Styczynski, 2014; Liu, 2015).

This programming language facilitates vendor interoperability and streamlines the integration process. SCL specifies the basic data formats used by the device configuration tool. SCL defines a file format that defines the communication between IEDs, the configuration of the switchyards, and any relationships between them. It ensures that IED capability descriptions (ICDs) and descriptions of substations are transmitted between IED and device engineering tools from various vendors (Padilla, 2016; Amjadi, 2016). The different SCL files each have a specific purpose include (Gers & Holmes, 2011; Padilla, 2016; Madonsela, 2018):

- **System Specification Description (SSD) files:** This file contains the full substation automation device specification, including physical connections, single line substation diagram, and its (logical nodes) functionalities.
- **IED Capability Description (ICD) files:** This outlines the maximum capability of an IED. The file includes a single section of the IED, an optional section of communication, and an optional portion of the substation denoting a physical object referring to the IED.
- **Substation Configuration Description (SCD) files:** Describes all IEDs, a part of the configuration of communication, and a part of the definition of the substation. A variety of .ICD and a.SSD files help to construct an SCD file.
- **Configured IED Description (CID) files:** Describes an IED built inside a project. It is regarded as an SCD file stripped of the IED concerned wants to know and includes an obligatory communication portion of the IED addressed.

Two SCL file forms, System Exchange Description (SED) and Instantiated IED Description (IID) files, have been implemented in IEC61850 Edition 2. Each SCL file is organized in the Extensible Markup Language (XML) format and, depending on its purpose, consists of any of the following five sections Header, Substation description, Communication system description, IED description, and Data type templates (Padilla, 2016).

3.14.4.1 SCL–IED configuration

The first and most important step in configuring an IED with SCL is to choose an appropriate IED for the intended purpose or task within the substation and configure it using the IED configuration tool. Based on a specific IED description file, the IED Capability Description (ICD) is generated for each relay. This file contains information about logical devices and nodes, GOOSE and SV data, communication services, and data addresses. The second stage will move all ICD files to the IED configuration tool. This assigns the device's functions to the IEDs inside the substation and configures them. After receiving the ICDs, SSD, and SED files, the device configurator generates a Substation Configuration Description File (.SCD). The

SCD file describes the relationship between various IEDs and contains all the information describing the substation. Lastly, an IED engineering tool is used to construct the CID file for each system based on this SCD file. Then the device configurator sends their particular CID files to the IEDs. The IEDs will parse these files during the initialization and complete the configuration (Joshi, 2020; Gers & Holmes, 2011). Figure 3.22 displays the previously mentioned file transfer and configuration system.

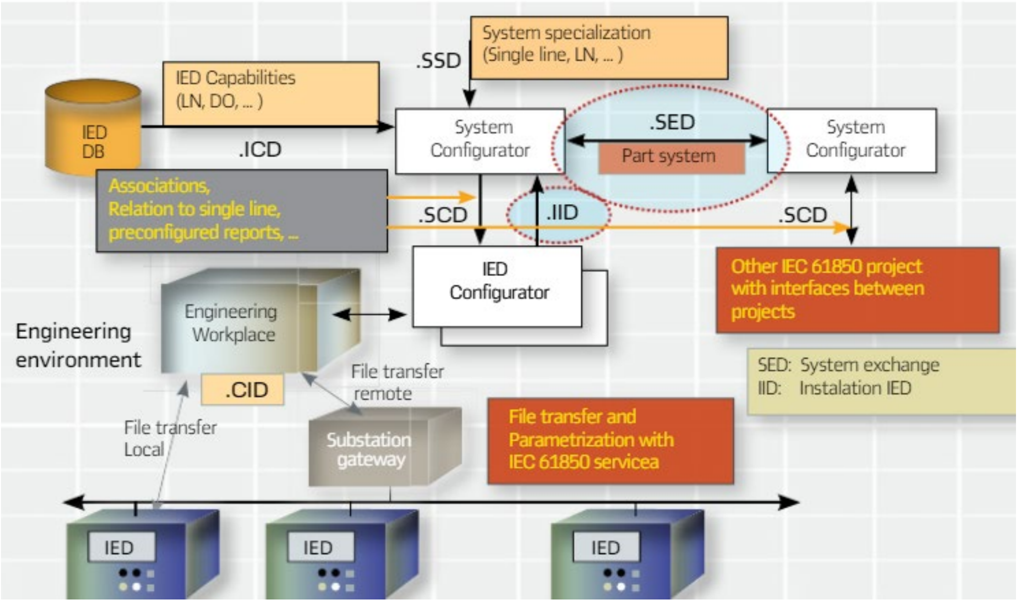


Figure 3.22: **IEC61850 SCL Use in Engineering Process (Wimmer, 2014)**

3.14.5 IEC 61850 Data Models

The manner in which the IEC 61850 standard organizes its data model varies from other protocols used in substation automation. It defines a detailed model for how devices with power systems should organize their data uniformly regardless of the installed devices' make or model. The standard IEC 61850 uses abstract models to model the common information from actual devices. Figure 3.23 displays relations between classes of IEC 61850 data model groups. The application's functions are decomposed into smaller entities used within the system for knowledge exchange. In the hierarchical model, as shown in Figure 3.24, the data/data attribute consists of five layers, from the physical unit to the smallest object (Eriksson, 2017; Bansal, 2019).

- **Physical device (PD):** A system controller is defined by the highest parent class, the server, and consists of one or more IEDs capable of sharing and processing data on them.

- **Logical Devices (LD):** Virtual equipment specified for the set of logical nodes and the purposes of communication.
- **Logical Node (LN):** LN regulates the functions of the actual system, and these LNs are made up of Data Objects.
- **Data Objects:** It is grouped into classes or, more precisely, into Common Data Classes (CDCs). Due to the abstract concepts of data and services, the final move was to map the abstract services into a real protocol.
- **Data Attribute:** A Common Data Class (CDC) defines the data form and structure. Various data types, including measured data and status information, are supported by CDCs (Common Data Classes). The CDCs are grouped into categories, as shown in Figure 3.24, a set of Functional Constraints (FC) such as status (ST).

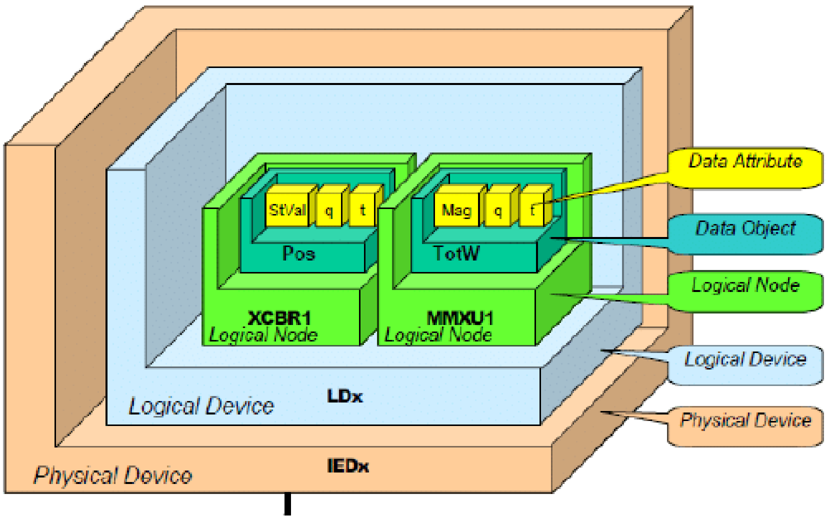


Figure 3.23: IEC 61850 Data Models (Verzosa, 2016)

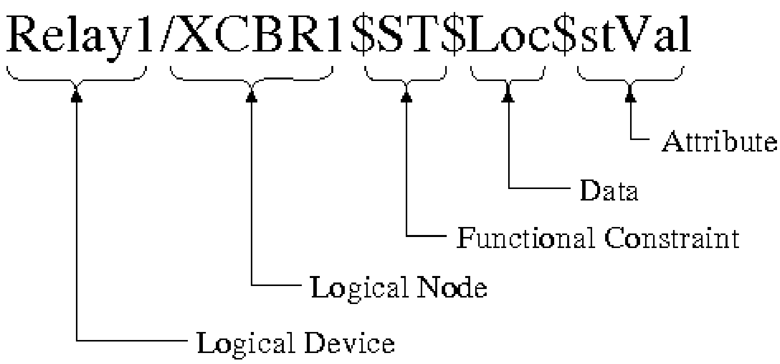


Figure 3.24: The object IEC 61850 transformed into a vector object called MMS with a unique reference for an element in the model (Eriksson, 2017)

3.14.6 Communication Structure for the IEC 61850 parts

There are three common communication groups for control, automation, and protection in addition to Client-server messages: the MMS, GOOSE, and SMV message groups, respectively (Sparks, 2018; Bansal, 2019).

On the other hand, the message groups SV and GOOSE are used exclusively as packets for transmitting signals and data between IEDs. Both these are real-time messages that bypass the stack of TCP/IP and the connection layer of the Ethernet interface. Figure 3.25 provides an overview of a protocol profile described in IEC 61850: both SV and GOOSE message classes are critical aspects of the IEC 61850 protocol and have been further addressed (Madonsela, 2018; Bansal, 2019).

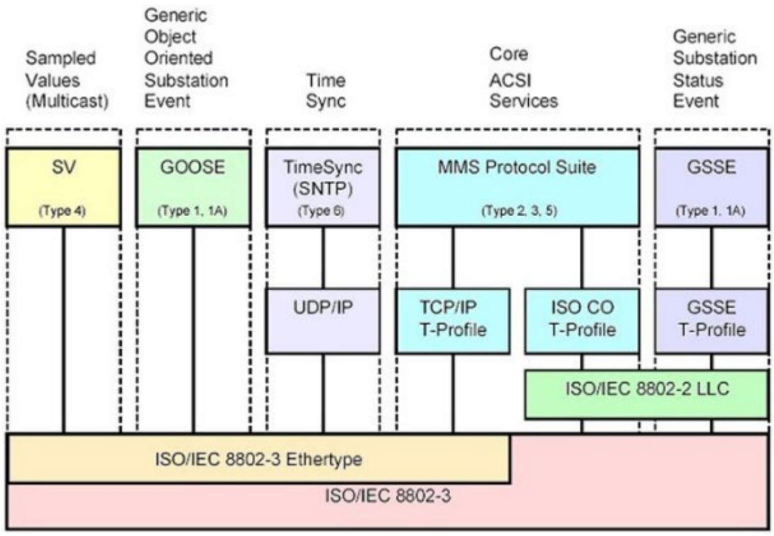


Figure 3.25: **Overview of the protocol profiles and IEC 61850 communication functionality (Verzosa, 2016)**

a) Open System Interconnection Reference Model (OSI model)

It is an abstract overview of network protocol architecture like the OSI model. It provides the details operators need to explain the communication control profiles, such as control of data series, control of error detection, and request control of time out. OSI-model split up the architecture of the network into seven layers: Application, Presentation, Session, Transport, Network, Data-link, and Physical layer corresponding with layer seven up to layer one, respectively, as shown in Figure 3.26. The MMS is a component of the application functions in the OSI model (layers 5-7). GOOSE messages and Sampled Values (SV) were not mapped to MMS but directly to the Ethernet layer. They cannot contain a lot of binary information as they are considered time-critical messages (Mcdonald & Grigsby, 2012; Suittio, 2010; Madonsela, 2018).

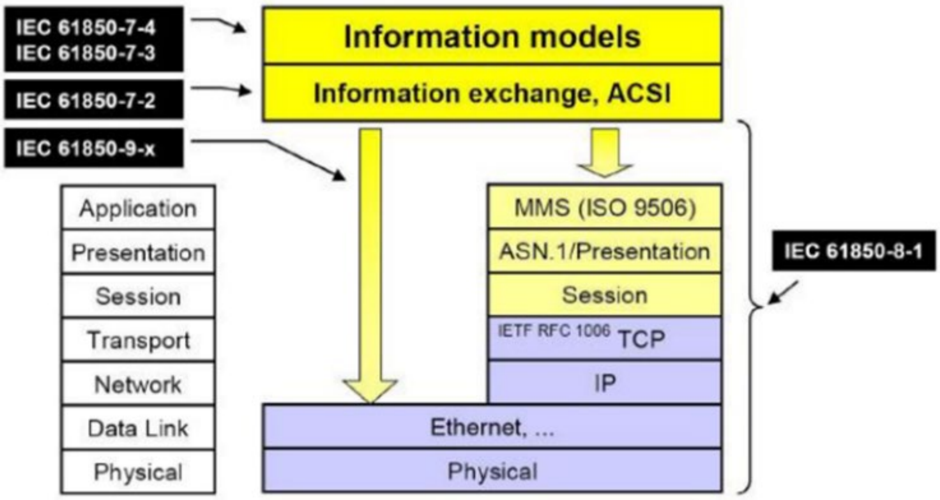


Figure 3.26: IEC61850 SCSMs are arranged under the OSI layers (Mguzulwa, 2018)

3.14.6.1 Generic Substation Events (GSE) Messages

For easy and reliable communication between IEDs, the IEC 61850 standard permits communication inside a substation between devices where the model of peer-to-peer is used for services from GSE. When implemented, this model ensures that several physical devices utilizing multicast or broadcast networks receive the same event code. The GSE model control is further broken down into message groups for GSSE and GOOSE. The key difference between them is that GOOSE can pass data formats such as analogue, binary, and integer information, while GSSE is only limited to the status of binary events (Bansal, 2019; Falk, 2019; Apostolov, 2022).

- **GSSE (Generic Substation State Events):** Only GSSE allows you to share status data, and it does it using a status list (string bit) instead of a dataset as GOOSE uses. GSSE messages are sent using the same mechanism as GOOSE messages via IEC/ISO 8802-2 and 8802-3. (See IEC 61850-7, IEC 61850-8-1). Since the format of GSSE is better than the GOOSE format, it is handled more easily by some devices. GOOSE is increasingly replacing GSSE, and aid will gradually vanish (Suittio, 2010).
- **GOOSE (Generic Object-Oriented Substation Event):** GOOSE messaging is considerably more prevalent than contact based on sampled values and thus has an established record of reliability in the electricity industry. GOOSE messages allow a vast array of common data to be transmitted and arranged by a DATA-SET. IEDs usually use GOOSE messages to report status events to other IEDs within and between feeders. The GOOSE is a versatile tool since it can support various

applications with different performance criteria and use different data types. It has been designed to run on TCP / IP Ethernet, or optical fibre networks, to replace old hard-wire or serial communication links between IEDs and legacy terminal bus relays (Skoff, 2020).

3.15 Discussion and Conclusion

This chapter also provides a theoretical overview of transformers, including transformer differential protection requirements for operation, typical transformer connections, zero sequence elimination, and fundamental harmonic frequencies. The chapter describes the importance of transformer protection in networks and the evolution of protection relays. It covers the theoretical factors affecting differential protection for transformers, such as harmonic sources of false differential currents and internal fault methods of inrush and over-excitation discrimination. The analysis and operating characteristics of the differential waveform are also explained.

Additionally, this chapter presents a theoretical overview of the most relevant SCL standard, the IEC 61850 standard, which includes a communication structure that can be mapped to specific protocols and a standard namespace of logical nodes, data objects, and attributes. Different types of power system components are described and analysed. The next chapter (Chapter Four) will describe the design technique procedure for modeling and simulation.

CHAPTER FOUR

DESIGN TECHNIQUE PROCEDURE AND DEVELOPMENT OF HARDWARE IN THE LOOP (HIL) TEST BENCH FOR TRANSFORMER PROTECTION SCHEME

4.1 Introduction

This chapter offers a summary of the design, hardware selection, and test facility construction (laboratory setup). The reasons for hardware selection, specifications for construction of the test facilities, and their pre-commissioning tests before being used to evaluate the substation automation system designs that comply with IEC 61850 are protected. Built substation automation systems using the testing plant are implemented.

4.2 The Intelligent electronic device (IED) era

As mentioned in Chapter Three, section 3.7, relays are getting more sophisticated, scalable, and flexible with the advent of relays-based microprocessor protection. The initial relay communication capabilities were primarily intended to promote commissioning. The protection engineers introduced the benefits of remote programming relays and developed a data retrieval need; thus, communication aspects of the relay have become ever more advanced. PLC functionality has been integrated into the relays. It soon became apparent with the evolution of the small remote terminal units (RTUs) that relays could be much more than just protective devices (Padilla, 2016; Mcdonald & Grigsby, 2012).

Therefore, the Intelligent Electronic Device (IED) features flexible protection of electrical functions, local advanced control information, monitoring capabilities, and robust communication capabilities directly to a SCADA network. Modern IED functions may be divided into five main fields: metering, communications, monitoring, protection, and control. IEDs receive measured signals of VTs and CTs from the secondary side and detect whether or not the protected device is under stressed conditions (based on its configuration and size type). Many IEDs may be more sophisticated than others, and some may prioritize some functional elements over others, but these key functionalities should be integrated to a greater or lesser degree (Hadbah et al., 2017; Daboul et al., 2015; Borlase, 2013).

4.2.1 Multi/Different Vendors IEDs

Today, several substation vendors moved away from serial to IEC 61850 based on Ethernet, a standard for communication clients/servers. It completely supports the IED's interoperability supplied in the substation by various vendors and can also be implemented in the substation automation process. A multi-vendor is different suppliers producing the products and applications under review across various platforms. Such IEDs and systems would have gone through the conformity test, including the Proprietary configuration IED tool and system-level Data Flow Development Tool of engineering (Weyer et al., 2015; Chen, 2016). Current differential protection is the most commonly used method of protecting a power transformer, as evidenced by a large number of vendors on the market. Below are some of these different vendors, and their main features are explained. Only the differential protection function is considered. These vendors are ABB, Siemens, Schneider Electric, General Electric (GE) Multilin, Alstom-MICOM, Schweitzer Engineering Laboratories (SEL), Toshiba, and Mitsubishi.

Additionally, the comparison of Relay characteristics on a transformer differential between different vendors, like available dimensions, protocol communication, and operating times, from various vendors is described in Table 4.1. The characteristics of these relays are derived from several manuals on the products Alstom-MiCOM and Schweitzer Engineering Laboratories (SEL) (SE, 2019; Alstom Grid, 2013; Inc Schweitzer Engineering Laboratories, 2020b).

4.2.2 Vendor Selection

Any class of logical architecture can have multiple device selection options. Real systems usually fall into one of three groups in terms of the use of devices from several vendors, with the integration of multivendor. The following are some criteria when choosing a Substation Network Equipment vendor, Compatibility and Interoperability, Experience in the Industry, Reputation and reliability, customized solutions, Security, Scalability and Flexibility, Future-proofing and Innovation, and the vendor's ability to provide cost-effective solutions (Byres & Wallaert, 2014):

- A vendor that can provide extended warranties network certification that will make a major contribution to future-proofing substations.
- A vendor with extensive expertise in protecting industrial substations and Protocols can have the highest payback on security technology investments.
- The use of a vendor selling everything from wires and connections to switches, routers, and security tools removes the need for several project managers from different organizations.

Table 4.1: Comparison of characteristics of a relay between Multi Vendors (SEL and Alstom-MiCOM) (SE, 2019; Alstom Grid, 2013; Inc Schweitzer Engineering Laboratories, 2020b; MiCOM, 2020a)

Comparison of characteristics of a relay between Multi Vendors			
Protection Relay	**Characteristic**	**Vendors**	
		SEL	**Alstom-MiCOM**
Differential Protection	Manufacturer's Differential Protection Units	SEL-487E	P-645
	Available Measurements	Voltages and currents values of RMS and Phasors; differential harmonic quantities energy; power;	Power factor; Neutral and Phase currents; frequency; differential currents: power; maximum demand;
	Diagnostic Features	Event recorder (1000 timestamped events)	512 events in a cyclic memory, five faults records, ten maintenance records
	Operation Time	< 20 ms	< 33 ms
	Programming and Software Features	ACSELERATOR QuickSet SEL-5030 Software	S1 Studio file editing software/applications and retrieval, event retrieval, and disturbance recording
	Additional Functions	Current imbalance; Over/under voltage; Volts/Hz; restricted earth fault; breaker failure:	Over/under frequency; Over-fluxing; V/Hz, Restricted earth fault; thermal overload; breaker failure; supervision of VT/CT
	Communication Method	IEC 61850; ModBus TCP/IP; C37.118 (synchrophasors); SEL; FTP; DNP; EVMSG; MIRROR BITS;	Courier/K-BUS ModBus; RS485; RS232; IEC 61850; DNP3.0; IEC 60870-5-103.

4.2.3 Multi-Vendor programming and software features

Here is a short overview of the functionalities and functionality of applications of the software for the user interface (Alstom Grid, 2013; Inc Schweitzer Engineering Laboratories, 2020a; SE, 2019). The various manufacturers list them as follows.

a) SCHWEITZER ENGINEERING LABORATORIES (SEL):

Two separate software are supported by SEL-487E: ACSELERATOR Quickset and AcSELerator Architect.

- ACSELERATOR Quickset: Offers SEL-relay analytical assistance. The program tool is used to quickly and easily commission, configure, and manage devices for control, protection, measurement, and monitoring of the power system (Inc Schweitzer Engineering Laboratories, 2020b).
- AcSELerator Architect: Uses CID files to define the data that the IEC 61850 logical node can provide within each relay. It is a user-friendly application designed to facilitate the configuration and logging of IEC 61850 communications among devices provided by different suppliers. To simplify your device implementation, import and export SCL files. Minimize the amount of engineering work required through the use of a user-friendly graphical interface that allows for effortless drag-and-drop functionality (Schweitzer Engineering Laboratories, 2018).

b) ALSTOM-MiCOM:

ASTOM MiCOM-P645 supports two separate software: MiCOM S1 Agile and MiCOM S1 Studio.

- MiCOM S1 Studio: This integrated engineering platform from Alstom Grid provides users with global access to all IED configuration automation. The application offers access to MiCOM protection IEDs, and It can also be used for analysing events and records of disturbance, which can act as an IED Configurator IEC 61850 (Alstom, 2011; Alstom Grid, 2013).
- MiCOM S1 Agile is the truly universal IED engineering toolset for MiCOM relays. You can edit system settings and commands for GE's selection of IEDs. It configures Ethernet and IEC 61850, including importing and exporting SCL (MiCOM, 2020b; MiCOM, 2020a).

4.2.4 Interoperability based on vendors

Interoperability means products produced by various suppliers can communicate effectively with each other without the need for complex and expensive protocol converters. Interoperability testing also relates to the individual systems and devices being tested, the network linking these tools and programs, and the roles related to knowledge exchange. Given the large number of commercially available IEDs that are suitable with the IEC 61850 specification of the standard, the difference in system architecture, free allocation of IED functions in substations IEC 61850, and other features. So, vendor-based interoperability tests may be categorized into two types: Single-vendor and Multi-vendor. Interoperability is a key requirement for adequate integration and performance of multivendor systems and can be described in four different levels: interoperability of data communication, functional interoperability, interchangeability, and interoperability of engineering (Bonetti, 2016; Ustun, 2016; Bonetti et al., 2019).

a) Interoperability of data communication

It is the capability of devices and applications to properly interchange protocol levels of data. Minor problems have been identified but have been resolved by using more flexible subscribers/ clients and device changes in firmware/software. Compliance certification and the use of a limited number of protocol stacks by vendors significantly contribute to the high degree of interoperability that has been identified.

b) Functional interoperability

It is the capability of the devices and applications to correctly execute distributed functions using the exchanged information. For multivendor systems, functional integration is possible but is not always easy. Current technology presents problems of interoperability which often require further analysis and sometimes limit the design options of a given system (e.g., the behaviour of the data object value, management of information, time, and clock attributes under abnormal circumstances, output, and optional data availability).

c) Interoperability of engineering

Can the tool quickly share and use information about the configuration for engineering purposes. The proposed IEC 61850 engineering model streamlines processes by focusing the user workload on the vendor system devices. Still, current implementations of the tools are lacking in the generation and interpretation/use of substation configuration language (SCL) files. To date, the lack of system-tool interoperability has facilitated the use of a device-driver-only approach to a single system configuration tool.

d) Interchangeability

It is the ability to replace one system without significant reengineering effort by another of different manufacturers. This capacity is not currently endorsed by the standard and is generally not accepted as a fact or a common practice shortly.

4.3 Proposed Interoperability Multi-Vendor Evaluation Methodology

The interoperability between devices, irrespective of the vendor, is one of the most advancing features of the IEC 61850 specification assessed with the test facility. This is an opportunity to share messages and use knowledge through multi-vendor IEDs. One of the main advantages of implementing the IEC61850 and DNP3 specifications is interoperability. The capacity of the system to retain such freedom levels allowing for the use of particular supplier functions, is also a major benefit, as it enables the incorporation of various philosophies of each vendor. IEDs from different manufacturers (can operate on a network or path to communications, sharing data and commands on the LAN substation as specified in IEC 61850 Interoperability (Yang & Yuan, 2019; Wilamowski & Irwin, 2016) The test facility proved that this standard could deliver vital information between two families of IEDs, the SEL and ASTOM MiCOM devices. The Interoperability testing of the IEDs is as follows:

- Needs two or more systems.
- Positive testing and limited negative testing.
- Can't test matching functions.
- Test report.
- Each system combination is to be tested.
- Error matching is not detected.

4.4 Device Testing in Substation Protection Systems Based on IEC61850

Checking, testing, and commissioning IEDs, equipment, and other related devices within a substation are tasks for protection engineers. This is a component of installing and maintaining instruments to ensure they are suitable and functional. For technicians and engineers, testing IEDs based on IEC 61850 and the related automation systems can be considered quite a new and abstract responsibility. Regarding substation systems based on IEC61850 and related components, two types of testing are classified according to the system specification and testing purpose, as shown in Table 4.2 (Amjadi, 2016).

Table 4.2: **The types of testing devices in substation protection based on IEC 61850**

TESTING	DESCRIPTIONS
PRODUCT TESTING	This includes all tests related to the devices, including Factory Acceptance Testing, Integration Testing, Device Interoperability Testing, and Device Acceptance Testing based on their technical requirements.
SYSTEMS TESTING	This includes all features and performance tests relevant to and compliant with the optimized IEC61850 substation system, such as Site Acceptance Testing, Conformance Testing, Commission Testing, and Maintenance Testing.

The first stage to confirm a new device's correct behaviour is called **Device Acceptance Test** (DAT) before being used for protection, automation, and system control of substations. This test guarantees that the product fulfils all the technical descriptions the consumer finds interesting in the device documentation. DAT is, therefore, a requirement for appropriate use of the substance in the system protection. Since DAT is an experiment in the laboratory, it must be designed on a variety of scenarios that simulate the user's substation environment as practically as possible.

Conformance Test the IED manufacturers must show that their devices can follow the standard mechanism IEC61850. Therefore, the conformance test is an experimental laboratory to ensure that the consumer of a device meets the IEC61850 standard specifications (Sparks, 2018).

Device Interoperability Test is one of the IEC 61850 Standard's most important goals is to ensure interoperability among various vendors' devices. The interoperability test guarantees the share of correct data in the system with other vendors' devices on a communication-based peer-to-peer network. The interoperability evaluation was consistently carried out to demonstrate the proper conduct of any instrument as an integral part of a multi-vendor devices scheme. The majority of the interoperability tests must be conducted in a standard operational condition from the perspective of the virtual isolation process, and requirement and no insulation is necessary. However, the exception occurs when IEDs have to test their ability to work together as a protection scheme (Falk, 2019). Virtual isolation is needed in this case and will be addressed later in section 4.4.1.

System Integration Test in addition to the interoperability potential between devices, their performance needs to be compatible with the specifications for the development of the protection system. While the interoperability test determines the communication of IEDs among them, the integration test works in one step and ensures fast and successful articulation. During integration testing, virtual isolation is not necessary.

Factory Acceptance Test (FAT) is another main customer measure agreed upon. The end user and the system integrator arrange to find potential issues that could occur in a system at an earlier stage of the project if they are less expensive and difficult to repair. As the FAT does not include all components of the system, the test system must be able to simulate any device absent from the current protection system. Furthermore, all existing FAT system components must be designed and programmed according to the actual system application requirements. Therefore, all devices built for the project must be designed in the SCD file format. FAT is a laboratory-based experiment, and no IED isolation test is required at this point.

Commissioning Test if properly configured and commissioned parts of the components designed application, the commissioning test must be conducted to demonstrate the necessary configuration of the devices as needed. Therefore, all functional elements used for the safety protection and control of the equipment shall be required under normal conditions for the commissioning test. During the commissioning test, there is also no need for virtual isolation.

A maintenance Test is a periodic maintenance check required to maintain and upgrade the protection of a substation in normal operating conditions, according to the current specifications of the industry standard. It is therefore intended as the identification, diagnosis, or confirmation of the effectiveness or non-efficacy of all necessary measures to amend configuration, replacement, repair, or upgrading of fault clearer equipment or components. The maintenance may be broken down into two subsections, as shown in Table 4.3.

Table 4.3: Test conducted for maintenance

MAINTENANCE TEST	DESCRIPTIONS
Scheduled Maintenance Test	This is a section of the "Site Maintenance Proposed Plan," which is regularly carried out to show that the protection system and its equipment meet all the system specifications. It also investigates whether all components function under standard conditions and in accordance with the protection system configuration. With multi-functional protection equipment such as IEDs, a large collection of monitoring functions exists in IEC61850. Equipment failure or human mistakes cause system and other equipment irreparable harm. Therefore, regularly conducting the expected maintenance test is important to reduce potential risks.
	This test is necessary if the device or its system function is defined as faulty: viz. If the system operates when it is not needed to do so or if it does not

Maintenance Test Performance of Abnormal System Protection	operate when required in the form of fault detection and clearing schemes. To locate the problem associated with it and to take appropriate steps to prevent any more harm to the rest of the system, the faulty device must also be checked. After the interface issues have been resolved, various forms of testing mentioned above, such as interoperability conformance and acceptance testing, are conducted.

4.4.1 Virtual Isolation (IED Isolation for Test Purposes)

Virtual isolation is required for the maintenance test when the device or its functional elements are being tested in an energized substation. IEC61850-based substation devices have varied levels of isolation based on the following testing objectives.

- Testing of functional elements.
- Testing of sub-functions or functions.
- IED testing as a whole.

As a result, the level of virtual isolation changes depending on the test objectives. For example, if a protective function like Overcurrent Protection (PTOC) is required to be evaluated, this test falls under the category of "isolation of sub-function or function testing." To be virtually isolated from the protective system, only the PTOC function is necessary. Similarly, the entire IED should be disconnected from the energized substation for whole IED testing.

When establishing a test plan for a zone substation system, it's important to consider the aforementioned isolation levels and the system's ability to manage and monitor the mode and behaviour of multiple functional elements. This capability is exclusive to IEC 61850-based substations, as conventional substation devices lack this functionality.

4.4.2 Interoperability Issues and Testing Tools

Setting the IED for the test function (changing IED mode to TEST mode) and configuring the test equipment according to the test plan are the two procedures to follow when dealing with virtual isolation for testing. As a result, both the IED and the test equipment must meet the standard criteria. There are still significant issues that power utilities are facing in terms of IED configuration for testing reasons since there aren't any easy-to-use IED configuration tools. Vendors configure IEDs with their proprietary tools, and they construct or modify CID and SCL files with their configuration tools.

For example, SEL employs a quickset AcSELerator for IED configuration, whereas MiCOM must be configured using their proprietary tools called MICOM S1 Agile. This causes issues when an IED needs to be put up for testing in an active substation. Engineers must be well- knowledgeable in all configurator tools.

4.5 Hardware Selection

4.5.1 IED Configuration Tools

IED manufacturers have their own proprietary instruments to customize their IEDs. The configuration methods used for this unique investigation were selected based on the IED selection criteria discussed below.

The IED criteria for selection included:

- The functionality of IED.
- Reliability IED.
- Time Frames of Procurement and Distribution.
- Ease of Use.
- Vendor Support (Other power utilities consulted).
- Overall Cost per Unit.

Because of the project's time constraints, it was determined that it would be good enough for this project to use two IEDs from different vendors and give more time to use the test facility rather than using more than two different vendors. Once all IEDs were subjected to the above criteria, IED vendors from Schweitzer Engineering Laboratories (SEL) and MiCOM were chosen for this thesis for protection schemes, and the functions of these vendors will be transformer Protection. The selection of IEDs, specifically transformer differential relays, over other existing options is typically based on several key factors and considerations. Table 4.4 outlines why the chosen IEDs may have been selected over other available options.

Table 4.4: **Summary of Key Factors for Selection of SEL and Alstom MiCOM transformer differential relays over other existing IEDs Relays**

Key Points	Summary
Performance and Reliability	The selected IEDs are known for their reliability and high performance in transformer protection. They have been rigorously tested and proven effective in safeguarding power transformers under diverse fault scenarios, ensuring their safety and integrity.
Advanced Features and Functions	These IEDs offer essential features for transformer protection, including differential, restricted earth fault, and overcurrent protection, along with a comprehensive range of advanced functions. They also provide features like harmonic analysis, communication capabilities, and event recording, enhancing their diagnostic capabilities and aligning well with complex requirements for parallel transformer protection.
Compatibility and Interoperability	Compatibility with existing substation equipment and communication protocols is crucial. The selected IEDs may have been chosen because they seamlessly integrate with other devices and systems within the substation, simplifying the overall protection scheme.
Vendor Reputation	SEL and Schneider Electric, the IED vendors, have strong reputations for producing reliable and high-quality equipment. Their established presence and respect within the power industry have led utilities and organizations worldwide to trust their products.
Scalability and Flexibility	The chosen IEDs offer potential scalability and flexibility, making them adaptable to various transformer sizes and configurations. Their configurable settings make them well-suited for a wide range of transformer protection applications.
Communication Capabilities	The selected IEDs are likely equipped with essential communication capabilities, enabling compatibility with industry-standard protocols for remote monitoring, control, and data retrieval in modern substations. These capabilities are crucial for integration into contemporary power systems and HIL testing, ensuring real-time communication with the RTDS simulator.
Customization and Configurability	These relays offer a high degree of customization and configurability, allowing researchers to tailor protection settings to specific transformer configurations and testing scenarios.
Overall Suitability	After considering all the factors, the SEL-487E and MiCOM-P645 relays were deemed the most suitable for the specific research goals related to parallel transformer protection schemes.

Overall, the selection of these specific IEDs for transformer differential protection may have resulted from a combination of their performance, features, compatibility, vendor reputation, and suitability for the specific requirements of the research or application. Table 4.5 illustrates the different configuration tools of the selected IEDs.

Table 4.5: **IED Configuration Tools**

Vendor	IED	Configuration Tool	Version
Schweitzer Engineering Laboratories	SEL-487E	AcSELerator Quickset and AcSELerator Architect	6.10.1.0 and 2.3.6.1014 respectively.
ALSTOM-MiCOM	MiCOM-P645	MiCOM S1 studio or MiCOM S1 Agile	9.2.1 or 2.1.2

The choice of the RTDS simulator over other testing devices is based on several compelling reasons. Firstly, its real-time simulation capability is crucial for dynamic and precise assessment of protection relay performance under real-world conditions. The simulator's high fidelity ensures that power system models, including transformers, network components, and transient behaviors, are realistically represented, guaranteeing the precision of testing and evaluation. Moreover, RTDS's flexibility allows for the creation of custom test scenarios, accommodating a wide spectrum of fault types and operational conditions, and seamlessly adapting to diverse testing requirements. Safety is paramount, and the virtual environment provided by RTDS eliminates the risks of physical equipment damage and ensures personnel safety, particularly when analyzing protection schemes under fault conditions.

Furthermore, the simulator offers reproducibility, simplifying the repetition of test scenarios for validation, fine-tuning, and verification, thereby ensuring consistent and reliable results. Advanced communication capabilities inherent to RTDS enable real-time interaction with protection relays and other devices, a vital component for HIL testing and coordination studies. The precise isolation of specific components, such as protection relays, provides another advantage, facilitating accurate evaluation and validation. RTDS's comprehensive capabilities encompass thorough testing of protection schemes, including coordination, response to various fault scenarios, and interaction with other protective devices within the power system.

Widely recognized and respected in the power industry, RTDS is a trusted choice for research, development, and testing activities due to its reliability and performance. Its seamless integration with existing substation setups streamlines the testing process, ensuring compatibility with the power system. While RTDS does have considerations such as cost, specialized training requirements, limitations in replicating certain physical phenomena, and maintenance needs, the overall benefits of accurate, safe, and versatile testing make it the preferred solution for numerous power system research and testing endeavors.

4.5.2 Test Plan and Rationale for HIL Testing with IEDs and RTDS Simulator

The test plan aims to evaluate the performance of parallel transformer differential protection schemes through hardware-in-the-loop (HIL) testing. The methodology involves implementing HIL testing with the RTDS simulator, utilizing MiCOM-P645 and SEL-487E relays for protection scheme testing, and subjecting the system to various fault scenarios and abnormal operating conditions for in-depth analysis. The rationale behind this plan is based on several key factors.

Firstly, HIL testing with the RTDS offers a highly accurate and realistic environment, replicating actual power system behavior, which is essential for precise assessment under real-world conditions. Additionally, HIL testing ensures personnel safety and prevents transformer damage. The RTDS's versatility enables comprehensive testing of a wide range of fault scenarios, and HIL testing allows for the isolation and precise evaluation of specific components such as relays. This approach is well-suited to achieve accurate and reliable results for assessing the performance of protection schemes in parallel transformer configurations.

4.5.3 System configuration

The first step in setting up communication is to allocate IP addresses to all the devices mentioned in the introduction. Configuring communication settings for the terminal unit and applying default protection settings to the relays is the next step in the process. The network mask address is 255.255.255.0 (Madonsela, 2018). Table 4.6 represents the IP addresses for all devices to be integrated into the substation LAN.

Table 4.6: **TCP/IP Communication Addresses for Devices**

Substation Equipment	IP Addresses	Network mask	Subnet
SEL-487E	192.168.1.219	255.255.255.0	0.0.0.0
MiCOM-P645	192.168.1.19	255.255.255.0	0.0.0.0
CMS 356	192.168.1.58	255.255.255.0	0.0.0.0
RTDS	192.168.1.(101 to 103)	255.255.255.0	0.0.0.0
Laptop (PC)	192.168.1.50	255.255.255.0	0.0.0.0
Ruggedcom Ethernet switches	192.168.1.14	255.255.255.0	0.0.0.0
Global HUB	192.168.1.254	255.255.255.0	0.0.0.0

4.5.4 The Test Setup's Structure

Figure 4.1 depicts the fundamental framework of the laboratory test setup, which uses the device hardware mounted at the test facility as well as a brief description of the essential components of the laboratory test setup:

1. **RTDS (Real-Time Digital Simulator):**
   - Function: Simulates voltage and current signals of the power system.
   - Output: Analogue signals are provided via GTAO for relay testing.
   - Purpose: To provide input signals to protection and control relays.
2. **Protection and Control Relays (IEDs - Intelligent Electronic Devices):**
   - Purpose: Ensures the safety and protection of the electrical transmission substation.
   - Vendor: Utilizes relays from various manufacturers.
   - Input: Receives RTDS voltage and current signals via analogue outputs.
   - Output: Send trip signals to RTDS and retrieve circuit breaker status via GOOSE messages.
   - Communication: Utilize GOOSE messages for communication.
3. **Industrial Ethernet Switches:**
   - Function: Facilitates communication using the IEC 61850 station bus and the exchange of GOOSE messages.
   - Connectivity: Both relays and RTDS are connected to Ruggedcom's Ethernet switch.
   - Speed: Utilizes 100 Mbps communication links for GOOSE message communication.
4. **AC/DC Power Supply:**
   - Function: Provides power to all equipment in the setup.
   - Input: 220 VAC input.
   - Output: 110 VDC output with switching circuit.
   - Purpose: Auxiliary voltage supply to energize the IEDs and other components.
5. **Omicron CMS356 and CMS156:**
   - Function: Voltage and current amplifiers for analogue low-level signals.
   - Application: State-of-the-art hardware used for testing various protection devices.
6. **Personal Computer with Software:**
   - Function: Used for configuring operations and running necessary applications for LAN operations.
   - Purpose: Accommodates setup and control of the test setup.
7. **Ethernet Cabling:**
   - Type: Standard Ethernet cables.
   - Usage: Connects the PC and IEDs through the industrial Ethernet switch.
   - Role: Enables data transfer and communication between devices.

These specifications outline the key components and their functions within the laboratory test setup for power system protection testing. The setup is designed to ensure accurate and reliable testing of protection and control relays for electrical transmission substations.

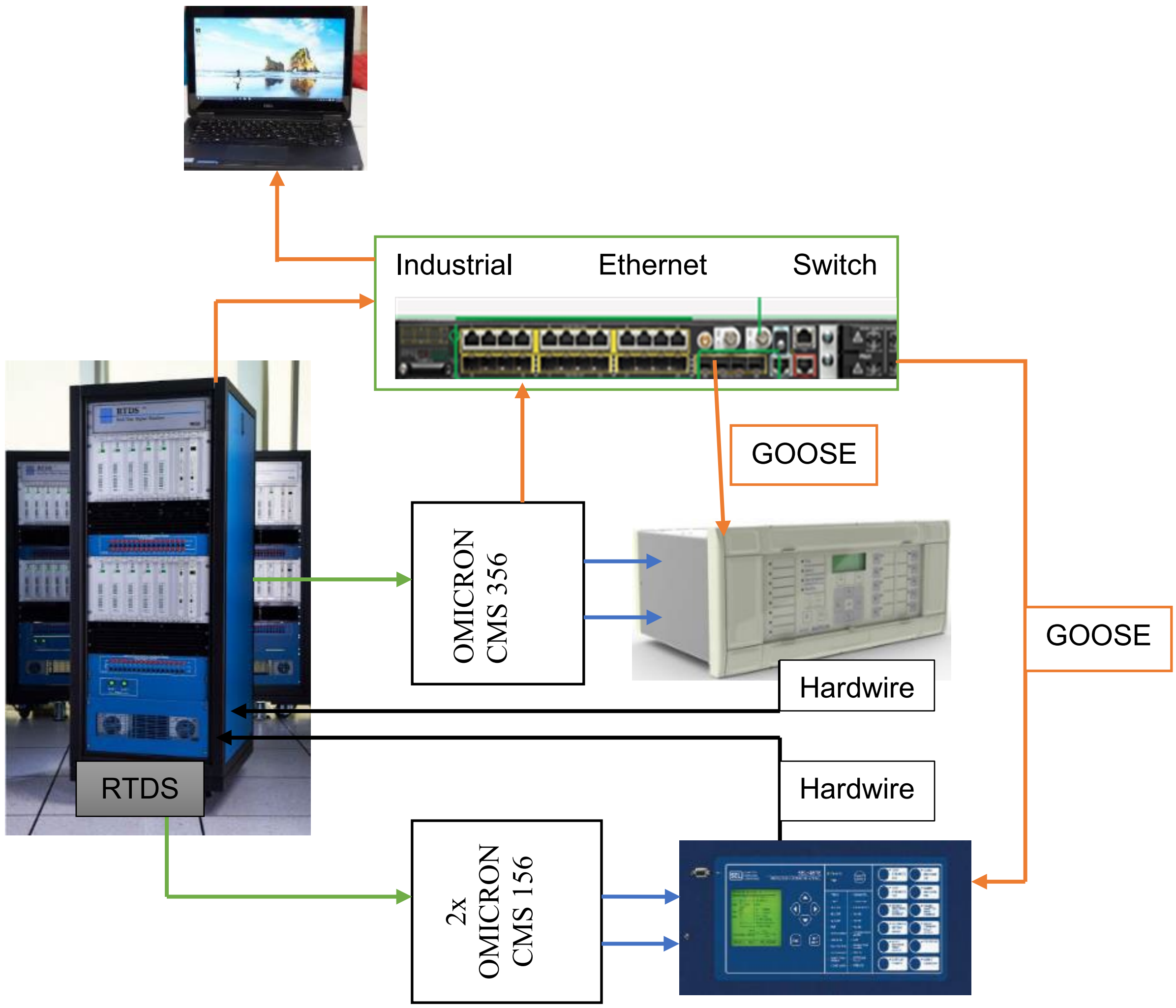


Figure 4.1: **The basic framework of HIL's laboratory test setup**

4.5.4.1 Modelling of Real-Time Digital Simulator (RTDS)

RTDS is capable of real-time simulation of power networks. One part of the OS runs on the RTDS Rack host machine (PC), and the other part runs on the GTWIF card. The RTDS compiler converts the simulations to an executable format for the computer. The compiler also takes care of parallel processing between memory allocation, digital signal processors, and communication.

The application used for running RTDS simulations is RSCAD software (RTDS, 2019a). The RTDS hardware is displayed in Figure 4.1.

RSCAD contains all libraries and features necessary for all forms of real-time simulation to be carried out. RSCAD provides many conversion programs allowing the user to conveniently import case files from other leading modeling power system software (RTDS, 2019a). The modules serve as a conduit for communication between the user and the RTDS Simulator. FileManager, Draft, RunTime, TLine, Cable, MultiPlot, Convert, and CBuilder are the RSCAD modules, as shown in Figure 4.2. In addition, via the automated batch operation module, the device will automatically run RSCAD Modules (Pieters, 2019; RTDS, 2019c).

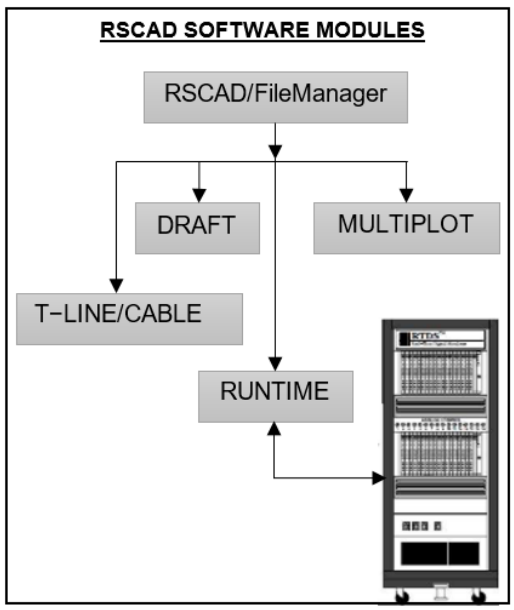


Figure 4.2: **RSCAD Graphical User Interface (Ratshitanga, 2018)**

4.6 Laboratory Setup

Creation of laboratory infrastructure, including real-time simulation facilities, using appropriate hardware and software. Laboratory development includes the selection and implementation of the required power system model through the use of the IEC-61850 station bus and the communication between various IEDs in a real-time simulator, the measurement of protection settings, and the use of them on protection relays, and the documentation of all aspects of the project.

4.6.1 The Test Setup's Structure

Section 4.5.4 of this chapter discusses the framework of the test setup, and Figure 4.1 depicts the fundamental framework of the laboratory test setup.

4.6.2 Power Transmission Network Implementation in RTDS

Using underground cables, electric power transmission may also be carried out. However, constructing an underground transmission line generally costs 4 to 10 times more than the equivalent overhead distance. It is to be remembered, however, that the cost of building underground transmission lines relies hugely on the local environment. Due to economic reasons, the three-phase three-wire overhead system is commonly used for the transmission of electric power.

Using simulation software tools, researchers employ IEEE systems to implement and test creative ideas and concepts. The transmission system of IEEE 9-Bus is selected as a case study. The IEEE 9 has been modified at bus 6 with sub-transmission and distribution. The Power System Control and Stability book by (Anderson & Fouad, 2003) introduced the 9-bus System. Appendix A displays the original configuration of the IEEE 9-bus system and also the table that shows all the data of the modified IEEE 9-bus system. The IEEE 9 Bus system represents a small transmission system that consists of 9 buses (nodes), three generators, three loads, six lines, and three transformers, while the modified part of sub-transmission and distribution consists of 10 buses (nodes), one load, two lines and three transformers (2 in parallel), the modified part on the network consists of two parallel transformers that have the same values as Voltage Ratio/Turns Ratio, Vector Group and 4 CTs.

The Three-phase diagram (3PH) is illustrated in Figure 4.4 of the modified IEEE 9 Bus transmission network simulated in the RTDS. SEL 487E and MiCOM P645 are used to protect the transformer from these relays manufactured by SEL and Alstom, respectively. Simulations of external and internal faults are used to investigate the performance of the two parallel transformers' protective relaying system.

Due to its size, the RTDS network system is divided into two areas, namely, Area A and Area B. Three racks were used on the RTDS Figure 4.4 also shows the sectionalized network under study with revised busbar identities. Area A is modelled in Subsystem 1 (Rack 1), while Area B is modelled on Subsystem 2 (Rack 2) of the (RTDS) as shown in Figure 4.3, and Substation 3 (Rack

3) was used for the second GTAO card as shown in Figure 5.6. A Global Bus Hub will be used to interface these racks to work together. When there are three or more racks in an RTDS Simulator, a special-purpose hub called a Global Bus Hub (GBH) is necessary to exchange synchronization signals between GTWIF cards.

A single-rack RTDS Simulator can run independently, whereas a two-rack RTDS Simulator can operate by connecting the two GTWIF cards directly. Each GTWIF links to the GBH through a fibre optic Tx/Rx cable for RTDS Simulators with three or more racks. The GBH is accessed from the cubicle's back with the IRC Switch and Ethernet Switch. GBH communication is distinct from the Ethernet communication used by GTWIF and the host workstation to exchange data. The panel can be configured with up to three hub cards. Each hub card can hold around ten GTWIF cards. As a result, a single GBH is capable of interconnecting up to 30 racks. However, two GBH panels can be ringed together to create a maximum of 60 interconnected racks (Gbadamosi, 2017).

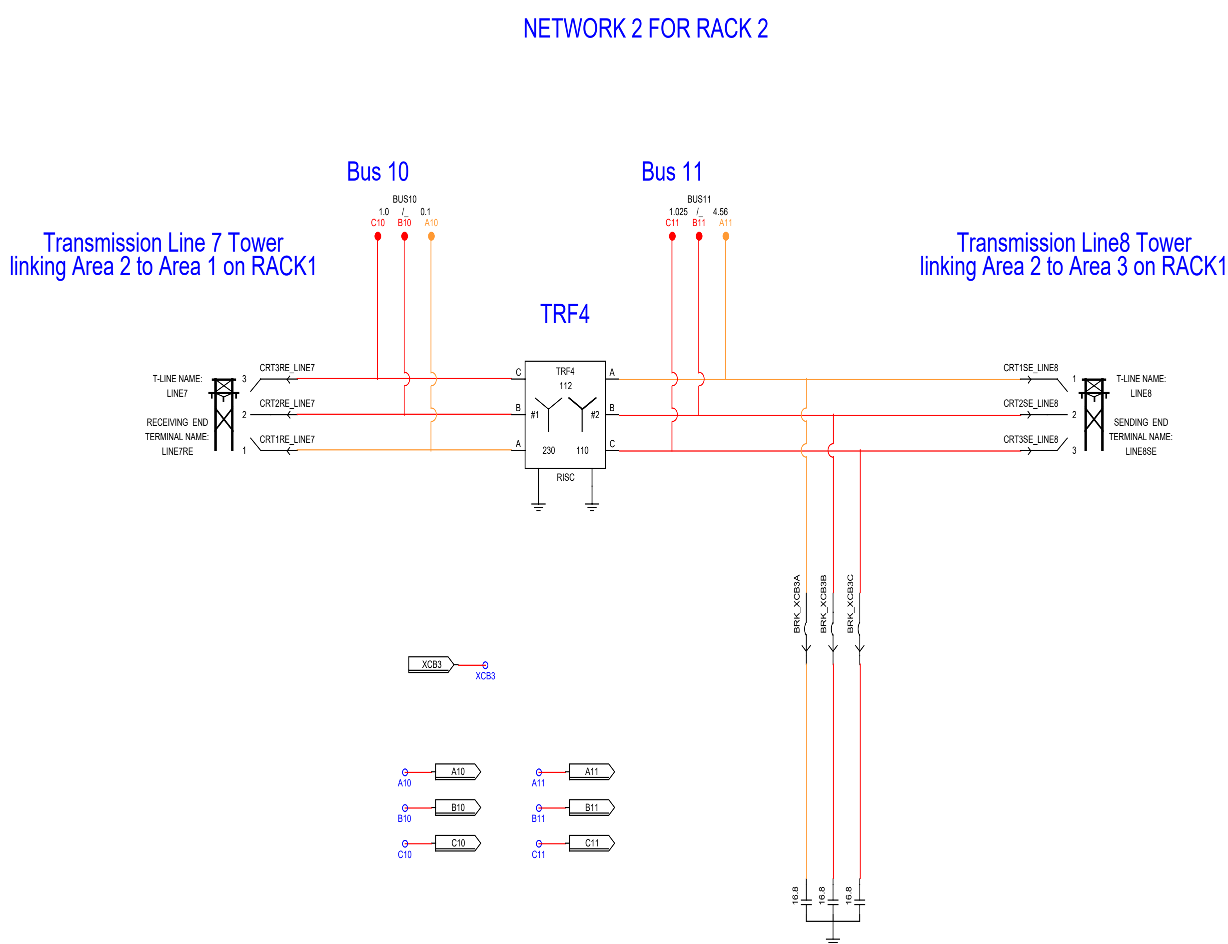


Figure 4.3: The modified IEEE 9-Bus system in Subsystem 2 (Rack 2)

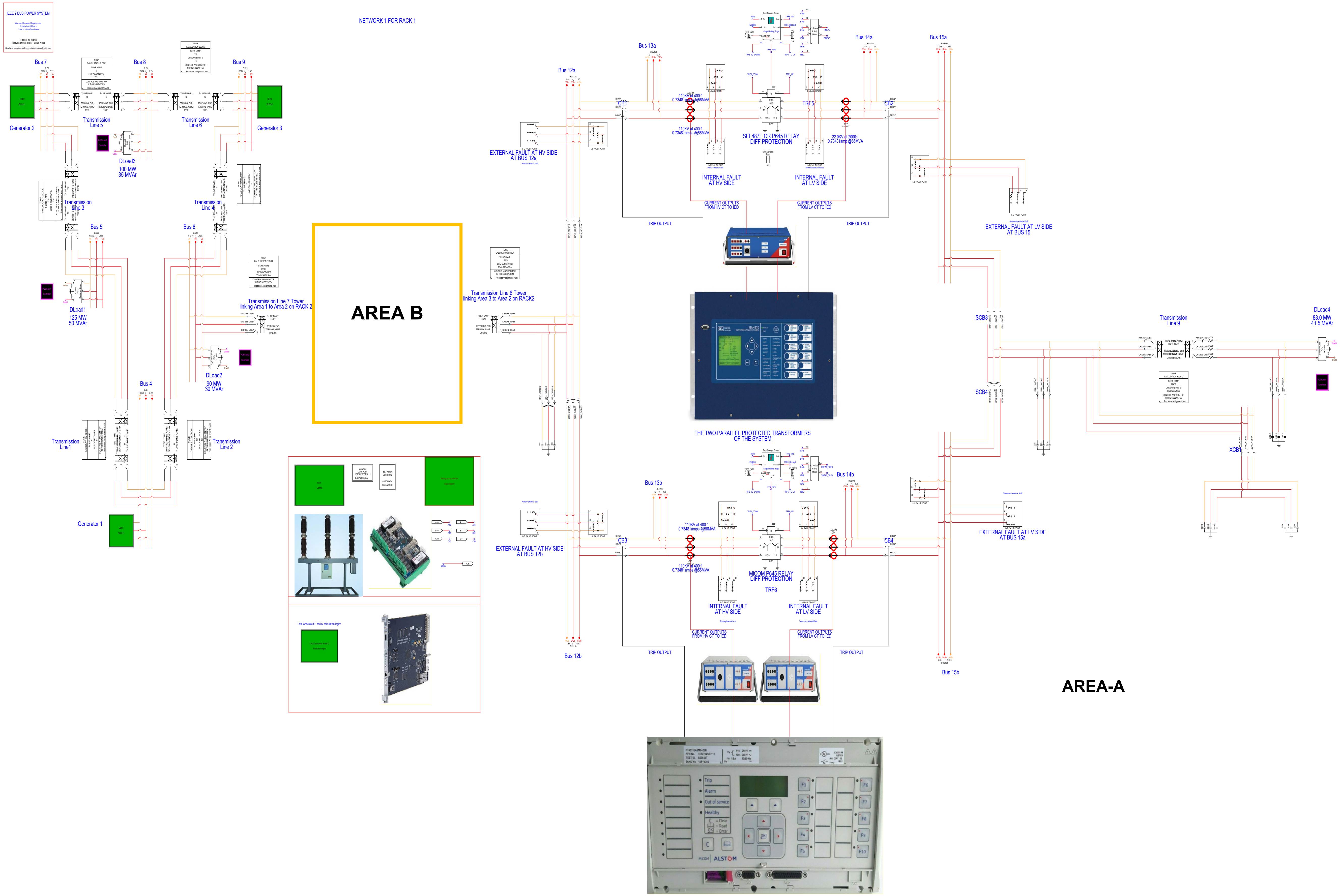


Figure 4.4: Diagram of the single-line modified IEEE Nine-Bus system substation simulated in RTDS

4.6.3 Relay Settings

The significance of proper settings of the relay cannot be overestimated. The correct circuit protection systems are all correct to use, but if the settings are inaccurate, there might be no fault or non-selective trip by CB, insulating more plants than is required. The end user (often a utility) is responsible for defining and maintaining the set policy and defining and regulating the settings to be applied to any given device object. The settings applied to any system should comply with the end-user setting policy. Modern numeric protection systems, however, typically have a very large number of configurations, as well as several setting classes (Wickremasuriya, 2016; Krieg & Finn, 2019).

For instance, if it is not possible to disable a particular unused overcurrent function, this can mean that it should be set to the limit to prevent unnecessary overflow. If improperly configured, such unused settings may remain undetected inside the system for days, months, or years but can only be detected under strict operating conditions. An additional load test can be performed during commissioning to avoid this by injecting the relay with secondary load voltage and current, if necessary, for a few minutes and ensuring that no unexpected/unwanted activity occurs (Krieg & Finn, 2019).

4.6.3.1 SEL-487E and ALSTOM MiCOM-P645 Relay

SEL-487E and P645 transformer protection relays are utilised to protect the other transformer, with the parameters described in Table 4.7. The primary protection of the SEL 487E and MiCOM P645 relays current differential protection, and they both accept the IEC 61850 standard; however, this research was more focused on the tripping side via GOOSE. These relays accept conventional voltage and current inputs via an amplifier and only support IEC 61850 GOOSE communication. Sampled Values are a more advanced form of communication that allows for the transmission of high-speed data from sensors to protection IEDs.

The important settings on the software related to the relay SEL 487E and MiCOM P645 relay are shown in Table 4.7. Parameters Differential Settings for SEL487E and MiCOM P645 are shown in Table 4.7, these parameters are obtainable on the relays manual (Inc Schweitzer Engineering Laboratories, 2020c; ALSTOM, 2020; GE, 2020).

Table 4.7: **Parameters Differential Settings for SEL487E and MiCOM P645**

Differential Settings Parameters:		
	SEL487E	MiCOM P645
Minimum Pick-Up (Idiff>)	0.5pu	0.5pu
Unrestraint Pick-Up (Idiff>>)	5.0pu	5.0pu
Slope 1 Gradient	25%	25%
Slope 2 Gradient	70%	70%
Slope 1 turning point	5.0pu (Ibias)	5.0pu (Ibias)
Bias Calculation	$\frac{\lvert I_p \rvert + \lvert I_s \rvert}{1}$	$\frac{\lvert I_p \rvert + \lvert I_s \rvert}{1}$
Combined Characteristic	No	Yes
2nd Harmonic Threshold	15%	15%
5th Harmonic Threshold	35%	35%

4.6.4 Calculations of the transformer parameters

The added network of the parallel transformer, as explained in section 4.6.2 and displayed in Figure 4.4, the new values are calculated. The parallel transformer have 56MVA, 110kV/22kV. To calculate the full load current of primary and secondary windings, Equation 4.1 was used.

$$I_{FL-W(P/S)} = \frac{S(VA)}{\sqrt{3} \times V_{P/S}} \qquad \text{Equation 4.1:}$$

For primary winding, full load current

$$I_{FL-p} = 56\ \text{MVA}/\ (\sqrt{3} \times 110000) = 293.924\text{A}$$

For secondary winding, full load current

$$I_{FL-S} = 56\ \text{MVA}\ /(\sqrt{3} \times 22000) = 1.469619\text{KA}$$

4.7 Schemes of Protection That Are Commonly Used

The extent or amount of protection given for a specific circumstance or device depends on numerous things, including the security standard of the system, the voltage level, and the owner of the asset/utility. In general, the higher the level of voltage, the greater the effects of mal-operation or the amount of power damaged, and the greater the level of protection applied. Two main protections and backups tend to be available at transmission voltages above 132 kV, but one main protection and backup could be at 132 kV and lower distribution voltages. Still, overcurrent/earth malfunction could be the only protection at lower voltages. Some criteria for utility application policy may be more stringent than this, and the decision to evaluate their needs ultimately rests with them as the asset owner; therefore, there is no hard and fast rule as to what they must meet (Krieg & Finn, 2019).

4.8 Discussion and Conclusion

As standard IEC61850, interoperability problems between Intelligent Electronic Devices produced by different vendors will be investigated, and propose solutions for improving communication between these devices will be discussed. This chapter discussed the intelligent electronic device (IED) era. Multi/Different Vendors IEDs theory, Vendor Selection for this thesis, including their programming software, and interoperability based on vendor's information process were covered. Device Testing in Substation Protection Systems Based on IEC61850 for Virtual Isolation (IED Isolation for Test Purposes) and Interoperability Issues and Testing Tools.

The hardware selection, including the laboratory setup, was discussed with the schemes of protection commonly used with few calculations of the transformer parameters. The proposed software used for simulation has also been identified in the above sections. The test bench setup is implemented in Figure 4.1 to test the vendor's IED current differential functions of the selected protective relaying systems.

The next chapter will focus on developing and modeling the transformer protection scheme, which includes tap changer control for parallel transformers and all logic circuits.

CHAPTER FIVE

DEVELOPMENT AND MODELLING OF HARDWARE IN THE LOOP (HIL) TEST BENCH FOR TRANSFORMER PROTECTION SCHEME

5.1 Introduction

This chapter analyses the development and modelling of the HIL transformer protection scheme for the modified IEEE 9-Bus system network with the parallel transformer's current differential relay protection, which is constructed and modelled in the RSCAD environment, as shown in Figure 4.4. The HIL setup employed the RTDS, SEL-487E, and MiCOM-P645 relay systems for its implementation. In the following sections, the modelling of various network components and RTDS/RSCAD will be discussed.

5.2 RSCAD testbed Development of The Protection Scheme implementation

The SEL-487E and MiCOM-P645, Protection Automation Control device, was interfaced with the RTDS via three Omicron analogue amplifiers, two CMS 156, and one CMS 356 to fulfil the HIL test requirements for the proposed protection scheme test. Control logic was also developed for the network to function as required. To make up the control logic, such as circuit breaker and fault logic, the following components were used Math, Logic Function, Selector Function, Input/output, Timers, Signal Processing, and RSCAD/Runtime Input Components.

5.2.1 Modelling of the power system network on RSCAD

Modern power systems are extensively interconnected across regions for economic reasons and to improve power system reliability. As a result, the mathematical models of these power systems are non-linear and have a high dimensionality. For this study, the modified IEEE 9-bus system, as shown in Figure 4.4, was used to model the network on RSCAD. RSCAD is a customized software and hardware combination designed specifically for real-time power system simulation. Circuit Construction, Component Builder, Operator's Module, Scripting and Test Automation, Transmission Line, and Cable Parameters are RSCAD modules and capabilities.

Generators, transformers, transmission lines, dynamic Loads, and busbars are the most important power system components that must be modeled.

5.2.2 Instrument Transformers

Voltage (or potential) and current transformers are modelled and employed in the power system circuit. VTs and CTs are utilized to reduce system voltage and current values that protection and control IEDs can accept. As mentioned in the above chapters, this thesis will focus only on the current transformer.

5.2.2.1 Selection, Modelling, and Configuration of Current Transformers (CTs)

Several hundred or thousands of amperes may flow through the power transformer's primary system current. The CT's purpose is to scale or transduce hundreds of amps of primary current down to a few amperes. Four sets of CTs were modeled for the modified IEEE 9 bus power system. The differential protection scheme is a protection method that analyses the current flowing into and out of the node. The selection of current transformers must be made correctly in order to generate this type of current flow and retain the accuracy of the differential calculations. According to the IEEE guide (Anon, 2021), the CT's primary rating should fall within the range of 120 to 150 percent of the current required at full load. This recommendation is intended to ensure accurate current measurement under normal operating conditions and reliable fault protection. Within this specified range, the CT can effectively handle both steady-state and transient currents without experiencing saturation, thereby preventing excessive burden during typical load scenarios.

The selection of the specific CT turns ratio within this range depends on the power system's characteristics, expected load currents, and the requirements of the protective relay, highlighting the critical importance of proper CT sizing and selection for precise and effective fault detection and response in the power system (Anon, 2021). By choosing CT transformers with a lot of turns, the goal is to reduce secondary currents as much as possible to avoid overloading current transformers. For this reason, Equation 5.1 and 136 percent of the interconnected network system's full load current are employed in the calculation. Choosing 136 percent ensures that the differential protection scheme remains sensitive to fault conditions, such as short circuits or internal transformer faults while preventing unnecessary tripping caused by temporary load fluctuations or inrush currents during transformer energization.

$$\mathrm{CT_{PrimaryTurns}} = 136\%\mathrm{I_{FullLoad}} \qquad \text{Equation 5.1:}$$

Where $CT_{PrimaryTurns}$ and $I_{FullLoad}$ stand for the current transformer's turns ratio and the full load current, respectively, as measured while the system operates under normal load circumstances. The system's load ampere current values must be known to determine the current transformer turns ratio values. Equation 5.1 is used to determine the maximum CT ratio.

For the primary, CT turns ratio calculations are as follows

$$CT_{PrimaryTurns} = 136\%(293.9238A) = 399.7364 \cong 400$$

For the secondary, CT turns ratio calculations are as follows

$$CT_{SecondaryTurns} = 136\%(1469.619A) = 1998.683 \cong 2000$$

There are possibilities for setting signals for monitoring in the RSCAD CT models. Because the physical device employed for the protection scheme employs the secondary currents from the CT for differential calculations and decision-making, they are more significant. The configuration setting for the current transformer (CT1 and CT3) is the same for the primary side of the protected parallel transformer, and also (CT2 and CT4) are the same for the secondary side of the protected parallel transformer. Only the setting for CT1 and CT4 will be displayed, regardless of the fact that all setting values were completed and the CTs established on RSCAD, as shown in Figure 5.1 and Figure 5.3.

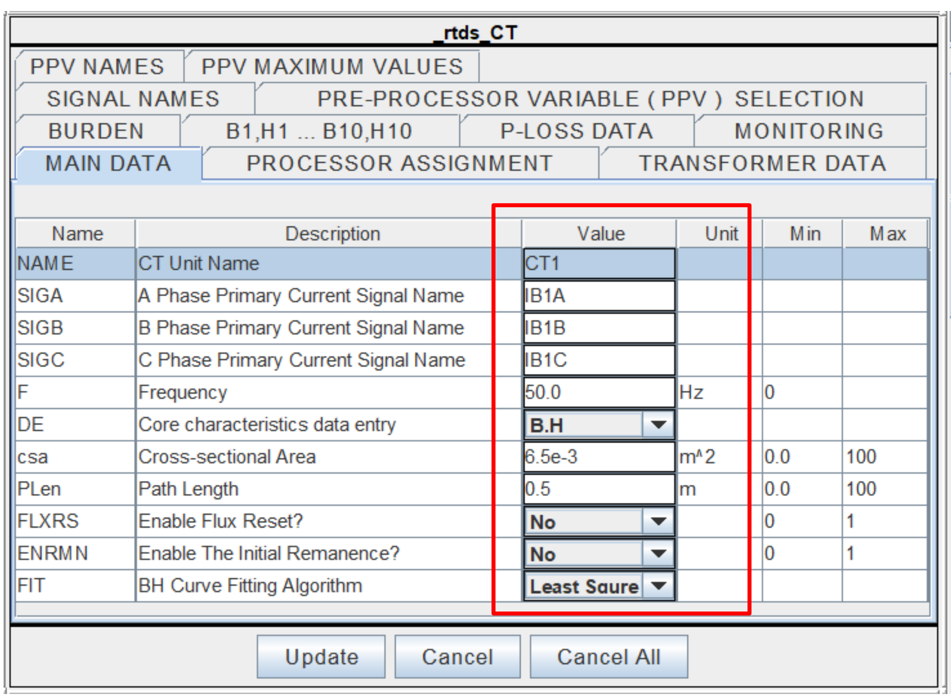


Figure 5.1: CT1's primary data parameter settings

The name of the CT, its primary current signal names, and, most crucially, the system's normal frequency are all entered in Figure 5.1 and Figure 5.2. The line currents monitored from the line where the current transformer is connected are listed as the primary current signal names. In RSCAD Runtime, these line currents were configured for monitoring.

The primary turn ratio and secondary winding resistance of CT1 and CT3 are configured as illustrated in Figure 5.3, and the current transformer data is established. The secondary turn ratio and secondary winding resistance of CT2 and CT4 are configured as shown in Figure 5.4, and the current transformer data is established.

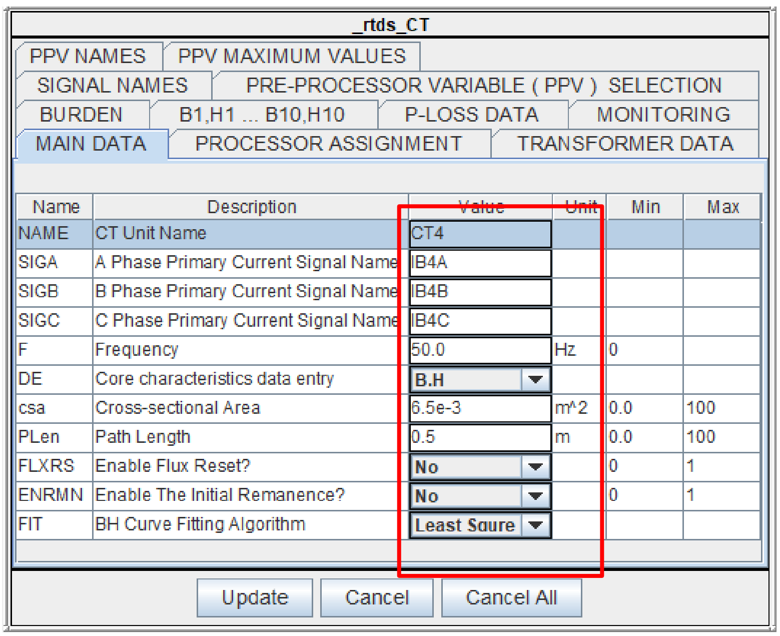


Figure 5.2: **CT4's primary data parameter settings**

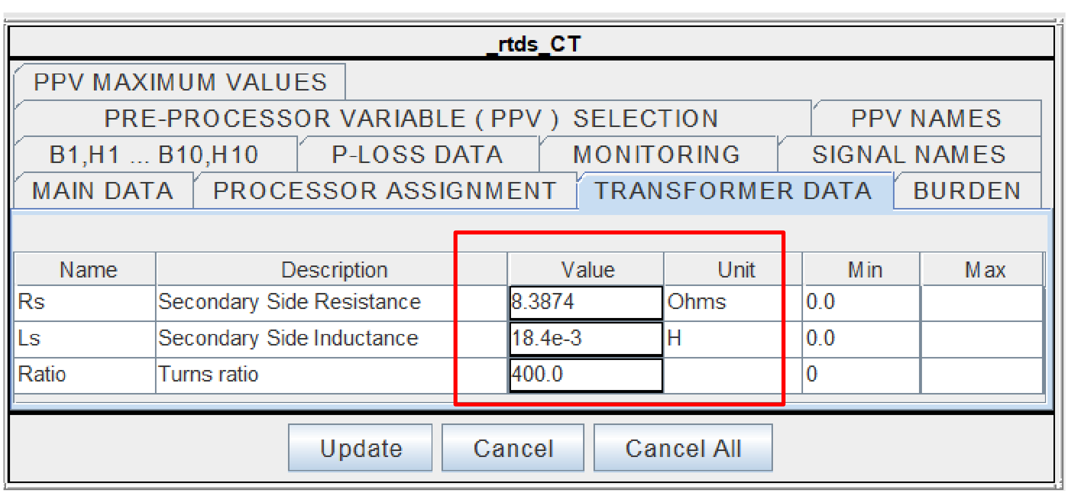


Figure 5.3: **Setting CT1's primary winding turn ratio and secondary winding series resistance**

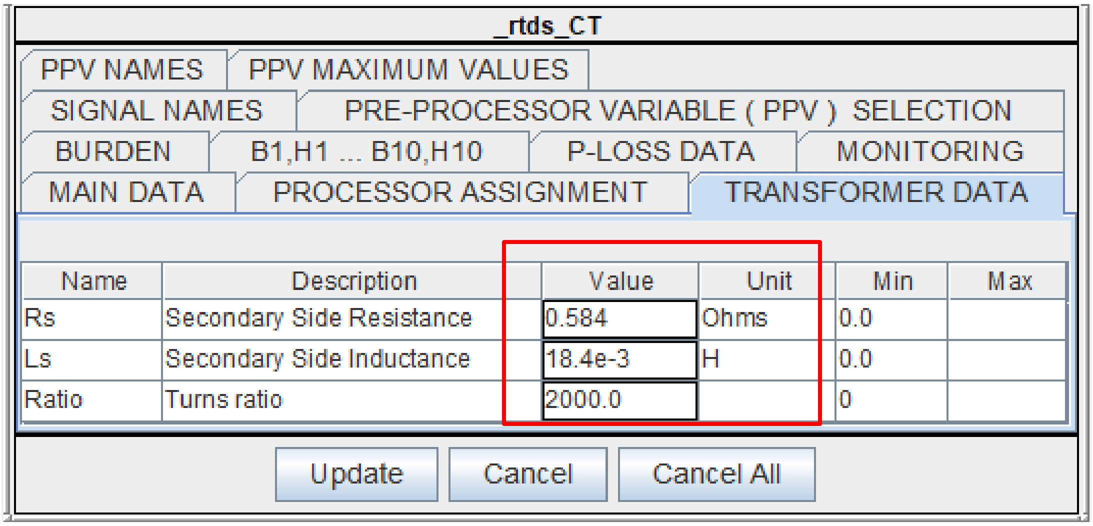


Figure 5.4: Setting CT4's secondary winding turn ratio and secondary winding series resistance

Once the CT's ratio has been calculated, it is also known that the ratios of the CTs may not always correspond to transformer winding ratios. As a result, CT correction factors can be selected based on the transformer's current ratings, and this can be done by using Equation 5.2.

$$\mathrm{TAP}_{\mathrm{HV/LV(Pri/Sec)}} = \frac{\mathrm{N}_{\mathrm{Pri/Sec-standard}}}{\mathrm{I}_{\mathrm{FL-Pri/Sec}}} \qquad \text{Equation 5.2:}$$

For the primary, CT correction factor calculations are as follows

$$\mathrm{TAP}_{\mathrm{HV/(Pri)}} = 400/293.9238 = 1.361$$

For the secondary, CT correction factor calculations are as follows

$$\mathrm{TAP}_{\mathrm{LV(Sec)}} = 2000/1469.619 = 1.361$$

Equation 5.3 was used to calculate the Current at maximum load.

$$\mathrm{I}_{\mathrm{Max\_Load(Pri/Sec)}} = \frac{\mathrm{I}_{\mathrm{FL-Pri/Sec}}}{\mathrm{N}_{\mathrm{Pri/Sec}}} \qquad \text{Equation 5.3:}$$

For the primary, Current at maximum load calculations are as follows

$$\mathrm{I}_{\mathrm{Max\_Load(p)}} = \frac{\mathrm{I}_{\mathrm{FL-p}}}{\mathrm{N}_{\mathrm{p}}} = \frac{293.924}{400} = 0.73481\mathrm{A}$$

For the secondary, Current at maximum load calculations are as follows

$$\mathrm{I_{Max\_Load(S)}} = \frac{\mathrm{I_{FL-S}}}{\mathrm{N_S}} = \frac{1.469619\mathrm{KA}}{2000} = 0.73481\mathrm{A}$$

5.2.3 Modelling and implementation of GTAO cards

The GTAO component in the RSCAD is a digital-to-analogue converter (DAC) used to send high-precision input signals to the GTAO analogue output board. The GTAO board accepts REAL input signals and is a 12-channel RTDS hardware component. The component transforms and scales the input signals to 16 bits before writing them to the GTAO card through the RTDS hardware's optical interface. The output of the GTAO is in the 10 V range. Between the RTDS rack and the Omicron amplifiers, the GTAO card served as an interface. The CT-measured currents are sent to the protective IED relay equipment via the GTAO and CMS omicron. Only two sets of three-phase current signals are allowed to be converted by this GTAO card. The RTDS Rack 1 and Rack 3 both have GTAO cards accessible. In order to prepare for exports and imports across Subsystem 1 and Subsystem 3 of the RTDS, the power system network model has its signals set for both.

Channels 1 to 3 and 7 to 9 are used for currents in Subsystem 1 (Rack 1), which models the GTAO1 portrayed in Figure 5.5. CT1 primary currents measured are designated IBUR1A, IBUR1B, and IBUR1C, whereas CT2 secondary currents measured are designated IBUR2A, IBUR2B, and IBUR2C, respectively.

The GTAO2 card simulated in Subsystem 3 (Rack 3) is shown in Figure 5.6; channels 1 To 3 and 4 to 6 are used for currents. CT3 primary currents measured are designated IBUR3A, IBUR3B, and IBUR3C, whereas CT4 secondary currents measured are designated IBUR4A, IBUR4B, and IBUR4C, respectively.

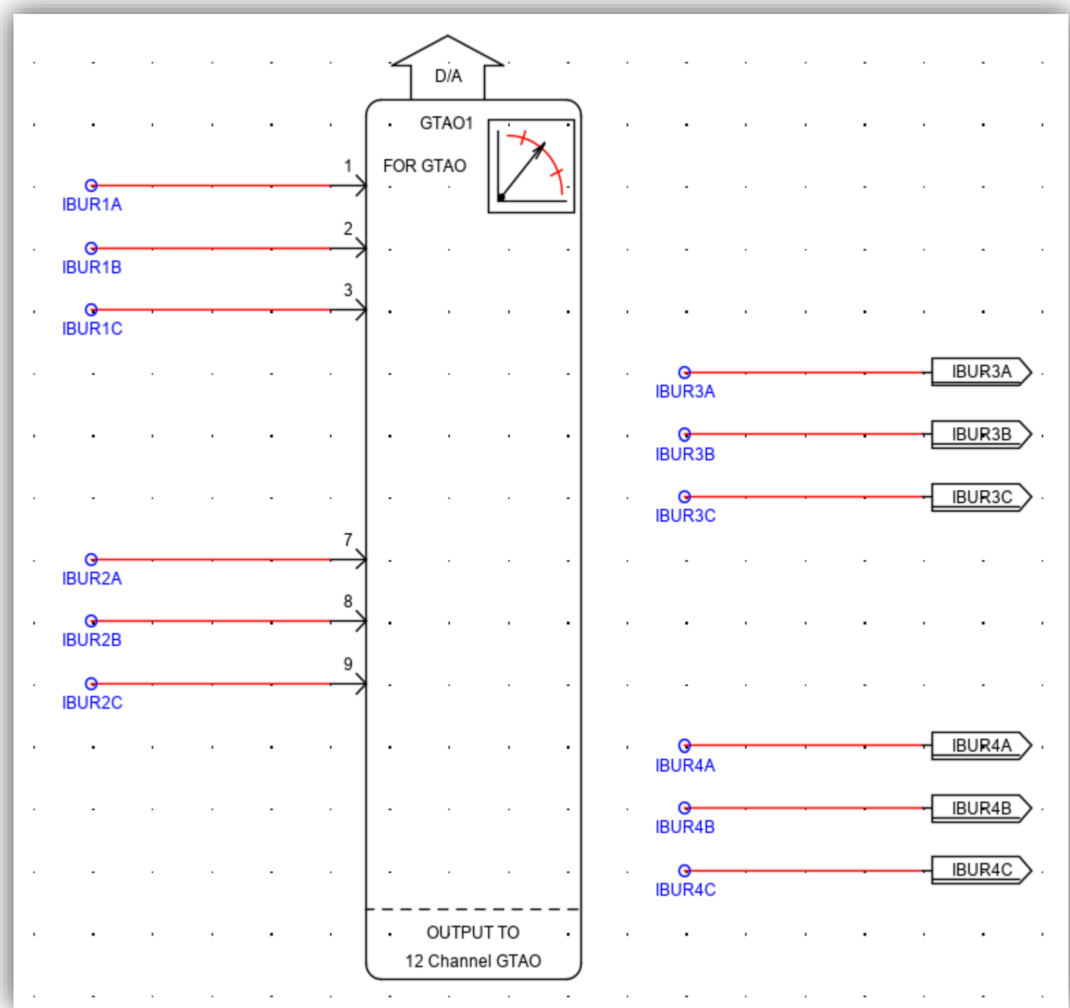


Figure 5.5: Subsystem 1's (Rack 1) GTAO1 card for CT1 and CT2 currents

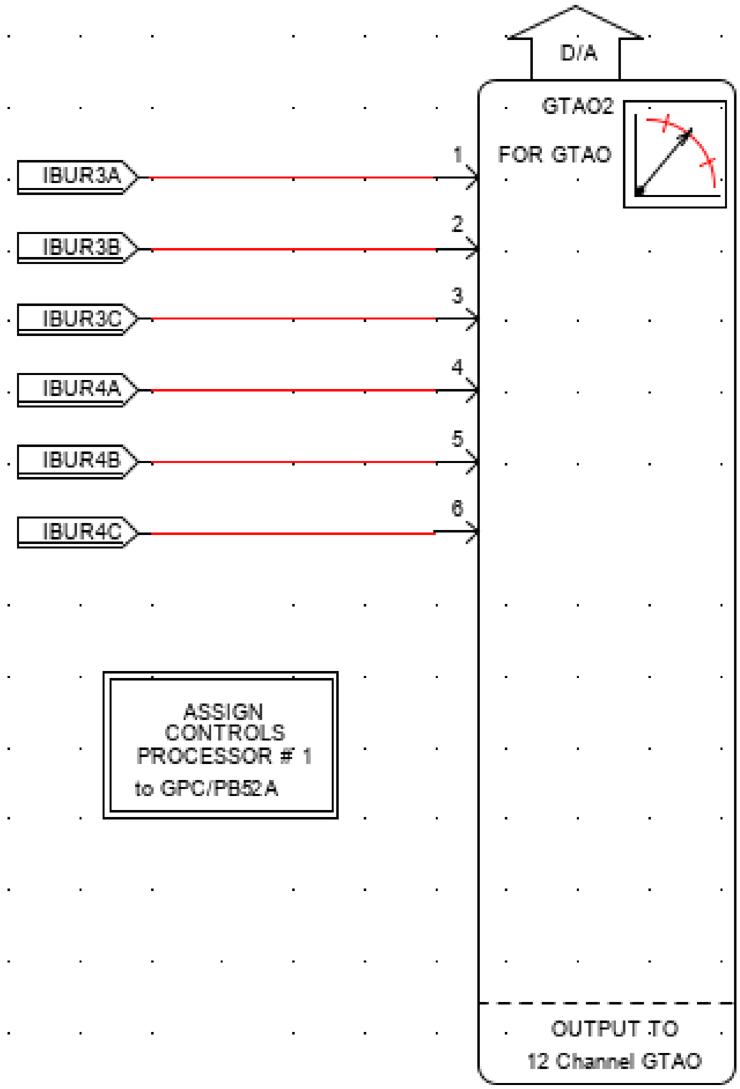


Figure 5.6: For CT3 and CT4 currents in Subsystem 3 (Rack 3) GTAO2 card

5.2.3.1 Low-Level Test Interface/Connection

An interface that allows reduced-scale test amounts to be inserted into the connection between the relay input transformers and the input processing module during relay testing. The secondary voltage and current signals from the HV instrument transformers are frequently fed into the relays' current and voltage inputs. Current transformers (CTs) have typical nominal secondary currents of 1A or 5A. SEL relays have a nominal input current of 1 A, while MiCOM Phase relays have a nominal input current of 1 A or 5 A. The instrument transformers inside the relays convert these current signals to lower values, which are suited for their inner circuit boards containing A/D converters. Current amplifiers are used to boost current signals from RTDS analogue outputs to match the relay input range in the traditional method of relay testing (Wickremasuriya, 2016). Figure 5.7 shows the SEL-487E IED low-level test interface.

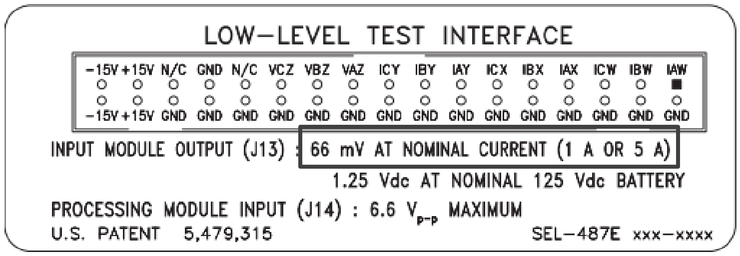


Figure 5.7: **Low-Level Test Interface for IED SEL487E (Schweitzer Engineering Laboratories, 2019)**

In RTDS, high-voltage instrument transformers that scale down primary currents and voltages are modelled using voltage and current transformer models that accurately capture their magnetic and saturation characteristics. These CT and VT values are transferred to GTAO cards, which provide analogue outputs. By inputting the proper scale factors to the GTAO setup component in RSCAD software, these analogue outputs can be scaled to the range of voltages accepted at low-level interfaces of the relays. Table 5.1 displays each relay's nominal secondary output and low-level interface input for current signals.

Table 5.1: **Nominal secondary output and low-level interface input of each relay**

Relay	Current	
	Nominal secondary output (A)	Nominal low-level input (V)
SEL 487E	1	0.066
MiCOM P645	1	0.059

a) Calculating GTAO Scaling Factors:

In this section, a systematic procedure for adjusting the scaling factors of a GTAO channel is explained. The following figure shows the relationship between the GTAO input and analogue output. The GTAO contains a scaling factor for each channel that adjusts the analogue signals to the levels required by the interfaced electronics. This relationship is shown by the following Equation 5.4:

$$\text{Analogue Output} = \frac{5\ \text{V}}{\text{G}} \times \text{RTDS Signal} \qquad \text{Equation 5.4:}$$

According to the SEL487E relay documentation for the low-level test interface (see Figure 5.7), at rated current, the RMS current of the CT is 1A or 5A, corresponding to 66 mV for the input of the low-level test interface. Therefore, the channels that output current signals are calculated using Equation 5.4:

$$66\ \mathrm{mV} = \frac{5\ \mathrm{V}}{\mathrm{G}} \times 5 \Rightarrow \mathrm{G} = \frac{5\ \mathrm{V}}{66\ \mathrm{mV}} \times 5 = 378.7879$$

With the above scaling factors, at rated current output of the GTAO for the current signals is 66 mV. With the above scale factor, we can run the simulation on the RSCAD measure the current output from the CMS amplifier, and use those values to calculate the exact current value that will be taken in as an input current to the relay, Equation 5.5: was used to calculate this values. By measuring the actual output analogue currents from the RSCAD virtual instrument transformers, this part of the GTAO modelling verifies that they are accurate.

$$\mathrm{IED_{GTAOX}} = \frac{\mathrm{Imeasured}}{\mathrm{Icalculated}} \times \mathrm{G} \qquad \text{Equation 5.5:}$$

For the primary, IED GTAO1 calculations are as follows

$$\mathrm{IED_{GTAO1}} = \frac{289.1}{293.9238} \times 14.5 = 14.26203$$

For the secondary, IED GTAO2 calculations are as follows

$$\mathrm{IED_{GTAO2}} = \frac{1856.99}{1469.61.89} \times 14.5 = 18.32$$

The setting for the analogue current signal scaling factor for GTAO1 and GTAO2 signals is shown in Figure 5.8 and Figure 5.9, respectively, and they are 5 times the amplifier gain of the Omicron.

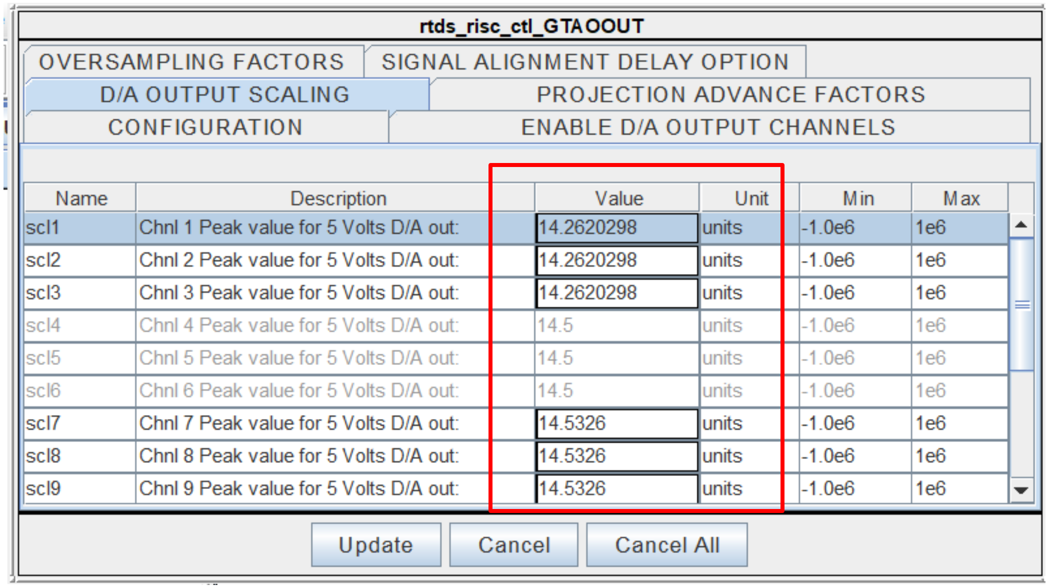


Figure 5.8: Scaling of the analog current signal for GTAO1

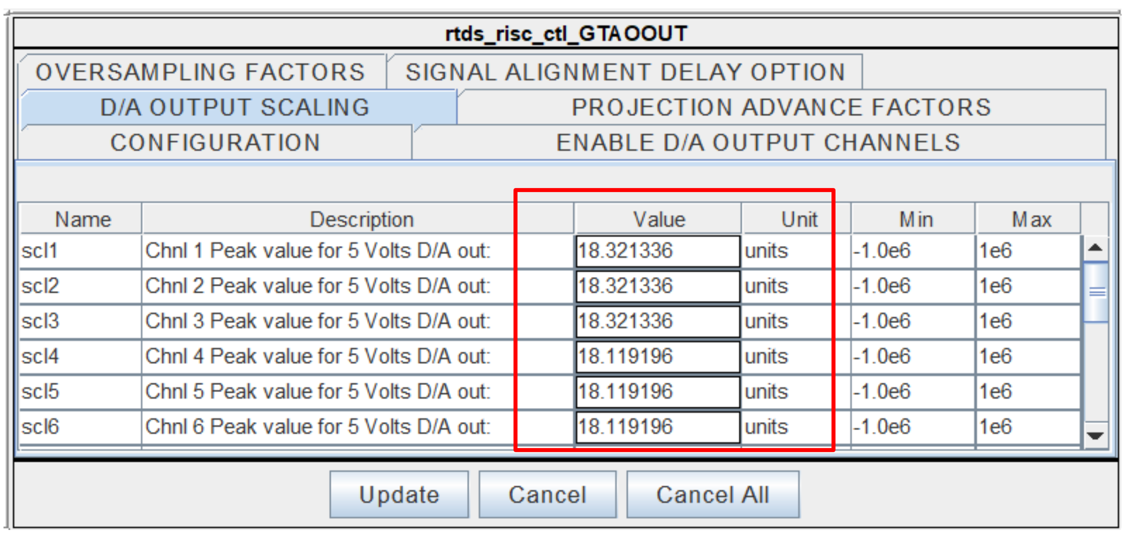


Figure 5.9: Scaling of the analog current signal for GTAO2

5.2.4 Modelling and configuration of GTWIF cards

The GTWIF card is used to export simulation outputs from the RTDS's RSCAD Runtime environment. The GTAO card is coupled to the Omicron amplifiers, which convert ±10V analogue current signals to the IED relay's winding current channels. The CTs modules of the IED relay receive these analogue current signals.

5.2.5 GTFPI cards modelling and configuration

GTFPI can use a GTFPI card to write and read binary integer data. The RTDS front panel is physically attached to a GTFPI card. A high-voltage front panel and a digital I/O front panel can use a GTFPI card. The GTFPI component has options for specifying whether to use the high-voltage or digital I/O panel. This system network's low-voltage digital I/O interface panel offers 16 digital input and output signals at TTL voltage levels. The digital input is pulled high (IEDs) for easy dry connections as input from protection equipment. Depending on the value of the simulation variables, the digital output channels, typically at 0 volts, can be driven to 5 volts. Figure 5.10 shows the IED Hard-wire trip signal's word-to-bit conversion using the GTFPI component. Output pin numbers 6 and 7 were used due to the first five fault digital I/O on the interface panel of RTDS.

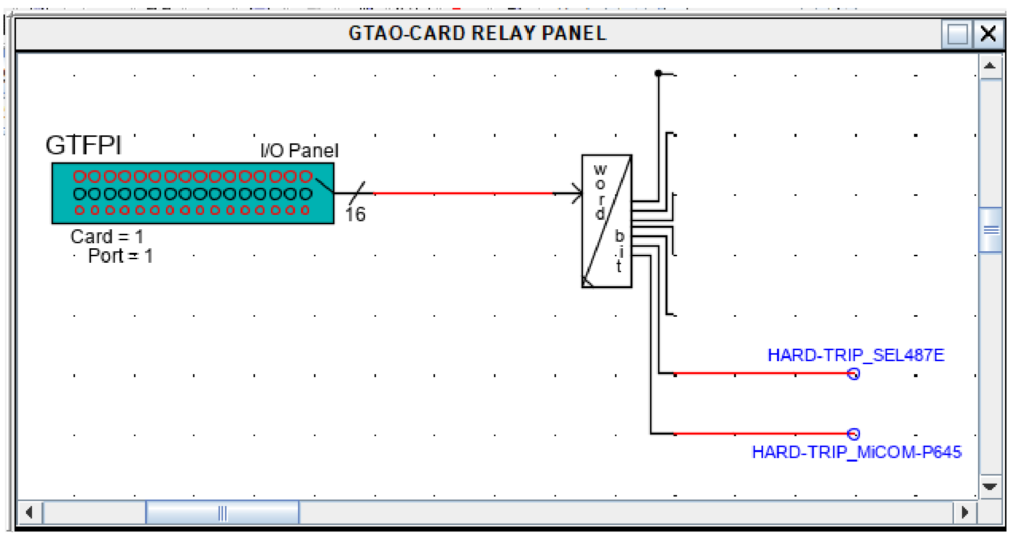


Figure 5.10: Conversion of word-to-bit for the GTFPI Component's trip signals

5.2.6 RTDS Inputs

The RTDS makes a range of faults easier to apply. When a fault is applied, a relay detects a failure using simulated voltage and current signals sent through the simulator's analogue outputs. After the fault has been detected, the relay sends a trip signal to the relevant circuit breaker simulated in the RTDS. Traditional hardwired connections and GOOSE messages are used in this study to send the trip signal from relays to RTDS (Wickremasuriya, 2016).

5.3 Logic Diagram Design for Network Control and Monitoring

5.3.1 RSCAD/Runtime Logic for Circuit Breaker Control (CBs)

Breakers on the transformers primary and secondary had to be opened and closed to demonstrate transformer inrush phenomena. The transformer will be de-energized when the breakers are opened, leaving a residual flux in the core. Inrush currents are generated when the transformer is re-energized by closing the primary breaker. Inrush current severity is determined by residual flux at the breaker terminal and a point on the voltage waveform. The maximum magnitude inrush currents occur when the circuit breaker is closed simultaneously as the voltage drops to zero because the flux increases in the same direction as the offset. The offset is caused by the residual flux (Jodice et al., 2016; Ravichandran, 2015).

Figure 5.11 shows the controller logic for operating the circuit breakers for SEL-487E and the MiCOM-P645. The design of the circuit breakers is the same for SEL-487E and the MiCOM-P645, only names that are different, as can be seen in Figure 5.11. Table 5.2: gives a summary explanation of the zones of circuit breaker logic shown in Figure 5.11. The logic circuit aims to offer a circuit breaker close and open pushbutton that can be used to operate the circuit breakers during RSCAD execution. These circuit breakers can open automatically during the internal fault simulation, depending on the fault's location on a transformer. This circuit breaker logic control is adopted from the RTDS manual and is modified according to this research design. The added parts are under areas such as (A, B, C, D, and E), as seen in Figure 5.11. The original circuit breaker is shown in Appendix C.

Table 5.2: **Summary explanation of the zones of the modified circuit breaker logic shown in Figure 5.11**

Area of the Circuit breaker	Description
Zone 1	The hardwire input signal from the RTDS and controlling the reset button of all CBs
Zone 2	Made up logic control of CB1 of TRF5 protected by the SEL-487E relay
Zone 3	Made up logic control of CB2 of TRF5 protected by the SEL-487E relay
Zone 4	Made up logic control of CB3 of TRF6 protected by the MiCOM-P645 relay
Zone 5	Made up logic control of CB4 of TRF6 protected by the MiCOM-P645 relay

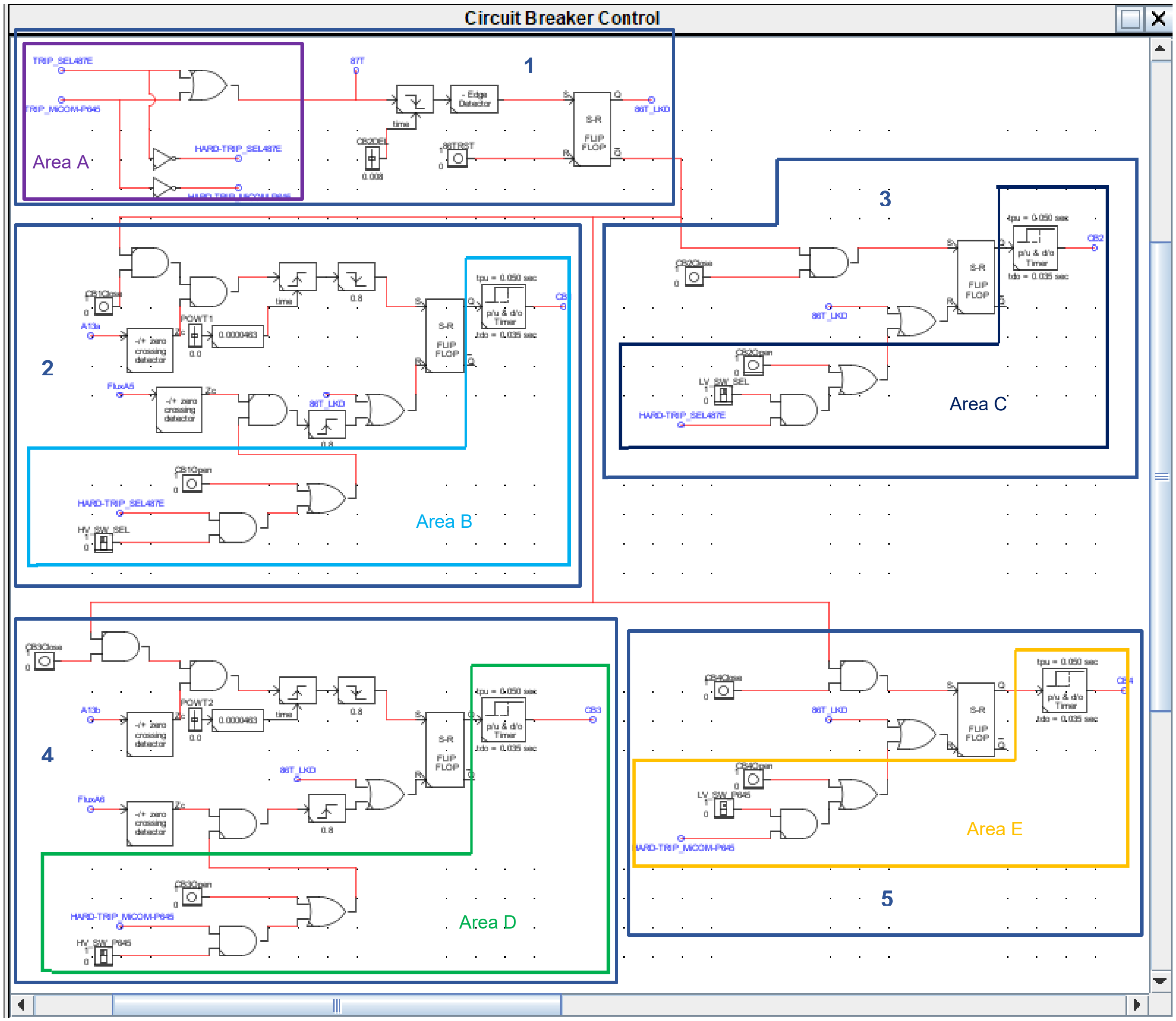


Figure 5.11: Logic for SEL-487E and MiCOM-P645 Circuit Breakers Control

The external differential IED relay and Hard-trip signals (SEL-487E and MiCOM-P645) are used to close/open circuit breakers (CB1, CB2, CB3, and CB4). As a result, when a trip signal is given from an IED relay or an RSCAD, an 87T differential trip signal is generated. The output duration timer is attached to the negative edge detector component by setting the slider CB2DEL to logic one for the desired duration. As seen in Figure 5.11, the S-R flip-flop has two inputs: a negative edge detector and a lockout relay reset (86TRST). The S-R flip-flop activates the lockout relay 86T_LKD or all circuit breakers (CB1, CB2, CB3, and CB4). As illustrated in Figure 5.11, each breaker has two pushbuttons, one for opening and the other for closing the breakers.

The breakers will open when the open pushbuttons are pressed in RunTime, and the flux crosses through zero in the positive direction. The POWT1/POWT2 slider manages the point on wave energization. To guarantee that the residual flux is positive, this was included. Similar to this, the primary breaker will close after the node voltage A13a/A13b has crossed through zero in the positive direction, and CB1Close/CB3Close is set to 1 in RunTime. The gain block changes the value of the point on the wave from degrees to time (0.000463).

5.3.2 RSCAD/Runtime Logic for Fault Control

The fault control logic initiates a fault and removes a fault; the “Fault Control” hierarchy box contains the implementation, which means it can control the point on the wave, duration, type, and fault location. RTDS runtime environment is where the fault may be managed and is used to examine how the relay operates during an external and internal fault. The majority of power system faults are single-line-to-ground faults. In addition to single-line-to-ground faults, the protection scheme phase elements are also subjected to simulated three-phase faults.

For fault simulation studies, short-circuit fault types (such as line-to-ground, three-phase-to-ground, all-three-phase, and so on) and duration (optionally in cycles) are defined using fault locators and logic. This section models the fault simulation logic, allowing at least single-phase-to-ground and three-phase faults at the system's busbars. A fault consisting of a triple line to the ground, a double line to the earth, and a single line to the ground are all possible with the fault control logic. As shown in Figure 5.12, the logic for the MiCOM-P645 fault control circuit, the SEL-487E fault control, is the same as the MiCOM-P645; the only difference is the name of the input and output.

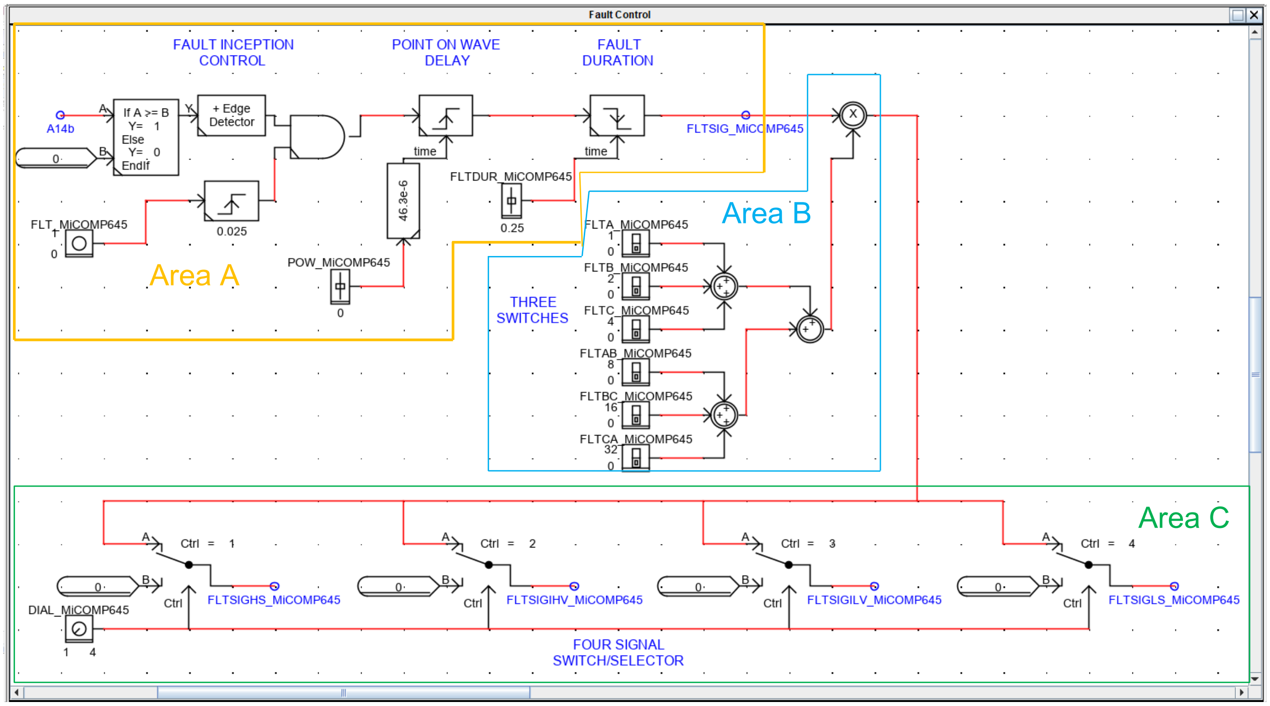


Figure 5.12: **Logic for MiCOM-P645 fault control circuit**

The top part area A of the logic shown in Figure 5.12 controls the point-on-wave (the fault inception angle) and fault duration upon which the fault is applied. Slider's 'POW_MiCOMP645/POW_SEL487E' and 'FLTDUR_MiCOMP645/FLTDUR_SEL487E' are utilized to set the fault inception angle (in degrees) and the fault duration (in seconds), respectively. The pushbutton 'FLT_MiCOMP645/FLT_SEL487E' will apply a fault when used.

While the middle part, area B of the logic shown in Figure 5.12, controls the fault type and the fault location, and area B is the modified part of this control logic since it was taken from the RTDS manual. Its original logic is shown in Appendix C. Switches 'FLTA,' 'FLTB,' 'FLTC,' 'FLTAB,' 'FLTBC,' and 'FLTCA' control the fault type selection.

Bottom part area C Signal switches 'FLTSIGHS,' 'FLTSIGIHV,' 'FLTSIGILV,' and 'FLTSIGLS' control the appropriate fault locations. It also has a 'DIAL' switch, and area C is modified according to the research aim.

The node voltages at the transformer determine the start of the faults in a protected parallel transformer. The logic for fault inception is an important part of HIL testing because it allows the fault to start before being detected by the relay's hardware.

Control of Fault Inception on (Area A)

- The fault inception logic consists of an If-Else logic gate with a constant logic 0 on B input and A14a/A14b on An input, which uses the protected power transformer's node voltage as a reference point for the point on wave delay.
- The A14a/A14b voltage is detected when it has crossed the x-axis and is on the positive side by the output of an If-Else logic gate with a positive edge detector.
- A signal with the value "1" is sent out using a raising edge detector as soon as the FLT_MiCOMP645/FLT_SEL487E pushbutton is pressed, which starts the fault sequence. The fault button and zero-crossing detector are combined in the AND gate, which creates a pulse afterward.

The Point on Wave Delay and Fault Duration (Area A)

- The pulse drives the logic of the wave's point, consisting of a gain block, a slider, and a pulse length timer programmed to detect an edge rising. The duration timer's output is set to logic one when the pulse reaches that value, equal to the amount of time needed to rotate the POW slider controls a specified number of degrees from zero-crossing detection.
- The POW and FLTDUR sliders can be used to change the position of the wave and the fault duration, respectively. Combining fault switches for phase-to-ground and phase-to-phase fault types creates the required integer value.

Switches for phase fault selection (Area B)

- The FLTA, FLTAB, FLTB, FLTBC, FLTCA, and FLTC switches are employed to determine which phase the fault will start.
- The fault type integer value is multiplied by the last signal from the logic, FLTSIG, and transmitted to the fault inception block at the protected transformer in the power system test scenario.

Four Signal Switch/Selector (Area C)

- The dial component DIAL_MiCOM-P645 is changed from FLTSIGHS, FLTSIGIHS, FLTSIGILV, and FLTSIGLS of the power transformer, which signifies an external fault on the HV side, an internal fault on the HV side, an internal fault on the LV side, and an external fault on the LV side, respectively. E.g., when the DIAL knob is turned to 2, the internal fault (FLTSIGIHS) channel A is selected when ‘Ctrl’ equals two while B is constant logic 0.

5.4 Setting for Differential Protection on Numeric IED Relays

5.4.1 Device Configuration setting of IEDs

This section uses the AcSELerator Quickset and MiCOM S1 Agile software to configure the SEL-487E and MiCOM P645 Differential Transformer Protection and Control devices, respectively. This scheme is set up so that both of the operating requirements of the resultant connected system are satisfied.

5.4.1.1 SEL-487E IEDs on AcSELerator Quickset software

Figure 5.13 illustrates the general global settings for the SEL-487E main protection power transformer relay, which include ABC as the system phase rotation, Station A as the station identifier, and SEL-487E-2 as the relay identifier.

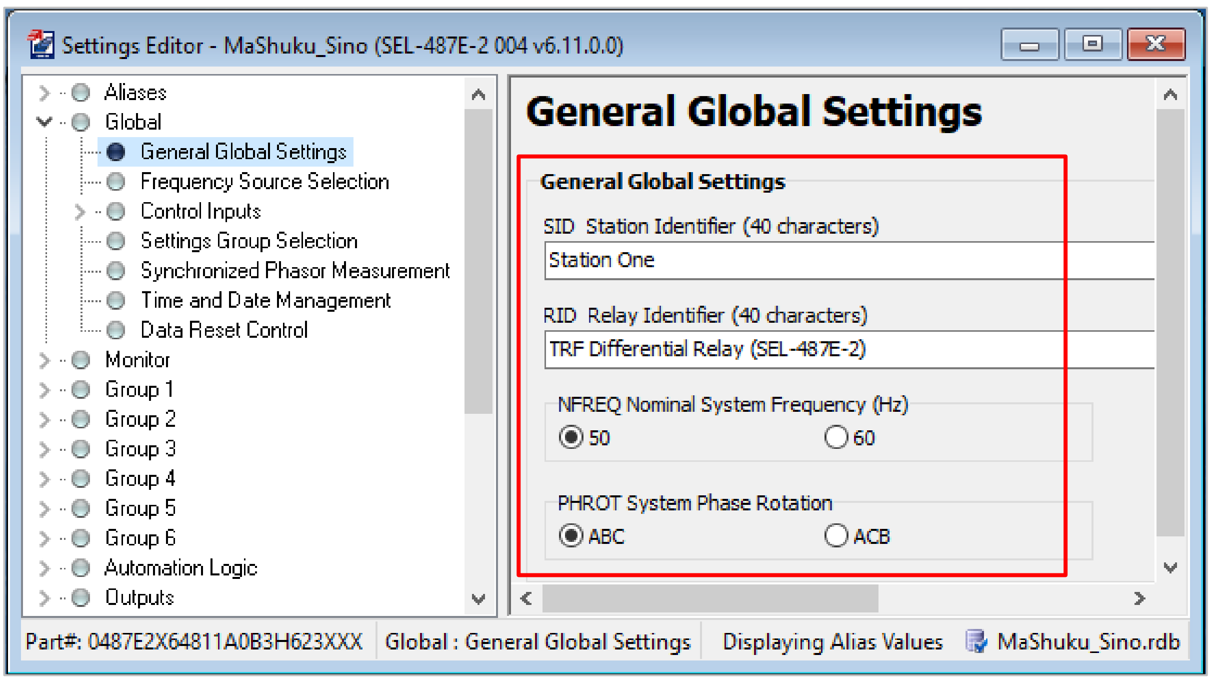


Figure 5.13: SEL-487E IED general global setting on AcSELerator Quickset

CT ratio settings of the parameters for SEL487E are shown in Figure 5.14. The CT primary winding is 400 and is connected to the star, while the secondary CT winding is 2000 and is connected to the delta.

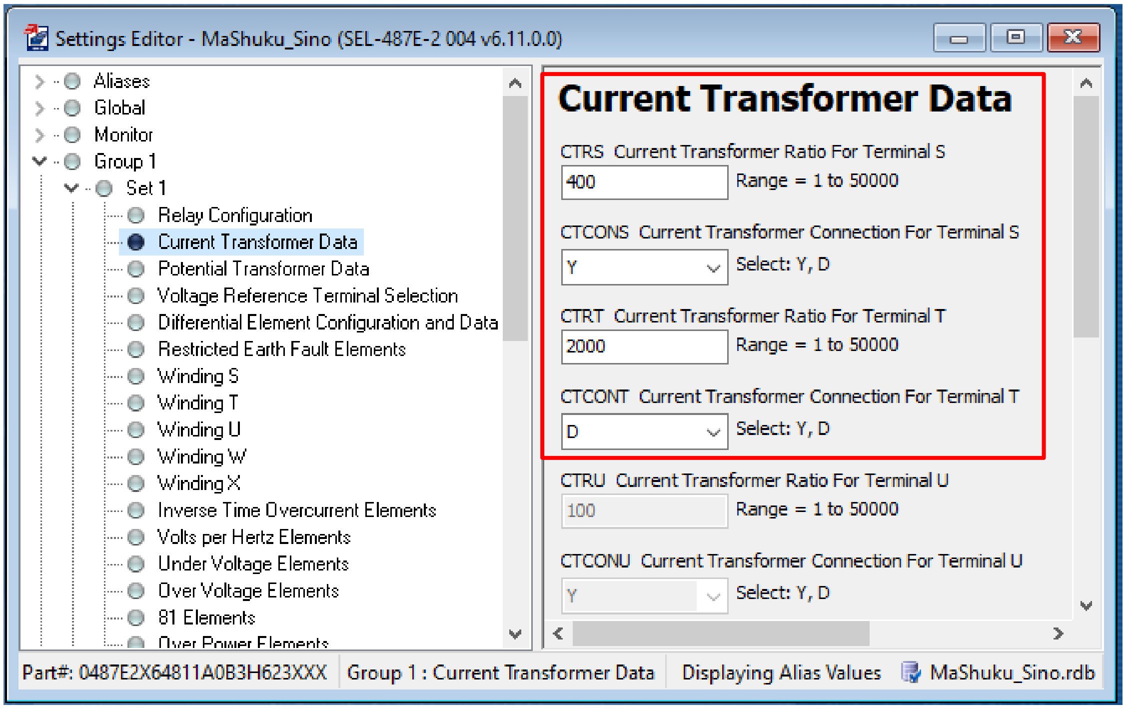


Figure 5.14: **SEL-487E IED current transformer setting**

The configuration setting of the differential transformer element for SEL487E is shown in Figure 5.15.

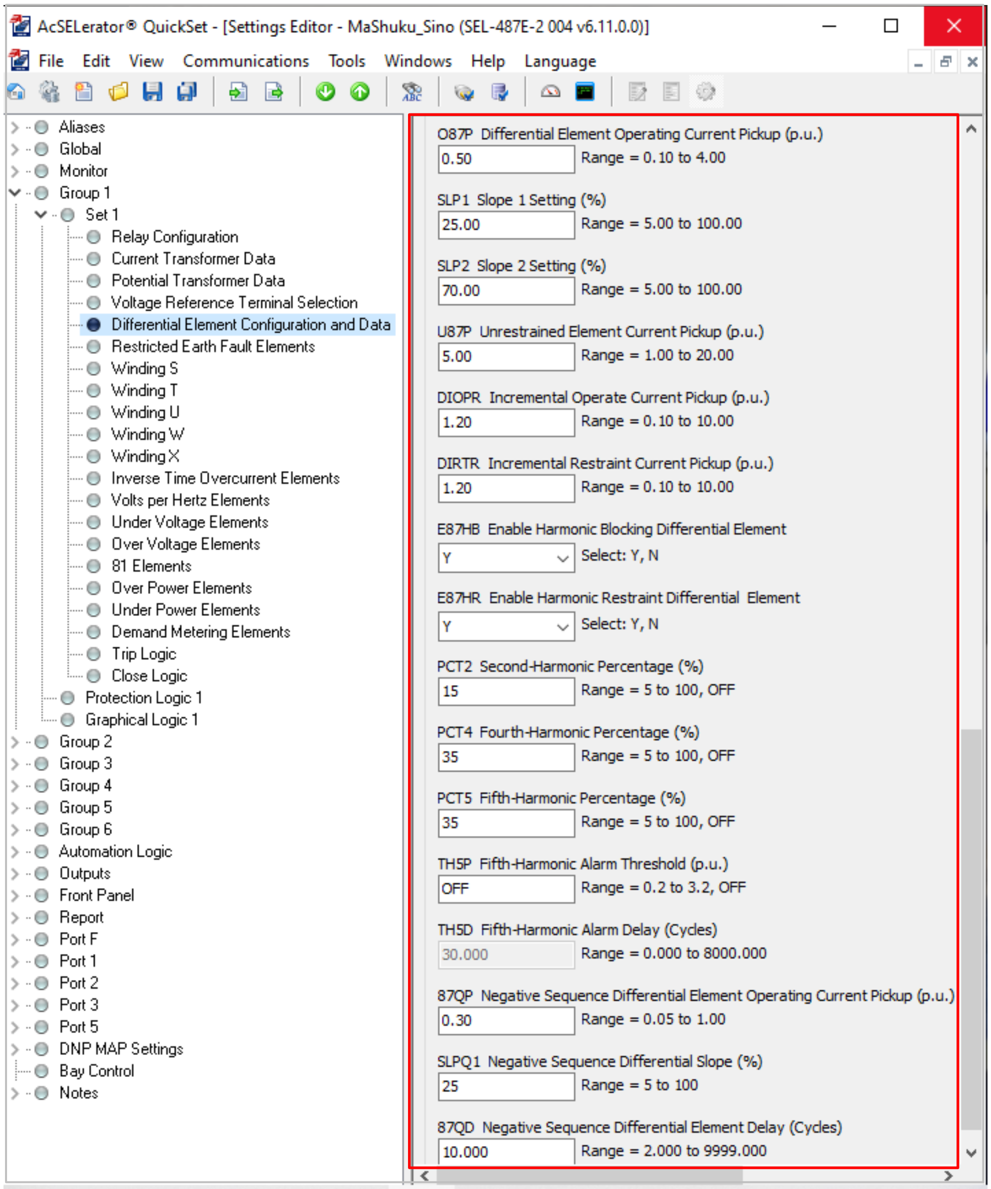


Figure 5.15: The configuration settings of the differential element in AcSELerator Quickset

5.4.1.2 MiCOM- P645 IEDs on MiCOM S1 Agile

The data model can be used to generate a new settings file, or the device can retrieve an already-existing settings file. It is possible to edit and send the device's settings file. Figure 5.16 shows the default settings file for the P645 device, which shows all folders. Settings of the system data power transformer relay protection main for MiCOM-P645 are shown in Figure 5.17, where the frequency is set to 50Hz.

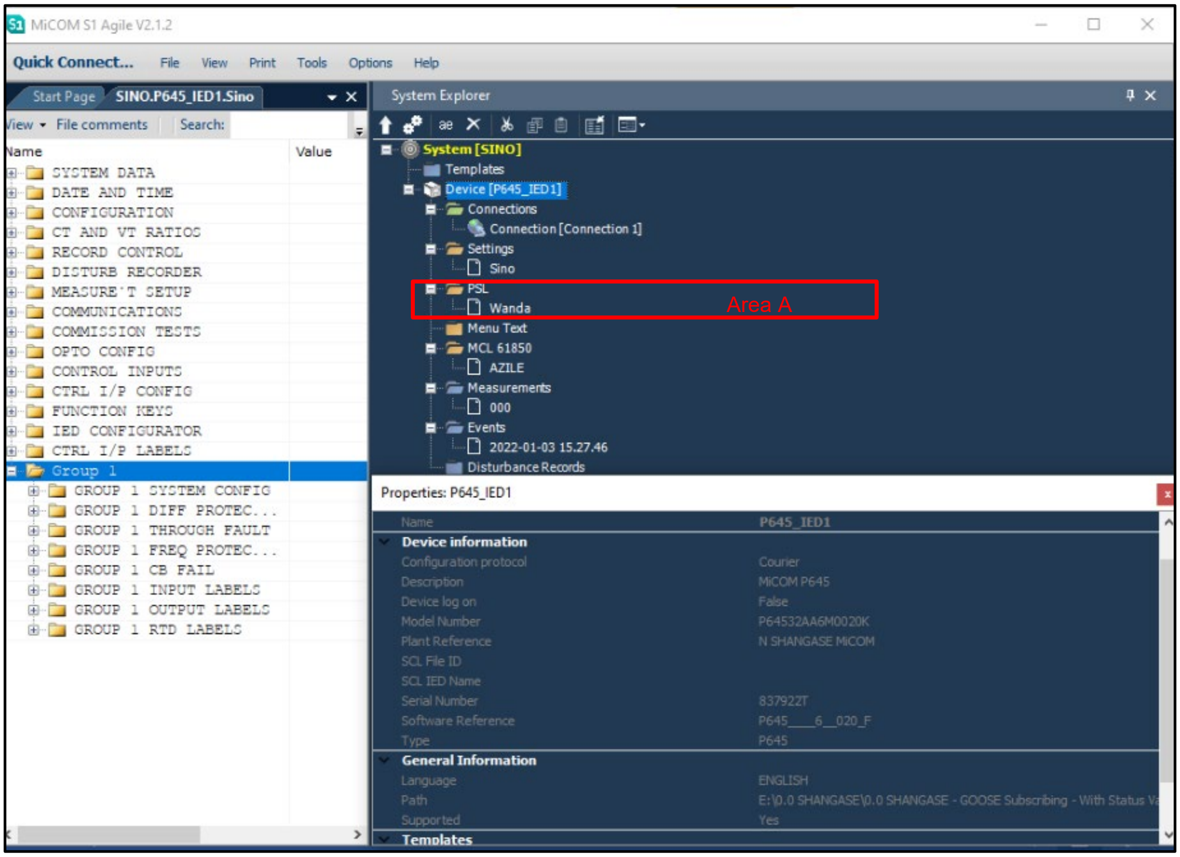


Figure 5.16: MiCOM-P645 Settings file on MiCOM S1 Agile

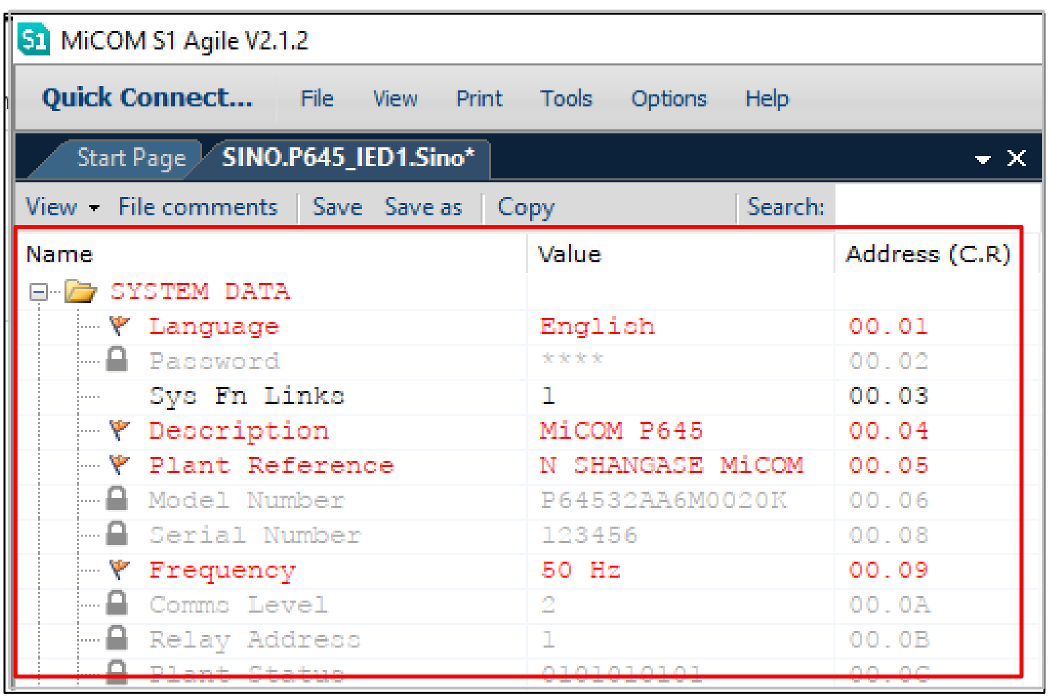


Figure 5.17: Settings of the System Data on MiCOM-P645 on MiCOM S1 Agile

On the configuration setting, we can enable the active settings group, as shown in red, while we disable the group that will not be used, as shown in Figure 5.18. The IED front display's setting menu or programmable scheme logic (PSL) can be used to change the active settings group. For example, the settings group can be changed when the device receives an input. Each of the other protections can be enabled or disabled (visible or invisible) depending on the test's requirements.

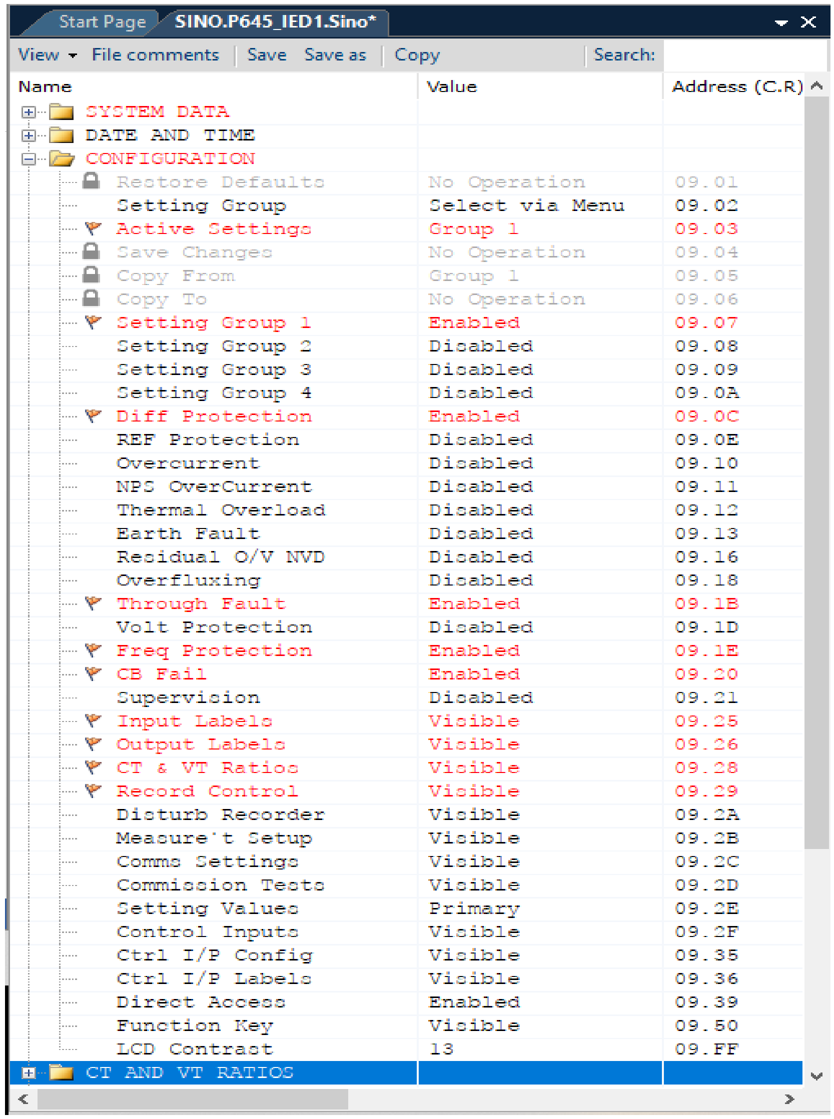


Figure 5.18: Configuration Settings file on MiCOM S1 Agile

a) Configuring the group system

Individual settings are available for each of the four setting groups. Each group comprises setting folders for different protection functions and the system settings (e.g., Earth Differential and over current) as represented in Figure 5.19 Group 1 setting.

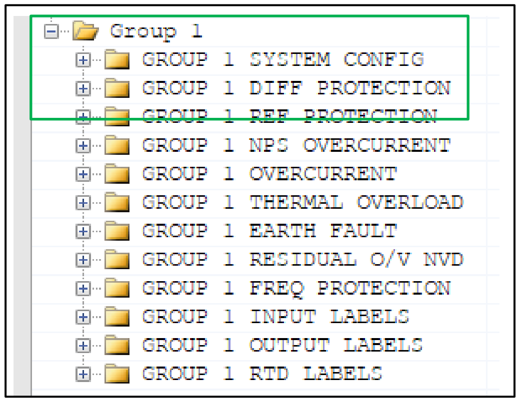


Figure 5.19: Settings for Group 1 on MiCOM S1 Agile

The transformer parameters are configured in each settings group's system configuration settings folder. Figure 5.20 shows the system configuration for Group 1 settings. A two-winding configuration was selected for group 1, voltages 110/22kV, with the rating of 56MVA, the connection of Yd11 power transformer primary and secondary, respectively. A winding might be ungrounded or grounded.

b) Transformer ratios for current and voltage

CT and voltage ratio settings of the parameters for MiCOM-P645 are shown figure. The CT primary winding is 400 and is connected to the star, while the secondary CT winding is 2000 and is connected to the delta. The voltage on the primary side is 110kV and star connected while the secondary voltage is 22kV and delta connected.

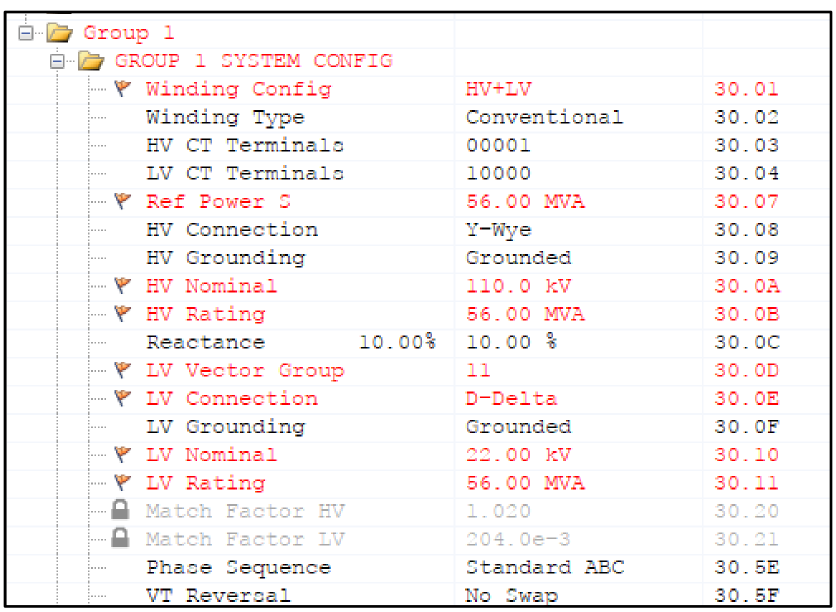
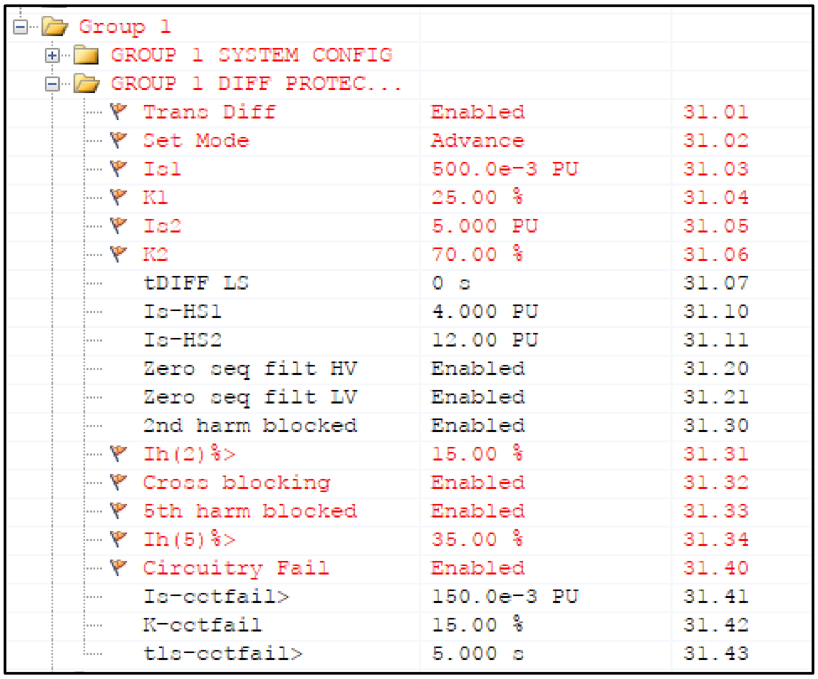


Figure 5.20: Group 1 system configuration on MiCOM S1 Agile

The transformer differential protection configuration setting for MiCOM-P645 is shown in Figure 5.21, and the edited values are shown in red.



Group 1		
GROUP 1 SYSTEM CONFIG		
GROUP 1 DIFF PROTEC...		
Trans Diff	Enabled	31.01
Set Mode	Advance	31.02
Is1	500.0e-3 PU	31.03
K1	25.00 %	31.04
Is2	5.000 PU	31.05
K2	70.00 %	31.06
tDIFF LS	0 s	31.07
Is-HS1	4.000 PU	31.10
Is-HS2	12.00 PU	31.11
Zero seq filt HV	Enabled	31.20
Zero seq filt LV	Enabled	31.21
2nd harm blocked	Enabled	31.30
Ih(2)%>	15.00 %	31.31
Cross blocking	Enabled	31.32
5th harm blocked	Enabled	31.33
Ih(5)%>	35.00 %	31.34
Circuitry Fail	Enabled	31.40
Is-cctfail>	150.0e-3 PU	31.41
K-cctfail	15.00 %	31.42
tls-cctfail>	5.000 s	31.43

Figure 5.21: Group 1 Differential protection configuration setting on MiCOM S1 Agile

5.4.2 Transformer trip logic

The trip logic of the relay is used in this research project for both IEDs SEL487E and MiCOM-P645. The transformer trip logic of the SEL487E is displayed in Figure 5.22, while Figure 5.25 displays the Transformer trip logic of the MiCOM-P645.

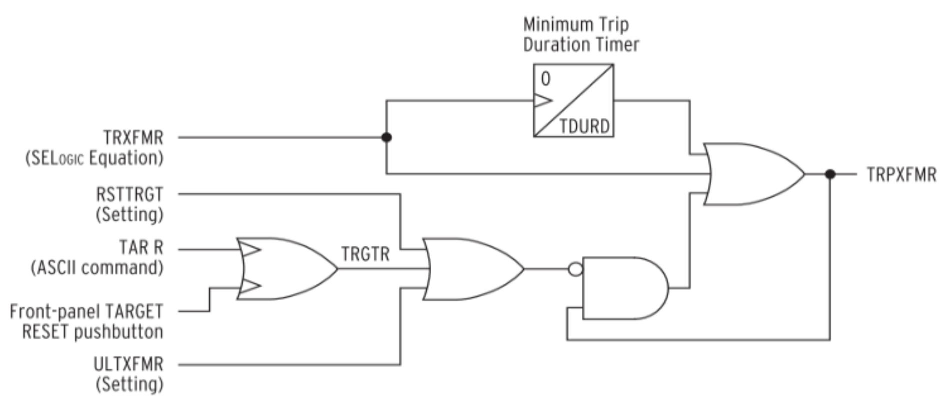


Figure 5.22: Transformer trip logic of the SEL-487E (Inc. Schweitzer Engineering Laboratories, 2020)

The transformer trip logic setting parameters of SEL487E shown in Figure 5.23 in areas A and B will be discussed further in section 7.3.3 of Chapter Seven.

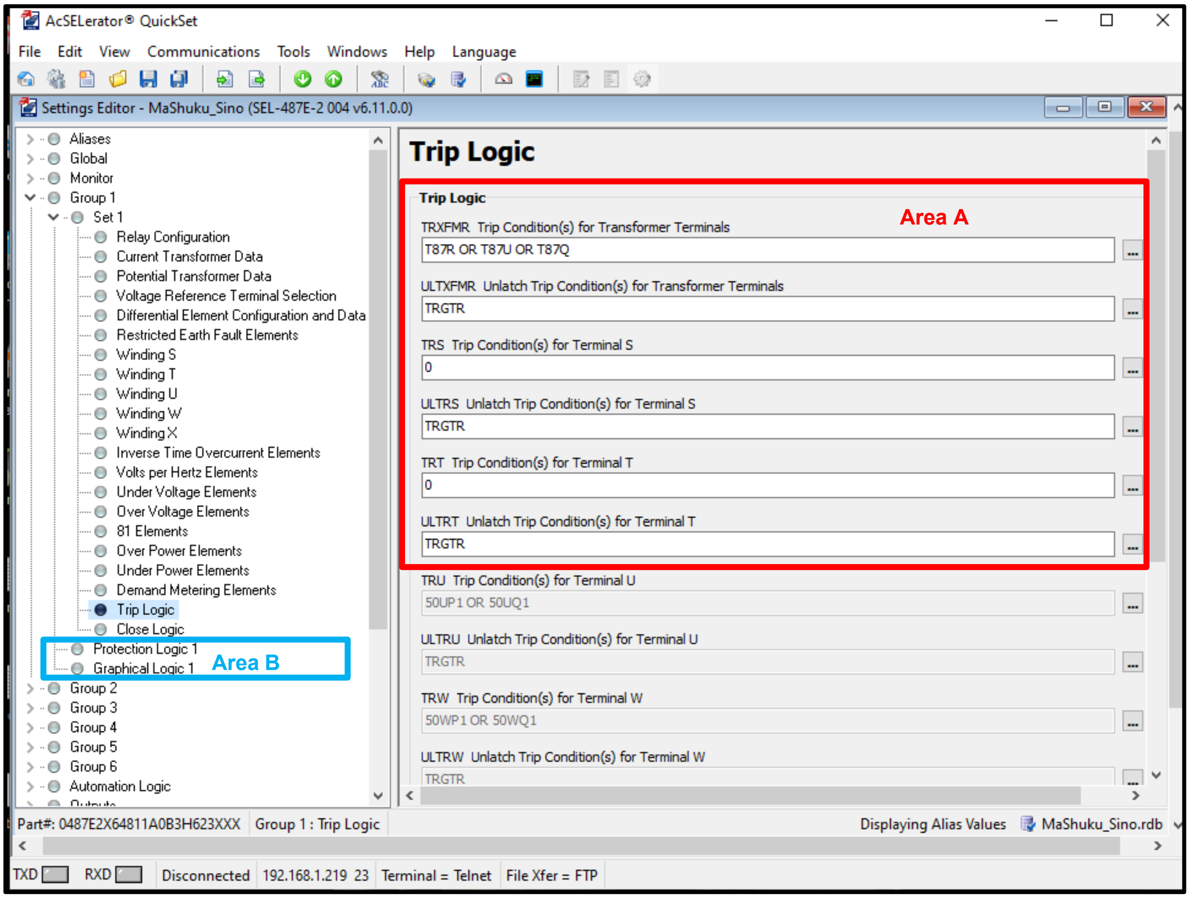


Figure 5.23: **Relay Word Bits of SEL487E on AcSELerator Quickset**

The Main Board outputs parameter setting for SEL487E is shown in Figure 5.24.

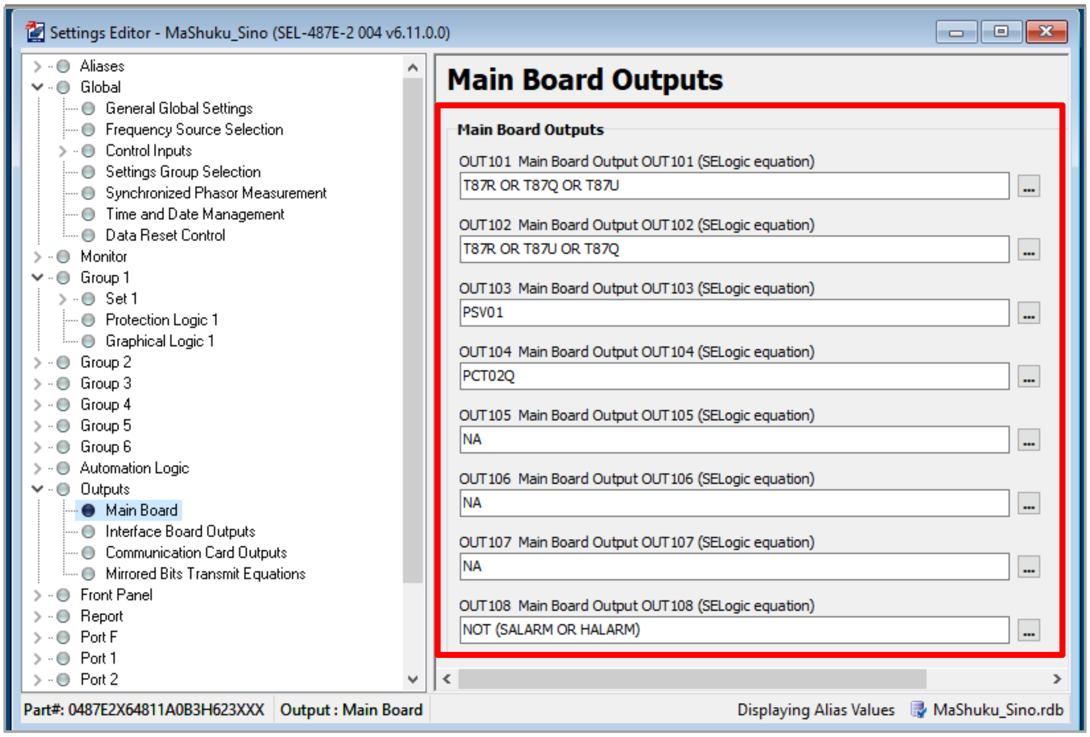


Figure 5.24: Main Board outputs for SEL487E on AcSELerator Quickset

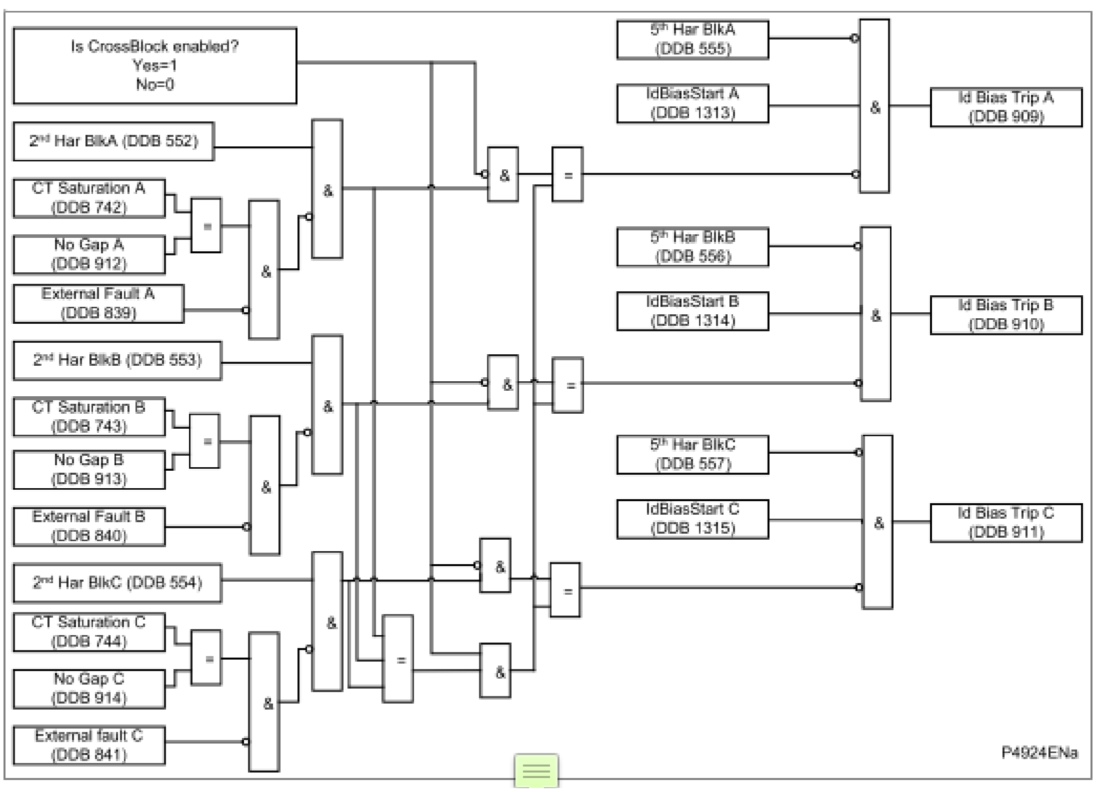


Figure 5.25: Differential biased trip logic of the MiCOM-P645 (MiCOM, 2020a)

5.5 Control Design for a Transformer Tap Changer and Circuit Breakers for parallel transformer operation

Tap Changer: Voltage regulation, or maintaining a constant voltage on the secondary side of the transformer under varying load conditions, is the primary purpose of tap changers, both on load and offload. The tap changer maintains a constant secondary side voltage while modifying the transformer's transformation ratio during operation by altering the primary winding turns. The differential protection relay must modify its sensitivity in order to compensate for the tap changer operation because it is difficult to change current transformation ratios for every tap change operation (Dube, 2016). An automatic tap changer controller is designed for a parallel power transformer system. In the RTDS/RSCAD software, the controller is designed and modelled. The following modes of the controller can be used:

- Follower or Master
- Automatic or Manual

Parallel transformers necessitate the use of Tap Changer Controller schemes. These controller schemes can function in either automatic or manual mode, offering flexibility in managing the Tap Changing process for each transformer.

In a parallel connection of two transformers, the TRF5 tap changer control serves as the master, while the TRF6 tap changer control acts as the follower, mirroring the operations of the master. When the transformers are individually connected and set to automatic mode, each controller independently manages the Tap changing process for its respective tap changer. Figure 5.26 clearly shows the TRF5 tap changer control on the RTDS/RSCAD simulation circuit, which includes the Tap Changer Control model, and the TRF6 Tap Changer Control is the same as TRF5, only the names that are different. To customize the Tap Changer Controller for the RTDS system configuration, logic functions are employed to construct a control circuit. This circuit incorporates the Tap Changer Controller Logic, enabling seamless adaptation of the tap changer controller to the specific system requirements.

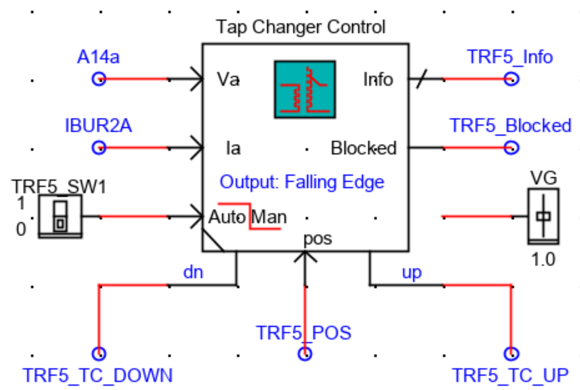


Figure 5.26: **Transformer (TRF5) RTDS Tap Changer Controller**

The transformers' parallel connection and individual operation are both represented as two different system configurations. If the condition of every circuit breaker under observation is closed (green), this means that the transformers are connected in parallel. If any circuit breakers are open, the function of the transformer is in individual mode. The truth table in Table 5.3 explains this. Figure 5.27 shows the control logic for changing the transformer between parallel to individual.

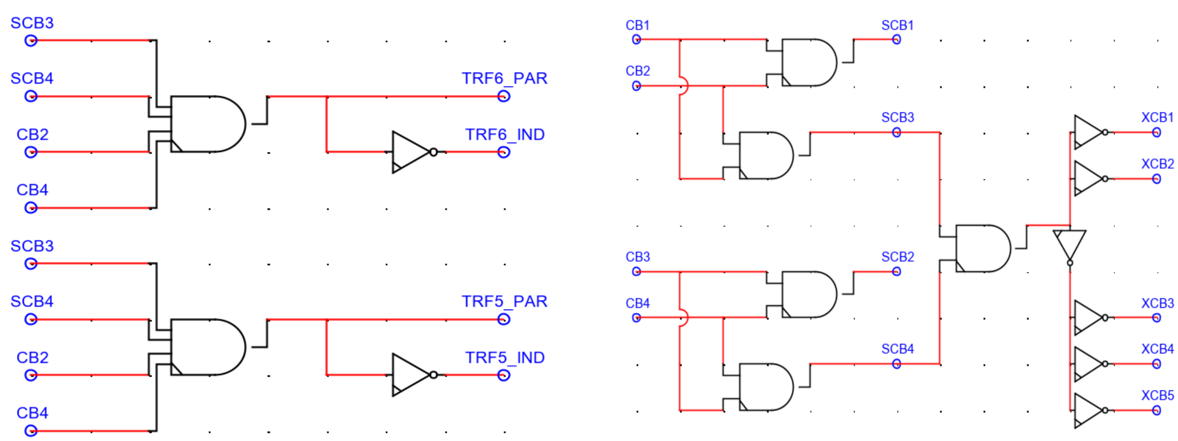


Figure 5.27: **Control logic for changing the transformer between parallel to individual**

Table 5.3: **The truth table to determine if the transformers are individually or parallel connected**

TRANSFORMERS ARE INDIVIDUALLY OR PARALLEL CONNECTED										
Transformer 5		**Transformer 6**							**Transformer output**	
CB 1	**CB 2**	**CB 3**	**CB 4**	**SCB1**	**SCB2**	**SCB3**	**SCB4**	**XCB1**	**Individual**	**Parallel**
Close	Close	Close	Close	Close	Close	Close	Close	Open	No	Yes
Open	Close	Close	Close	Open	Close	Open	Close	Close	Yes	No
Close	Open	Close	Close	Open	Close	Open	Close	Close	Yes	No
Close	Close	Open	Close	Close	Open	Close	Open	Close	Yes	No
Close	Close	Close	Open	Close	Open	Close	Open	Close	Yes	No

5.6 Logic Programming Using Graphical Logic Editor

The IED's Programmable Scheme Logic (PSL) module contains programmable logic gates and timers for creating customized internal logic. This is accomplished by combining the IED's digital inputs with internally generated digital signals and then mapping the resulting signals to the IED's digital outputs and LEDs using logic gates and timers. The PSL Editor can create and modify your application's scheme logic diagrams. Figure 5.28 shows the MiCOM-P645 PSL for transformer protection, area A shows the trip signal that has LED1 that will only illuminate when there is an internal fault on the MiCOM-P645, while in area B LED7 and LED8 will only illuminate when their circuit breaker is open for HV (CB1) and LV (CB2) respectively.

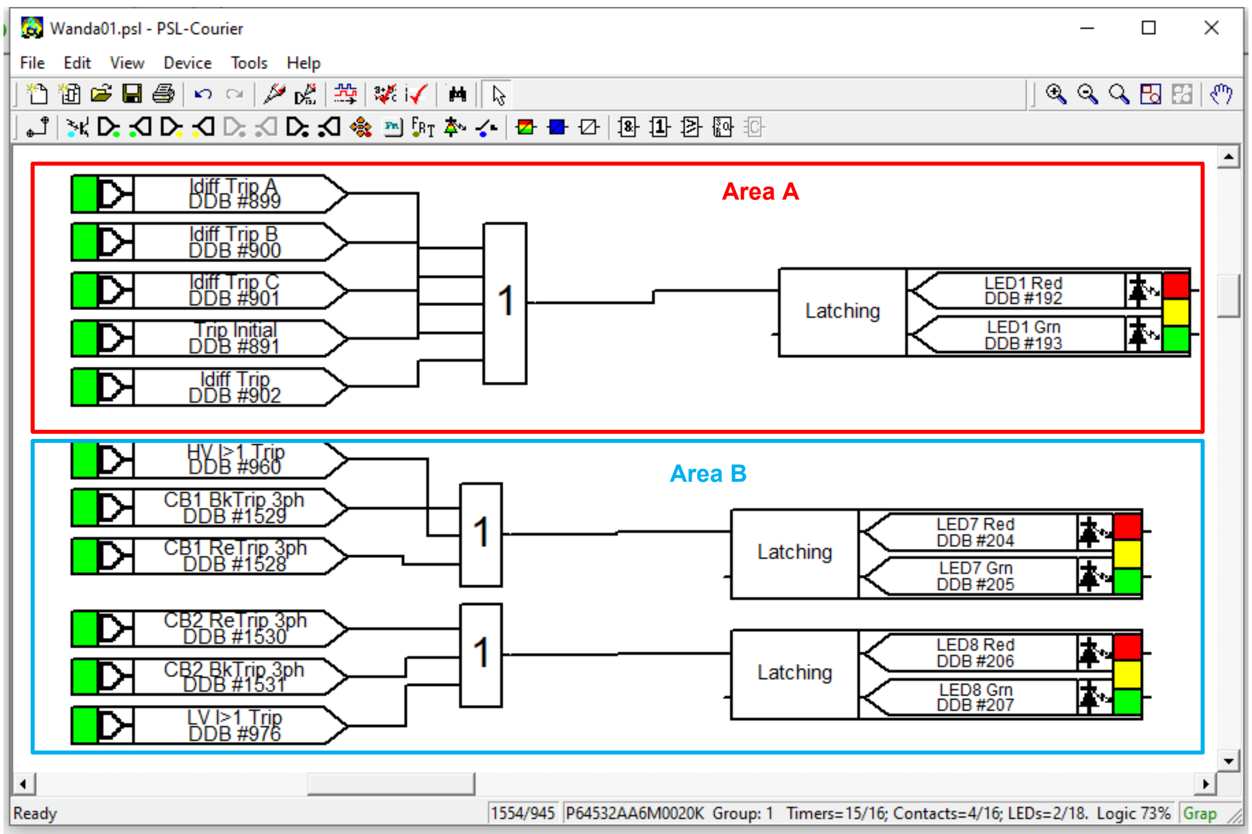


Figure 5.28: **MiCOM-P645 PSL logic diagrams for transformer protection**

5.7 Communication establishment between the Devices.'

AcSELerator Quickset and MiCOM S1 Agile is a Windows-based program provided by SEL and MiCOM that allows users to interact with relays via a communication link. These programs are used to create, upload, and retrieve relay settings from any relay connected to a computer via serial connection or Ethernet. To ensure proper configuration, the IP address domain of the computer's communication port should align with the IP address domain of the IED. The computer communication port must be properly configured to communicate with the IED numerical relay. The theory of the software communication of these two IEDs has been discussed in Chapter Four, section 4.5.

5.7.1 SEL-487E IED

Through the Human Machine Interface (HMI), AcSELerator Quickset is also used to analyse substation events recorded by the relay, meter logs, etc. Figure 5.29 shows the SEL-487E IED's communication settings. After establishing a reliable communication link, the user has the capability to modify, access, and store settings on the SEL-487E relay. Area A is where you can put the IP address and port number. In area B, you put the user name and the level one and level two passwords, and you can press apply then ok; the SEL manual has the password.

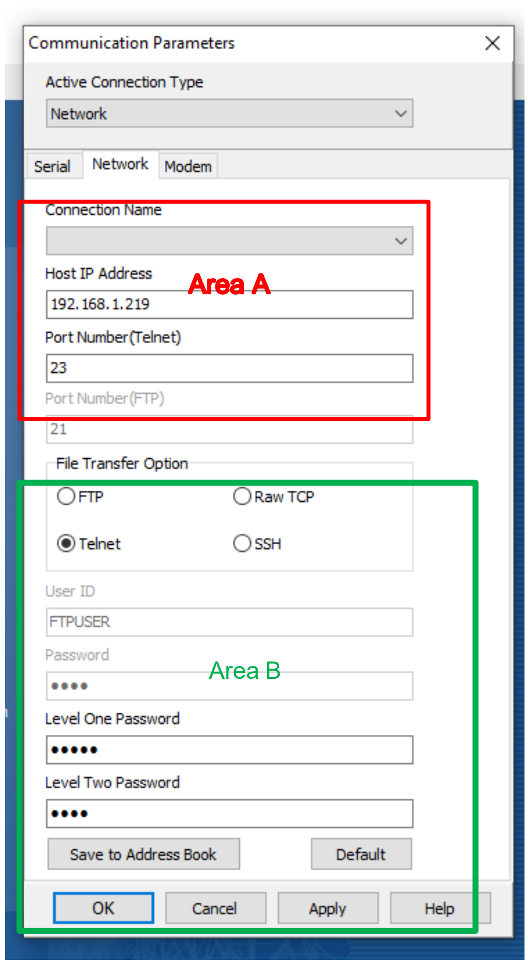


Figure 5.29: **Communication parameter setting for SEL-487E on AcSELerator Quickset**

5.7.2 MiCOM- P645 IEDs

Different tools are available in the Alstom Grid MiCOM S1 Agile software version to manage the MiCOM devices. The start page's folders contain the tools. Figure 5.30 shows the communication setting for MiCOM- P645 IED. Once a valid communication link has been established, the user gains the ability to modify, retrieve, and store settings on the MiCOM-P645 relay. The red indicates the device IP address with the relay address and the port number; then, you can press finish to send the setting to the IED.

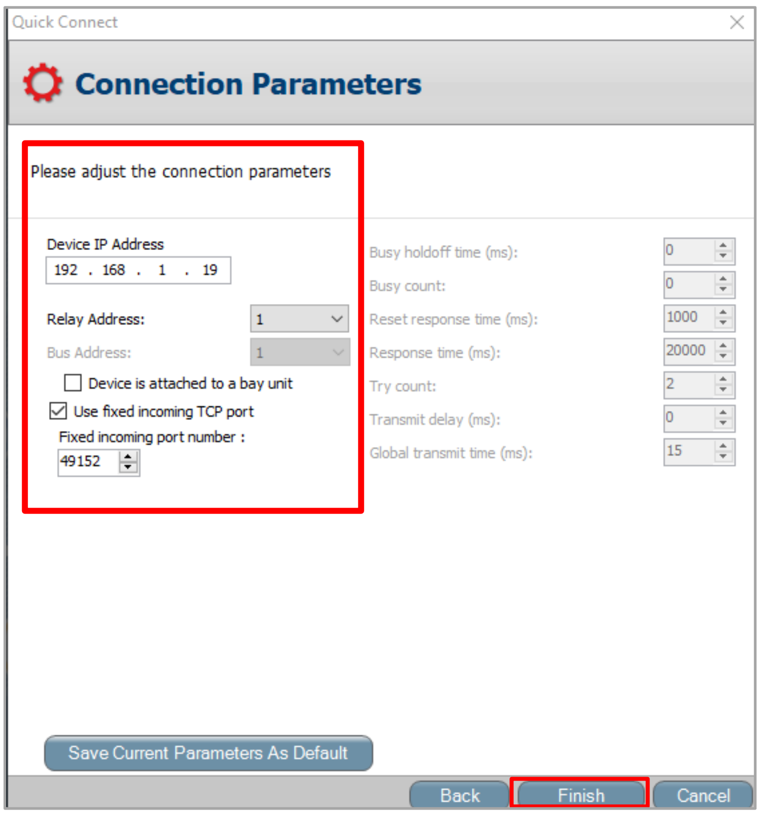


Figure 5.30: **Communication parameter setting for MiCOM- P645 on MiCOM S1 Agile**

5.7.3 Configuring the laptop to connect to multiple IEDs and RTDS via a switch

Once the physical connection between the two-transformer protection IED, OMICRON device (CMS 356 and CMS 156), Ethernet Switch, and RTDS is completed, a physical connection via a switch and the personal computer (PC) loaded with the software also needs to be added. When all physical connections between the IEDs and a PC via a switch are established, the network connection on the PC needs to be configured using the same steps as a direct point-to-point connection. Since the two IEDs are now connected to the PC via a switch together with RTDS, as can be seen in Figure 4.1, and their IP addresses are shown in Table 4.5. Using the ping command to test connectivity between the PC, RTDS, and IEDs through a switch. Figure 5.31 and Figure 5.32 display the results of the ping command.

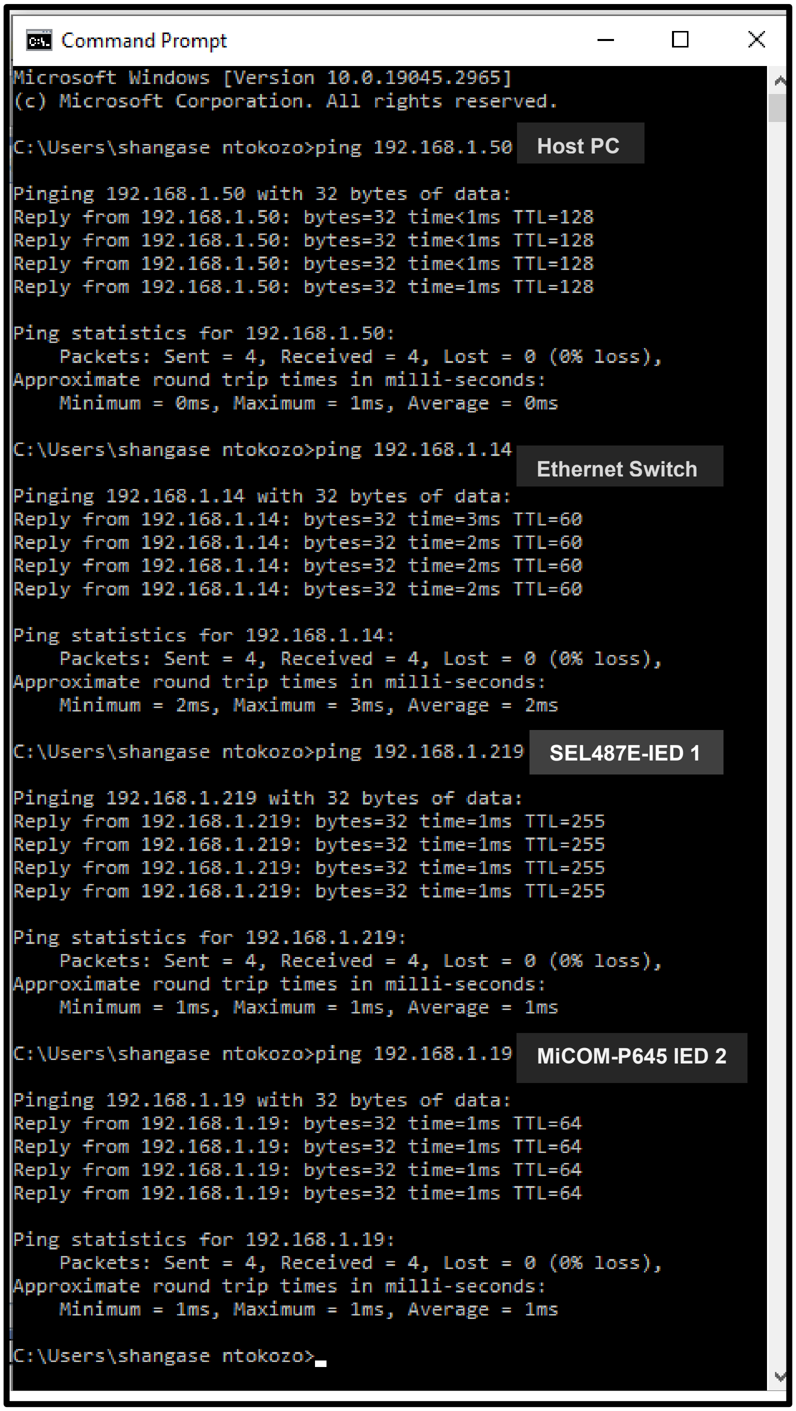


Figure 5.31: Ping command for the switch-based connection between the SEL487E IED 1, MiCOM-P645 IED 2, and host PC

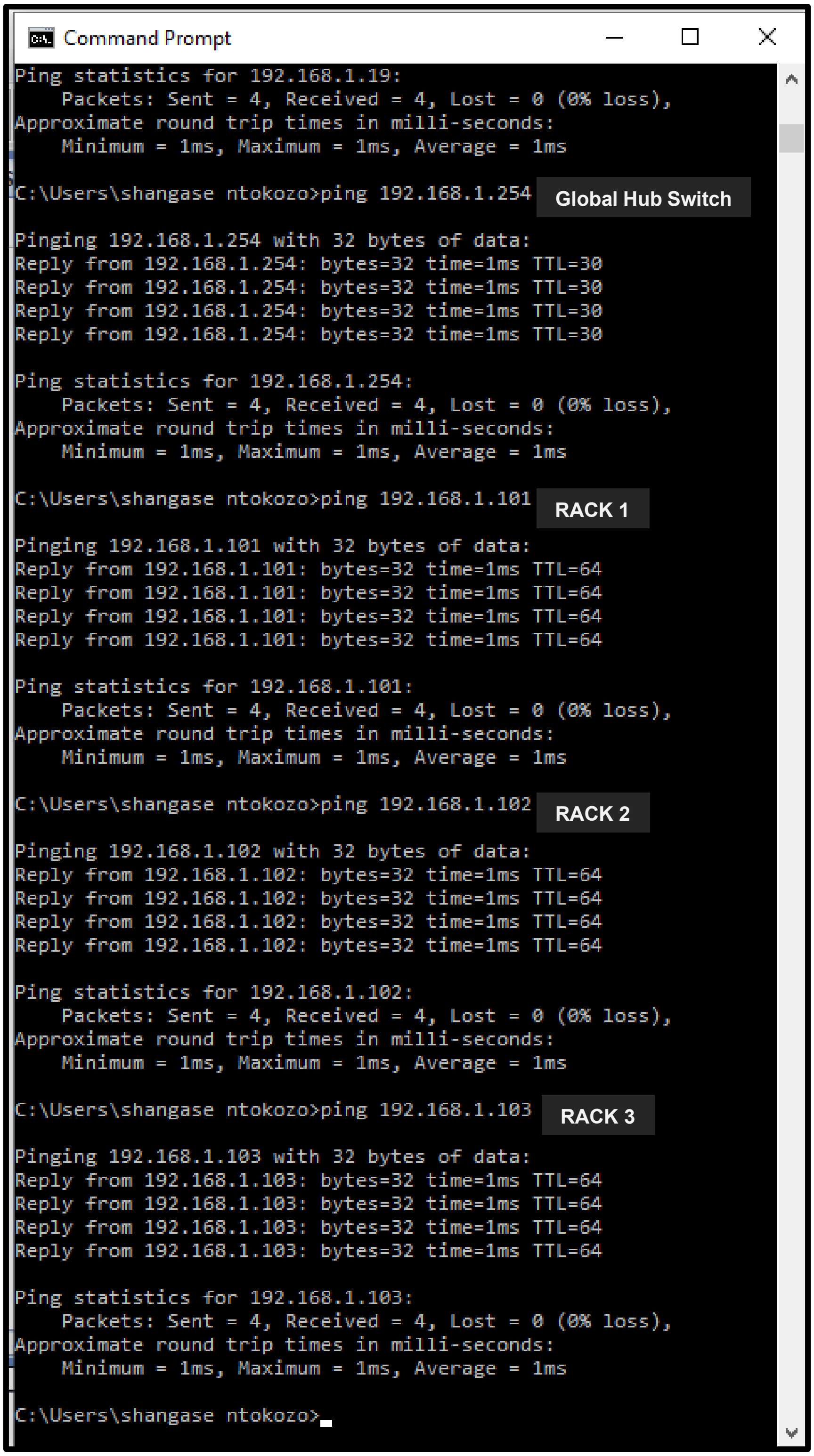


Figure 5.32: Ping command for the RTDS rack 1, RTDS rack 2, and RTDS rack 3 connected through a switch to the PC

5.7.4 Connecting the CMS 356 to a computer

CMS 356 communicates with a computer through the Ethernet network interface (ETH1 or ETH2), USB, or Wi-Fi. The ports are located at the rear of CMS 356. To connect CMS 356 to the controlling computer using the Ethernet interface, you may consider one of two possibilities:

- Connect CMS 356 directly to the controlling computer Ethernet port.
- Connect CMS 356 and the controlling computer Ethernet port to the Ethernet network.

Opening the CMS 356 web interface by launching the OMICRON Device Link will automatically find CMS 356. A green vertical bar indicates that the OMICRON Device Link successfully connected to the CMS 356 as shown in Figure 5.33 area B. Select your CMS 356 and click Open web interface. The start page of the CMS 356 web interface opens from the internet. The web interface comprises Configuration, Status, Discovery, Network, System, and Help pages. In area A Figure 5.33 shows the Ping command for the CMS 356 connected through a switch to the PC.

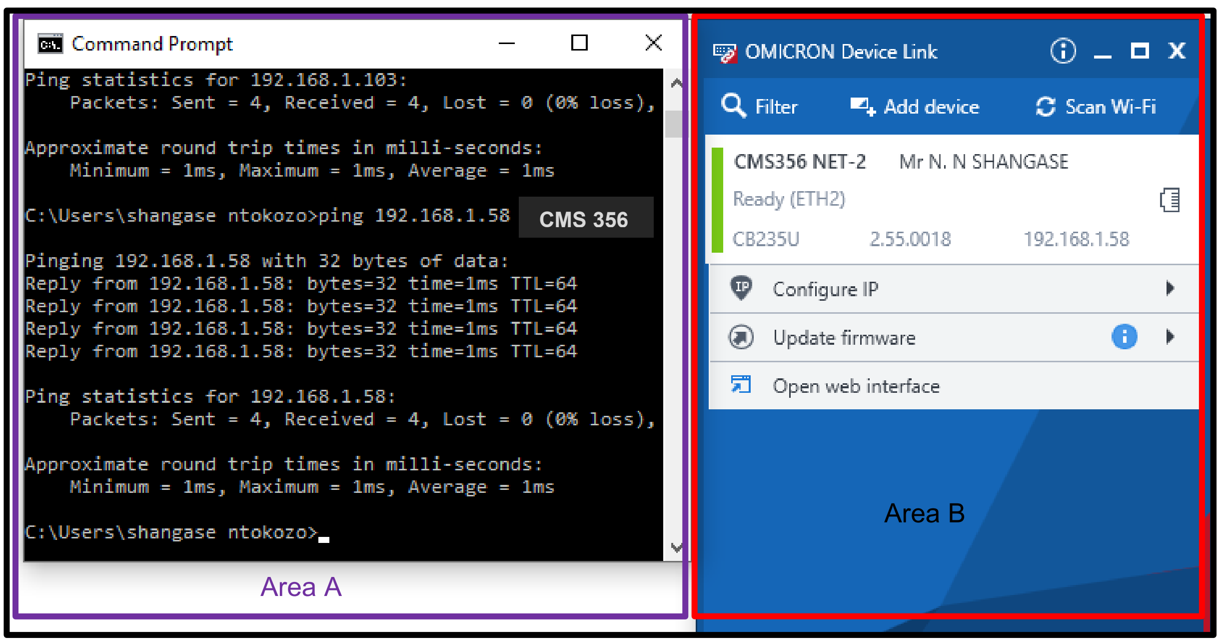


Figure 5.33: Ping command for the CMS 356 connected through a switch to the PC and Omicron Device Link status

5.8 Discussion and Conclusion

In this chapter, the configuration settings of the systems were done from calculations, modelling, and settings of the system parameters. The transformer differential protection function protection for SEL487E IED and MiCOM-P645 IED was configured in this chapter. Both differential test modules have a full description of the test object parameters as well as configuration hardware information. Figure 4.1 illustrates the test bench setup utilized to evaluate the current differential functionalities of the protective relaying systems, namely the SEL-487E and MiCOM-P645. In the subsequent chapter, the fully configured protection scheme for the interconnected system will undergo testing and simulation.

The next chapter (Chapter Six) will focus on testing/simulation and results on the network system functionality, like focusing on different cases such as testing Normal Operation for Parallel or Individual transformers. Testing the tap changer controllers' Master-Follower scheme and Hard-wire Hardware-In-Loop development for the modified IEEE 9-bus system network for different faults.

CHAPTER SIX

SIMULATION RESULTS OF THE TRANSFORMER PROTECTION IN HARDWARE IN THE LOOP

6.1 Introduction

This chapter analyses the HIL protection scheme simulation for the parallel transformer's current differential relay utilizing a hard-wire trip signal and real-time data (RTDS). The modified IEEE 9-Bus system network, constructed and modelled in the RSCAD environment, was used to implement the hardware-in-the-loop experiments. The implementation of the hardware-in-the-loop (HIL) technique for parallel transformer differential protection involving the utilization of RTDS, MiCOM-P645, and SEL-487E relay systems is a complex and advanced method for testing and validating the performance of protection schemes for power transformers. The RTDS Inputs make a range of faults easier to apply.

When a fault occurs, a relay detects the fault using simulated current signals sent through the simulator's analogue outputs. After the fault is detected, the relay sends a trip signal to the relevant circuit breaker, which is simulated in the RTDS. In this study, two methods are employed to send the trip signal from the relays to the RTDS: traditional hardwired connections and GOOSE messages. However, in this chapter, we will focus on the traditional hardwired trip method.

MiCOM-P645 and SEL-487E are two externally deployed IEDs used for differential current transformer protection. They are configured to send a trip signal to the RTDS and are connected in a closed-loop configuration. These two relay schemes were chosen for the research because they are advanced numerical relays commonly utilized in power systems for various protection and control functions. They come equipped with advanced communication capabilities for remote monitoring and control, including transformer protection, as well as other protective functions (Wickremasuriya, 2016).

Since we are investigating the different vendors on a parallel transformer system, the RTDS models and simulates a system of two paralleled 56MVA 110/22kV Yd11 power transformers. Figure 4.4 shows the section of the two parallel transformers of the modified IEEE 9-bus system. When two power transformers are linked in parallel, they share the load.

6.2 The simulation cases are executed using RSCAD Runtime

The RTDS is used to simulate normal operation for parallel or individual transformers and to determine whether the tap changer controller operates correctly for various system configurations. The system is simulated through two approaches: one where the transformers are interconnected in a parallel configuration, and another where they function independently. Two simulation cases are simulated before connecting the external IED relay, and Table 6.1 shows the simulation summary for Case 1, Normal Operation for Parallel or Individual Transformers. Table 6.2 shows the simulation summary for Case 2 for the Master-Follower scheme.

The interactive square symbol in the SLD RSCAD/RunTime indicates a Circuit Breaker (CB) as shown in Figure 6.1. A green square indicates a closed CB. A red square represents a CB with an open status. The CB is controlled by push buttons that open and close.

Table 6.1: **Simulation for Case 1 Normal Operation for Parallel or Individual Transformer**

Case 1	Scenario
Aim	Test Normal Operation for Parallel and Individual transformers while ensuring the CT current values remain the same.
Method	1. Run the simulation on Runtime while opening and closing the transformer 5 (TRF5) and transformer 6 (TRF6) circuit breakers. 2. Utilize the logic to identify whether both transformers are linked individually or parallel and evaluate the logic's accuracy while monitoring the network's currents and voltages.
Expected Results	1. The system network voltages and currents must always be approximately the same on parallel or individual mode transformers. 2. The circuit breaker's status must be correctly determined whether the transformers are used individually or in parallel.

Table 6.2: **Summary of Simulation for Case 2 for the Master-Follower Scheme**

Case 2	Scenario
Aim	Test the tap changer controllers' Master-Follower scheme.
Method	1. Establish a parallel connection between transformer 5 (TRF5) and transformer 6 (TRF6) by closing all circuit breakers. TRF5 assumes the role of the master, while TRF6 acts as the follower. Verify that TRF6 correctly following the tap changer operations performed by TRF5. 2. Disconnect TRF6 by opening CB4, and observe the results of the operation of the tap changer in manual and automatic modes. 3. Disconnect TRF5 by opening CB2, and observe the results of the operation of the tap changer in manual and automatic modes.
Expected Results	1. When they are connected in parallel, TRF6 adheres to the controller operations of TRF5.

	2. In automatic mode, each transformer operates under independent control by its respective controller. 3. When the transformer is in manual mode, push buttons individually control each one.

Once case 1 and case 2 have been simulated as explained in Table 6.1 and Table 6.2 respectively, the external IED relay can be connected. Table 6.3 shows the simulation summary for Hard-wire HIL development Case 3. Table 6.4 shows the simulation summary for Case 4 for Analysis of the transformers inrush current.

Table 6.3: **Case 3 Simulation Summary for Hard-wire Hardware-In-Loop Development**

Case 3	Scenario
Aim	Test Hard-wire HIL. This approach establishes a connection between the RTDS and hardware devices like protection IEDs, enabling functionality testing and the execution of closed-loop operations.
Method	1. Configuration of the CMS 156 and CMS 356. Do the calculation of the GTAO SCALING FACTORS to make sure that the output of CMS is the same as the calculated current. 2. Connect protection IEDs (SEL-487E and MiCOM-P645). 3. Run the simulation on the RSCAD and simulate different types of faults.
Expected Results	1. The protection IED should read the same current as calculated and as shown on the RSCAD runtime CTs. 2. Both transformers must not trip during the simulation of external fault. 3. Only the specified transformer should trip and open the specific circuit breaker during the internal simulation fault, using the Fault control logic as displayed in Figure 6.12.

Table 6.4: **Summary of simulation for Case 4 for Analysis of the transformers inrush current**

Case 4	Scenario
Aim	Test the inrush current of the parallel transformers.
Method	1. De-energise the transformer by opening the circuit breaker (E.g., CB3). 2. Re-energise the transformer by closing the circuit breaker (E.g., CB3).
Expected Results	1. Residual flux must be lower than normal, while the magnetizing current must be approximately zero during the de-energise transformer. 2. During this re-energisation of the transformer, the B-H loop must saturate.

6.3 Utilizing RSCAD Runtime to run the simulation cases results

The simulations are conducted to assess the correct functioning of the designed controller for automatic tap changers in a parallel power transformer system.

6.3.1 Simulation results of the Parallel or Individual transformer

The simulations are carried out to check the functionality of the designed control logic for a system of parallel power transformers. The logic control circuit shown in Figure 5.27 is used in Simulation Case 1 to automate the evaluation of the individual or parallel status of the two transformers. Monitoring and controlling the circuit breakers to see if the logic circuit correctly determines whether the status is individual or parallel allows the logic circuit to be tested.

The statuses of the TRF5 circuit breakers (CB1 and CB2), TRF6 circuit breakers (CB3 and CB4), and the Section Bus circuit breakers (SCB1 to SCB4) are used to determine whether the transformers are connected in individual or parallel. Figure 6.1 shows that all circuit breakers are green (closed), which means the system is in parallel status.

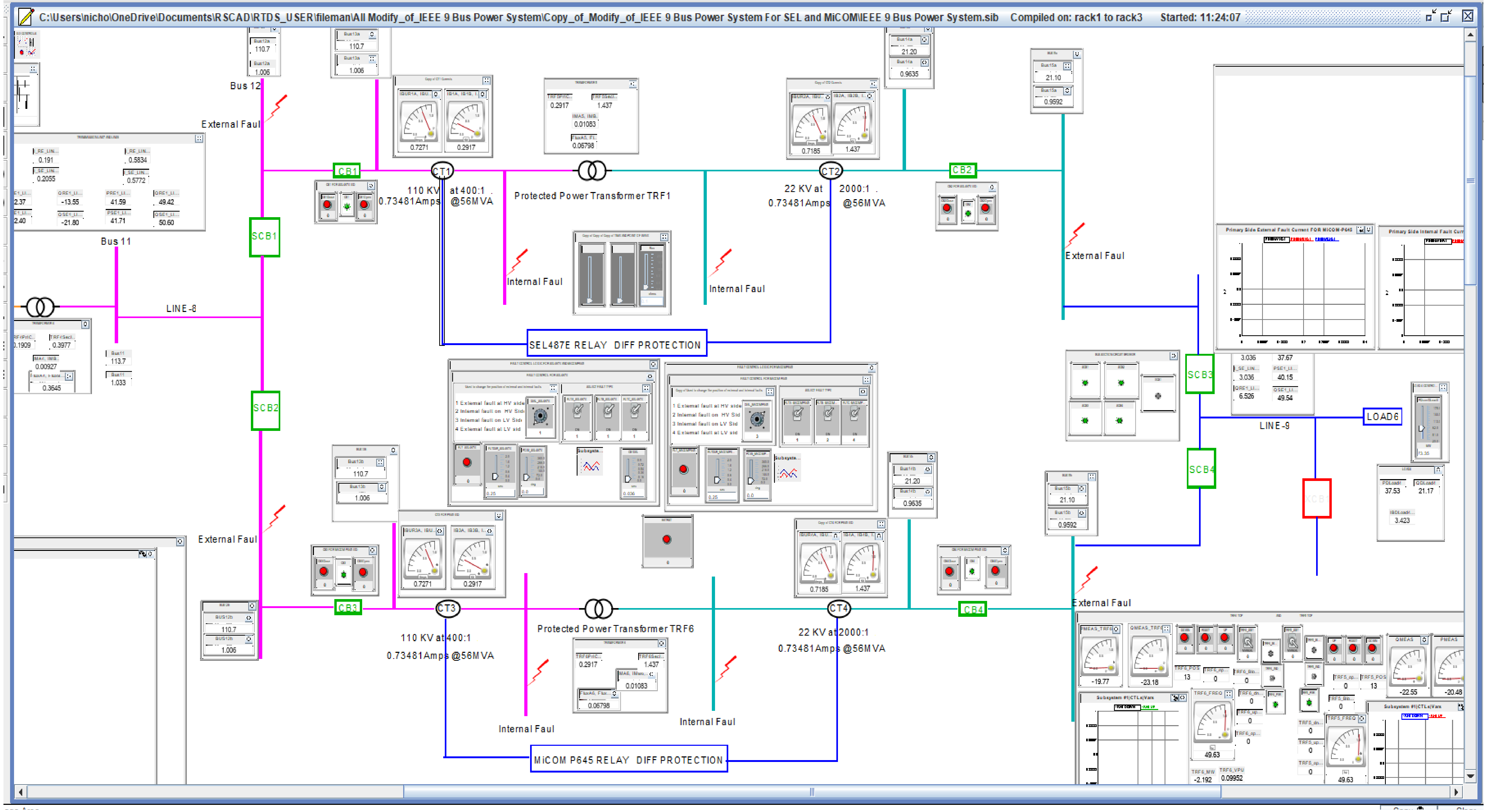


Figure 6.1: Parallel system, all circuit breakers are closed (green status)

6.3.2 In parallel transformer modem

During the normal operation of a parallel transformer, Figure 6.2 shows that all circuit breakers are high while TRF5_IND and TRF6_IND are low; this proves that the system is in parallel mode.

Figure 6.2: **Transformers in parallel mode and all circuit breakers are closed**

6.3.3 Individual transformer mode

During the individual transformer mode, we will open the circuit breaker of any of the transformers. The aim is to see if the remaining transformer will maintain its voltage and current values while the load remains unchanged.

6.3.3.1 Operating transformer 5

When CB4 is open, TRF5 is working, while TRF6 is not. Figure 6.3 shows that the TRF5 CBs are all green (closed) while the TRF6 CB4, SCB2, and SCB4 are red (open), indicating that the transformer is working individually. While on Figure 6.4 shows that the signals of CB4, SCB2, SCB4, TRF5_PAR, and TRF6_ PAR is all low (zero), while XCB1, TRF5_IND, and TRF6_IND are all high (1). Figure 6.5 shows what happens to the signals when CB4 has closed again.

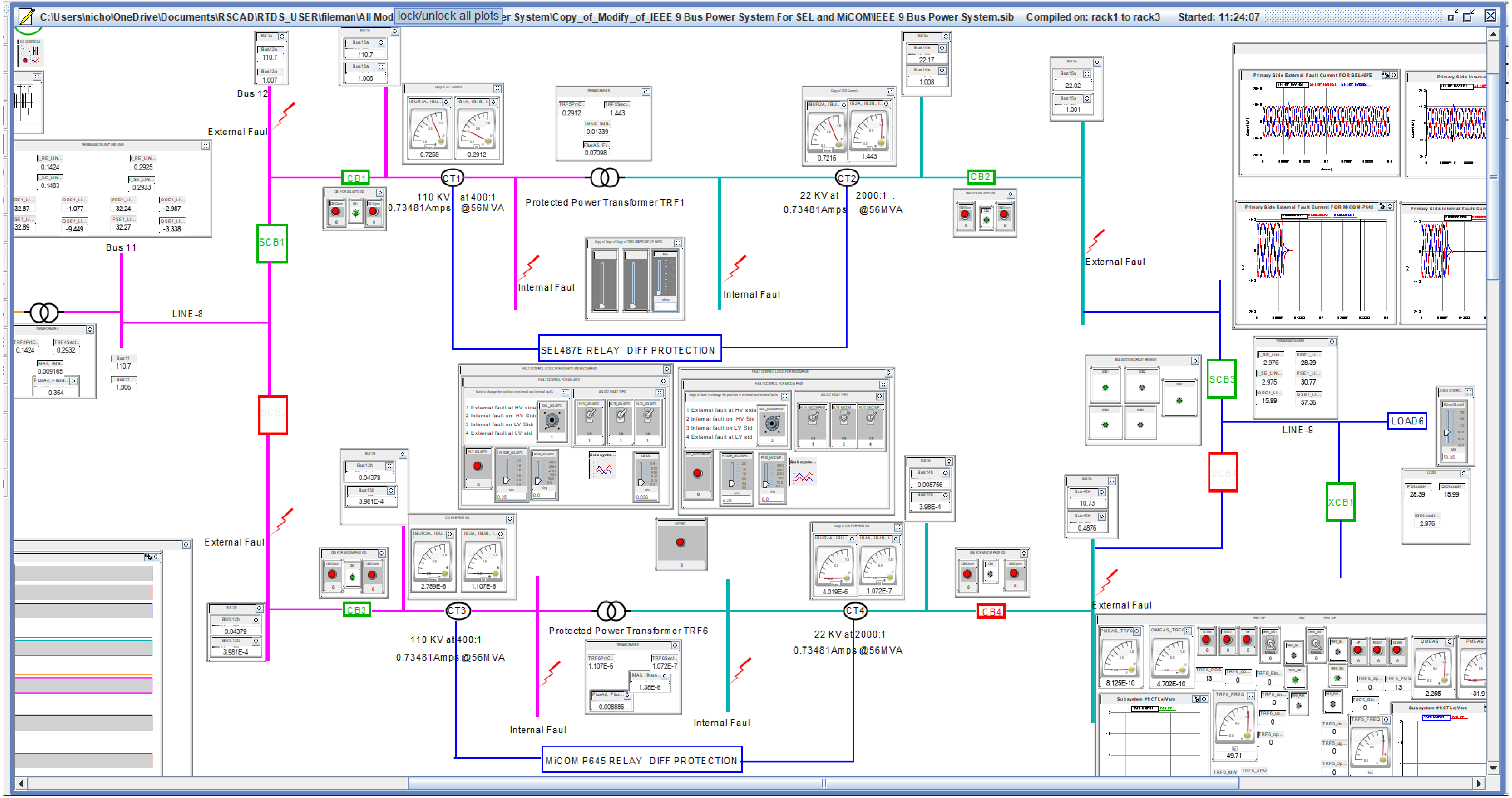


Figure 6.3: Transformer 6 not operating (CB4 opened indicated in red)

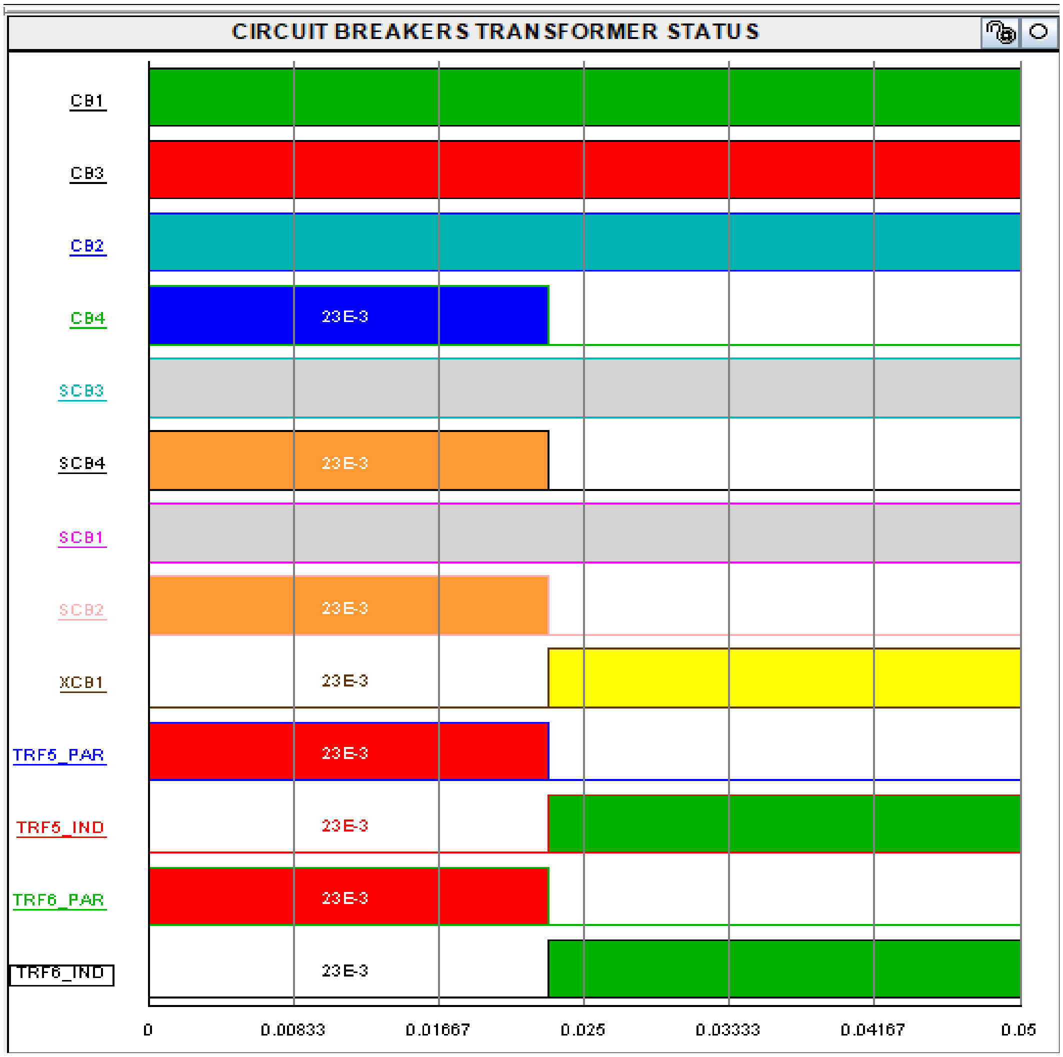


Figure 6.4: Signals when CB4 is open

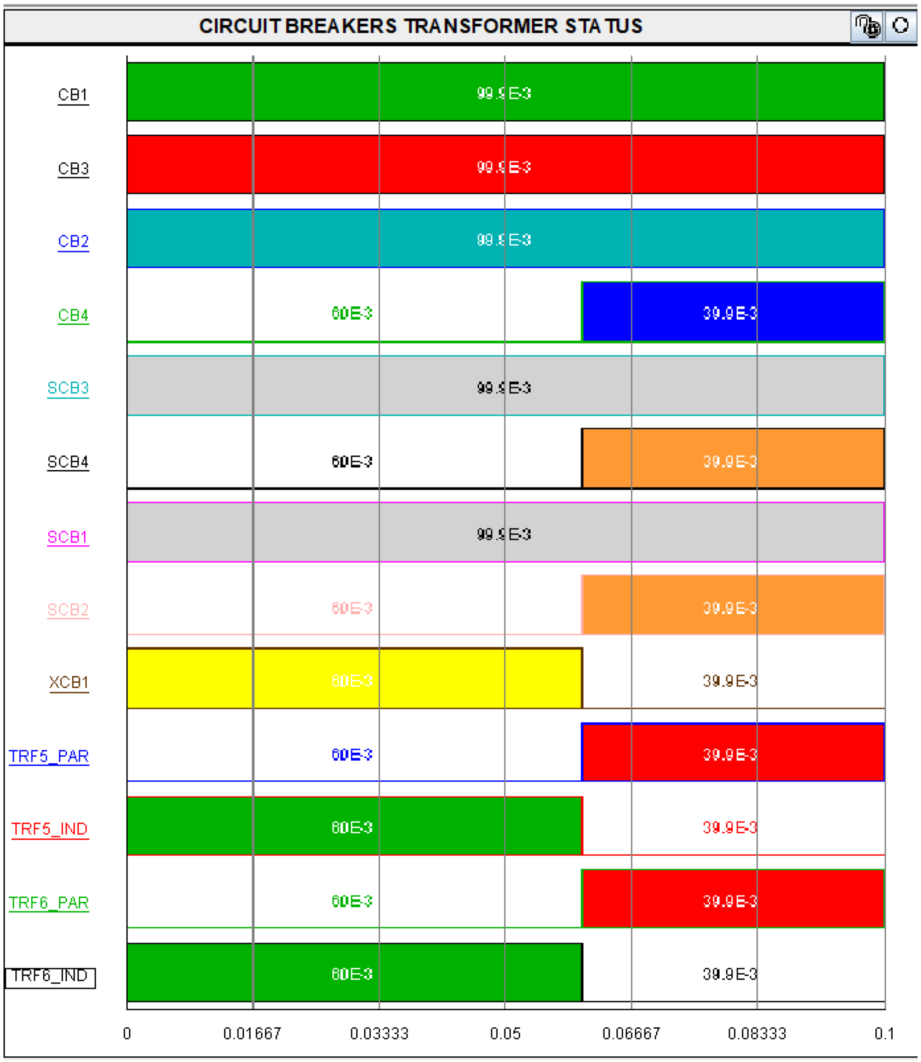


Figure 6.5: Signals when CB4 is closed

6.3.3.2 Operating transformer 6

When CB2 is open, transformer 6 is in operation while Transformer 5 is not working, as it can be seen in Figure 6.6 that the TRF6 CBs are all green (closed) while the TRF5 CB2, SCB1, and SCB3 are red (open) indicating that the transformer is working as an individual. As can be seen in Figure 6.7 the signal of CB2, SCB1, SCB3, TRF5_PAR, and TRF6_ PAR are all low (zero), while XCB1, TRF5_IND, and TRF6_IND are all high (1). Figure 6.8 shows what happens to the signals when CB2 has closed again.

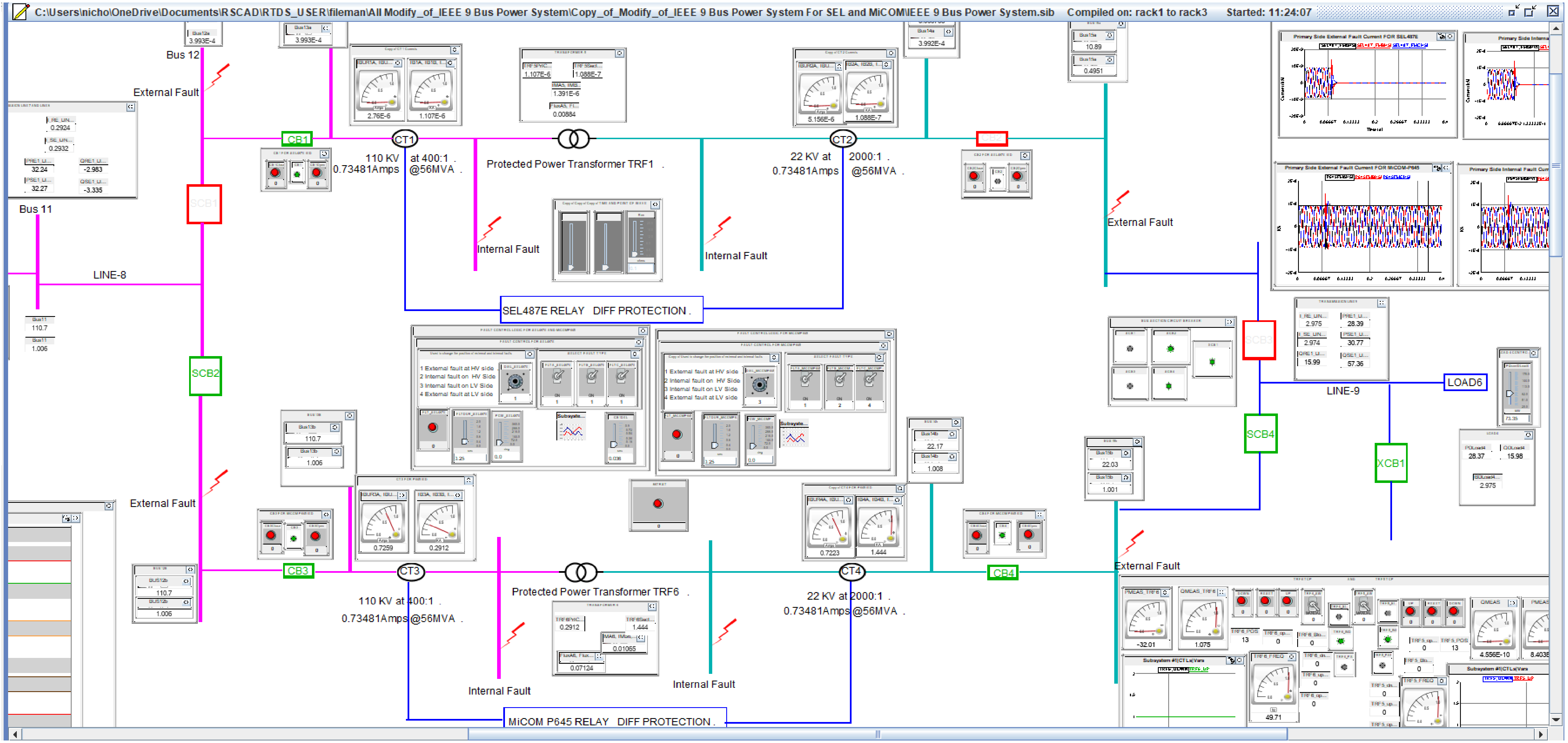


Figure 6.6: Transformer 5 not operating (CB2 opened indicated in red)

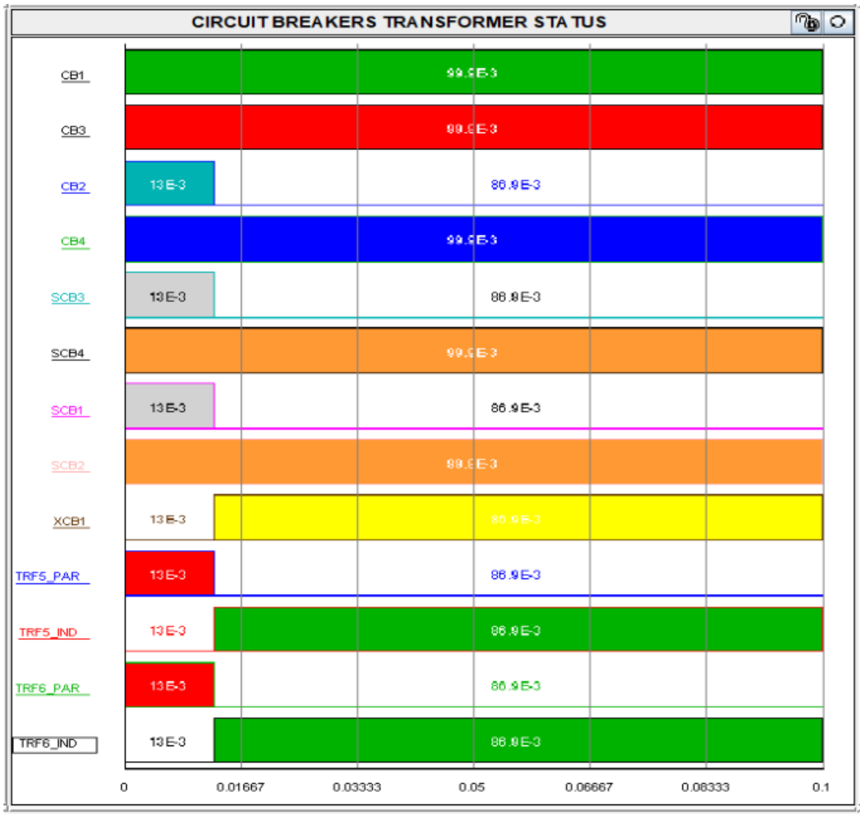


Figure 6.7: Signals when CB2 is open

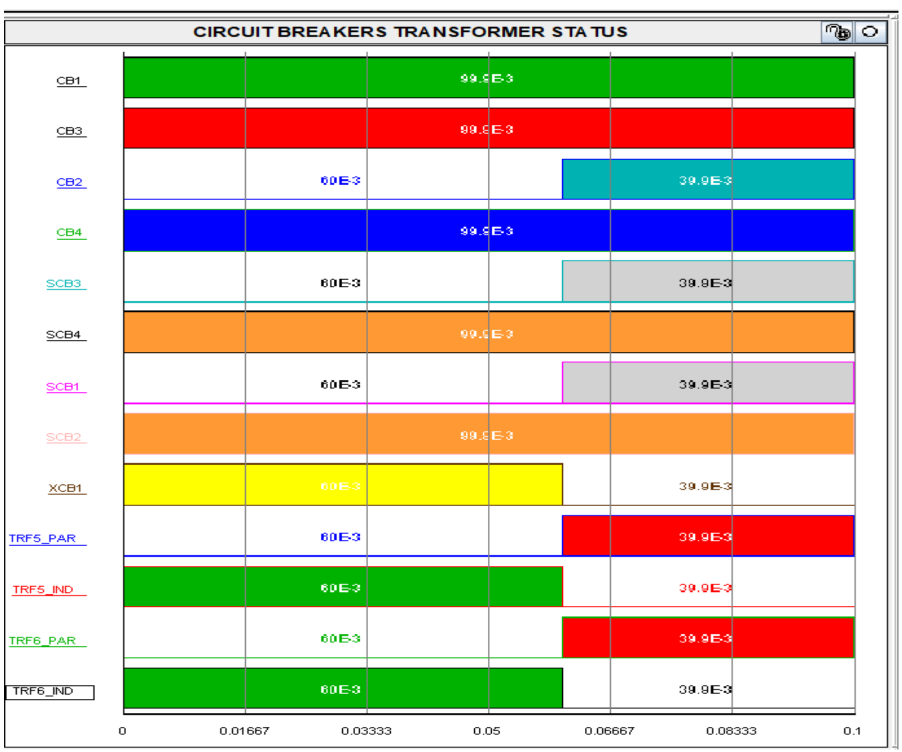


Figure 6.8: Signals when CB2 is closed

Table 6.5 below shows the calculated parameters with the simulated currents and voltages of transformer 5 (TRF5) and transformer 6 (TRF6).

Table 6.5: **The simulated values vs. the calculated parameters**

Transformer 5 (TRF5)			Original		Transformer 6 (TRF6)	
	Measured Values		Calculated Values			Measured Values
I_{TRF5_HV}	0.721A		0.73481A		I_{TRF6_HV}	0.721A
I_{TRF5_HV}	0.2921KA		0.2939238 KA		I_{TRF6_HV}	0.2921KA
I_{TRF5_LV}	0.7221A		0.73481 A		I_{TRF6_LV}	0.7221A
I_{TRF5_LV}	1.45 KA		1.46962 KA		I_{TRF6_LV}	1.45 KA
V_{TRF5_HV}	109.5 KV		110.0 KV		V_{TRF6_HV}	109.5 KV
V_{TRF5_LV}	21.45 KV		22.0 KV		V_{TRF6_LV}	21.45 KV

6.3.4 Tap changer controller mode Master-Follower Simulation Control Methods for Transformers Working in Parallel results

In simulation Case 2, parallel connected transformers operate as a master-follower system. Tap changer controllers are used to regulate the voltage output of transformers by adjusting the tap positions on their winding connections. TRF5 and TRF6 have two switches (TRF5 SW1 and TRF6 SW1), respectively, that can be used to switch between Automatic and Manual modes. When the input signal SW1 is set to a high state, the switch is in Automatic mode. In Manual mode, the tap change controller can receive up or down commands through push buttons.

Figure 6.9 illustrates how the TRF5 controller will control its tap changer on an individual basis when the TRF5 and TRF6 are not parallel connected. The TRF5 controller is in an automatic mode; as can be seen, the TRF5_SW1 is high while the TRF5_UP is also high.

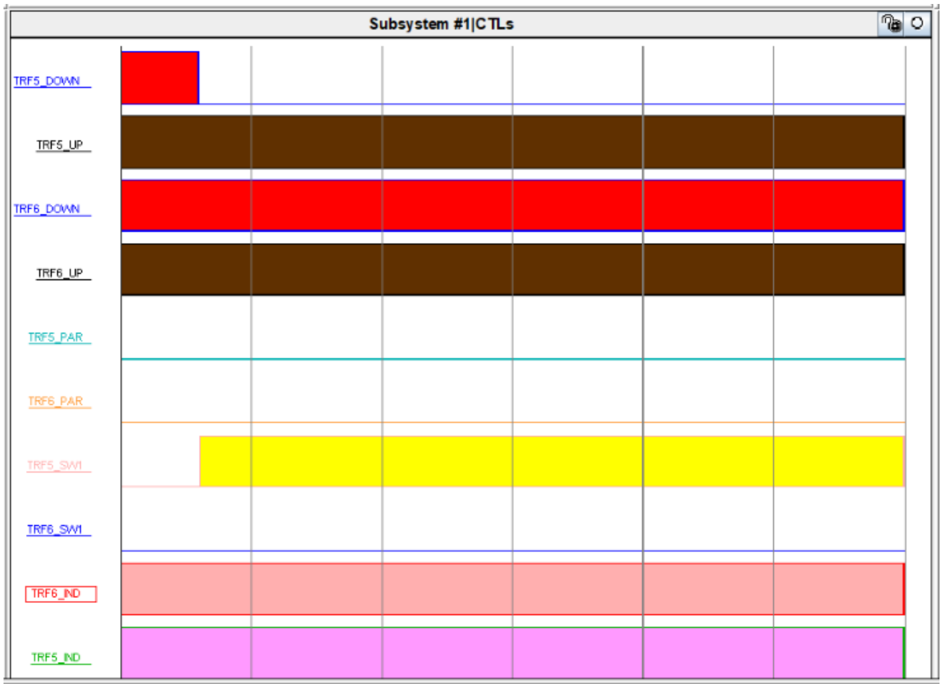


Figure 6.9: **Individual operation Transformer 5, in automatic mode switch where CB4 is open**

Figure 6.10 shows when the TRF5 is connected individually and operating in manual mode, its tap changer is controlled independently by the TRF5 controller. The signals TRF5_SW1 are now low, while the TRF5_UP is also low.

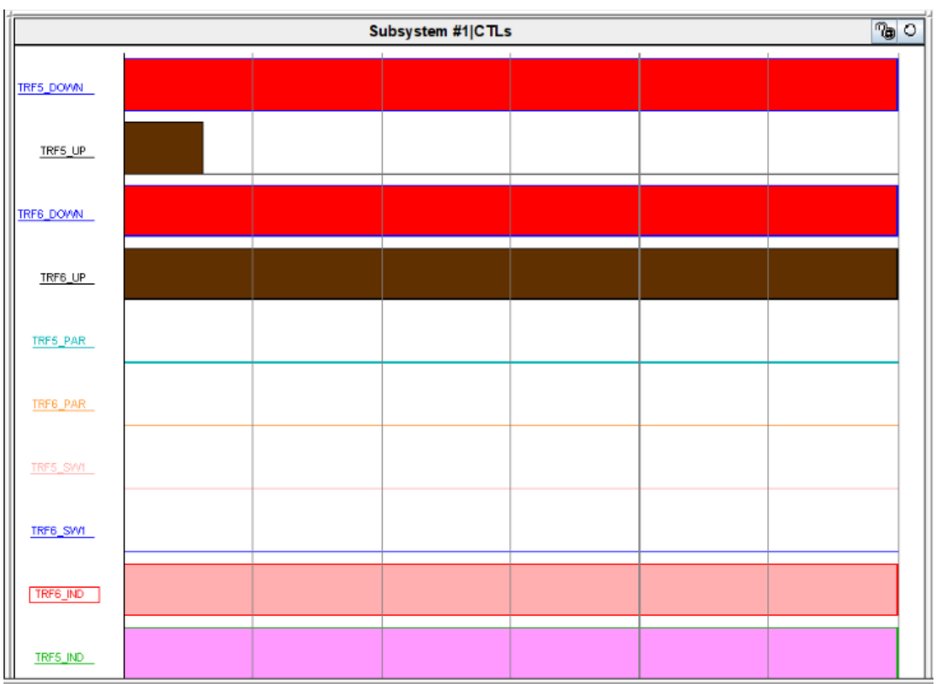


Figure 6.10: **Individual operation Transformer 5, in manual mode switch where CB4 is open**

When the transformers are parallel connected, TRF5 will be the Master, and TRF6 will follow the controller operation of TRF5. Figure 6.11 illustrates the signals of the parallel connected transformer. As can be seen in Figure 6.11, now the TRF5_IND and TRF6_IND are low to show that the system is not parallel connected.

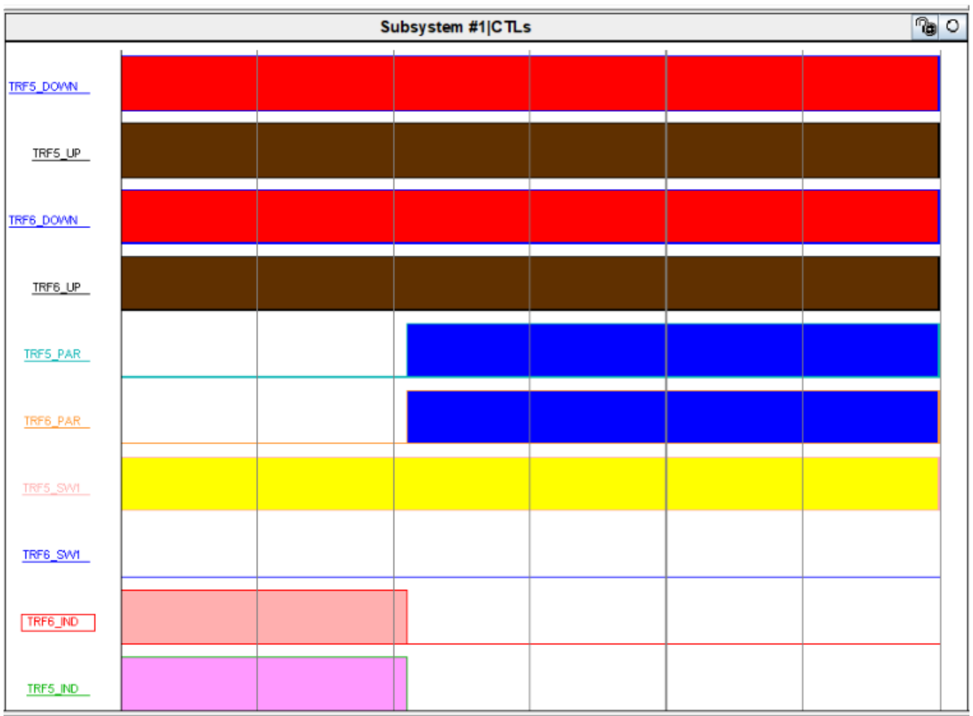


Figure 6.11: **In parallel operations, transformer 5 Master, and transformer 6 is a follower**

6.4 Hard-wired HIL protection scheme test

Hardware-in-the-loop testing was carried out, and the modified IEEE 9-Bus system was studied with the main focus on the parallel power transformer section. In this simulation, the external IED relays are connected to the system. According to Figure 4.4, external faults are placed on Bus 12, and 15 on the parallel transformers' high and low voltage sides, respectively, and internal faults are placed on Bus 13 and 14. It is important to highlight that establishing a connection between the circuit breaker, busbar, and the two-winding transformer using the RSCAD software is not feasible. As a result, internal nodes (bus 13 and bus 14) are made to link the parallel transformer's high and low-voltage sides using the circuit breakers to protect it, as displayed in Figure 4.4.

Three-phase parallel power transformers are protected using MiCOM-P645 and SEL-487E differential transformer relay. Numerous external and internal fault conditions are initiated at the Bus using a constructed fault inception block, as seen in Figure 5.12. Any relay that detects an internal fault immediately sends a trip signal to the protected transformer's breakers, causing them to open the power transformer and isolate it until the issue is resolved. To manually open and close the (CB1, CB2, CB3, and CB4) circuit breakers on each transformer using the four pushbuttons on runtime.

In Figure 6.12 area A and area B shows the runtime of the fault control logic for SEL-487E and MiCOM-P645 respectively. As illustrated in Figure 6.12, the system's fault is initiated by the pushbuttons FLT_SEL487E and FLT_MiCOMP645, and the switches FLTAB, FLTBC, and FLTCA are used to select the fault type from Line to Line while switches FLTA, FLTB, and FLTC are used to select the fault type from Line to Ground. As illustrated in Figure 6.12, the dial component DIAL1 is utilized to switch between positions 1, 2, 3, and 4, which, respectively, represent HV external (FLTSIGHS), HV internal (FLTSIGHV), LV internal (FLTSIGLV), and LV external (FLTSIGLS) faults.

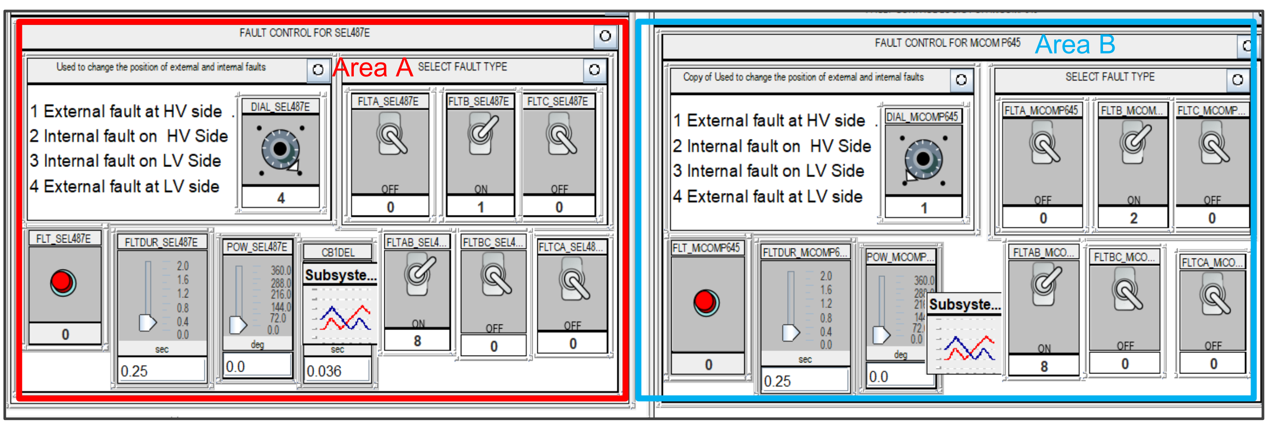


Figure 6.12: **Fault control logic in Runtime for SEL-487E and MiCOM-P645**

Analysing trip signals for different fault states is done as part of testing the protection system that has been developed. Therefore this section will be divided into two parts where fault conditions will be based on Line-to-ground and Line to Line.

6.4.1 The line to Ground internal and external fault Simulation for Parallel transformer

The objective of this case study is to evaluate the response and behavior of the parallel transformers and their protective systems when subjected to line-to-ground faults, considering both internal and external fault scenarios. The study aims to provide insights into the mechanisms used for fault detection, isolation, and clearing in the system to ensure that transformers operate reliably and safely.

6.4.1.1 External fault on a 3-Phase to-ground fault

a) Fault on an HV side transformer protected by MiCOM-P645

An external fault was applied on the LV side of the transformer protected by MiCOM-P645; the results are displayed in Figure 6.13. Figure 6.14 shows the MiCOM-P645 signal, current waveform, and Voltage waveform, respectively. It can be seen in Figure 6.13 that the trip signal is also low, which proves that the relay is functioning well for an external fault because it did not issue a trip signal.

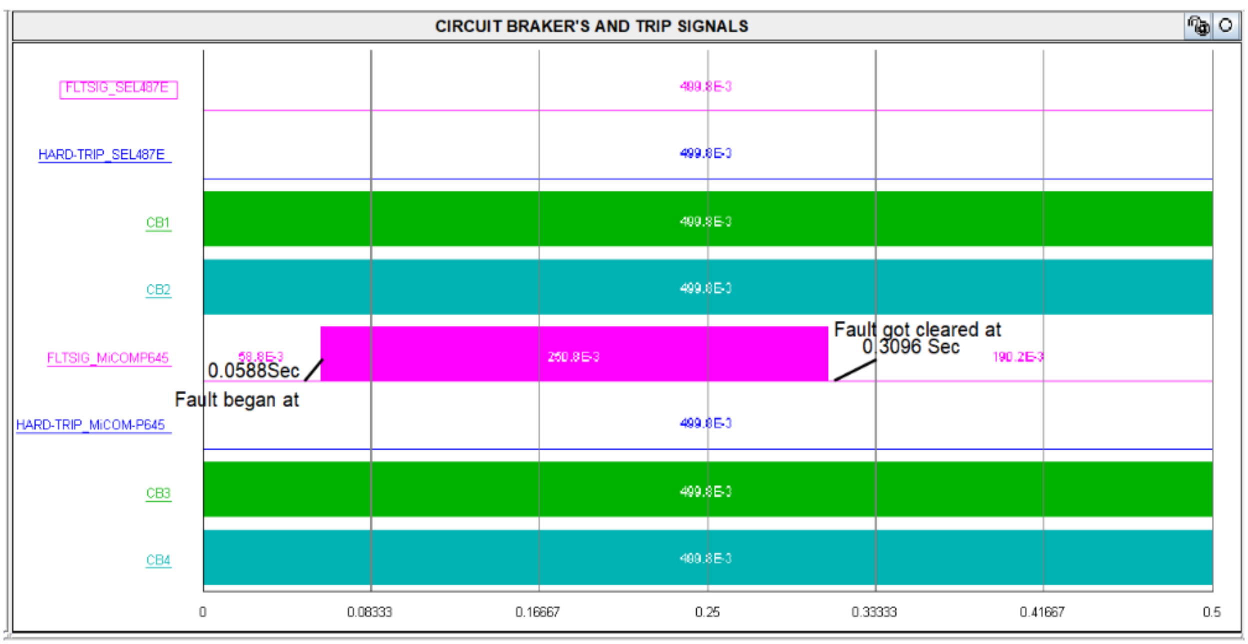


Figure 6.13: Circuit breaker signal for an LV side of the transformer protected by MiCOM-P645 for external LLLG fault

According to Figure 6.13, the fault started at 0.0588 seconds and was resolved at 0.3096 seconds. The fault lasted for a total of 0.192 seconds before being cleared. Figure 6.14 illustrates the signals of current and the voltage on the LV side of the transformer protected by MiCOM-P645 throughout a three-phase external to ground fault at Bus 15b that resulted in currents of about 4.5 kA and 2.4 Amps. While phase A, B, and C voltage signals were lowered to approximately 1.4 kV.

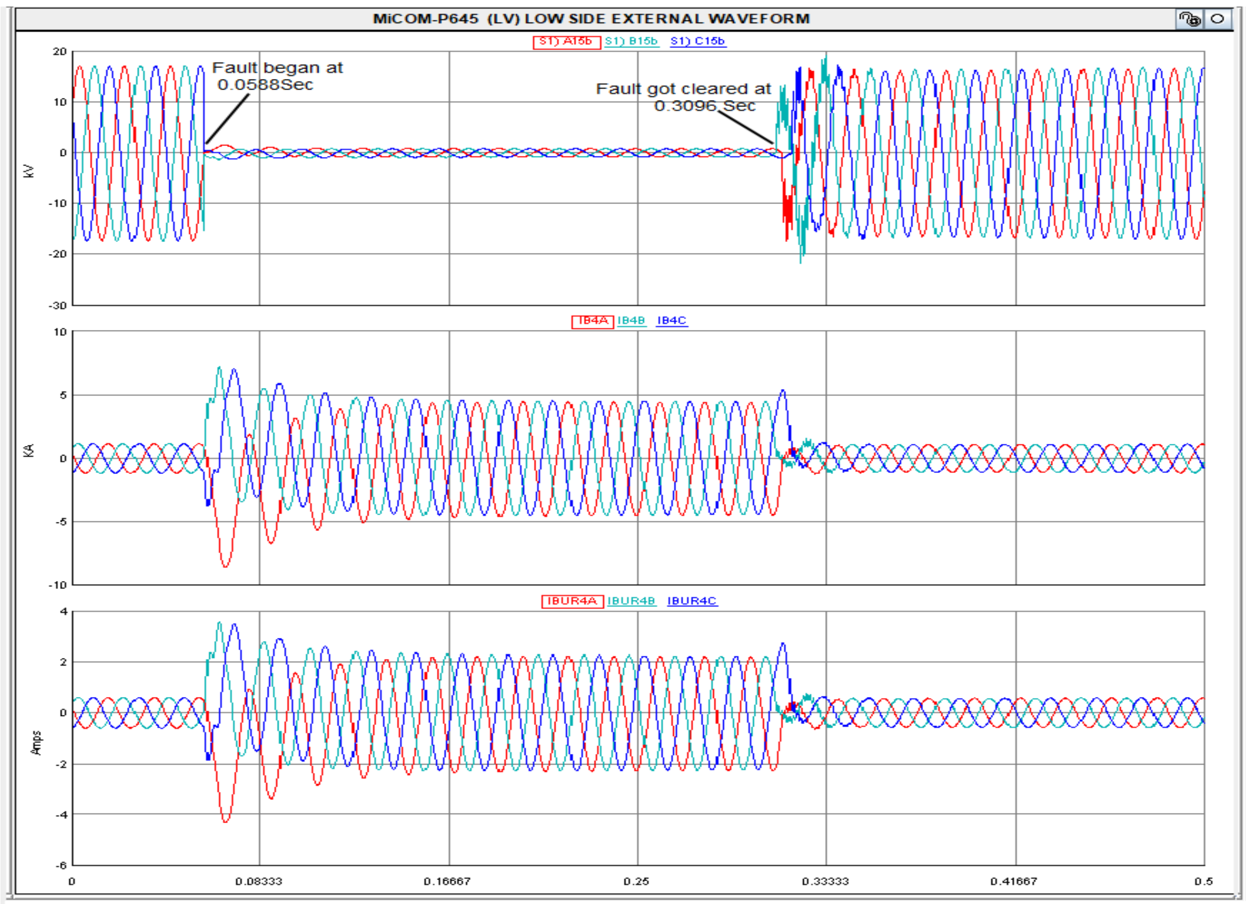


Figure 6.14: On the MiCOM-P645 LV side of the transformer, signals indicating an external LLLG fault show both current and voltage

6.4.1.2 Internal fault on a 3-Phase to-ground fault

a) Fault on a transformer HV side protected by MiCOM-P645

The internal fault was applied on a transformer HV side protected by MiCOM-P645, and the results are displayed in Figure 6.15. Figure 6.16 shows the MiCOM digital, voltage, and current waveform signals, respectively.

Figure 6.15 shows that the trip signal is now high, which means that the MiCOM-P645 IED has issued a trip signal to protect the transformer. At 0.0616 seconds, the fault began, and at 0.756 seconds, it was cleared, and CB3 is now open (low). The fault lasted for a total of 0.014 seconds before being cleared.

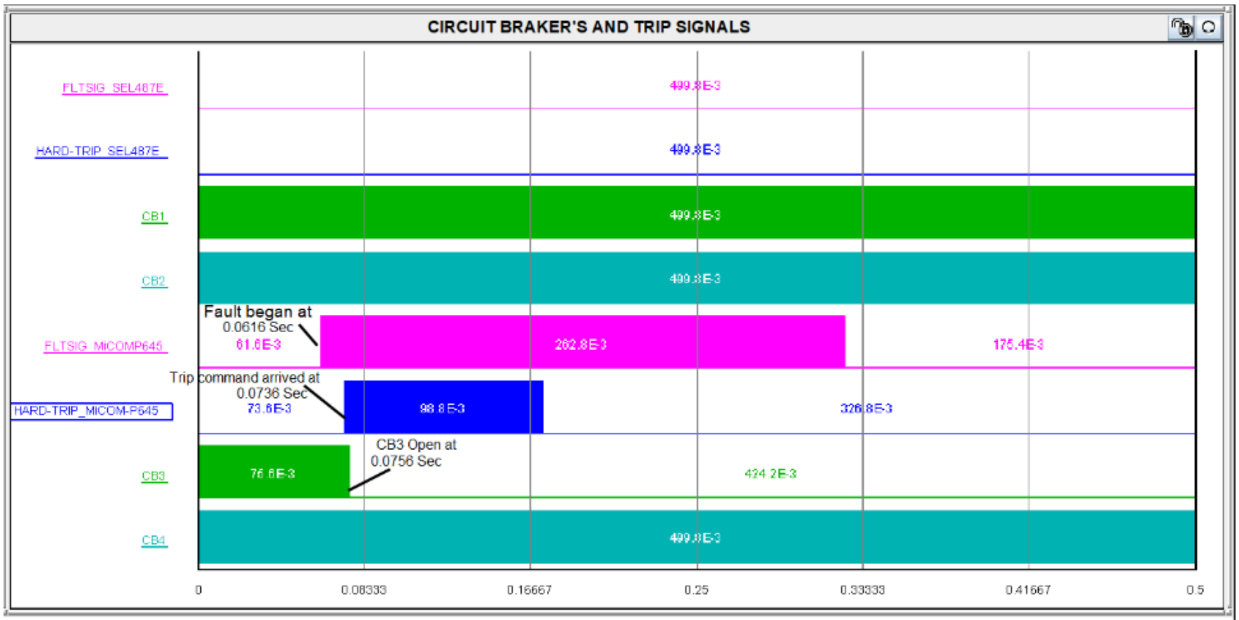


Figure 6.15: **Circuit breaker 3 signal open for a transformer HV side internal LLLG fault protected by MiCOM-P645**

The signals current and voltage on the HV side of the transformer are displayed in Figure 6.16 during a three-phase-to-ground internal fault at Bus 13b that resulted in currents of about 4.1 kA and 4.4 Amps. While phase-A, phase-B, and phase-C voltage signals were decreasing.

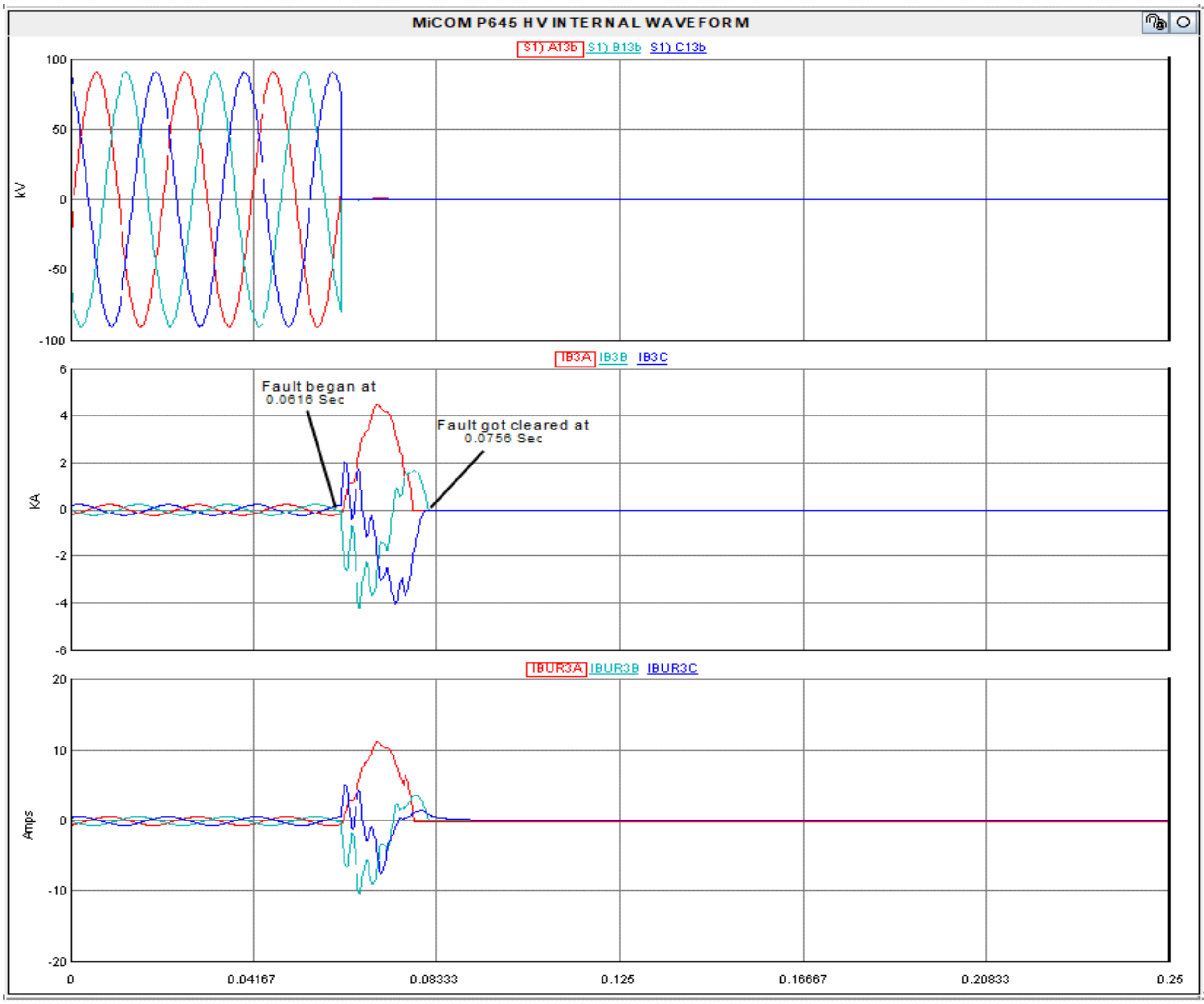


Figure 6.16: Signals Current and Voltage on the transformer's HV side for an internal fault LLLG protected by MiCOM-P645

6.4.1.3 Internal faulty on a Three Phase (LLL-G) fault

a) Fault on a transformer HV Side protected by SEL-487E

An internal fault was applied on a transformer HV Side protected by SEL-487E, and the results are displayed in Figure 6.17. Figure 6.18 shows the SEL-487E digital, voltage, and current waveform signals, respectively.

Figure 6.17 shows that the trip signal is now high on SEL-487E; this means that the IED SEL-487E has issued a trip signal to protect the transformer. At 0.0602 seconds, the fault was initiated, and at 0.0823 seconds, it was cleared. The fault lasted 0.0221 seconds in total and was cleared after that. At 0.0796 seconds, the trip signal was initiated/sent to open CB1.

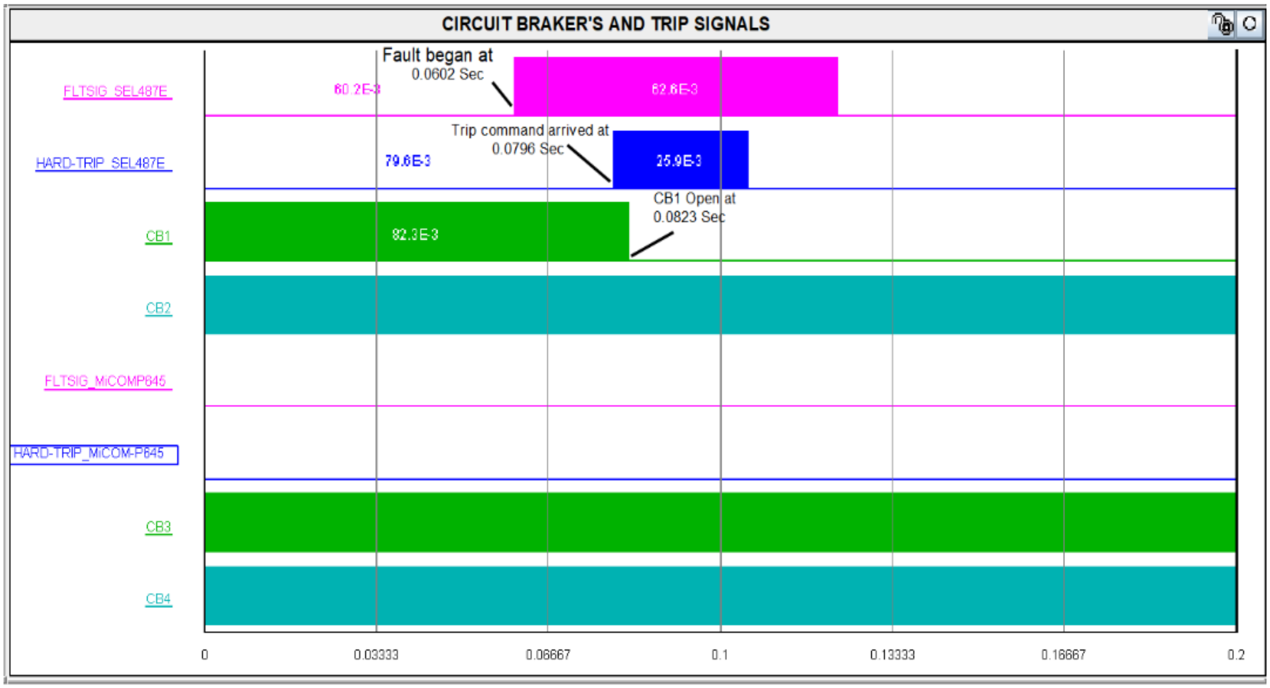


Figure 6.17: **CB1 received a hard-wired trip command signal for an HV SEL internal LLLG fault**

Figure 6.18 displays the signals current and voltage on the transformer's high-voltage (HV) side during an internal three-phase fault at Bus 13a, which generated a current of less than magnitude of 1.2 kA and 2.4 Amps.

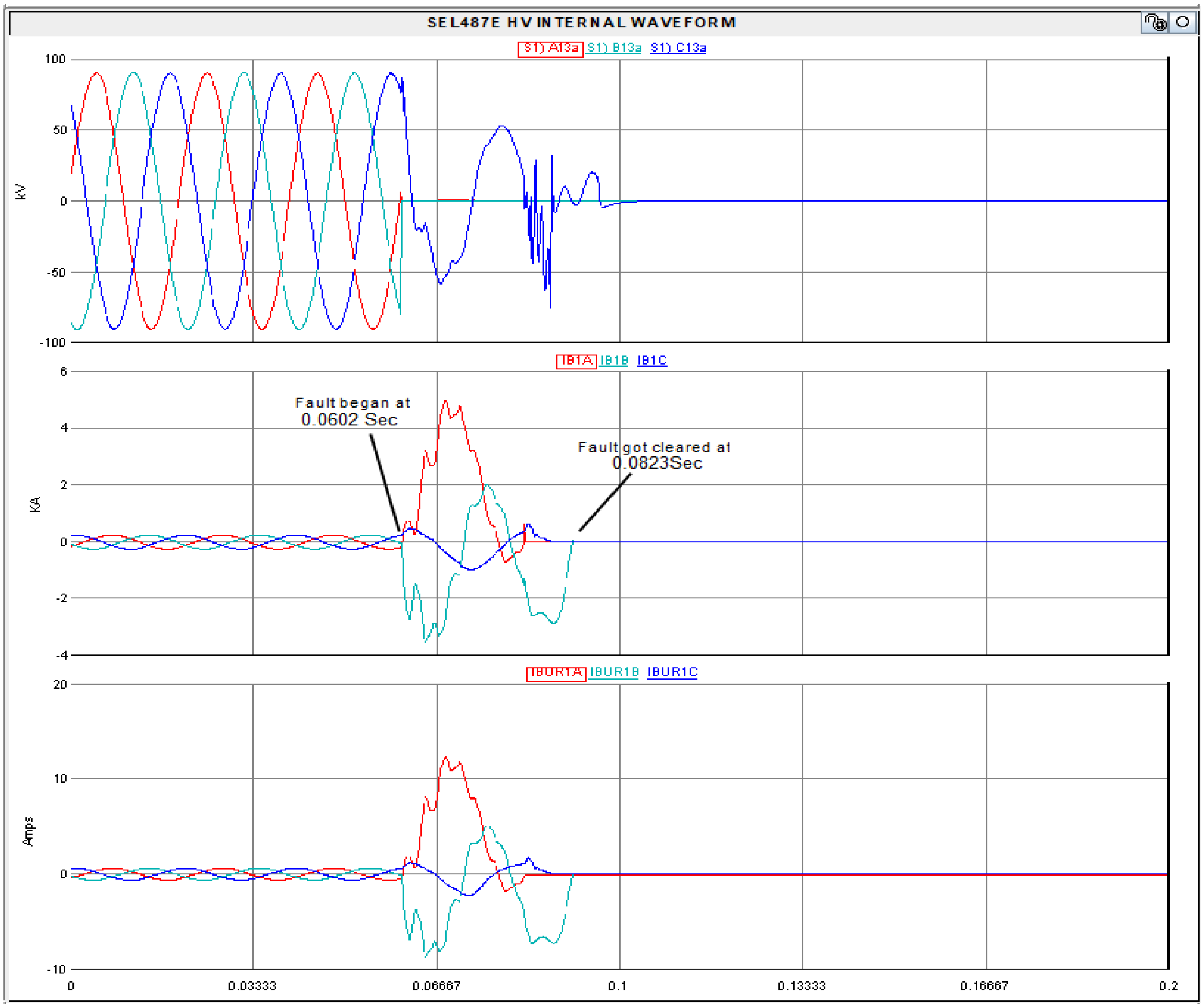


Figure 6.18: Internal LLLG fault current and voltage signals HV side of the transformer protected by SEL-487E

6.4.2 The line to Line internal and external fault Simulation for the Parallel transformer

This case study focuses on the simulation and analysis of line-to-line faults in a parallel transformer configuration, considering both internal and external fault scenarios. The study aims to provide insights into fault detection, fault isolation, and fault clearing mechanisms implemented in the system to ensure the reliable and safe operation of the transformers.

6.4.2.1 External fault on a Three-Phase Line-Line fault

a) Fault on a transformer LV Side protected by SEL-487E

An external fault was applied on the LV side of the transformer protected by SEL-487E, and the results are displayed in Figure 6.19. Figure 6.20 shows the SEL-487E, voltage, and current waveform signals, respectively.

Figure 6.19 shows that the trip signal is also low, which proves that the relay is functioning well. At 0.0996 seconds, the fault was first detected, and at 0.1406 seconds, it was resolved. The fault lasted for a total of 0.041 seconds before being cleared.

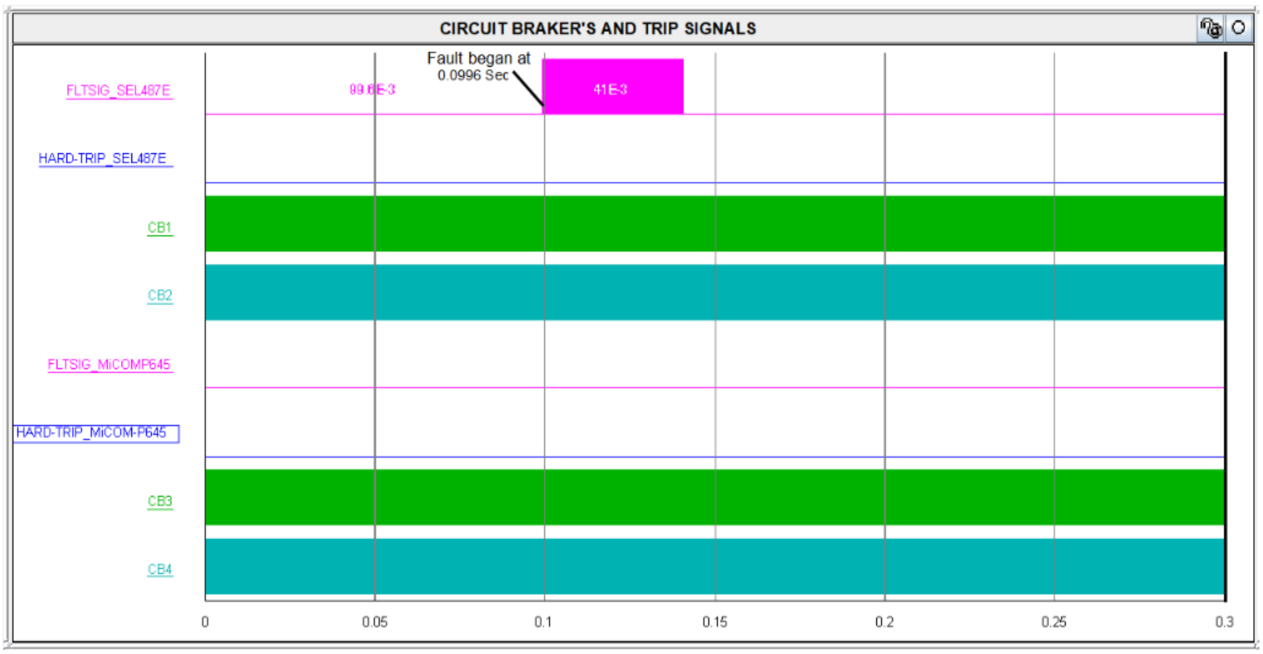


Figure 6.19: **All Circuit breaker signals are closed for transformers protected by IED during external 3ph L-L fault**

The signal current and voltage on the SEL-487E transformer LV side are displayed in Figure 6.20 during a three-phase line-to-line external fault at Bus 15a that resulted in currents of not less than the magnitude of 2.1 kA and 2.4 Amps. While reducing the voltage signals in all phases.

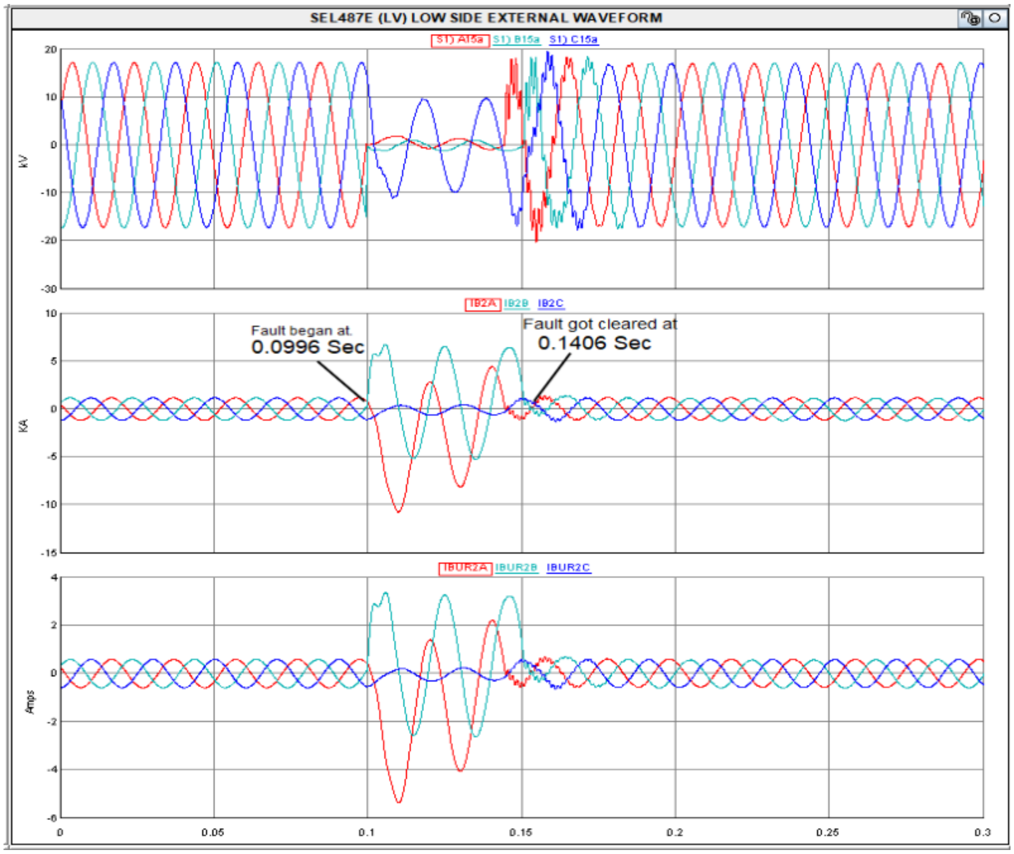


Figure 6.20: Signals for current and voltage for an external line-line 3ph fault on the transformer's LV side protected by SEL-487E

6.4.2.2 Internal fault on a Three-Phase Line-Line fault

a) Fault on a transformer LV side protected by MiCOM-P645

An internal fault was applied on the LV side of the transformers protected by MiCOM, and the results are displayed in Figure 6.21. Figure 6.22 shows the MiCOM, Voltage, and current waveform signals, respectively.

Figure 6.21 shows that the trip signal is now high, which means that the MiCOM-P645 IED has issued a trip signal to protect the transformer. At 0.0203 seconds, the fault was first detected and cleared at 0.0351 seconds. The fault lasted for a total of 0.0148 seconds before it was cleared up. At 0.0322 seconds, the trip signal was initiated/sent to open CB4.

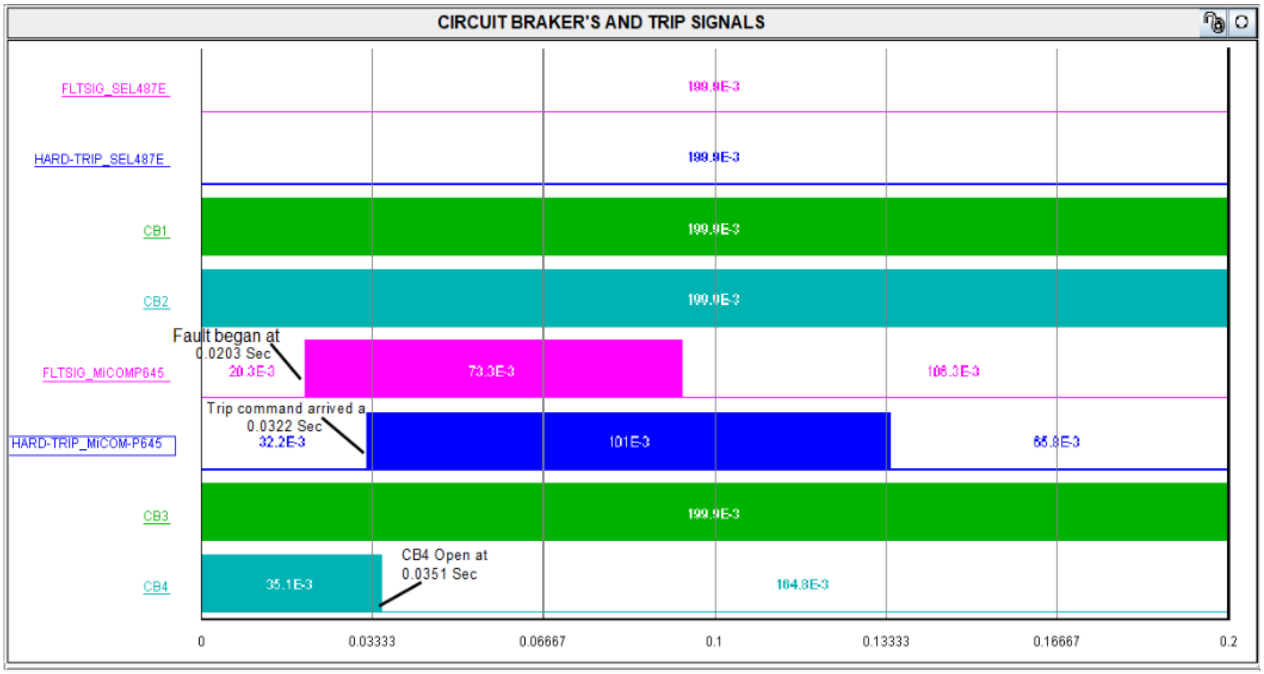


Figure 6.21: CB4 received a hard-wired trip command signal for a transformer LV side protected by MiCOM during a 3ph L-L fault

Figure 6.22 displays the signals current and voltage on the LV side of the MiCOM-P645 transformer during an internal Three-phase Line-to-Line fault at Bus 14b that resulted in a current of the approximate magnitude of 3.8 kA and 2.6 Amps. At the same time, the voltage signals on all phases were reduced.

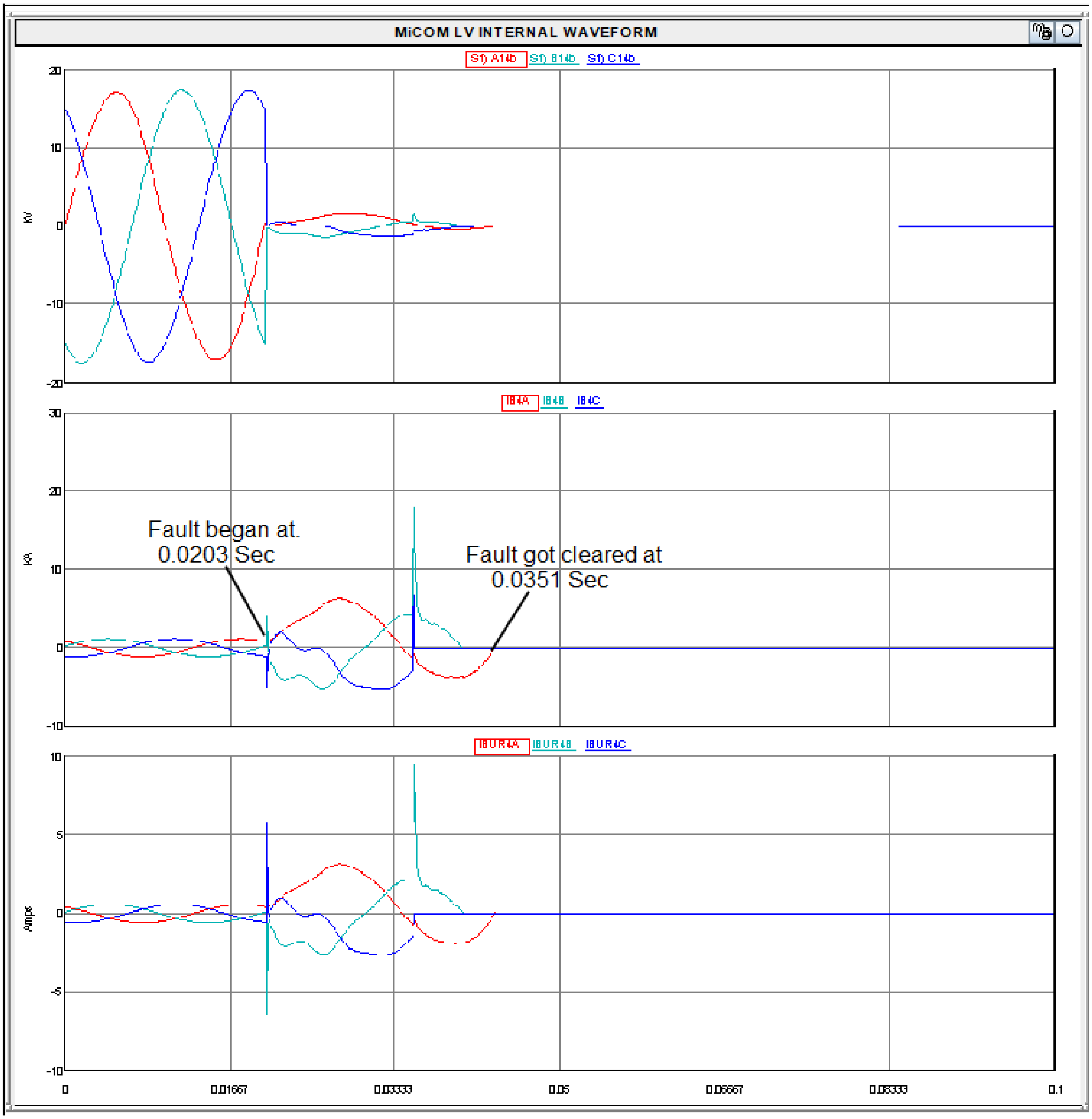


Figure 6.22: Signals for current and voltage for a 3Ph- internal L-L fault on the transformer's LV side protected by MiCOM-P645

6.4.2.3 Internal fault on a Phase AB Line to Ground fault

a) Fault on a transformer LV Side protected by SEL-487E

The internal fault was applied on the LV side transformer protected by SEL-487E, and the outcomes are displayed in Figure 6.23. Figure 6.24 shows the SEL-487E, voltage, and current waveform signals, respectively.

Figure 6.23 shows that the trip signal is now high, meaning that the IED SEL-487E has issued a trip signal to protect the transformer. At 0.0272 seconds, the fault was activated and cleared up at 0.0583 seconds. The fault was present for 0.0311 total seconds before it was cleared. At 0.0554 seconds, the trip signal was initiated/sent to open CB2.

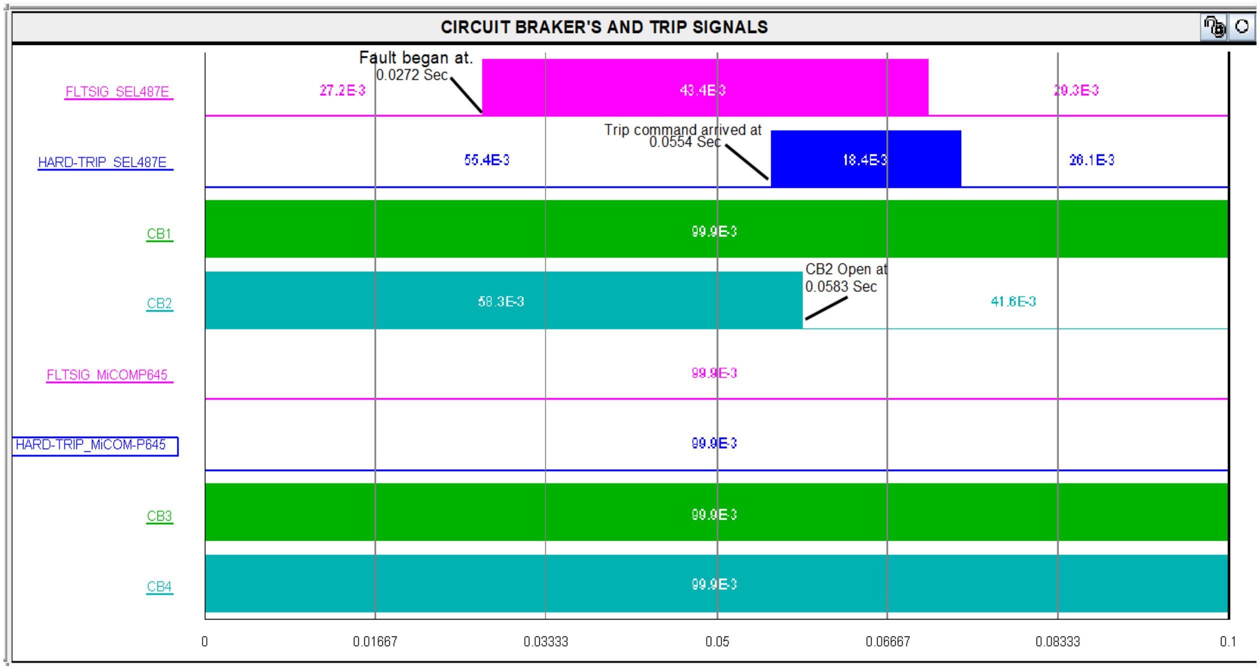


Figure 6.23: CB2 received a hard-wired trip command signal for a transformer LV side protected by SEL-487E during Phase AB L-G fault

Figure 6.24 shows the signals current and voltage on the LV side transformer protected by SEL-487E during an internal Phase AB Line to Ground fault at Bus 14a. On the current signal, Phase A and Phase B went up, while Phase C remained approximately the same, while the voltage signal shows that only Phase A and Phase B dropped down.

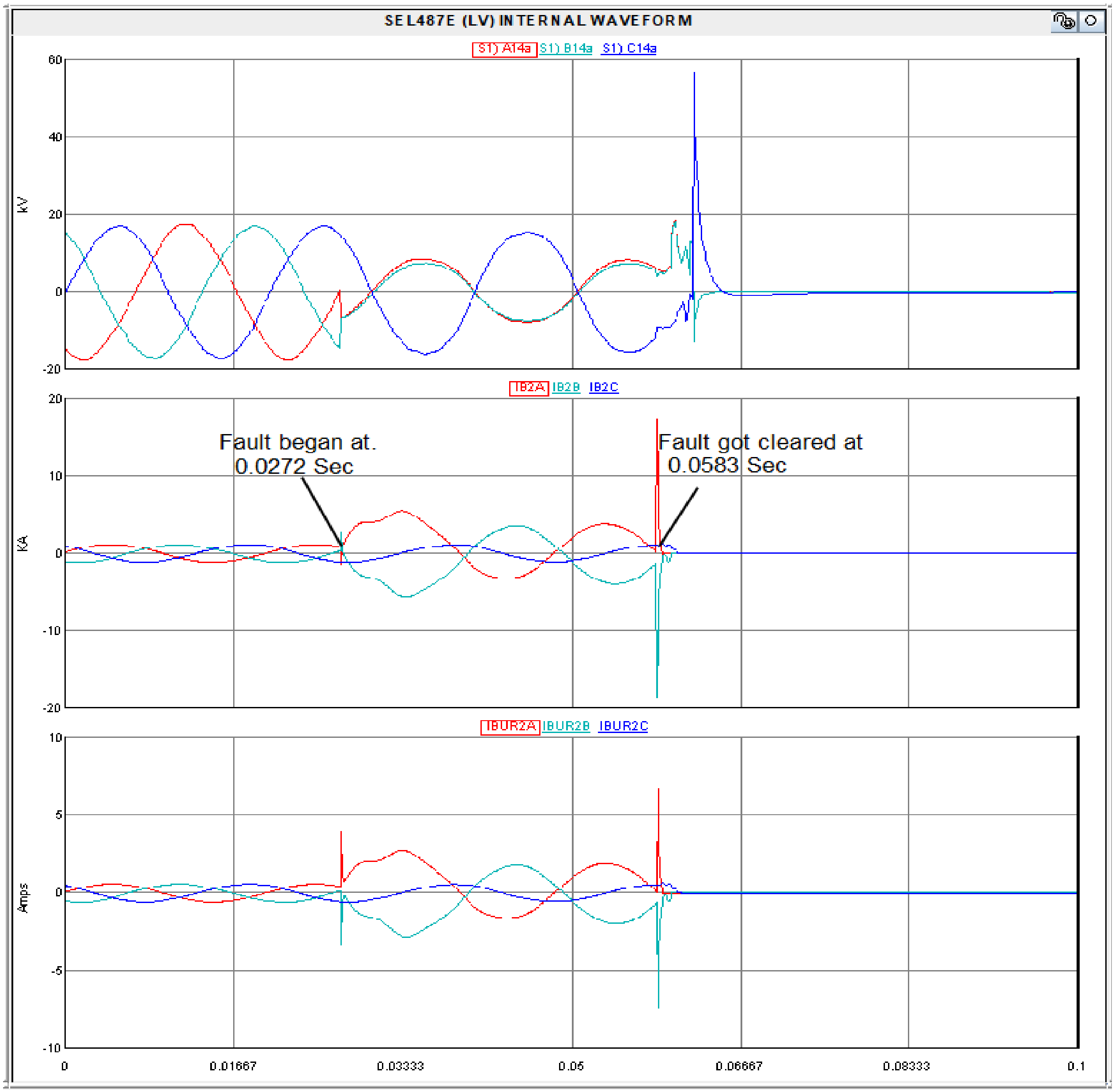


Figure 6.24: Signals for voltage and current for a Phase AB L-G fault on the transformer LV side protected by SEL-487E

6.4.2.4 Internal fault on a Phase AB Line to Line Fault

a) Fault on a Phase AB Line to Line transformer LV Side protected by MiCOM-P645

The internal fault was applied on the transformer LV Side protected by MiCOM-P645; the outcomes are shown in Figure 6.25. Figure 6.26 shows the MiCOM, Voltage, and current waveform signals, respectively.

Figure 6.25 shows that the trip signal is now high, meaning that the MiCOM-P645 IED has issued a trip signal to protect the transformer. The fault began at 0.034 seconds and was cleared at 0.0482 seconds. The fault lasted for a total of 0.0142 seconds before being cleared. At the same time, the trip signal was initiated/sent at 0.0452 seconds to open CB4.

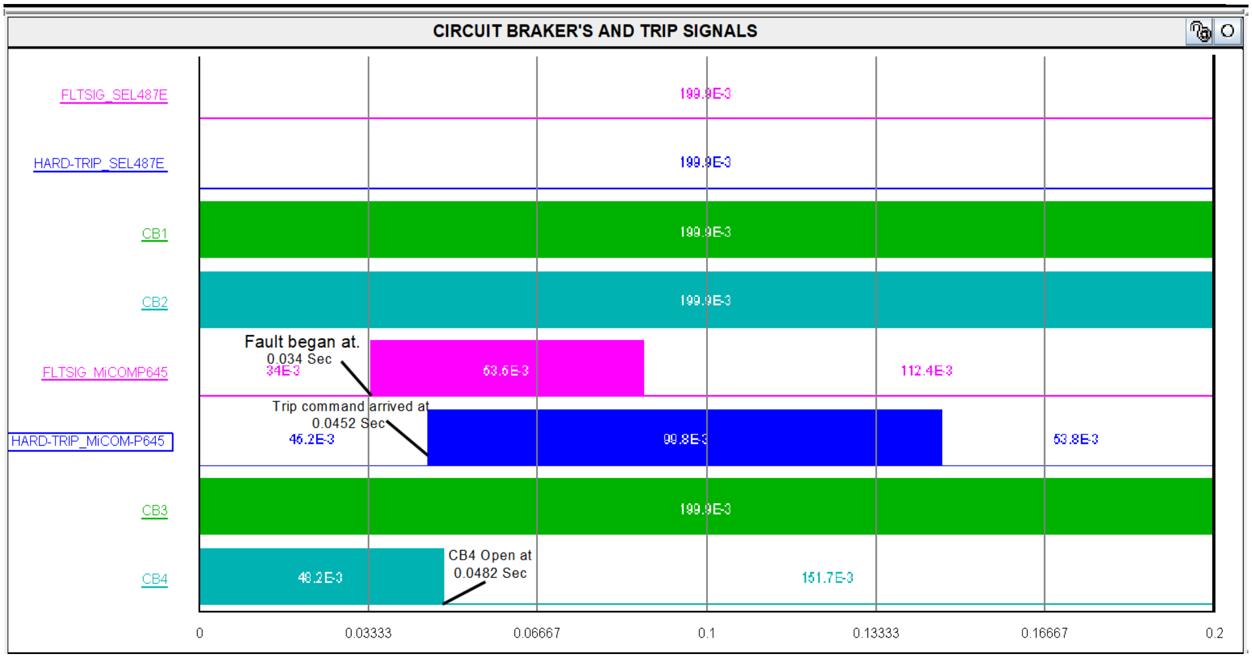


Figure 6.25: **CB4 received a hard-wired trip command signal for an LV MiCOM-P645 during Phase AB L-L fault**

The signals current and voltage on the MiCOM-P645 transformer LV side during an internal Phase AB Line to Line fault at Bus 14b. On a current signal, only Phase AB went up while Phase C remained approximately the same, and the voltage signal shows that only Phase AB dropped down, as seen in Figure 6.26.

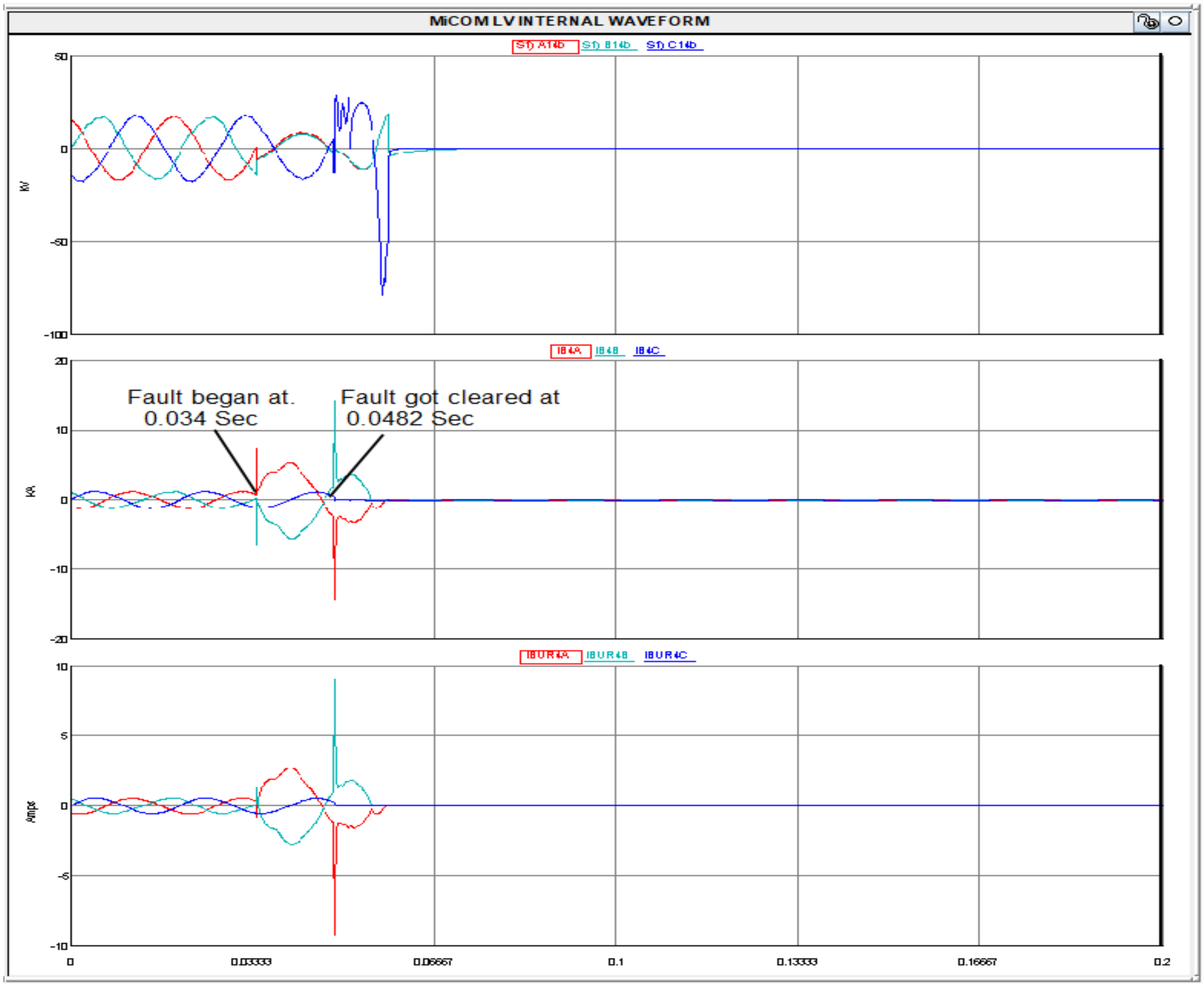


Figure 6.26: Signals current and voltage for a Phase AB L-L fault on the transformer's MiCOM-P645 LV side

6.4.3 Double Line to Ground fault for internal Simulation for Parallel transformer

The main focus of this case study is on the simulation and analysis of a double line-to-ground fault in a parallel transformer configuration, specifically investigating the internal fault scenario. The study aims to provide insights into fault detection, fault isolation, and fault clearing mechanisms implemented in the system to ensure the reliable and safe operation of the transformers.

6.4.3.1 Internal fault on Phase AB and Phase C to ground

a) Fault on a transformer HV side protected by MiCOM-P645

An internal fault was applied on the transformer HV side protected by MiCOM-P645, and the results are displayed in Figure 6.27. Figure 6.28 shows the MiCOM, Voltage, and current waveform signals, respectively.

Figure 6.27 shows that the trip signal is now high, which means that the MiCOM IED has issued a trip signal to protect the transformer. The fault began at 0.0233 and was cleared at 0.0392 seconds. The fault was present for 0.0159 total seconds before it was cleared. At the same time, the trip signal was initiated/sent at 0.0373 seconds to open CB3.

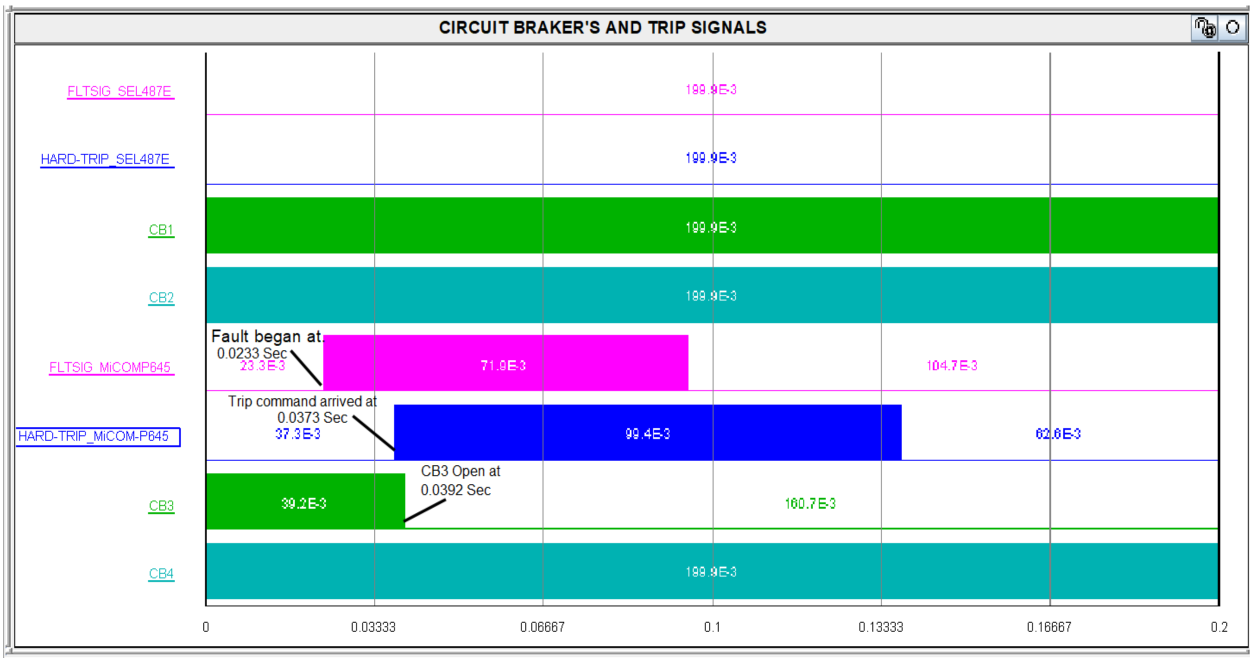


Figure 6.27: CB3 received a hard-wired trip command signal for an HV side of the transformer protected by MiCOM-P645 during Ph-AB and Ph-C to ground fault

The signal current and voltage on the MiCOM transformer HV side during an internal Phase AB and Phase C to ground fault at Bus 13b are shown in Figure 6.28.

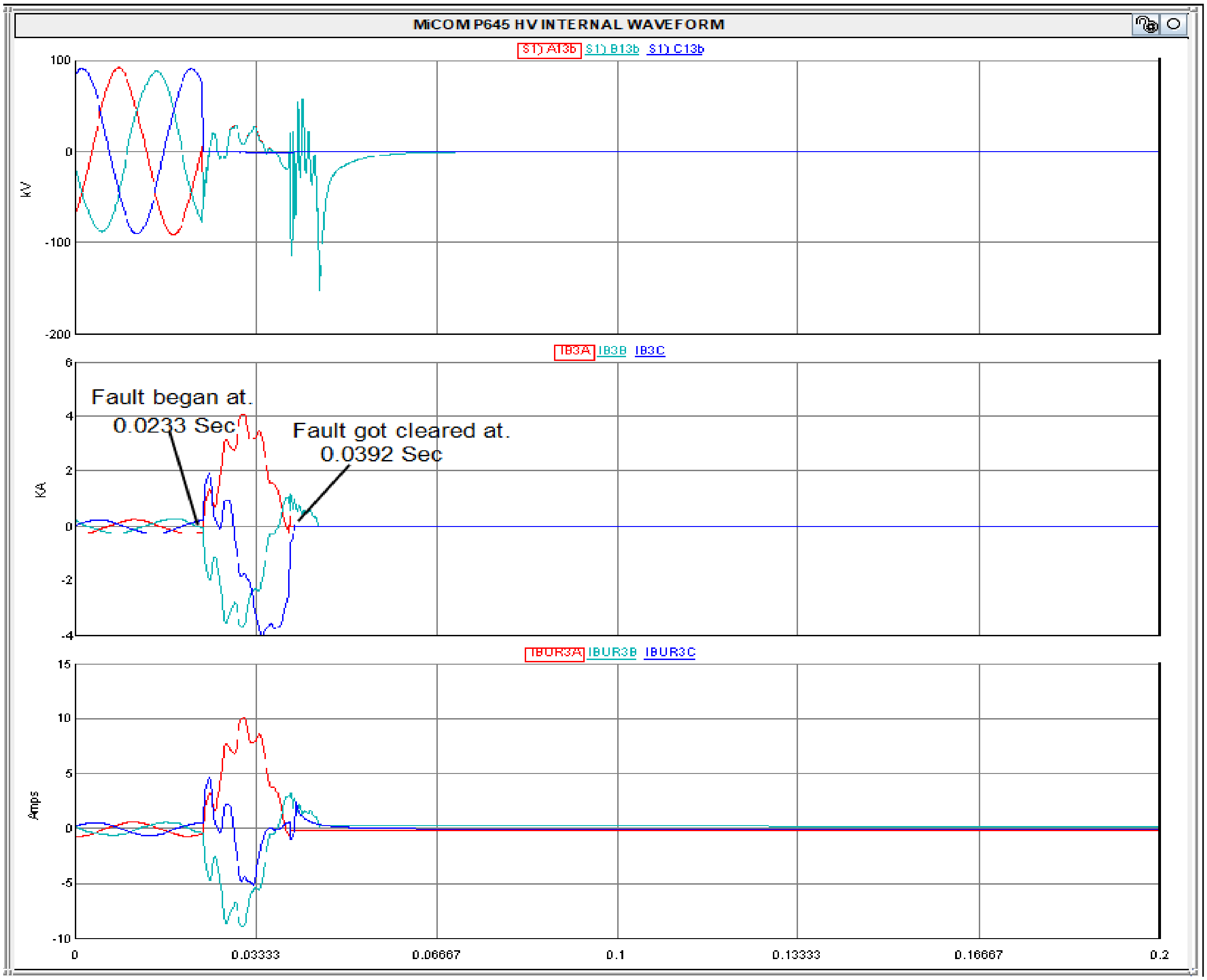


Figure 6.28: Internal Phase AB and Phase C to ground fault current and voltage signals on the transformer's HV side protected by MiCOM-P645

b) Fault on an LV side of the transformer protected by SEL-487E

A fault was applied internally on the LV side of the transformer protected by SEL-487E, and the results are displayed in Figure 6.29. Figure 6.30 shows the SEL-487E, voltage, and current waveform signals.

Figure 6.29 shows that the trip signal is now high, meaning that the SEL-487E IED has issued a trip signal to protect the transformer. At 0.028 seconds, the fault was first initiated, and at 0.0521 seconds, it was cleared. The fault lasted for 0.0241 seconds in total before being cleared. At the same time, the trip signal was initiated/sent at 0.0492 seconds to open CB2.

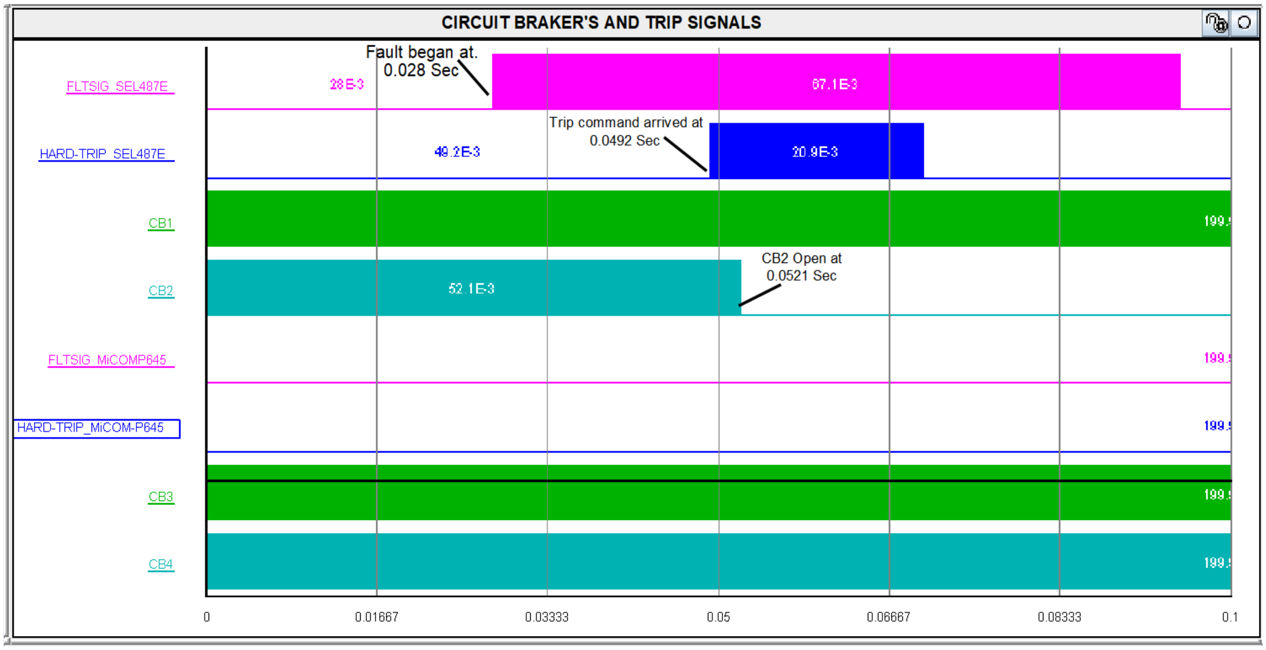


Figure 6.29: **CB2 received a hard-wired trip command signal for an LV SEL during Ph-AB and Ph-C to ground fault**

The SEL-487E protecting the transformer's LV side's current and voltage signals during an internal Phase-AB and Phase-C to ground fault at Bus 14a is displayed in Figure 6.30.

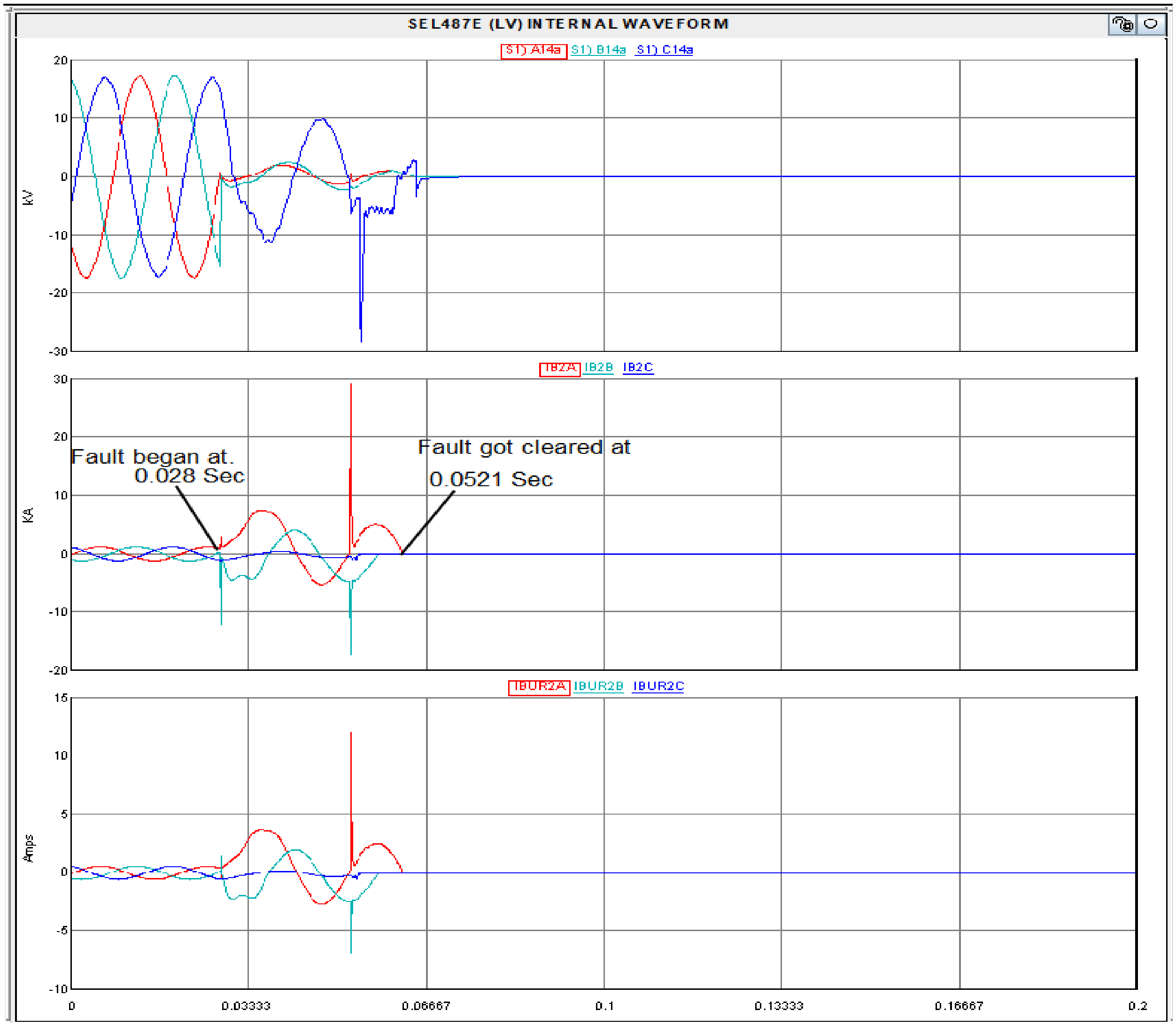


Figure 6.30: Transformer's LV side protected by SEL-487E internal Phase AB and Phase C to ground fault current and voltage signals

6.5 Analysis of the transformer's inrush current condition

As mentioned earlier in Chapter Three, the transformer's energization occurs when the magnetization inrush current occurs. The primary winding of the transformer experiences the inrush current, but the secondary winding does not experience an equivalent current. The protection relay must adjust for this situation because it appears to be an internal fault. Numerous circumstances may result in a magnetizing inrush condition for a power transformer. The terms initial, recovery, and sympathetic inrush are used to describe these conditions.

During a voltage terminal step change, a power transformer's magnetic circuit may require a sizable amount of current. Because a transformer is magnetic, the required magnetic flux must be produced by drawing an excitation current from the power source. Due to the steel core's hysteresis loop, the magnetic flux can be retained by a transformer during de-energization even though it lags the system voltage. Upon reapplying voltage to the transformer, the retention or residual magnetic flux can potentially have an adverse effect on the inrush current.

6.5.1 Analysing the transformer's inrush current situation when it's operating in a steady state

To maximize efficiency, transformers are typically operated close to the knee point of the characteristic. Increasing the terminal voltage causes core saturation and excessive magnetization currents to be drawn. During the energization process when the voltage is initially zero, there is a significant surge in the demand for magnetic flux, reaching twice the normal magnetic flux level. Consequently, this leads to the occurrence of a very high magnetizing current (I_M), commonly referred to as the transformer inrush current. The presence of residual flux, also known as remnant flux, amplifies the magnitude of this current when the transformer is energized. Figure 6.31 shows the magnetizing current, peak flux, and B-H LOOP during the steady state condition of transformer 6.

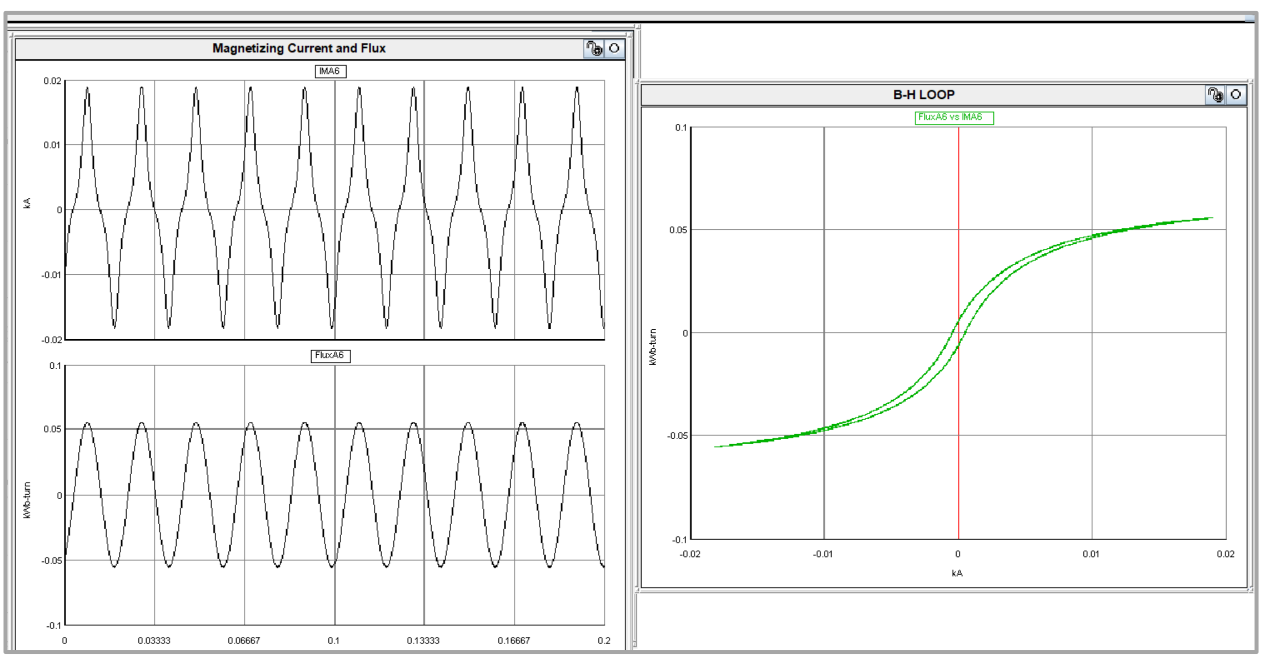


Figure 6.31: Magnetizing current, peak flux, B-H LOOP in steady state condition of the TRF6

6.5.2 Typical transformer inrush currents during de-energisation

To de-energize the transformer, utilize the circuit breaker's pushbuttons in RUNTIME to open the breakers; in these cases, the residual flux is measured from the phase A (FLUXA) plot on transformer 6. Figure 6.32 shows the Magnetizing current, residual flux, and hysteresis loop during the opening of CB3. In Figure 6.32, due to the circuit breakers switching event, it is observed that the residual flux is 0.013kWb, while the magnetizing current ranges from 0.018 kA to zero.

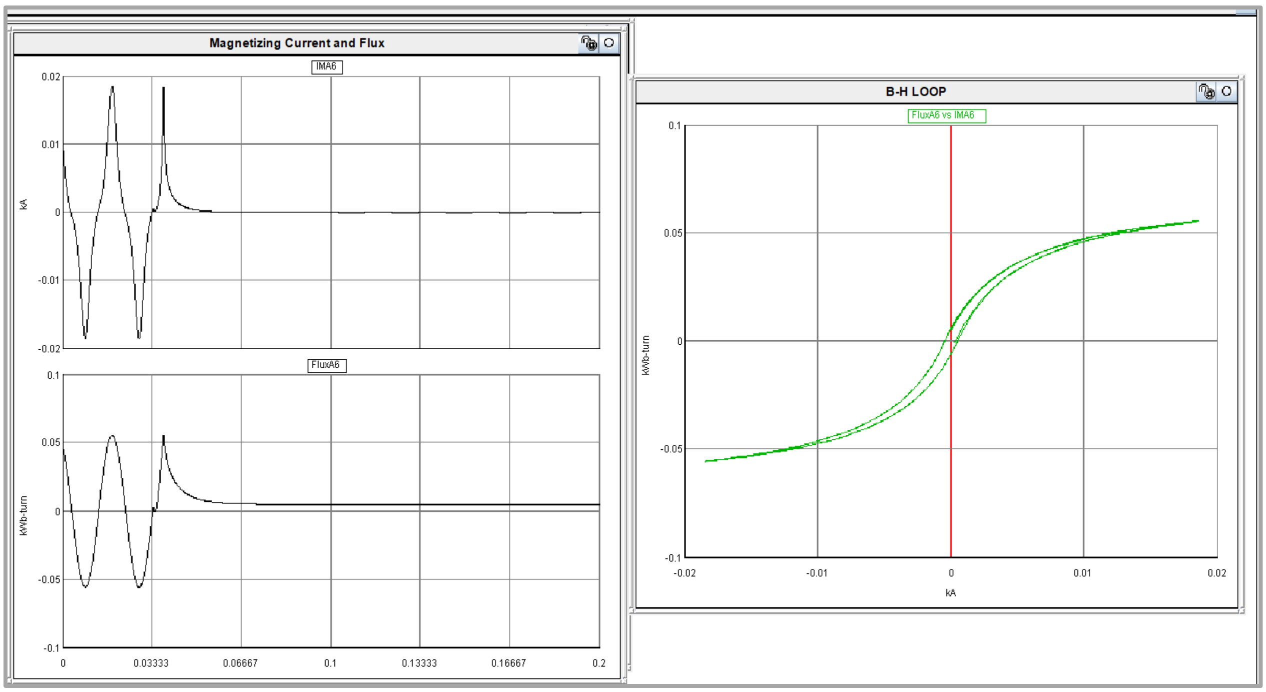


Figure 6.32: **Magnetizing current, residual flux, and BH-loop during de-energisation of transformer6**

6.5.3 Typical transformer inrush currents during energisation

CB3 is closed by pressing CB3Close pushbuttons in runtime in order to re-energise the transformer. Figure 6.33 shows the waveform of magnetizing Inrush current, residual flux, and BH-loop during the re-energisation of a transformer. During this re-energisation of a transformer, it is observed that the B-H loop has been saturated, as displayed in Figure 6.33.

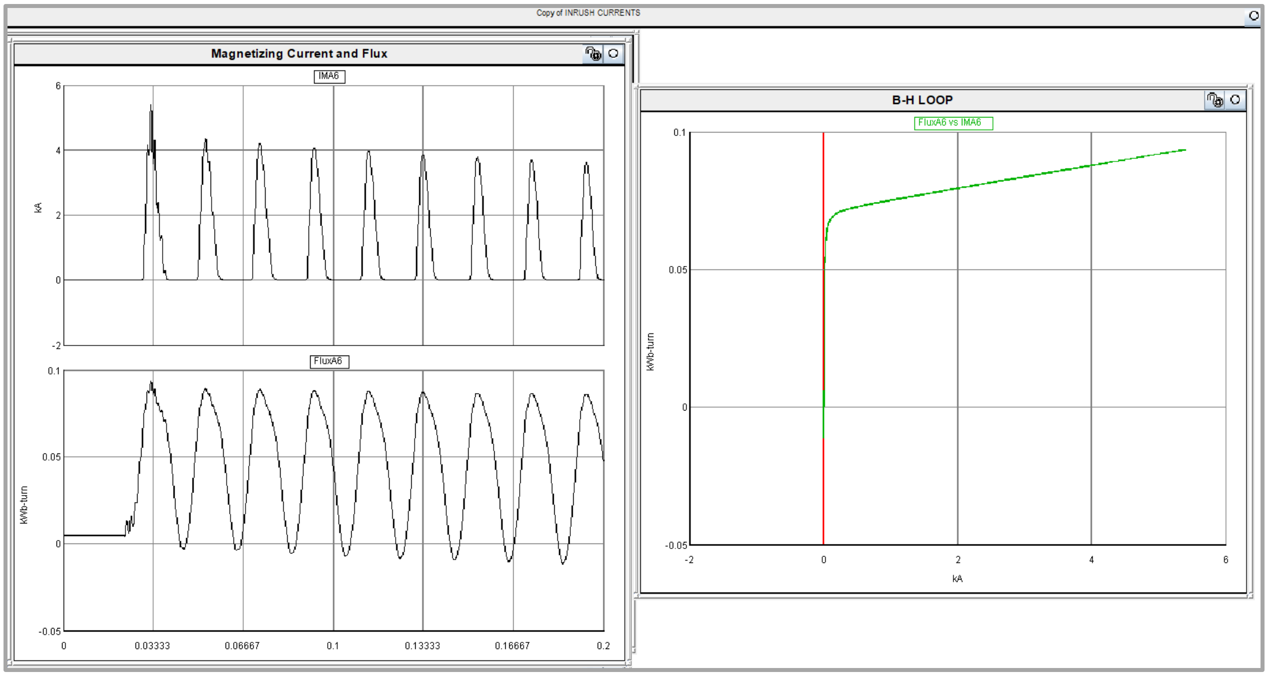


Figure 6.33: Transformer magnetizing Inrush current, residual flux, and BH-loop during energisation

6.6 Summary of the results

In the following table (Table 6.6), a summarized presentation of the results obtained in the preceding section, specifically focusing on 'Fault event summary results for the conventional trip,' is provided.

Table 6.6: Fault event summary results for conventional trip signal

Fault type	Circuit breaker operation in seconds (s)	Duration of fault clearance in seconds (s)
3-Phase to-ground (MiCOM-P645)	0.0756	0.0736
3Ph-Ground (SEL-487E)	0.08236	0.0796
3Ph-Line (MiCOM-P645)	0.0351	0.0322
Phase-AB-Ground (SEL-487E)	0.0583	0.0583
Phase-AB-Line (MiCOM-P645)	0.0482	0.0452
Double Line Ph-AB & Ph-C to Ground (SEL-487E)	0.0392	0.0373

6.7 Discussion and Conclusion

During runtime, different control operations can be performed using the runtime module, such as breaker operation, fault application, and setpoint adjustment. Runtime, which runs on a Linux Workstation or Windows PC, communicates back and forth via Ethernet with GTWIF simulator cards. You can control the network by changing switching states or set points from the RunTime. During runtime, different control operations can be performed using the runtime module, such as fault application, breaker operation, and setpoint adjustment.

For simulation Case 1, the RTDS is used to construct, model, and simulate the modified IEEE 9-Bus system. The logic control circuit utilizes the condition of the circuit breakers associated with the transformers and the bus section as input. This enables the determination of whether the transformers are connected in parallel or operating individually.

The outcomes indicate that:

- Using the monitored circuit breakers, the status of the logic circuit created on the RSCAD program accurately identifies whether the two transformers are being used individually or in parallel.
- While the parameter values of the systems monitored show that they don't change and remain the same as they should be, these are voltage and current.

Simulation Case 2 is to prove that the Tap Changer Control of the two parallel transformers is operating as it should.

The outcomes indicate that:

- When in automatic mode and not connected in parallel, each transformer is controlled by its own controller.
- In manual mode, individual control of each transformer is achieved through the use of push buttons.
- When two transformers are connected in parallel, any transformer can follow the controller operations of the other transformer. For example, transformer 5 serves as the Master, while transformer 6 serves as the Follower.

The simulation results provide insights into the performance and effectiveness of the Master-Follower control method for tap changer controllers in parallel transformer configurations. These findings can be used to optimize the coordination settings, improve voltage regulation accuracy, and enhance the overall stability and performance of the system.

For simulation Case 3, The IED Protection device was interfaced with the RTDS via Omicron analogue amplifiers, two CMS 156 and CMS 356, to finalize the Hardware-In-Loop (HIL) testing process. To accomplish a particular task, such as opening a circuit breaker while the simulator is running, a closed loop is established where the response from the device's IED is sent back to the RTDS simulator. The Fault control logic selects the type of fault to be sent to a transformer. And which transformer (TRF5 or TRF6) the fault will be inserted.

Comparing test results obtained from the RTDS testing platform with those from the relays is a critical step in validating the performance of the protection scheme and confirming the accuracy of the experiments. Here's an overview of how this comparison is typically conducted:

- In Hardware-in-the-Loop (HIL) testing, the RTDS generates simulated fault or disturbance events emulating real-world conditions to assess the protective relay's response. These relays are integrated with the RTDS and configured to operate based on the simulated events, aiming to detect and execute protective actions like circuit breaker tripping. Both the RTDS and the relays record comprehensive data, including voltage and current waveforms, relay operation times, and fault records.
- Subsequently, data from both sources are scrutinized and compared to evaluate whether the relay's response aligns with the expected behavior derived from the RTDS simulations, effectively confirming the proper functioning of the protective relay system. Any disparities necessitate further investigation, which may entail adjusting relay settings, refining the simulation, or addressing potential issues in the protection scheme. The testing process can be iterative, involving multiple rounds of refinement until the desired performance and accuracy levels are achieved.

In summary, the comparison of test results obtained from the RTDS with those from the relays serves as a validation process to confirm that the protective relay system operates correctly and in accordance with the simulated scenarios. It helps identify any issues, validates the protection scheme's effectiveness, and ensures that the relay can reliably protect the power system under various fault conditions.

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During the analysis of the simulated results, a key observation was the alignment of timing among various elements in the system. This synchronization encompassed the following components:

- **Waveform:** The simulated waveforms, which represent the electrical quantities in the power system, closely match the expected behavior during the fault or disturbance event.

This alignment was critical as it ensured that the simulation accurately reflected the actual electrical conditions.

- **Relay Response:** The protective relay's response time, i.e., the time it took to detect the fault or disturbance and initiate the appropriate protection actions, was found to be in precise accordance with the simulated waveforms. This synchronization is fundamental for the relay's timely and accurate operation.
- **Signals:** Signals generated or transmitted within the system, such as trip signals and communication signals, were also synchronized with the simulated events. This synchronization ensures that the relay communicates effectively with other devices in the power system and takes the necessary protective actions promptly.

The confirmation of timing consistency between these elements is crucial for validating the reliability and accuracy of the protective relay system. It assures that the relay can effectively detect and respond to real-world fault or disturbance scenarios, contributing to the safe and stable operation of the power system. Additionally, it enhances confidence in the hardware-in-the-loop (HIL) testing methodology used to assess the relay's performance under various conditions.

The outcomes indicate that:

- Using the Fault control logic, all different fault types were successfully selected.
- During the simulation of external fault, no transformer (TRF5 and TRF6) has issued a trip signal on any of the circuit breakers, and the fault is cleared after a couple of milliseconds, and the waveform goes back to its original operation state.
- During the simulation of internal fault, if any fault is applied on the TRF5 HV side, only TRF5 CB1 will trip while TRF6 will continue with its normal operation. Also, if a fault is applied on the TRF6 LV side, only TRF6 CB4 will trip while TRF5 continues its normal operation. The specific CB will open once a trip is sent during this simulation.

By adhering to the IEC 61850 communication standard, it becomes possible to share status information via a single Ethernet cable, which can be subscribed to by other field devices like circuit breakers. This approach significantly simplifies the communication infrastructure, reducing the reliance on numerous hard-wired binary outputs from the relay. In the subsequent chapter (Chapter Seven), we delve into the comprehensive implementation, configuration, and testing of the IEC 61850 standard's Generic Substation Event (GSE) control model and Generic Object-Oriented Substation Events (GOOSE) messaging. These protocols enhance communication and interoperability among various vendors involved in the developed protection scheme. The adoption of IEC 61850 ensures not only efficient data exchange but also lays the foundation for future-proof and scalable protection systems.

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CHAPTER SEVEN

THE DEVELOPMENT OF THE STANDARD-BASED GOOSE COMMUNICATION IEC 61850

7.1 Introduction

The objective standard of IEC 61850 is to make substation IEDs two-way communications. The ability of the IEDs from various vendors to communicate with one another is ensured through standard compliance. Special files in the IEC 61850 standard must be created to start GOOSE communication. All devices intended for inter-device communication must download these files. It is customary for IED vendors to give their clients access to their IED configuration tool, which was created especially to generate files required by their IEDs. The same Local Area Network (LAN) must be linked for IEC 61850-compatible devices to be able to receive data from or send data to one another. Each RTDS GTWIF, GTNET, external IEDs, and control computer should be physically connected to the LAN. As indicated in Table 4.5, each device in this scenario needs to have a different IP Address, and the location of the GTNET card is RTDS Rack 1.

This chapter advances the developed transformer protection scheme by demonstrating interoperability between the two IEDs of the parallel system using the communication standard IEC 61850 and its generic substation event (GSE) control model GOOSE.

7.2 IEC 61850 standard-based communication protection system's hardware-in-loop test configuration

The rest of the required hardware has already been addressed in the above chapter. The modified IEEE 9 bus system network configuration that acts as the developed testbed was already constructed in Chapter Five. The chapter also included settings for the protection scheme configuration, with the word bits relay designed per the ANSI. The RTDS system was controlled using the word bits relay established in the protection scheme presented in Chapter Five. The logical nodes (LNs) used in this chapter to transmit data containing status events via Ethernet are used in place of those relay word bits. RTDS utilizes the GTnet cards for this application to transfer the status event messages for protection and control to RTDS from the physical device. Due to the GTnet with GSE firmware in RTDS's GOOSE interface for closed-loop testing of IED signals that adhere to the IEC 61850 standard, a GOOSE-based IED can be simulated.

These signals are broadcast using the GOOSE messaging system published in IEC 61850 and transferred over Ethernet through the communication switch. The Giga-Transceiver Network

(GTNET) Communication Card, a component of RTDS, makes it possible for physical devices set up in the testbed to transmit and receive signals.

7.3 Configuration of the IEC 61850 standard communication

By configuring the SEL-487E and MiCOM-P645 device, RTDS GTnet, to specify the signals that need to be broadcast, the communication between the GTNET cards in RTDS/RSCAD and IEDs is established. This part makes using the GTNET hardware for IEC 61850 standard communication possible.

7.3.1 Configuring the GOOSE Algorithm Message

Configuring the GOOSE Algorithm and Logic Flow Message involves defining a structured sequence of actions and parameters that guide how GOOSE messages are processed and responded to within the substation's intelligent devices. It encompasses both the logical flow of operations and the underlying algorithms that govern the behavior of GOOSE messages. Together, these concepts represent the systematic approach to managing GOOSE messages in a substation environment. They ensure that critical events, such as faults or alarms, are efficiently communicated and acted upon, contributing to the reliable and secure operation of the electrical grid.

- **Logic Flow GOOSE message**:
  Is a sequence of steps or actions taken when processing GOOSE messages in an electrical substation or similar critical infrastructure environment. This logical flow ensures that real-time event data is properly received, validated, and acted upon. It encompasses the high-level process from message reception to response and maintenance Figure 7-1 shows the Logic Flow GOOSE message.

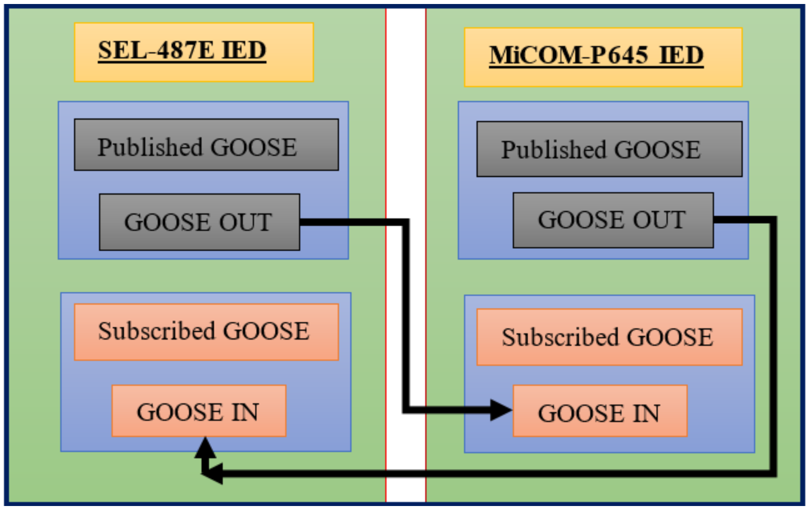

Figure 7.1: Logic Flow GOOSE message

- **GOOSE Messages Processing Algorithm**:

  Is a detailed set of instructions and procedures that define how GOOSE messages should be handled and processed within a substation's intelligent devices and communication systems. This algorithm provides a structured framework for validating, timestamping, locally processing, and responding to GOOSE messages while considering factors like security, redundancy, and real-time performance. Figure 7-2 shows the GOOSE Messages Processing Algorithm.

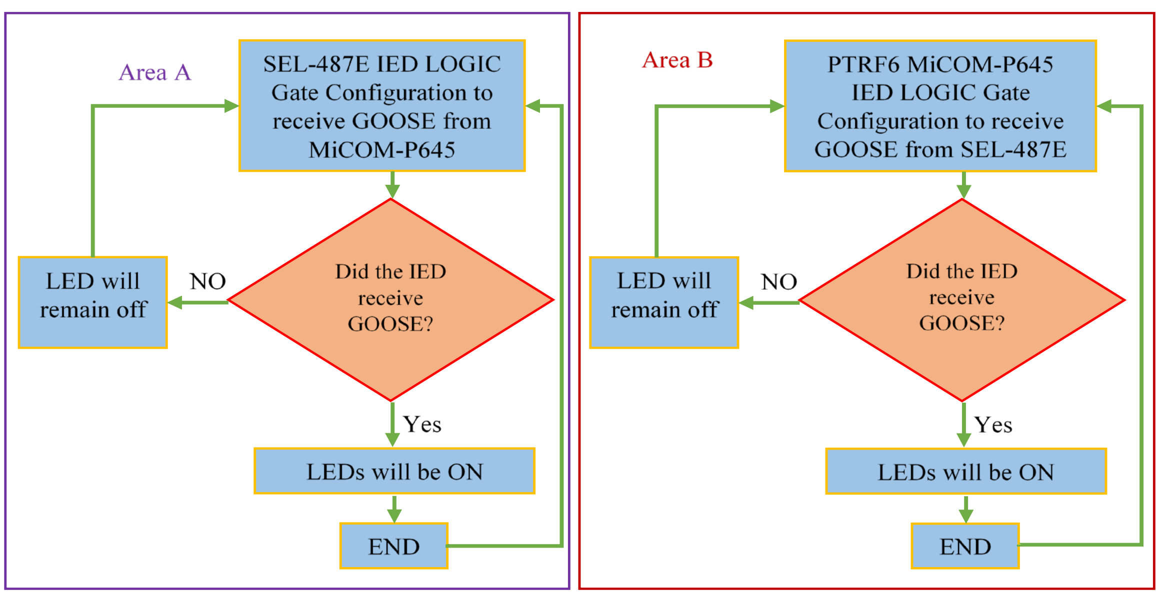

Figure 7.2: GOOSE Messages Processing Algorithm

In pursuit of improved interoperability and performance for IEDs in parallel power transformer differential protection, a GOOSE communication system based on the IEC 61850 standard has been meticulously crafted. This system's primary objective is to establish a fast and reliable communication link among various IEDs. Part of its development involves rigorous testing of GOOSE messages in an HIL simulation environment. These tests comprehensively assess the system's reliability under various operational conditions, ensuring a seamless exchange of real-time event data essential for power transformer protection and control.

7.3.2 Configuring the SEL-487E and MiCOM-P645 device's GOOSE messages in Engineering

The configuration of the MiCOM-P645 and SEL-487E Differential Transformer Protection and this section accomplishes the control device using the software MiCOM S1 Agile MCL and AcSELerator Architect, respectively. Both operational conditions of the resultant interconnected system are fulfilled after this scheme has been configured. For publishing status events across Ethernet, logical nodes (LNs) that correspond to the ANSI relay word bits must be used. The list of equivalent LNs for SEL487E and MiCOM P645 is shown in Table 7.1 below.

Table 7.1: List of SEL-487E and MiCOM P645 word bits relay and logical protection nodes

Physical IED Name	Logical Node	Attribute
SEL-487E	D87RAPDIF1	Op.general
		Str.general
	D87RBPDIF2	Op.general
		Str.general
	D87RCPDIF3	Op.general
		Str.general
	D87UPDIF1	Op.general
	D87RPDIF1	Op.general
	PSVGGI01	Ind01*
	PLTGGI02	Ind01*
MiCOM-P645	DifPDIF1	Op.general
	PTRC1	Str.general
	PTRC1	Tr.general
	GosGGI02	Ind1
	GosGGI02	Ind2

The MiCOM-P645 and SEL-487E Protection Automation and Control device's configured IED description (CID) file is configured using the logical nodes (LNs) listed in the table above. When the relay publishes the message containing the trip's status event to the circuit breakers, the RTDSs can use this file to configure the datasets sent over Ethernet. Several steps were taken for this relay's CID file configuration, and the snapshots are used to demonstrate how this configuration was accomplished.

7.3.2.1 SEL-487E IEDs on AcSELerator Architect Software

To communicate with GOOSE messages following the IEC 61850 protocol, you can configure SEL devices using the AcSELerator architect. Configurable IED description files, GOOSE messages, Datasets, and SCL files can all be created and edited using AcSELerator Architect. The CID file is hosted within this special file SCL type, which also houses all the relevant information to the substation. The device (IED) simulated within the SCD file is described in the CID files within the SCD file. Figure 7-3 clearly illustrates the essential parts of the AcSELerator Architect configuration tool and the IED properties, including IP address, Subnet mask, and Gateway.

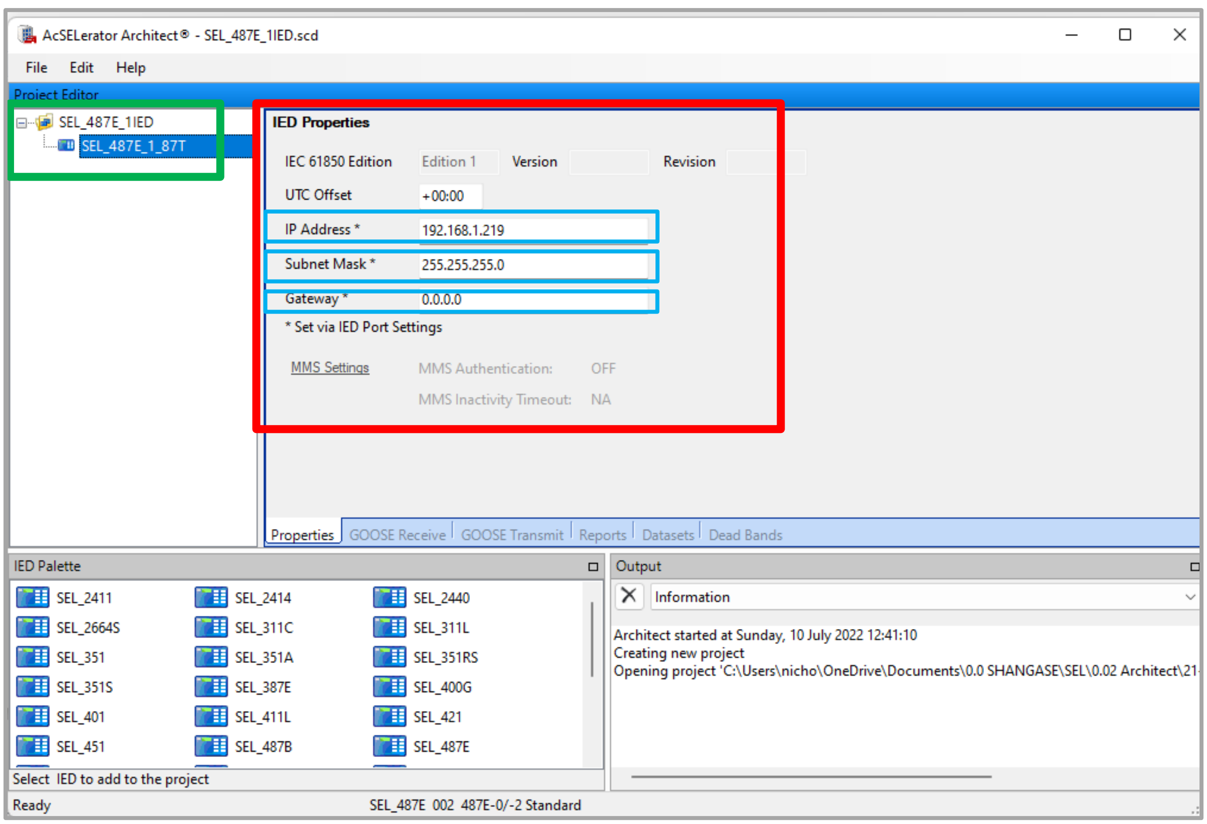

Figure 7.3: Main window of AcSELerator Architect

The project editor, IED configurations, and IED Palette tab are the three primary elements of the configuration tool, as shown in Figure 7-3. All SEL devices that adhere to IEC 61850 are listed in the IED Palette. A device is dragged into the project editor from the IED palette when starting a new project. The IED configuration window appears once a device has been successfully added to the project editor and requests the IED ClassFileVersion definition and the device's Description. The IED was renamed after it was successfully dropped and defined. We defined the device IP address, Subnet mask, and Gateway in IED properties. According to Figure 7-3, the GOOSE transmit configuration, GOOSE receive configuration, IED properties, Reports, dataset, and Dead bands configuration tabs are all parts of the IED configuration. By clicking the edit tab from the Dataset configuration menu, the newly created SEL-487E dataset to be published is defined by clicking on the indicated area A and area B as illustrated in Figure 7-4.

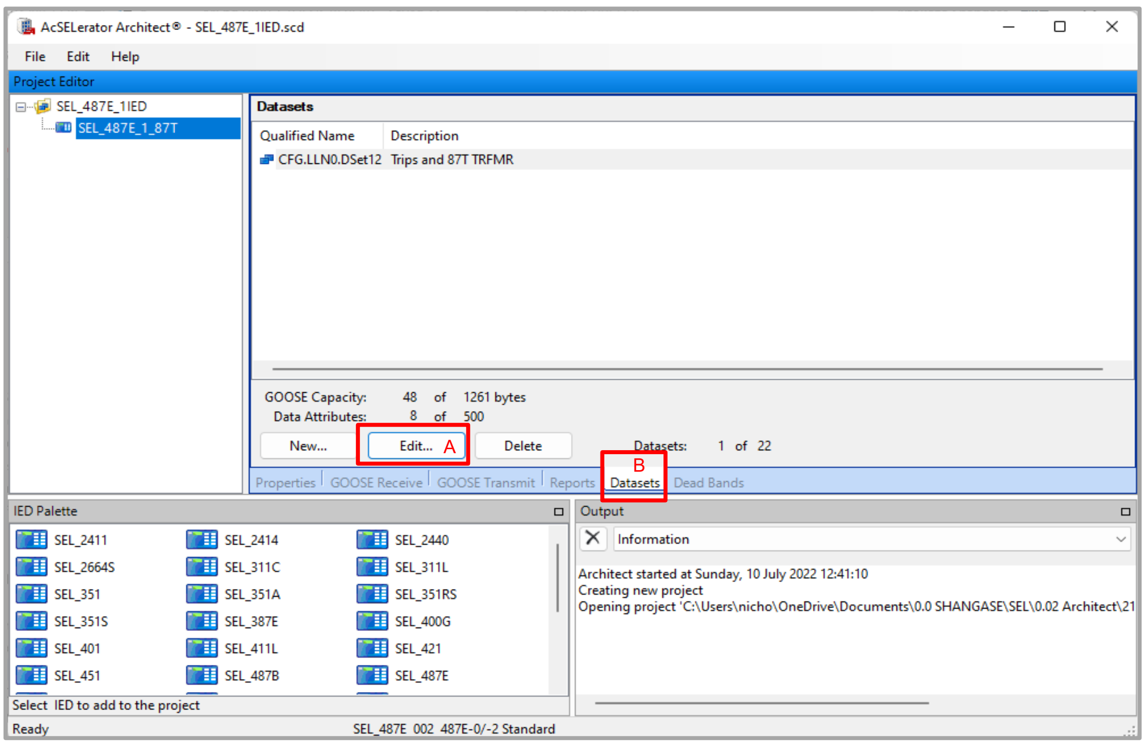

Figure 7.4: Datasets Definition

The window in Figure 7-5 contains a list of the new datasets defined for the SEL-487E relay, which appears when the "edit" button is clicked. By dragging and dropping the datasets from area B in the column to area C, only the differential element datasets are utilized for the protection scheme.

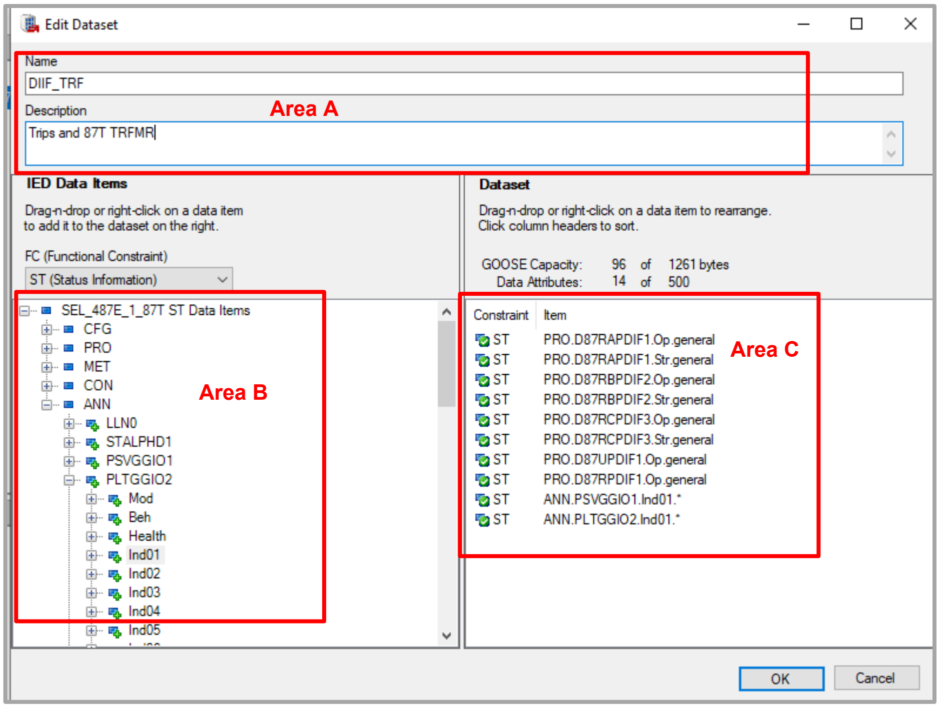

Figure 7.5: Configured data attributes for SEL-487E

As seen in Figure 7-6, the selected attributes/datasets are assigned to a GOOSE send with the provided logical node (LN), as seen in area A. The name, subnetwork, MAC address, and description of GOOSE are shown once the transmission mapping is finished, as can be seen in area C.

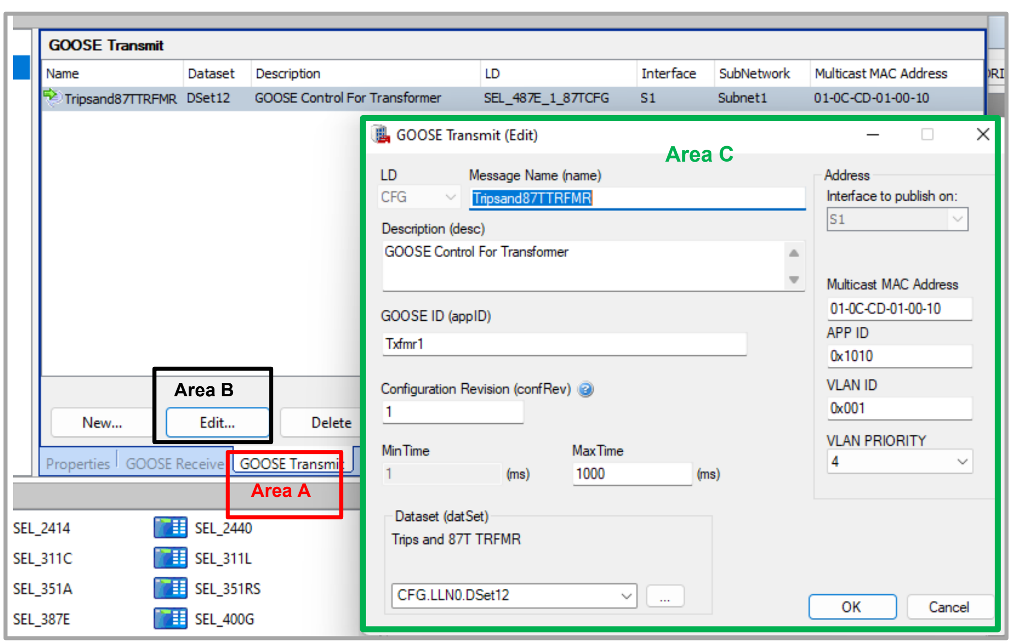

Figure 7.6: GOOSE transmits data set transfer mapping

After then, the SCD file is stored locally on the PC. The CID contains information about the GOOSE messages it should deliver and is transmitted to the IED when the SCD file is saved. The connection is first validated and confirmed in the terminal command window by pinging the actual IED using the IP address before it is transmitted. This demonstrates that the IED and PC are connected.

7.3.2.2 MiCOM-P645 IEDs MiCOM S1 Agile MCL Software

GOOSE messages connected to the element of each IED should be published over the LAN by configuring the MCL file for IED. In order to configure IEC 61850 GOOSE messages, there are a few key procedures that must be accomplished:

- GOOSE control blocks for IED configurator.
- New MCL File creation.
- Establish Communications.
- Establish Definitions for Datasets.
- GOOSE Publishing configuration.
- Establish GOOSE Subscribing.

a) GOOSE control blocks for IED configurator

First, you need to enable the GOOSE control blocks on the IED Configurator. The parameters for publishing a Dataset across the Ethernet LAN are specified via the GOOSE control block. We can connect Datasets to a maximum of eight separate GOOSE control blocks in the IEC 61850 Version 2 implementation. For GOOSE messages to function, the IED must have at least one GOOSE control block activated. It is a necessary procedure to leave the other GOOSE blocks deactivated if they aren't being used. Depending on the relay, the Front Panel or S1 Agile Software may be required to configure the GOOSE Control Block.

Open the settings file and find setting IED CONFIGURATOR -> GoEna. Gcb01 GoEna can be enabled by checking the corresponding box in the GoEna settings window that appears when you double-click the value field. Save the modifications by selecting OK, as shown in Figure 7-7.

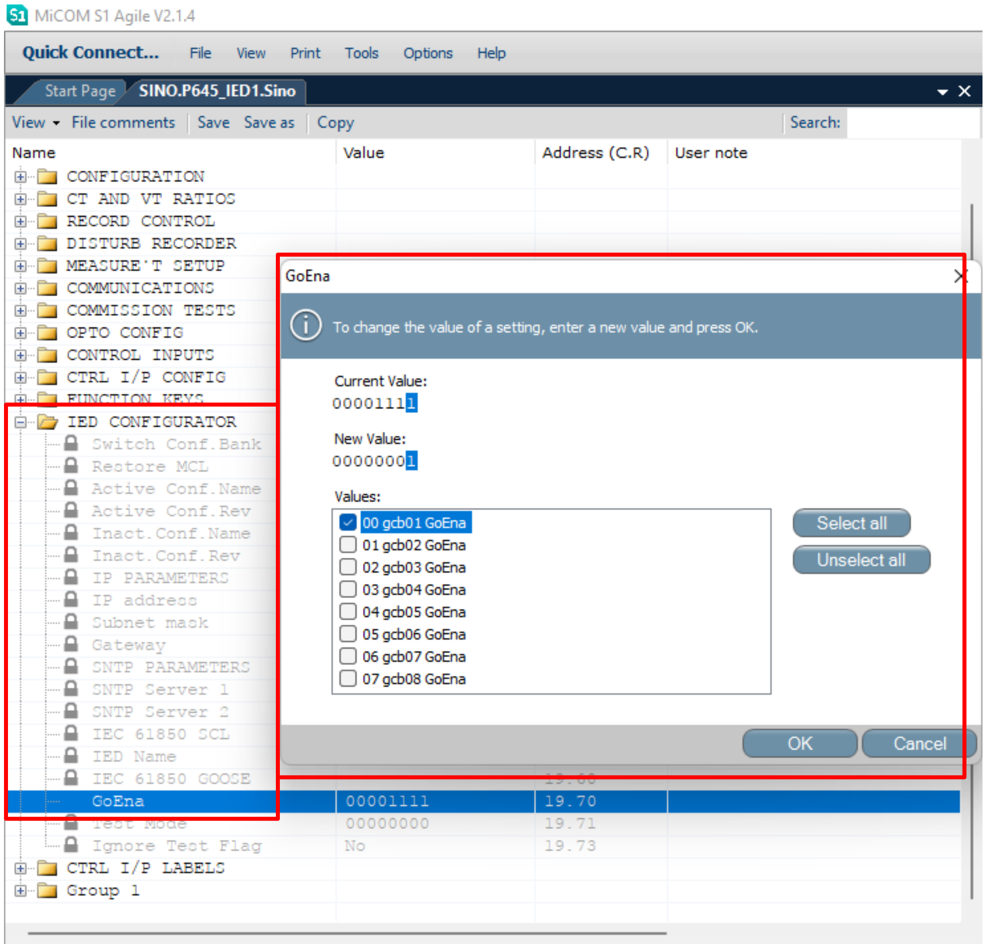

Figure 7.7: Gcb0X GoEna setting for MiCOM P645

b) Configure a new MCL file and edit it

Open the 000.MCL file after creating a new MCL file under System Explorer's Device > MCL-61850 tab. As seen in Figure 7-8, the IEC61850 IED Configurator window will appear. Click the "+" sign to expand the TEMPLATE tree on the left side of the explorer window. Click the Manual Editing Mode icon in the top toolbar menu. This will enable editing of the file and unlock all fields in the IEC 61850 IED Configurator. To open the IED Details window on the right-hand side, click IED Details. You can name it as shown in Figure 7-8 in the Name field.

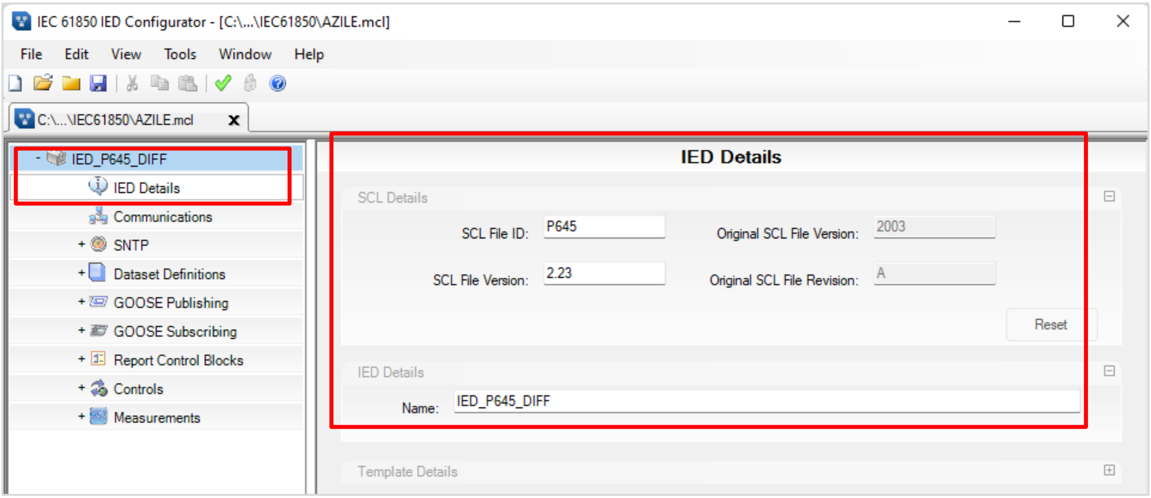

Figure 7.8: **MiCOM P645 MCL Configuration setting**

c) Configure Communications

Enter the address configuration information, such as IP address, Subnet mask, and Gateway Address, and select the Media configuration of your IED as specified in the Manual by clicking on Communications to examine the communication settings on the window. All the settings are shown in Figure 7-9.

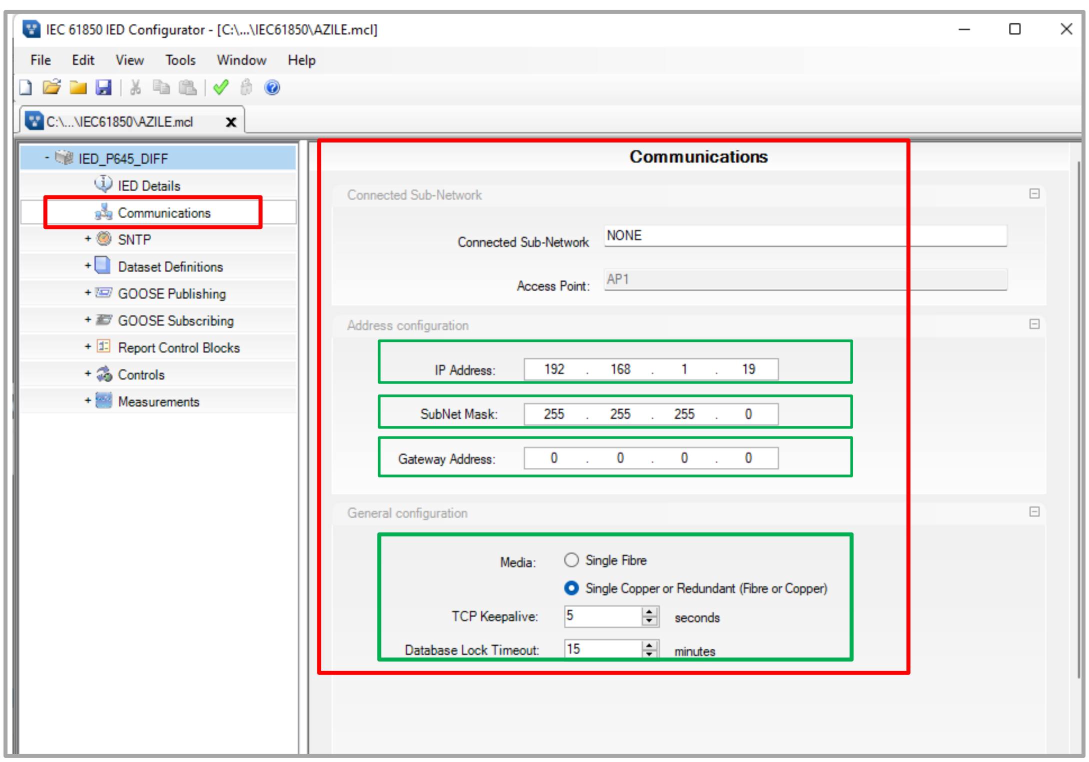

Figure 7.9: **Configuration of Communications for MiCOM P645**

d) Create Dataset Definitions and Report Control Blocks

The location of the dataset within the IED must be specified before choosing the data item it will include. Click the Add Dataset icon in the main window after selecting Dataset Definitions. Choose the dataset's location by choosing Protection and then clicking the Set command. Click the Add item button in the Dataset Definition panel to choose a specific data object. Verify the data object has been defined as a dataset component by looking in the Dataset Definitions window System\LLN0\trfmr_diff, as shown in Figure 7-10.

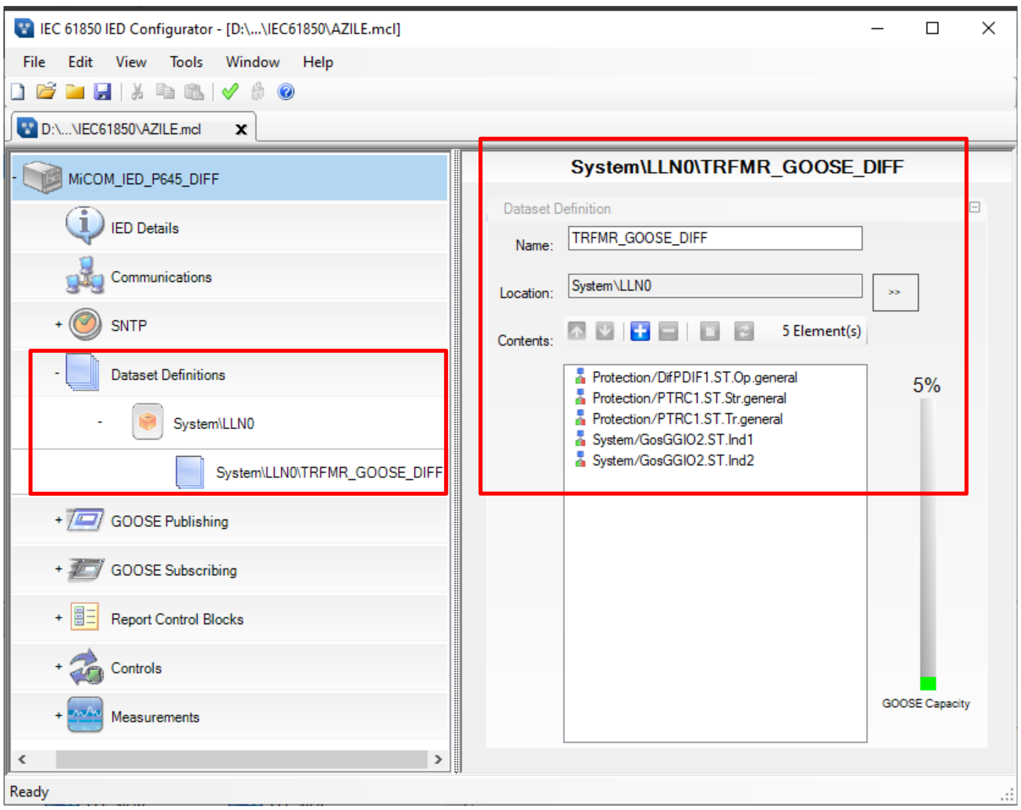

Figure 7.10: **Dataset Definition for MiCOM P645**

The Report Control Blocks are configured by linking; the dataset that was created, as shown in Figure 7-11 below.

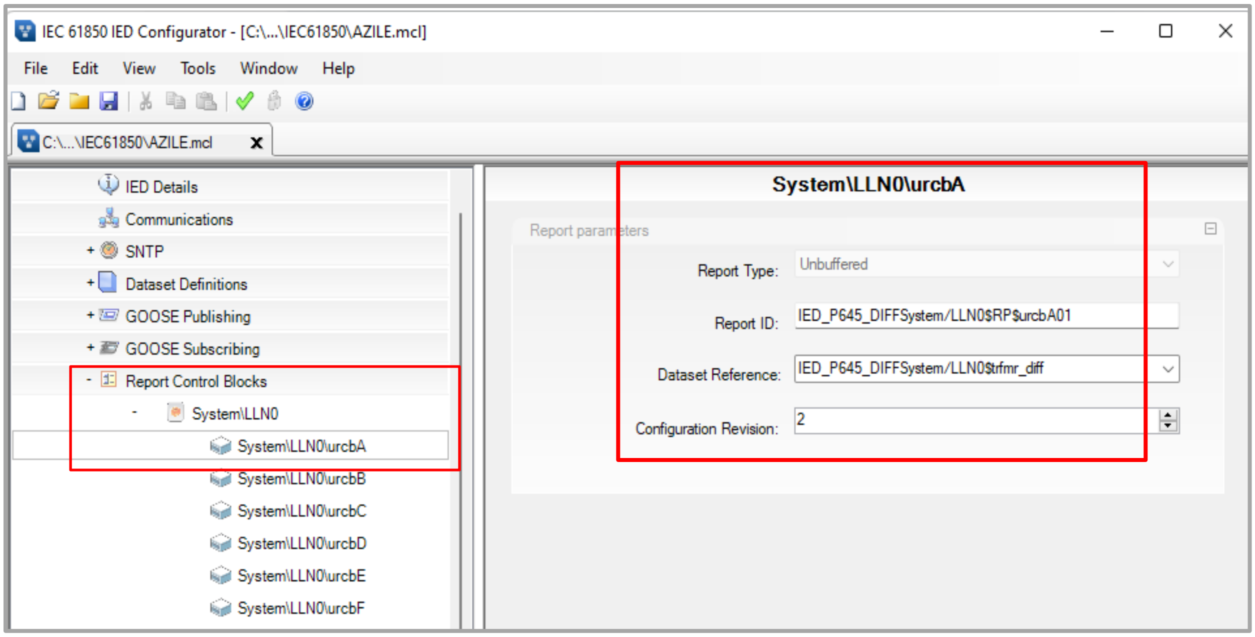

Figure 7.11: Configuration of Report Control Blocks for MiCOM P645

e) Configure of GOOSE Publishing

Link the dataset established in the previous step to the GOOSE control block gcb01, which was activated on the GOOSE Control blocks for IED CONFIGURATOR, to configure GOOSE Publishing. Set the Dataset Reference field by choosing it from the dropdown menu and setting the Application ID (hex) field to 1. Figure 7-12 shows the Configuration of GOOSE Publishing, showing the network parameters (MAC address, application ID (hex), VLAN priority), repeat message transmission parameters (cycle time), and message data parameters (GOOSE identifier). When you're finished configuring, you can save the 000.mcl file and check the MCL configuration files for mistakes by validating them. On the IEC61850 IED Configurator window, we can go to Tools and export the CID file; this file will be used letter when we configure the GTNet. After that, you can close the IEC61850 IED Configurator MCL configuration window.

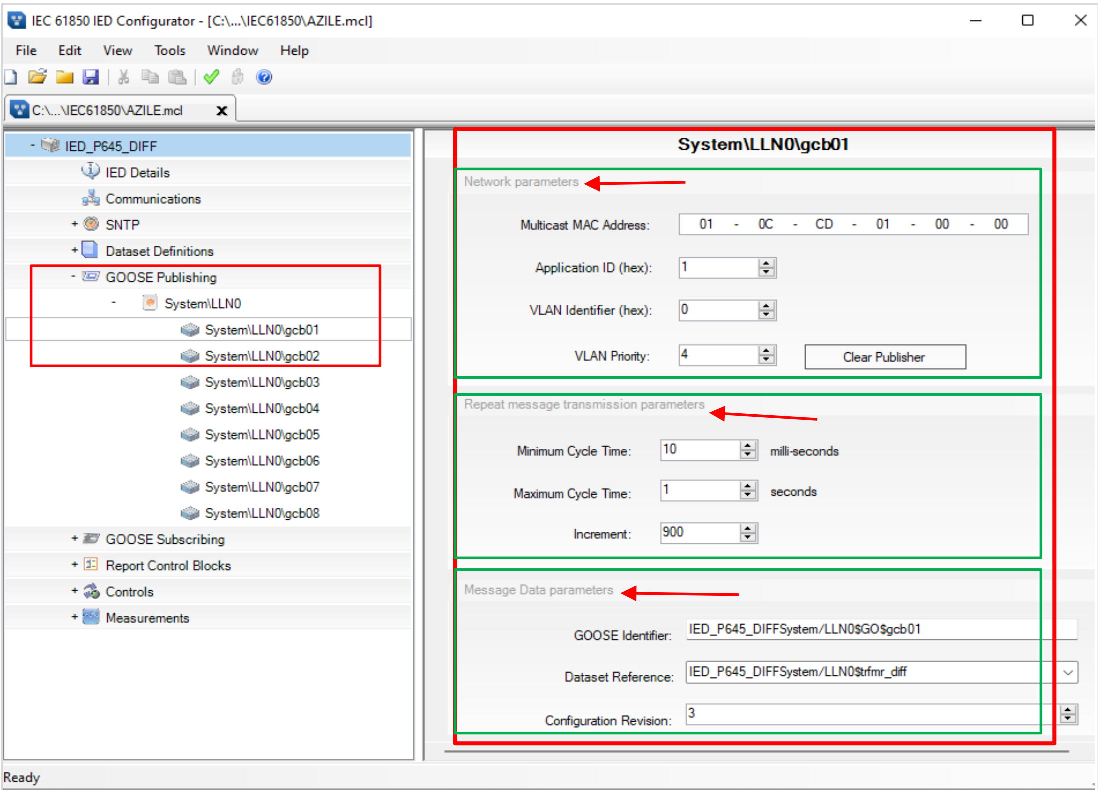

Figure 7.12: Configuration of GOOSE Publishing for MiCOM P-645

7.3.2.3 Configure GOOSE Subscribing/receive

During the subscribing/receiving of the file from one vendor to another, we can see the interoperability between the two if possible. The file that has been configured in section 7.3.1.1 and section 7.3.1.2 are IEC data model files shown in Table 7.2.

Table 7.2: The IEC data model files for SEL-487E and MiCOM P645

IEDs	IEC data models
SEL-487E	SEL_487_1_87T ST -PRO_D87RAPDIF1_OP.General
MiCOM-P645	MiCOM_P645_DIFF;System\LLNO -Protection/DIFPDIF1.ST.OP.General

All of the above configuration files can be exported as “CID” files and imported to different IEDs. However, on SEL-487E, you can export “CID & IID” only, while on MiCOM-P645, you can export as “CID, IID, ICD, & XML.” When subscribing/receiving (importing) on MiCOM-P645 from other IEDs, you can have access to the following files “SCD, IID, MCL, & CID.” While on the SEL-487E, you can have access to the following files, “SCD, ICD, & CID,” when subscribing from other IEDs.

a) SEL GOOSE Subscribing Configuration

It is necessary to assign the received GOOSE message to a specific function within the SEL-487E IED. To accomplish this, double-click the GOOSE message of the logical node to decode it fully, then drag and drop the status value onto a particular function, which is done using the AcSELerator Architect. According to Figure 7-13, the received GOOSE message for this application is mapped to CCIN002 and CCIN003 of the SEL-487E IED. If the MiCOM SCL file is dragged from Area D to area A, it will automatically appear in area B, where you have to drag it to area C to map it.

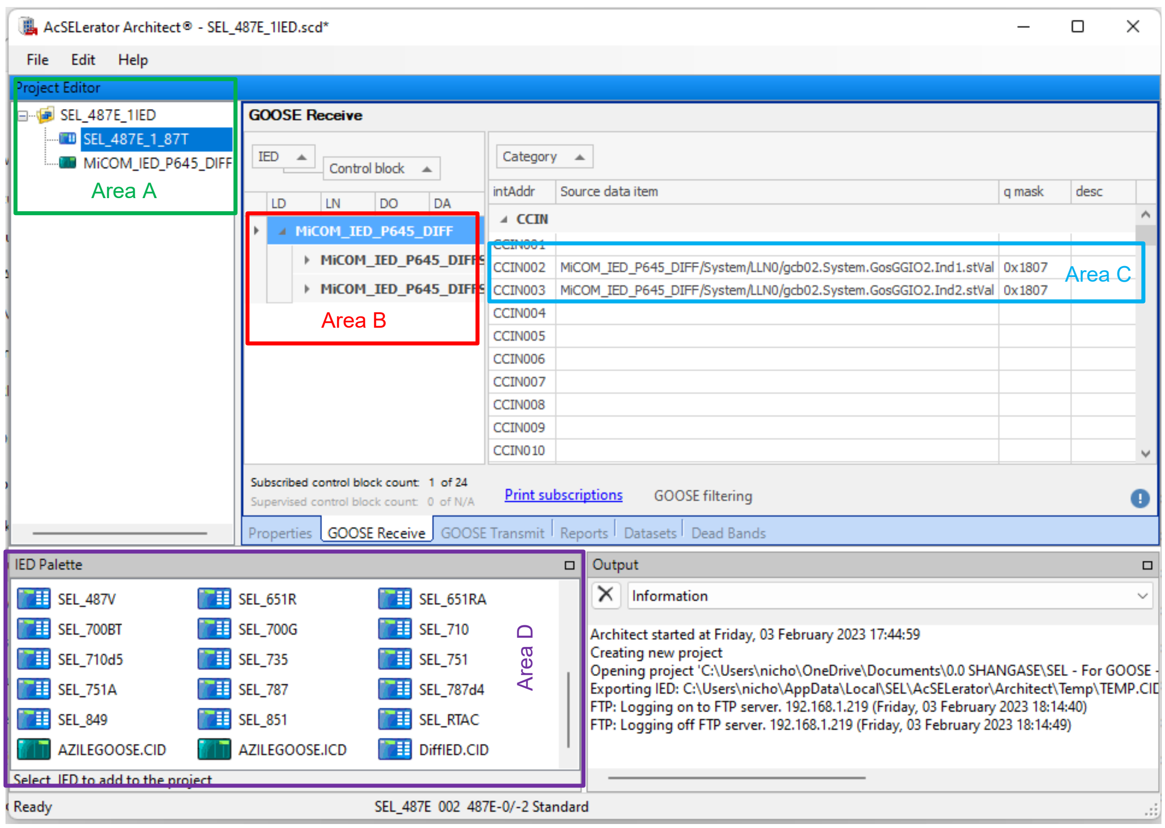

Figure 7.13: **SEL-487E Configuration of GOOSE received from the MiCOM P-645**

b) MiCOM GOOSE Subscribing Configuration

The GOOSE message broadcast by the other IED must be subscribed to as the last step in the configuration of the MCL file. The System\GosGGIO1\Ind1.stVal data object can be found by expanding the GOOSE Subscribing node in the tree explorer interface. Under the GOOSE Source parameters tab, select the command Browse. Choose (CID) from the Files of type drop-down menu after locating and selecting the IEC 61850 folder that houses the CID or SCL file for the other IED. Verify that the SEL-487E data object is subscribed to the MiCOM-P645 data object by filling in all the necessary GOOSE Source parameters. Figure 7-14 shows the Configuration of GOOSE Subscribing.

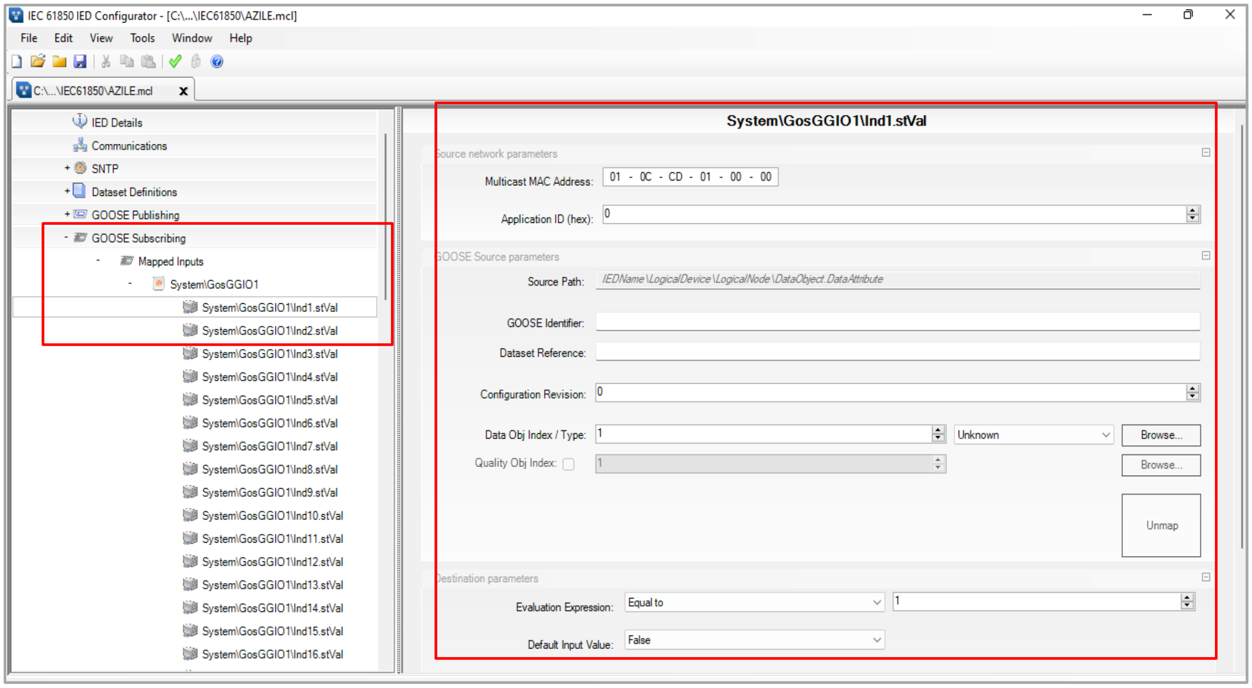

Figure 7.14: Configuration of MiCOM P-645 GOOSE Subscribing from SEL-487E

c) Discussion

What is observed from the above is that both IEDs communicate well because there is no missing information during the exportation and importation of their files. In conclusion, the interoperability is 100% functioning.

7.3.2.4 Sending the Configuration file to IED

a) SEL File to SEL-487E IED

IED description CID files can be uploaded onto IEDs by selecting "Send CID" from the menu that appears when you right-click on a particular IED in the project editor. Before uploading the CID file to the SEL-487E IEDs, an access control window will appear, asking the user to enter log-in information. Figure 7-15 shows what happened once the settings file of the IED was properly transmitted; you need to put the IP address, user name, and password, which are provided in the SEL manual. Figure 7-16 shows the CID file sent on the IED successfully, as seen in area B. Once the CID file is successfully sent on the IED, we can go to the file and export the CID file in area A; this file will be used letter when we configure the GTNet.

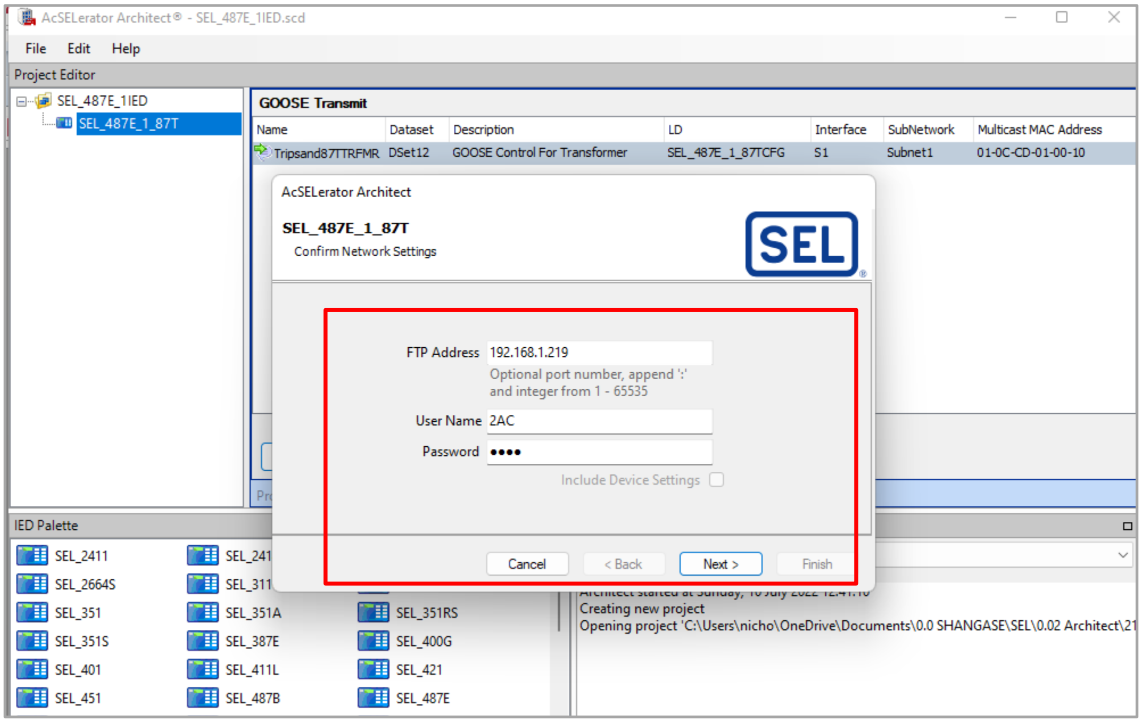

Figure 7.15: CID file transmission to the physical IED SEL-487E

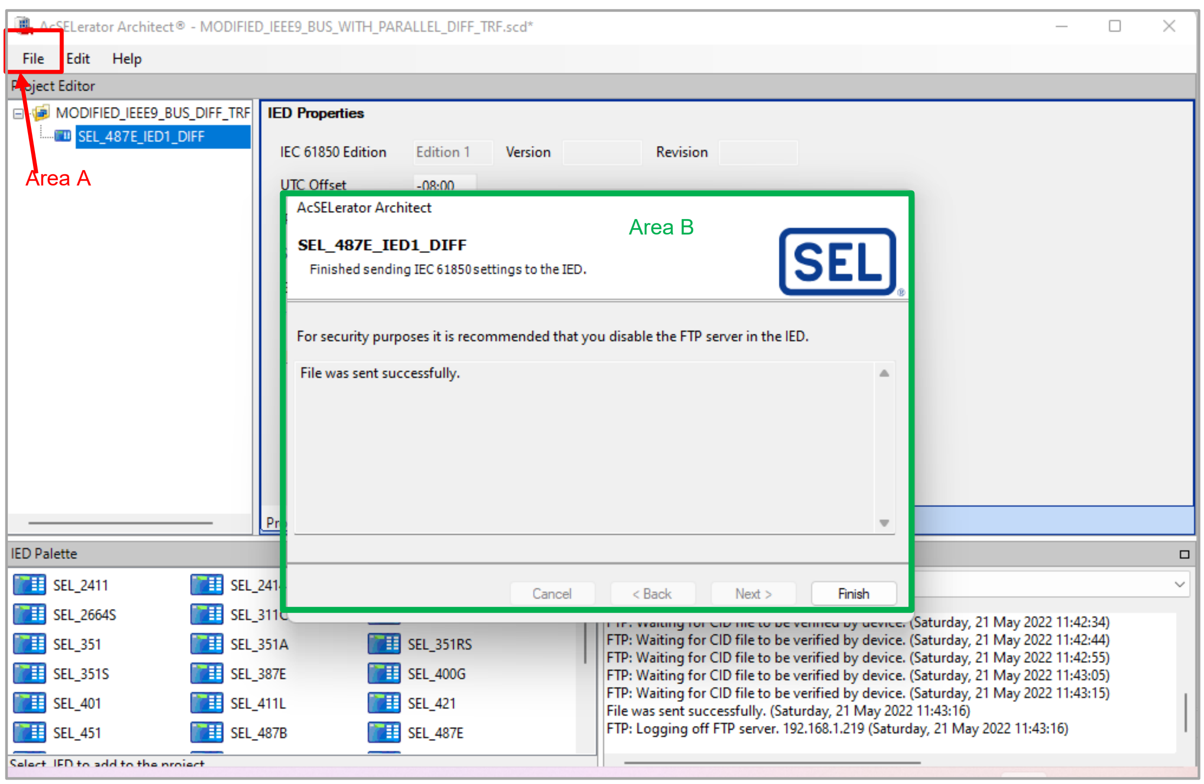

Figure 7.16: The CID file was sent successfully to the SEL-487E IED

b) MiCOM File to MiCOM-P645 IED

Now you can send all the configuration of the files to the MiCOM IED as shown in Figure 7-17 before you select the MCL file, you need to validate it again, then select and send all the files to the MiCOM IED.

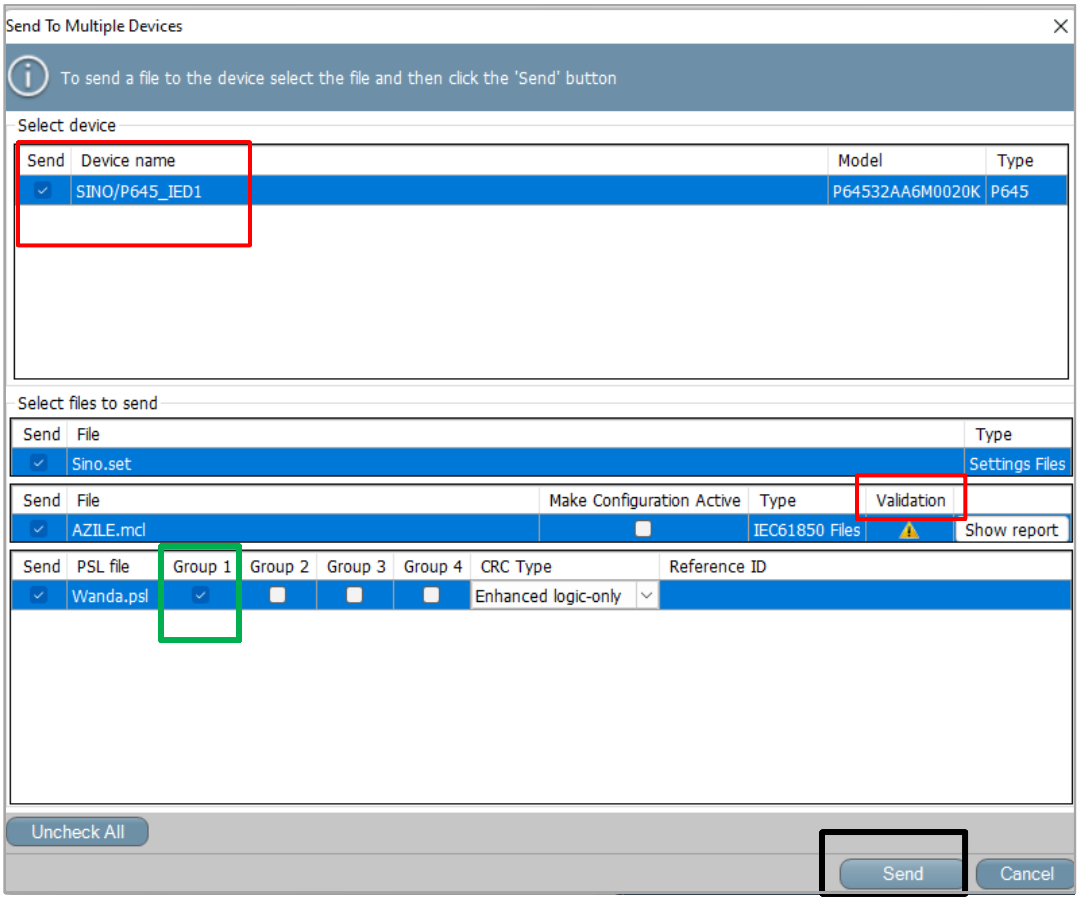

Figure 7.17: **Sending the configuration files to the physical MiCOM P-645 IED**

The following window, which shows a successful transfer of files to the device, as shown in Figure 7-18, will appear once all the settings have been transmitted to the IED. Figure 7-18 area A, area B, and area C show the successful operational event of file settings .Set, .MCL, and PSL respectively. Using the relay's front panel HMI, confirm that the MCL configuration files were successfully uploaded to the IED, and verify that the IED Name field has been changed to the one you specified by going to IED CONFIGURATOR -> IED Name.

To make the MCL file active, you must right-click on the MCL 61850, click switch the banks, and restore the MCL file of the relay. Note: For the setting to take effect on some MiCOM IED models, the device must be restarted by cycling power to the relay.

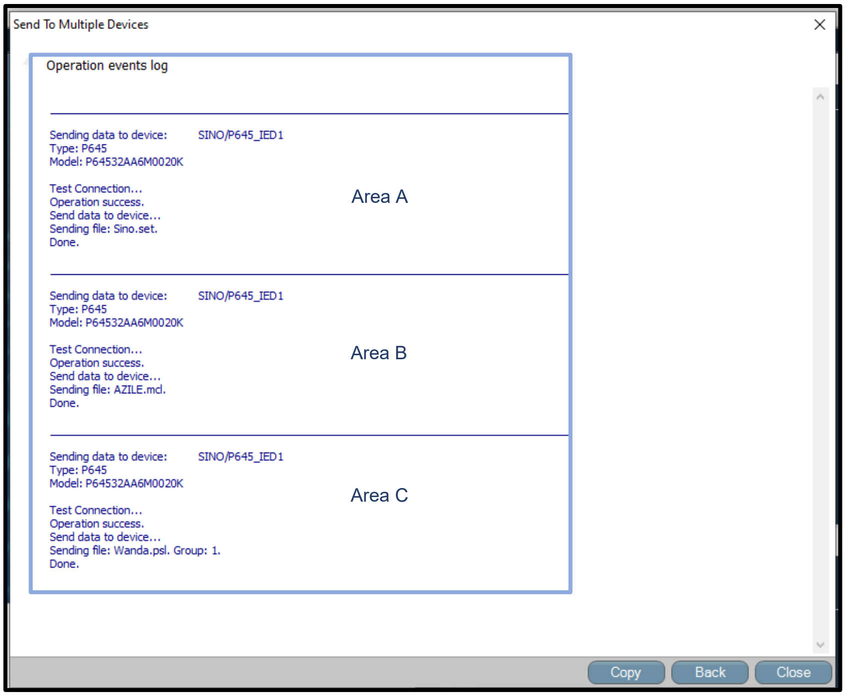

Figure 7.18: Confirmation message of the successfully sending the file to MiCOM P-645 IED

7.3.3 RTDS GTNet GSE card for GOOSE configuration

The RTDS makes use of the GTNET-GSE card to publish GOOSE communication messages over the Ethernet network. A GTNet's purpose is to subscribe to GSSE/GOOSE messages that are published by physical devices and use those signals to isolate faults by activating virtual system circuit breakers. The steps outlined here are used to create communication between the IEDs (SEL-487E and MiCOM-P645) and GTNET cards in RTDS/RSCAD. To configure the signals that require publication, it is necessary to import the GTNET-GSE component from the library. On the GTNET-GSE (RTDS/RSCAD), you can import the following file IEC-61850 "SCD, icd, & .cid", and XMF files. And its SCL file is saved as ".scd".

This part makes using the GTNET hardware for IEC 61850 standard communication possible. As shown in Figure 7-19 below, right-click to edit on the GTNET-GSE and select IEC 61850 Substation Configuration Language (SCD) template. Since we have to configure two different vendors of the IEDs on the GTnet-GSE, we have to enable two RX/TX parameters of GTnet, as shown in area A Figure 7-20. The GOOSE Control Box is shown in Figure 7-21, where the names of the IEDs MiCOM P645 and SEL-487E will be changed, corresponding with Gcb01 and Gcb02, respectively.

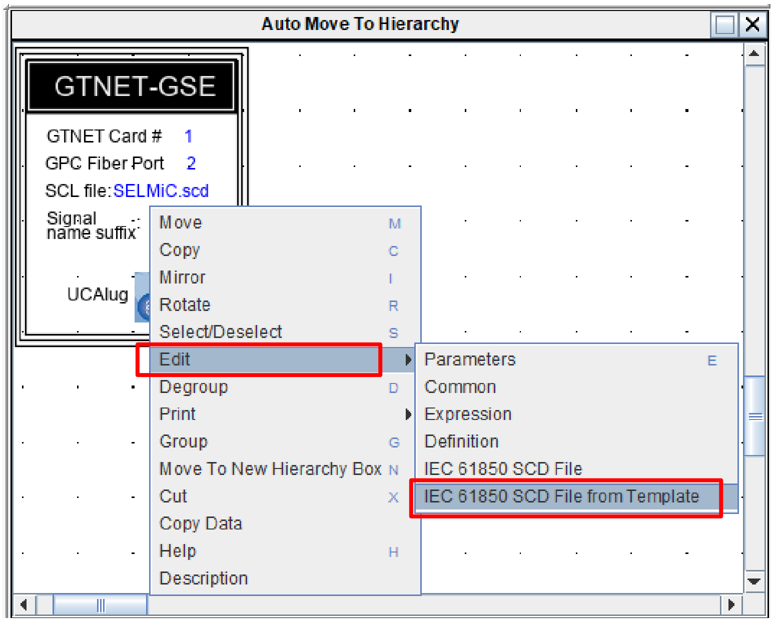

Figure 7.19: GTnet modeling of the IEC 61850 SCD file

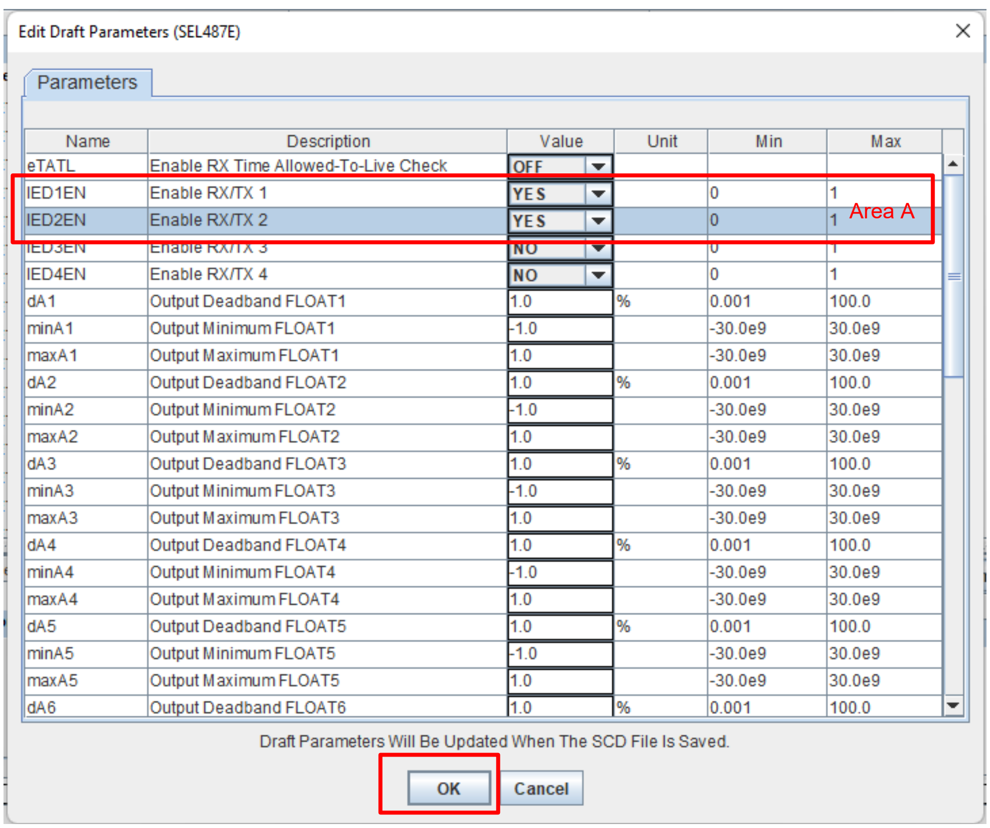

Figure 7.20: Enable the RX/TX parameters of GTnet

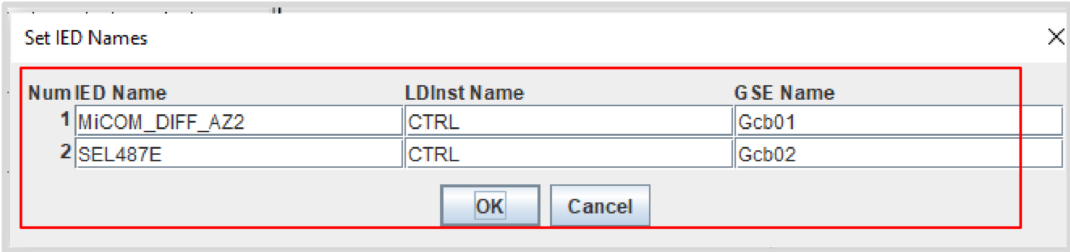

Figure 7.21: **GOOSE Control Box for MiCOM-P645 and SEL-487E**

After importing the two SCD files from SEL-487E and MiCOM-P645, the file contains data attributes that were created for status sharing (as defined by IEC 61850-7-2), as illustrated in Figure 7-22 and Figure 7-23. Within the RTDS simulation model, these data attributes are mapped to message lists for transport to virtual breakers for monitoring, control, and protection. Following mapping these attributes to messages, the file must be validated to complete the mapping process, as illustrated in area C, Figure 7-22, and Figure 7-23, respectively. After mapping is finished, the runtime must be compiled.

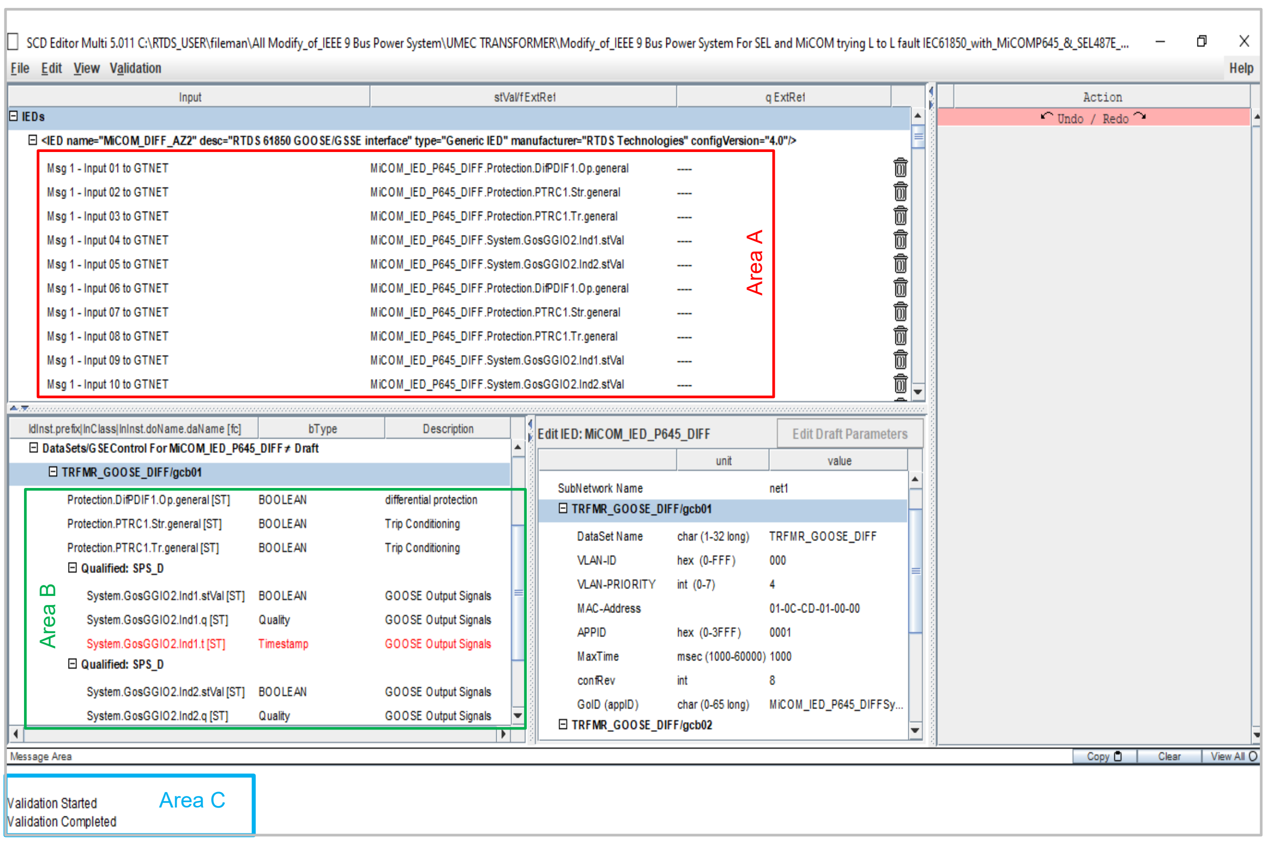

Figure 7.22: **MiCOM-P645 logical node mapping for GOOSE transmission**

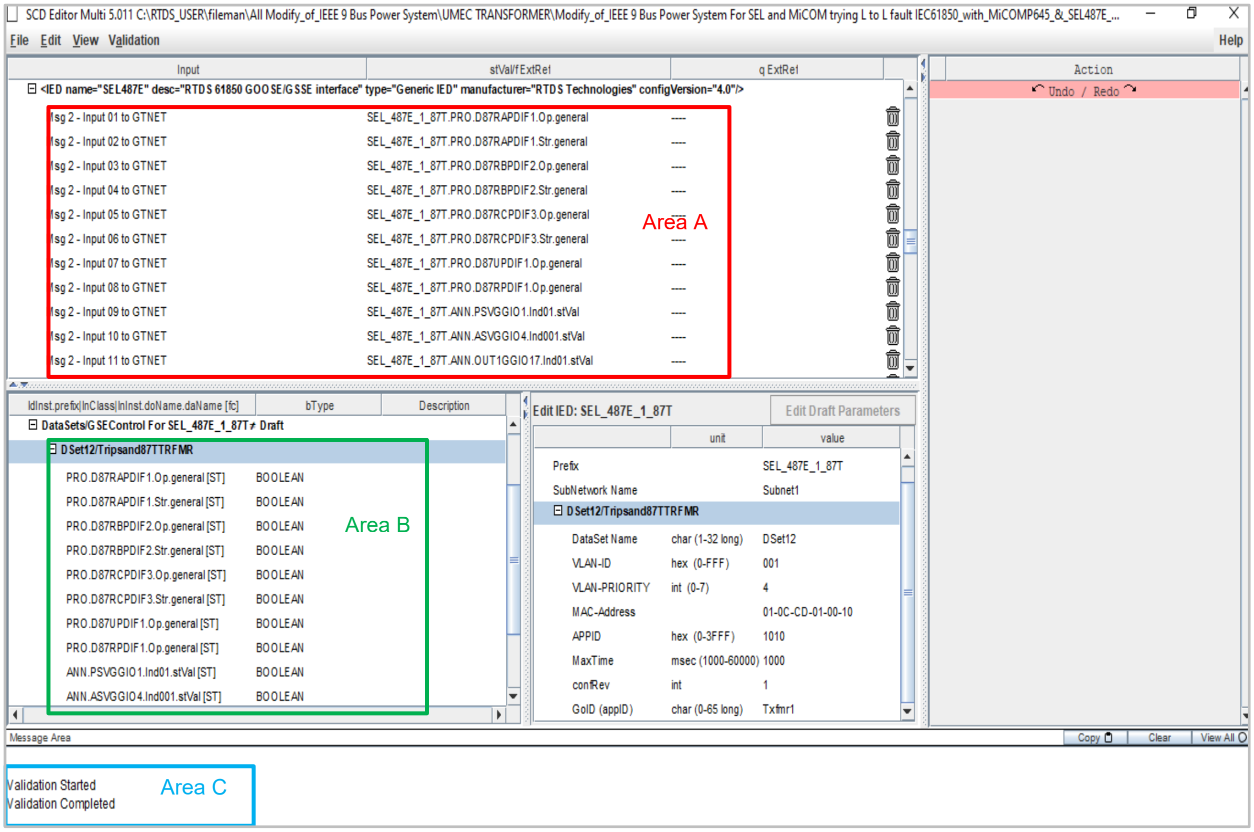

Figure 7.23: Mapping of logical nodes for GOOSE transmission for SEL-487E

Figure 7-20 only two RX/TX parameters were enabled for MiCOM-P645 and SEL-487E on the GTNET-GSE, requiring additional mapping of output signals from the GTnet component. Figure 7-24 shows the GTnet input signal settings for the MiCOM-P645 on the tab RX/TX 1 input signal. All SEL-487E settings are made on the RX/TX 2 input signal. In Figure 7-24 and Figure 7-25, the input words P645_GOOSE and S487E_GOOSE, respectively, are words that command Boolean bitmap signal input containing all the assigned GOOSE data attributes.

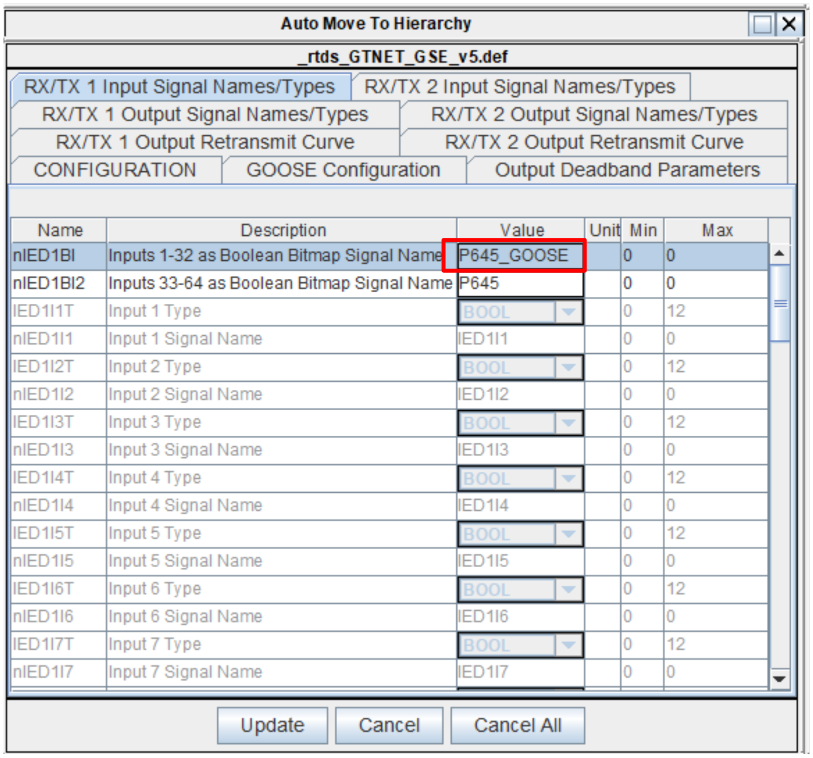

Figure 7.24: GTnet input signals for MiCOM-P645

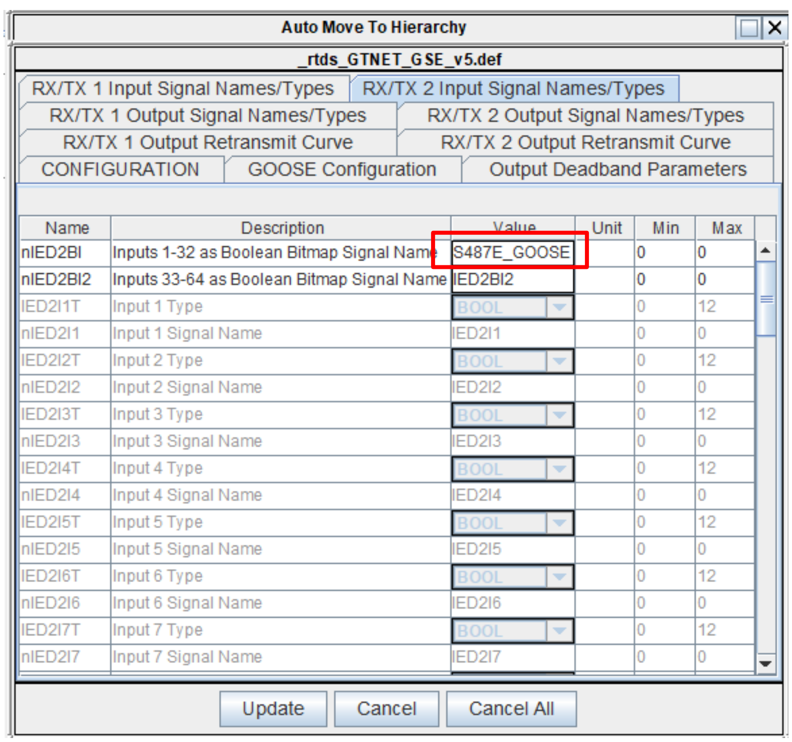

Figure 7.25: GTnet input signals for SEL-487E

This word input GOOSE is converted using a word-to-bit converter to produce the output data attributes that correspond to those defined during the IED's GOOSE configuration. The output of the word-to-bit converter (operating digital bits (1's and 0's) signals) is the input to the circuit breakers. Figure 7-26 shows the GTnet-GSE to word-to-bit converter interface.

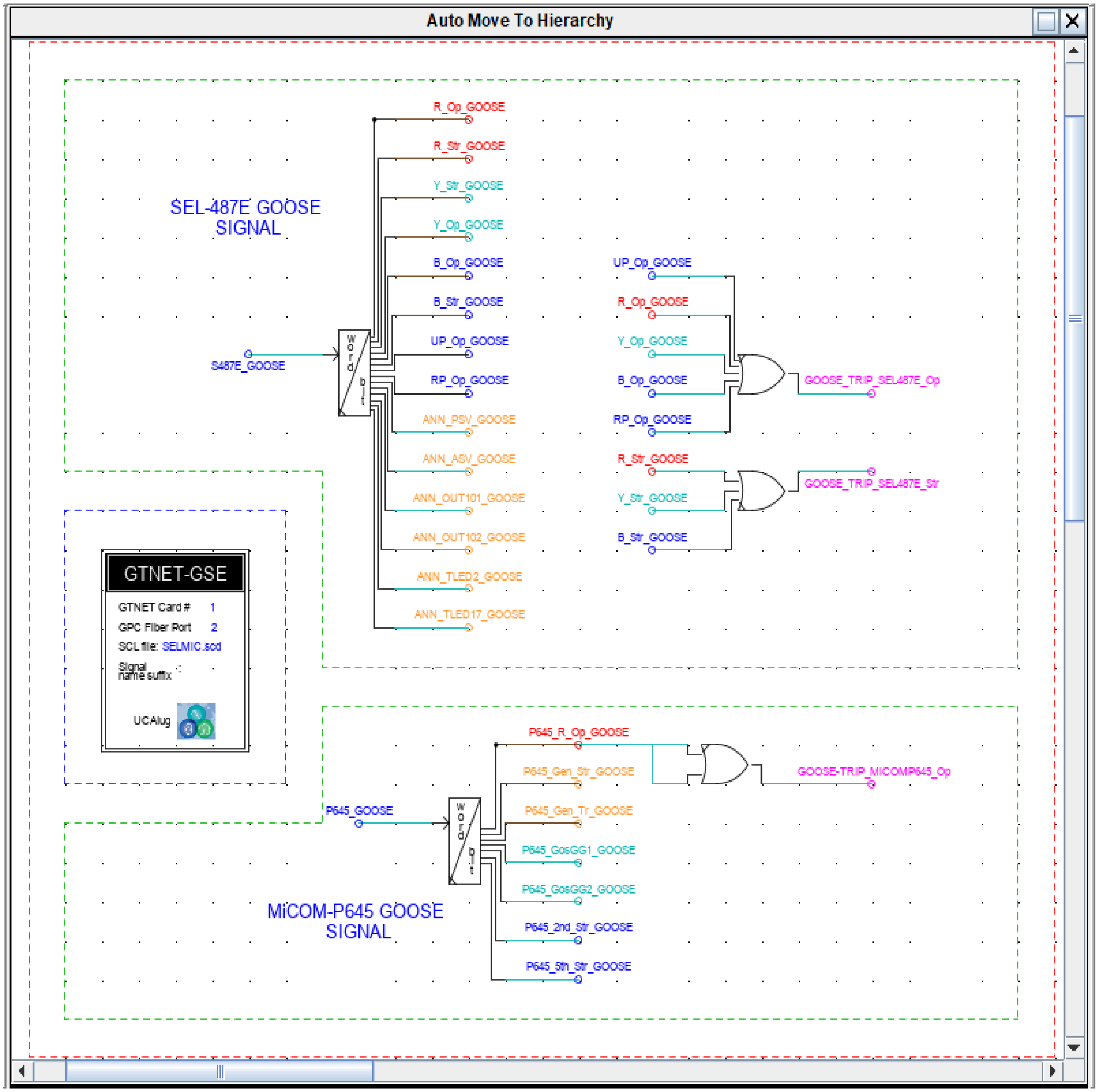

Figure 7.26: GTnet to word-to-bit converter interface for SEL-487E and MiCOM-P645 IEDs

Figure 7-27 shows the control logic Circuit breaker that gets input from the output of the word-to-bit converter (operating digital bits (1's and 0's) signals) from the GTnet GOOSE simulation. There are several areas in Figure 7-27: area A is the input GOOSE to the trip system via LAN, and area B is for hardwire trip signals; these areas are all new modifications of the original circuit that were taken on one of the examples on RTDS. The other part of the new modification/added includes all other areas such as (C, D, E, and F). The original circuit breaker is shown in Appendix C.

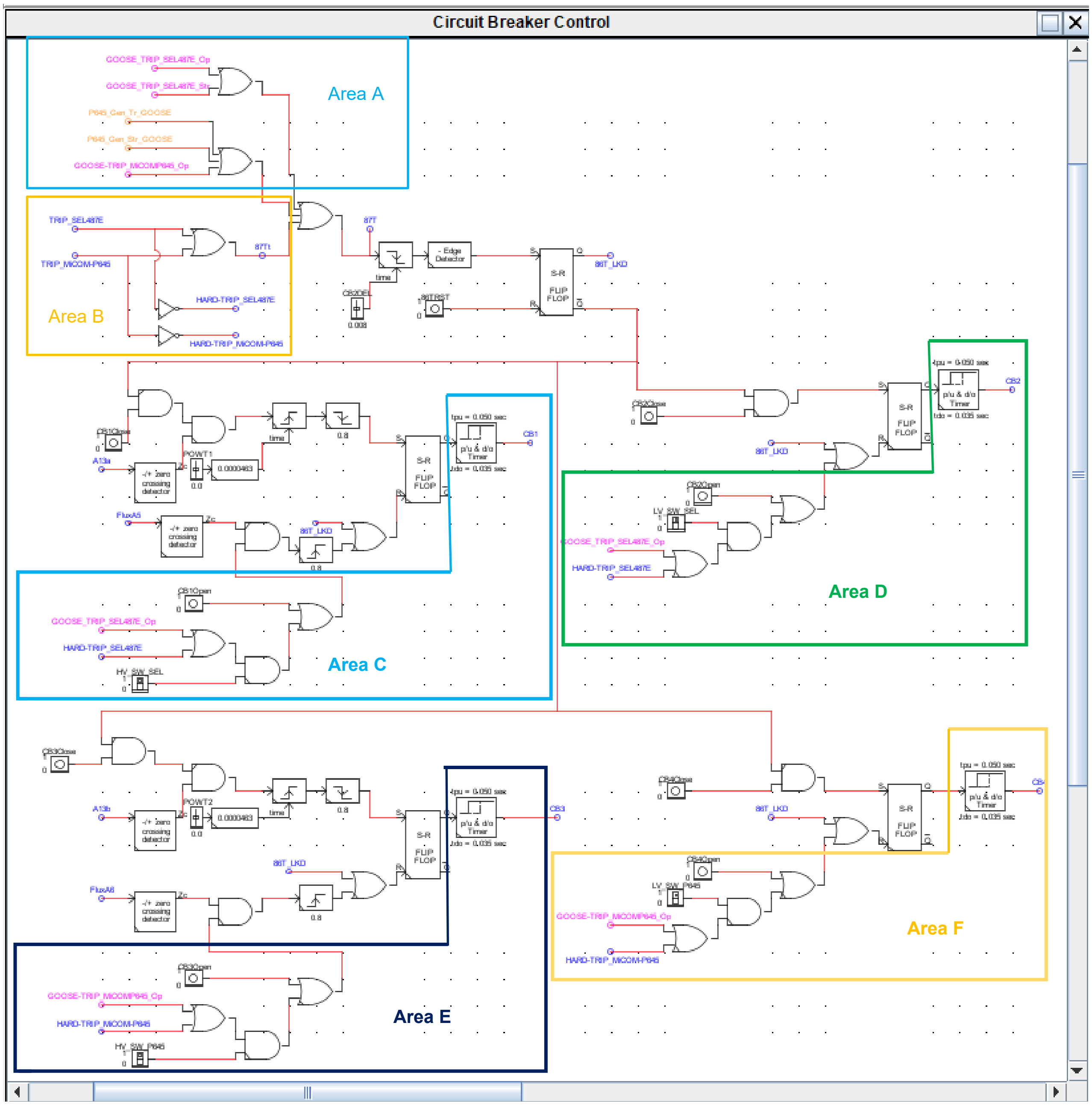

Figure 7.27: The logic responsible for controlling the circuit breaker

The circuit breakers are designed to open automatically when there is an internal fault and manual with the pushbuttons. The fault control logic circuit is still the same as the one in Figure 5-12. After mapping the output signal from RSCAD, the subsequent step involves saving the file and compiling the project. Once the compilation is done, run the simulation and verify the output signals published by GTNET using GOOSE inspector, section 7.3.4 will briefly explain this software and its simulation.

7.3.4 Configure Graphical GOOSE logic for SEL-487E and MiCOM-P645 for interoperability

The next step is configuring the required logic control of the GOOSE for both IED devices to confirm the interoperability between SEL-487E and MiCOM-P645 as per the case study. Table 7.3 is the case summary of the graphical logic for GOOSE interoperability that has been developed in Figure ***7-28*** and Figure 7-29 for SEL-487E and MiCOM-P645, respectively.

Table 7.3: Case summary of the Configure Graphical logic for GOOSE interoperability

DEVICE'S	CASE STUDY
SEL-487E	SEL device subscribes to MiCOM device GOOSE message. LEDs should illuminate on receiving the GOOSE message from the MiCOM device generated during the internal fault, and the SEL-487E IED device must publish a GOOSE message.
MiCOM-P645	MiCOM device subscribes to SEL device GOOSE message. LEDs should illuminate on receiving the GOOSE message from the SEL device generated during the internal fault, and the MiCOM-P645 IED device must publish a GOOSE message.

For SEL-487E configuration, choose the "Group 1" settings file and expand it to display the sub-settings files. To access the graphical settings file shown in Area B Figure 5-23, choose "Graphical Logic 1" from the options. Figure ***7-28*** shows the Configure Graphical GOOSE logic for SEL-487E in area A; there are two Incoming GOOSE "CCIN00x" that will accept GOOSE from MiCOM-P645, and the output is the LEDs, namely "T8_LED" and "T12_LED". Area B in Figure ***7-28*** is to publish a GOOSE message to MiCOM-P645 during the SEL-487E internal trip fault; an output is required, "CCOUTx" and the two LEDs are set up to monitor the GOOSE message status.

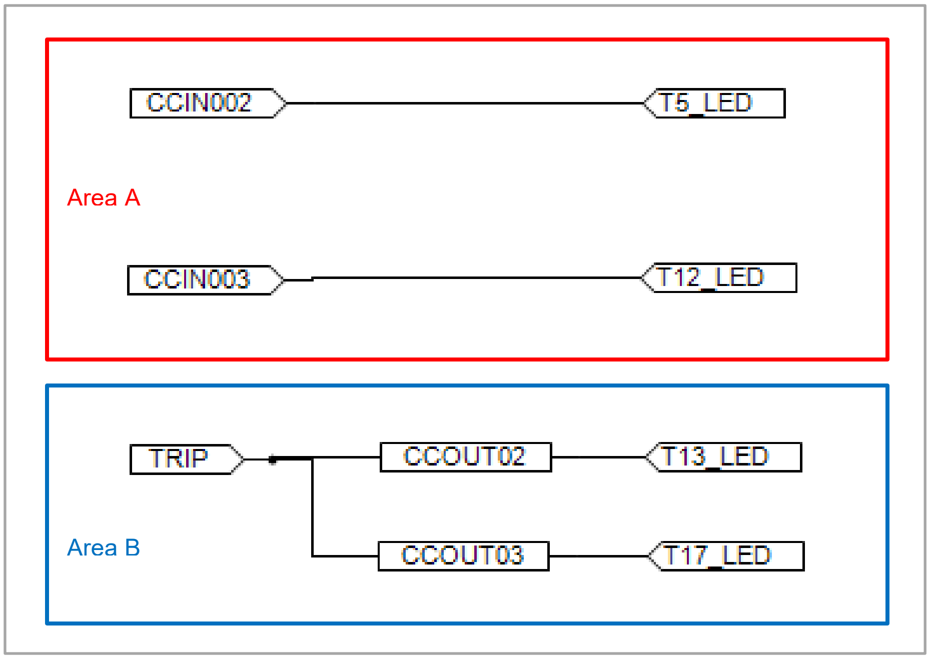

Figure 7.28: **Configure Graphical GOOSE logic for SEL-487E**

To set up the logic functions for the MiCOM-P645, navigate to the PSL folder and generate a new file. Double-click on the file to open it, as shown in area A Figure 5-16. Figure 7-29 shows the Configure Graphical GOOSE logic PSL for MiCOM-P645 with different areas, which function as follows. Area A shows the trip signal of the MiCOM-P645, area C is the MiCOM LED that will indicate when there is a fault/trip simultaneously, area B is the outgoing GOOSE signal to publish a GOOSE message to the SEL-487E device during the MiCOM-P645 internal trip fault. Two Incoming GOOSE will accept GOOSE from SEL-487E, and the output is the LEDs, namely LED3 and LED4, as shown in area D Figure 7-29 it is configured to monitor the status of the GOOSE message. Area E is explained in Chapter Five, section 5.6 in Figure 5-28.

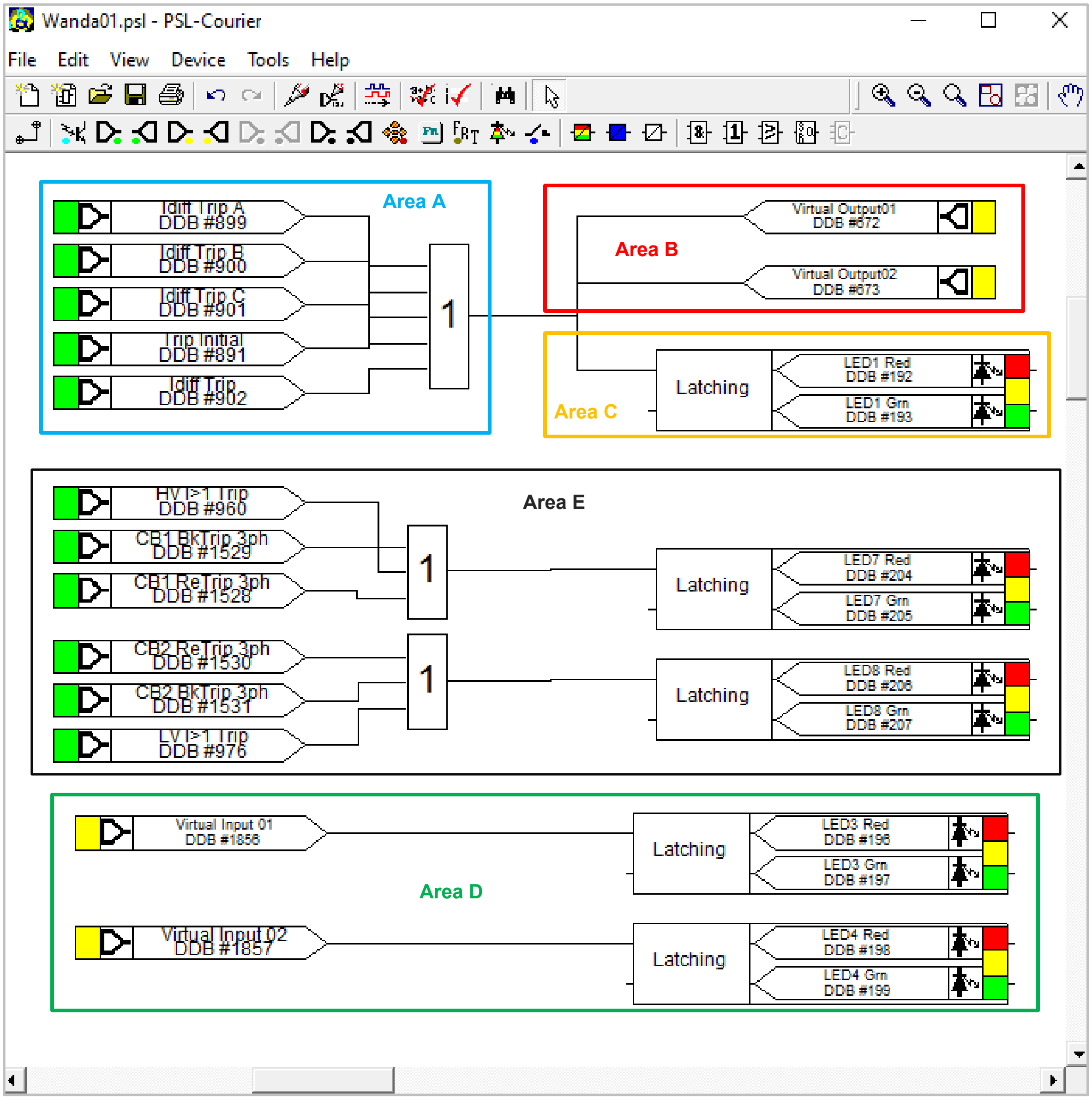

Figure 7.29: Configure PSL Graphical GOOSE logic for MiCOM-P645

7.3.5 Monitoring of GOOSE Messages

Programs that track IEC 61850 GOOSE messages via the network can stay updated on the message attributes when GOOSE is being broadcast. Wireshark and GOOSE Inspector are two such software. After successfully sending the settings file to the IED, the GOOSE Inspector software was used to confirm whether the IED was publishing GOOSE messages. Figure 7-30 shows the GOOSE Inspector Demo with the packet data, a Detailed View of the MiCOM P645, and the GOOSE Monitor window. On the GOOSE monitor window (area F), the indication is defined by different colour being;

- Dark Orange indicates at least one error, but warnings may be pending.
- Mustard yellow indicates at least one warning but no pending error.
- Green indicates no error or warnings.

In Figure 7-30, one of the most recent GOOSE packets captured prior to transmitting the GOOSE trip message is depicted. Area B of Figure 7-30 displays packet number 321, timestamped at 14:47, showcasing the MAC addresses of the sending and receiving devices, as well as the message type (GOOSE). The Detailed View pane, located to the right of the File View, offers supplementary details about the selected packet. In area C, the GOOSE protection logical node is discernible, allowing confirmation of the logical nodes that were defined within the corresponding IED. The sequence number in area D can also be identified. Area E, the number of elements (Boolean datasets) status can also be identified and are indicated as Object 1 to Object 5 in the software.

There are rules that must be followed in order to send GOOSE messages. To begin, a GOOSE Control Block (GoCB) must be defined. The GoCB must be made up of Datasets containing data objects and data attributes. GOOSE messages are forced to be transported when the data attribute triggers changes. The data sets will be duplicated and stored in the buffer before being transmitted. The buffer will contain both the replicated data sets and the actual values that will be conveyed as messages. GOOSE messages will then be delivered to the subscriber.

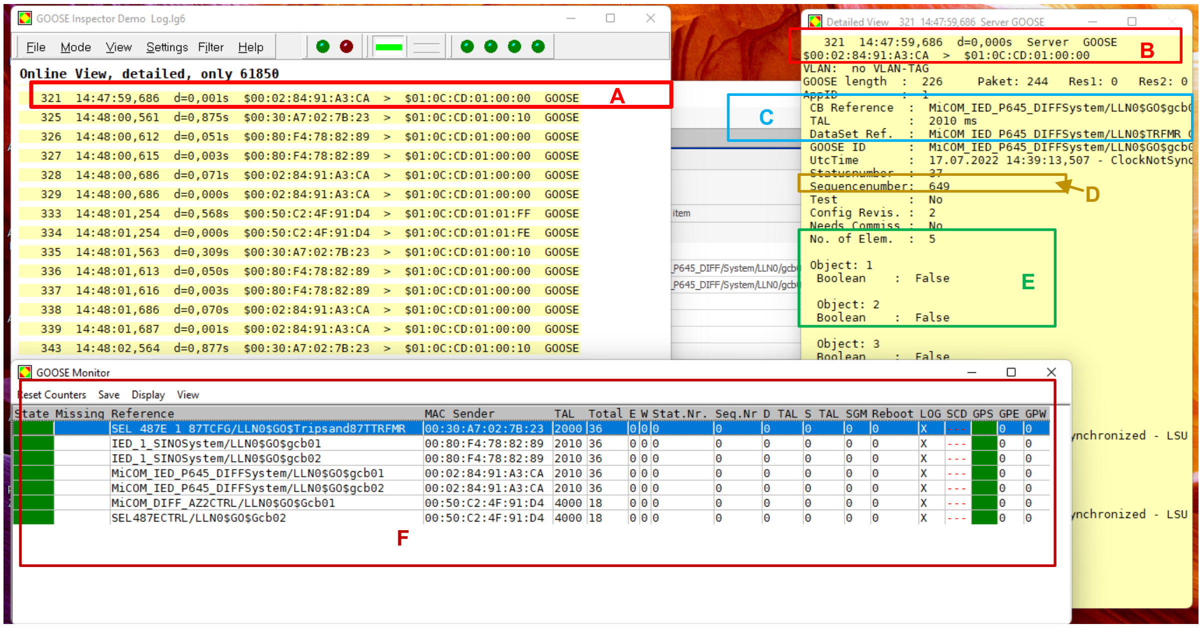

Figure 7.30: GOOSE Inspector Demo, Detailed View, and GOOSE Monitor window

For SEL-487E and MiCOM-P645, the Boolean datasets (indicated as Object in the software) that were set are fourteen and five, as shown in Figure 7-31 and Figure 7-32, respectively. The status of the Boolean number is "False" before the control GOOSE message is published (Figure 7-31), and it changes to "True" when the GOOSE trip logic is published (Figure 7-32), and the sequence number changes. Fault simulation case studies on HIL IEC-61850 will be performed after this simulation, which is covered in section 7.4.

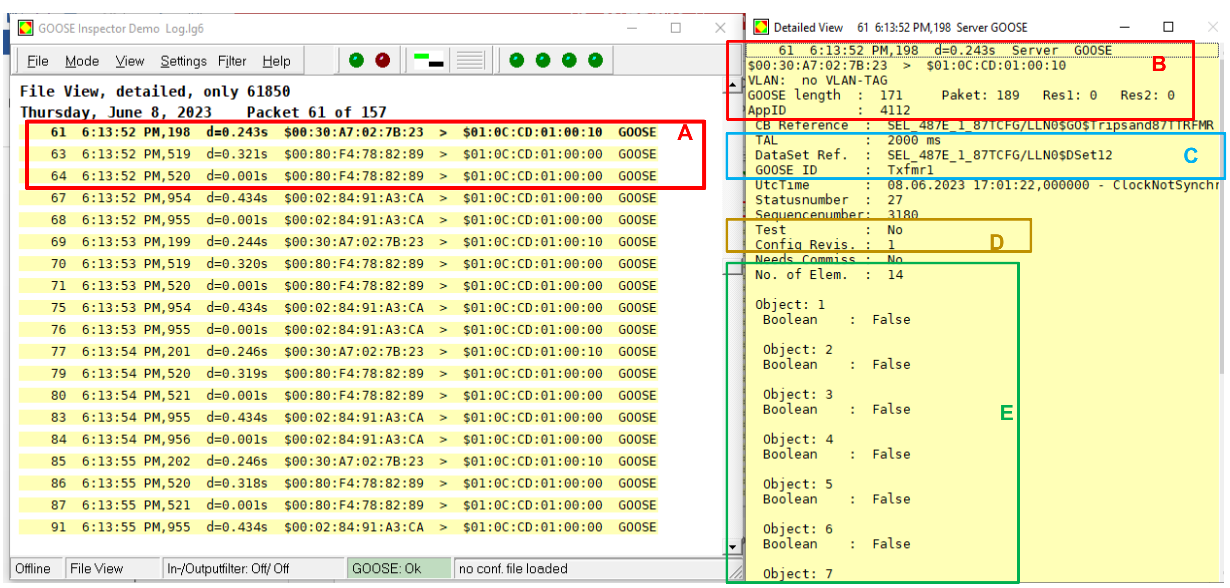

Figure 7.31: GOOSE message datasets for SEL-487E during normal operation with no fault present

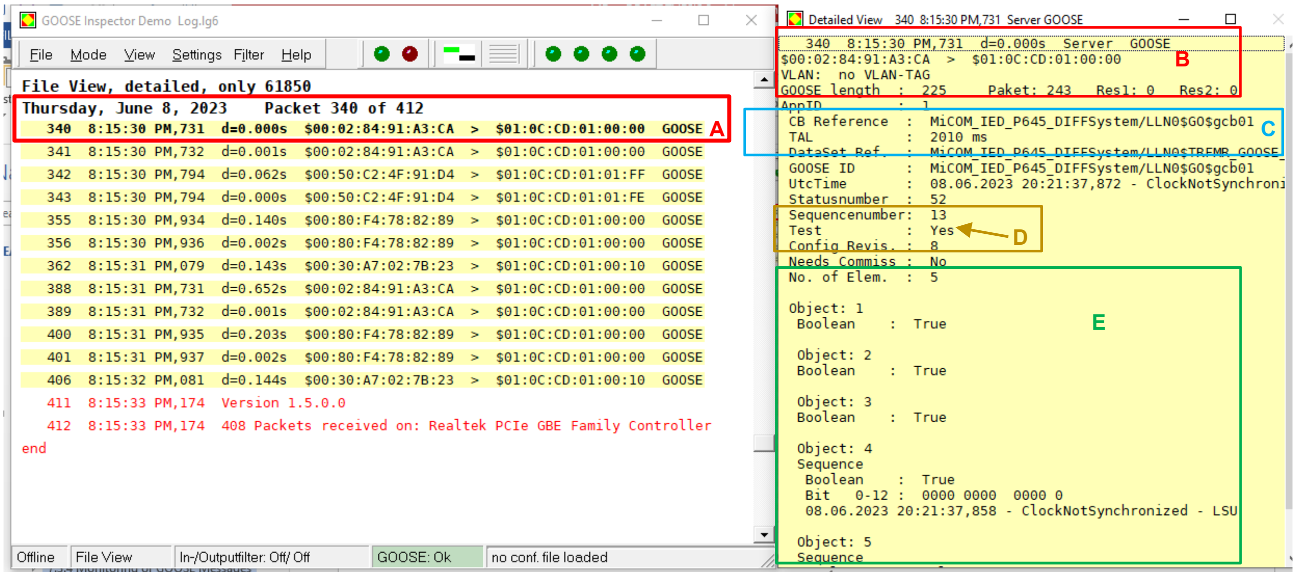

Figure 7.32: GOOSE message datasets for MiCOM-P645 during the fault (GOOSE trip)

7.3.5.1 Configuration setting of the two IED languages to communicate

This was covered in section 7.3.1.2 e) Configure of GOOSE Publishing in this chapter.

7.4 IEC61850 HIL protection scheme test

This section describes how the developed protection scheme was tested with the IEC 61850 standard GSE control model GOOSE. This test aims to prove the functionality of the interoperability between different vendors by making sure that if the SEL-487E relay has an internal faulty, it must send a signal status to the MiCOM-P645 relay to be notified about it but at the same time, MiCOM-P645 must not trip because the fault belongs to the SEL-487E relay.

7.4.1 The line to Ground internal and external fault Simulation for Parallel transformer

The objective of this study is to evaluate the response and performance of protective devices in parallel transformers when subjected to line-to-ground faults. The study aims to provide insights into fault detection, fault isolation, and fault clearing mechanisms implemented in the system to ensure the safe and reliable operation of the parallel transformers.

7.4.1.1 External fault on a 3-Phase to-ground fault

a) Fault on an LV side transformer protected by MiCOM-P645

An external fault was applied on the LV side of the transformer protected by MiCOM-P645, and the results are displayed in Figure 7-33. Figure 7-34 shows the MiCOM signal, current waveform, and Voltage waveform, respectively. It can be seen in Figure 7-33 that the trip signal is also low, which proves that the relay is functioning well for an external fault because it did not issue a trip signal.

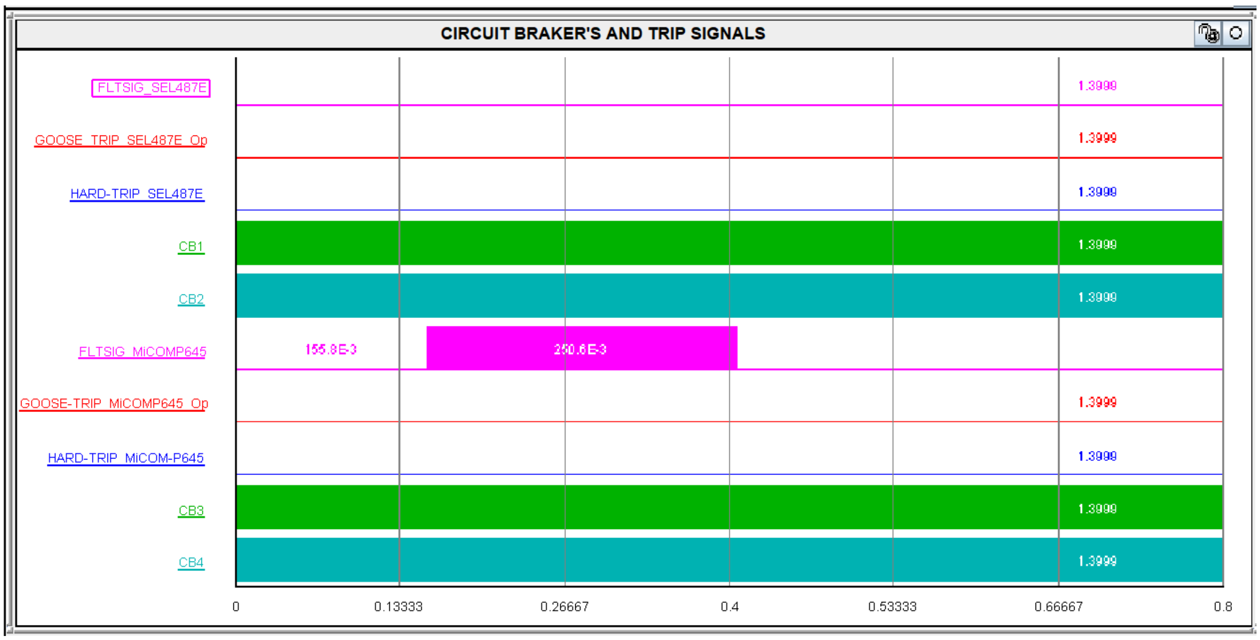

Figure 7.33: **Circuit breaker signal on the LV side of the transformer protected by MiCOM-P645 for external LLLG fault**

According to Figure 7-33, the fault started at 0.1558 seconds and was resolved at 0.4064 seconds. The fault lasted for a total of 0.2506 seconds before being cleared. Figure 7-34 illustrates the signals of voltage and the current on the LV side of the transformer protected by MiCOM-P645 throughout a three-phase external to ground fault at Bus 15b that resulted in currents of about 4.5 kA and 2.4 Amps. While phase A, B, and C voltage signals were lowered to approximately 1.4 kV.

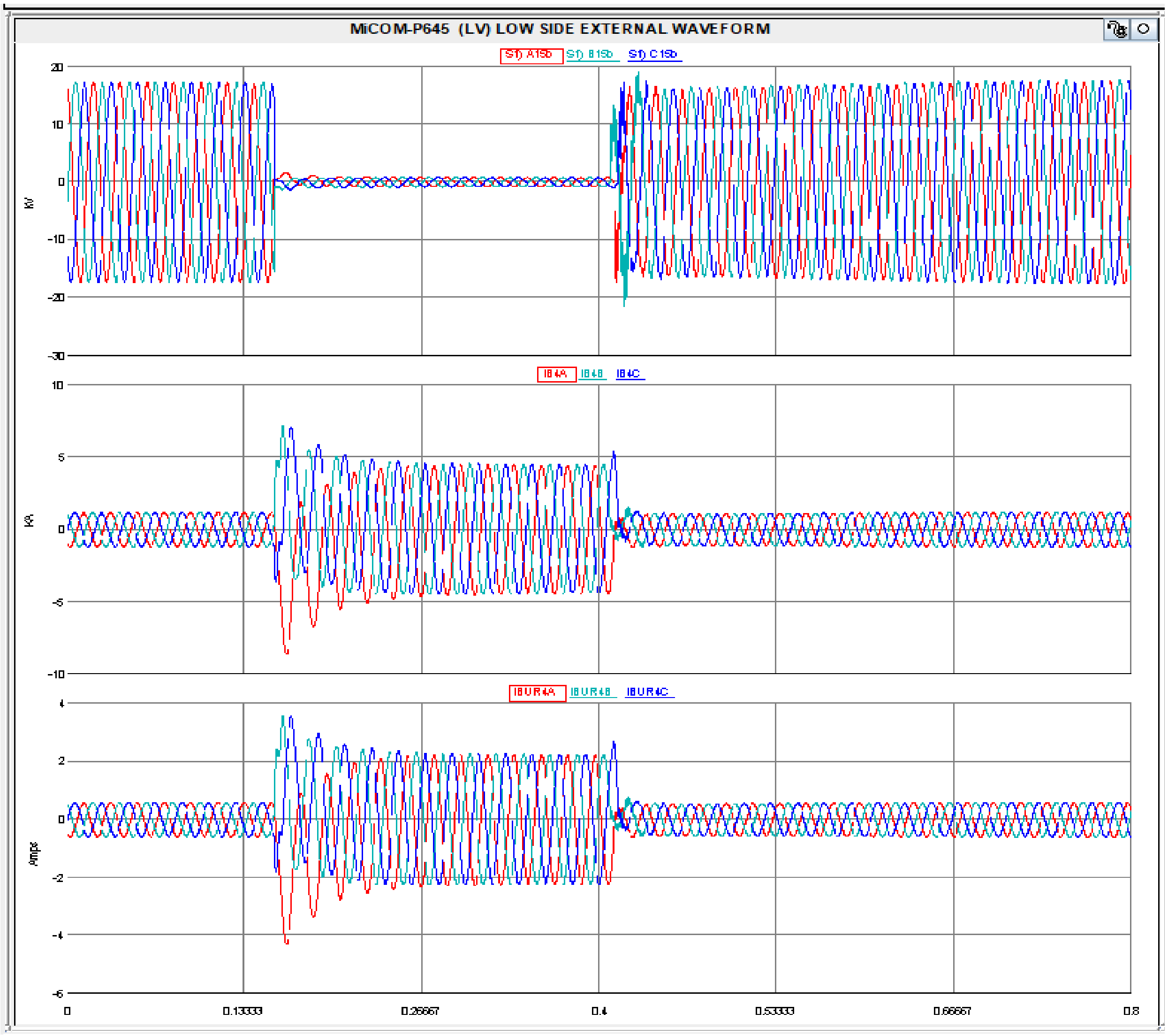

Figure 7.34: **Transformer signals indicating an external LLLG fault show both current and voltage for MiCOM-P645**

7.4.1.2 Internal fault on a 3-Phase to-ground fault

a) Fault on an HV side transformer protected by MiCOM-P645

The internal fault was applied on the HV side of the transformer protected by MiCOM-P645, and the results are displayed in Figure 7-35. Figure 7-36 shows the MiCOM digital signals, Voltage waveform signals, and current waveform signals, respectively. Figure 7-35 shows that the trip signal is now high, which means that the MiCOM-P645 IED has issued a trip signal to protect the transformer. At 0.07133 seconds, the fault began, and at 0.0964 seconds, it was cleared, and CB3 is now open (Low). The fault lasted for a total of 0.02507 seconds before being cleared.

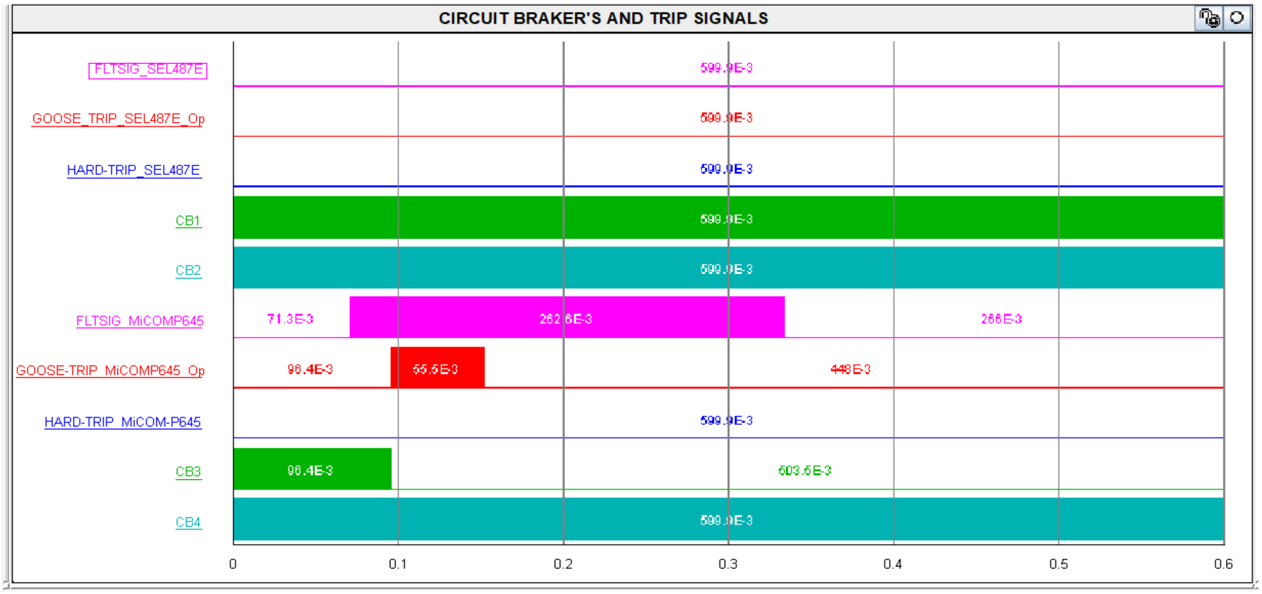

Figure 7.35: **Circuit breaker 3 GOOSE signal open for an HV MiCOM internal LLLG fault**

The signals current and voltage on the HV side of the MiCOM transformer are displayed in Figure 7-36 during a three-phase-to-ground internal fault at Bus 13b that resulted in currents of about 4.1 kA and 4.4 Amps. While phase-A, phase-B, and phase-C voltage signals were decreasing.

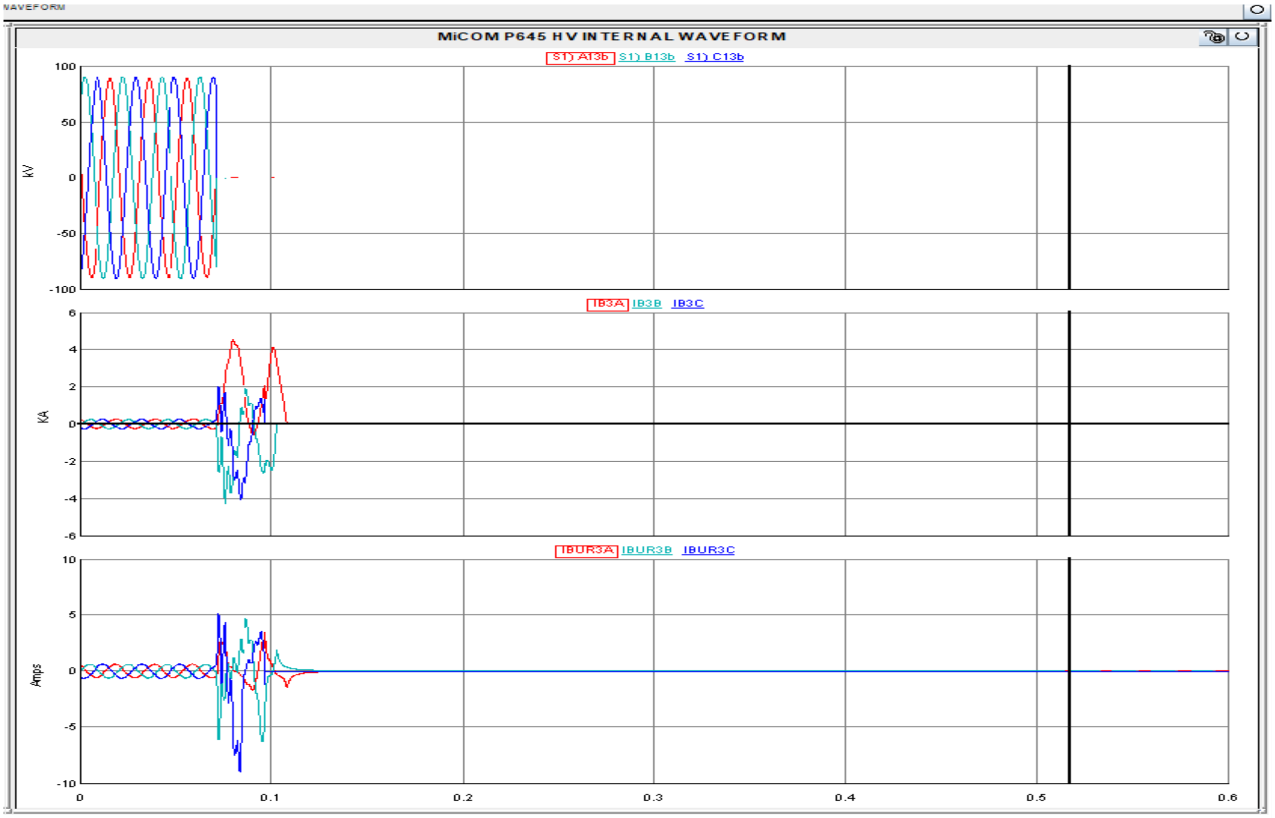

Figure 7.36: Signals Current and Voltage on the transformer's MiCOM HV side for an internal fault LLLG

7.4.1.3 Internal faulty on a Phase-A to Phase-B to ground (LLG) fault

a) Fault on a transformer HV Side protected by SEL-487E

An internal fault was applied to the HV side of the transformer protected by SEL-487E, and the results are displayed in Figure 7-37. Figure 7-38 shows the SEL digital, voltage, and current waveform signals, respectively.

Figure 7-37 shows that the trip signal is now on the high side of SEL-487E; this means that the SEL-487E IED has issued a trip signal to protect the transformer. At 0.1583 seconds, the fault lasted for 0.621 seconds before being cleared. At 0.7793 seconds, the GOOSE trip signal was initiated/sent to open CB1.

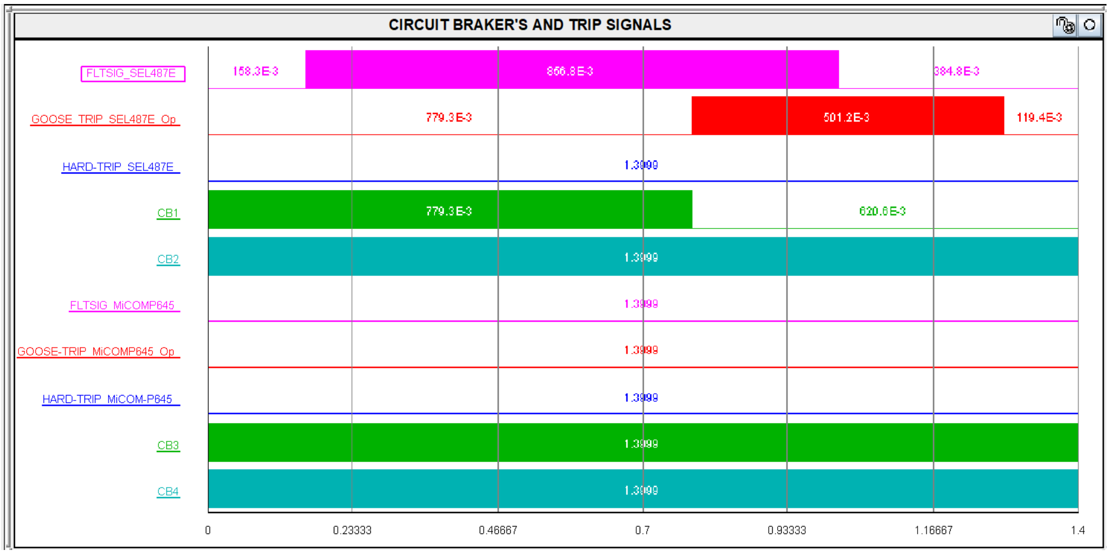

Figure 7.37: CB1 received GOOSE trip command signal for an HV SEL-487E internal Ph-A to Ph-B to ground (LLG) fault

Figure 7-38 displays the signals current and voltage on the HV side of the SEL-487E transformer during an internal LLG fault at Bus 13a.

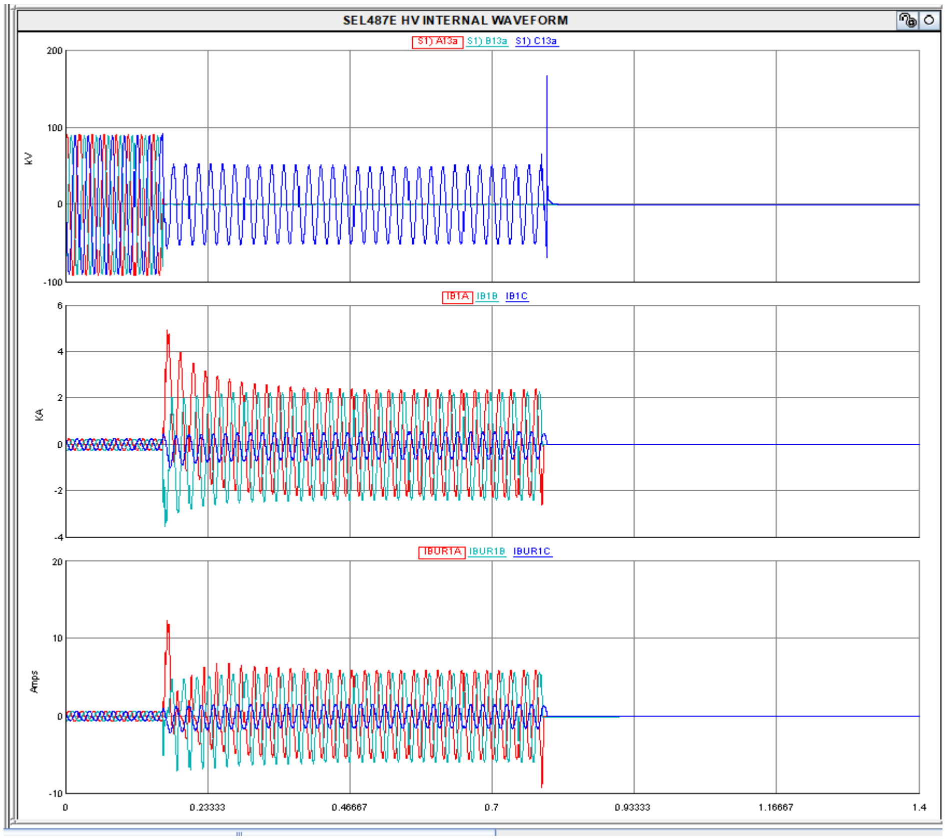

Figure 7.38: Internal LLG fault current and voltage signals of the HV side transformer protected by SEL-487E

7.4.2 Line to Line internal and external fault Simulation for Parallel transformer

This case study focuses on the simulation and analysis of line-to-line faults in a parallel transformer configuration, investigating both internal and external fault scenarios. The objective of this study is to evaluate the performance and response of protective devices in parallel transformers when subjected to line-to-line faults. The study aims to provide insights into fault detection, isolation, and fault-clearing mechanisms implemented in the system.

7.4.2.1 External fault on a Three-Phase Line-Line fault

a) Fault on a transformer LV Side protected by SEL-487E

An external fault was applied on the LV side of the transformer protected by SEL-487E, and the results are displayed in Figure 7-39. Figure 7-40 shows the SEL-487E, Voltage, and current waveform signals, respectively.

Figure 7-39 shows that the trip signal is also low, which proves that the relay is functioning well. At 0.1344 seconds, the fault was first detected, and at 0.3116 seconds, it was resolved. The fault lasted for a total of 0.1772 seconds before being cleared.

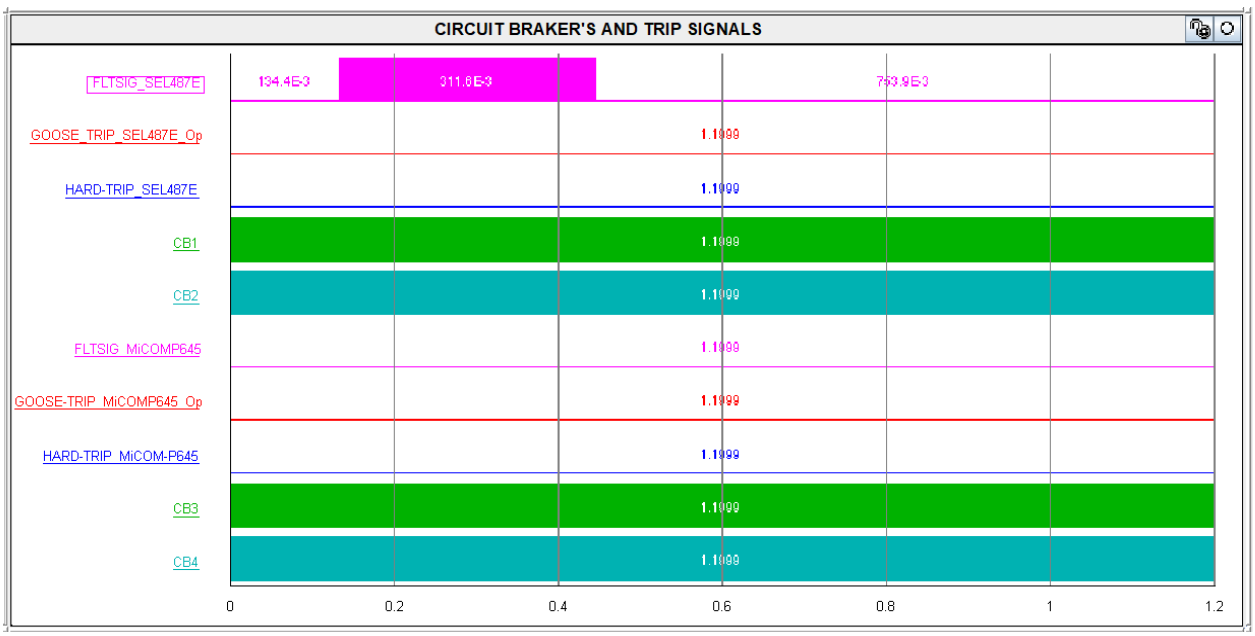

Figure 7.39: **All Circuit breaker signals are closed for transformers protected by IED during the GOOSE external 3ph L-L fault**

The signal current and voltage on the transformer LV side protected by SEL-487E are shown in Figure 7-40 during a three-phase line-to-line external fault at Bus 15a that resulted in currents of not less than the magnitude of 4.2 kA and 2.4 Amps. While reducing the voltage signals in all phases.

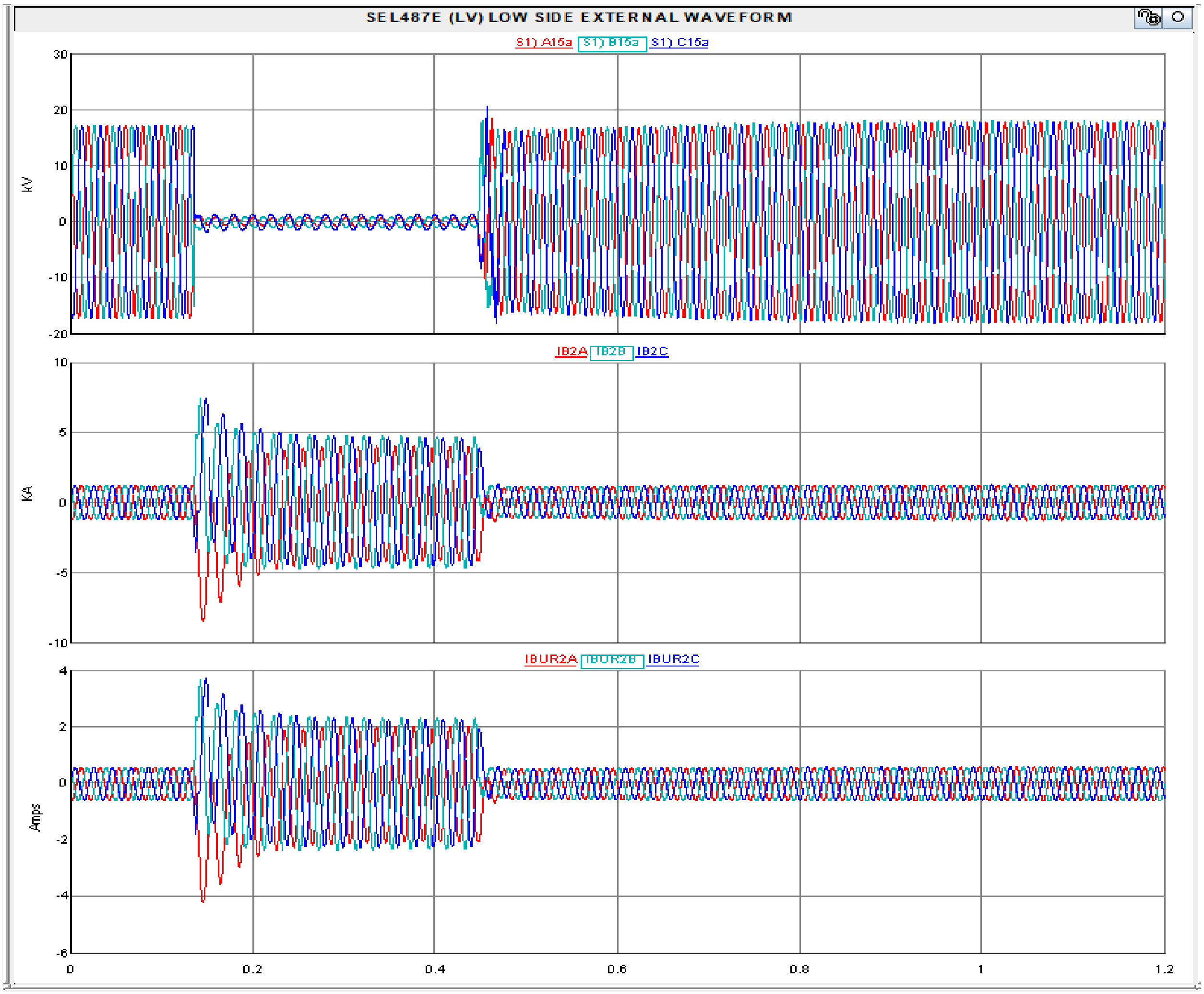

Figure 7.40: **Signals for current and voltage for an external line-line 3ph fault on the transformer's LV side protected by SEL-487E**

7.4.2.2 Internal fault on a Three-Phase Line-Line fault

a) Fault on a transformer LV side protected by MiCOM-P645

An internal fault was applied on the LV side of the transformers protected by MiCOM-P645. The results can be seen in Figure 7-41 and Figure 7-42, showing the MiCOM-P645 signal, Voltage waveform signal, and current waveform signal, respectively.

Figure 7-41 shows that the trip signal is now high, which means that the MiCOM-P645 IED has issued a trip signal to protect the transformer. At 0.0701 seconds, the fault was first detected, and it was cleared at 0.13 seconds. The fault lasted 0.035 seconds before the GOOSE trip signal was initiated/sent to open CB4 at 0.13 seconds.

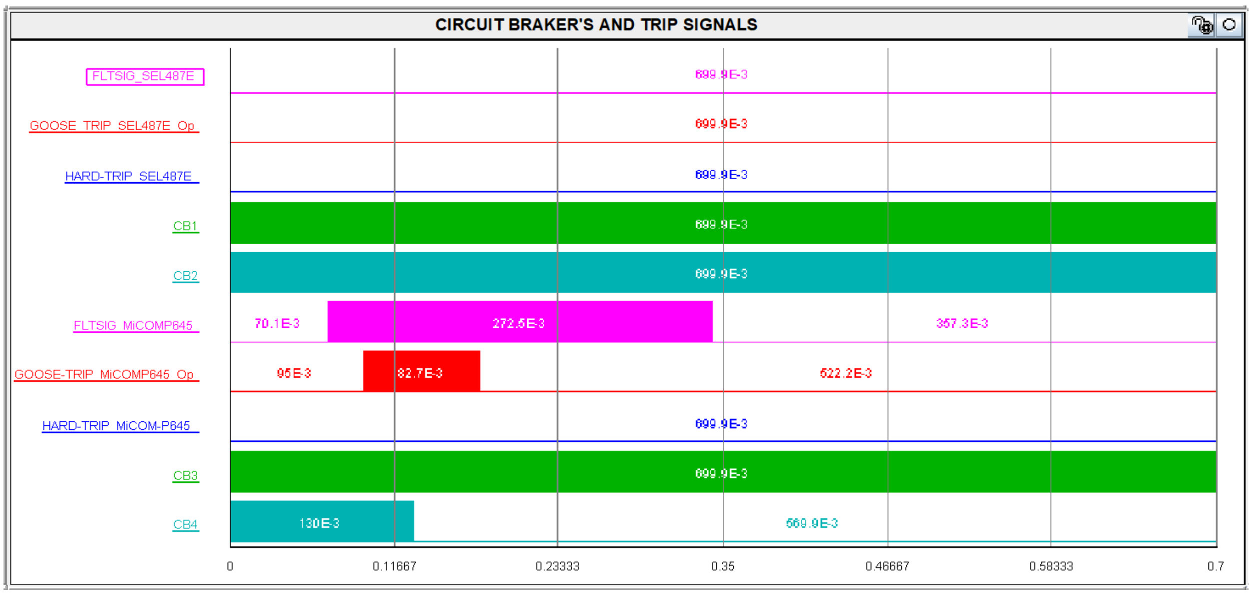

Figure 7.41: CB4 received a GOOSE trip command signal for a transformer LV side protected by MiCOM-P645 during a 3ph L-L fault

Figure 7-42 displays the signals current and voltage on the LV side of the transformer protected by MiCOM-P645 during an internal Three-phase Line-to-Line fault at Bus 14b that resulted in the current of the approximate magnitude of 3.8 kA and 2.6 Amps. At the same time, the voltage signals on all phases were reduced.

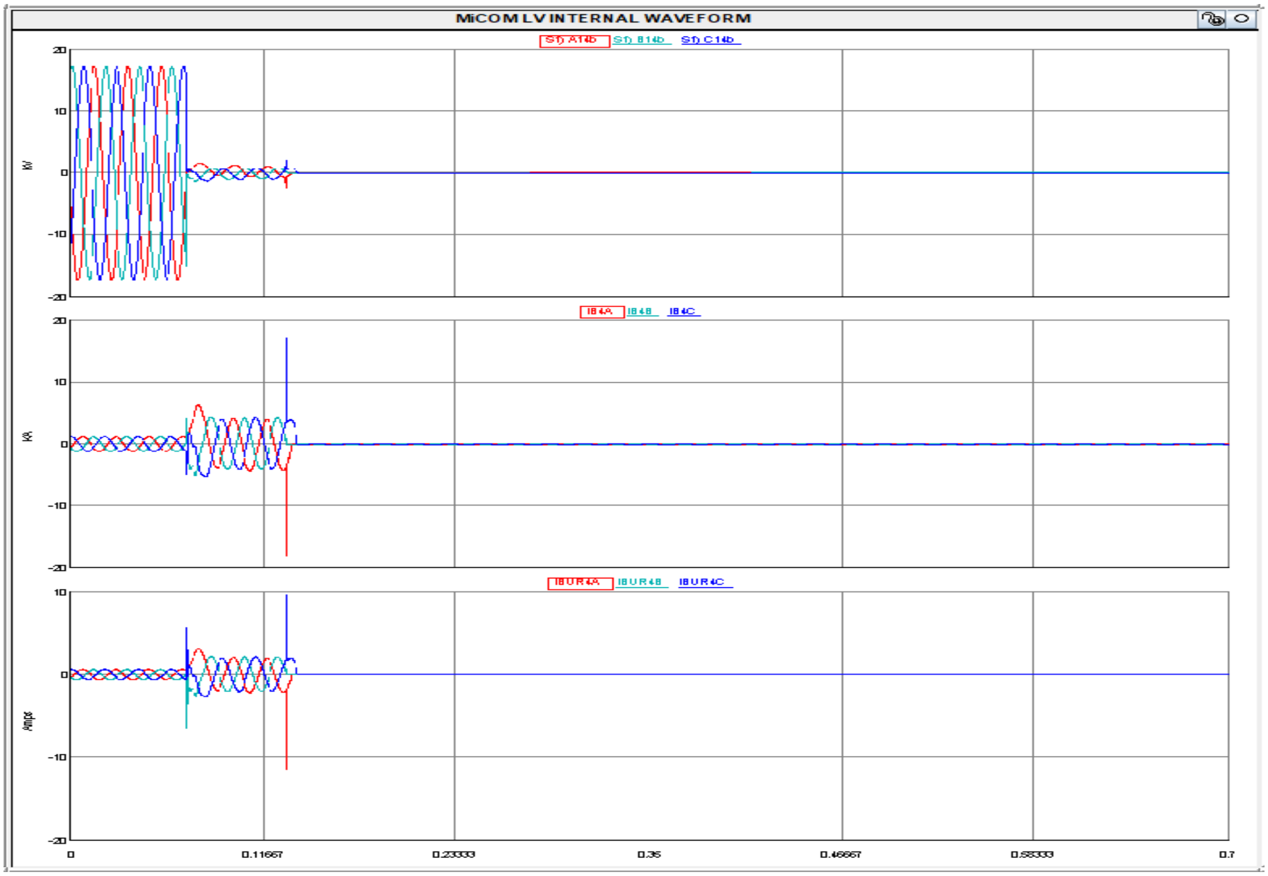

Figure 7.42: **Signals for current and voltage for a 3Ph- internal L-L fault on the transformer's LV side protected by MiCOM-P645**

7.4.2.3 Internal fault on a Phase BC Line to Ground fault

a) Fault on a transformer LV Side protected by SEL-487E

An internal fault was applied on the LV side of the transformer protected by SEL-487E, and the outcomes are shown in Figure 7-43. Figure 7-44 shows the SEL-487E, voltage, and current waveform signals, respectively.

Figure 7-43 shows that the GOOSE trip signal is now high, which means that the IED SEL-487E has issued a trip signal to protect the transformer. At 0.1463 seconds, the fault began, and at 0.6095 seconds, it was cleared. The fault lasted 0.4632 seconds before the GOOSE trip signal was initiated/sent to open CB2.

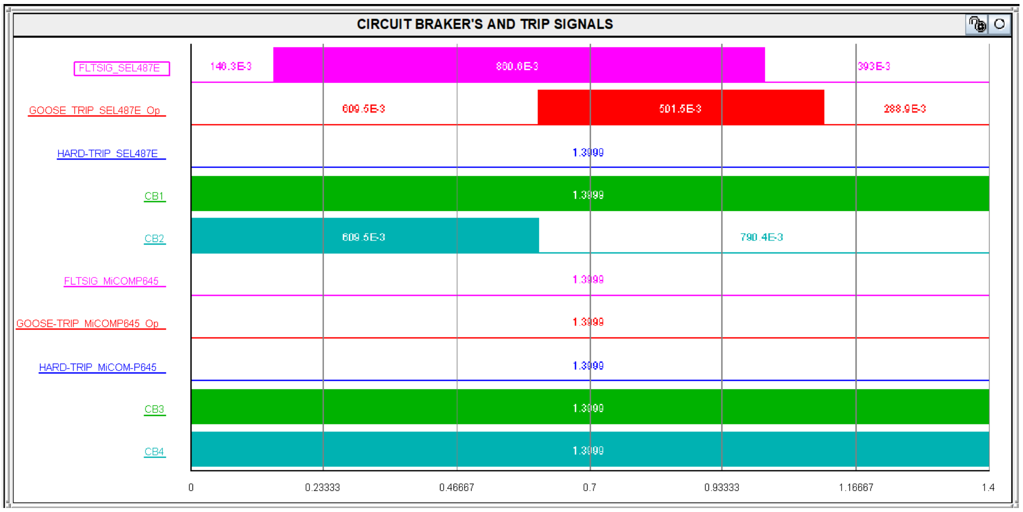

Figure 7.43: CB2 received GOOSE trip command signal for a transformer LV side protected by SEL-487E during Phase BC Line to Ground fault

Figure 7-44 displays the signals current and voltage on the LV side transformer protected by SEL-487E during an internal Phase BC Line to Ground fault at Bus 14a. On the current signal, Phase B and Phase C went up, while Phase A remained approximately the same, while the voltage signal shows that only Phase B and Phase C dropped down.

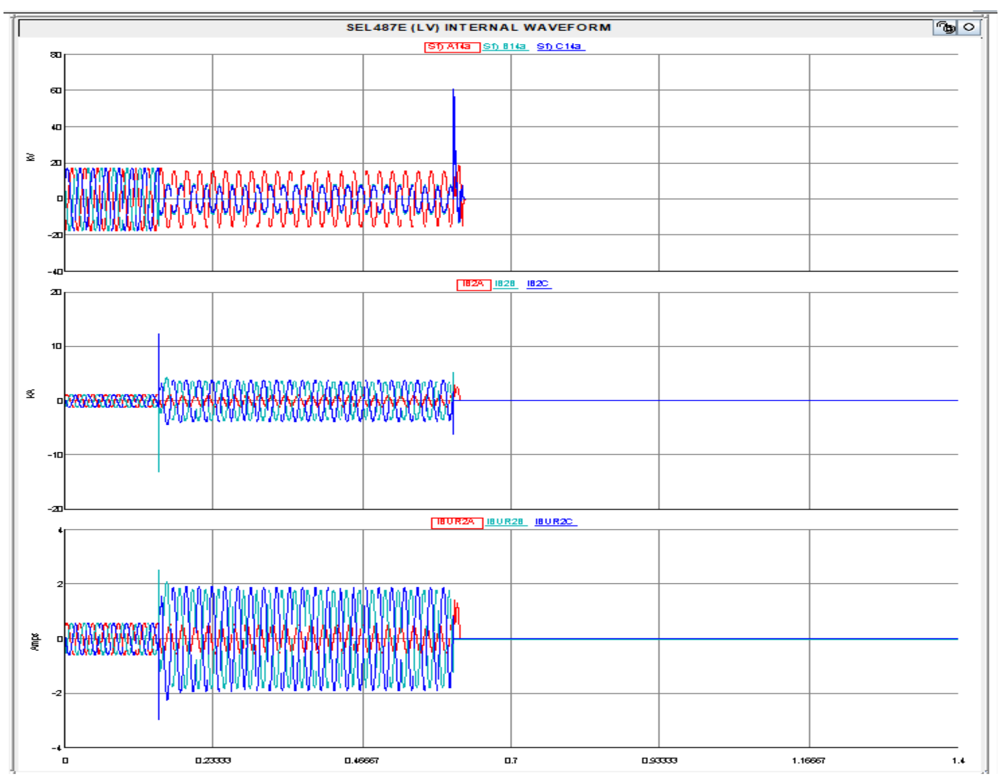

Figure 7.44: Signals for voltage and current for a Phase BC Line to Ground fault on the transformer LV side protected by SEL-487E

7.4.3 Double Line to Ground fault for internal

This case study focuses on the analysis of a double line-to-ground fault in an electrical power system, specifically investigating the response and behavior of protective devices in the event of an internal fault.

7.4.3.1 Internal fault on Phase AB and Phase B to ground

a) Fault on a transformer HV side protected by MiCOM-P645

On the transformer HV side protected by MiCOM-P645, an internal fault was applied, and the results can be seen in Figure 7-45. Figure 7-46 shows the MiCOM, Voltage, and current waveform signals, respectively.

Figure 7-45 shows that the GOOSE trip signal is now high, which means that the MiCOM-P645 IED has issued a trip signal to protect the transformer. At 0.1059 seconds, the fault began, and at 0.1316 seconds, it was cleared. The fault lasted for a total of 0.0257 seconds before being cleared. At the same time, the GOOSE trip signal was initiated/sent at 0.1316 seconds to open CB3.

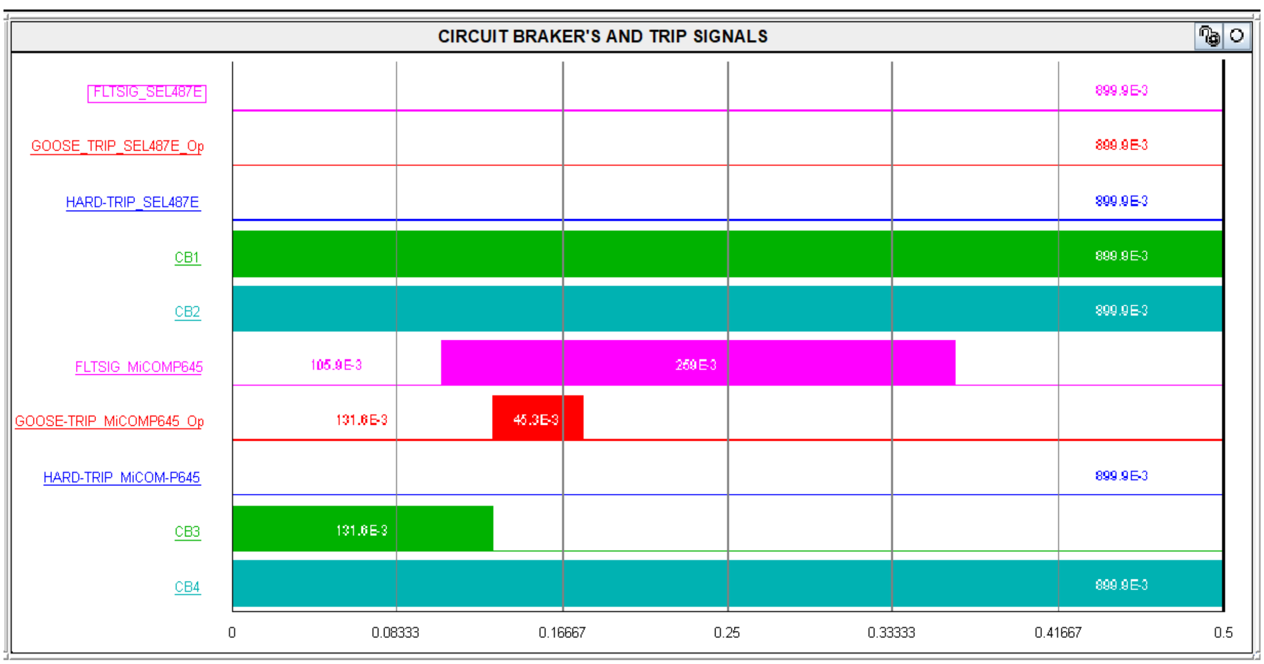

Figure 7.45: CB3 received GOOSE trip command signal for an HV side of the transformer protected by MiCOM-P645 during Ph-AB and Ph-C to ground fault

The signal current and voltage on the transformer HV side protected by MiCOM-P645 during an internal Phase AB and Phase B to ground fault at Bus 13b is shown in Figure 7-46.

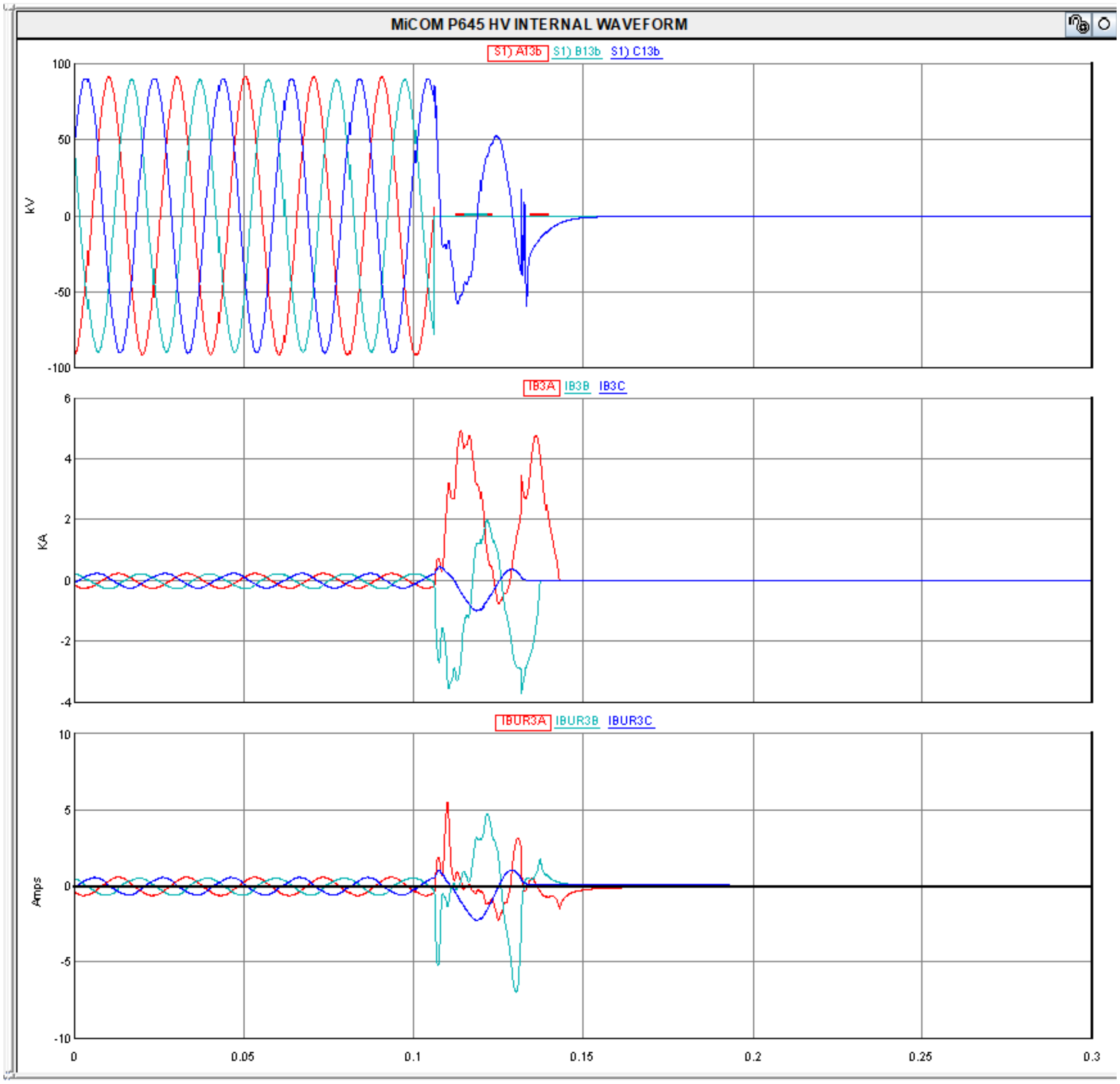

Figure 7.46: Internal Phase AB and Phase B to ground fault current and voltage signals on the transformer's HV side protected by MiCOM-P645

b) Fault on an LV side of the transformer protected by SEL-487E

A fault was applied internally on the LV side of the transformer protected by SEL-487E. The results in Figure 7-47, and Figure 7-48 shows the SEL-487E signal and Voltage and current waveform signal.

Figure 7-47 shows that the trip signal is now high, meaning that the SEL-487E IED has issued a GOOSE trip signal to protect the transformer. At 0.1533 seconds, the fault began, and at 0.5091 seconds, it was cleared. The fault lasted for a total of 0.3558 seconds before being cleared. At the same time, the GOOSE trip signal was initiated/sent at 0.5091 seconds to open CB2.

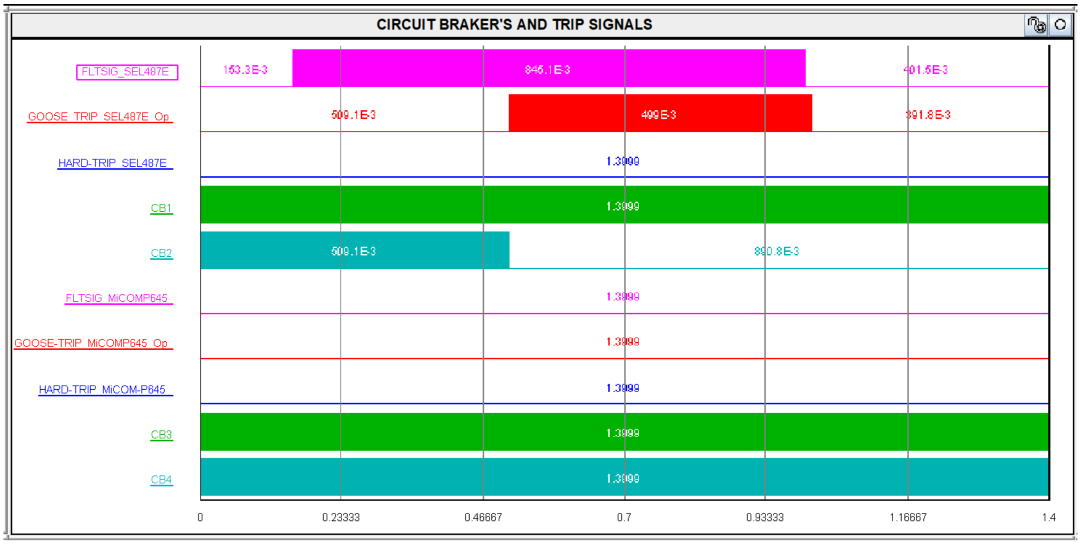

Figure 7.47: CB2 received GOOSE trip command signal on a transformer protected by SEL-487Eduring Phase AB and Phase B to ground fault

The SEL-487E protecting the transformer's LV side's current and voltage signals during an internal Phase-AB and Phase-B to ground fault at Bus 14a is shown in Figure 7-48.

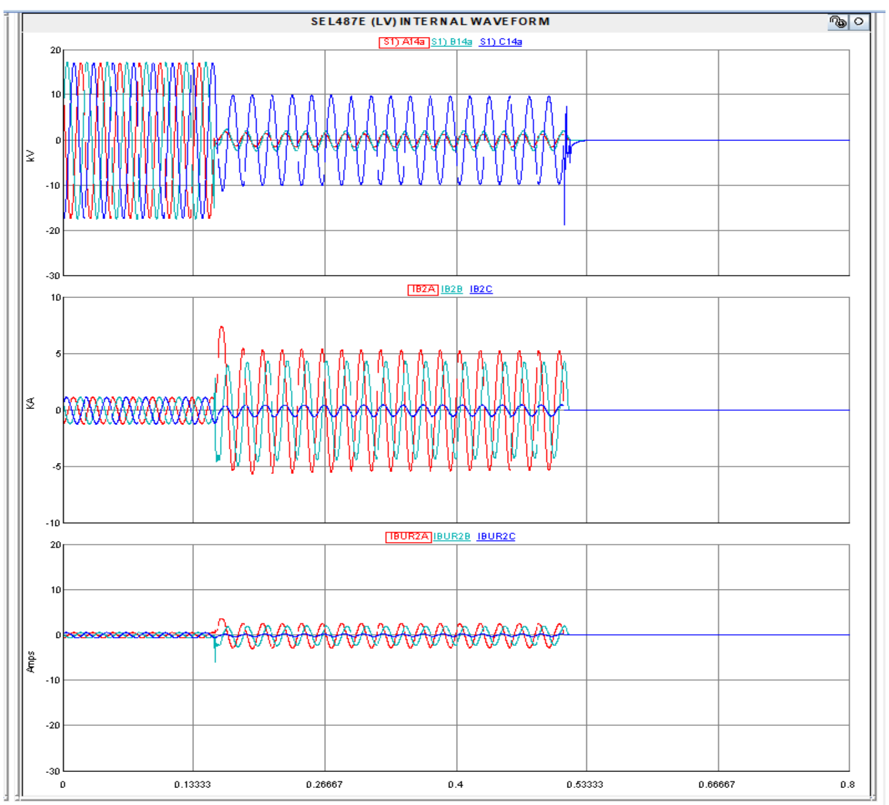

Figure 7.48: Transformer's LV side protected by SEL-487E internal Phase AB and Phase B to ground fault current and voltage signals

7.5 Summary Results of the case study

The case study aimed to investigate and evaluate the fault detection and reaction capabilities of the MiCOM-P645 device and the SEL-487E device in a specific system. The case study focused on analyzing the generation and exchange of GOOSE interoperability messages between the two devices in response to internal and external faults. Table 7.4 shows the summary of the case scenario of the GOOSE with the different types of faults. Table 7.5 shows the summary of the simulated different faults under the GOOSE communication trip signal.

Table 7.4: **Summary of the case study**

IEDs	FUNCTION
SEL-487E	a) Identifies a fault and reacts. b) A GOOSE message is generated and sent only if the faulty is internal to the MiCOM-P645 device. c) LED 5 and LED 12 on the SEL-487E device monitor the incoming GOOSE message from the MiCOM-P645.
MiCOM-P645	a) Identifies a fault and reacts. b) A GOOSE message is generated and sent to the SEL-487E device if the fault is internal. c) LED 3 and LED 4 on the MiCOM-P645 device monitor the incoming GOOSE message from SEL-487E.

Table 7.5: **Fault event summary results for GOOSE trip communication**

Fault type	Circuit breaker operation in seconds (s)	Duration of fault clearance in seconds (s)
3-Phase to-ground (MiCOM-P645)	0.0964	0.0251
3Ph-Ground (SEL-487E)	0.13	0.0.035
3Ph-Line (MiCOM-P645)	0.77	0.621
Phase-AB-Ground (SEL-487E)	0.0964	0.0251
Phase-AB-Line (MiCOM-P645)	0.5091	0.356
Double Line Ph-AB & Ph-C to Ground (SEL-487E)	0.0132	0.0257

These findings highlight the fault detection and reaction capabilities of both the MiCOM-P645 and SEL-487E devices, as well as the effective exchange of GOOSE messages between them. The case study demonstrates the significance of such communication and monitoring mechanisms in ensuring the prompt and accurate identification of faults within the system.

7.6 Discussion

In this section, we will delve into the significant terms utilized during the investigation of interoperability. We will discuss these terms based on the results obtained from the research.

7.6.1 IED Configuration Tools Evaluation

The goal of this evaluation IED is to confirm/investigate the following:

- The capability of an IED from a different vendor to comprehend and interpret a GOOSE message.
- The capability of an IED configuration tool to detect modifications in communication parameters (such as IP address and Subnet name), IED parameters (such as LN attribute), and data type template parameters, which are necessary for generating an SCD file.
- The capacity of an IED configuration tool to detect alterations in GOOSE messages originating from an SCD file.
- To verify that the IED configuration tool can successfully import and incorporate GOOSE subscription data from other IEDs present in an SCD file.

7.6.2 IED name (length/type)

Municipalities' and utilities' naming conventions can hamper efforts to achieve interoperability. This occurs because different vendors impose restrictions on the maximum character limit for naming purposes. In laboratory interoperability tests, naming conventions are rarely an impediment. It is of utmost importance that vendors extend the maximum allowable number of characters for naming conventions to ensure its criticality. The name of an IED is extracted from the IED section within an SCL file. Because this is an Object Reference type, each IED from a different vendor can be up to certain characters long and should be unique for all IEDs on the IEC 61850 network. However, IED names should be kept to a maximum of 8 characters or less in SEL and MiCOM.

7.6.3 Application Identifier (AppID)

The App ID is linked to the GOOSE message, it helps in distinguishing and identifying individual applications, enabling seamless interoperability and communication between them. The field is automatically populated with information from the SCL file and should have a unique value across the entire IEC 61850 network. It is not editable. To guarantee seamless interoperability, it is essential for each GOOSE message to possess a distinct AppID.

7.6.4 Configuration revision (ConfRev)

File management and interoperability rely heavily on configuration revision. ConfRev serves as a mechanism to track changes made to the configuration and ensures consistency and synchronization among devices or systems. Displays the published GOOSE message's Configuration Revision. In the event of modifications to the dataset reference or contents, the Configuration Revision must be incremented. This allows other peers who are listening to the published GOOSE messages to recognize the configuration change.

7.6.5 Substation Configuration Language file exchange

The Substation Configuration Language (SCL) is an essential component of GOOSE message interoperability. This is an XML-based standard language used in substations to configure IEC 61850 IEDs. It enables the exchange of common substation files between all devices and toolsets from different manufacturers. This contributes to fewer inconsistencies in system configurations. Users have the option to specify and supply their SCL files to ensure accurate configuration of IEDs. IEC 61850 uses four types of SCL files: CID, ICD, SCD, and SSD.

7.6.6 Specific challenges related to interoperability

The identification of specific challenges related to interoperability as specified in the IEC 61850 standard and potential solutions is vital for advancing the field of power system protection and ensuring seamless integration of multi-vendor IEDs. Here is a concise elaboration on this aspect:

a) Interpretation and implementation

One of the primary challenges in achieving interoperability as per the IEC 61850 standard is the variability in the interpretation and implementation of the standard by different vendors. This can lead to inconsistencies in data models, communication patterns, and device configurations, hindering effective communication between IEDs from diverse manufacturers.

To address this challenge, it is imperative to establish clearer and more standardized guidelines within the IEC 61850 standard. This might involve providing more detailed specifications for data models, communication profiles, and device behavior. Additionally, industry-wide collaboration and knowledge-sharing initiatives can foster a better understanding of the standard's intricacies among vendors, leading to more uniform implementations.

b) Data Models

Another challenge lies in the complexity of mapping IEC 61850 data models to specific application requirements. As power systems become more sophisticated, the need for customized data models increases. However, this customization can create interoperability issues when different IEDs attempt to communicate using non-standard data models.

To overcome this challenge, the standard could benefit from enhanced guidance on data model customization and mapping. This could include standardized templates for common power system applications, reducing the need for extensive customization and simplifying interoperability testing.

c) Cybersecurity

Lastly, cybersecurity concerns are a significant challenge in achieving interoperability, as ensuring the security of communication networks is paramount. The IEC 61850 standard should continue to evolve to incorporate robust cybersecurity measures, including encryption, authentication, and intrusion detection, to protect critical power system communication.

Handling online attacks in the developed system, especially related to the processing of GOOSE messages, is crucial to maintaining the security and integrity of power systems. Here are some key considerations for how the developed system can handle online attacks:

- **Access control**: Access to the GOOSE messaging system should be restricted to authorized personnel only. This can be achieved by implementing strong authentication and authorization mechanisms.
- **Encryption**: GOOSE messages should be encrypted to prevent unauthorized access and tampering. Encryption can be achieved using standard encryption algorithms such as AES (Advanced Encryption Standard).
- **Integrity checks**: Integrity checks should be performed on GOOSE messages to ensure that they have not been tampered with during transmission. This can be achieved using digital signatures or message authentication codes (MACs).

- **Intrusion detection**: Intrusion detection systems (IDS) should be deployed to detect any unauthorized access or malicious activities on the GOOSE messaging system. IDS can be used to monitor network traffic and detect any anomalies or suspicious activities.
- **Firewalls**: Firewalls can be used to protect the GOOSE messaging system from external attacks. Firewalls can be configured to block unauthorized access and prevent malicious traffic from entering the network.

By implementing these measures and maintaining a proactive and adaptive cybersecurity stance, the developed system can effectively handle online attacks, including those related to improperly processed GOOSE messages. It's essential to continuously monitor and improve the security posture of the system to stay ahead of evolving threats and vulnerabilities in the power system environment.

In summary, addressing challenges related to interoperability in the IEC 61850 standard requires a multi-faceted approach. Clearer standardization, enhanced guidance for data model customization, and robust cybersecurity measures are essential components in ensuring seamless communication between multi-vendor IEDs, ultimately enhancing the reliability and effectiveness of power system protection.

7.7 Conclusion

The integration of the IEC 61850 communication standard into the protection scheme aimed to validate and showcase interoperability between the SEL-487E and MiCOM-P645 relays. This was extensively tested in the previous chapter through fault simulations within the IEC 61850 framework. The configuration ensured smooth fault information exchange between the relays without triggering trips, emphasizing the reliability and collaborative potential of such integration. This interoperability strengthens the protection scheme by enhancing system performance and reliability.

Additionally, the proposed method for achieving interoperability among multi-vendor IEDs, especially within IEC 61850 using GOOSE messages, offers an effective approach. By analyzing communication patterns and data models in GOOSE messages, this approach ensures seamless data exchange among diverse IEDs. Overall, it elevates power system reliability, promotes effective protection coordination, and opens avenues for improved performance and comprehensive protection. In essence, the development and implementation of a parallel power transformer current protection system designed for interoperability across various vendor-specific IEDs significantly bolster the reliability and stability of power systems.

First, the configuration setting of the SCL/MCL languages was done to see which files of the languages can be imported or exported between the two vendors, and a few files are the same on both vendors, such as “SCD, and CID”. Therefore, this chapter used “CID" to subscribe/receive information between the two vendors. To confirm that the interoperability between the SEL-487E and MiCOM-P645 relay was successful.

As part of the conformance testing procedure, the structure of IEC 61850 GOOSE messages was verified using a network protocol analyser GOOSE inspect, which sniffs packets from a communication network to which IEC 61850-compliant IEDs are connected. The reliability of the IEC 61850 GOOSE messages was demonstrated to be equally dependable. For all the files that were imported to another IED, there was no missing information, and during the testing of different faults, all IEDs behaviour as they were configured. The evaluation of GOOSE message interoperability involves testing with IEC-61850 compliant IEDs from two different vendors. This confirms that GOOSE message interoperability can be achieved in a multi-vendor system. Therefore, interoperability has been achieved, and the test results are satisfactory.

The achievement of interoperability marks a significant milestone in the development and validation of the protection scheme. It signifies that the SEL-487E and MiCOM-P645 relays, representing multi-vendor Intelligent Electronic Devices (IEDs), can seamlessly communicate and collaborate within the power system environment. This interoperability ensures that critical information, such as fault data and protection statuses, can be effectively shared between these devices, enhancing their ability to coordinate and respond to potential electrical faults or disturbances.

Moreover, the test results, which include fault simulations and relay responses, have yielded highly satisfactory outcomes. These results demonstrate that the protection scheme, enabled by interoperable IEDs, can accurately and efficiently detect and mitigate various fault scenarios. The reliability and precision showcased by the relays during these tests instill confidence in the overall system's ability to safeguard the power transformer and maintain the integrity of the electrical network.

In summary, the successful achievement of interoperability not only validates the robustness of the protection scheme but also highlights the reliability and effectiveness of the SEL-487E and

MiCOM-P645 relays in ensuring the stability and security of power systems under diverse operating conditions.

The thesis serves as a comprehensive resource, equipping professional engineers with the knowledge, tools, and methodologies essential for the effective adoption and implementation of Hardware-in-the-Loop (HIL) tests. It not only imparts theoretical understanding but also guides engineers in translating this knowledge into practical applications. By doing so, it plays a pivotal role in promoting the wider adoption of HIL testing as a valuable tool in the realms of power system protection and reliability assessment.

Within this thesis, the steps and configuration procedures are meticulously presented, shedding light on the intricacies of setting up the parallel transformer differential protection system. This encompasses a deep understanding of interoperability and its core elements. Such insights not only benefit scholars but also serve as a practical reference for engineers seeking to configure and operate similar systems. The thesis, therefore, not only contributes to the academic discourse but also facilitates the practical implementation of cutting-edge technology in real-world applications, ultimately enhancing the field of power system protection and reliability.

The next chapter (Chapter Eight) marks the final section of the thesis, concentrating on summarizing the entire scope, deliverables, and offering recommendations for future work required in parallel transformer differential protection schemes.

CHAPTER EIGHT
CONCLUSION AND RECOMMENDATION

8.1 Introduction

Transformers are the most important components in power system networks; however, a transformer fault can cause a wide range of problems. As a result, a transformer protection scheme is required. For the transformer protection scheme to succeed, the following specifications must be met: sensitivity, stability, selectivity, and speed. To fulfil all the aforementioned criteria, the protection system needs to demonstrate reliability, ensuring that it activates the tripping mechanism when necessary and remains secure by not triggering falsely.

This research aims to develop a transformer current differential protection scheme, investigate the IEC61850 standard-based interoperability challenges between the Intelligent Electronic Devices produced by different vendors (Multi-Vendor), and propose solutions for improving communication between these devices. Using system simulation software tools, researchers employ IEEE systems to implement and test creative ideas and concepts. The transmission system of IEEE 9-Bus is selected as a case study, and IEEE 9 has been modified at bus 6 with sub-transmission and distribution with two parallel transformers.

RSCAD/ RTDS were used to model and simulate the protected parallel transformers' external, internal, and inrush current conditions. The developed transformer protection scheme was tested as a hardware-in-loop (HIL) on a test bench in the laboratory environment. A reliable transformer current differential protection scheme was developed and implemented using the IEC 61850 GOOSE application to overcome the interoperability problem between multi-vendors for tripping relays during certain conditions. By employing the IEC 61850 standard, utilities and municipalities can avoid dependence on a single vendor, as it eliminates the reliance on proprietary communication protocols.

Chapter Four highlighted the design technique, selection of the hardware, and construction of the test facility (laboratory setup) test bench for the transformer protection scheme. Chapter Five highlighted developing and modeling the HIL transformer protection scheme for the modified IEEE 9-Bus system network with parallel transformers constructed and modelled in the RSCAD environment. Control logic was also developed for the network to function as required in this chapter, such as control tap changers, CBs, etc.

Chapter Six analyses the simulation and results of the developed hardware-in-loop (HIL) transformer protection scheme for the modified IEEE 9-Bus system with parallel transformers. Four different case scenarios were analysed, and their results were presented. The first two simulation cases are simulated before connecting the external IED relay. The focus was on system stability when testing the normal operation for Parallel or Individual transformers and the Master-Follower of the parallel transformer scheme.

In the second last two cases of simulation, the external IED relay for the transformer's current differential was connected utilizing a hard-wire trip signal to simulate the different faults and test the inrush current of the parallel transformers. The injection of current into SEL-487E and MiCOM-P645 IEDs was facilitated by RSCAD through binary inputs, while the IEDs responded with trip commands through binary outputs.

Chapter Seven advances the developed transformer protection scheme by demonstrating interoperability between the two IEDs of the parallel system using the communication standard IEC 61850 and its generic substation event (GSE) control model GOOSE. A test environment is established to demonstrate the interoperability of GOOSE messages between the two vendors, namely SEL-487 and MiCOM-P645. And also, in this chapter, various fault simulations were analysed, and the IED sends the trip signal via Ethernet.

This Chapter presents a summary of the findings resulting from the thesis deliverables. Section 8.1 is the introduction of this chapter, and section 8.2 contains a list of the thesis' deliverables. Section 8.3 discusses the thesis deliverables' potential academic, research, and industrial applications. Section 8.4 proposes future research in transformer protection schemes for power systems. Section 8.5 details the status of paper publications, and section 8.6 is the conclusion of this chapter.

8.2 Thesis Deliverables

Based on the IEC 61850 communication standard, the research project aims to develop and implement interoperability between two different vendors for the transformer protection and control of parallel power transformers; the following objectives are satisfied:

The thesis' primary deliverables are listed below in order to achieve the goal mentioned above.

8.2.1 Literature review

The literature review in Chapter Two examined the various transformer protection techniques. The performance, stability, security, and reliability aspects of transformer protection scheme algorithms have been thoroughly examined and assessed. The IEC 61850 substation's new communication standard enables the development of a new range of transformer protection and control. Applications with significant advantages over traditional hardwired solutions have been reviewed. In addition, Hardware-in-the-loop (HIL) in real-time digital simulation for protecting IEDs has also been reviewed. This thesis's literature review focuses on the information presented in peer-reviewed journals and written books, which will guide the study's purpose and objectives.

8.2.2 Theoretical framework

Chapter Three provides an overview of transformer theory, parallel transformers, and transformer protection schemes such as a differential relay. Also summary theoretical foundation for IEC 61850 functions and standard communication. Theories about power system transformer protection, IEC 61850 communication standard on the power system. The books, online digital library, and other resources were used to conduct this research.

8.2.3 IEEE Nine-bus system modelling and simulation on RSCAD

Using system simulation software tools, researchers employ IEEE systems to implement and test creative ideas and concepts. The transmission system of IEEE 9-Bus is selected as a case study, and the IEEE 9 bus system is modified at bus 6 with sub-transmission and distribution. The 9-bus System was initially presented in the book "Power System Control and Stability" authored by (Anderson & Fouad, 2003). The reason to modify the system on Bus 6 is that IEEE 9-Bus was simulated on the DIgSILENT to analyse the network's power flow and protection performance. After so many simulations, it was found out that Bus 6 is the one that is not healthy in most cases. This was done by investigating the contingency. Then the network system of the modified IEEE 9-Bus was built/modelled on the RSCAD.

8.2.4 Design Technique Procedure

Chapter Four provides an overview of the test facility's design, hardware selection, and construction. The reasons for hardware selection, specifications for building test facilities, and their pre-commissioning tests are all protected before being used to evaluate substation automation system designs that comply with IEC 61850. The testing plant is used to build substation automation systems.

It is possible to accomplish the differential current transformer and implement interoperability between two multi-vendors by building laboratory infrastructure with appropriate hardware and software, including real-time simulation capabilities. The laboratory development includes selecting and implementing the required power system model using the IEC-61850 station bus and communication between various IEDs. In a real-time simulator measuring protection settings and their use on protection relays and documentation of all aspects of the project was covered in Chapter Five.

8.2.5 Monitoring and control of RSCAD's modified IEEE 9 bus system

A monitoring and control platform was built using the RSCAD runtime. The creation and assignment of plots, lights, meters, control switches, and other attributes. Voltage and current waveforms are also displayed when there is a change in the power system's events. Several internal and external faults were created and analysed.

8.2.6 IEC 61850 Substation Communication IED Configuration

For the HIL RTDS workstation, two different IEDs (SEL-487E and MiCOM-P645) were used. Both IEDs were set up to measure currents and send trip commands in the event of a short-circuit fault. The IEDs were set up for GOOSE communication to demonstrate the interoperability of this multi-vendor system. The RSCAD GTNET card, which can sample/process IEC 61850 GOOSE or GSE messages, was linked to this GOOSE message. The IEC 61850 and the RSCAD GTNET's IEC 61850 SCD files were configured and mapped to both IEDs and the GTNET card. After mapping on both sides was completed, each CID/SCD file was compiled in preparation for publishing and subscribing to GOOSE messages for interoperability.

8.2.7 Configurations with Hardware-in-Loop

As discussed in Chapter Four, Chapter Five, Chapter Six, and Chapter Seven, the test bench laboratory was set up for hardware in a loop configuration. The HIL testing offers the benefit of evaluating the functionality and performance of protection IEDs and other intelligent devices outside of computer-based or software systems. This means that the functionalities and capabilities of the scheme setup could be tested on these physical devices. The goal of this test method was:

- Real-time implementation of the designed transformer current differential protection scheme.
- Performance tests are conducted on the hardware for IEDs, protection, and various fault types.
- Implementing multi-vendor IEDs independent interoperability based on the IEC 61850 language communication standard.

8.2.8 The software used to configure the test bench

The test-bench components are configured using different types of software. The software is used to create models of the under consideration power system, controllers, logic algorithms, and interoperability communication based on IEC 61850 as part of the investigations and construction of the test bench. Table 8.1 describes the developed software.

Table 8.1: Project-related software packages

Software Package	Chapters	Description Of Functions Used
RTDS RSCAD	5, 6, and 7.	Draft Configuration ▪ Set up power system components and create a power system model. ▪ Breaker and fault control logic implementation. ▪ Tap Changer logic implementation. Control and run the simulation case ▪ Parallel case ▪ Master or follow the case ▪ HIL fault case. Mapping according to IEC 61850 ▪ Configure GTNET for GOOSE communication
MiCOM S1 Agile	5 and 7.	Configure the MiCOM-P645 relay IEC 61850 mapping
AcSELerator Quickset and Architect	5 and 7.	Configure the SEL-487E relay IEC 61850 mapping
GOOSE inspector	7	For GOOSE monitoring the Ethernet network packets.

8.2.9 Thesis Problems Solved

The main goal of the research was to develop a transformer current differential protection scheme and to investigate the IEC61850 standard-based interoperability challenges between the Intelligent Electronic Devices produced by different vendors (Multi-Vendor) and propose solutions for improving communication between these devices. The test bench at the laboratory was modelled and developed successfully in the form of the HIL, and different types of tests for fault were simulated in a hardwire and IEC 61850 GOOSE via LAN in order to achieve interoperability.

The IEC 61850 standard communication was implemented using GOOSE to exchange information between these two different vendors. It was proven that these IEDs were compatible with each other because there was no missing information when the MCL/SCL language of the MiCOM-P645 was imported to SEL-487E or vice versa. These demonstrations showcased the potential for achieving GOOSE message interoperability within a system that incorporates multiple vendors. The ability of GOOSE messages to seamlessly communicate between peers or achieve peer-to-peer communication was achieved and demonstrated between MiCOM-P645 and SEL-487E IEDs using GOOSE inspect as a network analyser. The summary of testing the GOOSE on the parallel transformer is as follows:

- The SEL-487E identifies a fault and reacts only if the fault is internal, a GOOSE message is generated and sent to the MiCOM-P645 device; its two LEDs will illuminate, but the MiCOM-P645 relay will not trip.
- The MiCOM-P645 Identifies a fault and reacts only if the fault is internal, a GOOSE message is generated and sent to the SEL-487E device; its two LEDs will illuminate, but the SEL-487E relay will not trip.

8.3 Application to Academia/ Research and Industrial

This research created a testing bench that academics can use to expand their knowledge of power transformer protection schemes in real-time digital simulation. The test bench has been designed to be adaptable for future transformer protection applications. Moreover, the test setup created for this research can serve as a valuable tool for conducting demonstrations and providing training to students and professionals in the industry. Utilizing these transformer protection schemes will also benefit utility companies.

8.4 Possible Future Research Work

The present study was based on developing a parallel transformer current differential protection scheme, investigating the IEC61850 standard-based interoperability challenges between the IED produced by different vendors, and proposing solutions for improving communication. Thorough investigations conducted on the real-time testbed confirm the theoretical analysis and demonstrate the susceptibility of the GOOSE-based IEC 61850 compliant substation system to malicious intruder attacks.

To safeguard the vital assets within IEC 61850 systems, it is imperative to establish security measures that ensure the reliability and resilience of the systems, effectively countering cyber-attacks. This can involve investigating techniques to detect and mitigate cyber threats, developing secure communication protocols, and designing robust authentication and encryption (Ustun & Hussain, 2020; Akbarzadeh et al., 2023; Holstein et al., 2023).

In particular, secure communication protocols such as Transport Layer Security (TLS) can be implemented to provide authentication, encryption, and message signing to ensure the integrity of communication. Additionally, intrusion detection systems (IDS) can be deployed to detect any unauthorized access or malicious activities on the GOOSE messaging system (Hussain et al., 2020; Holstein et al., 2023).

By implementing these measures, IEC 61850 systems can be made more secure and resilient against cyber-attacks.

8.5 Publication

- N. Shangase, M. Ratshitanga, and M. Mnguni, 2023. Parallel Power Transformer Current Differential Protection Scheme Based on IEC61850 Standard. Submitted to IEEE PES & IAS PowerAfrica Conference and is accepted for publication under IEEE.
- N. Shangase, M. Ratshitanga, and M. Mnguni, 2023. Interoperability Challenges in Multivendor IEC 61850 Devices for Parallel Power Transformer Differential Protection. Submitted to the International Journal of Electrical and Electronic Engineering and Telecommunications (IJEETC) and accepted for publication in November 2023.
- N. Shangase, M. Ratshitanga, and M. Mnguni, 2023. MiCOM-P645 Relay-Based Advanced Transformer Differential Protection System with IEC 61850 GOOSE Communication Protocol. Not yet been submitted to any organization. But the plan is to submit it to the SAUPEC Conference.
- N. Shangase, M. Ratshitanga, and M. Mnguni, 2023. Transformer Differential Current Protection Scheme based on IEC61850 Standard. Not yet been submitted to any organization. But the plan is to submit it to the ICECET Conference.

8.6 Conclusion

This concluding chapter encapsulates the comprehensive findings and contributions of the study. It commences by delineating the project's deliverables, providing a tangible representation of the study's achievements. These accomplishments are not only theoretical but also carry significant practical implications, bridging the gap between academic research and real-world applications.

Quantitative data on the study's testbeds and validation tests are meticulously presented, shedding light on the empirical aspects of the research. This data enriches our understanding of the implemented devices and their performance under various scenarios, adding a quantitative dimension to the study's findings.

The chapter goes on to underscore the vast potential applications of the implemented devices, transcending the boundaries of academia and delving into the realms of industry and research. It quantifies the versatility and adaptability of the developed system, showcasing its readiness for practical deployment.

Furthermore, it paves the way for future research work by offering quantitative insights into areas of interest and exploration. These suggestions are not mere conjecture but are grounded in the empirical data and observations gleaned throughout the study.

Finally, this thesis concludes with a quantitative list of publications related to this research, underlining the study's contribution to the academic and research community. These quantitative indicators enrich the conclusion by providing a numerical representation of the study's significance and impact, ensuring that the findings are not only described but also quantified for a more comprehensive understanding.

CHAPTER NINE

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CHAPTER TEN

APPENDICES

Appendix A
THE IEEE Nine-Bus System

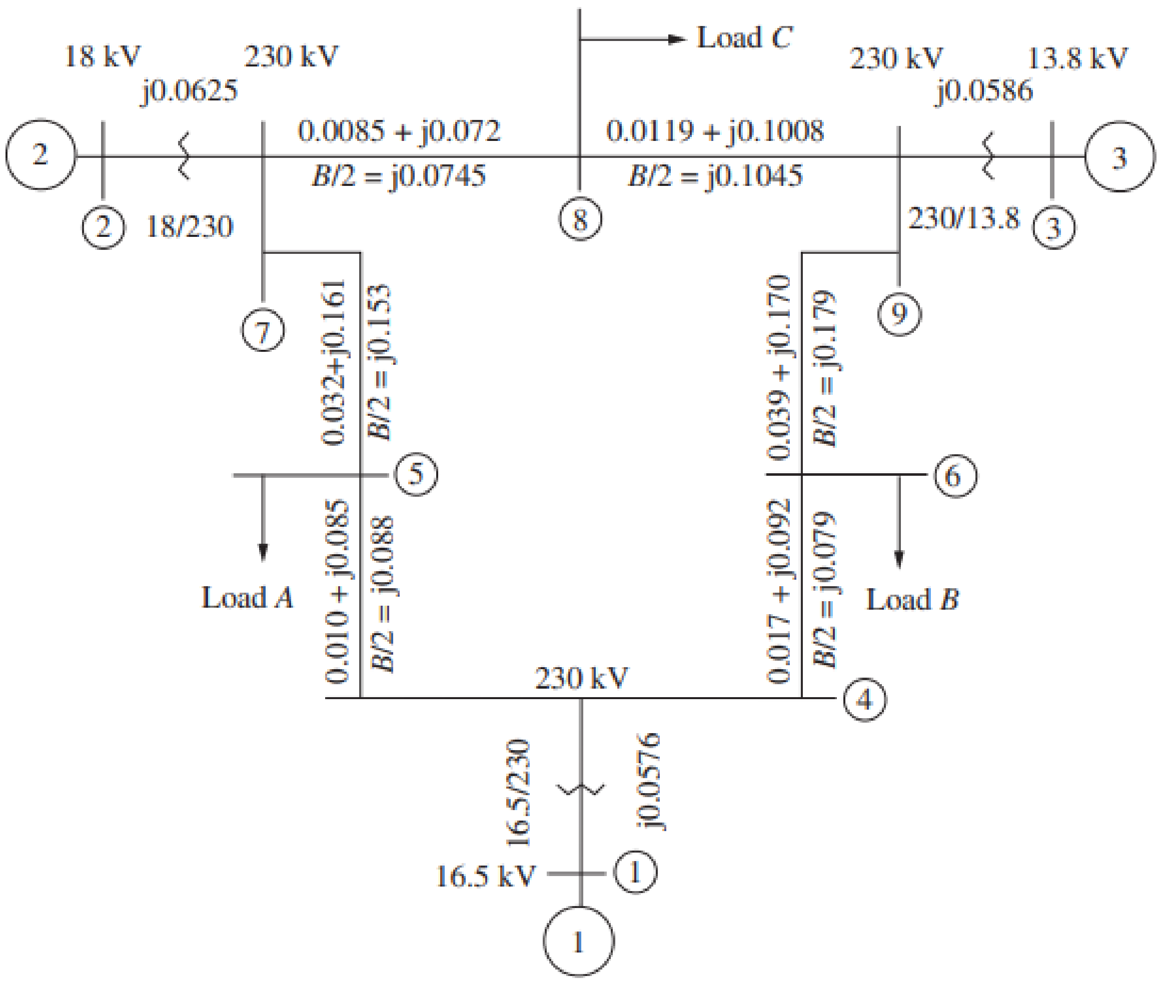

Figure 10.1: Original IEEE Nine-Bus System (Anderson et al., 2020)

Table 10.1, Table 10.2, Table 10.3, Table 10.4, and Table 10.5 show the data parameters for the Generator Data Source, transformers, Power Flow Data, transmission lines, and Power Load demand of the IEEE Nine-bus system.

Table 10.1: **Parameters of Generator Data Source**

Quantity	Generator1 (G1)	Generator2 (G2)	Generator3 (G3)
Nominal apparent power [MVA]	247.5	192.0	128.0
Nominal voltage [kV]	16.5	18.0	13.8
Nominal power factor	1.00	0.85	0.85
Plant Category	Hydro	Coil	Coil
Power (MW)	71.6	163.0	85.0
Q (MVAr)	27.0	6.7	-10.9

Table 10.2: **Parameters of Transformers**

Transformer	From	To	Rated Power [MVA]	Primary Voltage (KV)	Secondary Voltage (KV)	x1 [p.u.]	Winding Connection
IEEE 9 Bus transmission network							
TRF1	Bus 1	Bus 4	250	16.5	230	0.1440	Star-Star
TRF2	Bus 2	Bus 7	200	18.0	230	0.1250	Star-Star
TRF3	Bus 3	Bus 9	150	13.8	230	0.0879	Star-Star
Sub-transmission and distribution network							
TRF4	Bus 10	Bus 11	112	230	110.0	0.15	Delta-Star
TRF5	Bus 12	Bus 13	56	110.0	22.0	0.15	Star-Star
TRF6	Bus 12	Bus 13	56	110.0	22.0	0.15	Star-Star
Step-down Parallel Transformers (TRF5 and TRF6)							
Connection Winding 1				Star			
Connection Winding 2				Delta			
Leads Wye or Delta Lags				LV Leads HV			
Phase Shift				+30°			
(3 Phase) Transformer Rating				56 MVA			
Base Frequency				50 Hz			
Leakage Inductance of Tx				0.1 p. u			
(L-L RMS) Base Primary Voltage				110.0 kV			
(L-L RMS) Base Secondary Voltage				22.0 kV			
CT Ratio Primary				400:1A			
CT Ratio Secondary				2000:1A			
Primary Full Load Current				293.932 A			
Secondary Full Load Current				1469.662 A			

Table 10.3: Power Flow Data

BUS	Type	V (p.u.)	Voltage (KV)
IEEE 9 Bus transmission network			
1	SLACK	1.040 ∠0.0°	16.5
2	P-V	1.025 ∠9.3°	18
3	P-V	1.025 ∠4.7°	13.8
4	P-Q	1.026 ∠-2.2°	230.0
5	P-Q	0.996 ∠-4.0°	230.0
6	P-Q	1.013 ∠-3.7°	230.0
7	P-Q	1.026 ∠3.7°	230.0
8	P-Q	1.016 ∠0.7°	230.0
9	P-Q	1.032 ∠2.0°	230.0
Sub-transmission and distribution network			
10	P-Q	1.0 ∠-30.00°	230.0
11	P-Q	1.025 ∠-21.6361°	110.0
12	P-Q	1.032 ∠1.87°	110.0
13	P-Q	1.016 ∠0.630°	22.0

Table 10.4: Parameters of Transmission Lines

Line	From BUS	To BUS	R (Ω)	X (Ω)	B (μS)	Line Length (km)
IEEE 9 Bus transmission network						
Line 4-5	4	5	5.2900	44.9650	332.70	50
Line 4-6	4	6	8.9930	48.6680	298.69	50
Line 5-7	5	7	16.928	85.1690	578.45	50
Line 6-9	6	9	20.631	89.9300	676.75	50
Line 7-8	7	8	4.4965	38.0880	281.66	50
Line 8-9	8	9	6.2951	53.3232	395.08	50
Sub-transmission and distribution network						
Line 6-10	6	10	11.638	41.262	378.06	45
Line 11-12	11	12	3.703	31.4755	232.9187	20
Line 15	15					15

Table 10.5: Parameters of Power Load Demand

Load	Bus	Real Power (P) [MW]	Reactive Power (Q) [Mvar]
IEEE 9 Bus transmission network			
Load 1	Bus 5	125	50
Load 2	Bus 6	90	30
Load 3	Bus 8	100	35
Sub-transmission and distribution network			
Load 4	Bus 15	83.0	41.5

Appendix B

The IEC 61850 Standard Communication

Table 10.6: Overview of the different IEC 61850 Standard parts (Padilla, 2016)

IEC61850 PART NUMBER	DESCRIPTION		Content	
1		An outline and introduction	Defines the standard's communication between IEDs and the application scope.	
2	SYSTEM ASPECTS	Glossary of terms	Contains different terminology used by various sections of the standard.	
3		General Requirements	Establish qualitative SAS attributes such as availability, security, and reliability. Define the environmental conditions applicable to it.	
4		Project and System Management	Describe different SAS project subjects, including technical specifications, life-cycle definition, and best practices in quality control.	
5		The Requirements of Communication for Device Models and Functions.	Set up a common system SAS. Defines the bus and process bus from the station. Say interoperability is the standard's target. Introducing the definition and implementations of logical nodes	
6	CONFIGURATION	Configuration Description Communication language for IED-related electrical substations.	Specify a common general Communication file format (SCL). Defines devices in different configurations. Develop models for substations, IEDs, and communication. Defines common SCL file types.	PRIMARY PARTS
6-1:		Substation Configuration Language (SCL)		
7 7-1	Abstract Communication Service	Basic Substation and Feeder Communication Structure.		
		Models and Principles	Covers principles and definitions for the modeling of computer functions, historical details, hierarchy control, and time synchronization.	
		Abstract Communication Service Interface (ACSI)	Prepare models of communication for the exchange of information between IEDs.	
7-2 7-3	Data Models	Common Data Classes (CDC)	Specify the principles of data management for status information, assessment information, and facility setting.	
7-4		Compatible logical classes of nodes and classes of data.	Specify system models and logical node names for IEDS communication.	
8	Specific Communication Service Mapping (SCSM)	Specific Communication Service Mapping (SCSM)	Specify the methods of data exchange through MMS and GOOSE communication services into the Station Bus.	
8-1		MMS and ISO / IEC 8802-3 mappings		
9				
9-1		Sampled values over multidrop point-to-point serial unidirectional values Link		
9-2		Sampled Values over IEC 8802-3/ ISO	Specify the methods used to exchange data through process bus using the technique of sampled values.	
10	Testing	Conformance Testing	Specify conformance-checking monitoring techniques and calculation techniques to determine output parameters.	

Appendix C
Logic Control Diagram Design

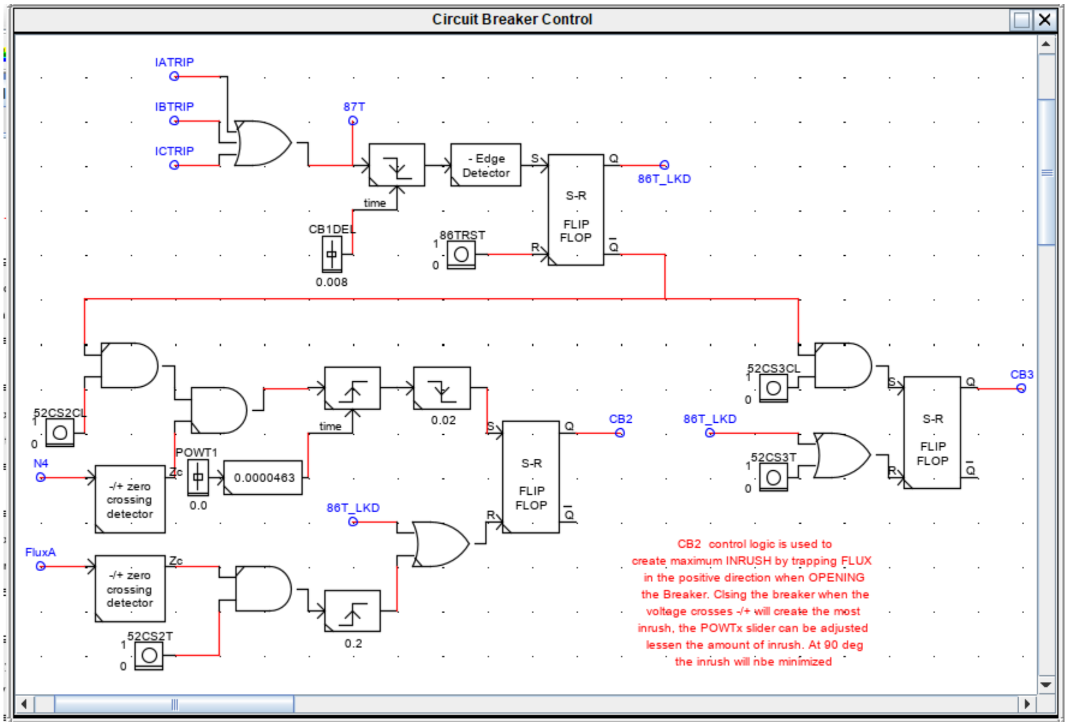

Figure 10.2: Circuit Breakers Control logic (RTDS, 2019b)

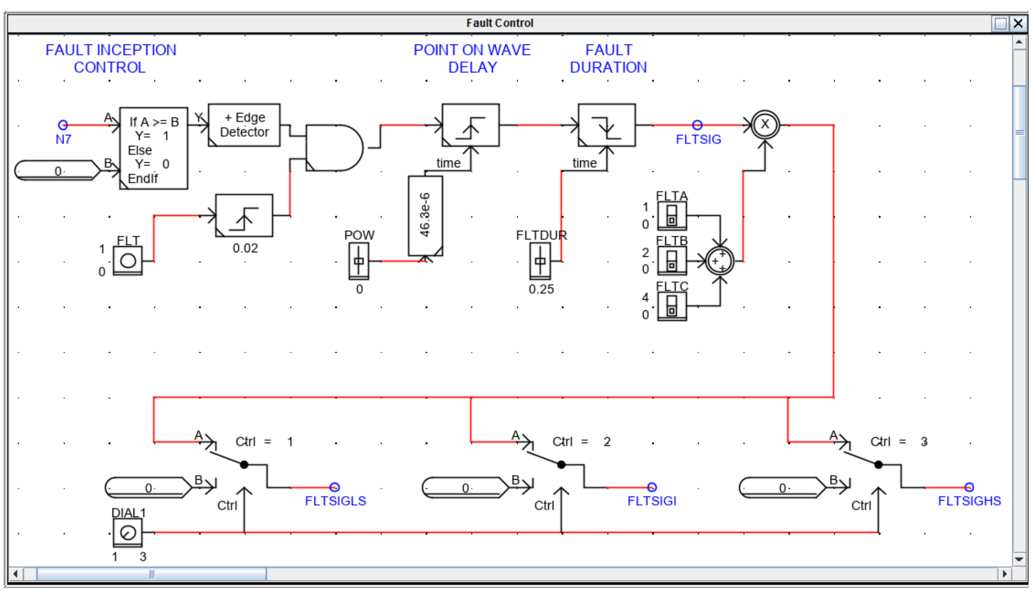

Figure 10.3: Fault control logic circuit (RTDS, 2019b)