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INVESTIGATION AND DESIGN OF AN INTEGRATED MONITORING, PROTECTION, AND CONTROL SYSTEM OF A POWER RETICULATION NETWORK

By

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I, Mukovhe Ratshitanga, declare that the contents of this dissertation/thesis represent my own unaided work, and that the dissertation/thesis 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.

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ABSTRACT

As far as substation automation systems are concerned, one of the prime requirements of most utilities today is the interoperability between Intelligent Electronic Devices (IEDs) of different manufacturers. The standard IEC 61850 - Communication Networks and Systems in Substations - allows such interoperability between IEDs for protection and automation of substations. Presently, many manufacturers have implemented, or are in the process of implementing this standard in their IEDs. This has encouraged some utilities to specify IEC 61850 based Substation Automation systems. Their aim is to ensure that both system requirements are met and the features and benefits of the standard are fully exploited. The author of this thesis investigated and brought forward the design of an integrated monitoring protection and control system of a network in Cape Peninsula University of Technology (CPUT) campus based of the IEC 61850 standard. A method of testing the physical IED based on Hardware-In-Loop (HIL) configuration with the Real-Time Digital Simulator (RTDS) is developed and implemented. Mapping of IED Substation Configuration Language (SCL) with that of the RTDS GTNET cards is discussed and implemented to further exploit the use of real-time testing with Generic Object Oriented Substation Event messages (GOOSE). The thesis highlight the benefits of interconnecting the reticulation IEDs into a standardised communication network for protection, control and monitoring of each substation event. This improves the access to information and reduces maintenance cost on the reticulation network.

Keywords: Interoperability, IEC 61850 standard, Substation Automation, RTDS, IED, SCL, GOOSE, HIL, CPUT.

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DEDICATION

The thesis is dedicated to my family for all their support but not forgetting my Mother – Ndishavhelafhi Ratshitanga, my Wife – Cebisa Ratshitanga, and my late younger brother Mpho Ratshitanga. Additionally, my close relatives who contributed in making this possible. *Vhadzimu vha thohoni na damuni, maanda na nungo zwe vha nnekedza u bva mbeboni ndi' ndi khou livhuwa. Ndaa!*

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GLOSSARY

DIgSILENT	Power system analysis software for applications in generation, transmission, distribution and industrial systems.
IED	A generic name that covers various protection, control, metering and monitoring devices that are implemented using microprocessor-based technology.
Current Transformer	A device that transforms current from one magnitude to another magnitude
Discrimination	The ability of two or more protection systems to decide which one should react to a certain fault and then take corrective action.
GOOSE	A high performance multi-cast messaging service for inter-IED communications, and is used for fast transmission of substation events.
Logical Device	Contains the information produced and consumed by a group of domain-specific application functions, which are defined as Logical Nodes.
Logical Node	A functional grouping of data and represents the smallest function, which may be implemented independently in the logical devices.
Interchangeability	Ability to replace an IED with a different IED from a different vendor without any impact.
Interoperability	Ability of two or more IEDs, regardless of the vendor, to exchange information and use that information for correct execution of specified functions.

Supervisory Control and Data Acquisition A process control system that enables a system operator to monitor and control processes distributed among various remote sites.

Numerical Relay A relay capable of acquiring instantaneous samples of voltage and/or current and process them using a mathematical algorithm

Substation Configuration description Language A description language for communication in electrical substations related to the IEDs.

Voltage Transformer A device that transforms voltage from one magnitude to another magnitude

Busbar A common connection point in a distribution network substation

Distribution The conveyance of electricity through a distribution network

Protection system A system, which includes equipment, used to protect facilities from damage due to an electrical or mechanical fault or due to certain conditions of the power system.

Merging Unit (MU): A device used for transmitting sampled measurements from transducers such as CTs, VTs and digital I/O for communication onto the process bus.

Notified Maximum demand (NMD): A contractual agreement for the supply of electricity between the supply authority and the relevant customer.

Physical device: Physical devices contain logical devices that contain logical nodes, with data nodes and data.

SCADA: A process control system that enables a system operator to monitor and control processes distributed along various remote sites.

SCADA Master: The term “SCADA Master” refers to the servers and software responsible for communicating with the field equipment, and then to the HMI software running on workstations in the control centre.

GOOSE	-	Generic Object Orientated Substation Event
CT	-	Current Transformer
HV	-	High Voltage
HT	-	High Tension
IEC	-	International Electrotechnical Commission
IEDs	-	Intelligent Electronic Devices
SAS	-	Substation Automation System
SCL	-	Substation Configuration Language
SCADA	-	Supervisory Control and Data Acquisition
VT	-	Voltage Transformer
A/D	-	Analogue to Digital
HMI	-	Human Machine Interface
SV	-	Sampled Values
LAN	-	Local Area Network

CHAPTER

1 INTRODUCTION

1.1 INTRODUCTION

The requirements of an electrical power system is to generate, transport over long distances, distribute from one substation to another and thereafter supply electrical energy to consumers or end-users. The reliability and economy are critical at utilisation points and the system should be designed and managed to account to these when delivering this energy. If power outages are frequent or prolonged on the power system, severe disruption to the daily normal routine of modern society is very likely and an increasing emphasis on reliability and security of the supply is required.

More fundamental, however, is that the power system should operate in a safe manner at all times. No matter how well planned and designed, faults will always occur on a power system due to internal or external factors, and these faults may pose a risk to life or property (Hewitson, 2004). Furthermore, when an electrical network has matured in age, it is prone to electrical faults due to aging equipment and unavailability of spares for maintenance. At some point in time, maintenance of an old electrical network is financially costly somehow due to shortage of skills to maintain existing equipment and technology.

New technology emerges with time to improve control, and monitoring of electrical network power flow, and protection. Technology is also widely used nowadays to reduce power consumption, hence save energy and cost associated. This could be done by switching off all unused appliances and items at the lower end of the distribution.

A problem exists at the Cape Peninsula University of Technology Bellville campus (hereafter referred to as CPUT) that the existing 11kV reticulation network is old, utilising switchgear that has reached the limit for safe maintenance. All existing breakers are oil immersed and leaking which is an unsafe practice. These cannot be controlled or monitored remotely as provision for such is not available and cannot be put in place. In order to perform this, new circuit breakers will have to be installed with provision for remote control and monitoring. A system of power monitoring and control which enables network status and tests, load management, and remote functions can be housed in a single control room to manage and monitor the entire reticulation network.

In addition, a safe and low maintenance switchgear medium such as Sulphur Hexafluoride (hereafter referred as SF6) can be used on all ring main units (hereafter referred to as RMU) at 11kV. In addition, protection relays can be identified for basic protection at each RMU and at the main incomer substation.

The installation of new switchgear and modern relay technology, will enable the institution to monitor, perform test, optimise load flow, and thus perform remote functions on the reticulation network and information storage for all or required network parameters such as; power flows and faults on the network. Various substation automation systems will be identified and their market availability will be considered. These will be analysed based on their compliance to the International Electro-technical Commission standard 61850 (IEC-61850 standard). The main chapters of this thesis will conduct load flow and protection studies, and development and modelling of the closed-loop testing of the Hardware-In-The-Loop testing of the protection Intelligent Electronic Devices (IEDs).

1.2 DESIGN PROBLEM STATEMENT

The network understudy is to be analysed for a complete switchgear overhaul and put in place a substation automation system. A simulation test-bench will be built in a laboratory to simulate network performance with the automation system in place. This research presents the following:

- Build a single line diagram and perform simulation studies of both the existing and upgraded campus 11kV network by making use of appropriate simulation software. Results of the simulation studies will then be used for protection grading calculations as well as for network capacity evaluation to cater for both the short and long term future load growth.

- Create a test-bed lab hardware and software environment for the implementation of the IEC-61850 standard functionalities. Create a substation environment and simulate the monitoring and control functionalities including data acquisition, including analysing, formatting and improving software tools for the configuration of the applicable Intelligent Electronic Devices (IEDs).

- Act as a technical representative as the Bellville campus technical services team by specifying detailed electrical network requirements and work jointly with the identified consultant(s) and vendor(s) in the planning, design and execution stages of the institutional project for the 11kV network upgrade, including the establishment of a network automation as per the IEC-61850 standard.

The IEC-61850 standard was put in place to regulate all communication of the Intelligent Electronic Devices (IEDs) via a standardized communication medium such as peer-to-peer (P2P) through wireless or hard wired medium. The standard also regulates that different vendors of items such as protection relays, metering equipment etc. be able to communicate together without being dependent on their manufacture. In summary the IEC-61850 governs the following communication;

- Covers all communication issues inside any kind of power system substation.
- Supports all types of architecture used.
- Must cope with fast development of communication technology in the existing slow evolving power system
- Assure ease of operability of functions that exists in the substation.

1.2.1 Reason for Studies on Existing Network

The primary objective for performing research work in this particular network is by making use of IEC-61850 standard and applies;

- The need to monitor and reduce power consumption remotely at overloaded substations,
- Be able to monitor and easily locate areas of faults in order to retain power with minimum time interruption.

Secondary objectives would be to expand the IEC-61850 standard regulation on the network to;

- Monitor overall load power distribution on the internal 11kV network.
- Switching of the 11kV network during maintenance or at fault conditions.

1.3 RESEARCH AIM AND OBJECTIVES

The aim of this research is to identify if it would be possible to implement IEC-61850 standard for substation automation to the existing CPUT distribution network. This takes into consideration the existing conditions of the network and making recommendation on what has to be upgraded and what needs to be implemented to the upgraded network in order to complete the objectives. The substation automation ideally is based on a monitoring system which should fulfil the requirements of the IEC-61850 standard.

The main objective of this research would be to bring forward network analysis and design which is made up of:

- Simulation of existing network power flow
- Simulate upgraded network power flow
- Simulate upgraded network fault levels
- Create and simulate the monitoring system for the 11kV network based on the IEC-61850 standard.

1.4 THE HYPOTHESIS

There is a possibility given by the reticulation network at CPUT stature to implement the standard IEC-61850 based substation automation system in which the monitoring functions will be housed at the planned control room. If implemented, the automation system should help reduce energy consumption and maintenance expenses while providing network protection and monitoring of power flow and other substation events.

However, some functionality will have to be addressed between a supervisory, control and data acquisition (SCADA) system and a form of an integrated building management system at a later stage in the future. This is based on that the SCADA system will be most suitable to functions at 11kV network while the building management system will look at 400V and 230V for management and monitoring of high energy use appliances, such as water heating and lighting.

1.5 DELIMITATION OF THE RESEARCH

The proposed research focuses on the application of IEC-61850 standard on the entire CPUT distribution network. The introduction of the IEC 61850 standard allows the control and monitoring of each substation event through the IEDs. The research analyses in detail the power flow (energy consumption) and prospective substation faults in which the results are used to determine protection relays and metering equipment for the purpose of power measurement and data acquisition.

The network is analysed for power flow and faults using DigSILENT Power Factory and also modelled on RSCAD real-time software for the purpose of simulating network monitoring, data acquisition, fault analysis and substation switching.

At this stage, the analysis of low voltage side of the reticulation network will not be covered. This requires a full analysis of loads connected on the 400V/230V, which will required more time to quantify.

1.6 MOTIVATION FOR THE RESEARCH PROJECT

The research will benefit the institution as it is meant to identify current shortfall of the reticulation network, thereafter determine ways to improve the network. Intentions are to install new switchgear and automation system on all substations for 11kV reticulation network. The system should identify the implementation of a monitoring system as mentioned in item 4 above for entire reticulation network.

In addition, worldwide implementation of substation automation system based on IEC61850 standard is becoming a norm, and bases of improving substation communication and operation. This standard, when implemented in CPUT network should bring the same benefits being experienced by institutions and utilities worldwide.

1.7 ASSUMPTION

The software environments of the DIgSILENT and RSCAD software allow to analyse the existing problems of the CPUT reticulation network substation automation system and find solution of the problem for the design and implementation of the IEC61850 standard-based substation automation, monitoring and control system of this network.

Real-time implementation of the developed system by Hardware-In-Loop (HIL) simulation using the Real-Time Digital Simulator (RTDS) allows verification of the used methods and confirms applicability of the proposed solutions.

Documentation from this research can be used to source funding to upgrade the existing CPUT network.

1.8 RESEARCH METHODOLOGY

The research aims to identify and develop possible solution to reticulation network protection requirements and the capability of implementing IEC 61850 standard. The research assesses information online through publications and related theory books.

1.8.1 Reticulation Network Data

The existing power reticulation network data is collected and analysed. Parameters are used to configure equipment modelling on simulation packages.

1.8.2 Modelling and Simulation.

Power flow simulation and protections settings are conducted in order to determine minimum requirements and performance of the network. The software packages used are DIgSILENT Power factory and RSCAD.

1.8.3 Test Bench Setup

Physical industrial grade IEDs are used during the simulation and testing. The configuration of utilising physical devices together with simulation tools is considered as “Hardware-In-Loop” (HIL) or “Hardware-In-The-Loop” (HITL) which both have same meaning. Protection settings of the IEDs are tested when the faults are introduced on the simulation power system network.

1.9 THESIS CHAPTERS

There are seven chapters in this document as follows:

1.9.1 Chapter 1

The awareness of the problem and introduction to the research project. Problem statement, research objectives, motivation for the research work, hypothesis, and delimitation of research, assumptions, and research methodology are described.

1.9.2 Chapter 2

This chapter covers the literature review on all aspects of substation automation, monitoring and control. In addition, the IEC6850 standard of substation communication is discussed.

1.9.3 Chapter 3

The chapter discusses the literature concerning all aspects of substation and distribution automation, networking, protection, the standard IEC61850, power flow and monitoring.

1.9.4 Chapter 4

Modelling and configuration of power reticulation network equipment on DIgSILENT PowerFactory are performed in this chapter together with methods for calculating short-circuit faults. Discussion of the results is provided.

1.9.5 Chapter 5

This chapter covers modelling of the power reticulation network on RSCAD real-time software environment. The development hardware-in-loop setup and the configuration and setting of physical devices is discussed. The network configuration is also discussed. Mapping of device Substation Configuration Language (SCL) is also discussed and diagrams developed for control and monitoring of substation events are proposed.

1.9.6 Chapter 6

The results of models developed in Chapter 4 and Chapter 5 are calculated and analysed under this chapter.

1.9.7 Chapter 7

This is the thesis concluding chapter. Deliverables, application of results, and future research possibilities are presented.

1.10 CONCLUSION

This chapter introduced the thesis and described the aim and methodology of the thesis together with highlighting the various chapters to be presented after. The next chapter focuses on the thesis literature review. The review cover is based on substation automation, distribution automation, IEC61850 standard and protection.

CHAPTER

2. LITERATURE REVIEW

2.1 INTRODUCTION

In today's word, most utilities and large system owners are opting for open systems using intelligent devices. The idea is based on simplifying the integration of devices through common communication standard to allow system designers to choose any device based on equipment available at the time (Northcote-Green and Wilson, 2006).

Substation automation and distribution automation play significant role in electrical substations and distribution network levels. They influence the overall performance of the protection devices in isolation and clearing faults in the network and restore supply to consumers (Moerane, 2014)

This chapter focuses on the history of protection, substation automation, and control, and brief history giving the benefits of implementation of the communication standard IEC61850 on electrical substations. It is widely known that the IEC61850 is not fully utilised in distribution grids in South Africa and attention will be focused on its implementation on medium voltage networks, in particular 11kV at a later stage. This chapter presents existing problems with conventional protection systems and the latest application solutions which have been studied till now. Moreover, benefits from application of the new standards such as IEC61850 on consumer networks are described.

The developing economies are now changing even the architecture of their electricity supply networks and performance due to concerns which are; safety and security of the network, global warming and greenhouse gas emissions, and competition internationally. Somehow their proposed solution to a controlled and automated networks are influenced by the growth and alteration on the network, nature of loads, primary system failures, secondary system failures, and network source impedance (Higgins et al., 2011). The remainder of the literature review incorporates distribution automation, protection requirements, implementation of the IEC61850 standard for communications in substations etc.

2.2 POWER QUALITY OF DISTRIBUTION NETWORK

Power quality can be defined through instability/stability of quantities such as voltage and current and at times determined by magnitude of overall power factor at a point of mains supply (Thompson, 2007). In order to improve the quality of supply, it is essential to monitor substation events and collect data for the purpose of analysis. The quantities to be identified are as mentioned above; voltage sags, interruptions, and equipment which contributes reactive power to the power network, and lastly but not least harmonics on the supply which may be caused by electronic devices.

Equipment loading can also contribute to loss of supply interruptions, or explosions due to overheating. These can happen to transformers, cables and other network equipment such as isolators and circuit breakers.

Kojovic and Hassler, 1981 presented the comparative analysis of the effects of distribution system expulsion and current limiting fuse operations on power quality. The analysis is performed with the use of digital fuse models developed for use with the EMTP/ATP program. The EMTP/ATP (Electromagnetic Transients Program / Alternative Transients Program) is a software program for analysis of electromagnetic transients and associated insulation issues.

2.3 DISTRIBUTION PROTECTION AND CONTROL

During normal operation, the power system network is assumed to be a balanced three-phase operation, with equal magnitudes of voltages and currents and a phase shift of 120° between phases. For a balanced four wire syste m which is considered a Star-connection, the fourth wire ideally carries zero current when all phase impedances and voltages are equal (Momoh, 2007). The situation is different during the unbalanced system case. When short circuits occur, they lead to single-phase-to-ground, phase-to-phase, double phase-to-ground, and balanced three-phase faults. The ground fault is determined as impedance fault Z_f, which is referred to as a bolted short circuit or a nonzero impedance.

The causes of faults are many. They include lightning, wind, objects falling on lines (trees, kites, airplanes, and debris), vandalism, accidental break or short circuit, or inadvertent operation of a circuit breaker.

(Apostolov and Vandiver, 2011) stated that the distribution industry is going through sizable adjustments due to the improved requirements for expanded exceptional of electricity furnished by means of the utility in order to avoid steeply-priced interruptions of manufacturing or other procedures precipitated by means of voltage sags, swells or unbalanced prerequisites when a quick circuit fault occurs in the distribution system. The paper further highlighted that the application of IEC 61850 GOOSE messages allows giant enhancements in the protection of distribution substations that minimize fault clearing instances and minimise the impact of short circuit faults on sensitive loads. Using such high-speed messages eliminates the need for a couple of hard wired connections.

(Vahamaki, Allen and Gaff, 1997), presented a development of serial data communication in conjunction with sensible blended protection and control relays to enhance availability, performance and flexibility of utility for power distribution networks. The paper identifies how the high speed communication exchange system, when mixed with a new generation of smart protection and control terminals now on hand for distribution circuits, gives peer-to-peer communication and allows implementation of substation automation software functions, which are not possible with previous systems using master-slave technology and highly gradual speed communication.

2.4 DISTRIBUTION AUTOMATION

Previously utility and industrial substation managers had a perception that there was no need and neither is it a worthwhile investment to implement efficient control of power distribution networks, however they are being forced to change this perception due to the deregulation of the power system and industry experience with the new cost effective control systems. Benefits of a downstream automation system are now being extended outside the substation itself to devices along the network up to items such as meters. Electrical utilities implementing distribution automation have produced business cases which are supported by a wide variety of advantages selected to be suitable to their operating environment (Northcote-Green and Wilson, 2006)

(Russell, 1977) stated that the use of microcomputer technology for future applications may include their use as dedicated modules for control in substation automation schemes as replacement of traditional protection schemes.

In developing countries, there is a rise in the need to change the architecture and performance of the electricity networks. This need for change came as a result of concerns due to energy security, global warming and greenhouse gas emissions, international competitions, market failure, performance of network service providers and the digital society (Higgins et al., 2011)

In distribution substations and network grids, protection and control is a provision and requirement of all technical means for optimal supervision, protection, control and management of all network components and equipment. The main task of network control begins at the initial point of supply downstream to the complex network systems for substations automation, network and load management, system failure and time based maintenance (Costianu et al., 2011).

Distribution automation is an integrated system which monitors, coordinate and controls the equipment of the grid applying modern communication and computer technology. This is an unavoidable trend of modernizing the power system. When the distribution grid operates abnormally or under fault condition, the distribution automation system can quickly find out the faulted area and abnormal event, then isolate the fault area quickly, and recover the power supply of non-fault area timely so as to reduce the power outage time. From this point the power supply reliability will be improved. Distribution automation system has four main functions: monitoring, control, protection, and management (Zhou *et al.*, 2016).

The function of monitoring is to display the operation state of the distribution network grid by gathering the events and state quantity of the distribution network grid equipment and switchgear such as the position of the switch, the state of protection action and the analog quantity such as voltages, currents, power, etc.
The function for control is to manage or control switch closing or opening and regulate transformer tap in the appropriate time in order to achieve the desired purpose such as to meet requirements of voltage quality, reactive power compensation, load balancing, etc. The protection function is to detect and analyse the fault area, isolate the fault area and restoring the network electrical power supply of the unaffected area.
The management function is to manage the equipment and switchgear and user electrical power supply and outage events by applying advanced software so as to improve reliability and the working efficiency and service quality (Zhou et al., 2016). Figure 2.1 shows the diagram of the Distribution SCADA system, which shows three

kinds of terminal units, where FTU is the Feeder Terminal Unit, DTU is the Distribution Terminal Unit and TTU is the Transformer Terminal Unit.

The realization of the characteristics of distribution automation relies upon the application of some key technologies in the distribution automation system which mainly include the distribution Supervisory Control and Data Acquisition (SCADA) technology, distribution geographic information system, load control and management technology and remote automatic meter reading technology.

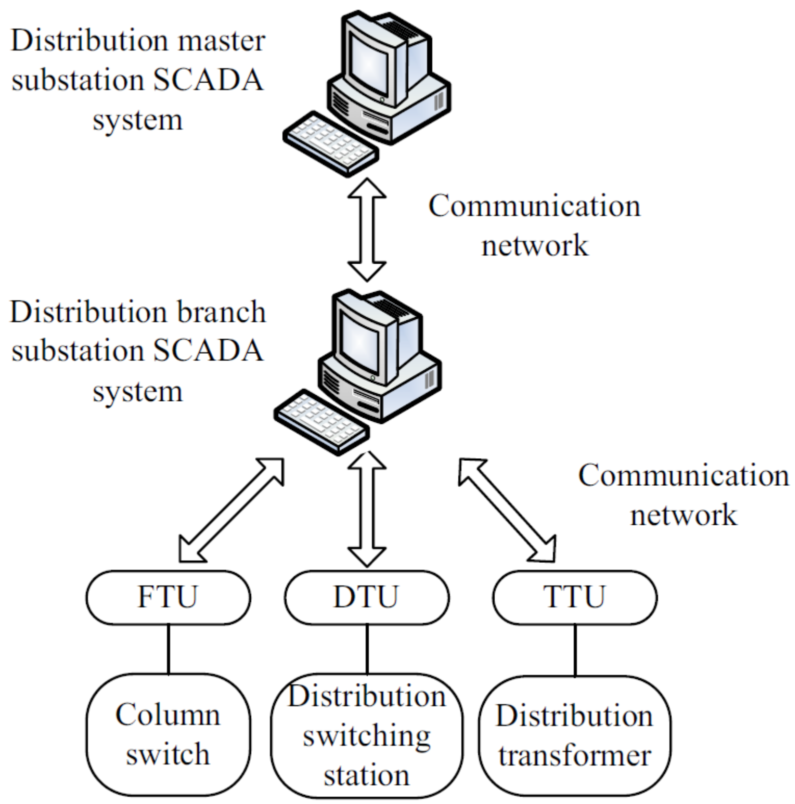


Figure 2.1: Structure Diagram of Distribution SCADA System (Zhou et al., 2016)

Benefits of using distribution automation can be seen from among others, reduction of cost on operation and maintenance, quality of power supply to various substations, improved reliability, and improved data information available. These support the network engineers and technicians to better manage the system with necessary/required information available daily (Northcote-Green and Wilson, 2006).

Information obtained from distribution automation systems helps improve network planning and scheduled maintenance and reduces operation and maintenance costs.

Location of faults can be easily identified thereby reducing the time required to locate the fault and its clearance.

Quality of supply – this is measured through voltage sags, unexpected power interruptions, and deviation of supply to unity power factors. If all these factors are known, the system supply quality can be improved.

Improved reliability – substation reliability is identified through the reduction of unexpected outages and faults. Automation of these networks provides the fastest and reliable way to reduce or minimise outage duration.

(Hjorth, Gupta and Balasubramanian, 2017) developed a Centralized Distribution Automation System (DAS) for Texas A&M University (TAMU). Their objectives were to stop using the conventional methods of detecting underground faults and isolation which were labour intensive, time consuming, expensive, and detrimental to equipment. The developed DAS had to automate tasks such as these and also perform specific sequence of operations before electric power can be restored to de-energized loads. DAS was developed to enhance overall system reliability and optimize operation by performing the following functions:

- Detection of permanent fault and isolation
- Service restoration through automatic reconfiguration
- Detection of substation dead-busbar
- Substation source loss automatic transfer
- Abnormal condition monitoring of the system
- Multiple simultaneous faults response
- Sequence for Automated Return-to-Normal (RTN)
- Detection of communications link
- Awareness of the system via Human-Machine Interface (HMI).

TAMU's automated part of the network consists of three ring (loop) networks each fed from two separate radial feeders. The two radial feeders in a loop scheme are separated through a normally open load break switch, illustrated as NO. The radial feeders on the TAMU network have multiple four-way load break switches which are distributed along the feeders installed in manholes and some above ground switchgear. Most load break switches on the network are manually operated while others are automated by integrating a 24 Vdc motor operator which can be controlled remotely by the DAS (Hjorth, Gupta and Balasubramanian, 2017).

The collection of important analog and digital information is done by the Distribution Automation Controller (DAC) for information required from substation IEDs by the DAS via the substation Ragged Automation Controllers (RACs). Discrete I/O devices wired to Fault Circuit Indicators (FCIs) communicate fault information using DNP3 Transmission Control Protocol/Internet Protocol (TCP/IP) to the Distribution Automation Controller. The Distribution Automation Controller uses the information to monitor the health of the system, such as feeder loading, voltage levels and system topology. It also provides system-wide awareness and control for a large group of feeders (Hjorth, Gupta and Balasubramanian, 2017). The developed data flow diagram is as shown in Figure 2.2 below.

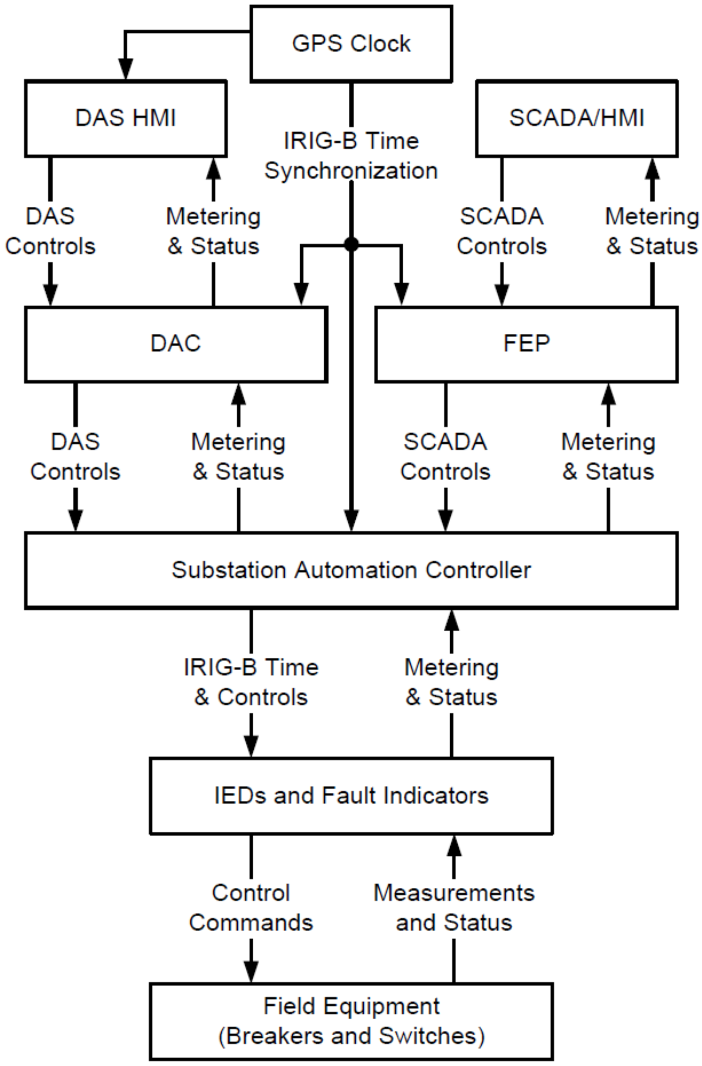


Figure 2.2: Data acquisition flow diagram (Hjorth, Gupta and Balasubramanian, 2017)

The TAMU DAS HMI controller at the Central Control Room (CCR) provides the HMI screens with data used for monitoring and controlling the DAS. The CCR includes devices such as automation controllers, HMI servers, Front End Processor (FEPs), and SCADA servers. The DAS status, IED collected data, fault location, switch position, system events, and alarms are displayed by the diagnostic HMI, and it provides operator control of the system. In addition, the HMI utilizes web-based access for multiple users to access the HMI simultaneously over the network (Hjorth, Gupta and Balasubramanian, 2017).

2.5 IEC 61850 COMMUNICATION STANDARD

Communication is the backbone of control and substation automation and IEC61850 is the most important key to designing the automated systems. IEC 61850 provides interoperability between the Intelligent Electronic Devices (IEDs) for monitoring, protection, control, metering and automation in substations (Andersson et al., 2005).

In the modern-day practice of power system monitoring and control, exclusive devices are separately designed to perform distinctive functions. Data concentrator processes collected data from the power system measurement devices via communication networks. Intelligent Electronic Devices (IED) are designed independently to perform different protection functions. The providers of the IEDs use different communication protocols. The bulkiness, cost, and communication requirements of implementing the monitoring, control and protection functions independently can be avoided by designing a new generation of smart power system network devices that implement these functions inside a standalone single device (Alouani, 2012).

According to (Yang, Yang and Yang, 2012) exchange of information via communication network between end users and power suppliers can estimate the power consumption more precisely, and a stable operation of the power utility can be possible if importance of the communication network is increased. In the digital substation or other power utilities, which employs the IEC 61850, the network system undertakes an important role for stable operation to provide advantages such as power utility ability to bi-directionally interact with users through communication networks, unlike traditional power utility networks, where the traditional power system only supplies electricity to loads and extracts usage information from the loads. Consumers will be able to trade electricity generated in their DERs (Distributed Energy Resources), e.g., photovoltaic generator or wind farm, and also they will be able to monitor usage or price of electricity in the market. This will make it possible to reduce emission of CO_2 and to encourage saving energy consumption through monitoring.

(Vasel, 2012) mentioned that in modern plants and facilities, substation visibility is becoming more critical. IEC 61850 can be leveraged to provide substation visibility in a cost effective way. A plant-wide asset management strategy can be created through the use of the substation communication standard, as well as other open fieldbus standards. Condition-based monitoring examples include Low Voltage (LV) motor starters via Profibus and Profinet while protective relays are integrated with IEC 61850.

The integration benefits help not only the process engineer but the power engineer as well. An integrated system allows for remote access to the Disturbance Recorders (DRs) and automated analysis of the recordings. Faster analysis of plant disturbances means faster problem resolution and root cause analysis which equates to increased plant up-time.

(Ali *et al.*, 2015) proposed that, to address the reliability, availability, and deterministic delay performance needs of SAS, an IEC 61850-9-2 process-bus based Substation Communication Network (SCN) architecture should be utilized.

2.6 MONITORING OF POWER SYSTEMS

According to (Repo et al., 2017), the real-time monitoring of electrical networks shall be extended from primary substations to secondary substations up to final customer where the advanced metering infrastructure is present. Examples of these metering units may be power quality meters, fault recorders and Phasor Measurement units. The control of an active distribution grid with pervasive monitoring should be designed in a logical and consistent way. In addition, Repo states that, the automation system should always be based on standards such as a de-facto role taken by IEC 61850

(Lane and Joly, 1997) defines the notion of a target architecture that manufacturer's should focus on as far as interoperability is concerned in protection and monitoring-control systems for electric substations. Lane further presented a model of an integrated digital system that might provide the answer which is currently available and is well adapted to medium voltage electrical installations in industrial networks.

2.7 POWER SYSTEM RESTORATION

Application of fault location, isolation and restoration is one of the advanced features of the modern distribution management system (DMS) used to support implementation of self-healing smart grids and control room operations.

Most industrial electrical network guidelines and regulations have now been reviewed due to the constant requirement of reliable supply of electricity from customers. Therefore infrastructure solutions decreasing fault frequency, outage duration and outage area will be needed in the future (Repo, Ponci and Giustina, 2014).

2.8 COMPARISON OF RESEARCH ON DISTRIBUTION AUTOMATION

Different researchers have identified better solutions for distribution automation and substation automation. Control and monitoring ideas developed are analysed. The IEC 61850 standard is a new communications standard that allows the development of new range of protection and control applications that result in significant benefits in contrast to conventional hard wired solutions.

2.8.1 Overview of Literature

The development of advanced Substation Automation system became modernised when Russell (1977) presented advantages of microcomputer based substation monitoring and control over the traditional remote terminal units and electro-mechanical relays. During these periods, remote elements could not be controlled however remote terminal units were utilized for measurements and metering with communication made possible using copper telephone wiring between remote units and Man-Machine-Interfaces (MMIs).

In 1982, Russell again presented "*New developments in systems for transmission and distribution substation control and protection*" where he highlighted the utilization of computer based technology and the problem of electromagnetic interference in the transmission substations.

Later on Bornard (1988) investigated trends and problems which are still to be solved on Substation Automation systems protective relaying equipment. Liu and Dillon (1992) presented a survey of knowledge-based system application to power system problems in which a survey of the literature on expert systems applications to power systems was provided and the capabilities and limitations of the proposed expert systems were discussed.

Yellamandamma *et al.*, 2009 presented the development of supervision, control, monitoring and protection functions for medium voltage substations using SCADA systems with Modbus communication. Their research is based on the use of microprocessor based numerical relays.

2.8.2 Description of the Criteria Used For Comparison of the Papers

The papers presented in Table 2.1 are compared based on their topics with respect to Distribution and Substation Automation, protection, monitoring and control. Developments researched in these papers are presented while some of them highlighted trends during their years of publications. In addition, comparison of papers discussing real-time digital simulations, real time testing of protection devices with closed-loop hardware-in-the-loop has been documented in Table 2.2 below. Each table provides the evaluations on the aim of the study, method and models used on the study, limitations on the study and the achievements.

2.9 COMPARISON OF EXISTING PAPERS ON APPLICATIONS OF MONITORING, PROTECTION, AND CONTROL OF POWER NETWORKS

2.9.1 Analysis of Various Papers on Distribution Protection and Substation Automation

Table 2.1: Analysis of various papers on Distribution and Substation Automation

	Paper	Aim	Methods and Model Used	Limitations	Achievements
1.	(Russell, 1977). **Distribution Automation Using Microcomputer Technology**	To present advantages of microcomputer based substation monitoring and control over the traditional remote terminal units and mechanical relays.	Comparison of conventional systems and microprocessor based systems	Limited to the study of microcomputer technology substation protection devices	The paper has shown the advantages of microcomputer based technology and the various application in remote substations
2.	(Russell, 1982). **New Developments in Systems for Transmission and Distribution Substation Control and Protection**	To describe the organisational structure for transmission and distribution control and protection utilizing computer based technology. In addition, the problem of electromagnetic interference in transmission substation is presented.	The funders of the project required further research findings on the overall picture of substation automation in detail.	The purpose of the panel meeting was to describe only two projects currently attempting to utilize several new technologies to automate substations.	The method developed a sophisticated instrumentation system and technique for measuring transients in substations. Significant progress is made in identification of proper procedure and techniques for substation automation.
3.	(Bornard, 1988). **Power System Protection and Substation Control: Trends, Opportunities and Problems**	To present the summary of trends in needs and opportunities, and to recall some of the developments and to outline the major difficulties which remain to be solved during the years of review.	Reviews and analyses: - advanced relay functional requirements - impact of technology progress and - trends in costs	The paper was limited to protective devices and the integration into the overall substation control design.	The paper has discussed relaying algorithms, reliability enhancements, and substation communication systems

	Paper	Aim	Methods and Model Used	Limitations	Achievements
4.	(Liu and Dillon, 1992). **State-of-the-Art of Expert System Applications to Power Systems**	To present a survey of knowledge-based system application to power system problems.	Investigated ten subjects which are: - reduction of alarm, - diagnosis of faults, - assessment of steady state and dynamic security, - network restoration, - remedial controls, - environments for operational aids, - substation monitoring and control, - maintenance scheduling, and - expert system development methods and tools	Limited to more in-depth survey of selected areas rather than to provide exhaustive survey since the application areas are diverse	The paper provided a survey of the literature on expert systems applications to power systems and the capabilities and limitations of the proposed expert systems were discussed.
5.	(Lane and Joly, 1997). **Digital Protection and Monitoring System for Medium Voltage Substations and Electric Installations.**	To define the notion of a "target architecture" that manufacturers should focus on as far as interoperability is concerned in protection and monitoring-control systems for electric substations.	Comparison between traditional control and protection systems with modern systems	Integrated control and protection.	The paper presented the model of an integrated digital system that might provide the solution for protection monitoring-control systems for electric substations.
6.	(Andersson and Brand, 2000). **Benefits of the Coming Standard IEC 61850 for Communication in Substations**	To present the benefits of the IEC 61850 standard	Review of the standard's ten part and their usefulness within substation automation	The paper was limited to an assessment of parts of the standard.	None

	Paper	Aim	Methods and Model Used	Limitations	Achievements
7.	(Skeie, Johannessen and Brunner, 2002). **Ethernet in Substation Automation**	To investigate whether Ethernet has sufficient performance characteristics to meet the real-time demands of substation automation.	Evaluation carried out in respect to switched fast Ethernet and User Data Protocol / Internet Protocol (UDP/IP) as the time-critical protocol. In addition evaluates the problem, the opportunity and the challenge.	Communication protocols for substation automation systems	The paper carried out extensive simulation on whether: - Switched Ethernet can meet the real-time demands of substation automation through their characteristics performance - UDP/IP may be used besides Ethernet as the real-time protocol.
8.	(Brand, Brunner and Wimmer, 2004). **Design Of IEC 61850 Based Substation Automation Systems According To Customer Requirements**	To present and outline the design process for protection, monitoring, metering, control and automation in substation based on IEC 61850 standard	Developed the design process with steps required.	The design process was limited to the performance requested, the functionality needed, and all constraints applicable.	A detailed process for the engineering design and allocation of substation functions was well presented in this paper.
9.	(Yellamandamma *et al.*, 2009). **Low Cost Solution for Automation and Control of MV Substation using Modbus-SCADA**	To present the development of supervision, control, monitoring and protection functions for medium voltage substation using systems with Modbus communication.	Substation automation via SCADA on Modbus communication.	Research limited to microprocessor based multifunctional numerical relays integrated to the substation automation system	Evaluation of utilizing low cost relays, Modbus communication, and SCADA for the remote substations

	Paper	Aim	Methods and Model Used	Limitations	Achievements
10.	(Apostolov and Vandiver, 2011). **IEC 61850 GOOSE applications to distribution protection schemes**	To present advantages of the IEC 61850 standard GOOSE message for distribution protection application. In addition, to present the requirements for the distribution protection systems performance and making them similar to protection systems requirements on transmission systems.	Research assessment of the impact of IEC 61850, and the use of GOOSE messages in distributed protection schemes that can reduce the fault clearing time in distribution substations.	Limited to analysis of voltage sags on the distribution system	Successfully presented various distribution protection schemes based on IEC 61850 GOOSE messages.
11.	(Costianu *et al.*, 2011). **Standards in Control and Protection Technology for Electric Power Systems.**	To show how modelling of functions independently from its allocation to devices allows optimizing existing applications and opening up for future intelligent applications	Comparison of conventional systems and microprocessor based systems	The paper only highlighted the protection requirements of substations and the use of IEC 61850. No modelling or simulation of any network and any method developed.	None
12.	(Zhu, Shi and Duan, 2011). **Standard Function Blocks for Flexible IED in IEC 61850-Based Substation Automation**	Proposes the function-block (FB)-based function model for flexible IEDs. A flexible IED is expected to permit different kinds of function integration or distribution by means of software reconfiguration without any change of hardware.	The standard FBs are established by combining the IEC 61850 model and the IEC 61499 model. the prototype system is implemented in PSCAD/EMTDC and MATLAB/Simulink to validate the feasibility and flexibility of FBs-based IEDs		Introduce flexibility in IED with function blocks without changing hardware

	Paper	Aim	Methods and Model Used	Limitations	Achievements
13.	(Higgins *et al.*, 2011). **Distributed Power System Automation with IEC 61850, IEC 61499, and Intelligent Control**	Investigates the interplay between two international standards, IEC 61850 and IEC 61499, and proposes a way of combining of the application functions of IEC 61850-compliant devices with IEC 61499 -compliant "glue logic," using the communication services of IEC 61850-7-2	Use of IEC 61499 as an integration, extension, and verification mechanism for IEC 61850-based systems. In order to enhance the benefits of this approach, devices like protective relays, bay controllers, and substation controllers could be implemented on IEC 61499-compliant platforms, which would add new value to IEC 61850 compliance—the ability to customize protection, monitoring, control, and automation functions	This vision depends on the creation of a ubiquitous peer-to-peer communications network of adequate speed, resilience, and security. While this is certainly within the capabilities of current technology, the industry standards necessary for universal interoperability and cost reduction are very early works, which are in progress	A new approach to power system automation is proposed aiming at the known challenges which is based on the ability to automatically detect changes and reconfigure the power system appropriately. The proposed solution aims at making power system automation more adaptable to uncontrolled environmental influences
14.	(Yang, Yang and Yang, 2012). **Performance Analysis of IEC 61850 based Substation**	Design and simulate the communication network for IEC 61850 based substation station bus and process bus of Poong-Dong digital substation, which is the first IEC 61850 based substation with multi-vendors' IEDs (Intelligent Electrical Devices)	System modelling, simulation, and analysis. Implementation of network components like several applications, VLAN configuration, and additional Network Simulator 2 (NS–2) module for IEC 61850.	Could not find simulator which completely supports the network components like protocol stack for GOOSE and SMV (Sampled Measured Value) used in IEC 61850. These could not be supported by NS-2	The proposed topology satisfies the timing requirement of IEC 61850 through a thorough analysis of simulation.
15.	(Aciu, 2012). **Software application for monitoring and protection systems in low-voltage distribution systems**	Presents a monitoring and alarm system based on GPRS (General Packet Radio Service) communication that can operate within a smart grid type of low voltage power delivery.	System modelling, simulation, and analysis. Used Power Manager Distribution System (PMDS) to obtain network events on voltages, overcurrent, electric arc and leakage to ground, and Microsoft SQL to manipulate data received from PMDS using C programming.	Usage of single software application PMDS rather that multiple software.	Highlights the advantages of using Power Manager Distribution System to improve network protection and reliability

	Paper	Aim	Methods and Model Used	Limitations	Achievements
16.	(Vasel, 2012). **One Plant, One System: Benefits of Integrating Process and Power Automation**	Highlights benefits of a single integrated system architecture.	System modelling, simulation, and analysis. Merge SCADA with DCS (Distributed control system) and load Petrobras energy management network for analysis.	Monitoring of MV and LV usually not with the single software package.	
17.	(Blair *et al.*, 2013). **An Open Platform for Rapid-Prototyping Protection and Control Schemes With IEC 61850**	The paper shows how a model-centric tool, such as the open-source Eclipse Modelling Framework, can be used to manage the complexity of the IEC 61850 standard, by providing a framework for validating SCD files and by automating parts of the code generation process.	A platform which involves automatically generating the data model and low-level communications code required for one or more IEDs, directly from their configuration description is developed. Automatically generates an IEC 61850 - compliant implementation of IEDs by means of programming language.	The paper focuses on distributed generation and micro-grids networks. Therefore understanding of application on low voltage consumer distribution power networks. Furthermore, the paper is limited to only one case study. Multiple case study scenarios could have been researched.	Improvement on micro-grids communication and protection. This approach is said to eliminate a significant engineering burden during the development and testing of prototype schemes which require communications.
18.	(Zhou *et al.*, 2016)**. An Overview on Distribution Automation System**	To introduce the four main functions of distribution automation system including monitoring function, control function, protection function and management function	To analyse distribution automation key technologies such as: distribution SCADA technology, distribution geographic information system, load control, and management technology, and remote automatic meter reading technology	The paper was only limited to assessment of different technologies applicable to distribution automation.	Key technologies were discussed and in addition, challenges of construction of distribution automation were also discussed, which helps future developments in this field.
19.	(Ma *et al.*, 2017)**. An overview on Algorithms of Distribution Network Reconfiguration.**	To introduce the optimization objective and constraints of the distribution network reconfiguration, analyse the complexity and difficulties in calculation, and overview of a variety of algorithms, including the heuristic, stochastic	A variety of algorithms, including the heuristic, stochastic, optimization and intelligent methods are presented	The paper was limited to load optimization algorithms only.	None

	Paper	Aim	Methods and Model Used	Limitations	Achievements
		optimization and intelligent methods.			
20.	(Kunz *et al.*, 2017)**. A Formal Methodology for Accomplishing IEC 61850 Real-Time Communication Requirements**	Present a systematic and formal methodology to be adopted to achieve the correct implementation of the communication requirements of the IEC 61850-8 standard	The methodology consists in five steps: - modelling of real-time communication requirements defined by the standard; - simulation of the obtained model; - formal verification of the model, improved in the previous step; - translation of the global model (simulated and verified) into the input language of the real controller; and, - Application of conformance testing technique to the computational routine implemented in the real controller.	The proposed methodology allows designers to synthesize reliable systems under IEC 61850 real-time communication requirements.	Results obtained by means of simulation, formal verification, and conformance testing showed that the proposed specification is in accordance with the IEC 61850 standard and accomplishes the respective communication requirements, leading finally to conclude that the proposed methodology allows the designers to achieve a precise implementation of the communication requirements of this standard, enabling the synthesis of reliable systems under IEC 61850 real-time communication requirements.
21.	(Fereidunian, Hosseini and Abbasi Talabari, 2017)**. Toward self-financed distribution automation development: time allocation of automatic switches installation in electricity distribution systems**	To present a novel idea for distribution automation (DA) implementation planning, in which the sequence and timings of installing automatic switches are optimised, to exploit periodical savings and to minimise the total externally financed investment.	A hybrid genetic algorithm - particle swarm optimisation (GA–PSO) algorithms were used to solve the optimisation model proposed. An optimisation model in the form of a mixed-integer non-linear problem is developed to calculate overall investments financed from outside of the project, where the target function is to minimise the overall external investment. A hybrid algorithm that combines GA and PSO is developed to achieve better and faster results. This hybrid algorithm exploits good local searching quality of GA along with fast convergence of PSO.	The method proposed is tested on parts of the network covered by Tehran Vicinity Electricity Distribution Company as well as bus number four of Roy Billinton test system.	The method proposed was successfully tested on parts of distribution network of Tehran Vicinity and the results were reported. According to reported results, planning optimisation of DA can finance a major part of automation investments internally. Effect of customer damage reduction on return of Investments.

	Paper	Aim	Methods and Model Used	Limitations	Achievements
22.	(Repo *et al.*, 2017). **Real-Time Distributed Monitoring and Control System of MV and LV Distribution Network with Large-Scale Distributed Energy Resources**	To provide a holistic overview of Active Network Management utilizing hierarchical decentralized distribution automation and flexibility services from Commercial Aggregators.	The proposed distribution automation concept is analysed and discussed in the paper based on experiences of laboratory and field demonstration implementations. The concepts are: - Active Network Management (ANM) and - Commercial Aggregator and interaction with Distribution System Operator (DSO)	Limited to how the general concepts of active network management and commercial aggregator is implemented and what is required from distribution automation viewpoint.	Holistic view of active network management utilizing advanced distribution automation and flexibility services from commercial aggregator has been described. Hierarchical and distributed architecture of distribution automation system has also been described. MV and LV grid monitoring and power control use cases utilizing the proposed automation architecture has been clarified and first set of demonstration results have been given as an example of the performance of proposed system and use cases.
23.	(Hjorth, Gupta and Balasubramanian, 2017)**. University Implements Distribution Automation to Enhance System Reliability and Optimize Operations**	To develop a distribution automation system for Texas University.	24Vdc motorised switches were installed in the network. Fault circuit indicators (FCI) were strategically installed along each distribution feeder to detect phase and ground short-circuits faults. The FCI auxiliary output contact is wired to the discrete I/O device to provide fault status to the DAS over the communications network. Each pad-mount switchgear that is part of the DAS includes a four-way load break switch, FCIs, a discrete I/O device, and a managed Ethernet switch (ESW)	Study limited to 12.75 kV underground distribution network.	A centralized DAS was developed and implemented for the underground distribution system at TAMU to enhance system reliability and optimize operations. The DAS uses information from IEDs and FCIs connected via high-speed communication to identify electric fault conditions. It determines the fault location, isolates the faulted section, and automatically restores power to unaffected de-energized loads from the normal source or alternative source, if available.

2.9.2 Analysis of various papers on Real-Time Digital Simulation

Table 2.2: Analysis of various papers on Real-Time Digital Simulation

	Paper	Aim	Methods and Model Used	Limitations	Achievements
1.	(McLaren *et al.*, 1992). **Real Time Digital Simulator for Testing Relays**	To describe the structure and performance of a Real Time Digital Simulator (RTDS) for testing relays	Closed loop testing of distance protective relay using RTDS	Presents tests on distance relay	Highlights the structure and the functionality and performance of Real Time Digital Simulators
2.	(Shirmohammadi *et al.*, 1996). **Distribution Automation System with Real-Time Analysis Tools**	To highlight an approach for utilizing the existing infrastructure and available data more effectively by introducing intelligence to Distribution Automation and SCADA systems through development of advanced analytical tools for operations decision support	- Initiated a project for real-time application for distribution automation systems - large scale installation of automatic meter reading systems - develop analytical tools for applications for load estimation, fault location, power flow analysis, short circuit analysis, reconfiguration, and volt/var support evaluation for distribution feeders.	Developed application to operations in real-time environment	The major accomplishments were in the exploitation of the integrated environment for computing and processing.
3.	(Desjardine, Forsyth and Mackiewicz, 2007). **Real Time Simulation Testing Using IEC 61850**	To presents a successful hardware implementation for IEC 61850 messaging on a real time simulator and discusses the key design criteria.	Use of the IEC 61850-9-2 sampled values, removing the need for amplifiers as the standard interface to protection devices.	Closed-loop testing in real-time with IEC 61850	IEC 61850 messaging capability was successfully developed for the RTDS Simulator. Sampled values of the voltage and current signals are sent via Ethernet, making it even more practical to perform testing on a protective relaying scheme rather than just individual devices thereby eliminating the need of amplifiers and greatly reducing costs.

	Paper	Aim	Methods and Model Used	Limitations	Achievements
4.	(Forsyth and Kuffel, 2007). **Utility Application of an RTDS Simulator**	To describe the RTDS simulator design and its utility applications in greater detail.	Review of the RTDS hardware and software.	Limited to functionality of the RTDS hardware and software platforms.	None
5.	(Rigby, 2007). **Automated Real-Time Simulator Testing of Protection Relays**	To describe the results of a project to develop a proof-of-principle working example of automated hardware-in-the-loop testing of protection schemes on an RTDS Technologies real-time simulator.	Automated Hardware-in-the-Loop testing of protection schemes using RTDS environment	Limited to the use of HIL automatic and manual testing only	The paper describes the test system configured to demonstrate automated closed-loop testing of the relays in a simple protection scheme, and presents the results of a typical set of such tests. The development of the script file to automate the tests is also discussed.
6.	(Saran *et al.*, 2008). **Designing and Testing Protective Overcurrent Relay using Real-Time Digital Simulation**	To present the modelling and testing of a Schweitzer Engineering Laboratories (SEL) 351S protective overcurrent relay using RTDS.	The first part of the paper discusses HIL tests conducted with the physical SEL 351S overcurrent relay for an eight-bus power system. The second part discusses the development of a software relay model in RSCAD and real time Software-in-Loop (SIL) simulation.	Limited to HIL and SIL testing of the SEL351 relay only	Hardware in the Loop (HIL) test has been presented using RTDS and SEL-351S relay. The development of an eight- bus power system, control logic, hardware and software setup were discussed in detail.
7.	(Kuffel, Ouellette and Forsyth, 2010). **Real Time Simulation and Testing Using IEC 61850**	To present a successful implementation for IEC61850 messaging on a Real-Time Digital Simulator (RTDS) using the GTNET card and discuss the key design criteria	IEC 61850 GOOSE messaging for all signal communications connected via single Ethernet between simulator and station bus LAN to which protection devices are connected and closed-loop testing of protective relays using P444	Closed-loop testing in real-time with IEC 61850 only	The paper has shown how such tests can be achieved with the help of a real time digital simulator interfaced to physical relays with dynamic control of IEC 61850 GOOSE and SV data.

	Paper	Aim	Methods and Model Used	Limitations	Achievements
8.	(Almas, Leelaruji and Vanfretti, 2012)**. Over-Current Relay Model Implementation for Real Time Simulation & Hardware-In-the-Loop (HIL) Validation**	Presents the modelling of an overcurrent relay in SimPowerSystems (MATLAB/Simulink).	A power system is modelled in SimPowerSystems and the overcurrent relay model is incorporated in the test case. The overall model is then simulated in real-time using Opal-RT's eMEGAsim real-time simulator to analyse the relay's performance when subjected to faults and with different characteristic settings in the relay model.	Paper limited to the use of HIL testing only	Hardware-in-the-Loop validation of the model was done by using the overcurrent protection feature in Relay SEL-487E. The event reports generated by the SEL relays during Hardware-in-the-Loop testing were compared with the results obtained from the standalone testing and software model to validate the model. Topic was well executed between the used software packages and the hardware IED.
9.	(Martinez *et al.*, 2017). **Hardware and Software Integration as a Realist SCADA Environment to Test Protective Relaying Control**	To introduce a novel hardware and software integration to reproduce a Real-Time (RT) performance environment of power system simulations, especially focused on protective relaying control adjustments and training tools.	The IEEE-9 bus system and a real validated model of a Colombian transmission systems section are presented; both cases are implemented in the real-time platform and reproduced with the aim of evaluating its performance. Protective relays are tested in Hardware in the Loop (HIL) techniques.	Paper limited to the use of HIL testing only	Presented a full framework to carry out power systems simulations in RT with HIL techniques; this simulation platform is a modern solution with low-cost hardware/software integration that successfully linked PowerFactory with National Instrument Tools.
10.	(Tuominen *et al.*, 2017). **Real-Time Hardware and Software-in-the-loop Simulation of Decentralised Distribution Network Control Architecture**	To introduce a laboratory test set up developed to evaluate the functionality of a novel decentralised distribution automation architecture. The main goal for this system was to test the functionality of the decentralised distribution automation architecture and track out any potential interfacing issues of automation system before	The demonstration system consists of a simulated distribution network in real-time simulation environment including simulated monitoring and control devices as well as physical devices interfaced with the simulator as hardware-in-the-loop test devices. System involves also substation automation units for real-time monitoring and control that are interfaced with the simulator and physical devices.	Integrated hardware-in-the-loop (HIL) and software-in-the-loop (SIL) testing of distribution network hardware and architecture only.	Based on the tests executed with the system described, the proper functionality of all the features of the automation architecture was verified and successfully deployed at the field test sites.

	Paper	Aim	Methods and Model Used	Limitations	Achievements
		implementing the concept to actual field demonstrations.			
11.	(Noureen *et al.*, 2017). **Real-Time Digital Simulators: A Comprehensive Study on System Overview, Application, and Importance**	To present the technological aspects and the concept of modern real-time digital simulators	Various simulating tools are discussed and reviewed in this paper based on the accessibility of information. These tools are: - Real Time Digital Simulators (RTDS), - OPAL-RT Simulator, - Network Torsion Machine Control (NETOMAC), - dSPACE, - Real-Time solution by MathWorks (xPC target, Real-Time Windows target), - Power _ system Online _ simulation Unveil Your Analysis (POUYA) Simulator and - Typhoon HIL Simulator	The paper only reviews and compares the capabilities of the packages in the method used.	The paper comprehensively brings forward the capabilities of the various simulators and their real-time applications for various industries.

2.10 LITERATURE COMPARISON AND DISCUSSION

2.10.1 New Development

(Bornard, 1988) indicated that power system relaying techniques have been at crossroads of power engineering, electro-mechanics, electronics, automatics and telecommunications. After that period, more developed integrated control and protection systems for substations techniques emerged with digital signal processing, real-time computing, and high speed data transmission which enhances engineers' knowledge in becoming specialists in Local Area Networks (LAN) protocols and real time distributed database management.

Furthermore, (Shirmohammadi et al., 1996) indicated that distribution automation (DA) had been principally focused on remote monitoring and control of the system and their equipment with SCADA being the most contributing attribute. Real-time data became available to human operators, enabling them to monitor events and to control automatic equipment remotely. The added volume of real-time data had created data overloads at distribution control centres and if operators had no support tools, they could only rely on their experience in making proper operating decision based on the subset of data they received. The result will leave large volumes of real-time data along with much of infrastructure built for automatic operation of the system remained underutilized.

(Kuffel, Ouellette and Forsyth, 2010) indicated that it is important for closed loop testing tools for substation protection devices to keep up with advancements in technology. These are developments modelled using communication protocol IEC 61850 which significantly reduces the amount of wiring required between protection relays with current and voltage signal and merging units (MUs). This communication is simplified via IEC 61850 GOOSE and Sampled Values data which has speed and wiring advantages compared to conventional wiring between substation devices.

2.10.2 Communication

According to (Xin and Sun, 2009), it is very important for both conventional and non-conventional sensors to have the ability to interface together to allow the implementation of IEC 61850 based substation system in existing and new substations as shown in Figure 2.3. A significant improvement in functionality and of cost reduction of integrated substation protection and control system can be achieved

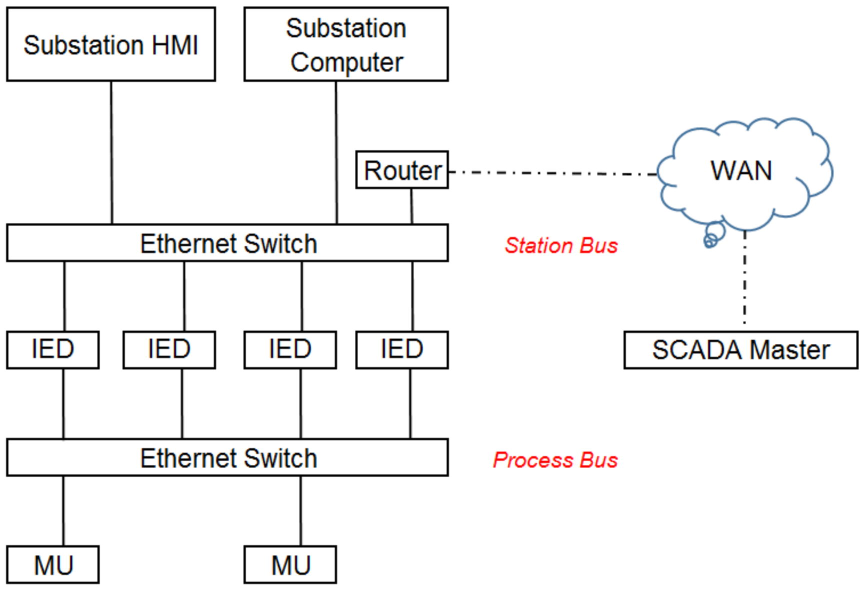


Figure 2.3: Communication architecture of an IEC 61850 based substation protection system (Xin and Sun, 2009)

(Kunz et al., 2017), developed methodologies requirements for accomplishing the IEC 61850 real-time communication. Their research dealt with the proposition of a strategy / methods to synthesize and validate models of systems developed under IEC 61850 real-time requirements for Generic Object Oriented Substation Event (GOOSE) and Sampled Measured Values through easy operational conditions cases that can be used in overall performance and conformance testing of highly complex systems, once validated. These are according to the list below;

- Modelling of real-time communication requirements defined by the standard;
- Obtained model simulation;
- Model verification formally,
- Previous step improvements;
- Global model translation into the input language of the real controller;
- Conformance testing technique application to the computational routine implemented in the real controller.

The proposed methodology above allows designers to produce reliable systems under IEC 61850 real-time communication requirements.

2.10.3 Protection

In the congested underground utilities networks, cables are vulnerable to interference by third parties effects (due to road excavations) that may lead to open circuits inside cable joints. Distribution network systems with closed-ring configuration have the advantage of higher supply reliability but with costly protection systems. In case of a short-circuit or open-circuit fault on one of the circuits, the other circuits in the ring will take up the load flow without supply interruption Wong, Chen, Lau, Tang, Liu (2006).

Wong et al (2006) In order to further improve supply reliability, a simple and cost-effective approach is developed to detect the open-circuit defects. The approach is to monitor the unbalanced secondary neutral currents of the existing unit feeder protection relays by one set of split-core current transformers (CTs) and corresponding current transducers.

2.11 CONCLUSION

The chapter presented a brief summary of literature on related topics investigated. The substation and distribution automation was discussed, protection and the use of IEC 61850 standard was also highlighted. For the reticulation network, the testing of HIL provides the development of utilizing GOOSE communication on customer reticulation network and utility distribution networks. These two smart networks never researched to date and majority of researches concentrate on transmission substations with few penetration in distribution substations.

Theoretical aspects of these topics are discussed in the following chapter (Chapter 3).

CHAPTER

3. PROTECTION, MONITORING, AUTOMATION, AND CONTROL THEORY

3.1 INTRODUCTION

Power system planning takes into consideration reliability of supply, reliability of network distribution, simplicity of operation and maintenance, and protection and safety of life. In addition to this, the cost and regulations are assessed to complete the design. When design of a power system takes place, protection of the network equipment is essential to prevent unexpected power supply interruptions. Distribution protection prevents damages on equipment and in order to have reliable supply, protection against short circuits, over-current and earth faults is essential.

Distribution automation and network management systems are also tasked with energy management besides network control. These network management systems take all system quantities such as voltages, currents, power flow, and status of all links of the whole power system (Brand, Wimmer and Lohmann, 2003).

Substation automation system operation depends on the substation itself and the associated equipment to provide a high level of reliability of the power system operation and control.

This chapter focuses on the history of protection, substation automation, and control, and brief history of implementation of the communication standard IEC 61850 in substations. It is widely known that the IEC 61850 is not fully utilised in distribution grids in South Africa and attention is focussed on its implementation on low voltage networks, in particular 11kV. This chapter, in addition presents existing problems with conventional protection systems and the latest application solutions which have been studied. Moreover, benefits from application of new standards such as IEC 61850 on consumer networks are discussed.

3.2 DISTRIBUTION AUTOMATION (DA)

Companies implementing distribution automation (DA) are benefiting from areas such as fast methods of reliability improvements and ensuring the operating functions are more efficient and have extended asset life. New cost-effective control systems have contributed in changing perceptions from past management on whether the efficient control of distribution is a worthwhile investment. The perception changes are also as a result of deregulation and ever improving industry experience. Implementation of downstream automation systems depends largely on the site and targeted to areas where improved performance will produce measurable benefits. These benefits are now being extended outside substations to devices along the feeders and metering equipment. Table 1 shows a summary of the key areas of benefits down the control hierarchy (Northcote-Green and Wilson, 2006).

Table 3.1: Key Automation Benefit Classifications by Control Hierarchy Layer (Northcote-Green and Wilson, 2006)

Control Hierarchy Layer	Reduce O&M	Capacity Project Deferrals	Improved Reliability	New Customer Services	Power Quality	Better Info for Engr. & Planning
1. Utility	X	X		X		X
2. Network	X	X	X		X	X
3. Substation	X	X	X		X	X
4. Distribution	X	X	X		X	X
5. Customer	X	X	X	X	X	X

3.2.1 Reduced Operation and Maintenance Costs (O&M)

Automation reduces operating and maintenance costs and contributes to fast fault location substantially as this reduces the travel times for maintenance personnel because the crew will be dispatched directly to the faulted area of the network. This eliminates the time-consuming traditional fault location practices using line patrols in combination with field operation of manual switches and the feeder circuit breaker in the primary substation. Condition monitoring of network elements through real-time data access in combination with an asset management system allows advanced condition and reliability-based maintenance practices to be implemented (Northcote-Green and Wilson, 2006).

3.2.2 Capacity Project Deferrals

Real-time analysis of the network component loading could allow its life to be optimised against operational requirements. Short-term load transfer between substations could avoid the need for additional substation transformers or transformer capacity upgrades through purchasing of new transformers when open points between substations are utilised (Northcote-Green and Wilson, 2006).

3.2.3 Improved Reliability

Distribution Automation provides the fastest way to reduce outage duration. When remote-controlled switching devices and fault passage indicators are implemented in combination with control room management systems, this improves outage management and substantially reduces duration and frequency of outages (Northcote-Green and Wilson, 2006).

3.2.4 Customer Services

When automation is deployed at the customer layer through remote meter reading, it allows utilities to offer more flexible tariffs and the customer more selectivity and control of consumption (Northcote-Green and Wilson, 2006).

3.2.5 Power Quality.

Monitoring of power quality includes voltage sags, unbalances, and harmonics. With increased penetration of electronic consumer loads, these quantities/characteristics are now receiving closer scrutiny. Distribution automation enables dynamic control of voltage regulations through remote control of capacitor correction banks and voltage regulators (Northcote-Green and Wilson, 2006).

3.2.6 Improved Information for Engineering and Planning.

The real-time data availability increase from Distribution Automation offers more visibility to planners and operators of the network. The optimization of the communications infrastructure is an important aspect of the automation implementation that delivers the required data to the appropriate application. This data is fundamental to better planning and asset management under business objectives, forcing lower operating and capital investments (Northcote-Green and Wilson, 2006).

3.2.7 Architecture

Distribution automation architecture comprises of three main components which are:

- Devices to be operated such as IEDs
- Communication system, and
- Automation gateway

A gateway is a substation computer which captures and manages the data from multiple substation intelligent devices. This replaces the remote terminal units as a mode of communication system and receives and sends information to a central control computer (Northcote-Green and Wilson, 2006).

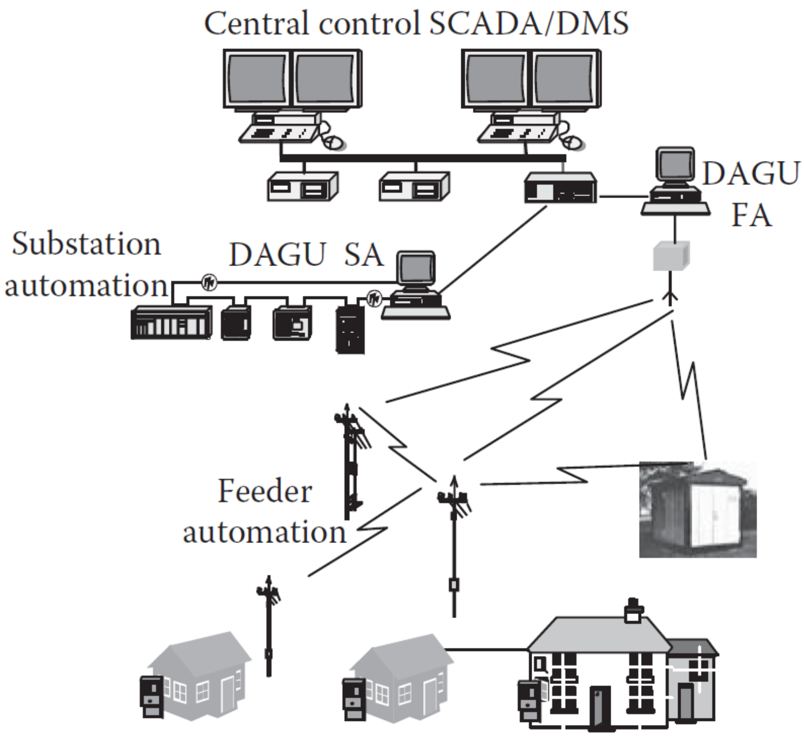


Figure 3.1: Typical Distribution Substation Components (Northcote-Green and Wilson, 2006)

3.2.8 Components of the Distribution Automation System

The major components of the distribution automation system are in primary substations and feeder devices found outside substations such as pole mounted switches and ground mounted units and secondary substations (Northcote-Green and Wilson, 2006).

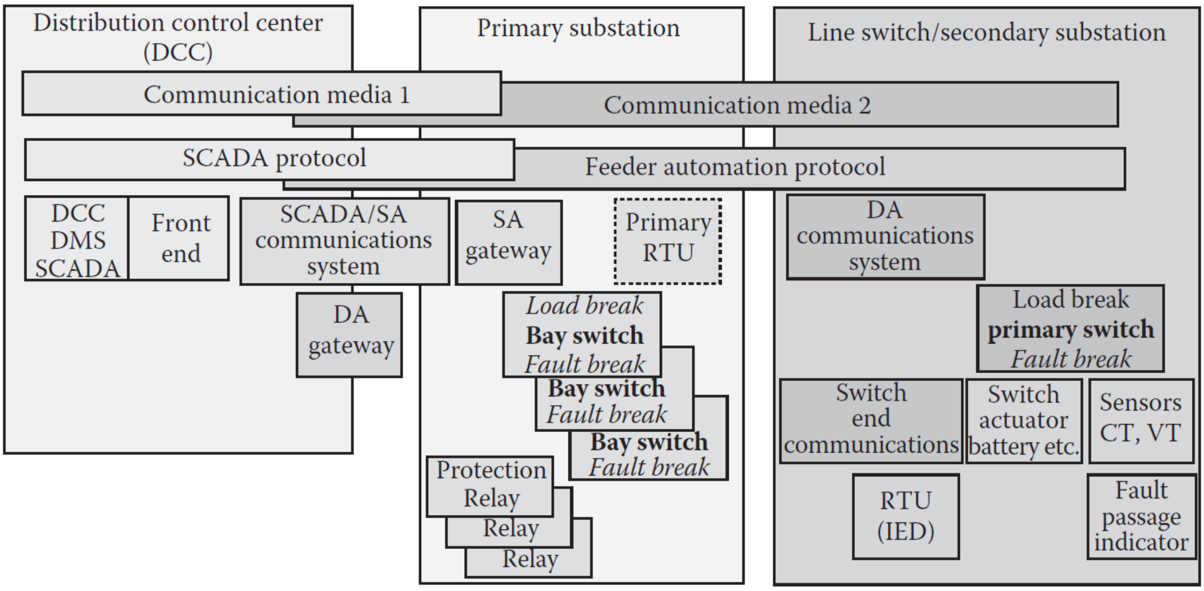


Figure 3.2: Components of Distribution Automation integrated to make a working system (Northcote-Green and Wilson, 2006).

Where:

- DMS : Distribution management system
- SA : Substation automation
- RTU : Remote terminal unit

Primary substations hold switchgears and intelligent devices. Switchgear bays consist of circuit breaker with actuators and protection relays and are wired with terminal blocks ready for connection to station control bus.

Remote control could be achieved in two ways which are:

- Hardwiring – control, indication and measurement circuit are hardwired to a primary Remote Terminal Unit (RTU).
- Implementing Substation Automation (SA) – a local area network (LAN) is established between protection relays and PC-based SA gateway to manage the data flow within the substation. This eliminates the hardwiring of substations devices. The substation gateway communicates back to the distributed control centre using SCADA protocol.

Secondary substations hold remote control switches of the primary substations. This has previously been implemented through SCADA systems. Little standardisation left room for many alternative standard configurations at a switch as to what accuracy, and parameters of measurements are required and the automation level required for application. These decisions configure the number of sensors, type of intelligent devices, and communication burden. In addition, the selection of primary switching devices and the specification of the function of the intelligent devices are required in order to determine the type of local automation. These determine whether intelligent devices are supposed to be for full protection or a simple communication interface. Once these are defined, the communication media and protocol are selected and integrated into the complete distribution automation architecture.

There are two basic approaches to implement distribution automation which are: 1). Retrofitting remote-control facility into installed switches and 2). Installation of new automation-ready devices to replace existing manual operated switches (Northcote-Green and Wilson, 2006).

3.3 SUBSTATION AUTOMATION AND CONTROL

The need for reliable power supply and reduction of manned substations during faults is increasing with time. Utilities and system owners are now automating their substations to achieve that goal. Reduction in operating and maintenance personnel staff and developments in technology has resulted in unmanned automated substations. To effectively manage the substation communication hubs that connect the different sections of the system, communications networks are used to provide control over the circuit breakers, switches, and other primary equipment that control the flow of power in the power system. The control of these intelligent devices can be done by communication channel either automatically through pre-defined messages or directly from a control centre located at any point outside the actual substation yard. This control centre can be manned to collect real-time activities at each of the substations on the system.

3.3.1 Local Functions

There are two local functions within the substation which are data acquisition and control. Data acquisition is achieved via sensors and instrument transformers while the control is achieved via actuators, change switches or devices which could change states. Quantities such as voltage and current are measured via instrument transformers and active and reactive power. Frequency may either be measured or calculated out of the measured voltage and current. Power quality may also be measured if required (K.-P. Brand, Wimmer and Lohmann, 2003)

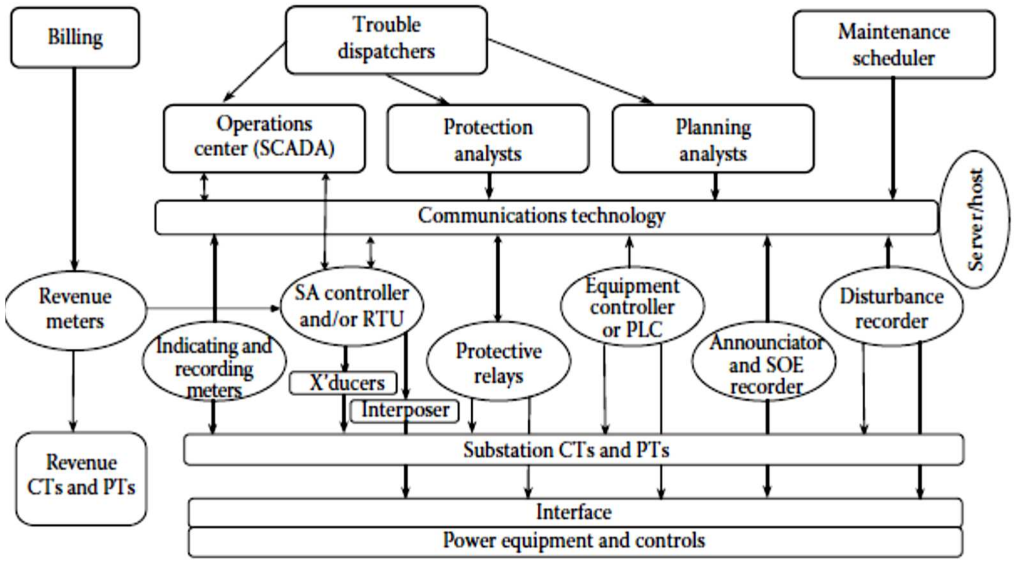


Figure 3.3: Power station substation automation system functional diagram (K. P. Brand, Wimmer and Lohmann, 2003)

3.3.2 Components of Substation Automation System (SAS)

The substation automation system uses substation equipment with any number of devices to communicate and to process monitoring, protection, and control the substation. These may include Intelligent Electronic Devices (IEDs) such as protection relays, metering devices (energy meters) and measurement devices (CTs and VTs) and Programmable Logic Controllers (PLCs). Additional devices/elements which may be included in SAS would be energy consumption of substation buildings from lighting and power circuits. This could also be extended to the control centre and any other building for energy management.

3.3.3 Required Measurements and Performance

Substation Automation Systems gather network performance parameters such as voltage, currents, power (watts and vars). In addition, energy output and usage measurements such as kilowatt-hour and kilovar-hour which are important to the accounts departments are measured too. These measurements could be taken from equipment such as generators, solar systems or wind systems (renewable sources) and loads connected to the system.

The economics of measurements quality are to be compared with the cost of installations and maintenance to avoid excessive budget. The system requirements are to be decided in concept stages to suit the users and functions of the system. Specifying higher performance measuring system raises the overall costs of the system.

3.3.4 State Monitoring

State monitoring is an important part of substation automation as it indicates events such as device “on or off”, “open or closed” and “in or out”. These states could be read from circuit breakers, switches, motor operators, battery chargers, etc.

3.4 DATA FLOW AND COMMUNICATION

Substation communication plays an important role in power system operation as it enables engineers to interact with substation components from remote locations. This interaction could be in the form of monitoring and control of the power system. Monitoring is an important part on any critical power system network. It enables system engineers to predict conditions which will place the network at faults and reduce supply availability.

During the 19th century, monitoring and control of substations was being done by means of operating personnel who were often stationed at substations to respond to any problem that might arise.

As the demand for reliable power supply became greater, technology to do remote monitoring and control of power system parameters was developed and known as “Supervisory Control and Data Acquisition” – SCADA. This technology took away personnel stationed at the substations.

To avoid slow data transmission from the intelligent electronic devices to the control centres, it is important to separate which data are much required to be accessed in real-time and which is not. If the system is old, it is advisable to migrate to modern technology of digital communication to avoid expensive operational and maintenance cost associated with old devices and equipment.

Data can be accessed from substation devises through:

1. Communication to IEDs via a network.
2. Physically visiting a substation and obtaining data directly
3. Pass-through communication to IEDs through gateway
4. Communication to data concentrator

Modern communication is done through Ethernet or fibre-optic cables which speed up communication between devices as compared to standard copper or telephone lines. For a transmission or distribution network system owner, it may be more economical to install a fibre-optic communication network than to continue leasing lines from telecom companies. The fibre-optic or Ethernet networks are usually Transmission Control Protocol / Internet Protocol (TCP/IP) or Synchronous Optical Network (SONET) based.

3.4.1 Design Aspect

The design aspect of communication lines needs to take into consideration the response time acceptable and the acceptable worse-case response time that can be tolerated. The degree of communication safety in case of disturbances cannot be overlooked and lastly the exchange method which may require data to be transmitted as soon as there is a change on the system (K. P. Brand, Wimmer and Lohmann, 2003). The communication requirements are classified with the following three criteria:

- Maximum allowed age
    - The maximum allowed age is for data usage by the receiving function. This means the worst case time response that can be tolerated.
- Data integrity
    - This could be the degree of communication safety in case of disturbances.
- Exchange method
    - The exchange method could be *spontaneous* or *on request* whereby under *spontaneous* is where data could be communicated as soon as there is change happening while *on request* only acquired when there is need by some function etc.

Table 3.2 below illustrates the classification stated above for a typical kind of data exchange in the SA system.

Table 3.2: Classification of communication functions (K. P. Brand, Wimmer and Lohmann, 2003)

Data Type	Maximum allowed age	Data integrity	Exchange method	Remarks
Alarm	1s	Medium	Spontaneous	Alarm are urgent and must be brought to the attention of the operator
Commands	1s	High	Spontaneous	Commands directly act on process
Process state data	2s (binary), 5-10s	Medium	Spontaneous	Provides an operator with overview of states
Time stamped data	10s	Low	On request	Sequence used for later analysis
Interlocking data	5ms (fast block)	High	Spontaneous	Used to prevent dangerous commands
Interlocking data (state information)	100ms	High	On request	Used for interlocking to prevent dangerous commands
Trip from protection	3ms	High	Spontaneous by fault in the power system or switchgear	Used to clear dangerous situations

3.4.2 Communication Modes

If there is a free transfer of data from one device to another, this might lead to collision of information at bus level of the structure. To prevent this, a more regulated sending of messages by communication media access mechanism restricts the communication access to allow the handling of collisions. This has an impact on the possibilities to distribute a function between devices. The following communication modes were observed (K. P. Brand, Wimmer and Lohmann, 2003).

- Master/Slave communication
- Periodic process state transfer
- Peer-to-peer communication
- Multi-peer communication
- Client-server communication

3.4.3 Time Synchronization

Standard time stamp resolution within a substation is 1ms. For a distribution substation, all changed data must be transmitted to central time stamping device within 1ms or all clocks must run simultaneously within 1ms accuracy. An external master clock is to be used if data is shared across multiple substations where time synchronisation is required. This could be achieved via publicly available radio clock time master for synchronization such as global position system (GPS) satellite (K. P. Brand, Wimmer and Lohmann, 2003)

3.4.4 Asset Management

It is important for utilities and system owners to implement methods for better managing the life cycle of their substations. This improves the reliability of the supply and reduces the costs associated with power outages and other faults. Greater intelligence is required for monitoring equipment, such as:

1. Primary
a. Circuit breakers
b. Switches
c. Transformers
d. Generators

2. Secondary
a. IDEs
b. Protective relays

Equipment condition monitoring should be implemented as part of a broad-based asset management policy and plan which offers improvements of reliability. In addition, this may include the monitoring of simple alarms or as complex as identifying characteristics of a breaker before, during and after fault.

3.4.5 Redundancy

Redundancy is not always required in the substations as its need can be determined by the size and criticality of the substation, regulatory pressures and cost. The cost is measured in more engineering time required to design, test, commission, and maintain such a system, while a non-redundant system is much easier to maintain.

3.5 SYSTEM INTEGRATION

3.5.1 Protocol Considerations

Selection of the right protocol for a network application is important to the success of a given substation project. While it may sound easy and simple, or even natural; however, there are many factors that play into the selection. It may be best to select a protocol that is based on an international standard (J. McDonald, 2012), but there are also other factors to consider, such as the applicability of the protocol, type of devices in the system, functions of the system, etc.

For example, the IEC 60870-5-103 protocol may be well suited to communication from a bay controller to a protective relay, but it may not be the best protocol for a control centre to communicate with remote substation RTUs. IEC 61850 may be well suited to a fast moving and modern thinking utility but may not be the best for a cautious, “keep it simple” organization (J. D. McDonald, 2012).

When designing substations system architecture, it is important for engineers to take account of the reliability of the system. For the control and visibility of substation and system network, accurate information from the network system is important with whichever way it is obtained. However, the decision is based on the cost of implementation and criticality of the supply (J. McDonald, 2012).

3.6 POWER SYSTEM MONITORING

Power system monitoring addresses faults and problems in a network. Data acquisition is completed by IEDs for protection and control. These IEDs also record information such as events and disturbances and performance, statistical value evaluation and power quality analysis.

Monitoring systems use the IEDs which may be located at substations and personal computers (PCs) for centralized data evaluation and failure analysis. In more ways monitoring is done in order to determine the exact type of a fault, to find proper ways to clear the fault, to check the reactions of protective devices, and to do reporting. Another goal was to improve the theoretical models of the electrical networks and thus studying the appropriateness of the calculated behaviour against the actual behaviour of the network (K. P. Brand, Wimmer and Lohmann, 2003).

3.6.1 Modernizing Substations

Over the last years, the following key technologies and marketing developments have affected the entire electric power system world:

- Invention of large-scale microprocessors
- Development of high speed digital communication
- World-wide implementation of Internet networking

These have all become great enablers with regard to new power system business opportunities, challenging market needs and new requirements such as multi-vendor device inter-operability. Pressure on utilities for cost reduction and productivity improvements require new concepts for energy management, substation automation, and feeder automation. For plants to work harder and smarter, modernization of existing substations is a prerequisite and utilities will require more comprehensive service support.

3.7 PROTOCOL FUNDAMENTALS

To ensure that substation IEDs work as a system, there has to be a proper communication between these devices either via copper wiring or fibre-optic cables. Wireless communication is not supported in substation communication due to interference with other communications and security concerns. Substation communication protocols are as follows;

- Distributed Network Protocol (DNP)
- Proprietary protocols
- IEC 60870
- Modbus
- IEC 61850

Though the thesis focus is on IEC 61850 protocol, the operability of the other protocols to substation communication are highlighted. This enables a substation engineer to have better understanding of different protocols applicable to substations.

3.7.1 Distributed Network Protocol DNP3

DNP has been successfully used in energy management worldwide and has been used for communication between substations and control centres. The protocol allows any vendor to implement DNP 3.0 as it is an open protocol. DNP 3.0 has primarily been used for communication between master control stations RTUs and IEDs. It mainly focusses on physical, data-link, network, and application layers (Dorf, 2000)

3.7.2 Proprietary Protocol

Proprietary protocols have been developed for the following reasons

- Market differentiation
- Speed development
- Open protocols insufficient for the desired performance
- Open protocols insufficient for the desired purpose
- Open protocol which do not exist

3.7.3 IEC 60870

IEC 60870 standard describes an open system for SCADA communications. In the substation, the following companion standards are of particular interest:

- IEC 60870-5-101: Serial communications from a control centre to a data concentrator
- IEC 60870-5-103: Serial communications from a data concentrator or controller to a protection IED
- IEC 60870-5-104: Networked (LAN-based) communications from a control centre to a data concentrator

3.7.4 Modbus

Modbus is less popular than DNP3 and IEC 60870 for substation communications. However, it has been widely used in industrial applications. This protocol stores information in registers that are accessed for reading and writing. Unfortunately, it is not the best protocol required to achieve interoperability communications between the devices of the different vendors.

3.7.5 IEC 61850

The talk of today substation communication technology, the IEC 61850 standard, simplifies substation communications in many ways and makes the access of information on IEDs faster than the other protocols. It eases interoperability of IEDs and enhances protection and control of equipment in substations. System owners and engineers continue to look for systems that are simple to integrate and provide high performance and flexibility. Different vendors have to make their IEDs communication protocols open for interoperability between them. The IEC 61850-6 standard describes an Extensible Mark-Up Language (XML) - based syntax for modelling substations called Substation Configuration Language (SCL) which contributes to complementation of the interoperability (McDonald, 2003, 2012).

IEC 61850 standard covers communications between IEDs for monitoring, protection and control (Station Bus), which is replacing traditional copper hard-wiring connection between IEDs and replacing copper hard-wiring from instrument transformers to IEDs (process bus). In addition the standard provides a standard method for an object-oriented modelling of the substation

3.7.5.1 IEC 61850 Configuration Paradigm

IEC 61850 uses configuration paradigm where each device in the system is described by IED capability description (ICD) file written in substation configuration language (SCL) (McDonald, 2012).

3.7.5.2 GOOSE Messages

GOOSE (Generic Object Orientated Substation Event) is the IEC 61850 standard's beneficial piece. GOOSE messages are transmitted through a managed Ethernet switch with priority before non-critical data are transmitted. These messages use high speed network to replace copper with fibre-optic wiring and this method has advantages such as:

- Reduce material cost
- Reduce cost of maintenance
- Simplifies physical construction
- Increased speed of communication

3.7.5.3 Station bus

Station bus is used for monitoring and control of IEDs in the substations

3.7.5.4 Process bus

Process bus is used to communicate the sampled values messages sent by a Merging Unit which samples values at physical locations of the instrument transformers and publish these sampled values to an Ethernet network for any protective rely which need the information. The process bus replaces traditional copper wiring used for communication with fibre-optic based interpretation.

3.8 IEC 61850 FUNDAMENTALS

The IEC 61850 – Communication Networks and System in Substations standard was developed in early 2000 to standardize the communication between the Intelligent Electronic Devices (IEDs) in electrical substations. Utilities, industries, commercial, and residential consumers are transforming all aspects of their lives into the digital domain. It is also expected that every electrical piece of item will possess some kind of setting, monitoring and control (Adamiak, Baigent and Mackiewicz, 2009). In substations, different IEDs could not communicate together which forced substation owner to use only one vendor IED for most applications. The standard then got developed to provide interoperability between different vendors for all functions such as control, protection, monitoring, and automation and also to standardise communication between substation IEDs.

Communication in a power system network has always played a critical and important role in the real-time operation of the power system. In the beginning, the telephone network was used to send back power line loadings to the control centre as well as to enable the dispatch operators to perform switching operations at substations. Telephone-switching based remote control units were available as early as the 1930’s and were able to provide status and control for a few points. As digital communications became a viable option in the 1960’s, Data Acquisition Systems (DAS) were installed to automatically collect measured data from the substations. Since bandwidth was limited during that time, the DAS communication protocols were optimized to operate over low-bandwidth communication channels. The “cost” of this optimization was associated with the time it took to configure, map, and document the location of the various data bits received by the protocol (Adamiak, Baigent and Mackiewicz, 2009).

In today’s substation, the communication system’s main important component is the description ability for both data and service, and may also include:

- High-speed IED to IED communication
- Networkable throughout the utility enterprise
- High-availability
- Guaranteed delivery times
- Standards based

- Multi-vendor IEDs interoperability
- Support for Voltage and Current sampled data
- Support for File Transfer
- Auto-configurable / configuration support
- Security support

The scope of IEC 61850 standard had been communication within the substation and specification of various aspects of substation communication, and these are highlighted in Table 3.3 below:

Table 3.3: Overview of IEC 61850 standard

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

The objective of the IEC 61850 standard is to provide guidelines for design of a communication system that provides interoperability between the control or measurement functions to be performed in a substation, but residing in equipment or physical electronic devices from different suppliers, while meeting the same functional and operational requirements. To reach that goal, the functions of a substation are split into sub-functions logical nodes (Andersson, Brunner and Engler, 2003).

3.8.1 Substation Configuration Description Language (SCL) Engineering

The engineering of the substation automation may start with the design of the substation device functionality and all other equipment where functions are allocated to each device to complete all required action. This could be limited to device functionality and configuration capabilities. The requirements for configuration language are such that (IEC, 2008b):

- A single-line diagram with all devices of the substation and the allocation of Logical Nodes (LN) to each device on the single-line which will describe the functions required on the device
- IEDs which are pre-configured with fixed number of logical nodes which are not bind to any specific process.
- Pre-configured IEDs with a pre-configured semantic for a process part of a certain structure.
- All IEDs must provide a complete configuration process leading to individual process functions on primary equipment, enhanced by the access point connections and possible access paths in sub-networks for all possible clients.

The IED Configurator tool is manufacturer-specific and provides IED-specific settings and generates IED specific configuration files that shall be able to import or export the files (which contains logical nodes) defined by IEC 61850 standard. In addition it also loads the IED configuration into the IED. An IED shall only be considered compatible with the IEC 61850 standard (IEC, 2008b), if:

- It is accompanied either by a tool that can generate the SCL file from the IED or a SCL file describing its capabilities.
- It can use a system SCL file directly to set its communication configuration, as far as setting of minimum required addresses is possible in this IED, or it is accompanied by a tool which can import a system SCL file to set these parameters to the IED.

Figure 3.4 below illustrates the SCL data exchange engineering and the area where the SCL is described and implemented.

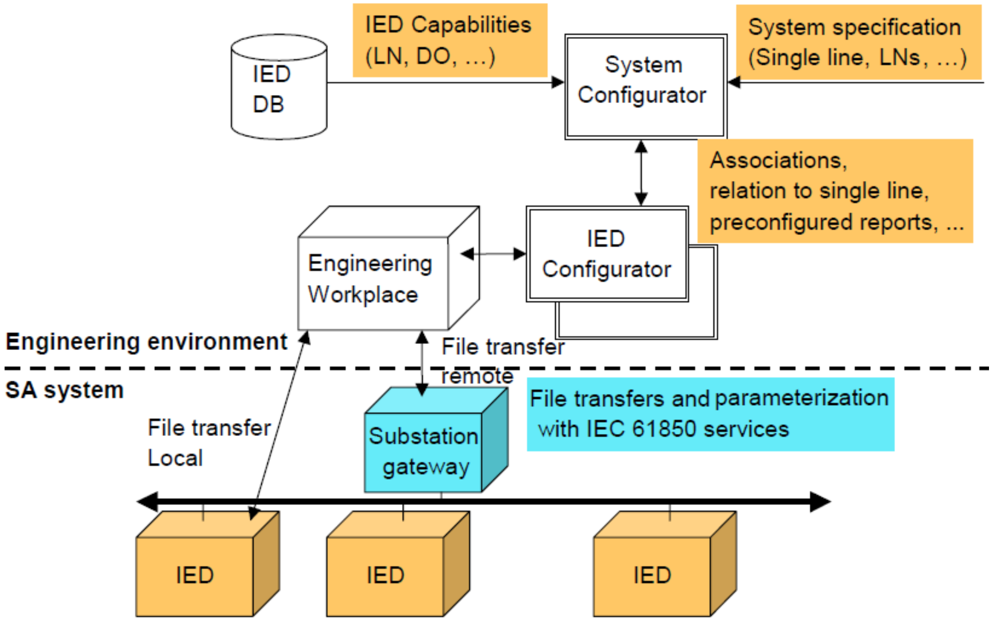


Figure 3.4: SCL engineering model (IEC, 2008b)

Some of the core components of the standard are the object model which defines and describe the functions from different substation equipment, a defined specification of the IEDs. Communication interfaces between substation automation systems is represented in the general interface structure shown in Figure 3.5 below.

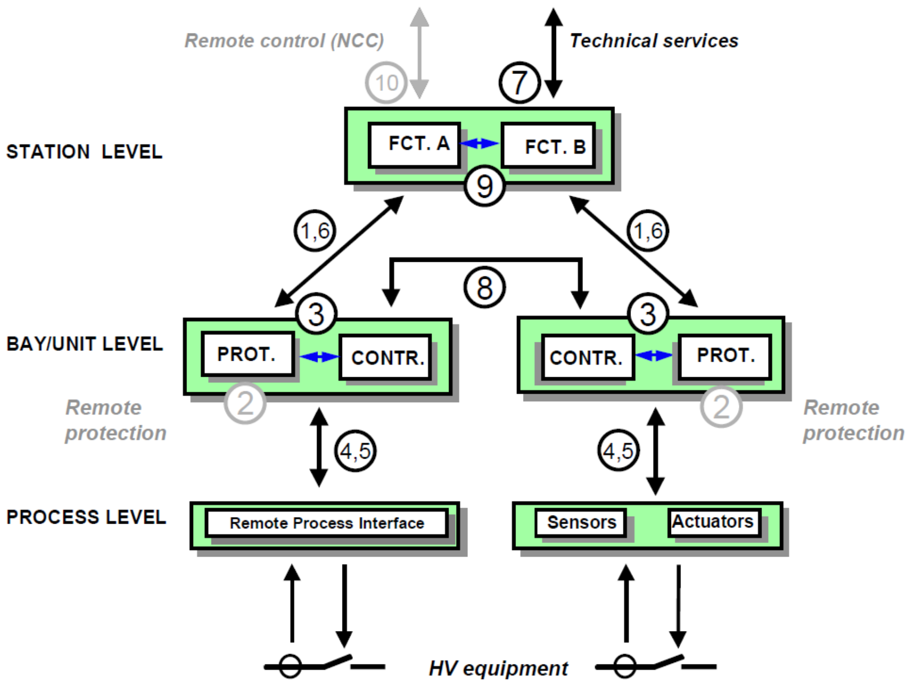


Figure 3.5: Interface model of substation automation system (IEC, 2005a)

The devices of Substation Automation System may be located physically in station, bay and process functional levels, as shown above. The meaning of interfaces as shown in Figure 3.5 above are as follows (IEC, 2005a).

1 - Protection-data exchange between the bay and station level.

2 - Protection-data exchange between the bay level and remote protection (beyond the scope of this standard).

3 - Data exchange within the bay level.

4 - CT and VT instantaneous data exchange (especially samples) between the process and bay levels.

5 - Control-data exchange between the process and bay levels.

6 - Control-data exchange between the bay and station levels.

7 - Data exchange between the substation (level) and a remote engineer's workplace.

8 - Direct data exchange between the bays, especially for fast functions such as interlocking.

9 - Data exchange within the station level.

10 - Control-data exchange between the substation (devices) and a remote control centre (beyond the scope of this standard).

3.8.2 Defining Functions of the Substation

Process level devices are typically intelligent sensors, remote I/Os, and actuators. Bay level devices consist of protection, control, or monitoring units per bay while the station level devices consist of the human machine interface with a database, the operator's workplace, interfaces for remote communication, etc.

To reach standardisation for substation automation systems, all functions within a substation were split into sub-functions or logical nodes. Logical nodes are smallest part of the function that exchange data (IEC, 2008c). These may reside in different devices and at different levels. The relationship between substation functions, logical nodes and physical devices is illustrated in Figure 3.6 below.

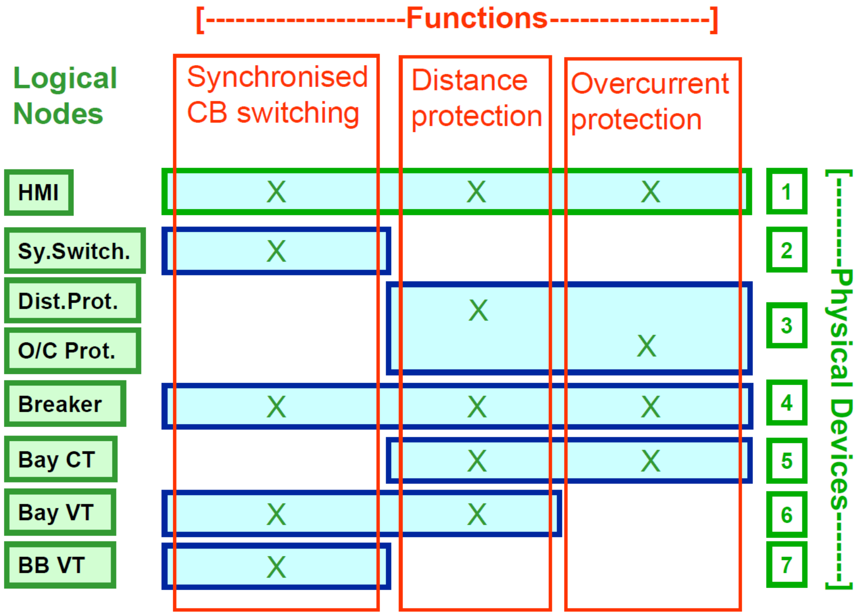


Figure 3.6: Example of relationship between substation functions, logical nodes and physical nodes (IEC, 2008a)

Physical devices may be described as follows:

- Station computer
- Synchronised switching devices
- Distance protection with integrated overcurrent function
- Bay control units
- Current transformers
- Voltage transformers
- Busbar voltage transformers

Most logical functions have minimum three types of logical nodes which are for actual functionality, process interface, and the human-machine interface. An example of three logical nodes is represented in Figure 3.7 below. These are described as operator interface (IHMI), protection (P), and circuit breaker to be tripped (XCBR) which could all be located in three physical devices

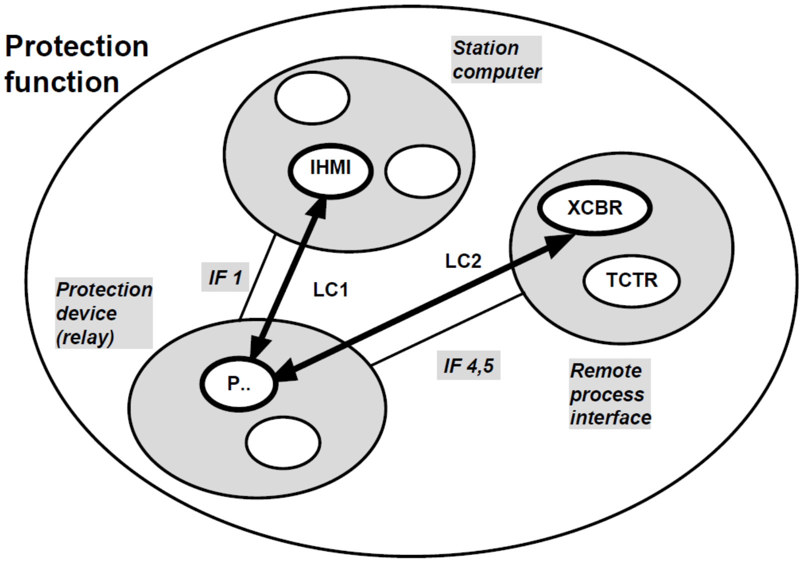


Figure 3.7: Protection function consisting of three logical nodes (IEC, 2008a)

3.8.3 Logical Nodes Descriptions

The logical nodes represent the power system equipment with all its data, related settings, and relevant communication behaviour in the substation automation system. If data exchange requires more details, the use of generic logical nodes such as GGIOs is presented. The Table 3.4 below illustrates descriptions and locations of some logical nodes on the substation automation.

Table 3.4: Logical node for protection function (IEC, 2008a)

LOGICAL NODE	IEC 61850	IEEE	DESCRIPTION
General nodes			
AC time overcurrent protection	PTOC	51	AC time overcurrent relay is a relay when the AC input current exceeds a predetermined value, and in which the input current and operating time are inversely related through a substantial portion of the performance range.
Located at Interfaces for logging and achieving			
Operator interface - control local at bay level - control at station level	IHMI		1. Front-panel operator interface at bay level to be used for configuration, etc., and local control. 2. Local operator interface at station level to be used as workplace for the station operator. The role of the different HMI is not fixed for most of the functions and is defined in the engineering phase.
Located at metering and measurements			
Measuring - for operative purpose	MMXU		To acquire values from CTs and VTs and calculate measurands such as r.m.s. values for current and

LOGICAL NODE	IEC 61850	IEEE	DESCRIPTION
			voltage or power flows out of the acquired voltage and current samples. These values are normally used for operational purposes such as power flow supervision and management, screen displays, state estimation, etc. The requested accuracy for these functions has to be provided.
Metering - for commercial purpose	MMTR		To acquire values from CTs and VTs and calculate the energy (integrated values) out of the acquired voltage and current samples. Metering is normally also used for billing and has to provide the requested accuracy.
Located on a physical device			
Logical node device	LLN0		This LN contains the data related to the IED of the Physical Device (PD) independent from all included logical nodes (device identification/name plate, messages from device self-supervision, etc.). This LN may also be used for actions common to all included logical nodes (mode setting, settings, etc.), if applicable. This LN does not restrict the dedicated access to any single LN by definition. Possible restrictions are a matter of implementation and engineering.
Located at switching devices and substation parts			
The LN "circuit breaker" covers all kinds of circuit breakers, i.e. switches able to interrupt short circuits • without point-on-wave switching capability • with point-on-wave switching capability	XCBR	52	An AC circuit breaker is a device that is used to close and interrupt an AC power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions (IEEE C37.2-1996). If there is a single-phase breaker, this LN has an instance per phase. These three instances may be allocated to three physical devices mounted in the switchgear.
Generic			
Generic I/O	GGIO		Outputs such as analog outputs, auxiliary relays, etc. not covered by the above-mentioned switchgear related LNs are sometimes needed. In addition, there are additional I/Os' representing devices not predefined such as horn, bell, target value etc. There are input and outputs from non-defined auxiliary devices also. For all these I/Os', the Generic Logical Node GGIO is used to represent a generic primary or auxiliary device (type X…, Y…, Z…).

The main protection functions have communication structure for protection logical nodes as shown in the Figure 3.8 below

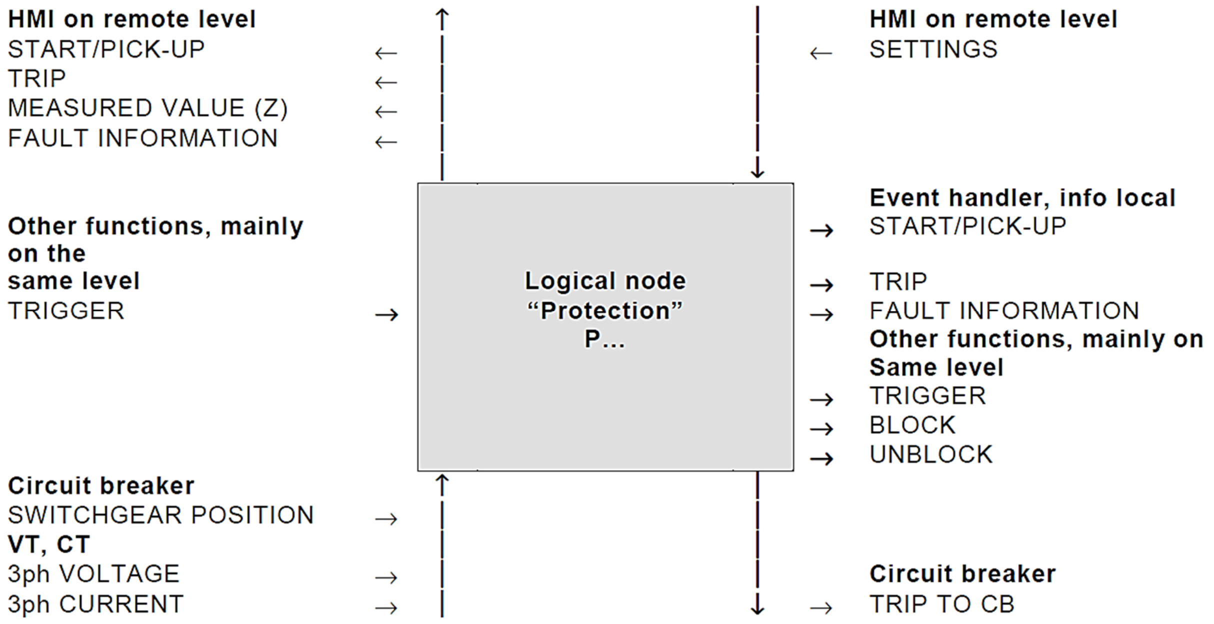


Figure 3.8: Basic communication links of the logical node of main protection (IEC, 2008a)

3.8.4 Generic Substation Events

The Generic Substation Event (GSE – GOOSE and GSSE) provides system wide distribution of peer-to-peer data exchange between inputs of data attributes of one IED to output data of many other IEDs (multicast). The GOOSE and GSSE messages received by an IED may be used to compute data for internal purposes also. An example for internal purposes are received switch positions to calculate the interlocking conditions locally. GOOSE is the Generic Object Oriented Substation Event which supports the exchange of wide range of data organised by a data-set. GSSE is the Generic Substation State event which provides the capability to convey the state change information (IEC, 2005b)

Many data attributes can be set with the set-service such as SetDatavalue or SetDataSetValues which are usually constrained only by the application. Various control blocks such as Setting Group Control Block (SGCB), the Buffered Report Control Block (BRCB) and the Log Control Block (LCB) have control blocks that could be set to a specific value. Setting the values of the control block attributes is constrained by the state machine of the corresponding control block. The control blocks behave according to the values of their attribute sets and these values may also be configured using the Substation Configuration Language (SCL) file or by other local means. All control block attributes can be read by another IED (IEC, 2005b).

3.9 AVAILABLE NETWORK TOPOLOGIES

Substation communication networks are required to have high level of reliability. This ensures that information is transmitted between devices without unnecessary breakdowns. Control and protection of the power system are of particular importance and hence Ethernet system has to be highly reliable. Some important substation automation system topologies are as follows;

- Ring topology
  - Ring topology has simple network on design and maintenance. It has an advantage of speed due to its ability to transmit in both sides of the ring. However it provides inefficient bandwidth utilization and changes in the location of the block port impacts the switching latency

- Seamless redundancy
  - This topology promises a network that can withstand failure of one of its core devices without losing data. Each of the devices within the network performs switching by itself therefore no switches are required on the network. This system was primarily designed for ring topology

- Parallel redundancy
  - Parallel redundancy offers high level of redundancy although it does not take away the use of switches on the network. This protocol is described IEC 62439 standard and also the High-availability Seamless redundancy.

- Star topology
  - The star topology has an advantage of speed. However, if there is a failure on the star point this result in a shutdown of the system hence the topology is not ideal for critical applications

- Hybrid topology

- The use of multiple ring and star configurations is appealing when examining methods for applying redundancy to a network. This topology is complex to design and to troubleshoot during faults or failure which is not as easy as in a ring topology.

3.10 POWER SYSTEM PROTECTION

Many items of power system are very expensive and so the complete network represents a very high capital investment. To maximise returns, the system must be used as much as possible within the specified design limits of security and reliability of supply. In addition, the power system should be operated in a safe manner. No matter how well designed, faults will always occur on a power system, and these faults may represent a risk to life and/or property (Alstom Grid, 2011).

Short-circuit faults on the power system are caused by human error, lightning or by switching surges that are accidental. The impact of the resulting currents and voltages can cause severe damage to insulation and cause conductor breakdown, which may lead to explosion or fire and the potential loss of life, property, or business. Consequently, any faults detected must be isolated quickly from the power system.

The three-phase network is decomposed into positive-sequence, negative-sequence, and zero-sequence networks when the system experience faults. These sequence networks are connected to represent the different types of fault classification for which the corresponding fault currents are decoupled into positive-sequence, negative-sequence, and zero-sequence currents that are computed for fault conditions. To simplify the power system model for deriving the equivalent sequence diagram, the following occurs (Momoh, 2007):

- It is assumed that, when a system is balanced, the positive-sequence, negative-sequence, and zero-sequence networks are uncoupled before a fault occurs.
- They are connected to represent a particular fault category during the fault.
- Pre-fault load current is neglected so that pre-fault voltage for each fault location is equal to the internal voltage of all machines.
- Shunt capacitance of line, shunt elements of line, and series resistance of line are neglected.
- Synchronous machine armature resistance, saliency, and saturation effects are neglected.

- It is assumed that the internal voltage source is $1\angle 0°$ per unit for the pre-fault voltage at its normal value prior to application of fault.

Power system protection comprises of the following (Alstom Grid, 2011):

1. Protection system.

   An arrangement of protection equipment and other devices required to achieve a specific protection function based on protection principles.
2. Protection equipment

   A collection of protection devices such as relays and fuses
3. Protection scheme

   A collection of protection equipment providing a defined which includes all equipment required to make the scheme work.

Protection in any electrical distribution has to take into consideration reliability, speed, selectivity and costs. However it is known that these cannot be achieved all at once as the cost can considerably go high.

3.10.1 Protection Equipment

Standard protection systems are designed to clear faults, to restore the system, or to isolate the faulty region to minimize the impact. In order to fulfil the requirements of protection with the optimum speed for the many different configurations, operating conditions and construction features of power systems, it has been necessary to develop many types of protection scheme that respond to various functions of the power system quantities. The protection scheme includes fuses, reclosers, and relays coupled with circuit breakers that are used to protect primary distribution systems. For example, simple observation of the fault current magnitude may be sufficient in some cases but measurement of power or impedance may be necessary in others. Relays frequently measure complex functions of the system quantities, which may only be readily expressible by mathematical or graphical means (Momoh, 2007; Alstom Grid, 2011).

3.10.1.1 Relays

A relay is defined as a device whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control action. Relays are classified in the following technologies:

- Electromechanical relays
- Static relays
- Digital relays
- Numerical relays

In general, a relay is used to close a normally open circuit or open a normally closed circuit upon detection of an abnormality. Relays facilitate meeting the following objectives of protection design criteria (Momoh, 2007):

1. Reliability:
   a. must detect and isolate the faults instantaneously and operate dependably
2. Selectivity:
   a. must discriminate between normal and abnormal system conditions
3. Speed:
   a. must operate speedily to minimize fault duration and equipment damage and to restore the system quickly
4. Economy:
   a. must provide maximum protection at minimum cost of equipment or operation
5. Simplicity:
   a. must be simple in design and usage of circuitry

3.10.1.2 Instrument transformers

The fault currents measured on an abnormal systems and nominal voltage measured during normal operation are usually very high and can damage power system equipment being protected. To achieve power network safety, economy, and convenience of measurement, a step-down transformer is needed. The instrument transformers, namely voltage and current transformers (VT and CT, respectively), are used for this purpose (Momoh, 2007). They are used in conjunction with the relays to step-down the measured quantity in line with the magnitude a relay could manage

3.10.1.3 Fuses

Fuses are one-time use overcurrent protection devices for interrupting fault currents. They are non-reusable once the metallic conducting element melts in response to an overload current and opens the circuit. Fuses are typically coordinated with reclosers and time-delay overcurrent relays (Momoh, 2007; Holmes, 2011). A typical schematic diagram is shown in Figure 3.9 below

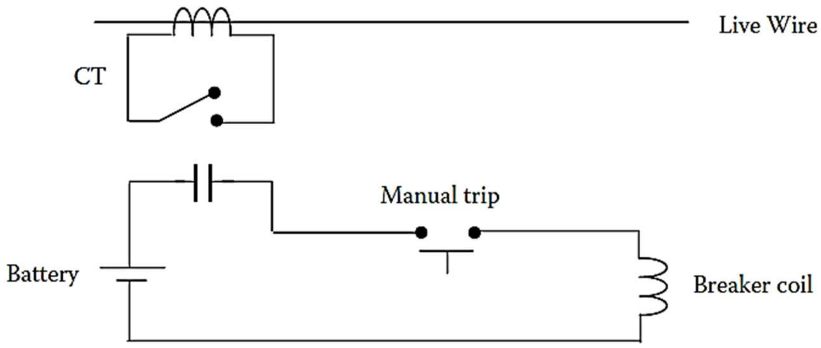


Figure 3.9: Schematic diagram of relay circuit with a CT

3.10.2 Reliability

Reliability is dependent on factors such as the following (Alstom Grid, 2011):

- Incorrect design or settings
    - Design of protection scheme is of paramount importance to ensure that the system will operate successfully under required conditions. Due consideration must be given to nature, frequency and duration of the fault which are likely to happen and all relevant parameters of the power system and type of equipment to be used on the scheme.
    - It is essential to ensure that settings are chosen for protection relays which must prevent incorrect operation during faults and systems which take into account the parameters of the primary system, including fault and load levels, and dynamic performance requirements, etc.

- Incorrect installation testing
    - The need for correct installation of protection systems is obvious, but the complexity of the interconnections of many systems and their relationship to the remainder of the system may make checking troubleshooting the installation difficult. Site testing is therefore necessary. Alternatively, hardware-in-loop (HIL) testing with real-time digital simulators (RTDS) may be used.
    - During set-up and installation stage, the checks and tests must demonstrate the accuracy of the connections, relay settings, and freedom from damage of the equipment.

- Testing should cover all aspects of the protection scheme, reproducing operational and environmental conditions as closely as possible.

- Deterioration in service
    - Subsequent to installation, deterioration of equipment will occur and may eventually interfere with correct functioning of the device. The time between operations of protection relays could also be years instead of days. Defects may develop during this period unnoticed until discovered by the failure of the protection to respond to a power system fault. For this reason, relays should be routinely tested in order to check whether they are in expected functioning condition.

3.10.3 Selectivity

During short-circuit fault conditions, the protection scheme should trip the circuit breaker nearest to the fault. This is also called discrimination and could be achieved by current magnitudes or by time.

Protection systems in successive zones are arranged to operate in times which are graded through the sequence of protection devices so that only those relevant to the faulty zone shall complete the tripping function while the others will make an incomplete operation and then reset. This is called time grading.

3.10.4 Stability

Stability of protection applied to unit protection schemes refers to the ability of the protection system to remain unaffected by faults conditions outside their protection zone

3.10.5 Speed Of Protection

It is important for the power system protection to isolate faults as quickly as doable. One of the fundamental objectives is to safeguard continuity of supply by removing every disturbance before it results in widespread loss of power system synchronism and consequent collapse of the power system. As the loading on a power system increases, the phase shift between voltages at distinct busbars on the system additionally will increases, and therefore so does the likelihood that synchronism will be lost when the system is disturbed by a fault. The shorter the time a fault is allowed to remain in the system, the larger will be the loading of the system. Figure 3.10 shows typical relations between system loading and fault clearance times for the various types of fault.

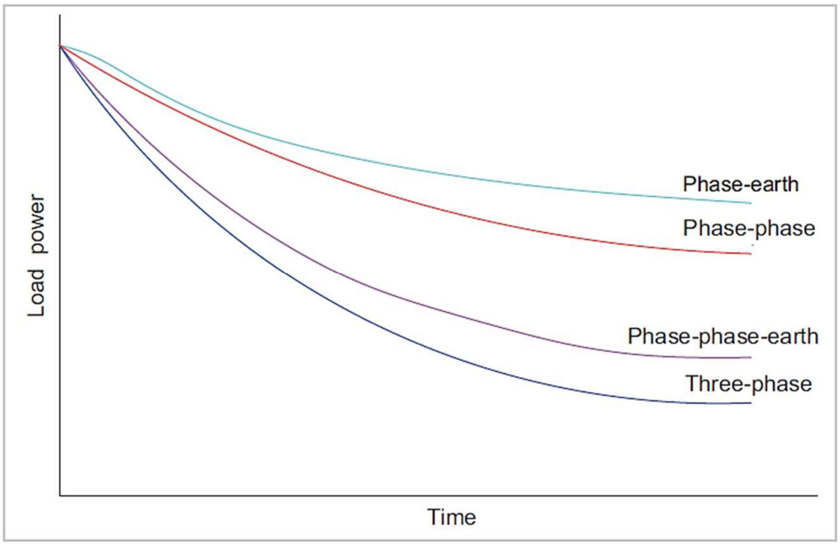


Figure 3.10: Typical power vs. time relationship for various types of faults

3.11 METHODS FOR CALCULATING SHORT-CIRCUIT CURRENTS

A power system is ordinarily regarded as a balanced symmetrical three-phase network. When a fault occurs, the symmetry is generally lost, resulting in unbalanced currents and voltages appearing in the network. This is regarded as asymmetric fault condition and occurs when phase-to-ground, phase-to-phase and phase-to-phase-to-ground faults are on the system. The only exception is the three-phase fault, where all three phase magnitudes are equal at the same fault location. This is described as a symmetrical fault. By using symmetrical component analysis and replacing the normal system sources by a source at the fault location, it is possible to analyse these fault conditions (Holmes, 2011).

It is essential to know the fault current distribution throughout the system and the voltages in different parts of the system due to the fault which may assist in the correct application of protection equipment. Further, boundary values of current at any relaying point must be known if the fault is to be cleared with discrimination. The information normally required for each kind of fault at each relaying point is (Alstom Grid, 2011):

- maximum fault current
- minimum fault current
- maximum through fault current

Balanced three phase faults can be assumed or calculated using single phase representation. These faults are three phase to ground and three phase short circuit. Three-phase faults are unique in such a way that they have equal magnitudes and therefore considered as balanced, that is, symmetrical in the three phases, and can be calculated from the single-phase impedance diagram and the operating conditions existing prior to the fault (Alstom Grid, 2011). However the system becomes asymmetrical with phase to phase faults, phase to ground faults, and phase to phase to ground faults.

Short-circuit faults can be classified as follows:

- Phase to phase fault
- Phase to ground fault
- Phase to phase to ground fault
- Three phase to ground fault

Short-circuits can also be classified according to three characteristics which are:

The origin

- The origin could be mechanical which is due to breakdown of conductor or accidental connection between two conductors via foreign bodies such as tools or mammals.
- It could also be due to insulation breakdown between phases or to earth
- It could also be due to operating errors with earthing of phase or connection between two different voltage supplies by mistake.

The location

- The location of short-circuit could be internal on an equipment such as transformer, motor, switchboard which generally lead to equipment deterioration.
- Others could be external to equipment and may be limited to disturbances which are wear-and-tear due to time and may lead to deterioration and thereby cause an internal fault.

Duration

- Faults may extinguish on their own meaning they could be self-extinguishing.
- Faults may disappear due to protective devices and not reappear when the equipment is re-started.

- Faults require de-energization of cables, machines and may require intervention by operating personnel.

3.11.1 Symmetrical Component Analysis of Three-Phase Network

It is necessary to consider the fault currents due to many different types of fault. The most common type of fault is a single-phase to earth fault, which in LV systems, can produce a higher fault current than a three-phase fault. A method of analysis that applies to unbalanced faults is required. By applying the 'Principle of Superposition', any general three-phase system of vectors may be replaced by three sets of balanced (symmetrical) vectors; two sets being three-phase but having opposite phase rotation and one set being co-phase. These vector sets are described as the positive, negative and zero sequence sets respectively.

According to IEC 60909 standard, the definition of the short circuit currents are as follows:

I_{kks} – initial symmetrical short-circuit r.m.s current.
I_p – peak short-circuit instantaneous current.
I_b – symmetrical short-circuit breaking r.m.s current.
I_{th} – thermal equivalent short circuit r.m.s current.

The following Figures 3.11 - 3.14 illustrate how each of the above short-circuit faults can be viewed on the power system network. The major features taken into account in the planning and operation of the power system is the management of short circuit currents. These short circuits are classified as follows:

- Single phase to ground
- Phase to phase
- Phase to phase to ground, and
- Three phase to ground

3.11.1.1 Single phase to ground fault

For a single phase to ground fault, any phase of the network may be considered conducting to ground as shown in Figure 3.11 below. Consider a single-phase to ground fault on phase A to ground. The conditions for the solid phase to ground fault are represented by equations $V_A = 0,\ I_B = 0,\ and\ I_C = 0$.

For sequence networks in Figure 3.11 (b), it could be deduced that

$$I_{a1} = I_{a2} = I_{a0} = V_a/(Z_1 + Z_2 + Z_0) \qquad (3.1)$$

The current and voltage conditions should remain the same when considering an open-circuit fault in line B and line C.

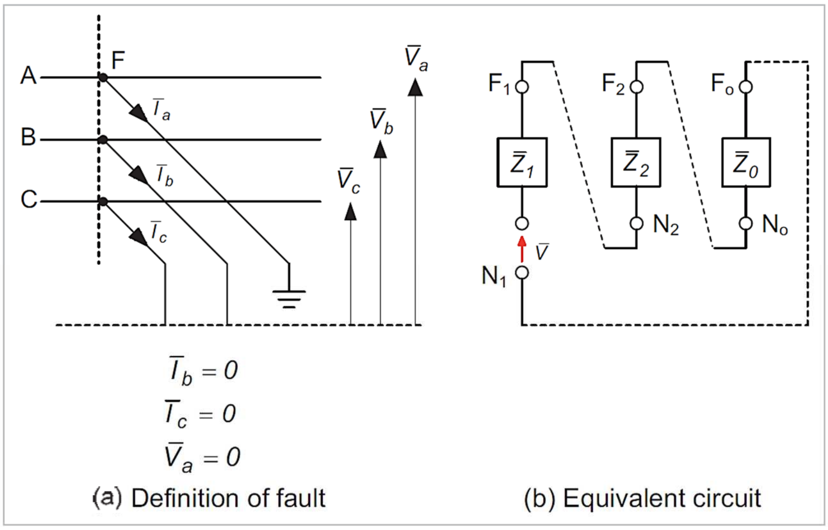


Figure 3.11: Single-phase to ground short-circuit fault

Where:

V_A or V_a = No load voltage to ground for positive sequence network for phase A

Z_1 = Positive sequence impedance of the network during fault condition

Z_2 = Negative sequence impedance of the network

Z_0 = Zero sequence impedance of the network

I_{a1} = Positive sequence fault current for phase *a*

I_{a2} = Negative sequence fault current for phase *a*

I_{a0} = Zero sequence fault current for phase *a*

3.11.1.2 Phase to phase fault

The phase to phase fault could occur when there is short-circuit between the two phases. This scenario is illustrated in Figure 3.12 below. Condition for solid fault between the phases B and C are represented by equations $I_A = 0,\ I_B = -I_C\ and\ V_B = V_C$. It can also be shown that $I_{a0} = 0\ and$:

$$I_{a1} = \frac{V_A}{Z_1 + Z_2} = -I_{a2} \tag{3.2}$$

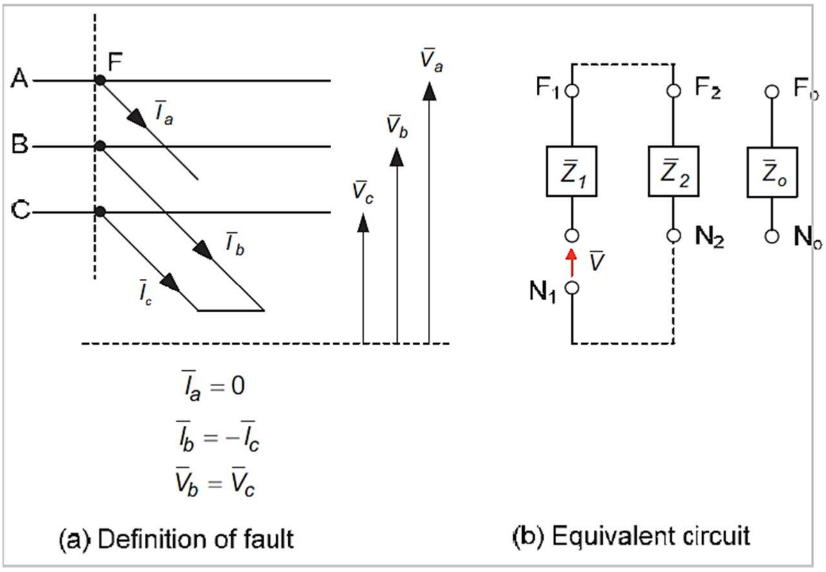


Figure 3.12: Phase-phase short-circuit fault

For this case with no zero-sequence current, the zero-sequence network is not involved and the overall sequence network is composed of positive-sequence and negative-sequence networks in parallel as illustrated in Figure 3.12 (b).

3.11.1.3 Phase to phase to ground fault

The phase to phase to ground fault could occur when there is short-circuit between the two phases while bolted to ground. This scenario is illustrated in Figure 3.13 below.

The sequence network for these three asymmetrical components is shown in Figure 3.13 (b). Conditions for fault between line B and C and ground are represented by equation $I_A = 0 \ and \ V_B = V_C = 0$. From these it can be shown that:

$$I_{a1} = \frac{V_A}{Z_1 + (Z_0 Z_2 / Z_0 + Z_2)} \tag{3.3}$$

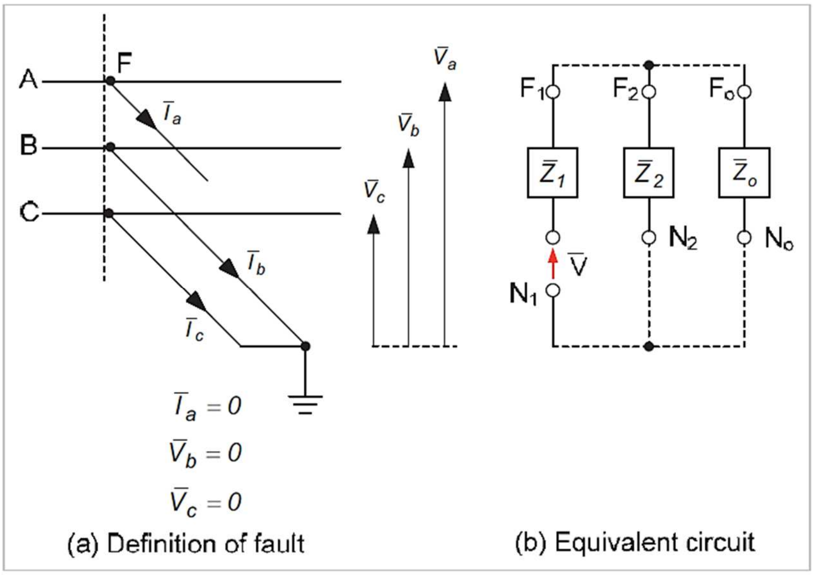


Figure 3.13: Phase-phase to ground short-circuit fault

3.11.1.1 Three phase to ground fault

This scenario is shown in Figure 3.14 below and applies when all three phases of the network experience a fault to ground and are represented by equation $I_A = I_B = I_C \neq 0$ $and\ V_A = V_B = V_C = 0$.

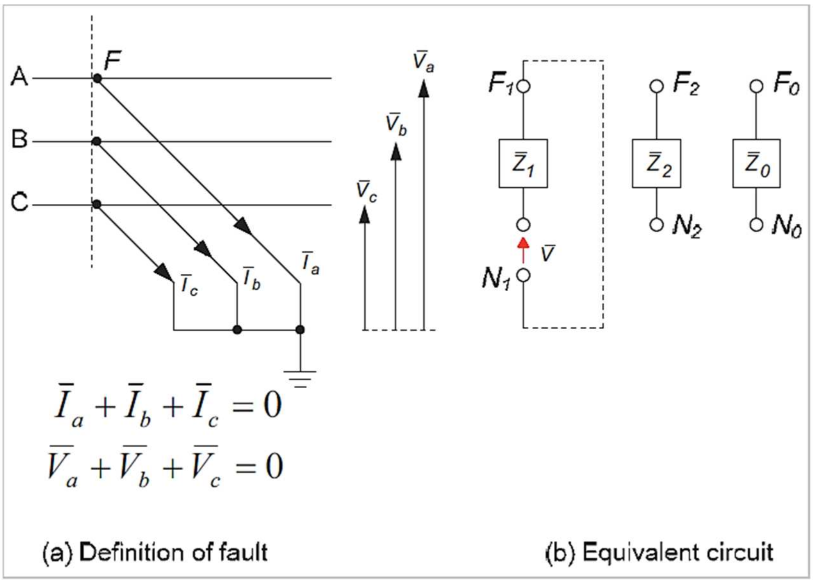


Figure 3.14: Three-phase to ground short-circuit fault

On a three phase system, the vectors of current and voltages shall all be represented on all three phases to complete all vectors for the system. The balanced three phase vectors are positive sequence, negative sequence, and zero sequence components (Gers and Holmes, 2011).

- Positive Sequence – three phases of equal magnitude at 120° apart rotating in positive direction.
- Negative Sequence - three phases of equal magnitude at 120° apart rotating in reverse direction to positive sequence.
- Zero Sequence – three phases of equal magnitude and in phase with each other and rotating in the same direction as the positive sequence.

For a three phase system, the voltages of each phase $V_a,\ V_b\ and\ V_c$ can be represented by:

$$
\begin{aligned}
V_a &= V_{a0} + V_{a1} + V_{a2} \\
V_b &= V_{b0} + V_{b1} + V_{b2} \\
V_c &= V_{c0} + V_{c1} + V_{c2}
\end{aligned} \tag{3.4}
$$

$$V_{a0} = \frac{1}{3}(V_a + V_b + V_c)$$

$$V_{a1} = \frac{1}{3}(V_a + aV_b + a^2V_c)$$

$$V_{a2} = \frac{1}{3}(V_a + a^2V_b + aV_c)$$

Where:

V_{a0},V_{b0}, and V_{c0} represent the Zero sequence voltage components.

V_{a1}, V_{b1} and V_{c1} represent the Positive sequence voltage components.

V_{a2}, V_{b2} and V_{c2} represent the Negative sequence voltage components.

Similarly the currents in the system will be as follows:

$$
\begin{aligned}
I_a &= I_{a0} + I_{a1} + I_{a2} \\
I_b &= I_{a0} + a^2I_{a1} + aI_{a2} \\
I_c &= I_{a0} + aI_{a1} + a^2I_{a2}
\end{aligned} \tag{3.5}
$$

$$I_{a0} = \frac{1}{3}(I_a + I_b + I_c)$$

$$I_{a1} = \frac{1}{3}(I + aI_b + a^2I_c)$$

$$I_{a2} = \frac{1}{3}(I_a + a^2I_b + aI_c)$$

The neutral current is the sum of the line currents Ia, Ib, and Ic. If the applied voltages are equal (balanced system), the positive and negative sequence impedances of cables are identical however, the zero sequence impedance differs from that of the positive and negative sequences.

3.11.2 Fault Calculations

Traditional fault hand calculation takes too long to solve more especially, if the system is too large, the problem becomes more complex. Computers use today is becoming more and more popular, even for protection studies. Classical hand calculation requires many formulas and conversion with either ohmic or per unit methods. These are prone to calculation errors and time consuming. However a short and quick Mega-Volt-Ampere (MVA) method could be used for fault calculation of small distribution utility network systems.

The ohmic method becomes complex when having to convert all different voltage levels on the system. Per unit is more complex when changing many data to chosen base values and when solving using symmetrical theory for single phase to earth faults, phase to phase faults and phase to phase to earth faults.

The MVA method is a modification of the ohmic method (Lee and Meng, 2003). The initial step is to redraw the typical single line diagram to the equivalent MVA single line diagram, and then to reduce the MVA single line diagram into a single MVA value at the point of fault. The typical single line diagram components are the utility source, transformers, cables, motors, and internal generators and other loads. Case studies of this method are highlighted in the following chapters.

Advantages of MVA method are:

- Conversion of impedance from one voltage to another is not required or needed. This is a requirement in the ohmic method.
- A common MVA base selection and then to convert the data to the common MVA base is not required nor needed. This is a requirement in the per unit method. The formulas for conversion are complex and not easy to remember.
- Both the ohmic method and the per unit method usually end up with small decimals. It is more prone to make mistakes in the decimal with resulting errors several orders of magnitude from the correct value.

- The MVA method uses large whole numbers which makes for easier manipulation and hence less prone to errors.

Formulas which are applicable from the ohmic method are;

At the utility side where voltage and fault current is known, the fault power may be calculated using the following equation;

$$MVA_{SC} = \sqrt{3}\, V_L I_F \tag{3.6}$$

Where:

MVA_{SC}	- is the short-circuit power seen by the source.
V_L	- is the line voltage on the system
I_F	- is the fault current seen by the source

At a transformer side where MVA rating and Impedance % is known, the short circuit power is calculated using the following equation;

$$MVA_{SC} = \frac{MVA}{Z} \tag{3.7}$$

Where:

MVA	- is the rated transformer power in mega-volt-ampere
Z	- is the transformer impedance expressed in percentage

At the load side where the voltage rating and reactance % is known, the short circuit power is calculated using the following equation;

$$MVA_{SC} = \frac{V}{X_r} \tag{3.8}$$

Where:

X_r	- is the transformer reactance expressed in percentage

At the current carrying conductor where the voltage to be carried and cable impedance is known, the short circuit power is determined by:

$$MVA_{SC} = \frac{V^2}{Z} \tag{3.9}$$

3.12 DESIGN OF THE IEC 61850 BASED SUBSTATION AUTOMATION SYSTEM

The standard IEC 61850 - Communication Networks and Systems in Substations provides interoperability between the Intelligent Electronic Devices (IEDs) for protection, monitoring, metering, control and automation in substations. Device interoperability and free allocation of functions opens up a vast range of possible substation solutions. Communication is the backbone of Substation Automation and, therefore, IEC 61850 standard is the most important key for designing systems (Brand, Brunner and Wimmer, 2004).

The design must account for the three areas of requirements which are:

- Functionality needed
  - o The single-line diagram of the electrical network, substation and the protection and control functions of the substation automation system.
- Performance required
  - o Reaction times during certain events occurrences.
- Constraints applicable
  - o Process interfaces, remote control systems and the geographical area, distance between components, and prescribed IED types

3.12.1 Single line diagrams

The single line diagram (SLD) shows all the power system network components which may include equipment to be controlled and protected. This defines how the design should be done in the operator’s viewpoint. The topology, how the power equipment is electrically connected, gives further information needed e.g. for interlocking and synchro-check functionality. The XML based Substation Configuration description Language (SCL) of IEC 61850 offers a formal way to describe the SLD. Passing the SLD in this form as a file reduces misunderstandings and enables automatic processing of it without new data entry (Brand, Brunner and Wimmer, 2004; IEC, 2008b).

3.12.2 Functions

All requested functionality should be specified without reference to any implementation to allow optimizing the solution. Only by this approach, the system design can exploit all benefits of state-of-the-art technology. Function numbering is required to be applied and the IEC 61850 offers the concept of Logical Nodes (LN) for formally defining these functions. The LN is the smallest part of a function, which communicates with other LNs and which may be implemented in a separate IED. The LN is an object, which comprises at least all related mandatory data and attributes and all extensions according to the rules of IEC 61850 (Brand, Brunner and Wimmer, 2004; IEC, 2008a). Examples of LN is shown in Section 3.8.3 above. Some of the most used functions are assigned to the following LNs class definitions according to IEC 61850:

- XCBR - Circuit breaker
- XSWI - Isolator switch
- TCTR - Current transformer
- TVTR – Voltage transformer
- MMXU – Measuring unit
- PTOC – Time overcurrent protection

3.12.3 Performance

Performance is referred to the processing speed or response time, safety and reliability and this guides the allocation of the LN and their related functions to the devices. Response time requirements can be subdivided into absolute worst case requirements, whose deviation might lead to dangerous process states, and average response time requirements, which are not process critical.

3.12.4 Constraints

Constraints could be attributed to a variety of elements which have an influence on the Substation Automation system architecture regarding possible locations for IEDs and the required communication links. Constraints could be assumed to be as:

- Geographical area
- Topology of the substation
- Existence of the housing structure
- Switchyard kiosks
- Rooms for the station HMI
- Distance between substation equipment, etc.

3.12.5 The Design Process

The process of the design includes the gathering of customer requirements and gathering required information and specification and thereafter start the design process. The design process may include the standard requirements for safety and others to facilitate this process. An example of the self-explanatory design process for substation automation is shown in Figure 3.15 below.

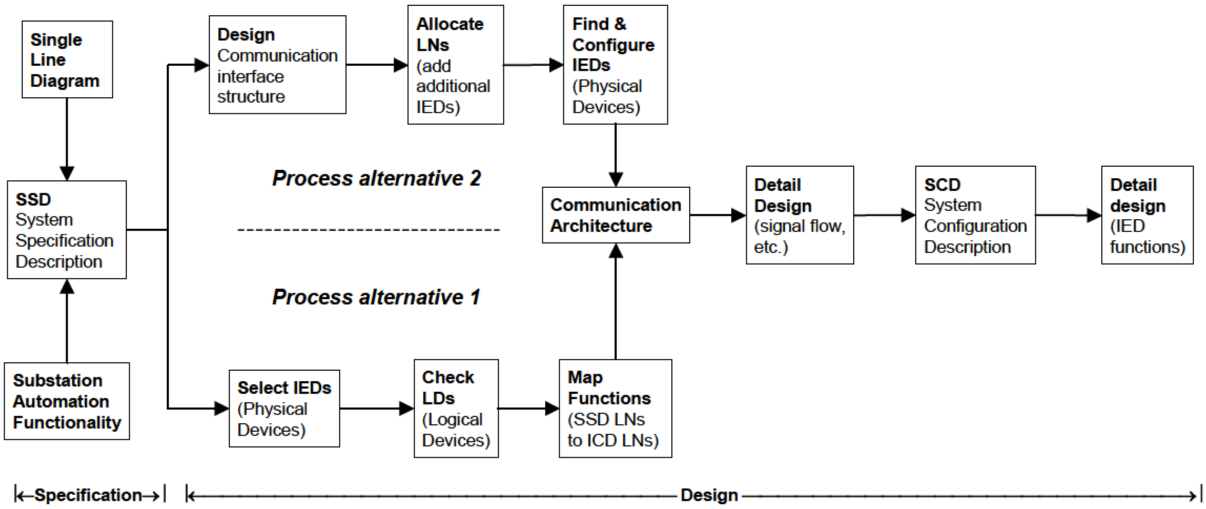


Figure 3.15: Steps of the design process (Brand, Brunner and Wimmer, 2004)

3.12.6 Detail Engineering

The design process for the IEC 61850 based systems is formally described in a Substation Configuration Description (SCD) file, which contains the logical communication connections between the IEDs within the sub-networks and routers between sub-networks. Any conformant IED has to provide a Substation Configuration Language (SCL) based description which contains all its capabilities in the form of an IED Configuration Description (ICD) file. This standardized file can be read and written by all conformant system engineering tools. This tool may also contain a database with all ICDs for IEDs, which are common for the system integrator.

3.12.7 Communication Topology

The IEC 61850 communication takes place between the IEDs LNs. The IEC 61850 is based on Ethernet protocol and any communication topology connecting all related IEDs fulfils the functional requirements. Therefore, the final determination of the communication topology is strongly influenced by constraints (Brand, Brunner and Wimmer, 2004). The selected IEDs together with the communication architecture represent the final system.

3.12.8 The final system

Two extreme examples are given which include all essential functions from the station bus level communication with its station computer and gateway to the network control centre down to the process bus level with conventional and unconventional sensors and actuators. Functional requirements are given according to section 3.12.2 above.

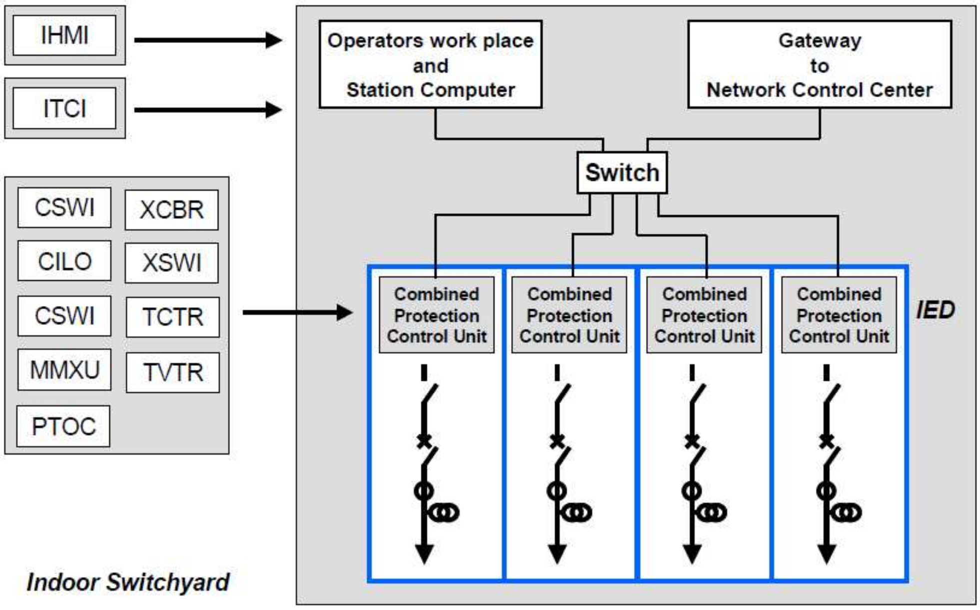


Figure 3.16: Compact Substation Automation System for MV substation (Brand, Brunner and Wimmer, 2004)

The following non-functional requirements apply: Determined hardwired process interface, switchgear cubicles at one place, prescribed combined protection-control units, average system availability, indoor switchyard with no separated control room. The result is a SA system with protection independent from any serial communication but with a single point of failure for the control and information exchange from station level and from remote as shown in Figure 3.16 above. The communication system is considered to attract reduced costs if only one switch and one communication link (fibre, etc.) per bay is employed.

3.13 CONCLUSION

For this chapter, importance of substation and distribution automation were discussed. Aspects of protection and factors which contribute to short-circuit on a power system have all been discussed. Distribution protection, monitoring and control requirements and the requirements for data flow in substations are discussed in this chapter.

The chapter also presented the communication protocol fundamentals and the future substation communication protocol IEC 61850 summary of theory and its advantages. In addition, the design process and requirements for Substation Automation have been discussed.

The theory discussed under this chapter is used as bases of building Chapters 4, 5, and 6 where Chapter 4 presents modelling and simulation of the power reticulation network, Chapter 5 presents the protection of the power reticulation network incomer substation, and Chapter 6 the Real-Time Hardware-In-Loop test bench development and simulations.

CHAPTER
4. MODELLING AND SIMULATION

4.1 INTRODUCTION

Power system studies are modelled and simulated in various simulation tools. This is a modern way of solving mathematical problems faster than conventional methods of hand based calculations. For the purpose of this chapter, DIgSILENT power factory package was used to simulate power flow and the protection on the incomer feeder busbars of the CPUT network. DIgSILENT PowerFactory is an integrated power system analysis software developed to solve power system modelling and simulation problems. The software package is a computer aided engineering tool for the analysis of transmission, distribution, and industrial electrical power systems. It is capable of solving complex mathematical algorithms and functions. It has been designed as an advanced integrated and interactive software package dedicated to electrical power system and control analysis in order to achieve the main objectives of network planning and operation optimization (Choden, Sither and Namgyel, 2017).

Real-Time Digital Simulator (RTDS) was used to study the network hardware in the loop configuration for protection and monitoring with Siemens relays used. A SCADA mimic system was built on the RSCAD Runtime in order to visualize the performance of the single line in conjunction with plotted waveforms. Different short-circuit fault types were simulated on RSCAD package to monitor the performance of the network and relays on the incoming feeder busbar. This is presented later in Chapter 5 & 6.

4.2 POWER FLOW

The present power system network arrangement is a natural starting point for planning purposes. The various types of power system network equipment, their location on the system, electrical and thermal loading and mechanical conditions are all factors to be taken into account when considering future developments. It is not possible to assess the overall technical capability of any network unless studies are carried out to determine the performance under steady-state load condition, or short-circuit fault conditions (Lakervi and Holmes, 2008). Computer-based information systems are used for this purpose. The initial network study conducted was load flow to determine power loading and the capacity of existing equipment and requirements for size upgrades.

4.3 POWER FLOW METHODS FOR SIMULATION

For a power system network to be considered successfully operable under normal three-phase steady state conditions, it must fulfil the following requirements (Glover, Sarma and Overbye, 2012):

- Generation supplies the load taking account the network losses
- Bus voltage magnitudes stay close to rated values
- Generators operate within specified real and reactive power limits
- Transmission lines, distribution cables and transformers are not overloaded

Power flow analysis involves the calculations of power flows and voltages of a power system network for specified terminal or bus conditions (Kundur, 1994). The power flow computation or simulation is the basic tool for investigating the above requirements. The program computes bus voltage magnitudes and angles under balanced steady-state conditions, and real and reactive power flow for all equipment interconnecting the buses including the equipment losses. The starting point for a power-flow problem is a single-line diagram of the power system, from which the input data for computer solutions can be obtained. Input data consist of bus data, transmission line data, and transformer data. (Glover, Sarma and Overbye, 2012).

Most Medium Voltage (MV) and Low Voltage (LV) networks are operated in radial configuration which contributes to simple operation and less costly safety requirements. As a consequence studies on such networks are relatively simple due to power flow in one direction and non-requirements for bi-directional protection schemes. On the other hand, the number of load points per network is higher and the information on the individual points is often limited with only the annual unit consumption figures at low voltage being known. The power flow through each section of the network is influenced by the disposition and loading of each node point, and by system losses. (Lakervi and Holmes, 2008).

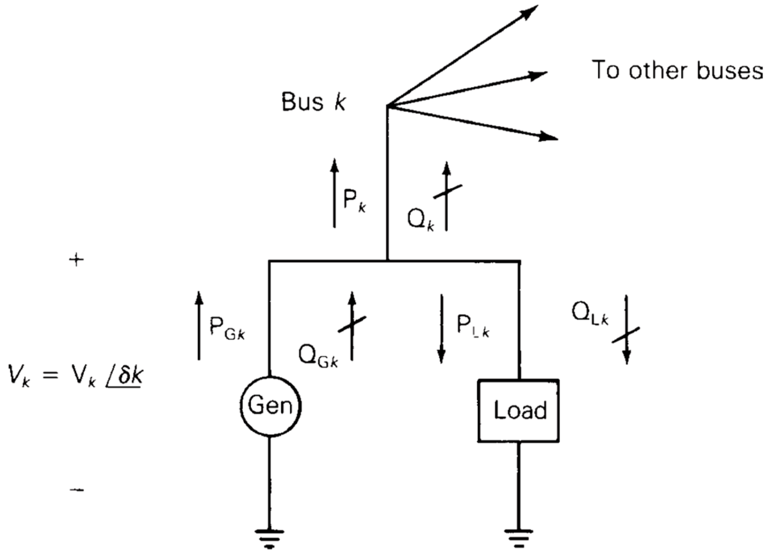


Figure 4.1: Power flow bus variables (Glover, Sarma and Overbye, 2012)

Figure 4.1 shows bus variables which are associated with Bus *k*. These variables are voltage V_K, voltage phase angle δ_K, real power P_K and reactive power Q_K. For power flow at any bus, two of these four variables may be specified while the remaining two are computed by the program. For Figure 4.1, power delivered to bus *k* is given by:

$$\begin{aligned} P_k &= P_{Gk} - P_{Lk} \\ Q_k &= Q_{Gk} - Q_{Lk} \end{aligned} \tag{4.1}$$

Where P_{Gk} and Q_{Gk} are the generator real and reactive powers, and P_{Lk} and Q_{Lk} are load real and reactive powers.

Each bus of the network may be categorised as Swing bus, Load bus, or Voltage controlled bus where:

1. Swing bus (or slack bus) is the reference bus or bus 1 for which $V_1 \angle \delta_1, = 1.0\angle 0°$ per unit
2. Load bus (PQ) - P_K and Q_K are input data to this bus.
3. Voltage controlled bus (PV) - P_K and V_K are input data to this bus.

The following methods describe the process of developing real and reactive powers of the power system network. These will describe the power flow as applied to the steady-state performance of the power system (Kundur, 1994).

4.3.1 Gauss-Seidel Method

Consider a set of linear algebraic equation of matrix format from Gauss elimination (Glover, Sarma and Overbye, 2012):

$$Ax = y \tag{4.2}$$

Where: A is a $n \times n$ square matrix, and $x \ and \ y$ are n vectors. Given $A \ and \ y$, x can be calculated as in iteration form, as follows:

$$x_k(i+1) \ = \ \frac{1}{A_{kk}}\left[y_k - \sum_{n=1}^{k-1} A_{kn}x_n(i+1) - \sum_{n=k+1}^{N} A_{kn}x_n(i)\right] \tag{4.3}$$

$n = 1, 2, 3, \ldots \qquad k = 1, 2, 3, \ldots, N$

Equation 4.3 is an algebraic representation of Gauss-Seidel method where; $x_k(i)$ is the solution of an $n \ vector$ at node k at the i^{th} iteration and A_{kk} is the $n \times n$ square matrix and N being the maximum number of nodes. The power flow equation is then derived from the complex power equation which yields the following:

$$S_k = P_k + jQ_k = V_k I_k^* \tag{4.4}$$

Where: S_k is the complex power delivered to node k. This equation can be expanded to obtain;

$$P_k + jQ_k = V_k \sum_{n=1}^{N} Y_{kn} V_n e^{j(\delta_k - \delta_n - \theta_{kn})} \tag{4.5}$$

Where Y_{kn} , is the sum of admittances connected between buses k and n, where $k \neq n$, $\delta_k - \delta_n$ is the voltage angle difference between bus angle and angle during the iteration.

The real and reactive powers can be computed independently as;

$$P_k = V_k \sum_{n=1}^{N} Y_{kn} V_n \cos(\delta_k - \delta_n - \theta_{kn}) \tag{4.6}$$

$$Q_k = V_k \sum_{n=1}^{N} Y_{kn} V_n \sin(\delta_k - \delta_n - \theta_{kn}) \tag{4.7}$$

$k = 1, 2, 3, \ldots, N$

Y_{kn} is the k bus admittance matrix which is used to solve the power flow problem. Either the bus self and mutual admittances which compose the bus admittance matrix Y_{bus} or the driving point and transfer impedances which compose Z_{bus} could be used when solving the load flow problem (Grainer and Stevenson, 1994). Bus admittance matrix is computed as follows;

$$Y_{kn} = |Y_{kn}| \cos\theta_{kn} + j|Y_{kn}| \sin\theta_{kn} = G_{kn} + jB_{kn} \tag{4.8}$$

Applying Gauss-Seidel method to Equation 4.8, the voltage at any bus k is expressed by the following equation.

$$V_k(i) = \frac{1}{Y_{kk}} \left[\frac{P_k - jQ_k}{V_k^*(i-1)} - \sum_{n=1}^{k-1} Y_{kn} V_n(i) - \sum_{n=k+1}^{N} Y_{kn} V_n(i-1) \right] \tag{4.9}$$

$n = 1, 2, 3, \ldots$ $\quad$ $k = 1, 2, 3, \ldots, N$ $\quad$ $k \neq n$

The subscript i denotes the number of iteration for which the voltage is being calculated while $i - 1$ denotes the previous calculated iteration. To obtain reactive power when the voltage magnitude is specified (for the voltage controlled bus), the equation is computed as follows;

$$Q_k(i) = -Im \left[V_k^*(i-1) \left(\sum_{n=1}^{k-1} Y_{kn} V_n(i) + \sum_{n=k+1}^{N} Y_{kn} V_n(i-1) \right) \right] \tag{4.10}$$

Equation for V_k and Q_k calculations are used to obtain the load power flow for the CPUT network.

4.3.2 Newton-Raphson Method

A set of algebraic equations in matrix format is given by (Kundur, 1994; Glover, Sarma and Overbye, 2012):

$$f(x) = \begin{bmatrix} f_1(x) \\ f_2(x) \\ \vdots \\ f_N(x) \end{bmatrix} = y \tag{4.11}$$

Where $x \; and \; y$ are N vectors and $f(x)$ is a function of N vectors. The Newton-Raphson method for iterative equations is computed as

$$x(i+1) = x(i) + J^{-1}(i)\{y - f[x(i)]\} \tag{4.12}$$

Where J is a $N \times N$ Jacobean matrix of the form

$$J(i) = \frac{df}{dx}\bigg]_{x=x(i)} = \begin{bmatrix} \frac{\partial y_1}{\partial x_1} & \frac{\partial y_1}{\partial x_2} & \cdots & \frac{\partial y_1}{\partial x_N} \\ \frac{\partial y_2}{\partial x_1} & \frac{\partial y_2}{\partial x_2} & \cdots & \frac{\partial y_2}{\partial x_N} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{\partial y_N}{\partial x_1} & \frac{\partial y_N}{\partial x_2} & \cdots & \frac{\partial y_N}{\partial x_N} \end{bmatrix} \tag{4.13}$$

The equations below then complete Newton-Raphson iteration

$$\Delta y(i) = \begin{bmatrix} \Delta P(i) \\ \Delta Q(i) \end{bmatrix} = \begin{bmatrix} P - P[x(i)] \\ Q - Q[x(i)] \end{bmatrix} \tag{4.14}$$

$$\begin{bmatrix} J1(i) & J2(i) \\ J3(i) & J4(i) \end{bmatrix} \begin{bmatrix} \Delta\delta(i) \\ \Delta V(i) \end{bmatrix} = \begin{bmatrix} \Delta P(i) \\ \Delta Q(i) \end{bmatrix} \tag{4.15}$$

$$x(i+1) = \begin{bmatrix} \delta(i+1) \\ V(i+1) \end{bmatrix} = \begin{bmatrix} \delta(i) \\ V(i) \end{bmatrix} + \begin{bmatrix} \Delta\delta(i) \\ \Delta V(i) \end{bmatrix} \tag{4.16}$$

Starting with the value *x(0),* the procedure continues until convergence is obtained. This method is the *power equations* way of solving iteration in Newton-Raphson techniques. From Equation 4.17,

$$I_k = \sum_{n=1}^{N} Y_{kn} V_n \tag{4.17}$$

The expression for P_k and Q_k may be written in real form as follows:

$$P_k = V_k \sum_{n=1}^{N} G_{kn} V_n \cos\theta_{kn} + B_{kn} V_n \sin\theta_{kn} \tag{4.18}$$

$$Q_k = V_k \sum_{n=1}^{N} G_{kn} V_n \sin\theta_{kn} - B_{kn} V_n \cos\theta_{kn} \tag{4.19}$$

The above equations are a function of voltage magnitude V and angle θ for all buses (substations) on the system.

4.3.3 Fast Decoupled Method

The Fast-Decoupled Power Flow (FDPF) method is a simplified method for Newton-Raphson algorithm. This method takes the Jacobian matrix and simplifies it by approximating partial derivatives of real power equations with respect to voltage magnitude as zero. The Jacobian matrix needs not be computed with each iteration as in the Newton-Raphson method. The FDPF method is mainly useful for solving large power system networks as an alternative way of improving computational efficiency (Grainer and Stevenson, 1994; Glover, Sarma and Overbye, 2012). This power flow method is developed to compute solutions in seconds or less time. Algorithms are based on the simplified Jacobian matrix from simplified Equation 4.20 & 4.21 which reduces to two sets of decoupled equations:

$$J_1(i)\Delta\delta(i) = \Delta P(i) \tag{4.20}$$

$$J_4(i)\Delta V(i) = \Delta Q(i) \tag{4.21}$$

The above equations simplifications can result in rapid power-flow solutions for most large power systems. While the FDPF usually takes more iterations to converge, it is usually significantly faster than the Newton-Raphson algorithm since the Jacobian matrix size is considerably reduced or does not need to be recomputed with each iteration (Grainer and Stevenson, 1994; Ochi *et al.*, 2013).

4.4 SIMULATION USING DIGSILENT

DIgSILENT PowerFactory is a computer aided power system electromagnetic-transients simulation engineering tool for the modelling and analysing transmission, distribution, and industrial electrical power systems. The PowerFactory database environment fully integrates all data for defining cases, scenarios, single line graphics, outputs, run conditions, calculation options, graphics, user defined models, etc… (DIgSILENT, 2013; Choden, Sither and Namgyel, 2017).

4.4.1 CPUT Reticulation Network Parameters

The CPUT reticulation is made up of 14 interconnected substations. Figure 4.2 below shows a single-line diagram for the arrangement of these substations.

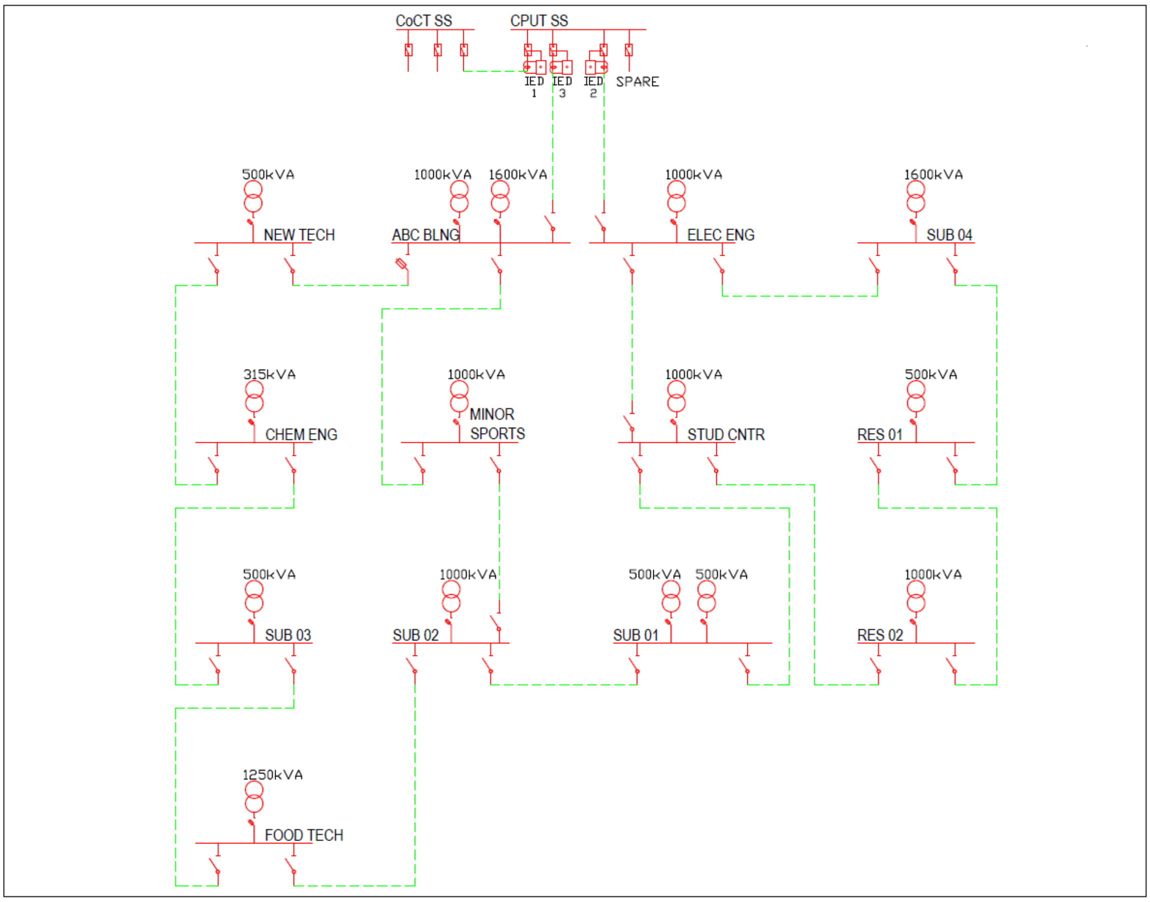


Figure 4.2: CPUT Reticulation Network Single-line Diagram

Parameters of these substations' transformers are shown in Table 4.1 below. All transformers have vector group Dyn11.

Table 4.1: CPUT Reticulation Transformer capacity

Sub #	Description	Size (kVA)	Voltage (kV)	Impedance (Z %)
1.	Main Incomer	-	11	-
2.	ABC Building (ABC)	1000 + 1600	11 / 0.4	5.12, 6.22
3.	Electrical Engineering (EE)	1000	11 / 0.4	4.98
4.	Minor Sports Hall (MSH)	1000	11 / 0.4	5.26
5.	Student Centre (SC)	1000	11 / 0.4	5.39
6.	Residence 1 (Res 1)	500	11 / 0.4	4.5
7.	Residence 2 (Res 2)	1000	11 / 0.4	4.58
8.	Substation 2 (Sub 2)	1000	11 / 0.4	5.12
9.	New Technology (NT)	500	11 / 0.4	4.5
10.	Chemical Engineering (CE)	315	11 / 0.4	4.08
11.	Substation 4 (Sub 4)	1600	11 / 0.4	5.7
12.	Substation 1 (Sub 1)	500 + 500	11 / 0.4	4.45, 4.5
13.	Substation 3 (Sub 3)	500	11 / 0.4	4.72
14.	Food Technology	1250	11 / 0.4	5.5

Measurements of substation quantities taken are shown in the Table 4.2 below. These measurements are used to model load in the software to simulate load flow analysis.

Table 4.2: CPUT Substation Transformer Loading

Sub #	Description	P (kW)	S (kVA)
1.	Main Incomer	-	-
2.	ABC Building	692	742
3.	Electrical Engineering	888	1043
4.	Minor Sports Hall	353	484
5.	Student Centre	438	452
6.	Residence 1	431	451
7.	Residence 2	302	321
8.	Substation 2	418	451
9.	New Technology	133	204
10.	Chemical Engineering	138	165
11.	Substation 4	751	893
12.	Substation 1	231	253
13.	Substation 3	204	388
14.	Food Technology	343	350

Table 4.3 below shows reticulation network underground cable length and cable properties according to Abedare cable manufacture properties. The length of each cable is as measured, while the resistance per kilometre, inductive reactance per kilometre, and impedance per kilometre are as obtained from manufacture's properties. The total resistance R, inductive reactance X, and inductance L have been calculated based on the measured length of each cable. Underground cables for the network are modelled with parameter of Paper Insulated Lead Conductor (PILC) of which only two sizes were utilized namely 70mm^2 and 120mm^2. Length of each cable was measured via AutoCAD design package and these were modelled as approximate measurements. Parameters of these cables are as defined on Aberdare cable manufacturer's properties.

Table 4.3: CPUT Underground Cable Properties

Cable Type	Area	Length (m)	R (Ω /km)	R (Ω)	Xl (Ω /km)	Xl (Ω)	L (H)	Z (Ω /km)
PILC Cu 120mm^2	Incomer - EE	385	0.1839	0.071	0.091	0.035	0.00011	0.079
	Incomer - ABC	270	0.1839	0.050	0.091	0.0246	0.00008	0.0554
	EE –Sub 4	221	0.1839	0.041	0.091	0.0201	0.00006	0.0454
	EE -SC	192	0.1839	0.035	0.091	0.0175	0.00006	0.0394
	ABC - MSH	176	0.1839	0.032	0.091	0.016	0.00005	0.0361
	MSH - Sub 2	256	0.1839	0.047	0.091	0.0233	0.00007	0.0526
	SC - Sub	377	0.1839	0.069	0.091	0.0343	0.00011	0.0774
	Sub 1 - Sub 2	271	0.1839	0.050	0.091	0.0247	0.00008	0.0556
PILC Cu 70mm^2								
	Sub 4 – Res 1	397	0.3211	0.127	0.101	0.0401	0.00013	0.1336
	Res 1 – Res 2	195	0.3211	0.063	0.101	0.0197	0.00006	0.0656
	Res 2 – Student Centre	349	0.3211	0.112	0.101	0.0352	0.00011	0.1174
	Sub 3 - Sub 2	252	0.3211	0.081	0.101	0.0255	0.00008	0.0848
	Sub 3 - Chem ENG	89	0.3211	0.029	0.101	0.0089	0.00003	0.0299
	NewTech - Chem ENG	135	0.3211	0.043	0.101	0.0136	0.00004	0.0454
	MSH - NewTech	540	0.3211	0.173	0.101	0.0545	0.00017	0.1817

4.4.2 Modelling of Reticulation Network Parameters

The workflow for DIgSILENT is generally based on the method shown on the Figure 4.3 below.

Data collection is for network elements which are, cables, transformers, load measurements, and switchgear across all substations.

Modelling of the reticulation network involves computation of these obtained data in DIgSILENT PowerFactory software.

After completing the modelling, load flow analysis is carried out to determine power flow limits.

Additional required analysis includes short circuit analysis (Chapter 5), overcurrent relay coordination (Chapter 5), Analysis of simulated relays results (Chapter 5), and furthermore, harmonic analysis, contingency studies etc… (As and when required).

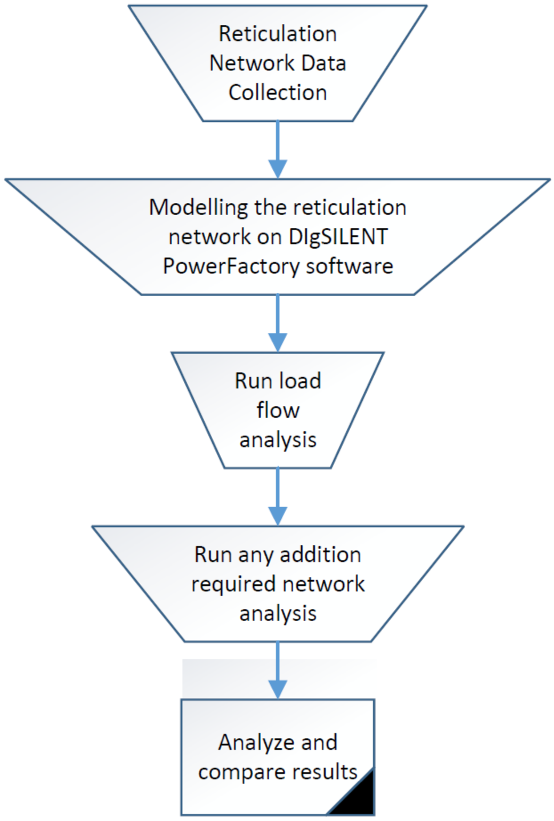


Figure 4.3: DIgSILENT PowerFactory simulation process flow

4.4.2.1 Transformer modelling

Upon completing collection of data, modelling of network elements is completed in DIgSILENT based on the data collected. For transformer modelling, an illustrative diagram is shown in Figure 4.4 below. Basic requirements such as technology, rated power, nominal frequency, rated voltage, vector group, and positive sequence impedance must be defined.

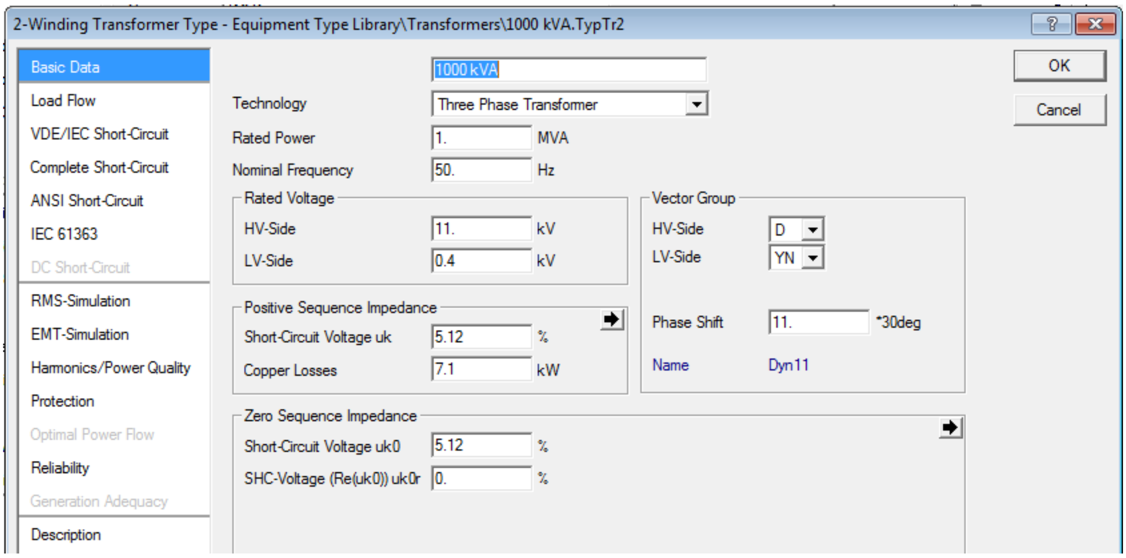


Figure 4.4: Modelling of Transformer parameters

4.4.2.2 Load modelling

Each load parameters are defined based on the load type. Technology type shall be defined for ether single phase, two phases, three phases with or without neutral and earth etc… the load actual values are computed depending on available information as shown in Figure 4.5 below (such as real, reactive, or apparent power etc.).

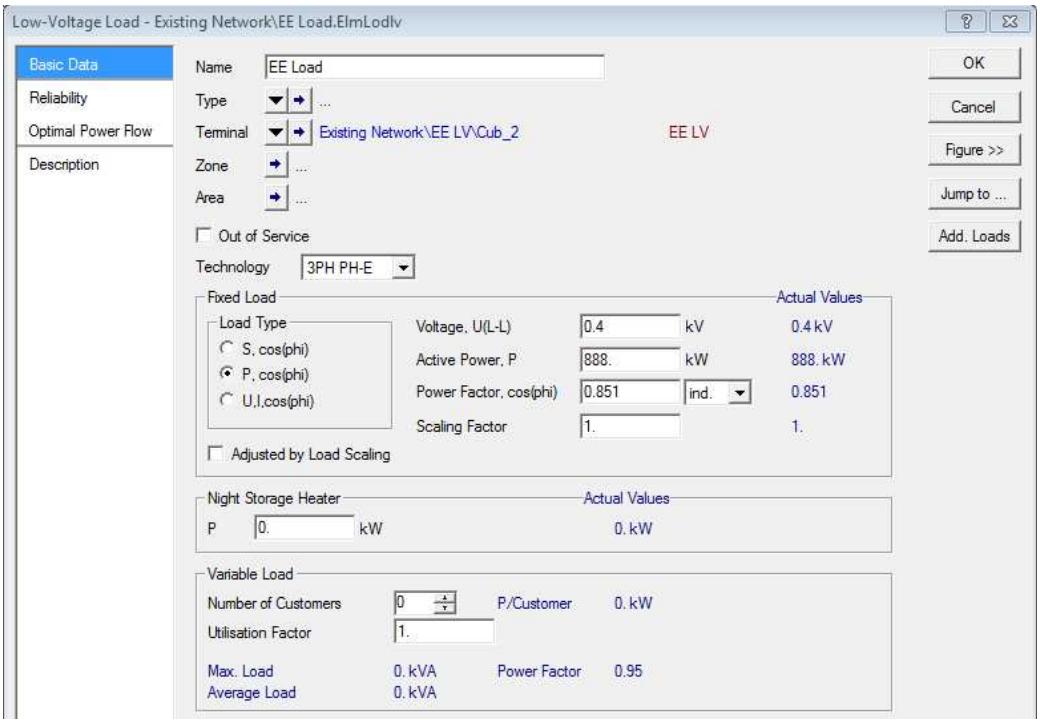
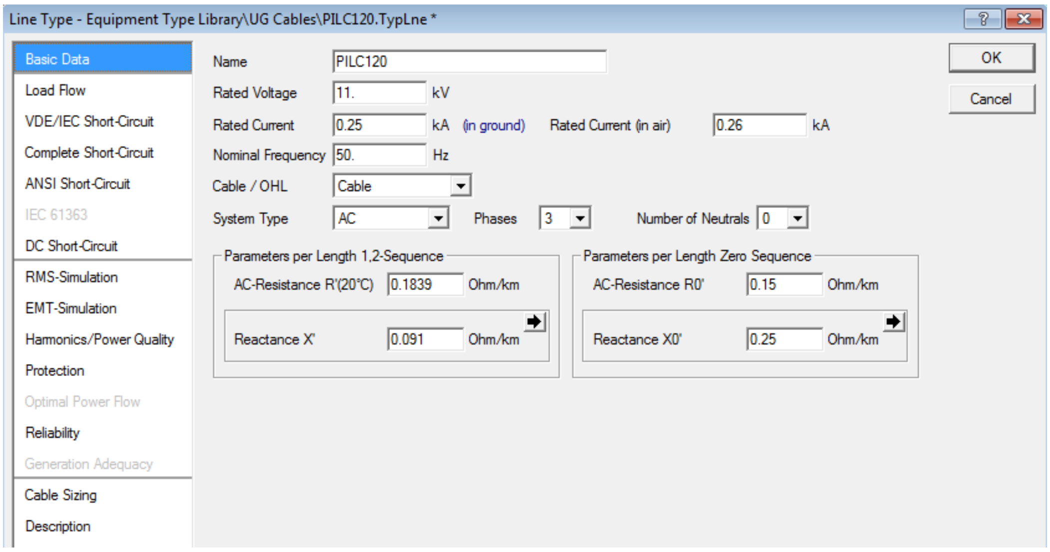


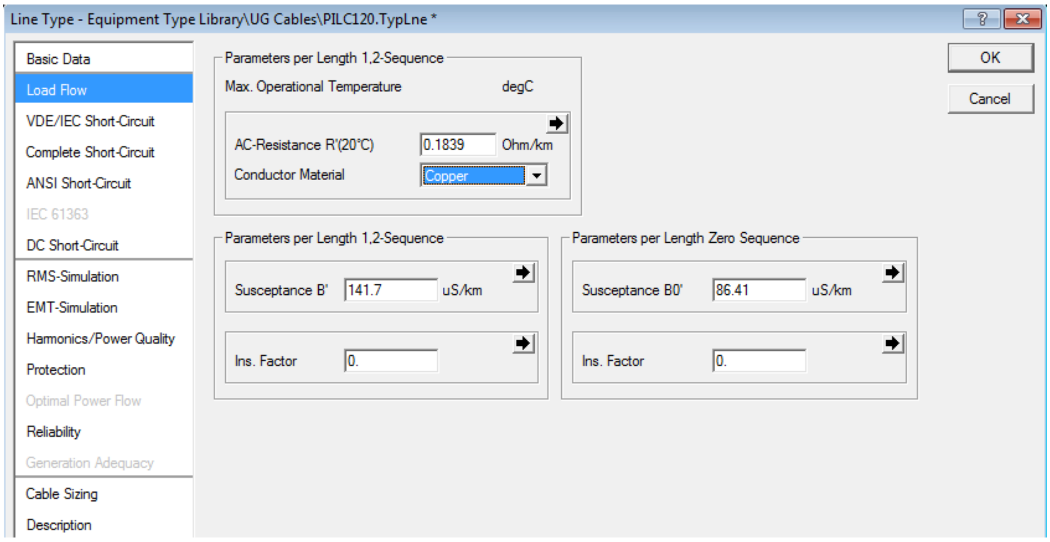
Figure 4.5: Modelling of Load parameters

4.4.2.3 Cable modelling

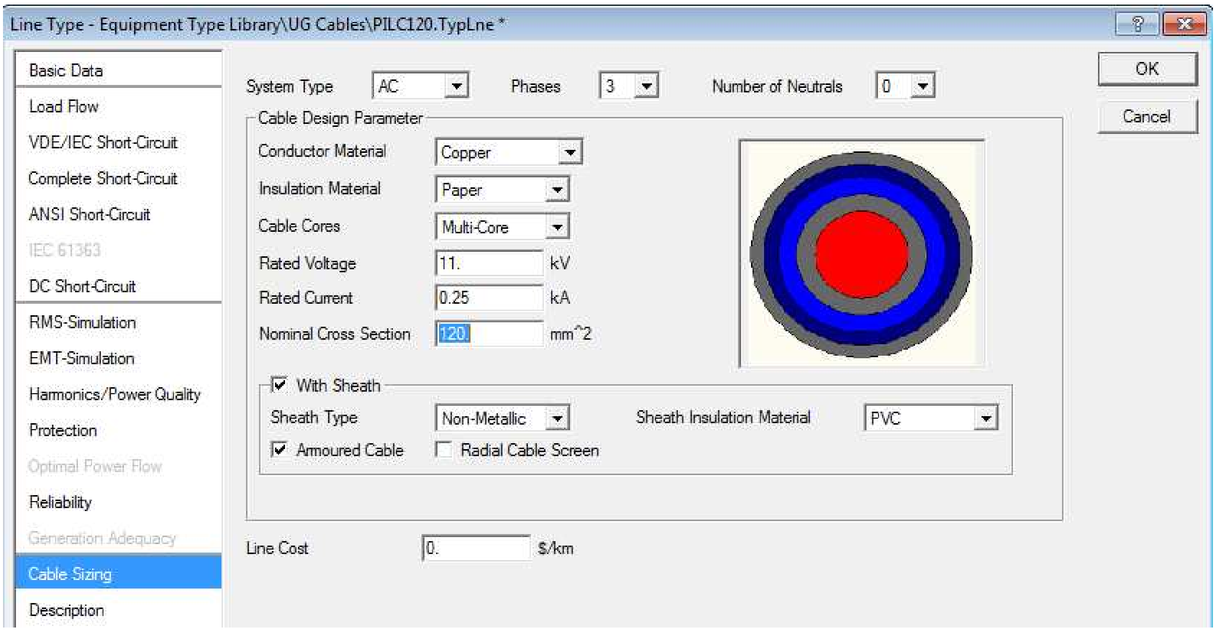
Cable modelling requires knowledge of the properties as supplied by cable manufacturers together with general network parameters. Basic data, load flow, and cable sizing requires proper computation in order to correctly simulate networks load flow. Failure to compute these correctly may lead to incorrect results for load flow. In addition method of installation must be described whether cable installed in ground, in ducts or in air, with sometimes a combination of all, however where most part of the cable lays may be assumed as the installation method. Figure 4.6 (a-d) below shows cable parameters window where useful parameters are computed from cable datasheets. These parameters are also shown in Table 4.3 above



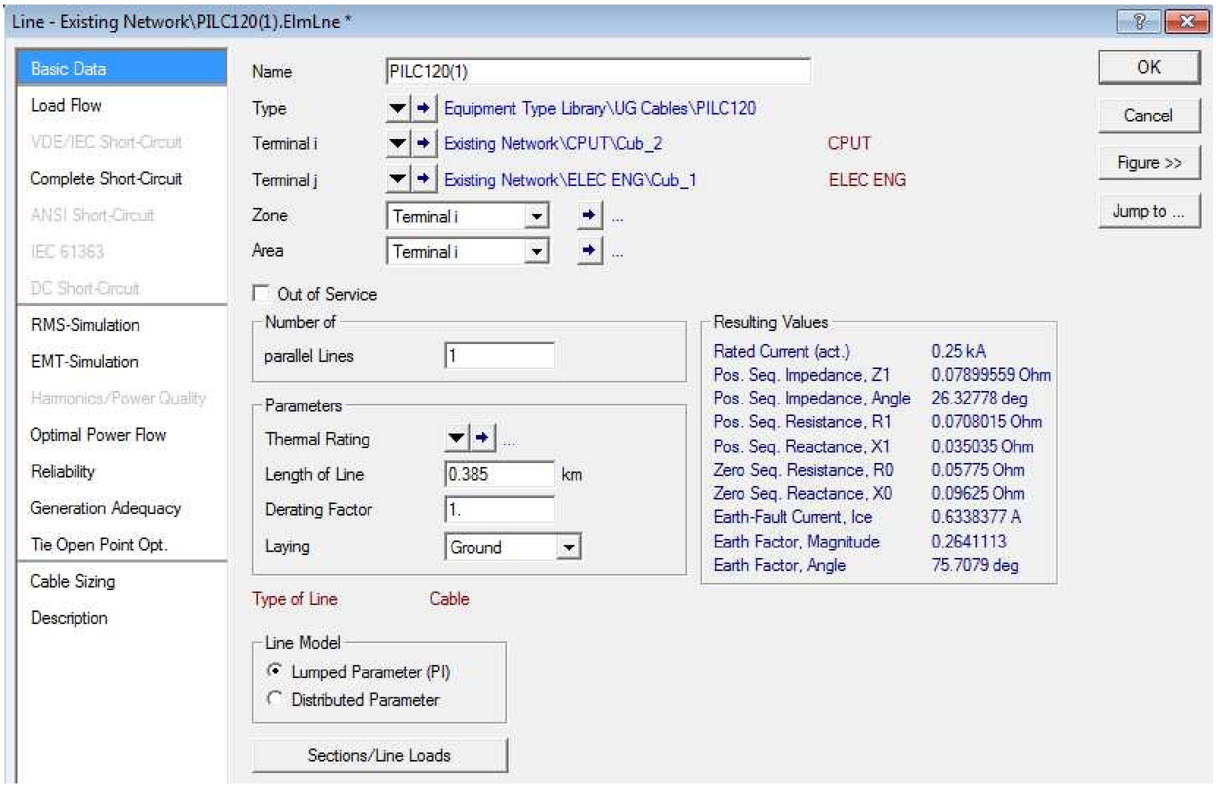
(a) Basic Data



(b) Load Flow



(c) Cable Sizing



(d) Location of the cable

Figure 4.6: Modelling of Cable parameters

4.4.3 Load Flow Analysis

After the reticulation network modelling is completed, load flow is run based on the Newton-Raphson method – AC load flow, balanced, positive sequence with power equations. Load flow analysis simulation provides the results of voltages, currents, real and reactive powers flowing on the reticulation network during steady-state conditions. It also provides power losses in the system, the voltage profile and the percentage loading of the lines and transformers. The other importance of the load flow analysis are as follows (Choden, Sither and Namgyel, 2017):

- To plan ahead and account for various hypothetical situations that may occur in the system.
- The impact of increased load on the system.
- Solutions for loss reduction in the system.
- Improvement of voltage profile

Solutions for power system load flow were computed with DIgSILENT PowerFactory and the results are shown in Table 4.4 below and Figure 4.7 for Main Incomer Maximum demand. The complete load flow results are shown in Figure 4.8 below. The method used is Newton-Raphson. These results provided a summary of maximum apparent, real and reactive powers which were used to configure current transformer burden.

Table 4.4: Power flow result summary

```
----------------------------------------------------------------------------------------------------------------------------
| Load Flow Calculation                                                                                Total System Summary |
----------------------------------------------------------------------------------------------------------------------------
|     AC Load Flow, balanced, positive sequence          |  Automatic Model Adaptation for Convergence           No          |
|     Automatic Tap Adjust of Transformers          No   |  Max. Acceptable Load Flow Error for                              |
|     Consider Reactive Power Limits                No   |     Nodes                                             1.00 kVA    |
|                                                        |     Model Equations                                   0.10 %      |
----------------------------------------------------------------------------------------------------------------------------
----------------------------------------------------------------------------------------------------------------------------
| Total System Summary                                 | Study Case: Study Case                | Annex:                 / 1 |
----------------------------------------------------------------------------------------------------------------------------
|                                                                                                                          |
| No. of Substations     0         No. of Busbars       30        No. of Terminals     0        No. of Lines          17     |
| No. of 2-w Trfs.      15         No. of 3-w Trfs.      0        No. of syn. Machines 0        No. of asyn.Machines  0      |
| No. of Loads          15         No. of Shunts         0        No. of SVS           0                                   |
|                                                                                                                          |
| Generation          =      0.00  MW            0.00  Mvar       0.00  MVA                                                |
| External Infeed     =      5.96  MW            3.25  Mvar       6.79  MVA                                                |
| Load P(U)           =      5.87  MW            3.12  Mvar       6.64  MVA                                                |
| Load P(Un)          =      5.87  MW            3.12  Mvar       6.64  MVA                                                |
| Load P(Un-U)        =      0.00  MW            0.00  Mvar                                                                 |
| Motor Load          =      0.00  MW            0.00  Mvar       0.00  MVA                                                |
| Grid Losses         =      0.09  MW            0.13  Mvar                                                                 |
| Line Charging       =                         -0.06  Mvar                                                                 |
| Compensation ind.   =                          0.00  Mvar                                                                 |
| Compensation cap.   =                          0.00  Mvar                                                                 |
|                                                                                                                          |
| Installed Capacity  =      0.00  MW                                                                                      |
| Spinning Reserve    =      0.00  MW                                                                                      |
|                                                                                                                          |
| Total Power Factor:                                                                                                      |
|   Generation        =         0.00  [-]                                                                                  |
|   Load/Motor        =  0.88 / 0.00  [-]                                                                                  |
|--------------------------------------------------------------------------------------------------------------------------|
```

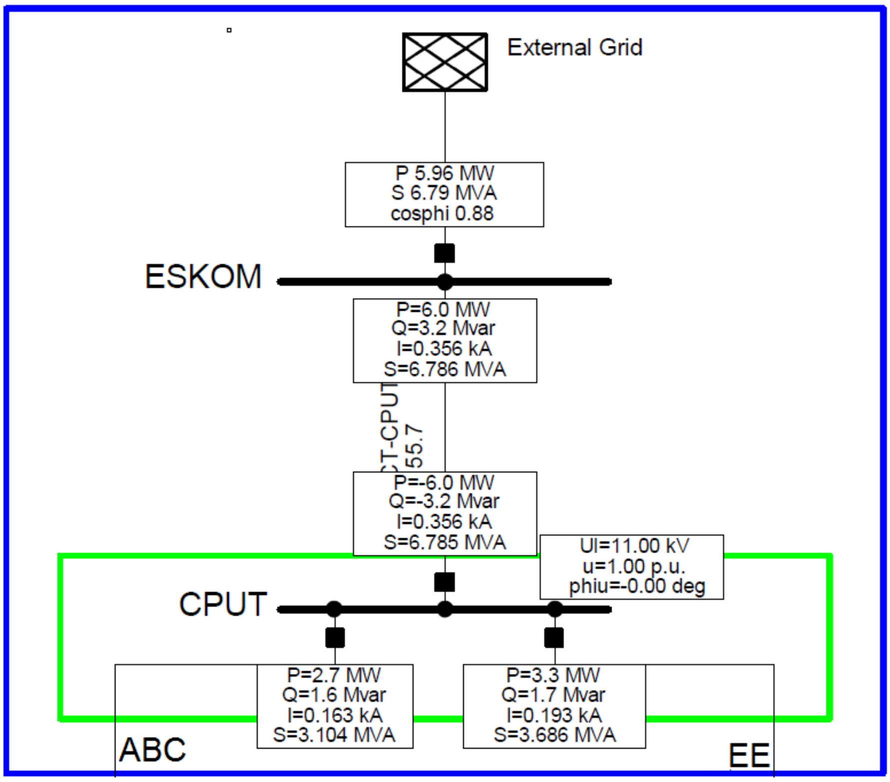


Figure 4.7: Power Flow Results for Incomer Substation

A complete set of power flow results could be used to analyse steady state conditions of the power system network. When the maximum current or real and reactive power flows have been determined, the series active and reactive power losses in a 3-phase circuit or any item of equipment, P_l and Q_l, can be calculated from the following equations (Lakervi and Holmes, 2008):

$$P_l = 3I^2R_l \quad or \tag{4.22}$$

$$P_l = \left[\frac{P}{V}\right]^2 R_l + \left[\frac{Q}{V}\right]^2 R_l \quad and \tag{4.23}$$

$$Q_l = 3I^2X_l = \left[\frac{P}{V}\right]^2 X_l + \left[\frac{Q}{V}\right]^2 X_l \tag{4.24}$$

Where R_l and X_l refer to series resistance and reactance of the circuit.

The analysis of the results for voltage profiles in the Table 4.5 below shows that most voltages are averaging around 0.998 per unit with the lowest at 0.996 per unit which illustrates that they are within the criteria of IEEE 141-1993 and SANS 10142 standards. The MV side presents the profiles with better or minimal voltage drop with the substation at highest voltage drop being at 0.4 percent.

Table 4.5: Substations load flow voltage profiles

```
| Load Flow Calculation                    Complete System Report: Substations, Voltage Profiles, Grid Interchange |
|     AC Load Flow, balanced, positive sequence          |   Automatic Model Adaptation for Convergence        No
|     Automatic Tap Adjust of Transformers         No    |   Max. Acceptable Load Flow Error for
|     Consider Reactive Power Limits               No    |      Nodes                                         1.00 kVA
|                                                        |      Model Equations                               0.10 %
| Grid: Existing Network     System Stage: Existing Networ | Study Case: Study Case          | Annex:          / 6 |
```

	rtd.V [kV]	Bus - voltage [p.u.]	[kV]	[deg]	Voltage - Deviation [%] (-10, -5, 0, +5, +10)
CPUT	11.00	1.000	11.00	-0.00	
ABC Bld	11.00	0.999	10.98	0.01	
ELEC ENG	11.00	0.998	10.97	0.00	
SUB_4	11.00	0.997	10.97	0.00	
NEW TECH HV	11.00	0.997	10.97	0.04	
CHEM ENG	11.00	0.997	10.96	0.05	
MAJOR SH	11.00	0.998	10.98	0.01	
SUB_3	11.00	0.996	10.96	0.06	
SUB_2	11.00	0.998	10.98	0.01	
CE LV	0.40	0.985	0.39	29.43	
EE LV	0.40	0.974	0.39	28.53	
ABC LV1	0.40	0.989	0.40	29.04	
ABC LV2	0.40	0.986	0.39	28.82	
STN CNT	11.00	0.997	10.97	-0.00	
RES_1	11.00	0.996	10.96	0.00	
SC LV	0.40	0.988	0.40	28.76	
R1 LV	0.40	0.975	0.39	27.88	
S4 LV	0.40	0.977	0.39	28.77	
SUB_1	11.00	0.997	10.96	-0.00	
RES_2	11.00	0.997	10.96	-0.00	
S1 LV2	0.40	0.982	0.39	28.91	
S1 LV1	0.40	0.984	0.39	29.01	
R2 LV	0.40	0.989	0.40	29.15	
S2 LV	0.40	0.986	0.39	28.83	
S3 LV	0.40	0.961	0.38	29.38	
MSH LV	0.40	0.978	0.39	29.09	
NT LV	0.40	0.980	0.39	29.54	
FOOD TECH	11.00	0.996	10.96	0.05	
FT LV	0.40	0.990	0.40	29.06	
ESKOM	11.00	1.000	11.00	0.00	

Two substation transformers show that they are loaded above 80% after running load flow simulation as shown in Figure 4.8. Substation 3 shows a percentage loading of 80.8%, while Residence 1 transformer shows a loading of 92.5%. Upgrading of these two substations may be required depending on whether future additional load is anticipated. The total loading profile is shown in Tables 4.6 - 4.8 below.

Table 4.6: CPUT Reticulation Network Equipment Loading (part 1)

Grid: Existing Network   System Stage: Existing Networ | Study Case: Study Case | Annex: / 1

Name	Type	Loading [%]	Busbar	Active Power [MW]	Reactive Power [Mvar]	Power.-factor [-]	Current [kA]	Current [p.u.]
ABC Load1	Lodlv		ABC LV1	0.346	0.134	0.93	0.541	1.011
ABC Load2	Lodlv		ABC LV2	0.692	0.267	0.93	1.086	1.014
CE Load	Lodlv		CE LV	0.138	0.091	0.84	0.242	1.015
EE Load	Lodlv		EE LV	0.888	0.548	0.85	1.546	1.026
FT Load	Lodlv		FT LV	0.343	0.070	0.98	0.510	1.010
MSH Load	Lodlv		MSH LV	0.353	0.331	0.73	0.714	1.022
NT Load	Lodlv		NT LV	0.131	0.152	0.65	0.296	1.020
R1 Load	Lodlv		R1 LV	0.431	0.129	0.96	0.666	1.026
R2 Load	Lodlv		R2 LV	0.302	0.107	0.94	0.467	1.011
S1 Load1	Lodlv		S1 LV1	0.211	0.094	0.91	0.339	1.017
S1 Load2	Lodlv		S1 LV2	0.231	0.103	0.91	0.372	1.018
S2 Load	Lodlv		S2 LV	0.419	0.167	0.93	0.660	1.014
S3 Load	Lodlv		S3 LV	0.202	0.331	0.52	0.582	1.040
S4 Load	Lodlv		S4 LV	0.748	0.481	0.84	1.314	1.024
SC Load	Lodlv		SC LV	0.434	0.111	0.97	0.654	1.012
External Grid	Xnet		ESKOM	5.958	3.248	0.88	0.356	0.093
CoCT-CPUT	Lne	55.65	ESKOM	5.958	3.248	0.88	0.356	0.556
			CPUT	-5.957	-3.248	-0.88	0.356	0.557
PILC120	Lne	65.22	CPUT	2.665	1.591	0.86	0.163	0.652
			ABC Bld	-2.661	-1.594	-0.86	0.163	0.652
PILC120(1)	Lne	77.45	CPUT	3.292	1.657	0.89	0.193	0.774
			ELEC ENG	-3.284	-1.660	-0.89	0.194	0.774
PILC120(2)	Lne	19.64	ABC Bld	0.783	0.507	0.84	0.049	0.196
			MAJOR SH	-0.782	-0.510	-0.84	0.049	0.196
PILC120(3)	Lne	28.63	ELEC ENG	1.194	0.649	0.88	0.071	0.286
			SUB_4	-1.193	-0.652	-0.88	0.072	0.286
PILC120(4)	Lne	26.68	ELEC ENG	1.193	0.426	0.94	0.067	0.267
			STN CNT	-1.192	-0.429	-0.94	0.067	0.267
PILC120(5)	Lne	10.38	STN CNT	0.447	0.202	0.91	0.026	0.103
			SUB_1	-0.447	-0.208	-0.91	0.026	0.104
PILC120(6)	Lne	9.61	MAJOR SH	0.424	0.166	0.93	0.024	0.096

Table 4.7: CPUT Reticulation Network Equipment Loading (part 2)

Grid: Existing Network System Stage: Existing Networ | Study Case: Study Case | Annex: / 2

Name	Type	Loading [%]	Busbar	Active Power [MW]	Reactive Power [Mvar]	Power.-factor [-]	Current [kA]	Current [p.u.]
			SUB_2	-0.424	-0.170	-0.93	0.024	0.096
PILC120(7)	Lne	0.10	SUB_2	0.000	-0.005	0.00	0.000	0.001
				-0.000	-0.000	-1.00	0.000	0.000
PILC70	Lne	30.23	ABC Bld	0.829	0.660	0.78	0.056	0.301
			NEW TECH HV	-0.827	-0.666	-0.78	0.056	0.302
PILC70(1)	Lne	24.54	NEW TECH HV	0.694	0.510	0.81	0.045	0.245
			CHEM ENG	-0.694	-0.512	-0.80	0.045	0.245
PILC70(2)	Lne	13.13	SUB_4	0.437	0.143	0.95	0.024	0.131
			RES_1	-0.437	-0.148	-0.95	0.024	0.131
PILC70(3)	Lne	0.07		-0.000	-0.000	-1.00	0.000	0.000
			RES_2	0.000	-0.002	0.00	0.000	0.001
PILC70(4)	Lne	9.26	STN CNT	0.306	0.105	0.95	0.017	0.092
			RES_2	-0.306	-0.110	-0.94	0.017	0.093
PILC70(5)	Lne	19.80	CHEM ENG	0.554	0.419	0.80	0.037	0.198
			FOOD TECH	-0.554	-0.420	-0.80	0.037	0.198
PILC70(6)	Lne	0.09	SUB_2	0.000	-0.003	0.00	0.000	0.001
				-0.000	-0.000	-1.00	0.000	0.000
PILC70(7)	Lne	11.46	FOOD TECH	0.207	0.344	0.51	0.021	0.114
			SUB_3	-0.207	-0.345	-0.51	0.021	0.115
1.25 MVA	Tr2	35.69	FOOD TECH	0.347	0.076	0.98	0.019	0.357
			FT LV	-0.343	-0.070	-0.98	0.510	0.353
1.6MVA	Tr2	47.28	ABC Bld	0.699	0.286	0.93	0.040	0.473
			ABC LV2	-0.692	-0.267	-0.93	1.086	0.470
1.6MVA(1)	Tr2	67.16	ELEC ENG	0.898	0.586	0.84	0.056	0.672
			EE LV	-0.888	-0.548	-0.85	1.546	0.669
1000 kVA	Tr2	32.72	RES_2	0.306	0.112	0.94	0.017	0.327
			R2 LV	-0.302	-0.107	-0.94	0.467	0.324
1600 kVA	Tr2	57.13	SUB_4	0.756	0.509	0.83	0.048	0.571
			S4 LV	-0.748	-0.481	-0.84	1.314	0.569
1MVA	Tr2	37.85	ABC Bld	0.351	0.141	0.93	0.020	0.378
			ABC LV1	-0.346	-0.134	-0.93	0.541	0.375
1MVA(2)	Tr2	46.06	SUB_2	0.424	0.178	0.92	0.024	0.461
			S2 LV	-0.419	-0.167	-0.93	0.660	0.457
1MVA(3)	Tr2	45.68	STN CNT	0.439	0.121	0.96	0.024	0.457
			SC LV	-0.434	-0.111	-0.97	0.654	0.453
1MVA(4)	Tr2	49.75	MAJOR SH	0.358	0.344	0.72	0.026	0.498
			MSH LV	-0.353	-0.331	-0.73	0.714	0.495
500kVA(1)	Tr2	41.15	NEW TECH HV	0.133	0.156	0.65	0.011	0.411
			NT LV	-0.131	-0.152	-0.65	0.296	0.410
500kVA(2)	Tr2	33.70	CHEM ENG	0.140	0.093	0.83	0.009	0.337
			CE LV	-0.138	-0.091	-0.84	0.242	0.335
500kVA(3)	Tr2	92.53	RES_1	0.437	0.148	0.95	0.024	0.925
			R1 LV	-0.431	-0.129	-0.96	0.666	0.923
500kVA(5)	Tr2	51.73	SUB_1	0.234	0.109	0.91	0.014	0.517

Table 4.8: CPUT Reticulation Network Equipment Loading (part 3)

Grid: Existing Network System Stage: Existing Networ | Study Case: Study Case | Annex: / 3

Name	Type	Loading [%]	Busbar	Active Power [MW]	Reactive Power [Mvar]	Power.-factor [-]	Current [kA]	Current [p.u.]
			S1 LV2	-0.231	-0.103	-0.91	0.372	0.515
500kVA(6)	Tr2	47.19	SUB_1	0.213	0.099	0.91	0.012	0.472
			S1 LV1	-0.211	-0.094	-0.91	0.339	0.470
500kVA(7)	Tr2	80.80	SUB_3	0.207	0.345	0.51	0.021	0.808
			S3 LV	-0.202	-0.331	-0.52	0.582	0.807

With respect to underground cables loading , Table 4.6 part 1 has a loading percentage of 77.45% which is located between Main intake substation and Electrical Engineering substation. Followed by the cable between Main intake susbtation to ABC Building which has a loading percentage of 65.22%

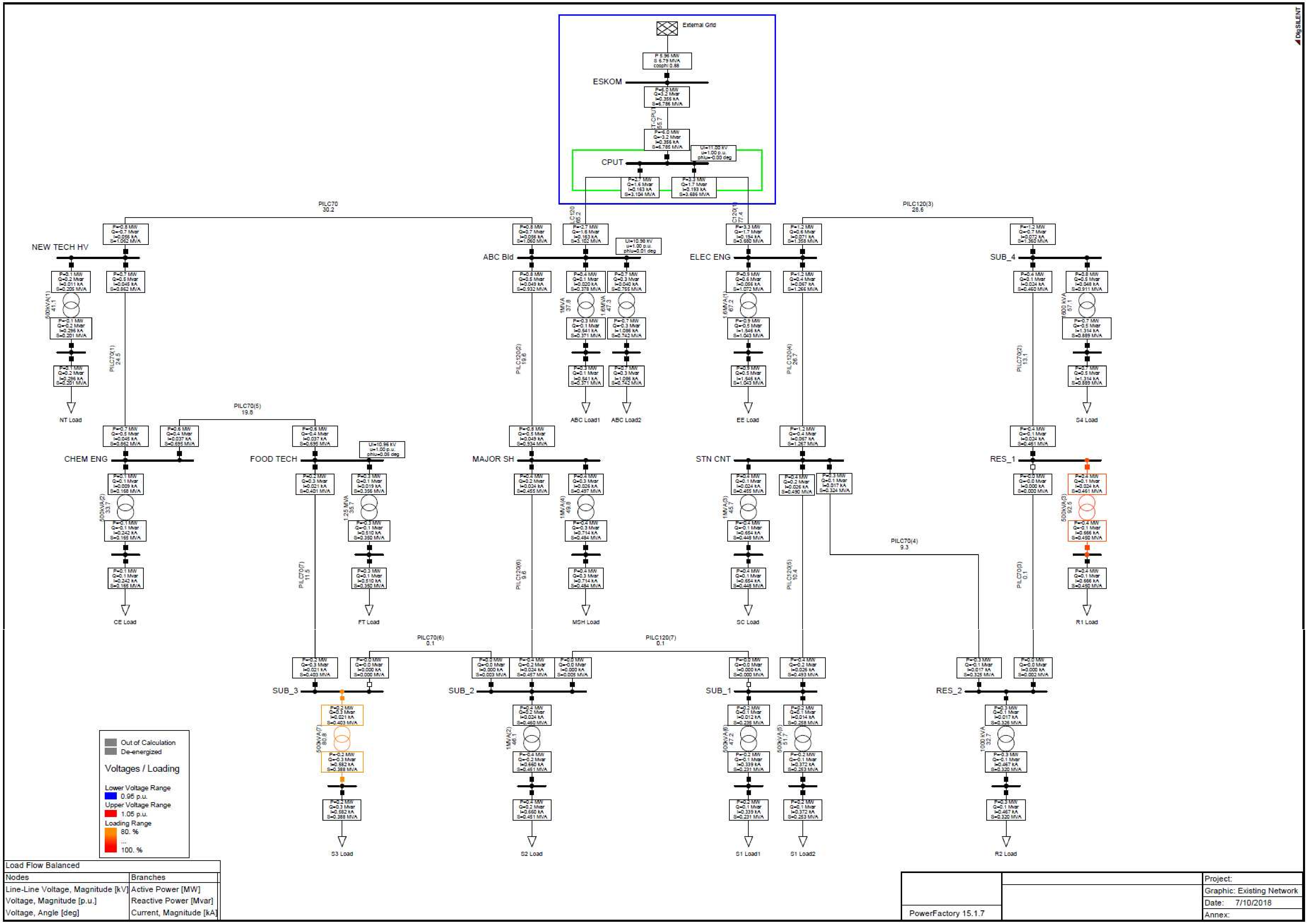


Figure 4.8: Complete Load Flow Results

4.5 CONCLUSION

Electromagnetic transient analysis software packages are essential tool for power system modelling and simulation. Various packages have their capabilities and similarities with respect to methods of modelling and their mathematical calculation algorithms and methods embedded in these programs. DIgSILENT PowerFactory is one such tool with vast capabilities for simulation and analysis. This chapter described the calculation methods required to compute load flow calculations. The chapter further described methods of modelling power reticulation network equipment. The load flow simulation for CPUT reticulation was modelled and simulated based on the Newton-Raphson power flow method and the results were analysed.

The results obtained from this chapter are further used to build analysis in Chapter 5 for short circuit calculations on the reticulation network.

CHAPTER

5. INCOMER PROTECTION

5.1 INCOMER PROTECTION

Large currents on the electrical power distribution system are usually caused by short-circuit faults on the network. Such currents are used to determine whether there is a short-circuit fault on the system or not and to operate the designated protection Intelligent Electronic Devices (IEDs) and associated switchgear. The protection IEDs and switches can vary in design depending on the complexity and accuracy required. Common types of protective devices are thermo-magnetic switches, moulded-case circuit breakers, fuses and overcurrent relays of which the first two are mainly used in low-voltage networks. These have simple operating arrangements. Fuses are often used in protection of overhead lines and distribution transformers on low-voltage networks (Bango, 2011; Gers and Holmes, 2011). Basic overcurrent protective IEDs are suitable to protect the MV network in Figure 5.1 below.

Power system protection is an important aspect in designing and upgrading of electrical power systems. This chapter covers the modelling and analysis of the fault level and protection settings of the Cape Peninsula University of Technology (CPUT) Distribution Network using DIgSILENT software package. Different types of phase faults are applied and simulated at different locations, to analyse their effect and impact on the above mentioned systems as well as' the critical clearing times while maintaining the stability of the network. The IED settings, grading and co-ordination is carefully analysed and applied in order to protect the distribution feeders, busbars, transformers, conductors and insulators, as it is the objective that the faulted part should be isolated rapidly from the rest of the system so as to increase stability margin and therefore decrease damage to the equipment. This chapter therefore presents the details of the power systems configurations that were chosen, the simulation studies carried out as well as discussion of the simulation results obtained.

5.2 OVERCURRENT PROTECTION OF THE CPUT RETICULATION NETWORK

The CPUT reticulation network is composed of 14 interconnected substations. Protection of equipment against short-circuits and overcurrent is required across all substations in order to safeguard the equipment. These equipment fused switchgear or oil immense switchgear are generally applied to distribution systems downstream of main intake. New technology such as Sulphur Hexafluoride Six (SF_6) is extensively applied nowadays. These are accompanied by relays or Intelligent Electronic Devices (IEDs) for providing protection function and decision making of breaking excessive currents of the power system network. The complete single line diagram of the CPUT reticulation network is shown in Figure 5.1 below

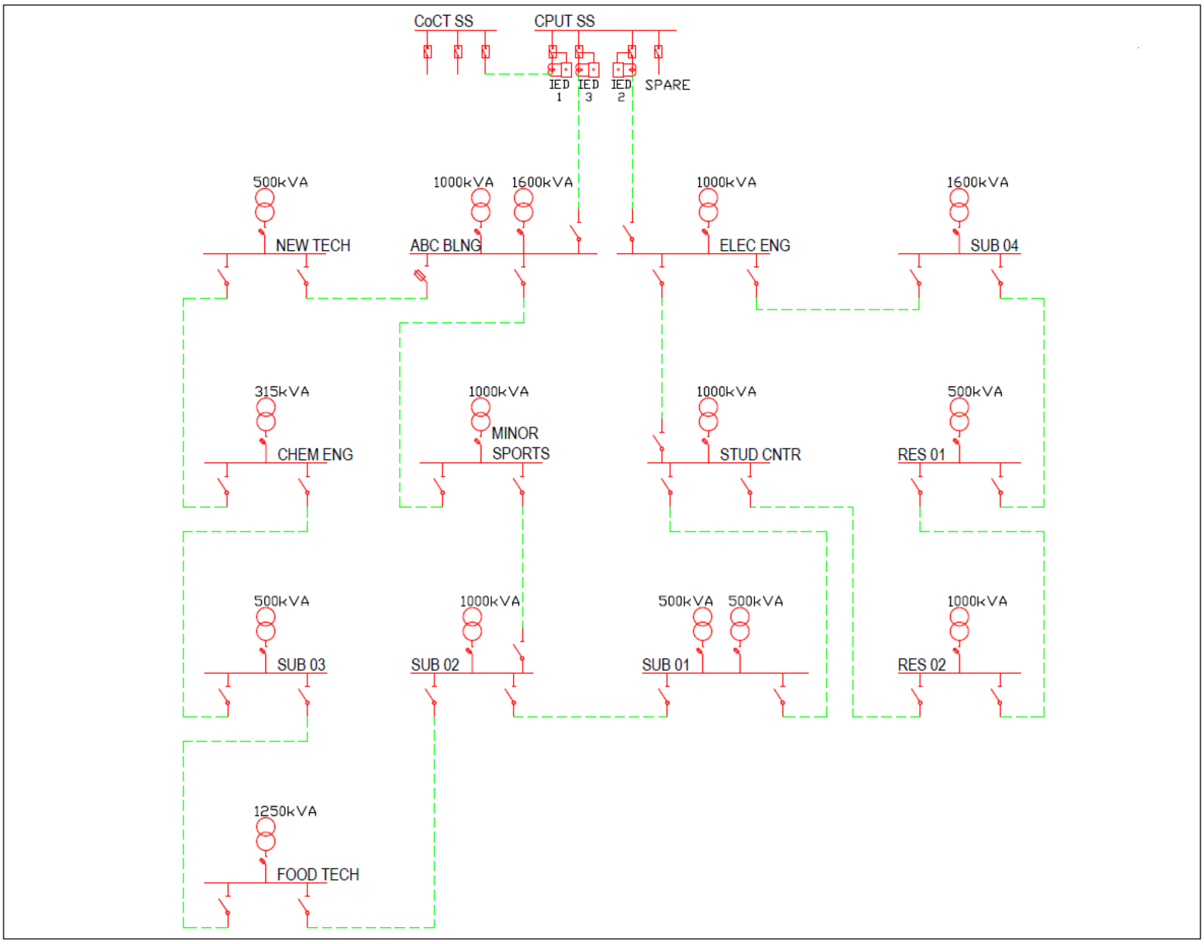


Figure 5.1: CPUT reticulation network diagram

Protective relays or IEDs are devices that permanently compare the electrical variables of networks such as current, voltage, frequency, power, and impedances with predetermined values, and then automatically emit orders for action, usually the opening of a circuit-breaker, or give off an alarm when the monitored value goes above the threshold (Prévé, 2006; Gers and Holmes, 2011). The role of protective relays is to detect any kind of abnormal phenomena that may arise in an electrical circuit, such as short-circuits, variation in voltage, machine faults, etc. Figure 5.2 shows a wiring diagram illustrating how the protection devices are connected to the circuit (line) being protected.

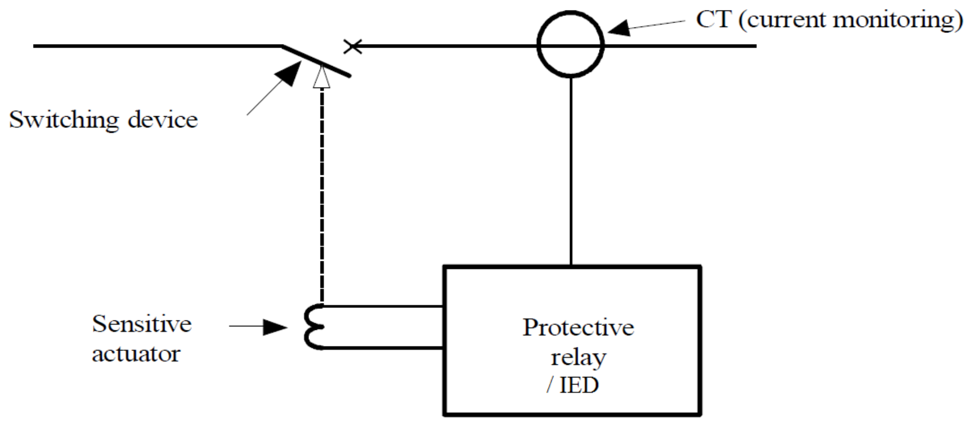


Figure 5.2: Connection of an overcurrent relay or IED

5.2.1 Phase Overcurrent Protection

Single-phase, two-phase, and three-phase overcurrent are detected by the phase overcurrent function of the protection device (ANSI code 50 or 51). Protection is activated when one, two, or three currents concerned rise above the specified setting threshold (Prévé, 2006). This protection can be time delayed and in this case will only be activated if the current monitored rises above the setting threshold for a period of time at least equal to the time delay selected. This delay can be an independent (definite) time or inverse time delay. More information is described in section 5.3 below.

5.2.2 Earth Fault Protection

The earth fault protection (ANSI code 50N, or 51N, 50G, or 51G) provides protection against earth faults whose protection is activated if the residual current rises above the setting threshold (Prévé, 2006). The residual current corresponds to current flowing through earth.

5.3 OVERCURRENT RELAYS CHARACTERISTICS

Overcurrent relays are most commonly employed to detect and treat the excessive currents on the electrical power system. The overcurrent relays protection is primarily employed to operate only under short-circuit fault conditions. The types of overcurrent relays applicable can be classified in three groups namely; definite or instantaneous current, definite time and inverse time. The behaviour and characteristics curves of these relays are described below (Gers and Holmes, 2011).

5.3.1 Definite-Current Relays

The definite current relay operates instantaneously when the current reaches a pre-defined magnitude. On a radial distribution network, the settings of a downstream substation relay are chosen such that the relay operates for low voltage current magnitude and the relay operating currents are progressively increased at each substation approaching the source. Thus, the relay lowest current setting operates first and disconnects the point nearest to the short-circuit fault (Gers and Holmes, 2011). Figure 5.3 illustrate the definite current characteristic curve.

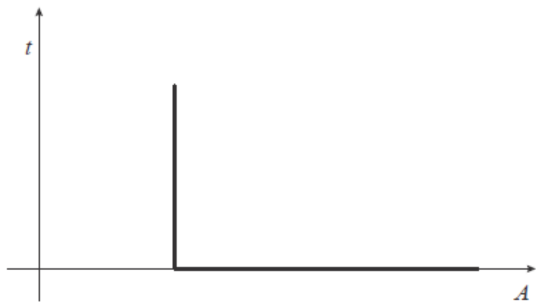


Figure 5.3: Definite (Instantaneous) Current Relay Characteristic Curve

5.3.2 Definite-Time Relays

The definite time relays enable various time settings to handle different current magnitudes. These settings can be arranged such that the breaker nearest to the short-circuit fault operate in the shortest time. The remaining breakers are tripped in succession using longer time delays moving towards the source. This difference between tripping times for the same current magnitude is called discrimination margin (Gers and Holmes, 2011). The illustrative diagram of the definite-time is shown in Figure 5.4 below.

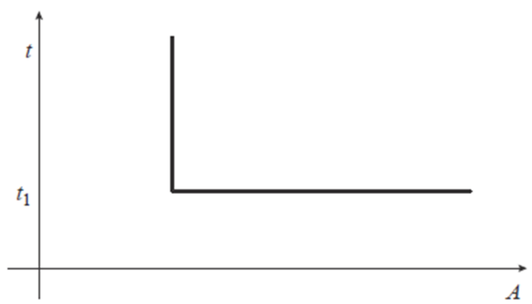


Figure 5.4: Definite Time Relay Characteristics Curve

5.3.3 Inverse-Time Relays

Inverse-time relays operate in a time that is inversely proportional to the short-circuit fault current. The advantage of inverse-time over definite time relays is that when very large short-circuit fault current are detected, the shorter tripping time can be achieved without the risk to protection for selectivity. The inverse-time relays are popularly referred to as inverse definite minimum time (IDMT) overcurrent relays. They are commonly defined in three categories being inverse, very inverse, and extremely inverse and are classified according to their characteristics curve that indicates the speed of operation (Gers and Holmes, 2011). Figure 5.5 shows the illustrative curves for (a) inverse-time which depends on a ratio between the current measured and the operating threshold and (b) inverse-time with instantaneous unit where if a specific large current is measured, the instantaneous function activates the protection device to isolate the circuit. For the inverse-time in (a), the higher the current the shorter the time delay

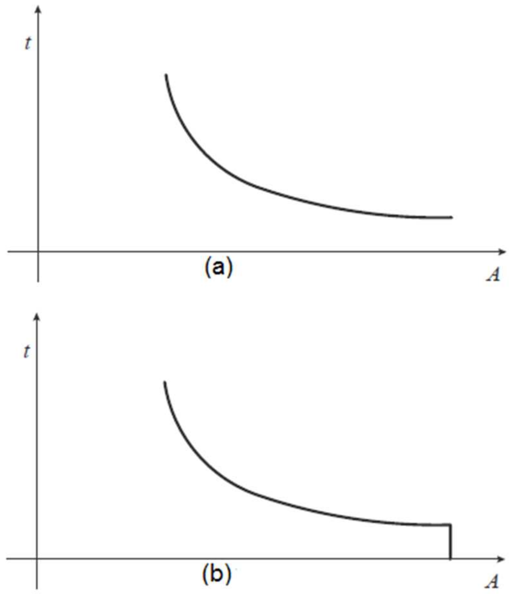


Figure 5.5: Relay characteristics curve for (a) Inverse-Time and (b) Inverse-Time with Instantaneous Unit (IDMT)

The Siemens multifunction protection relay with synchronization, SIPROTEC 7SJ64, was used to protect one of the two outgoing feeders at the CPUT main intake substation for the case of the DIgSILENT PowerFactory simulation. This relay was used too on the built test bench on one of the outgoing feeders in a Hardware-in-the-Loop (HIL) scheme using Real-Time Digital Simulator software RSCAD to model an internal RSCAD overcurrent relay for the second outgoing feeder from the protection library. The Siemens line differential protection SIPROTEC 7SD53 relay is used on the incomer feeder configured to function as an overcurrent protection device.

The time-overcurrent protection function for SIPROTEC 7SJ64 IED could be set for any of the ANSI 50, 50N, 51, 51V, and 51N three phase currents and earth fault currents measurements. Table 5.1 presents the protection functions of the considered relay. Three definite-time overcurrent protection elements (DMT) exist both for phase and earth faults and current threshold and delay time can be set in wide range. These could be set also in different stages as illustrated in Figure 5.6 below.

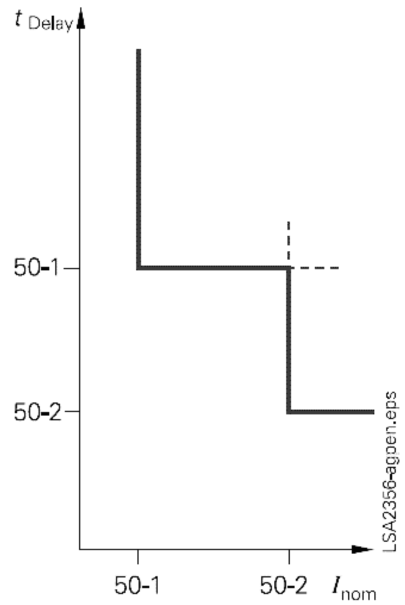


Figure 5.6: Definite-time overcurrent protection with multiple stages for Siemens 7SJ64

Table 5.1: Description of protection functions (Siemens, 2008)

ANSI No.	IEC	Protection function
50	I>, I>>, I>>>	Definite-time overcurrent protection (phase)
50N	I_E>, I_E>>, I_E>>>	Definite-time overcurrent protection (earth)
51	I_P	Inverse-time overcurrent protection (phase)
51N	I_{EP}	Inverse-time overcurrent protection (earth)

5.4 METHOD FOR PARAMETER SETTING OF THE OVERCURRENT RELAYS

Overcurrent relays are usually supplied with instantaneous element and time delay element all housed in the same unit case. Previously, the electromechanical relays used to be supplied with these elements in separate cases, however modern IEDs have three-phase overcurrent unit and earth fault unit contained within the same case. When setting an overcurrent relay, this involves the selection of required parameters that define time or current characteristics for both time-delay and instantaneous units. On the Siemens protection devices, this process has to be carried out twice with one for the phase currents operation and the other for earth fault operation. Although the two processes are similar, the three-phase short-circuit current should be used for setting the phase relays while the phase-to-earth fault current should be used for the earth-fault relays. The algorithm proposed in Figure 5.7 below illustrates the method used for setting the overcurrent relays for the CPUT reticulation network.

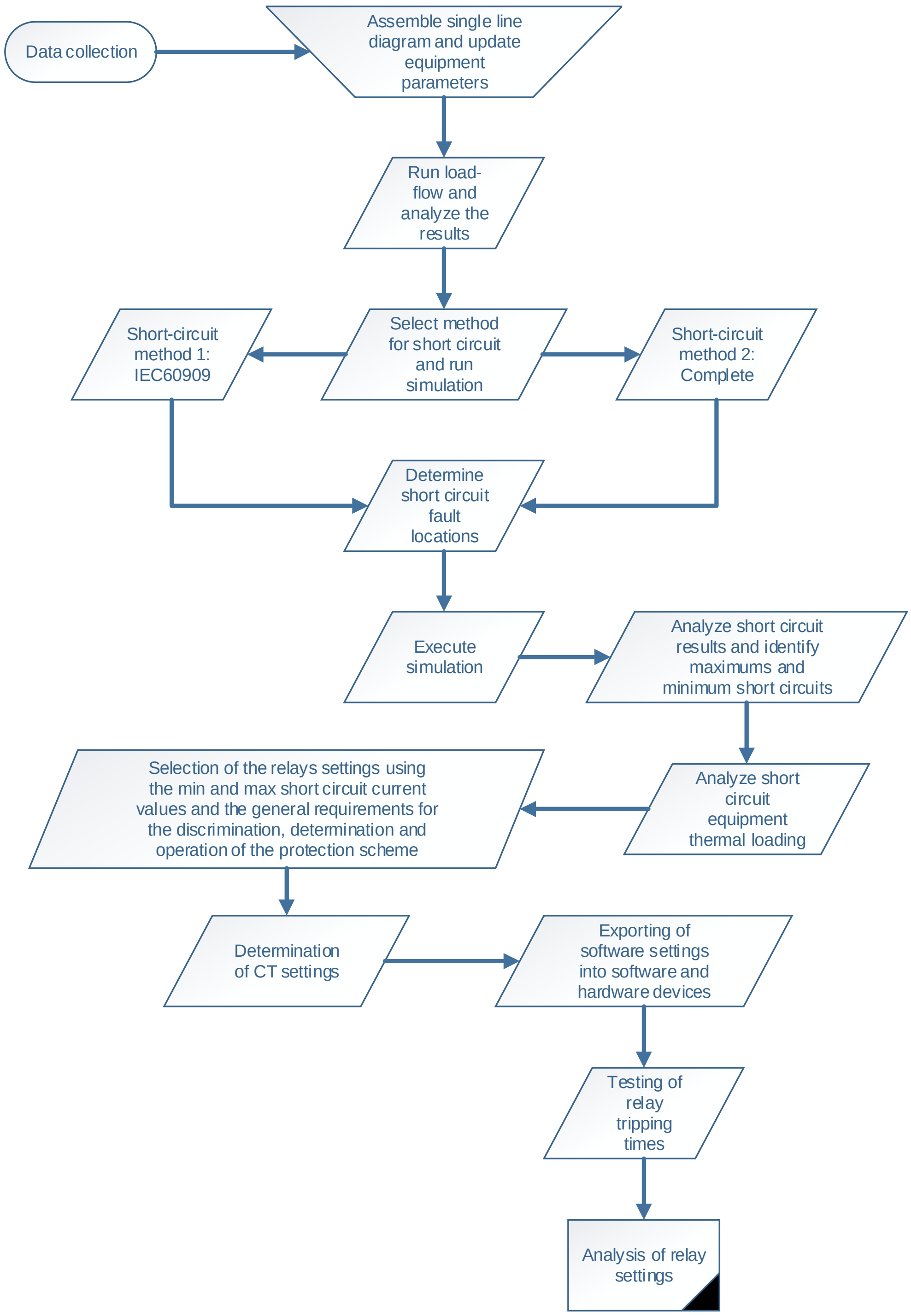


Figure 5.7: Block diagram of the method for design of the protection relays settings

5.5 CPUT RETICULATION NETWORK LAYOUT

The initial network study conducted is load flow to determine power loading and the capacity of existing equipment and requirements for any size upgrades. Data has been collected from the network maintenance department and photographic walk around at each substation has been completed. All cables types and sizes, transformers, and loads are modelled on the DIgSILENT simulation package. All transformers are two winding, Dyn11 type, 11/0.4 kV. Underground cables for networks are modelled with parameter of Paper Insulated Lead Conductor (PILC) of which only two sizes were utilized in the network namely 70mm2 and 120mm2. Length of each cable is measured via AutoCAD design package and these are modelled as approximate measurements. Parameters of these cables are as defined on Aberdare cable manufacturer's properties. The 3-way incomer switchgear with incomer feeder and two outgoing feeders is modelled with an IED protective device at each feeder. The layout arrangement of the CPUT network is as shown in Figure 5.1 above. Modelling and simulation of the load flow has been described in detail in Chapter 4 section 4.4.

5.6 STRUCTURE OF THE CPUT INCOMER SUBSTATION OVERCURRENT PROTECTION SCHEME

Chapter 4 provides the full description of the CPUT reticulation network (Refer to section 4.4). For the network in Figure 5.8, overcurrent protection scheme in the DIgSILENT software environment and the characteristics curves in Figure 5.3 were used to simulate this scheme. Three overcurrent relays were used for the short-circuit faults, which would be seen at the CPUT incomer busbar as shown in Figure 5.8. One relay is on the incoming feeder of the busbar while the remaining two are located on the outgoing feeders towards ABC and EE buildings respectively.

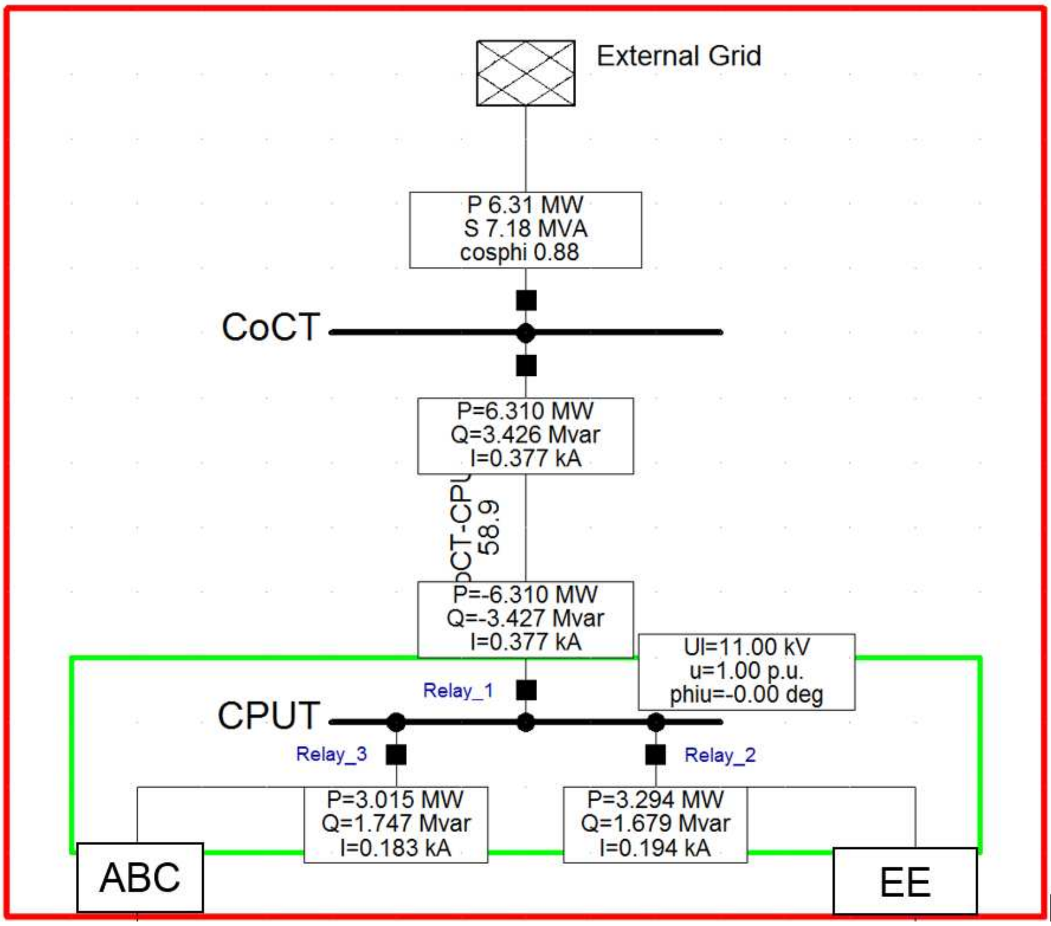


Figure 5.8: Loading profile of the CPUT incomer substation

The SIPROTEC 7SJ80 IED was used on CPUT intake substation to protect the incoming and outgoing feeders. Its time-overcurrent protection functions (ANSI 50, 50N, 51 & 51N) are based on phase selective measurement of the three phase currents and ground currents. Three definite-time overcurrent protection elements (DMT) are available both for phase and the ground current elements. The current threshold and delay time threshold can be set in a wide range. The inverse-time overcurrent protection characteristics (IDMT) can also be selected and activated.

5.7 LOAD FLOW SIMULATION RESULT FOR CPUT NETWORK

Solutions for power system load flow were computed with DIgSILENT and the results are shown in Table 5.2 below. These results provided a summary of maximum apparent, real and reactive powers which were used to configure current transformer burden. From the Table 5.2 below, a total power consumption of 5.96 MW is measured at the main intake feeder while total loads consumption is measured at 5.87 MW. The difference of 90 kW is consumed as power losses by power reticulation equipment such as lines and transformers. Similarly, the reactive power of 3.25 MVar is measured at the intake while 3.12 MVar and 0.13 MVar are conumed at the loads and equipment losses respectively. A complete set of power flow results could be used to analyse steady state conditions of the power system network.

Table 5.2: Power flow result summary

```
-----------------------------------------------------------------------------------------------------------------------------------
| Load Flow Calculation                                                                                      Total System Summary |
-----------------------------------------------------------------------------------------------------------------------------------
|     AC Load Flow, balanced, positive sequence          |   Automatic Model Adaptation for Convergence            No       |
|     Automatic Tap Adjust of Transformers          No    |   Max. Acceptable Load Flow Error for                            |
|     Consider Reactive Power Limits                No    |      Nodes                                             1.00 kVA  |
|                                                        |      Model Equations                                   0.10 %    |
-----------------------------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------------------------
| Total System Summary                                   | Study Case: Study Case                | Annex:                   / 1 |
-----------------------------------------------------------------------------------------------------------------------------------
|                                                                                                                                 |
| No. of Substations    0         No. of Busbars      30        No. of Terminals     0         No. of Lines         17           |
| No. of 2-w Trfs.      15        No. of 3-w Trfs.    0         No. of syn. Machines 0         No. of asyn.Machines 0            |
| No. of Loads          15        No. of Shunts       0         No. of SVS           0                                           |
|                                                                                                                                 |
| Generation            =       0.00  MW          0.00   Mvar        0.00  MVA                                                  |
| External Infeed       =       5.96  MW          3.25   Mvar        6.79  MVA                                                  |
| Load P(U)             =       5.87  MW          3.12   Mvar        6.64  MVA                                                  |
| Load P(Un)            =       5.87  MW          3.12   Mvar        6.64  MVA                                                  |
| Load P(Un-U)          =       0.00  MW          0.00   Mvar                                                                     |
| Motor Load            =       0.00  MW          0.00   Mvar        0.00  MVA                                                  |
| Grid Losses           =       0.09  MW          0.13   Mvar                                                                     |
| Line Charging         =                        -0.06   Mvar                                                                     |
| Compensation ind.     =                         0.00   Mvar                                                                     |
| Compensation cap.     =                         0.00   Mvar                                                                     |
|                                                                                                                                 |
| Installed Capacity    =       0.00  MW                                                                                          |
| Spinning Reserve      =       0.00  MW                                                                                          |
|                                                                                                                                 |
| Total Power Factor:                                                                                                             |
|   Generation          =         0.00  [-]                                                                                       |
|   Load/Motor          =  0.88 / 0.00  [-]                                                                                       |
|---------------------------------------------------------------------------------------------------------------------------------|
```

5.8 SHORT-CIRCUIT CALCULATIONS FOR DETERMINATION OF THE PROTECTIVE RELAYS SETTINGS

The short-circuit fault currents and tripping time at various points on the network has been established and simulated. Discrimination has been achieved by overcurrent, time and by a combination of both overcurrent and time. Since discrimination by current relies upon the fact that the short-circuit fault current varies with the position of the fault, this variation is due to the impedance of various equipment of the network such as cables and transformers between the source and the short-circuit fault.

The selection of current transformers and protection calculation are performed based on the load flow results. The ideal CT ratio is chosen to give low working current on the IEDs. In order to obtain correct discrimination, it is necessary to have a correct time interval between two series IEDs. This time interval also called grading margin is obtained and the factors that influences this margin is determined. These factors include the circuit breaker interrupting time, relay overshoot time, errors and safety margin. Any fault on the system irrespective of the location can be cleared within a minimum period as correct discrimination and grading margin is used. Overcurrent protection and the grading of downstream versus upstream protection was part of the modelling process.

Beside load flow calculation, short-circuit is one of the most frequently performed calculation when dealing with electrical networks. This is used both in system planning and design, and system operation (DIgSILENT, 2013). Generally a power system network is treated as a balanced system until a time when a single-phase short-circuit fault occurs on the system. A single-phase short-circuit fault creates an unbalance on the system due to that the remaining two phases are not subjected to the same short-circuit fault. The exception is the three-phase short-circuit fault which is considered balanced due to the fact that all phases are subjected to the same short-circuit fault at the same point (Alstom Grid, 2011).

Short circuit calculation is performed for the purpose of:

- Ensuring that the defined short-circuit capacity of the equipment is not exceeded with system design, expansion and system strengthening.
- Co-ordination of protective equipment such as fuses, over-current and distance relays.
- Verification of sufficient short-circuit fault level capacities at load points (e.g. uneven loads such as arc furnaces, thyristor-driven variable speed drives or dispersed generation).
- Verification of admissible thermal limits of cables and transmission lines.

Application of short-circuit analysis in system operation may include:

- Ensuring that short-circuit limits are not exceeded with system reconfiguration.
- Determining protective relay settings as well as fuse sizing.

5.8.1 Short Circuit Faults Types

The short-circuit currents calculations are useful for correctly rating the new switchgear and other power system equipment of the network during planning stage. For this, the maximum and minimum expected short circuit currents are the most important ones for the design of the protection schemes (Mnguni, 2014). In practical cases, the supply authority shall provide the consumer with the short-circuit fault levels at the point of connection upon request in order to grade properly the downstream short-circuit fault levels. At times if one knows the transformer supplying the customer, the short-circuit fault current may be calculated based on the transformer size and impedance levels. The short-circuit current at the customer point of connection will be determined after considering the length and impedance of the supply cable. For CPUT, the short-circuit current provided by supply authority is 21 kA at the point of connection. This yields to short-circuit power of 400 MVA which is automatically determined on DIgSILENT simulation package. For this case, only one parameter between short-circuit-power Sk"max and short-circuit-current Ik"max is required as input on the External Grid (refer to Figure 5.7 and 5.8 single line diagrams) input data as shown in Figure 5.9.

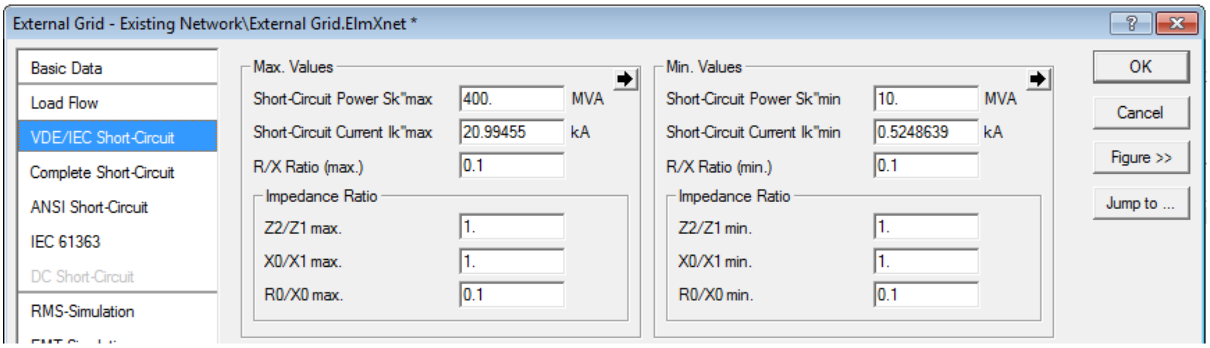


Figure 5.9: Incomer short-circuit parameters

Similarly by first principle, the method of calculating short circuit current at the main CPUT intake substation is:

$$I_f = \frac{S}{\sqrt{3} \times V_L \times C_{factor}} \tag{5.1}$$

Where:

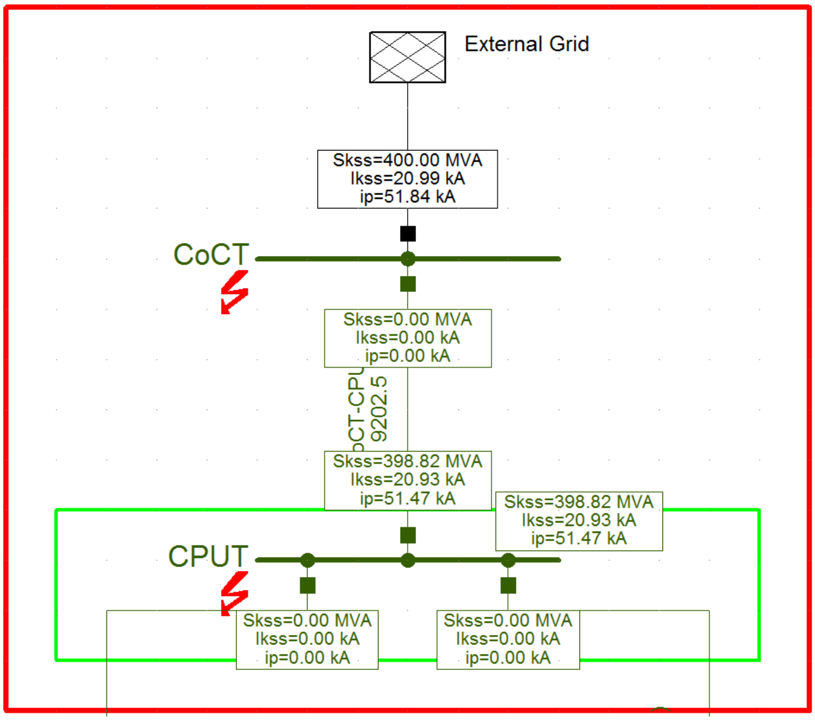
I_f – fault current in kA

V_L – line-line voltage

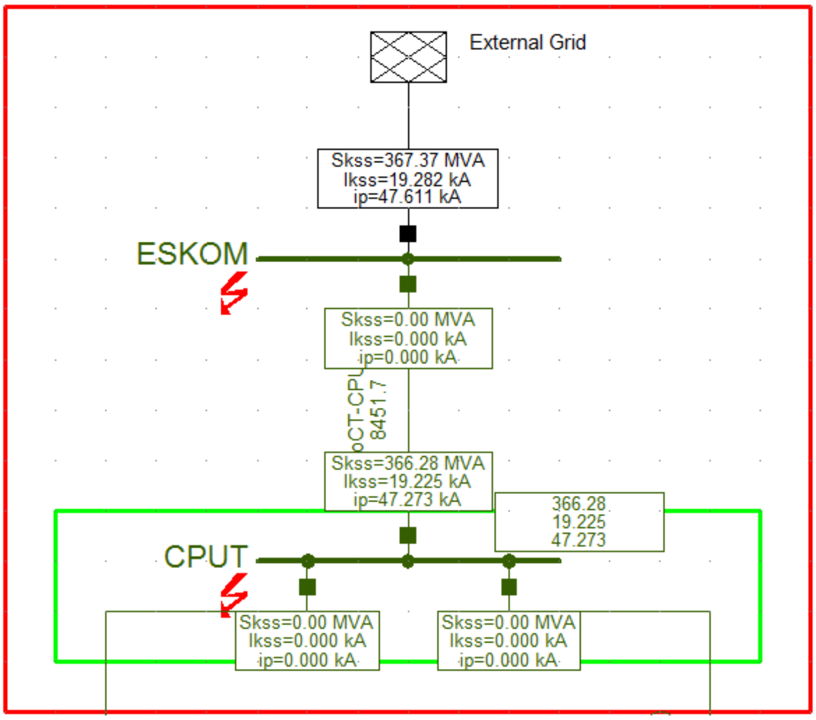
C_{factor} – maximum voltage correction factor of which C_{factor} = 1.1 is used for complete method and C_{factor} = 1.0 for IEC60909 method.

The *IEC60909* method is used primarily for design and planning stages of the network while the *Complete* method is used for operation and maintenance stages of the network. Both these methods were applied in DIgSILENT and the results are highlighted in Table 5.3 and Table 5.4 respectively.

After completing a three phase short-circuit calculation across all substations using *IEC60909* and *Complete* method, the results in Figure 5.10 below were produced.



(a)



(b)

Figure 5.10: Intake three-phase short-circuit calculations using (a) IEC60909 and (b) Complete methods

At CPUT intake substation a maximum short-circuit power of 398.82 MVA, initial symmetrical short-circuit r.m.s current of 20.99 kA and peak short-circuit instantaneous r.m.s current of 51.84 kA are recorded from the software based on the *IEC60909* method as shown in Figure 5.10 (a). Additionally, a maximum short-circuit power of 366 .28 MVA, initial symmetrical short-circuit r.m.s current of 19.225 kA and peak short-circuit instantaneous r.m.s current of 47.273 kA are recorded from the software calculated using the *Complete* method as shown in Figure 5.10 (b).

5.8.2 Calculation of the Thermal loading profile

The corresponding short circuit thermal loading diagram colour legend is shown in Figure 5.11 below. The complete short-circuit thermal loading profile and short-circuit calculation results are given below in Figure 5.12.

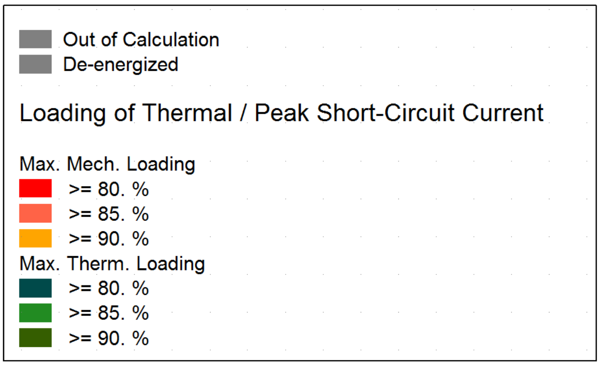


Figure 5.11: Short-circuit thermal loading profile legend

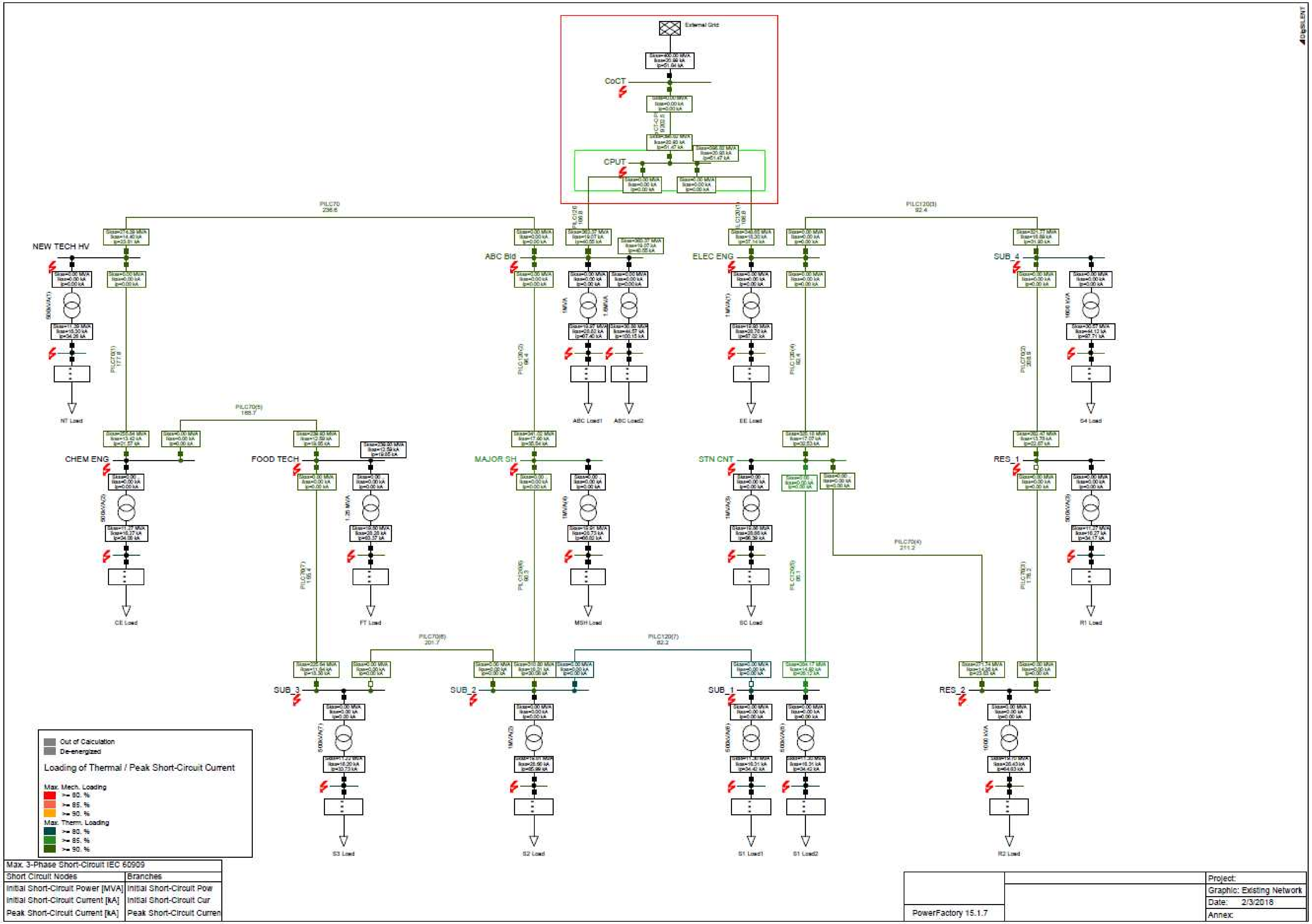


Figure 5.12: Short-circuit calculation for CPUT reticulation network including thermal loading

5.8.3 Determination of maximum and minimum short circuit currents

For correct application of protection equipment, it is important to know the magnitudes of short-circuit fault at all parts of the distribution network being maximum and minimum and to effectively apply current grading where necessary. For these maximum and minimum short-circuit fault levels to be known, the generation limits, and possible operating conditions and earthing conditions shall be known. In general, short-circuit faults are always assumed to be flowing through zero fault impedance (Alstom Grid, 2011).

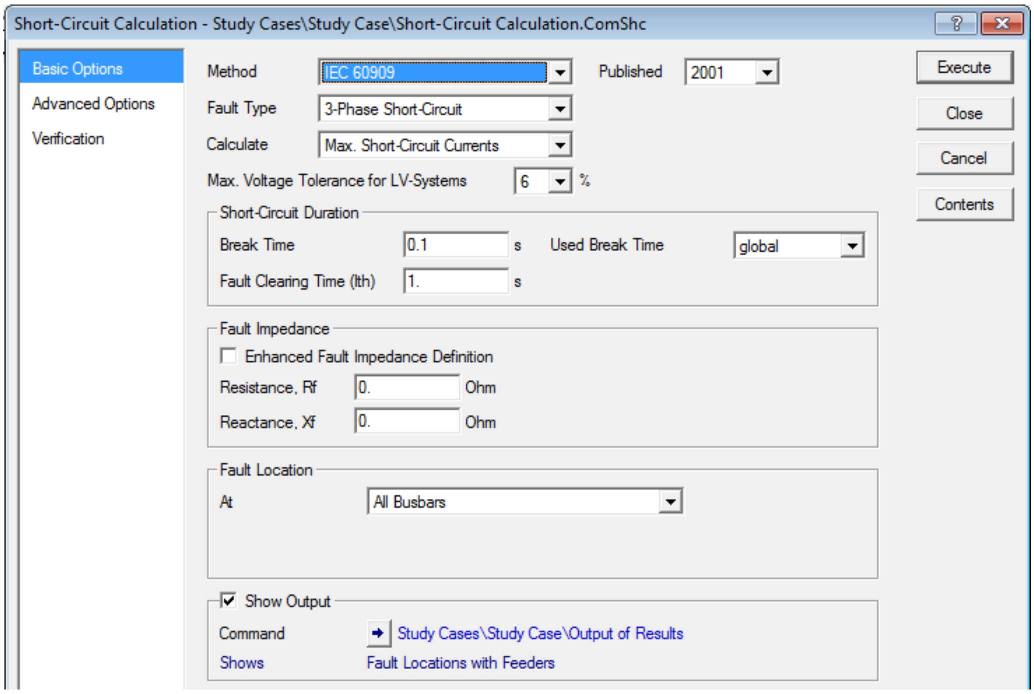


Figure 5.13: Short-circuit calculation in DIgSILENT using IEC60909 method

Table 5.3 shows the calculated short-circuit power and current across various CPUT substations which were calculated using IEC60909 method with break-time of 0.1s and fault clearing time of 1s as shown in Figure 5.13 above. The short-circuit calculation results accuracy could determine whether there are similarities between the symmetrical short-circuit currents with that of the thermal equivalent currents (DIgSILENT, 2013). Table 5.4 provides this little differences with intake fault of 20.99 kA and thermal equivalent of 21.35 kA. The difference in fault level is 0.36 kA which cannot be considered as a high current in fault level magnitudes. The second method of calculation is the complete method with the same parameters as used with IEC60909 method.

Table 5.3: Substation three-phase short-circuit results based on "IEC60909" method

Substation	Rated Voltage	Maximum Short-Circuit Power	Symmetrical Short-Circuit Ik"	Peak Short-Circuit ip	Thermal Equivalent Ith
	[kV]	[MVA/MVA]	[kA/kA]	[kA/kA]	[kA]
CoCT	11	400	20.99	51.84	21.35
CPUT	11	398.82	20.93	51.47	21.28
ABC	11	363.37	19.07	40.55	19.21
ELEC ENG	11	348.65	18.3	37.14	18.41
MINOR SH	11	341.02	17.9	35.54	18
STN CNT	11	325.18	17.07	32.53	17.15
SUB_4	11	321.77	16.89	31.93	16.97
SUB_2	11	310.8	16.31	30.08	16.38
SUB_1	11	284.17	14.92	26.12	14.97
NEW TECH	11	274.29	14.4	23.81	14.44
RES_2	11	271.74	14.26	23.83	14.3
RES_1	11	262.47	13.78	22.67	13.81
CHEM ENG	11	255.64	13.42	21.57	13.45
FOOD TECH	11	239.93	12.59	19.85	12.62
SUB_3	11	225.64	11.84	18.38	11.87

Table 5.4: Substation three-phase short-circuit results based on "Complete" method

Substation	Rated Voltage	Maximum Short-Circuit Power	Symmetrical Short-Circuit Ik"	Peak Short-Circuit ip	Thermal Equivalent Ith
	[kV]	[MVA/MVA]	[kA/kA]	[kA/kA]	[kA]
CoCT	11	367.50	19.29	47.63	19.62
CPUT	11	366.42	19.23	47.29	19.55
ABC	11	333.25	17.49	37.19	17.62
ELEC ENG	11	319.64	16.78	34.05	16.88
MINOR SH	11	312.33	16.39	32.55	16.48
STN CNT	11	297.70	15.63	29.78	15.70
SUB_4	11	294.57	15.46	29.23	15.53
SUB_2	11	284.13	14.91	27.50	14.98
SUB_1	11	259.50	13.62	23.85	13.67
NEW TECH	11	250.24	13.13	21.72	13.17
RES_2	11	247.84	13.01	21.73	13.05
RES_1	11	239.32	12.56	20.68	12.60
CHEM ENG	11	233.04	12.23	19.67	12.26
FOOD TECH	11	218.57	11.47	18.08	11.50
SUB_3	11	205.43	10.78	16.73	10.81

5.8.4 Setting of Intelligent Electronic Devices (IEDs)

Overcurrent protection is directed primarily to clear fault currents on the system and may secondarily include settings adopted to address overload protection.

The overcurrent relay application requires knowledge of short-circuit faults occurring on all parts of the system which are to be protected. The data required for relay settings study are but not limited to (Alstom Grid, 2011):

- Single-line diagram of the power system network
- Type and ratings of the protective devices and associated current transformers
- Maximum and minimum short-circuit currents
- Maximum load currents
- Starting current for any machines connected to the network

The relay settings are determined to clear maximum short-circuit currents within shortest time and also see if the minimum short-circuit currents could be cleared within satisfactory time.

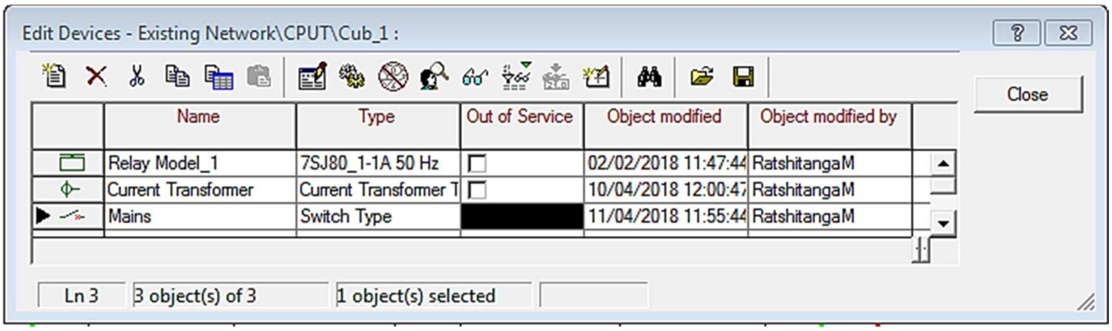
5.8.5 Current Transformer Settings

For one incoming and two outgoing relays, there should be parameters defined for the relays to trip during short-circuit fault conditions. Each relay must have a corresponding instrument transformers such as current transformer (CT). The transformer ratios must be defined based on standard selections such as 100:1 or 100:5, 200:1 or 200:5, 400:1 or 400:5 etc.

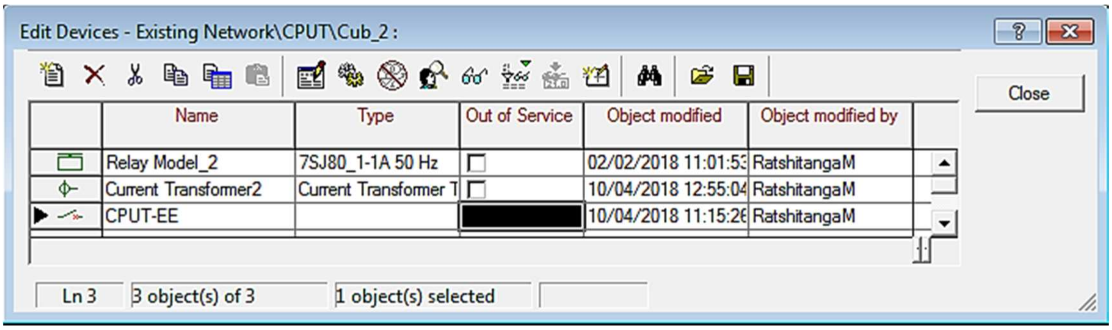
Due to the network maximum short-circuit fault of 20.93 kA (IEC60909) and 19.23 kA (Complete), the CT is then chosen to be 2000:1 which will limit the working current of 10.465 A and 9.615 A respectively.

These magnitudes are obtained by dividing the fault current level by the CT ratio, e.g. $20\,930/2000 = 10.465\ A\ and\ \ 19\,230/2000 = 9.615\ A$. Therefore, on the event where the fault current on the CPUT substation is 20.93 kA, the CT will only experience (measure) a current of 10.465 A which may illustrate a better working current for equipment and personnel.

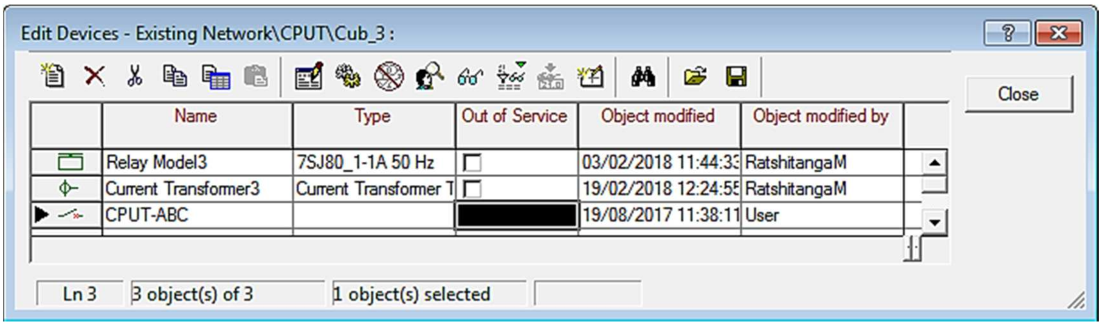
Figure 5.14 shows the location of each device at the CPUT incomer substation on the DIgSILENT software.



(a) Relay 1



(b) Relay 2



(c) Relay 3

Figure 5.14: Protection devices at the incomer busbar (a) Incomer feeder, (b) outgoing feeder to EE, and (c) outgoing feeder to ABC

The full load demand of the reticulation network is obtained during the calculation of the load flow. This is required to determine the CT burden parameters. An example of the calculated load flow is shown again in Figure 5.15 below.

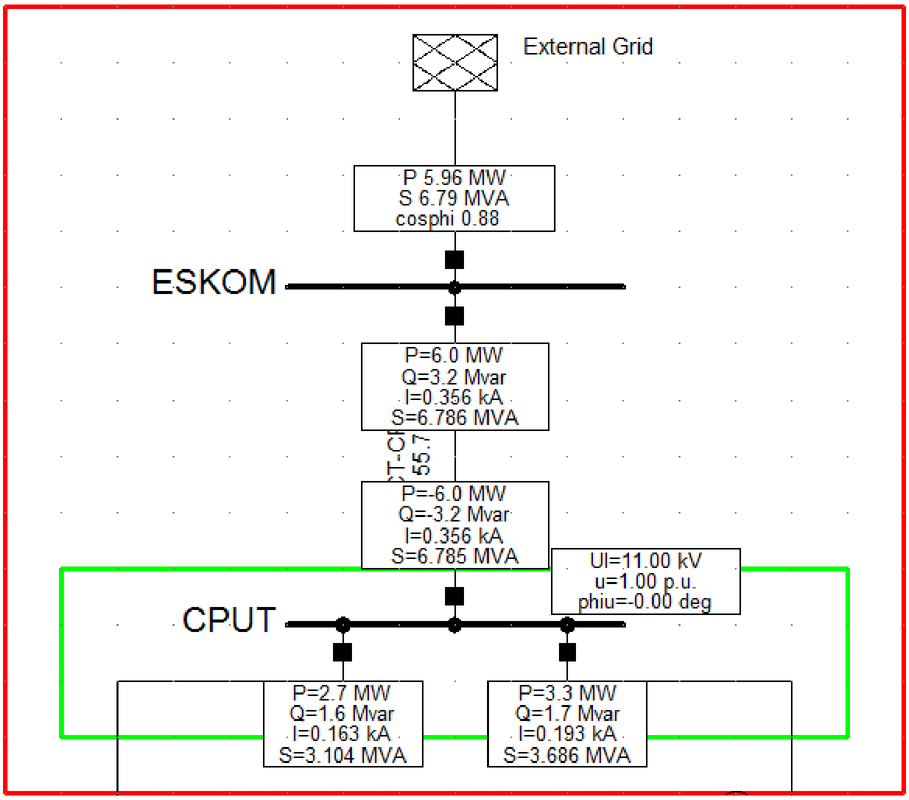
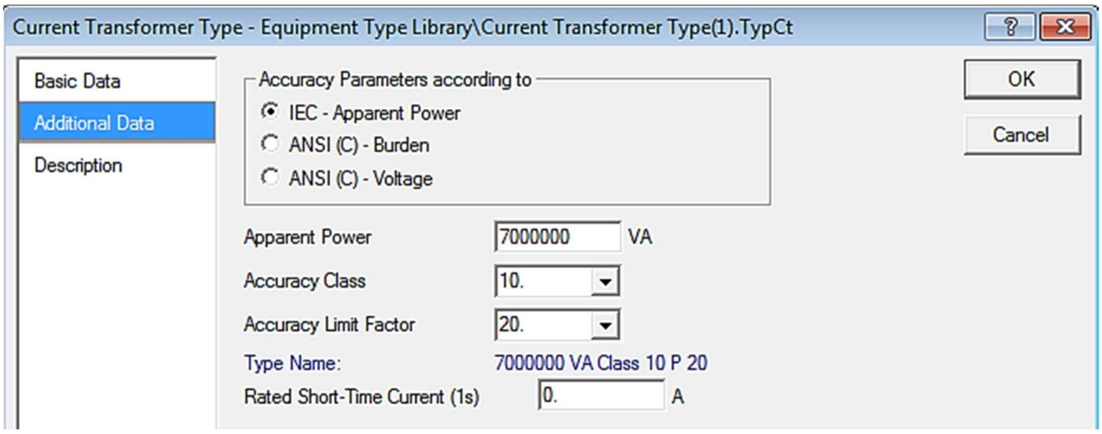
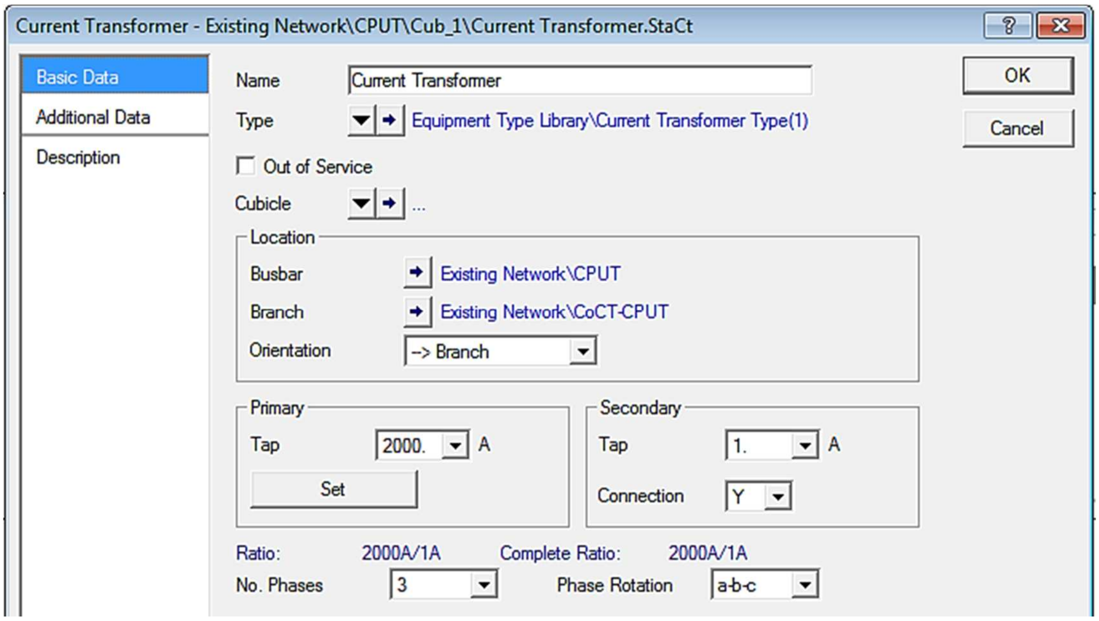


Figure 5.15: CPUT Incomer substation maximum expected full load demand

CT parameters could be configured based on information stated in the paragraph above, the methods illustrated at the beginning of section 5.8.5 and also analysis of results in Figure 5.15 above in order to determine the CT burden. All CTs should be configured for the relays to operate correctly. Based on the simulated results in Figure 5.15, the maximum apparent power of 6.786 MVA allows the burden of 7 MVA to be used for CT1. The apparent powers of 3.686 MVA and 3.104 MVA allows the use of 4 MVA and 3.5 MVA for CT2 and CT3 respectively. Configuration settings for the CT 1 for Relay 1 are as shown in Figure 5.16 below repeated for each CT based on the method stated in this paragraph.



(a)



(b)

Figure 5.16: CT configuration parameters (a) burden input and (b) basic data input

5.8.6 Relay Settings Determination

Among various methods used to reach correct relay grading are those in definite or time or a combination of both which are employed to give the correct co-ordination between the relays.

Discrimination by time ensures that the relays operating the circuit breaker nearest to the short-circuit fault shall open first. Discrimination by current relies on the fact that the short-circuit fault currents may vary with respect to position on the power system network due to difference in impedances between the short-circuit fault and the source. Both these methods have disadvantages when implemented alone on the relays. Discrimination by time alone result in more severe short-circuit faults being cleared in longest operating time, while discrimination by current can be applied only where there is applicable impedance between any two circuit breakers of concern (Alstom Grid, 2011).

The relay elements which are chosen or selected on the DIgSILENT software for the simulation are definite time 50 and 51N of which only stage 1 has been utilised (meaning no backup as stage 2 is considered as backup to stage 1).

In Figure 5.17 below for a phase short-circuit fault of 19.23 kA the expected current on the CT is 9.615 A and for ground short-circuit fault of 19.17 kA the expected current on the CT is 9.585 A.

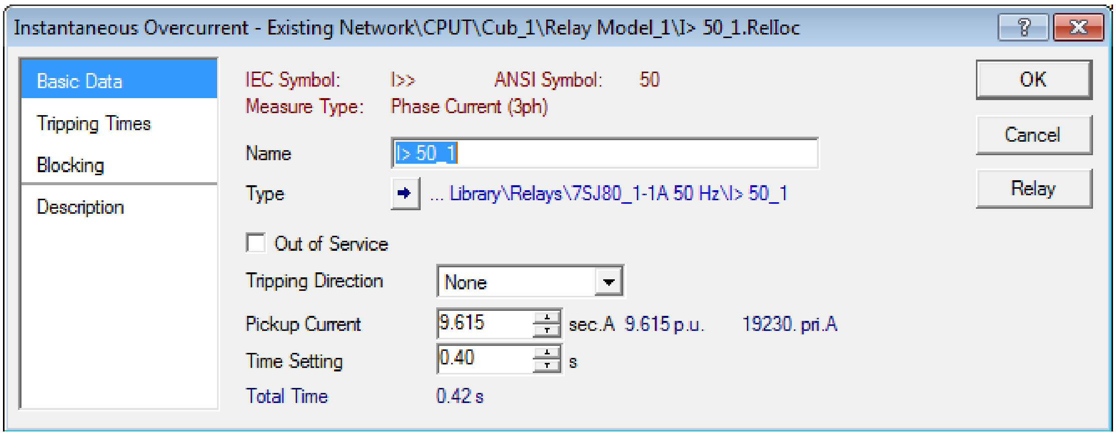


Figure 5.17: (a) Relay 1 definite current pick up settings (stage 1)

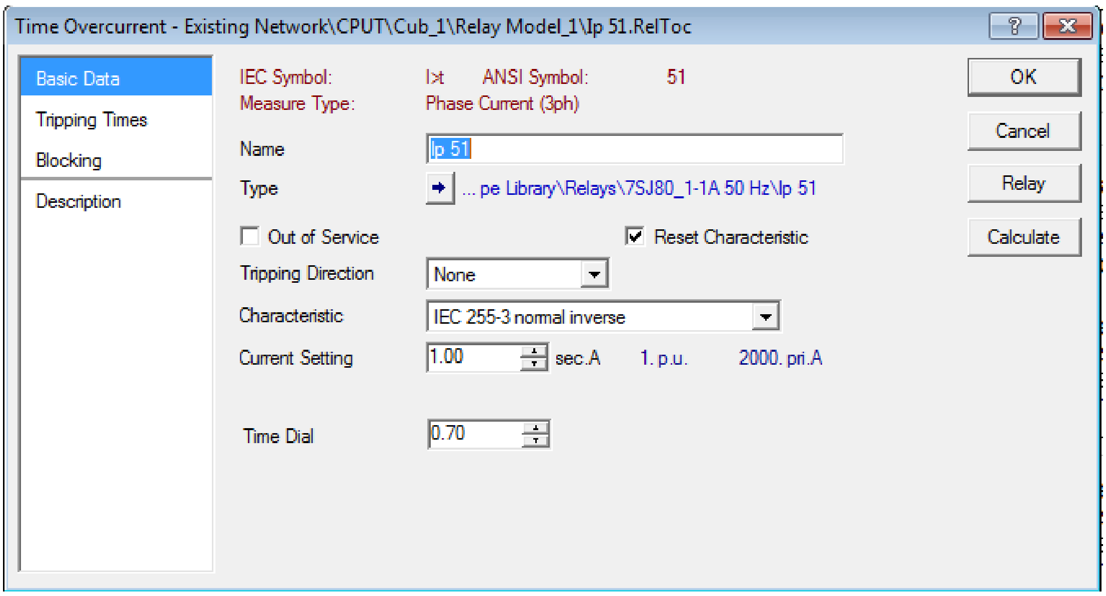


Figure 5.18: Relay 1 time overcurrent pick up settings inverse

Relay 2 will experience a minimum phase short-circuit fault from reticulation substation “Res 1” (refer to single line diagram in Figure 5.1 and Figure 5.19) which are 12.56 kA and ground short-circuit fault of 11.87 kA with their respective pick-up currents at 6.28 A and 5.935 A respectively.

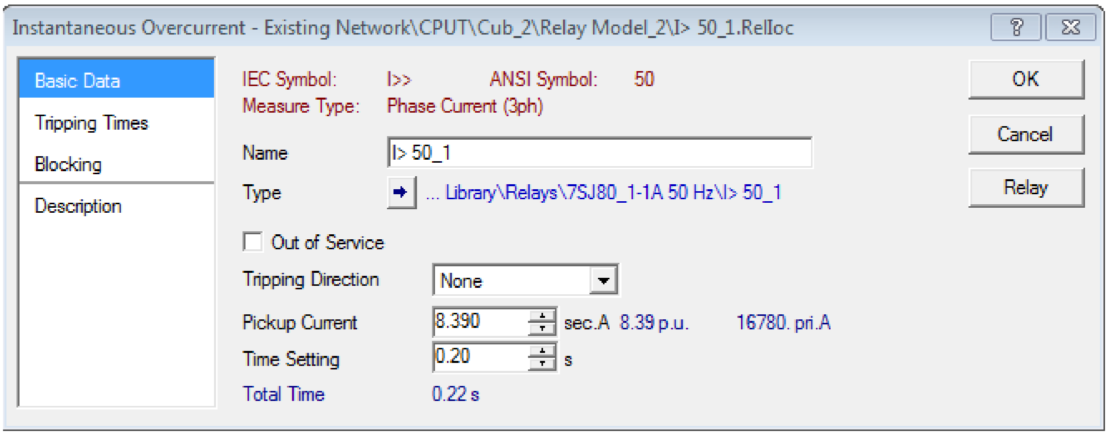


Figure 5.19: Relay 2 pickup settings for phase short-circuit faults

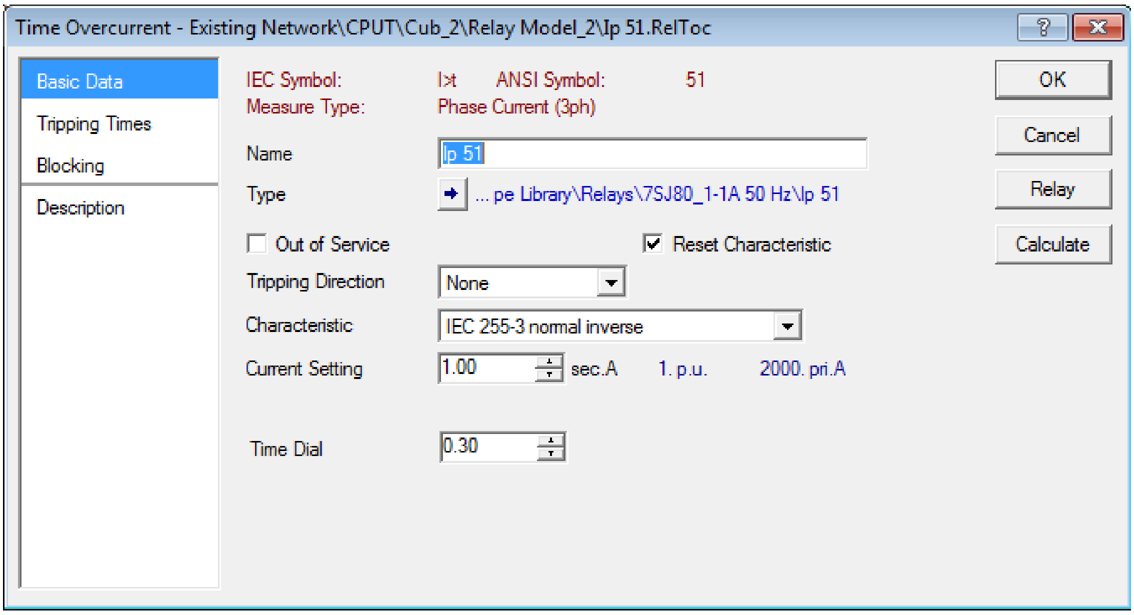


Figure 5.20: Relay 2 pickup settings for phase inverse

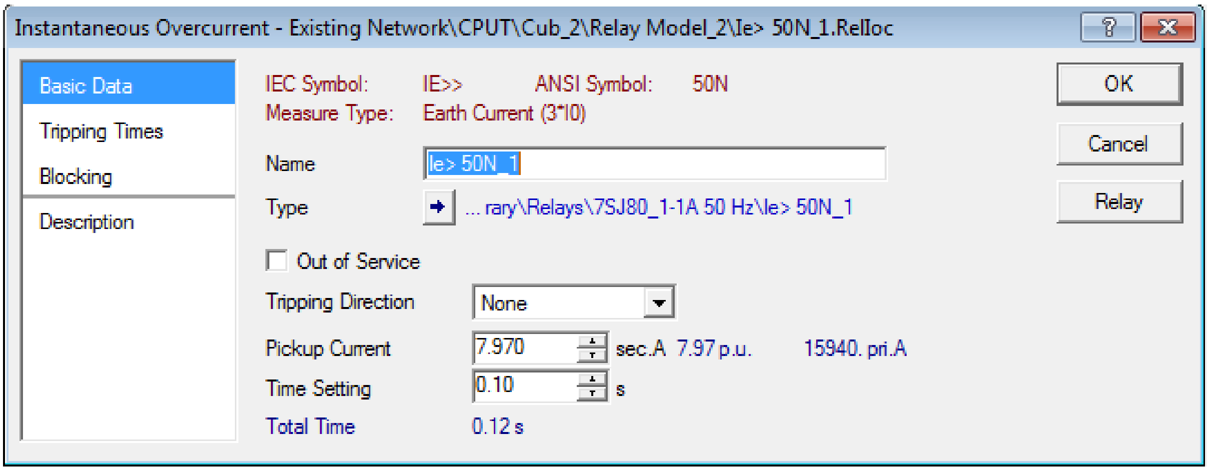


Figure 5.21: Relay 2 pickup settings for ground short-circuit faults

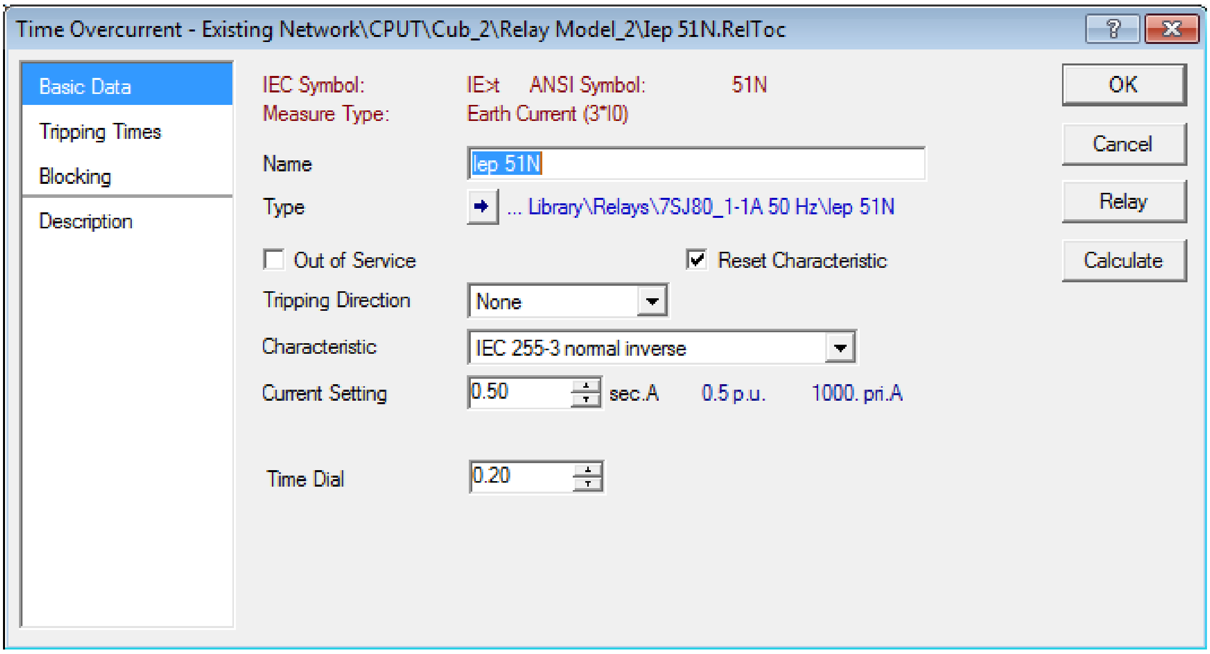


Figure 5.22: Relay 2 pickup settings for ground inverse

Relay 3 settings are applied similar to Relay 2 as shown in Figure 5.19 – 5.22 above. Relay 3 will experience a minimum phase short-circuit fault from “Sub 3” (refer to single line diagram in Figure 5.1) which is 10.78 kA and ground short-circuit fault of 10.32 kA with respective currents at 5.39 A and 5.16 A respectively.

5.8.6.1 Settings for grading times

Time interval (grading margin) between subsequent relays must be allowed to obtain correct discrimination between the relays. In the instance where the relays are not properly graded or grading is insufficient, more than one relay may operate for the same short-circuit fault which may complicate the identification of the short-circuit fault location and unnecessary loss of supply to unaffected consumers (Alstom Grid, 2011). The grading margins depend on the following factors:

- Fault interrupting time of circuit breakers
- Relay timing errors (technology dependant)
- Relay overshoot time (technology dependant)
- CT errors
- Final margin on completion operation.

The grading times are calculated using DIgSILENT during the EMT simulations. The table below shows typical timing errors at different technologies.

Table 5.5: Typical relay timing errors - standard IDMT relays (Alstom Grid, 2011)

	Electro-mechanical	**Static**	**Digital**	**Numerical**
Typical basic timing error (%)	7.5	5	5	5
Overshoot time (s)	0.05	0.03	0.02	0.02
Safety margin (s)	0.1	0.05	0.03	0.03
Typical overall grading margin – relay to relay (s)	0.4	0.35	0.3	0.3

The table above could be used as calculating grading times for relays could be tedious when performing protection grading of a power system. However one may calculate these grading times as follows:

$$t' = \left[\frac{2E_R + E_{CT}}{100}\right] t + t_{CB} + t_0 + t_S \qquad (seconds) \tag{5.2}$$

Where:

t' – grading time interval

E_R – relay timing error (IEC60225-4)

E_{CT} – allowance for CT ratio error (%)

t – Nominal operating time for relay nearer to fault (s)

t_{CB} – Circuit breaker interrupting time (s)

t_0 – relay overshoot time (s)

t_S – Safety margin (s)

5.9 TESTING OF THE PERFORMANCE OF THE OVERCURRENT PROTECTION SCHEME

The overcurrent protection scheme was selected for the protection of the CPUT incomer substation. The overall process flow chart of the proposed algorithm for overcurrent protection scheme operation is as shown in Figure 5.23.

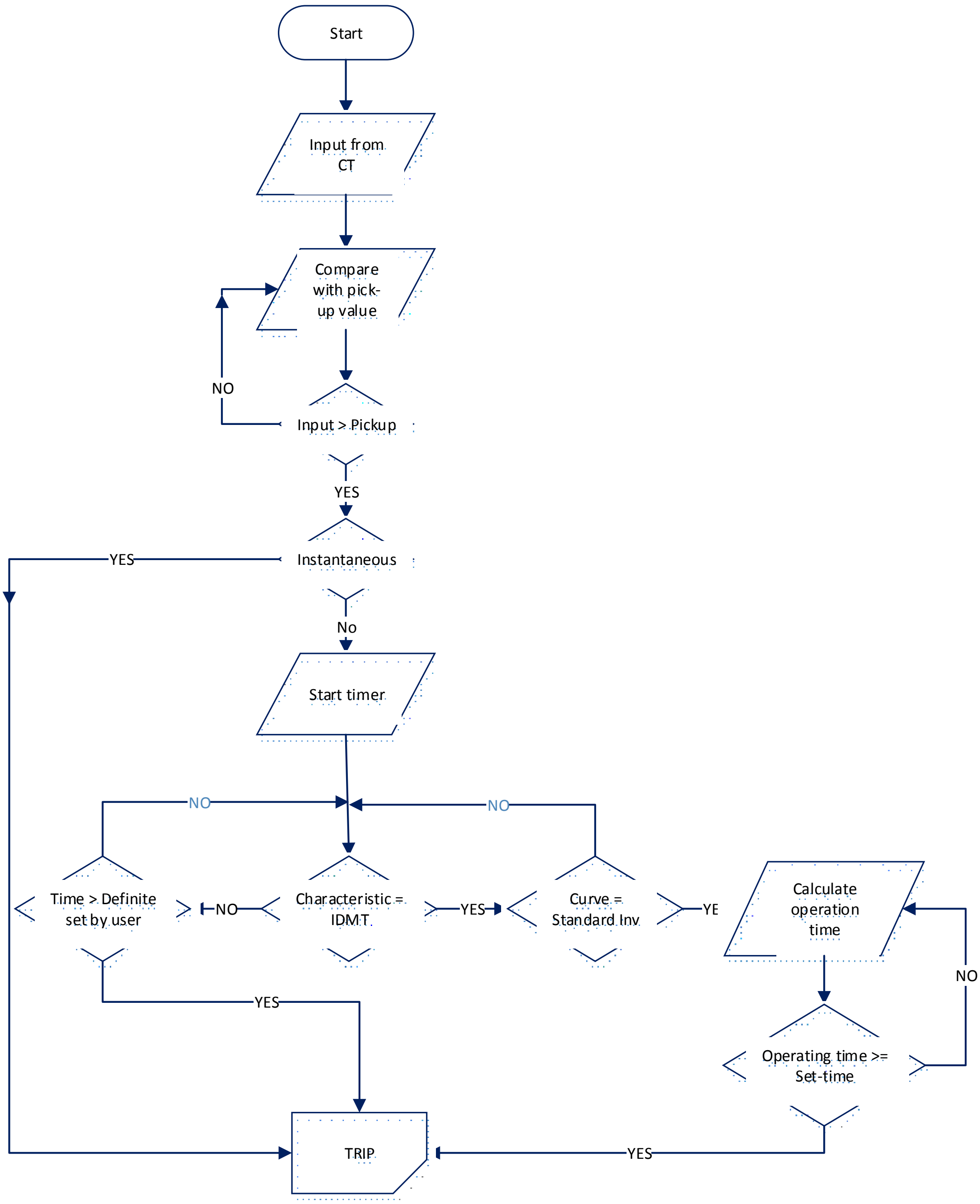


Figure 5.23: Flow-chart process for overcurrent relay operation

5.9.1 Testing of the Relay Tripping Times

After settings of the relays are calculated, simulation of the protected incomer substation is performed for various faults. In power system protection, it is not possible to protect against all hazards with relays that respond to only one quantity. For this case several relays may be employed to cater for other quantities on the system, and moreover, a relay that contains several elements with each responding independently to a different quantity may be employed (Alstom Grid, 2011). Numerical relays have such advantage of multiple elements which could be employed when required.

Single-phase and three-phase short-circuit faults were simulated at various locations of the network and results were captured. Each relay was configured with time-overcurrent and definite-time overcurrent characteristics. In addition phase together with neutral/earth characteristics curves are plotted on the same axis for each of the three relays. The cases considered for the testing are:

- Single-phase to ground faults at CPUT substation busbar
- Three phase to ground faults at CPUT substation busbar
- Single-phase to ground faults on the line between CPUT and ABC Building substations
- Three phase to ground faults on the line between CPUT and ABC Building substations

5.9.1.1 Three-phase to ground short-circuit fault at CPUT substation

The results for the power and current after three-phase to ground short-circuit fault at CPUT bus are obtained and shown in Figure 5.24 below. Short-circuit current magnitude was calculated to be 19.232 kA with a short-circuit power of 366.42 MVA. In addition Table 5.6 below shows complete short-circuit results for the expected Relay 1. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.25. The magnitude 9999.999s on Figure 5.25 and Table 5.6 means that the protection function did not trip during the said period.

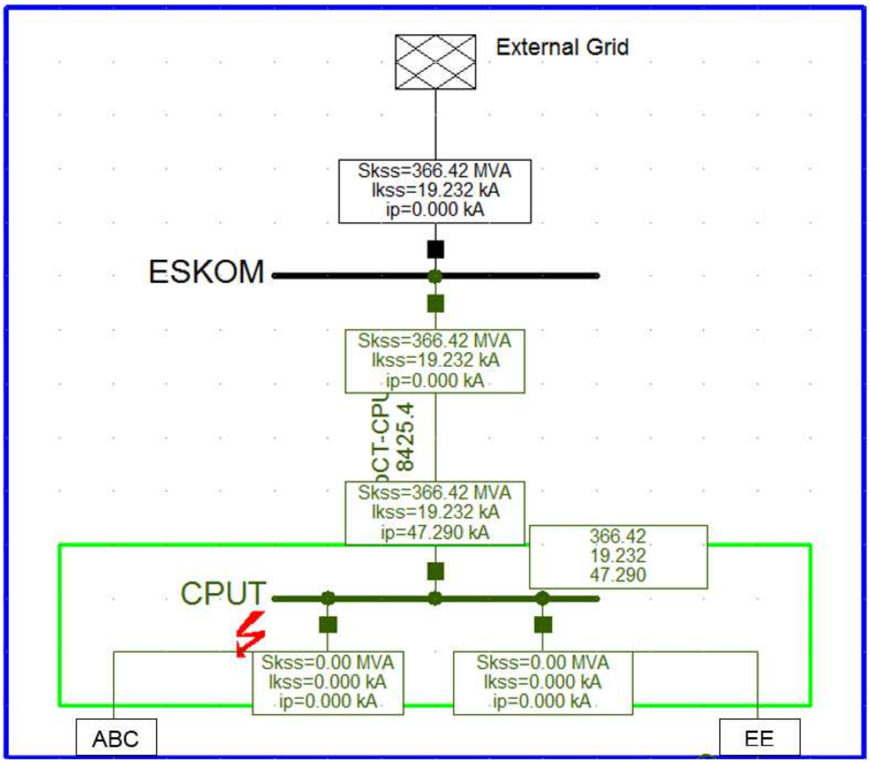


Figure 5.24: Three-phase short-circuit fault at the CPUT substation busbar

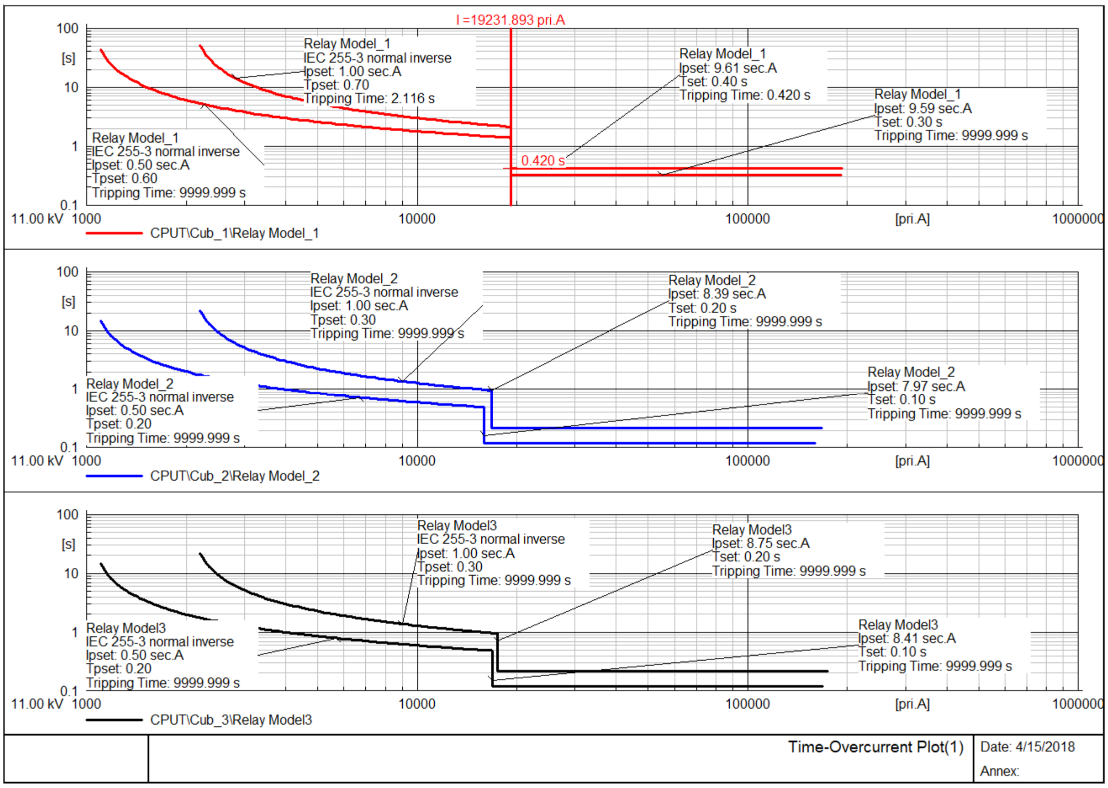


Figure 5.25: Relay characteristic curves and tripping times during three-phase short-circuit fault at the CPUT substation

Table 5.6: CPUT bus three-phase short-circuit relay results

```
-------------------------------------------------------------------------------------------------------------------------------
| Relay Model_1                    Relay Type : 7SJ80_1-1A 50 Hz                                                              |
|   Ct-3p : Current Transformer    Location   : Busbar       : CPUT              /                 Ratio       : 2000A/1A     |
|                                               Branch       : CoCT-CPUT                            Connection  : Y            |
|                                                            :                                                                 |
|   Ct-0  : Current Transformer    Location   : Busbar       : CPUT              /                 Ratio       : 2000A/1A     |
|                                               Branch       : CoCT-CPUT                            Connection  : Y            |
|                                                            :                                                                 |
|   Ip 51   : Ip 51                ( IEC: I>t   ANSI: 51   )       Current  [sec.A]       [pri.A]           Tripping Time     |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.    A :      9.616      19231.89             2.116 s        |
|     Time Dial       :   0.700     Time Shift :   1.000              B :      9.616      19231.89                            |
|     Characteristic  :   IEC 255-3 normal inverse                    C :      9.616      19231.89                            |
|   I> 50_1 : I> 50_1              ( IEC: I>>   ANSI: 50   )       Tripping Current       [pri.A]           Tripping Time     |
|     Pickup Current  :   9.615 sec.A  19230.00 pri.A   9.615 p.u.    A :      9.616      19231.89             0.420 s        |
|     Time Setting    :   0.400 s                                     B :      9.616      19231.89                            |
|     Total Time      :   0.420 s                                     C :      9.616      19231.89                            |
|   Iep 51N : Iep 51N              ( IEC: IE>t  ANSI: 51N  )       Tripping Current       [pri.A]           Tripping Time     |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.             0.000          0.00           9999.999 s       |
|     Time Dial       :   0.600     Time Shift  :   1.000                                                                      |
|     Characteristic  :   IEC 255-3 normal inverse                                                                            |
|   Ie> 50N_1 Ie> 50N_1            ( IEC: IE>>  ANSI: 50N  )       Tripping Current       [pri.A]           Tripping Time     |
|     Pickup Current  :   9.585 sec.A  19170.00 pri.A   9.585 p.u.             0.000          0.00           9999.999 s       |
|     Time Setting    :   0.300 s                                                                                             |
|     Total Time      :   0.320 s                                                                                             |
|   Output LogicOutput Logic                                                      yout           :     0.420 s              |
|     Breaker          Cubicle      Branch                 Busbar            / Substation      Fault Clearing Time          |
|      Mains            Cub_1        CoCT-CPUT              CPUT             /                             0.420 s          |
|   Closing Logiclosing Logic          Tripping Block:                                       Tripping       :  9999.999 s      |
|     Breaker          Cubicle      Branch                 Busbar            / Substation      Fault Clearing Time          |
|      Mains            Cub_1        CoCT-CPUT              CPUT             /                             0.420 s          |
-------------------------------------------------------------------------------------------------------------------------------
```

5.9.1.2 Single-phase to ground short-circuit fault at the CPUT substation

The results for single-phase to ground short-circuit fault at the CPUT substation (busbar) are obtained and shown in Figure 5.26 below. Short-circuit current magnitude was calculated to be 0.313 kA with a short-circuit power of 1.99 MVA. In addition Table 5.7 below shows complete short-circuit results for the Relay 1. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.27.

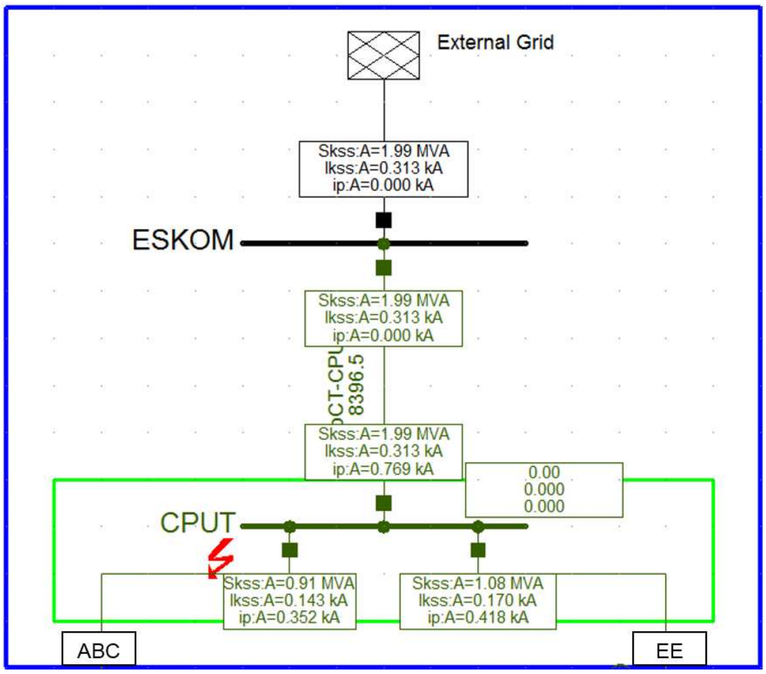


Figure 5.26: Single-phase to ground short-circuit fault at the CPUT substation busbar

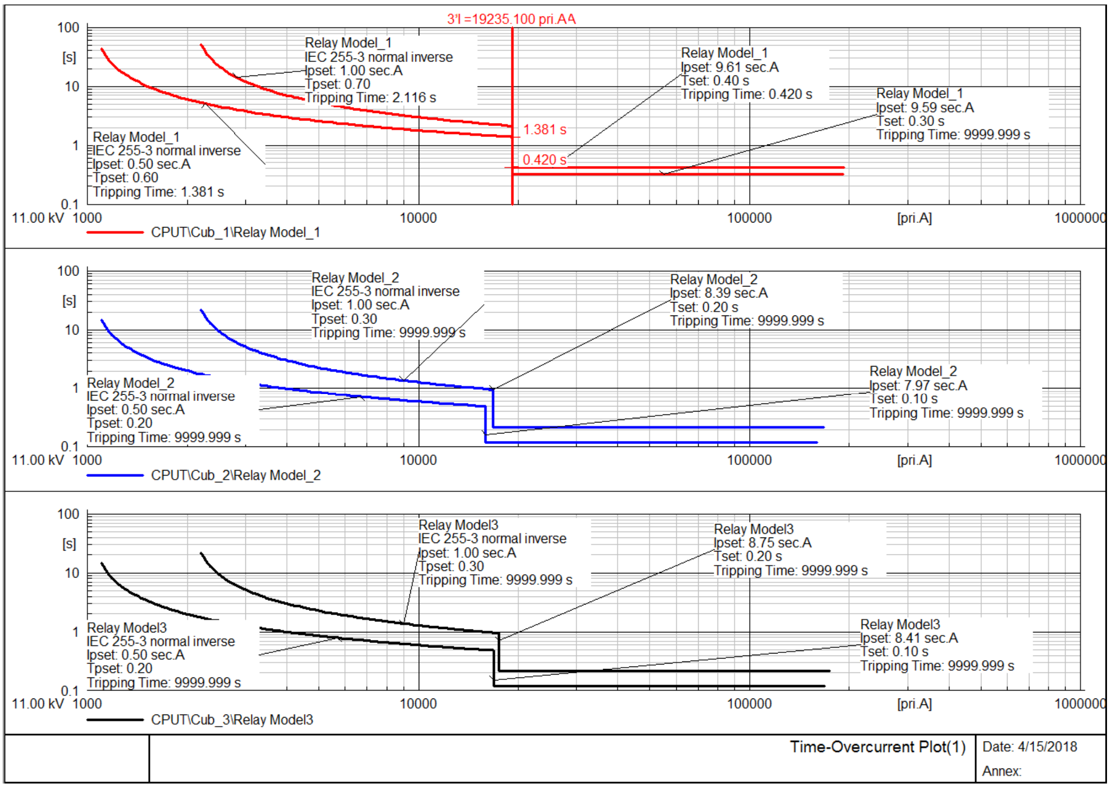


Figure 5.27**: Relay characteristic curves and tripping times during single-phase short-circuit fault at the CPUT substation**

Table 5.7: CPUT substation single-phase short-circuit relay results

```
| Relay Model_1                    Relay Type : 7SJ80_1-1A 50 Hz
|   Ct-3p : Current Transformer    Location   : Busbar        : CPUT                /                    Ratio        : 2000A/1A
|                                                Branch        : CoCT-CPUT                                Connection   : Y
|                                                              :
|   Ct-0  : Current Transformer    Location   : Busbar        : CPUT                /                    Ratio        : 2000A/1A
|                                                Branch        : CoCT-CPUT                                Connection   : Y
|                                                              :
|   Ip 51    : Ip 51                    ( IEC: I>t    ANSI: 51    )      Current  [sec.A]       [pri.A]            Tripping Time
|     Current Setting :   1.000 sec.A    2000.00 pri.A    1.000 p.u.         A :     0.156        312.91              2.116 s
|     Time Dial       :   0.700       Time Shift :    1.000                  B :     9.618      19235.10
|     Characteristic  :   IEC 255-3 normal inverse                           C :     0.158        315.32
|   I> 50_1 : I> 50_1                   ( IEC: I>>    ANSI: 50    )      Tripping Current       [pri.A]            Tripping Time
|     Pickup Current  :   9.615 sec.A  19230.00 pri.A    9.615 p.u.          A :     0.156        312.91              0.420 s
|     Time Setting    :   0.400 s                                            B :     9.618      19235.10
|     Total Time      :   0.420 s                                            C :     0.158        315.32
|   Iep 51N : Iep 51N                   ( IEC: IE>t   ANSI: 51N   )      Tripping Current       [pri.A]            Tripping Time
|     Current Setting :   0.500 sec.A    1000.00 pri.A    0.500 p.u.               9.584      19168.51              1.381 s
|     Time Dial       :   0.600       Time Shift  :   1.000
|     Characteristic  :   IEC 255-3 normal inverse
|   Ie> 50N_1 Ie> 50N_1                 ( IEC: IE>>   ANSI: 50N   )      Tripping Current       [pri.A]            Tripping Time
|     Pickup Current  :   9.585 sec.A  19170.00 pri.A    9.585 p.u.                9.584      19168.51           9999.999 s
|     Time Setting    :   0.300 s
|     Total Time      :   0.320 s
|   Output LogicOutput Logic                                                                    yout           :     0.420 s
|     Breaker             Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time
|      Mains               Cub_1         CoCT-CPUT               CPUT                /                              0.420 s
|   Closing Logiclosing Logic            Tripping Block:                                       Tripping        :   9999.999 s
|     Breaker             Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time
|      Mains               Cub_1         CoCT-CPUT               CPUT                /                              0.420 s
```

5.9.1.3 Three-phase to ground short-circuit fault on the line from the CPUT substation to the ABC substation

The results for three-phase to ground short-circuit fault on the underground cable between the main incomer substation (CPUT bus) and the ABC Building substation are obtained and shown in Figure 5.28 below. Short-circuit current magnitude is calculated to be 18.360 kA located at 50% of the cable length. In addition Tables 5.8 and 5.9 below show the complete short-circuit results for the Relay 3 and Relay 1 tripping times respectively. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.29. The upstream relay tripping times should act as backup to downstream when the downstream circuit breaker fails to extinguish the fault. Downstream Relay 3 trips on definite-time overcurrent characteristics while Relay 1 applies IDMT overcurrent characteristics to clear the fault.

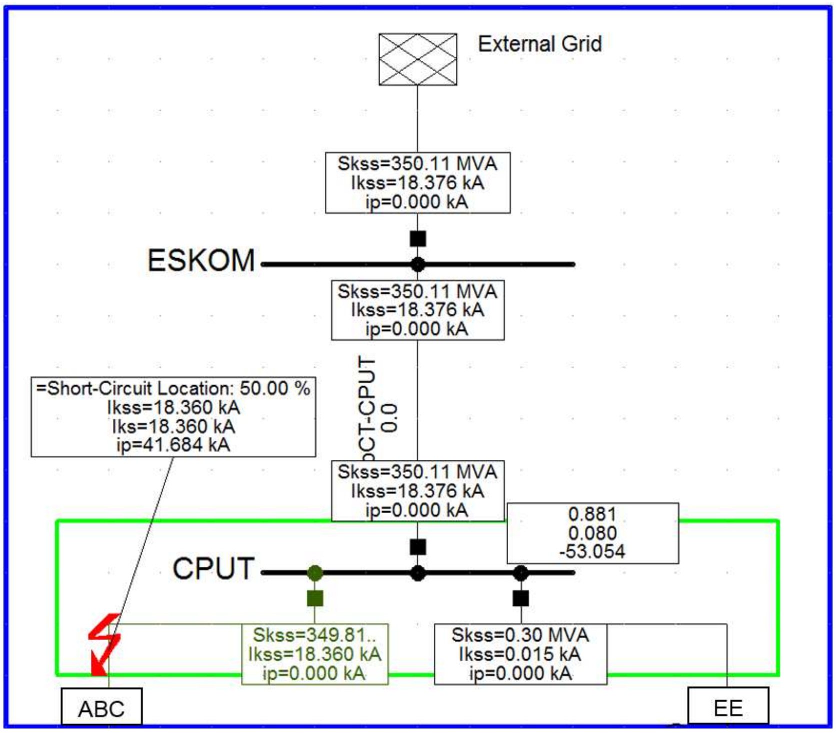


Figure 5.28: Three-phase to ground short-circuit fault on an outgoing cable to the ABC substation

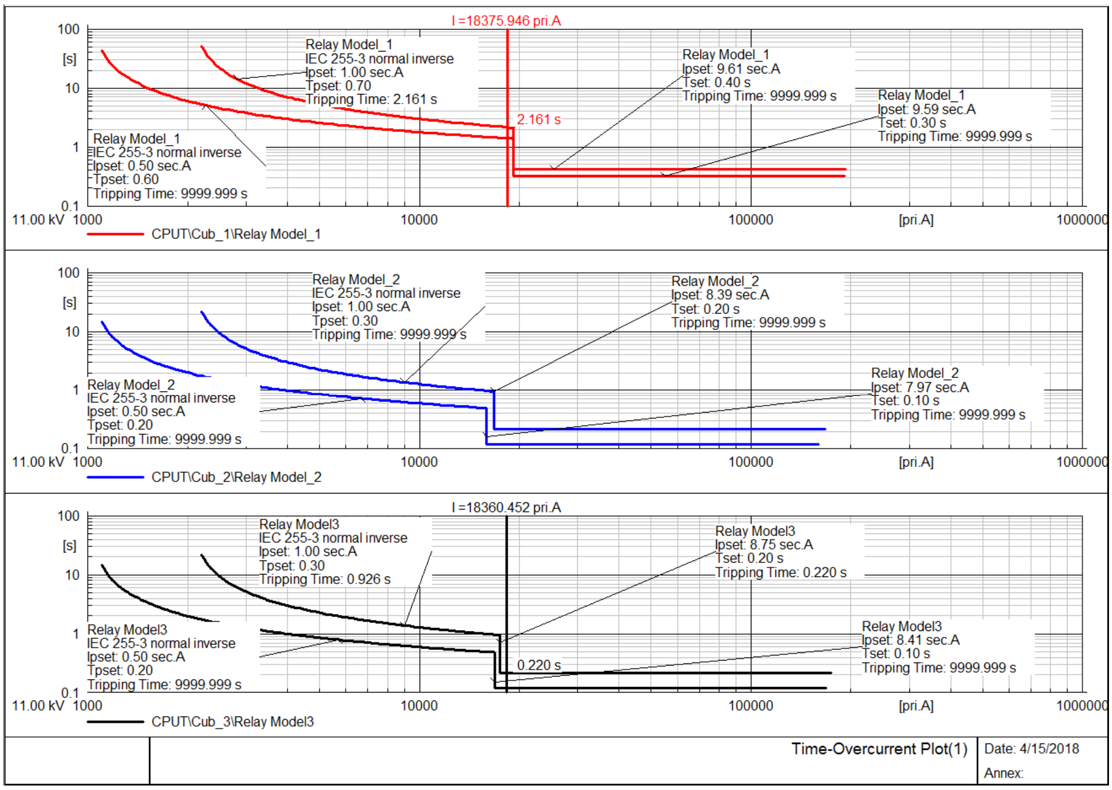


Figure 5.29: Relay characteristic curves and tripping times during three-phase short-circuit fault on outgoing cable towards the ABC substation

Table 5.8: CPUT-ABC cable three-phase short-circuit Relay 3 results

```
-------------------------------------------------------------------------------------------------------------------------------
| Relay Model3                     Relay Type : 7SJ80_1-1A 50 Hz                                                               |
|   Ct-3p : Current Transformer3   Location   : Busbar       : CPUT                /                Ratio        : 2000A/1A   |
|                                               Branch       : PILC120                                Connection   : Y          |
|                                                            :                                                                 |
|   Ct-0  : Current Transformer3   Location   : Busbar       : CPUT                /                Ratio        : 2000A/1A   |
|                                               Branch       : PILC120                                Connection   : Y          |
|                                                            :                                                                 |
|   Ip 51    : Ip 51                 ( IEC: I>t    ANSI: 51    )      Current  [sec.A]        [pri.A]          Tripping Time   |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.        A :     9.180       18360.45             0.926 s     |
|     Time Dial       :   0.300     Time Shift :     1.000               B :     9.180       18360.45                         |
|     Characteristic  :   IEC 255-3 normal inverse                       C :     9.180       18360.45                         |
|   I> 50_1 : I> 50_1                ( IEC: I>>    ANSI: 50    )      Tripping Current        [pri.A]          Tripping Time   |
|     Pickup Current  :   8.750 sec.A  17500.00 pri.A   8.750 p.u.        A :     9.180       18360.45             0.220 s     |
|     Time Setting    :   0.200 s                                        B :     9.180       18360.45                         |
|     Total Time      :   0.220 s                                        C :     9.180       18360.45                         |
|   Iep 51N : Iep 51N                 ( IEC: IE>t   ANSI: 51N   )      Tripping Current        [pri.A]          Tripping Time   |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.                0.000           0.00            9999.999 s   |
|     Time Dial       :   0.200      Time Shift   :    1.000                                                                 |
|     Characteristic  :   IEC 255-3 normal inverse                                                                          |
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| Grid: Existing Network      System Stage: Existing Networ | Study Case: Study Case              | Annex:                 / 3  |
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-------------------------------------------------------------------------------------------------------------------------------
|   Ie> 50N_1 Ie> 50N_1              ( IEC: IE>>   ANSI: 50N   )      Tripping Current        [pri.A]          Tripping Time   |
|     Pickup Current  :   8.410 sec.A  16820.00 pri.A   8.410 p.u.                0.000           0.00            9999.999 s   |
|     Time Setting    :   0.100 s                                                                                           |
|     Total Time      :   0.120 s                                                                                           |
|   Output LogicOutput Logic                                                              yout            :     0.220 s     |
|     Breaker            Cubicle       Branch                  Busbar               / Substation       Fault Clearing Time   |
|      CPUT-ABC           Cub_3         PILC120                 CPUT                 /                              0.220 s   |
|   Closing LogicClosing Logic          Tripping Block:                                    Tripping        :  9999.999 s     |
|     Breaker            Cubicle       Branch                  Busbar               / Substation       Fault Clearing Time   |
|      CPUT-ABC           Cub_3         PILC120                 CPUT                 /                              0.220 s   |
-------------------------------------------------------------------------------------------------------------------------------
```

Table 5.9: CPUT-ABC cable three-phase short-circuit Relay 1 results

```
-----------------------------------------------------------------------------------------------------------------------------------
| Relay Model_1                 Relay Type : 7SJ80_1-1A 50 Hz                                                                      |
|   Ct-3p : Current Transformer    Location    : Busbar       : CPUT                /                  Ratio        : 2000A/1A    |
|                                              Branch       : CoCT-CPUT                                Connection   : Y           |
|                                                           :                                                                      |
|   Ct-0  : Current Transformer    Location    : Busbar       : CPUT                /                  Ratio        : 2000A/1A    |
|                                              Branch       : CoCT-CPUT                                Connection   : Y           |
|                                                           :                                                                      |
|   Ip 51   : Ip 51               ( IEC: I>t   ANSI: 51   )       Current  [sec.A]       [pri.A]          Tripping Time           |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.     A :      9.188      18375.95              2.161 s            |
|     Time Dial       :   0.700     Time Shift :   1.000               B :      9.188      18375.95                                 |
|     Characteristic  :   IEC 255-3 normal inverse                    C :      9.188      18375.95                                 |
|   I> 50_1 : I> 50_1             ( IEC: I>>   ANSI: 50   )       Tripping Current       [pri.A]          Tripping Time           |
|     Pickup Current  :   9.615 sec.A  19230.00 pri.A   9.615 p.u.     A :      9.188      18375.95           9999.999 s            |
|     Time Setting    :   0.400 s                                     B :      9.188      18375.95                                 |
|     Total Time      :   0.420 s                                     C :      9.188      18375.95                                 |
|   Iep 51N : Iep 51N             ( IEC: IE>t  ANSI: 51N  )       Tripping Current       [pri.A]          Tripping Time           |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.               0.000          0.00           9999.999 s            |
|     Time Dial       :   0.600     Time Shift  :   1.000                                                                          |
|     Characteristic  :   IEC 255-3 normal inverse                                                                                 |
|   Ie> 50N_1 Ie> 50N_1           ( IEC: IE>>  ANSI: 50N  )       Tripping Current       [pri.A]          Tripping Time           |
|     Pickup Current  :   9.585 sec.A  19170.00 pri.A   9.585 p.u.               0.000          0.00           9999.999 s            |
|     Time Setting    :   0.300 s                                                                                                  |
|     Total Time      :   0.320 s                                                                                                  |
|   Output LogicOutput Logic                                                         yout            :     2.161 s              |
|     Breaker            Cubicle      Branch                  Busbar             / Substation       Fault Clearing Time          |
|      Mains              Cub_1        CoCT-CPUT                CPUT             /                             2.161 s          |
|   Closing Logiclosing Logic          Tripping Block:                                Tripping        :  9999.999 s              |
|     Breaker            Cubicle      Branch                  Busbar             / Substation       Fault Clearing Time          |
|      Mains              Cub_1        CoCT-CPUT                CPUT             /                             2.161 s          |
-----------------------------------------------------------------------------------------------------------------------------------
```

5.9.1.4 Single-phase to ground short-circuit fault on the line from the CPUT substation to the ABC substation

The results for single-phase to ground short-circuit fault on the underground cable between main incomer substation (CPUT bus) and the ABC Building substation are obtained and shown in Figure 5.30 below. Short-circuit current magnitude is calculated on the phase C (blue phase) of the cable assuming ABC rotation (red-white-blue or red-yellow-blue) to be 17.946 kA located at 50% of the cable length. In addition Table 5.10 and 5.11 below show complete short-circuit results for the expected Relay 3 and Relay 1 tripping times. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.31. The upstream Relay 1 tripping time of 1.413 sec should act as backup to the downstream Relay 3 of 102 ms when the downstream circuit breaker fails to extinguish the fault. Downstream Relay 3 trips on definite-time overcurrent characteristic while Relay 1 applies IDMT overcurrent characteristic to clear the fault.

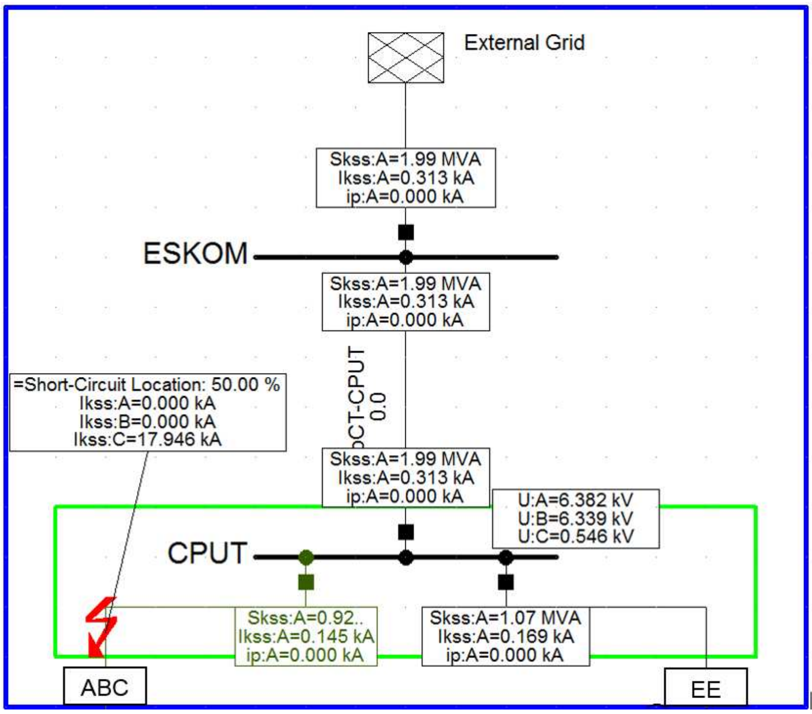

Figure 5.30: Single-phase to ground short-circuit fault on an outgoing cable to ABC substation

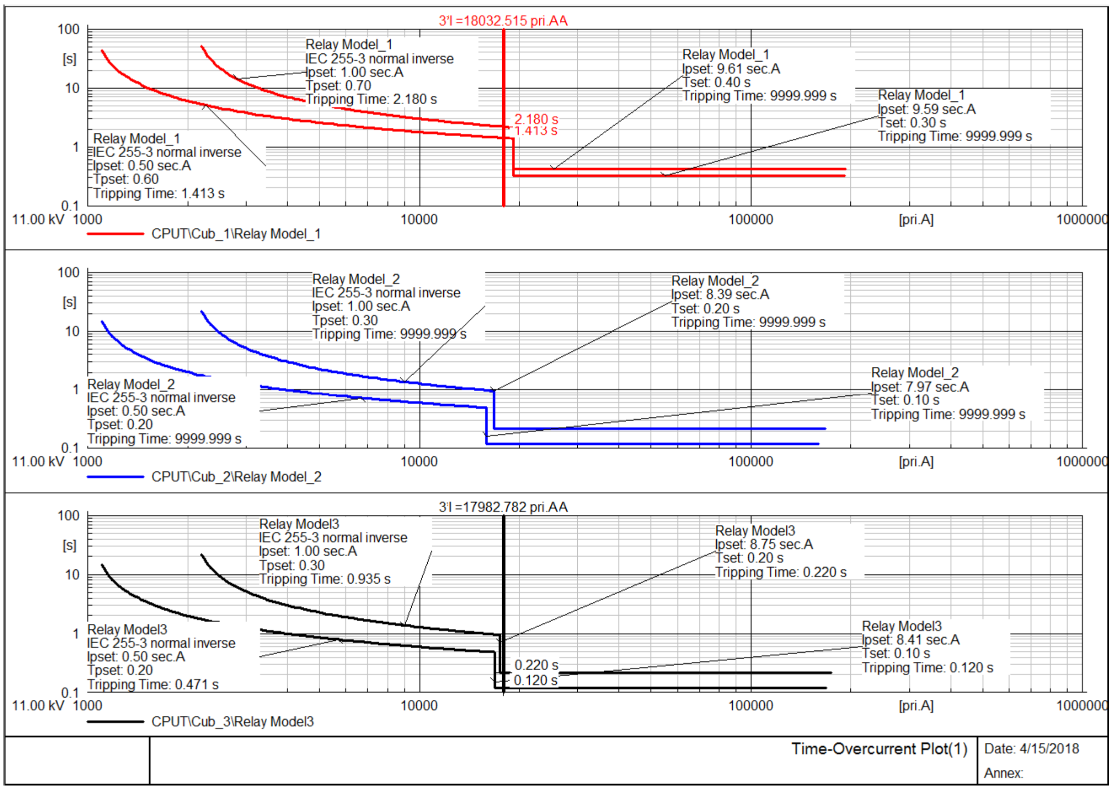

Figure 5.31: Relay characteristic curves and tripping times during single-phase short-circuit fault on outgoing cable towards ABC substation

Table 5.10: CPUT-ABC cable single-phase short-circuit Relay 3 results

```
--------------------------------------------------------------------------------------------------------------------------------
| Relay Model3                     Relay Type : 7SJ80_1-1A 50 Hz                                                                  |
|   Ct-3p : Current Transformer3   Location   : Busbar       : CPUT                /                    Ratio       : 2000A/1A   |
|                                               Branch       : PILC120                                    Connection  : Y          |
|                                                            :                                                                     |
|   Ct-0  : Current Transformer3   Location   : Busbar       : CPUT                /                    Ratio       : 2000A/1A   |
|                                               Branch       : PILC120                                    Connection  : Y          |
|                                                            :                                                                     |
|   Ip 51    : Ip 51                ( IEC: I>t    ANSI: 51    )        Current  [sec.A]       [pri.A]          Tripping Time       |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.        A :     0.072         144.88             0.935 s          |
|     Time Dial       :   0.300      Time Shift :    1.000               B :     0.071         142.89                              |
|     Characteristic  :   IEC 255-3 normal inverse                       C :     8.991       17982.78                              |
|   I> 50_1 : I> 50_1               ( IEC: I>>    ANSI: 50    )        Tripping Current       [pri.A]          Tripping Time       |
|     Pickup Current  :   8.750 sec.A  17500.00 pri.A   8.750 p.u.        A :     0.072         144.88             0.220 s          |
|     Time Setting    :   0.200 s                                        B :     0.071         142.89                              |
|     Total Time      :   0.220 s                                        C :     8.991       17982.78                              |
|   Iep 51N : Iep 51N               ( IEC: IE>t   ANSI: 51N  )         Tripping Current       [pri.A]          Tripping Time       |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.               8.974       17947.50             0.471 s          |
|     Time Dial       :   0.200      Time Shift  :    1.000                                                                        |
|     Characteristic  :   IEC 255-3 normal inverse                                                                                 |
--------------------------------------------------------------------------------------------------------------------------------
□-------------------------------------------------------------------------------------------------------------------------------
| Grid: Existing Network      System Stage: Existing Networ | Study Case: Study Case                  | Annex:                  / 3  |
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--------------------------------------------------------------------------------------------------------------------------------
|   Ie> 50N_1 Ie> 50N_1             ( IEC: IE>>   ANSI: 50N  )         Tripping Current       [pri.A]          Tripping Time       |
|     Pickup Current  :   8.410 sec.A  16820.00 pri.A   8.410 p.u.               8.974       17947.50             0.120 s          |
|     Time Setting    :   0.100 s                                                                                                  |
|     Total Time      :   0.120 s                                                                                                  |
|   Output LogicOutput Logic                                                                 yout              :     0.120 s       |
|     Breaker            Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time       |
|      CPUT-ABC           Cub_3         PILC120                 CPUT                /                             0.120 s          |
|   Closing Logiclosing Logic          Tripping Block:                                      Tripping          :  9999.999 s       |
|     Breaker            Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time       |
|      CPUT-ABC           Cub_3         PILC120                 CPUT                /                             0.120 s          |
--------------------------------------------------------------------------------------------------------------------------------
```

Table 5.11: CPUT-ABC cable single-phase short-circuit Relay 1 results

```
--------------------------------------------------------------------------------------------------------------------------------
| Relay Model_1                    Relay Type : 7SJ80_1-1A 50 Hz                                                                  |
|   Ct-3p : Current Transformer    Location   : Busbar       : CPUT                /                    Ratio       : 2000A/1A   |
|                                               Branch       : CoCT-CPUT                                  Connection  : Y          |
|                                                            :                                                                     |
|   Ct-0  : Current Transformer    Location   : Busbar       : CPUT                /                    Ratio       : 2000A/1A   |
|                                               Branch       : CoCT-CPUT                                  Connection  : Y          |
|                                                            :                                                                     |
|   Ip 51    : Ip 51                ( IEC: I>t    ANSI: 51    )        Current  [sec.A]       [pri.A]          Tripping Time       |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.        A :     0.157         313.35             2.180 s          |
|     Time Dial       :   0.700      Time Shift :    1.000               B :     0.158         317.00                              |
|     Characteristic  :   IEC 255-3 normal inverse                       C :     9.016       18032.51                              |
|   I> 50_1 : I> 50_1               ( IEC: I>>    ANSI: 50    )        Tripping Current       [pri.A]          Tripping Time       |
|     Pickup Current  :   9.615 sec.A  19230.00 pri.A   9.615 p.u.        A :     0.157         313.35           9999.999 s          |
|     Time Setting    :   0.400 s                                        B :     0.158         317.00                              |
|     Total Time      :   0.420 s                                        C :     9.016       18032.51                              |
|   Iep 51N : Iep 51N               ( IEC: IE>t   ANSI: 51N  )         Tripping Current       [pri.A]          Tripping Time       |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.               8.974       17948.67             1.413 s          |
|     Time Dial       :   0.600      Time Shift  :    1.000                                                                        |
|     Characteristic  :   IEC 255-3 normal inverse                                                                                 |
|   Ie> 50N_1 Ie> 50N_1             ( IEC: IE>>   ANSI: 50N  )         Tripping Current       [pri.A]          Tripping Time       |
|     Pickup Current  :   9.585 sec.A  19170.00 pri.A   9.585 p.u.               8.974       17948.67           9999.999 s          |
|     Time Setting    :   0.300 s                                                                                                  |
|     Total Time      :   0.320 s                                                                                                  |
|   Output LogicOutput Logic                                                                 yout              :     1.413 s       |
|     Breaker            Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time       |
|      Mains              Cub_1         CoCT-CPUT               CPUT                /                             1.413 s          |
|   Closing Logiclosing Logic          Tripping Block:                                      Tripping          :  9999.999 s       |
|     Breaker            Cubicle       Branch                  Busbar              / Substation        Fault Clearing Time       |
|      Mains              Cub_1         CoCT-CPUT               CPUT                /                             1.413 s          |
--------------------------------------------------------------------------------------------------------------------------------
```

5.9.1.5 Three-phase to ground at Res 1 substation

The results for three-phase to ground short-circuit fault at the Res 1 substation are obtained and shown in Figure 5.32 and Figure 5.34 below. Short-circuit current magnitude is calculated to be 12.562 kA with a short-circuit power of 239.34 MVA. In addition Tables 5.12 and 5.13 below show complete short-circuit results for Relay 2 and Relay 1 respectively. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.33. This substation is the furthest to the incomer substation by length of the cables between the two substations. Cable length contributes to impedance magnitudes which are defining factors on the magnitude of short-circuit faults currents.

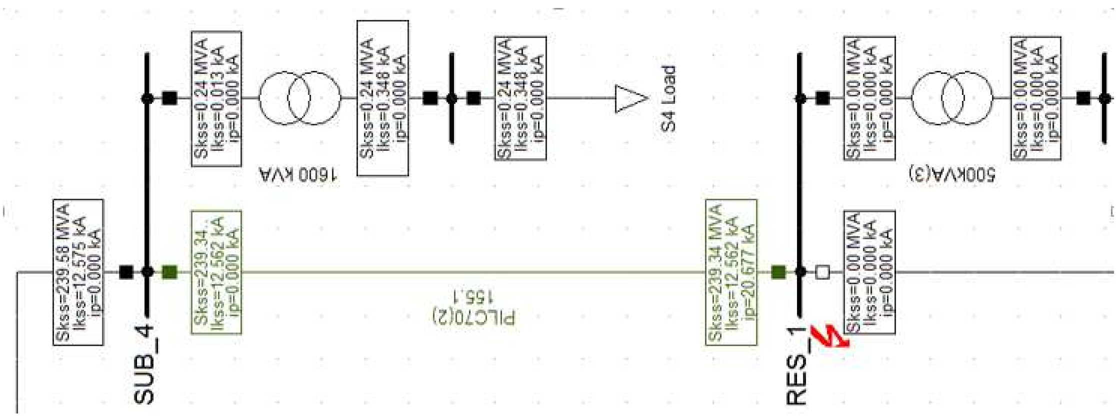

Figure 5.32: Three-phase to ground short-circuit fault at Res 1 substation (clear view)

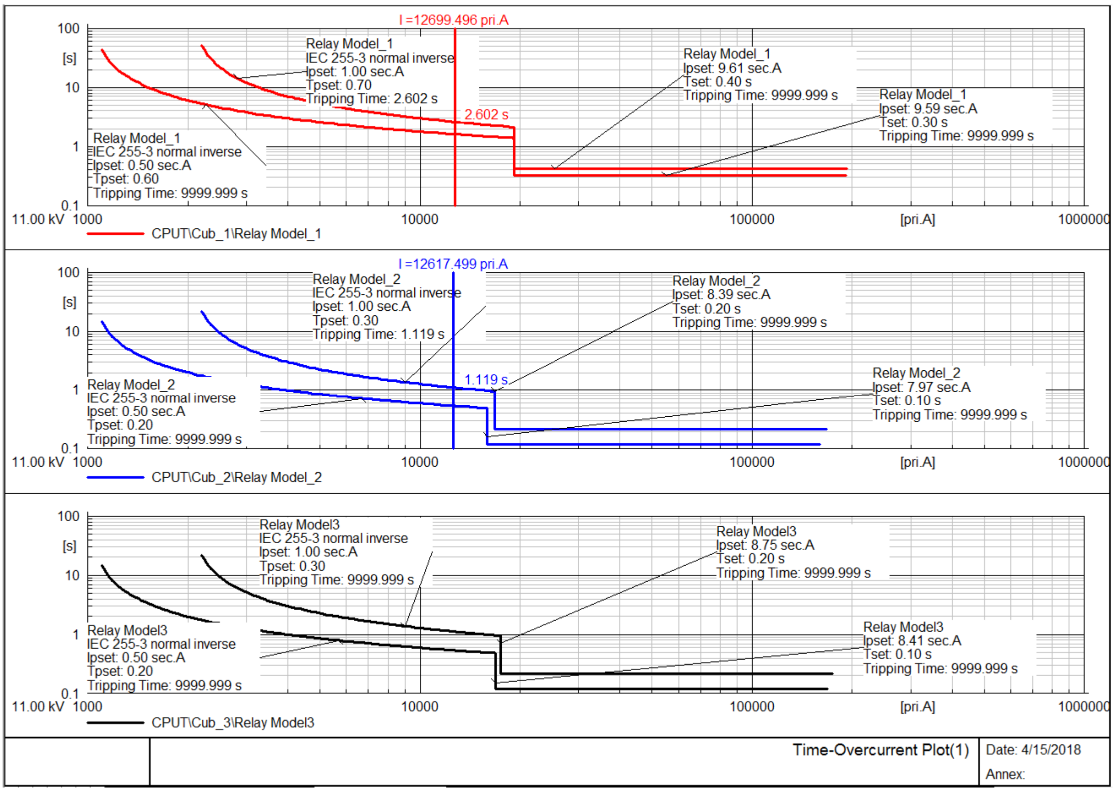

Figure 5.33: Relay characteristic curves and tripping times during three-phase short-circuit fault at Res 1 substation

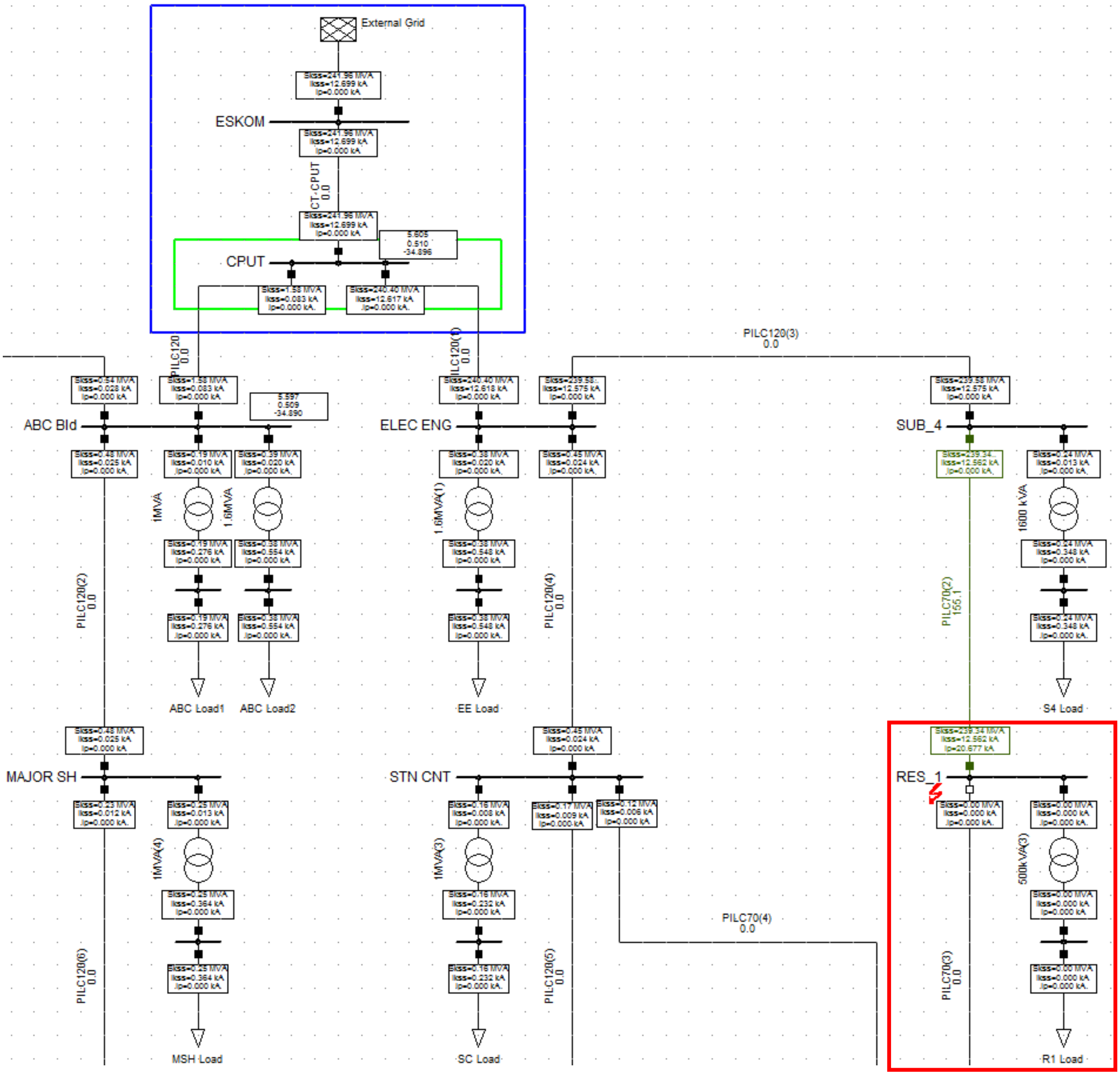

Figure 5.34: Three-phase to ground short-circuit fault at Res 1 substation

Table 5.12: Res 1 three-phase short-circuit Relay 2 results

```
--------------------------------------------------------------------------------------------------------------------------------
| Relay Model_2                  Relay Type : 7SJ80_1-1A 50 Hz                                                                   |
|   Ct-3p : Current Transformer2  Location   : Busbar       : CPUT              /                Ratio       : 2000A/1A          |
|                                             Branch       : PILC120(1)                         Connection  : Y                 |
|                                                          :                                                                     |
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| Grid: Existing Network     System Stage: Existing Networ | Study Case: Study Case                | Annex:                 / 2  |
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--------------------------------------------------------------------------------------------------------------------------------
|   Ct-0  : Current Transformer2  Location   : Busbar       : CPUT              /                Ratio       : 2000A/1A          |
|                                             Branch       : PILC120(1)                         Connection  : Y                 |
|                                                          :                                                                     |
|   Ip 51    : Ip 51              ( IEC: I>t   ANSI: 51   )         Current  [sec.A]       [pri.A]           Tripping Time      |
|     Current Setting :  1.000 sec.A   2000.00 pri.A   1.000 p.u.     A :      6.309      12617.50              1.119 s          |
|     Time Dial       :  0.300      Time Shift :   1.000              B :      6.309      12617.50                               |
|     Characteristic  :  IEC 255-3 normal inverse                     C :      6.309      12617.50                               |
|   I> 50_1 : I> 50_1             ( IEC: I>>   ANSI: 50   )         Tripping Current       [pri.A]           Tripping Time      |
|     Pickup Current  :  8.390 sec.A  16780.00 pri.A   8.390 p.u.     A :      6.309      12617.50             9999.999 s        |
|     Time Setting    :  0.200 s                                      B :      6.309      12617.50                               |
|     Total Time      :  0.220 s                                      C :      6.309      12617.50                               |
|   Iep 51N : Iep 51N             ( IEC: IE>t  ANSI: 51N  )         Tripping Current       [pri.A]           Tripping Time      |
|     Current Setting :  0.500 sec.A   1000.00 pri.A   0.500 p.u.             0.000          0.00             9999.999 s        |
|     Time Dial       :  0.200      Time Shift  :   1.000                                                                        |
|     Characteristic  :  IEC 255-3 normal inverse                                                                               |
|   Ie> 50N_1 Ie> 50N_1           ( IEC: IE>>  ANSI: 50N  )         Tripping Current       [pri.A]           Tripping Time      |
|     Pickup Current  :  7.970 sec.A  15940.00 pri.A   7.970 p.u.             0.000          0.00             9999.999 s        |
|     Time Setting    :  0.100 s                                                                                                |
|     Total Time      :  0.120 s                                                                                                |
|   Output LogicOutput Logic                                                          yout              :      1.119 s          |
|     Breaker            Cubicle       Branch                 Busbar              / Substation       Fault Clearing Time        |
|      CPUT-EE            Cub_2         PILC120(1)             CPUT                /                             1.119 s        |
|   Closing Logiclosing Logic            Tripping Block:                                 Tripping       :  9999.999 s           |
|     Breaker            Cubicle       Branch                 Busbar              / Substation       Fault Clearing Time        |
|      CPUT-EE            Cub_2         PILC120(1)             CPUT                /                             1.119 s        |
--------------------------------------------------------------------------------------------------------------------------------
```

Table 5.13: Res 1 three-phase short-circuit Relay 1 results

```
--------------------------------------------------------------------------------------------------------------------------------
| Relay Model_1                  Relay Type : 7SJ80_1-1A 50 Hz                                                                   |
|   Ct-3p : Current Transformer   Location   : Busbar       : CPUT              /                Ratio       : 2000A/1A          |
|                                             Branch       : CoCT-CPUT                          Connection  : Y                 |
|                                                          :                                                                     |
|   Ct-0  : Current Transformer   Location   : Busbar       : CPUT              /                Ratio       : 2000A/1A          |
|                                             Branch       : CoCT-CPUT                          Connection  : Y                 |
|                                                          :                                                                     |
|   Ip 51    : Ip 51              ( IEC: I>t   ANSI: 51   )         Current  [sec.A]       [pri.A]           Tripping Time      |
|     Current Setting :  1.000 sec.A   2000.00 pri.A   1.000 p.u.     A :      6.350      12699.50              2.602 s          |
|     Time Dial       :  0.700      Time Shift :   1.000              B :      6.350      12699.50                               |
|     Characteristic  :  IEC 255-3 normal inverse                     C :      6.350      12699.50                               |
|   I> 50_1 : I> 50_1             ( IEC: I>>   ANSI: 50   )         Tripping Current       [pri.A]           Tripping Time      |
|     Pickup Current  :  9.615 sec.A  19230.00 pri.A   9.615 p.u.     A :      6.350      12699.50             9999.999 s        |
|     Time Setting    :  0.400 s                                      B :      6.350      12699.50                               |
|     Total Time      :  0.420 s                                      C :      6.350      12699.50                               |
|   Iep 51N : Iep 51N             ( IEC: IE>t  ANSI: 51N  )         Tripping Current       [pri.A]           Tripping Time      |
|     Current Setting :  0.500 sec.A   1000.00 pri.A   0.500 p.u.             0.000          0.00             9999.999 s        |
|     Time Dial       :  0.600      Time Shift  :   1.000                                                                        |
|     Characteristic  :  IEC 255-3 normal inverse                                                                               |
|   Ie> 50N_1 Ie> 50N_1           ( IEC: IE>>  ANSI: 50N  )         Tripping Current       [pri.A]           Tripping Time      |
|     Pickup Current  :  9.585 sec.A  19170.00 pri.A   9.585 p.u.             0.000          0.00             9999.999 s        |
|     Time Setting    :  0.300 s                                                                                                |
|     Total Time      :  0.320 s                                                                                                |
|   Output LogicOutput Logic                                                          yout              :      2.602 s          |
|     Breaker            Cubicle       Branch                 Busbar              / Substation       Fault Clearing Time        |
|      Mains              Cub_1         CoCT-CPUT              CPUT                /                             2.602 s        |
|   Closing Logiclosing Logic            Tripping Block:                                 Tripping       :  9999.999 s           |
|     Breaker            Cubicle       Branch                 Busbar              / Substation       Fault Clearing Time        |
|      Mains              Cub_1         CoCT-CPUT              CPUT                /                             2.602 s        |
--------------------------------------------------------------------------------------------------------------------------------
```

5.9.1.6 Single-phase to ground short-circuit faults at Res 1 substation

The results for single-phase to ground short-circuit fault at the Res 1 substation are obtained and shown in Figure 5.35 below. Short-circuit current magnitude on phase A is calculated to be 11.872 kA with a short-circuit power of 75.40 MVA. In addition Table 5.14 and 5.15 below show complete short-circuit results for the expected Relay 2 and Relay 1 respectively. Tripping curves for all relays during this short-circuit fault are shown in Figure 5.36. This substations is the furthest to the incomer substation by length of cable between the two substations. This cable length contributes to impedance magnitudes which are defining factors on the magnitude of short-circuit faults currents.

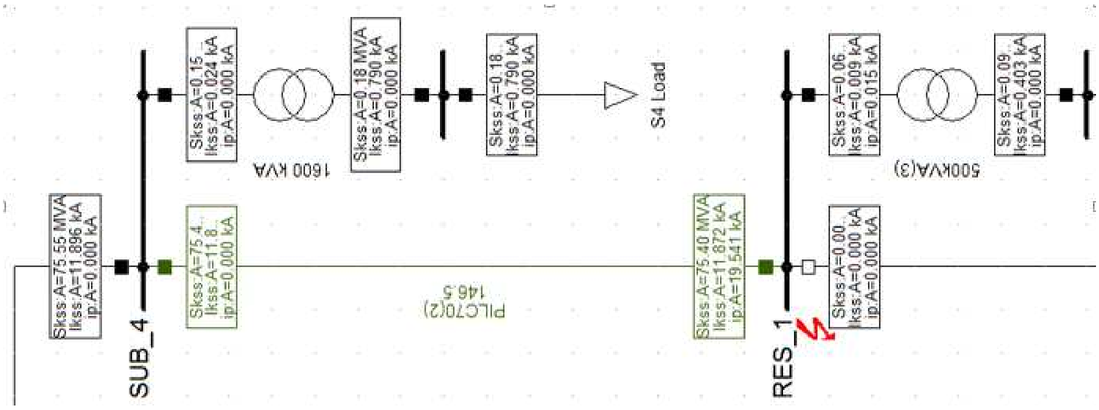


Figure 5.35: Single-phase to ground short-circuit fault at Res 1 substation

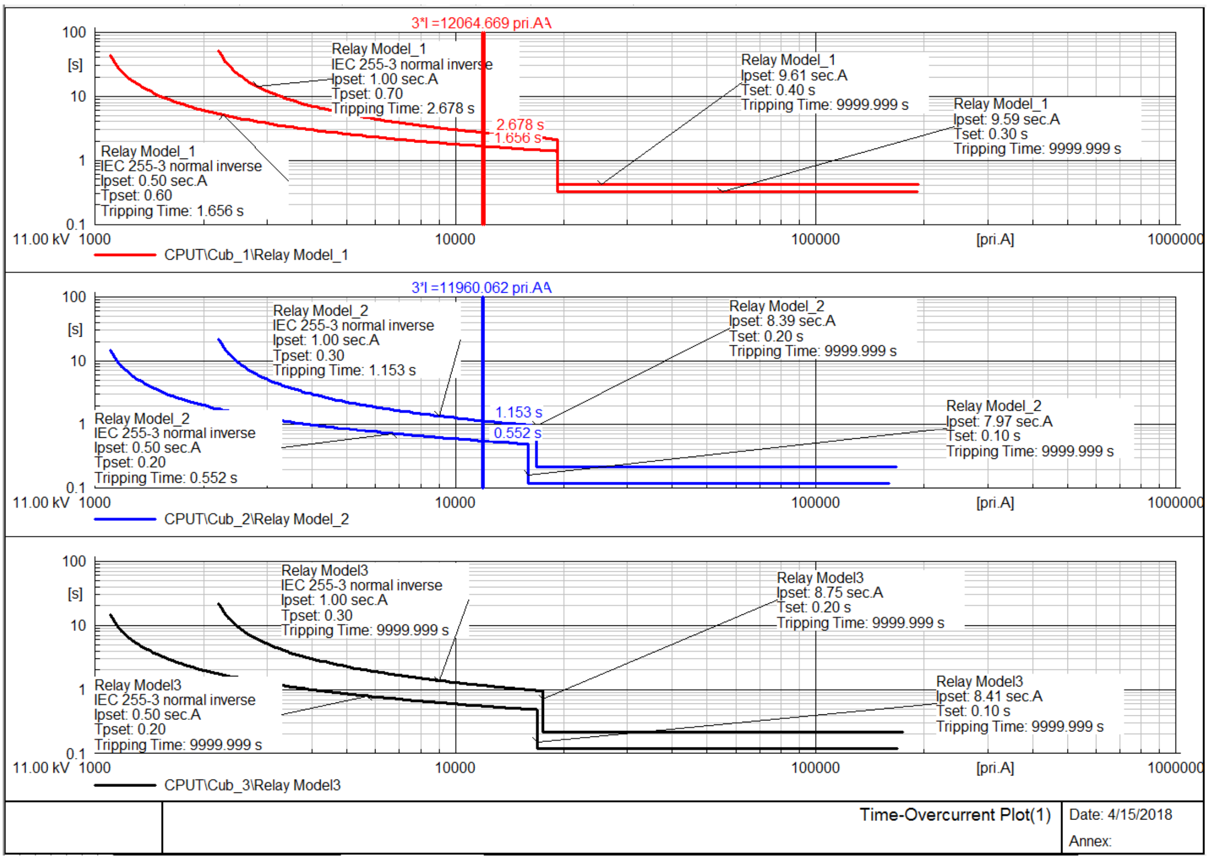


Figure 5.36: Relay characteristics curves and tripping times during single-phase short-circuit fault at Res 1 substation

Table 5.14: Res 1 single-phase short-circuit Relay 2 results

```
-----------------------------------------------------------------------------------------------------------------
| Relay Model_2                    Relay Type : 7SJ80_1-1A 50 Hz                                                  |
|   Ct-3p : Current Transformer2   Location   : Busbar        : CPUT              /               Ratio      : 2000A/1A   |
|                                               Branch        : PILC120(1)                         Connection : Y          |
|                                                             :                                                        |
-----------------------------------------------------------------------------------------------------------------
□----------------------------------------------------------------------------------------------------------------
| Grid: Existing Network     System Stage: Existing Networ | Study Case: Study Case              | Annex:              / 2 |
-----------------------------------------------------------------------------------------------------------------
-----------------------------------------------------------------------------------------------------------------
|   Ct-0  : Current Transformer2   Location   : Busbar        : CPUT              /               Ratio      : 2000A/1A   |
|                                               Branch        : PILC120(1)                         Connection : Y          |
|                                                             :                                                        |
|   Ip 51    : Ip 51                   ( IEC: I>t   ANSI: 51   )        Current  [sec.A]      [pri.A]          Tripping Time |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.        A :     5.980      11960.06             1.153 s   |
|     Time Dial       :   0.300      Time Shift :   1.000                 B :     0.083        165.53                        |
|     Characteristic  :   IEC 255-3 normal inverse                        C :     0.092        183.72                        |
|   I> 50_1 : I> 50_1                  ( IEC: I>>   ANSI: 50   )        Tripping Current      [pri.A]          Tripping Time |
|     Pickup Current  :   8.390 sec.A  16780.00 pri.A   8.390 p.u.        A :     5.980      11960.06           9999.999 s   |
|     Time Setting    :   0.200 s                                         B :     0.083        165.53                        |
|     Total Time      :   0.220 s                                         C :     0.092        183.72                        |
|   Iep 51N : Iep 51N                  ( IEC: IE>t  ANSI: 51N  )        Tripping Current      [pri.A]          Tripping Time |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.                5.933      11866.15             0.552 s   |
|     Time Dial       :   0.200      Time Shift  :   1.000                                                               |
|     Characteristic  :   IEC 255-3 normal inverse                                                                     |
|   Ie> 50N_1 Ie> 50N_1                ( IEC: IE>>  ANSI: 50N  )        Tripping Current      [pri.A]          Tripping Time |
|     Pickup Current  :   7.970 sec.A  15940.00 pri.A   7.970 p.u.                5.933      11866.15           9999.999 s   |
|     Time Setting    :   0.100 s                                                                                      |
|     Total Time      :   0.120 s                                                                                      |
|   Output LogicOutput Logic                                                          yout            :     0.552 s     |
|     Breaker            Cubicle       Branch                   Busbar              / Substation       Fault Clearing Time |
|      CPUT-EE            Cub_2         PILC120(1)               CPUT                /                           0.552 s |
|   Closing Logiclosing Logic            Tripping Block:                                   Tripping        :  9999.999 s  |
|     Breaker            Cubicle       Branch                   Busbar              / Substation       Fault Clearing Time |
|      CPUT-EE            Cub_2         PILC120(1)               CPUT                /                           0.552 s |
-----------------------------------------------------------------------------------------------------------------
```

Relay 2 tripping current of 11.96 kA is recorded on the simulation which took 1.153 seconds to trip the circuit breaker. A ground fault tripped at 11.866 kA with a time of 0.552 seconds.

Relay 1 backup which is recorded to operate at a tripping current of 12.065 kA took 2.678 seconds to trip the circuit breaker. A ground fault tripped at same fault current with Relay 2 at 11.866 kA, however with a time delay of 1.656 seconds. This implies a time difference of 1.104 seconds between the two relays for the case where Relay 2 fails to trip.

Table 5.15: Res 1 single-phase short-circuit Relay 1 results

```
-----------------------------------------------------------------------------------------------------------------
| Relay Model_1                     Relay Type : 7SJ80_1-1A 50 Hz                                                 |
|   Ct-3p : Current Transformer     Location   : Busbar        : CPUT              /               Ratio      : 2000A/1A   |
|                                                Branch        : CoCT-CPUT                          Connection : Y          |
|                                                              :                                                       |
|   Ct-0  : Current Transformer     Location   : Busbar        : CPUT              /               Ratio      : 2000A/1A   |
|                                                Branch        : CoCT-CPUT                          Connection : Y          |
|                                                              :                                                       |
|   Ip 51    : Ip 51                   ( IEC: I>t   ANSI: 51   )        Current  [sec.A]      [pri.A]          Tripping Time |
|     Current Setting :   1.000 sec.A   2000.00 pri.A   1.000 p.u.        A :     6.032      12064.67             2.678 s   |
|     Time Dial       :   0.700      Time Shift :   1.000                 B :     0.151        301.53                        |
|     Characteristic  :   IEC 255-3 normal inverse                        C :     0.174        347.09                        |
|   I> 50_1 : I> 50_1                  ( IEC: I>>   ANSI: 50   )        Tripping Current      [pri.A]          Tripping Time |
|     Pickup Current  :   9.615 sec.A  19230.00 pri.A   9.615 p.u.        A :     6.032      12064.67           9999.999 s   |
|     Time Setting    :   0.400 s                                         B :     0.151        301.53                        |
|     Total Time      :   0.420 s                                         C :     0.174        347.09                        |
|   Iep 51N : Iep 51N                  ( IEC: IE>t  ANSI: 51N  )        Tripping Current      [pri.A]          Tripping Time |
|     Current Setting :   0.500 sec.A   1000.00 pri.A   0.500 p.u.                5.933      11866.95             1.656 s   |
|     Time Dial       :   0.600      Time Shift  :   1.000                                                               |
|     Characteristic  :   IEC 255-3 normal inverse                                                                     |
|   Ie> 50N_1 Ie> 50N_1                ( IEC: IE>>  ANSI: 50N  )        Tripping Current      [pri.A]          Tripping Time |
|     Pickup Current  :   9.585 sec.A  19170.00 pri.A   9.585 p.u.                5.933      11866.95           9999.999 s   |
|     Time Setting    :   0.300 s                                                                                      |
|     Total Time      :   0.320 s                                                                                      |
|   Output LogicOutput Logic                                                          yout            :     1.656 s     |
|     Breaker            Cubicle       Branch                   Busbar              / Substation       Fault Clearing Time |
|      Mains              Cub_1         CoCT-CPUT                CPUT                /                           1.656 s |
|   Closing Logiclosing Logic            Tripping Block:                                   Tripping        :  9999.999 s  |
|     Breaker            Cubicle       Branch                   Busbar              / Substation       Fault Clearing Time |
|      Mains              Cub_1         CoCT-CPUT                CPUT                /                           1.656 s |
-----------------------------------------------------------------------------------------------------------------
```

5.9.2 Analysis of the Results for the Performance of the Designed Settings of the Relays

This chapter presented the results for load flow and short-circuit levels calculated on DIgSILENT Power factory. The maximum and minimum short-circuit levels were calculated at various substations on the power reticulation network. Single-phase to ground and three phase to ground faults were simulated. The Table 5.16 below illustrates the findings when faults were simulated at various locations of the reticulation network. For the instant where there are two relays in series, it is clear the grading of the tripping by time has been achieved based on the upstream Relay tripping at much later time than the downstream relay closer to the fault.

Table 5.16: Tripping time results for faults at various locations

Fault Type	Location	Magnitude (kA)	Magnitude (MVA)	Trip Time (s)	Trip Relay
3-phase-to-ground	Intake busbar	19.232	366.42	0.420	Relay 1
1-phase-to-ground	Intake busbar	0.313	1.99	1.381	Relay 1
3-phase-to-ground	Line CPUT-ABC	18.36	350	0.220 & 2.161	Relay 3 & Relay 1
1-phase-to-ground	Line CPUT-ABC	17.946	1.99	0.120 & 1.413	Relay 3 & Relay 1
3-phase-to-ground	Res 1 busbar	12.562	239.34	1.119 & 2.602	Relay 2 & Relay 1
1-phase-to-ground	Res 1 busbar	11.872	75.40	0.552 & 1.656	Relay 2 & Relay 1

5.10 CONCLUSION

The chapter focussed on the protection of the CPUT incomer substation. Methods of calculating short-circuit currents were discussed and the chosen protection scheme designed. Methods for modelling and simulation of load flow and the protection requirements of the power system network were developed. The relay protection characteristics curves were determined and calculation results at various locations were obtained from the simulation. It is required to know the current amplitude at any relaying point so that the fault is to be cleared with precise discrimination.

In addition, the chapter also highlighted first principle determinations of power flow and short-circuit fault currents while modelling and simulations were performed on DIgSILENT package.

The next chapter focusses on hardware-in-the-loop testing of the protective devices taking into consideration some of the parameters obtained in this chapter while comparing the speed between the hard-wiring via the relay binary inputs and the communication via IEC 61850 GOOSE messages

CHAPTER

6. TEST BENCH SETUP FOR HARDWARE-IN-LOOP REAL-TIME SIMULATION

6.1 INTRODUCTION

Traditional substations used hard copper wiring for most substation monitoring and control of equipment. These were largely connected using binary input and output (I/O) signals, etc. This created a large number of communication wires between the substation equipment. Processing and communication always had delays. These delays could be from measurement equipment to the processing relay and from the state processing relay which then sends information to any other receiving equipment within or outside the substation. Modern technology is now slowly phasing out the traditional set-up by using Ethernet based communication.

The test bench to implement the Hardware-In-Loop Real-Time simulation using the Real-Time Digital Simulation and the SIPROTEC devices is developed. The SIPROTEC devices are a group of Siemens Intelligent Electronic Devices for protection of power system equipment. The test bench is implemented using IEC 61850 standard GOOSE message communication protocol.

Short-circuit fault monitoring, control, and analysis of the network are presented under this chapter. IEC 61850 GOOSE messaging is used to open a circuit breaker from the relay trip command via Ethernet communication. Configuration of network elements and control logic diagrams are shown and various case studies are presented. In addition the real-time simulated events of the network are presented and discussed which includes the performance of the IEDs located at the point of the incomer substation.

6.2 THE IEC 61850 SUBSTATION

The IEC 61850 standard simplifies substation communication and automation in many ways. Access of information on IEDs is made faster than in other protocols. The standard has been defined in cooperation with manufacturers and users to create a uniform, future-proof basis for protection, communication and control. Traditional substations heavily used copper wiring from one device to another. The IEC 61850 simplifies the communication wiring and reduces the amount of cables between the IEDs. Additional advantages of IEC 61850 are as follows:

- No copper interconnections between feeders, control devices, and signalling devices, therefore reduced wiring and cost.
- One communication channel for all data in real-time, synchronised via Ethernet.
- No transducers and SCADA interface
- Interoperability between multi-vendor IEDs
- Reduced time for setup and configuration
- Reduced manual efforts and errors
- More capability and flexibility
- Continuous supervision of the system through an HMI computer

With modern substations based on IEC 61850 standard, access of information between substation devices can be made easy with a remote HMI or a standard walk-in laptop with a capable software. Since there are few wires between devices, troubleshooting can be made easy and within a short period of time. Two illustrative diagrams are shown in Figure 6.1 and Figure 6.2 below showing the wiring of devices in traditional ways and with the use of IEC 61850 standard.

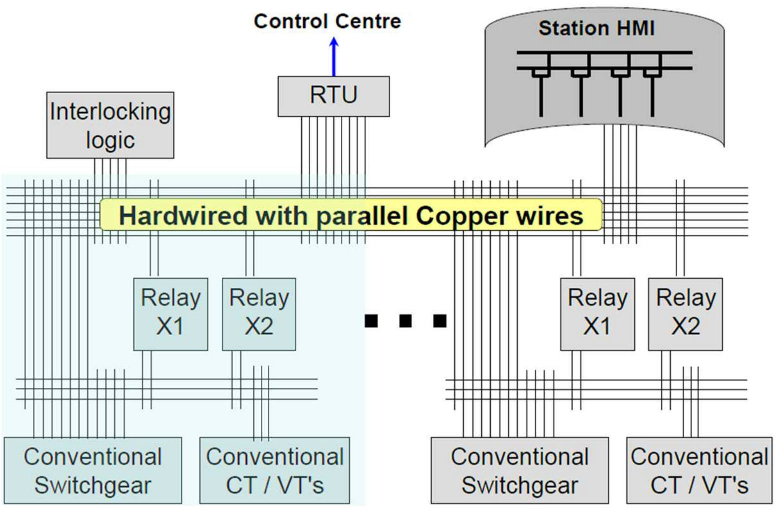


Figure 6.1: Traditional substation wiring

In Figure 6.1, devices communicate with each other simply via contacts and binary inputs and additionally with station units. This results in a large number of cables required in the substation. If the substation contains devices from different vendors, each of these devices has to use their own busbar for their configuration tools; for inter-bay communication the system needs hardwiring and binary inputs and outputs.

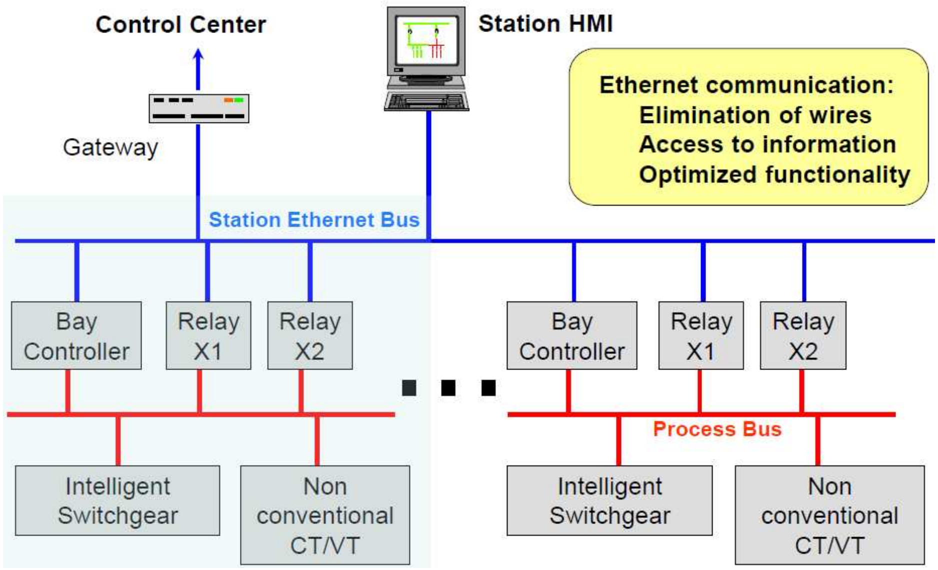


Figure 6.2: IEC 61850 substation

Figure 6.2 illustrate that with IEC 61850 standard, the system can have the possibility of running all services on any device of any vendor on the same busbar in parallel at the same time. Each of the SIPROTEC devices has two Ethernet ports which could be used for primary network and for redundancy purposes.

Ethernet has the advantage of being the widely used in most applications in today's world. The IEC 61850 standard specifies Ethernet network as a communication platform entirely and it will continue being the future network of communication within IEC 61850. The CPUT incomer substation is designed to be fully compliant with the IEC 61850 standard.

6.3 MODELLING AND SIMULATION IN RSCAD SOFTWARE ENVIRONMENT OF THE REAL-TIME DIGITAL SIMULATOR (RTDS)

Traditional simulation of power system transient phenomena has been carried out on slow speed analogue simulators which were limited in performance. Recent developments have contributed to fast digital transient network analysers which carried the purpose to test control and protection equipment and performance dynamics of such equipment in the power network environment. In normal closed-loop testing mode, the Real-Time Digital Simulator continuously performs all required calculations in time steps faster than actual time (Watson and Arrillaga, 2003).

RSCAD is a simulation software tool designed specifically for interfacing with RTDS (Real-Time-Digital Simulator) hardware to perform real-time digital simulations. The RTDS hardware is a special purpose computer designed to model electromagnetic transient phenomena in real-time. The software RSCAD and hardware RTDS work together to produce the desired results. RTDS hardware is made up of digital signal processor (DSP) and reduced instruction set computer (RISC), and utilizes advanced parallel processing techniques in order to achieve the computation speeds required to maintain continuous real−time operation. Figure 6.3 gives an interface layout of RSCAD functions with RTDS rack. The simulator has an advanced and easy to use graphical interface comprising of several modules designed to allow the user to perform all necessary steps to prepare and run simulations and to analyse simulation output.

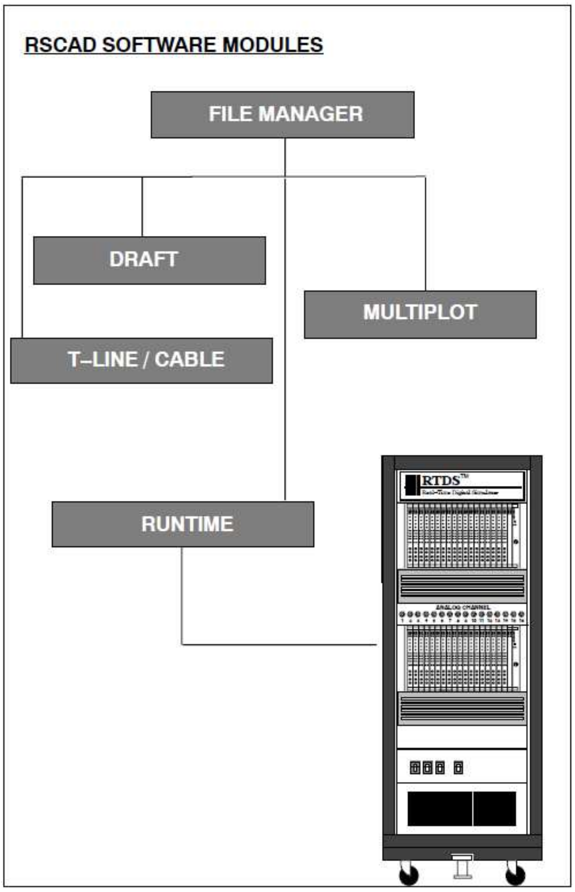


Figure 6.3: RSCAD Graphical User Interface (RTDS, 2008)

The network layout is modelled in *draft* with all components loaded from the RSCAD library. The transmission line and underground cables properties will be modelled in *T-Line/Cable* within the file manager. The *runtime* is used to read real-time data of simulated case(s) in the RTDS hardware rack. An added advantage of the runtime is that it may also be used as a supervisory control and data acquisition to either start/stop commands, sequence initiation, set point adjustment, short-circuit fault application, breaker operation, etc.

The advantage of RSCAD draft is that all elements required for the intended system operation will be directly positioned on the network layout. These could be circuit breakers, current and voltage transformers and short-circuit fault logic in which all require a logic signal to operate. The RTDS can be used in closed-loop testing of IEDs when combined with voltages and currents amplifiers. Closed-loop testing of actual hardware may influence the simulation model as illustrated in Figure 6.4 below. Signals can be sent back to the IED contacts controlling circuit breakers in the simulation workstation or externally as a physical hardware.

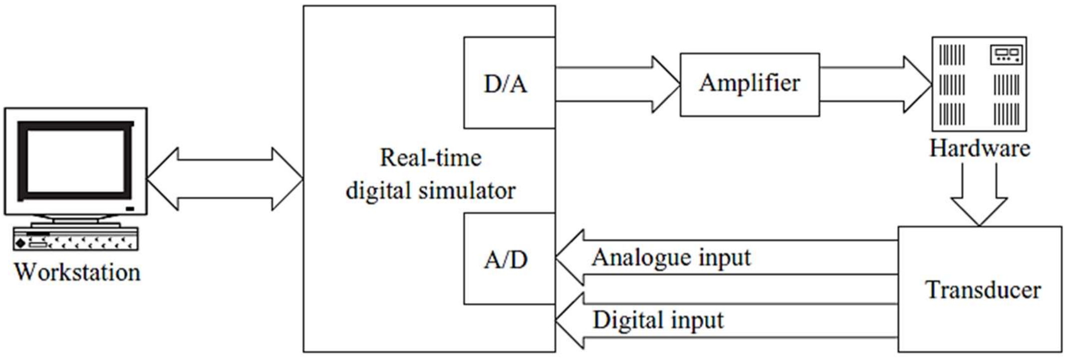


Figure 6.4: Schematic diagram of real-time simulation (Watson and Arrillaga, 2003)

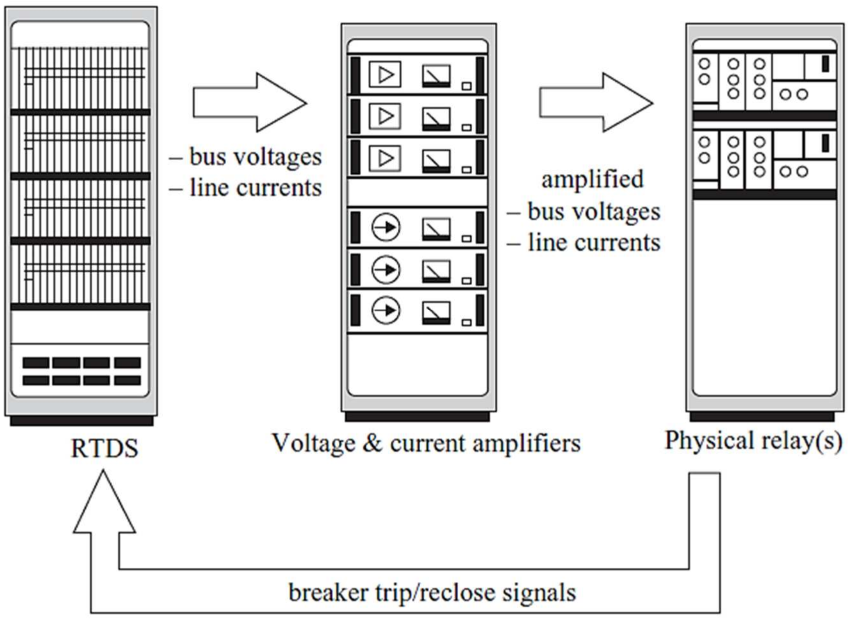


Figure 6.5: RTDS IED setup (Watson and Arrillaga, 2003)

The test bench has to operate in a manner such that a workstation (HMI) as shown in Figure 6.4 above runs the simulation in RSCAD runtime which is processed in the Real-Time Digital Simulator (RTDS) (Figure 6.4 and Figure 6.5) connected via the network. Monitoring of quantities such as substation busbar voltages and currents are viewed on the runtime. Waveforms of the quantities are also viewed if plotted. These monitored substation quantities are sent to the hardware devices such as IEDs via an amplifier. The hardware (physical) devices process the measured quantities and perform required functions in the case of changes of events depending on the severity of such events. When an event which required tripping of the breakers occurs on the network system, the hardware device (IED) sends an output as an analogue or digital signal to the RTDS to either trip or reclose the circuit breaker located in the RTDS RSCAD as shown in Figures 6.4 and 6.5 above. The RTDS processors process these required functions in real-time and these are monitored back in the workstation computer (HMI).

6.4 RSCAD MODEL OF THE CPUT INCOMER SUBSTATION

The intake substation RSCAD model was developed as shown in Figure 6.6 in simple three phase view and in Figure 6.7 in single line view. The entire network model can be viewed in Appendix E and Appendix F. Parameters of the network are the same as the ones used in Chapter 4 for DigSILENT calculations. This model is used for building the HIL RTDS real-time simulation. Having the incomer substation diagram is necessary to describe how the monitoring, protection and control scheme is implemented.

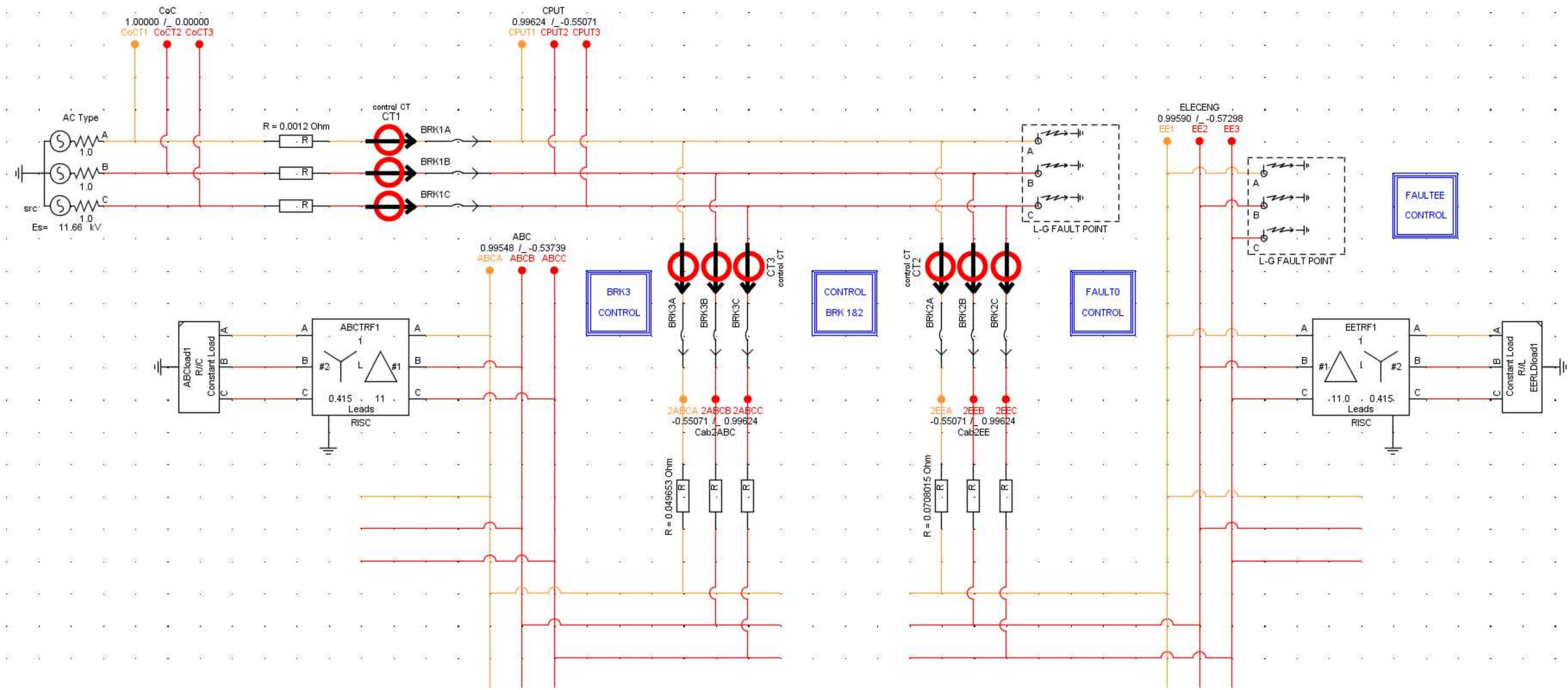


Figure 6.6: Intake Substation Modelling on RSCAD Draft – 3-line mode

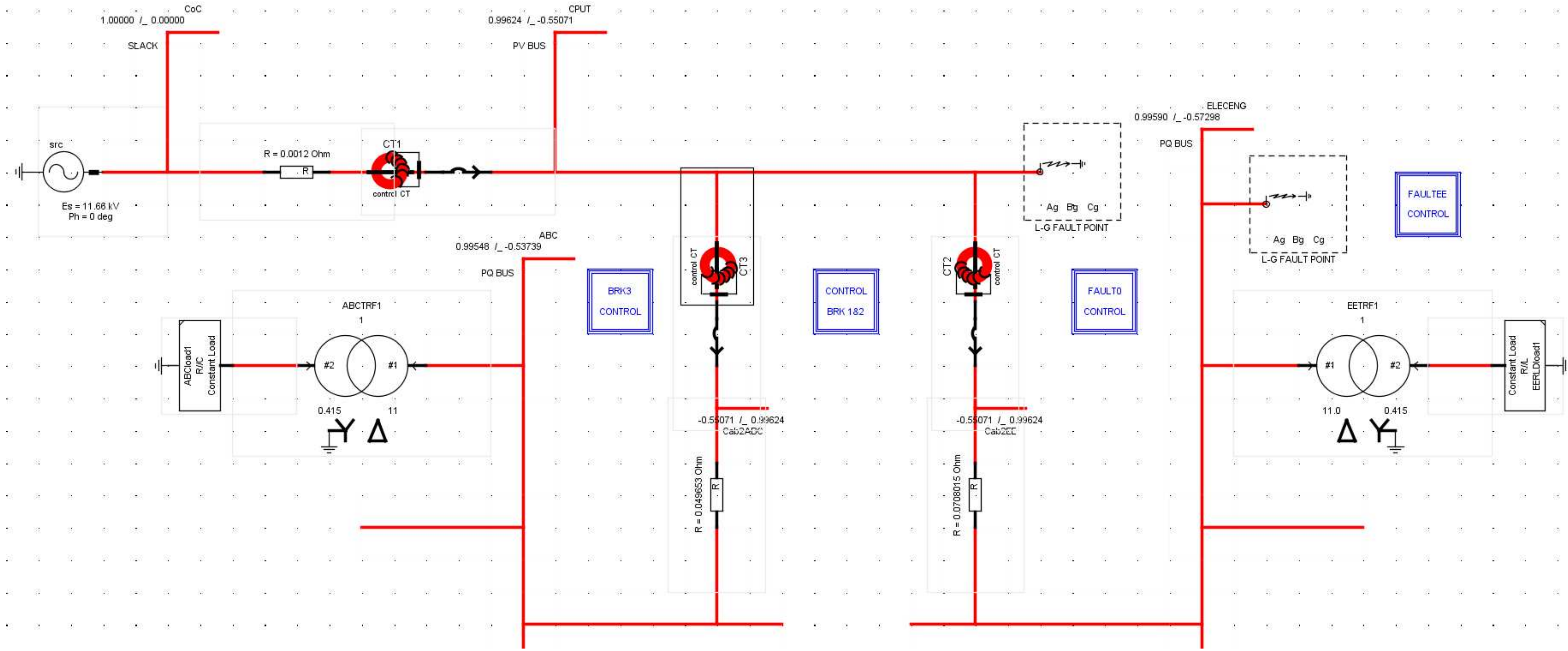


Figure 6.7: Intake Substation Modelling on RSCAD Draft – Single-line mode

6.5 SETTING UP LABORATORY WORKSTATION

The workstation is to be implemented using the HIL RTDS simulation. The monitoring, protection and control scheme has to have the 3 relays (also referred as IEDs in this chapter) as discussed in the previous chapters. The role of the devices in the HIL scheme are:

- RTDS – Real-time simulation of the incomer substation and the network
- IED 1 – SIPROTEC 7SD5 for protection of the incomer feeder.
- IED 2 – SIPROTEC 7SJ64 for protection of the outgoing feeder towards ELEC ENG building substation
- IED 3 – RTDS internal relay for the protection of the outgoing feeder towards ABC building substation.
- Network switch – Ruggedcom RS900G network switch for interconnecting the hardware devices
- HMI 1 – Computer 1 for management of software that only functions on Windows XP operating system
- HMI 2 – Computer 2 for management of RSCAD 5 on latest Windows operating system
- Circuit breakers 1, 2, and 3 – operated within RSCAD
- CTs 1, 2, and 3 – operated within RSCAD

Software packages used for building of the test-bench

- Windows XP – HMI 1
- Windows 10 – HMI 2
- DiGSI 4 - Siemens software for configuration of SIPROTEC devices (IEDs)
- RSCAD – for real-time simulation in RTDS
- DIgSILENT – Power flow simulation software package.
- Wireshark – GOOSE message sniffing tool
- GOOSE Inspector – GOOSE message sniffing tool.

All components of the workstation were assembled as shown in Figure 6.8 below. Each device requires a unique Internet Protocol Address (IP Address) to communicate effectively on the network without conflicting with any other device. In order for IEC 61850 complying devices to be able to send or receive data with one another, they need to be connected in the same Local Area Network (LAN) network. The RTDS GTWIF card, the GTNET card, the external IEDs 7SD5 & 7SJ64 and the control computers should each have a physical connection to the LAN via Ethernet cables. It shall be noted that the use of two HMIs in the workstation was only to enable working in different Windows platforms. The DiGSI4 manager only operates in Windows XP which in this case is used in HMI 1. HMI 1 configures each device and HMI 2 runs the system simulations and monitors power system measurements and equipment status via *RSCAD runtime*.

The two external IEDs were configured from their primary functions to perform overcurrent protection.

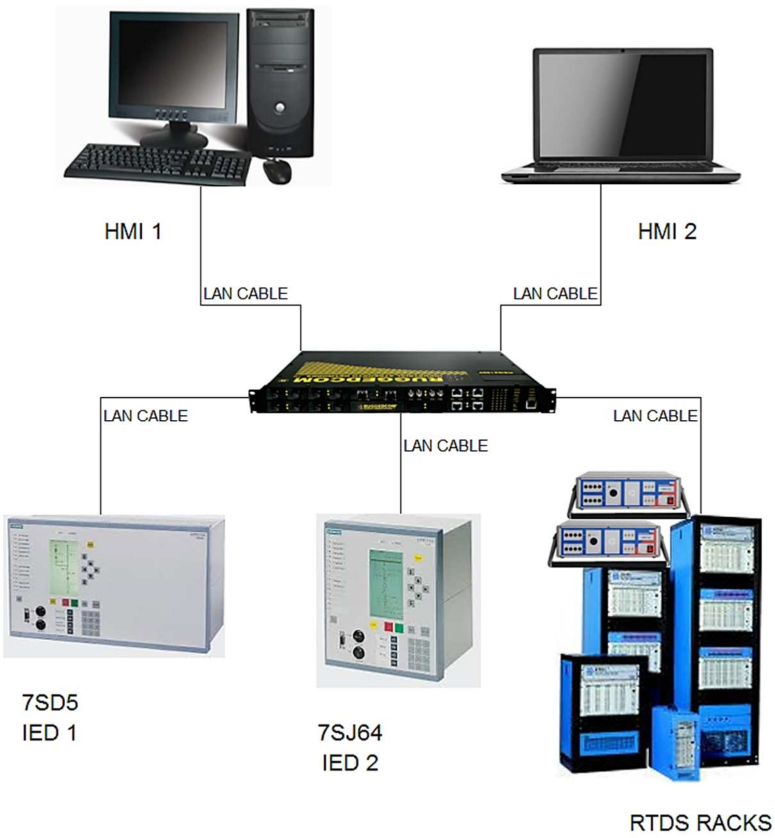


Figure 6.8: Laboratory test workstation

Each device is assigned a unique IP Address as listed in Table 6.1 below. The GTNET card is located within rack 1 of the RTDS and it has its own unique IP Address which was found to be 192.168.1.201. This address can be checked on command prompt via Telnet which will be discussed later. IED 1 is assigned to control the incomer feeder breaker from the Utility while IED 2 takes control of outgoing feeder breaker towards Electrical Engineering substation.

Table 6.1: Device unique IP addresses

DEVICE	DESCRIPTION	IP ADDRESS
Control PC (HMI1)	DIGSI4 Controller	192.168.1.100
Control PC (HMI2)	RSCAD	192.168.1.120
IED 1	SIPROTEC 7SD5	192.168.1.1
IED 2	SIPROTEC 7SJ64	192.168.1.2
RTDS	Rack 1 and location of GTNET card	192.168.1.101
RTDS	Rack 2 for additional nodes	192.168.1.102

6.5.1 Setting Up Device Configuration with DIGSI4 Manager

The SIPROTEC family devices use the DIGSI Manager to manage the changing of properties for all SIPROTEC devices. To achieve configuration it is needed to insert two IEDs as shown in Table 6.1, the RTDS GTNET and the IEC 61850 GOOSE mapping station (these are explained in later sections). IED 1 and IED 2 were inserted into the DiGSI4 device manager and the IEC 61850 station within DiGSI4 which manages the mapping of IEDs to complete the GOOSE communication. The GTNET card is also inserted in the IEC 61850 station to receive the GOOSE message which will be published from IED 2.

Before configuration of devices occurs, each of these devices must be connected on the same network via Ethernet as shown in Figure 6.9. IP addresses of the HMIs must be computed and HMI 1 must be connected with IED 1 and IED 2 via serial communication. The serial communication is the first method of connecting the device with the DIGSI4 device manager. Once the IP address of the IEDs has been changed, then the communication via Ethernet is made possible.

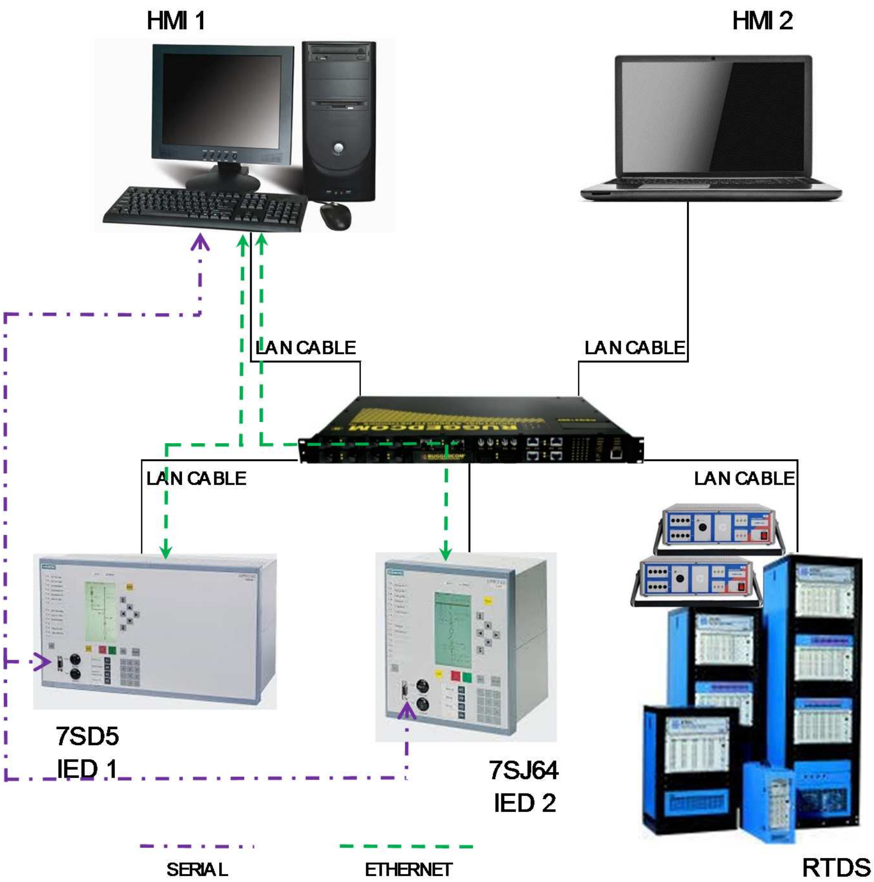


Figure 6.9: Setting up devices for communications

Step by step implementation of the above is as follows:

1. Go to *File* and create new folder.
2. Rename the folder with the name *Substation* or any other preferred name.
3. In order to insert a device on this *Substation*, *right click* on the substation folder and the device dialog presents itself in the manner as shown in Figure 6.10 below and then select *SIPROTEC device.*
4. A new device catalog dialog of the SIPROTEC devices opens (Figure 6.11 (a)). Select the required IED version on the list (Figure 6.11 (b)) and *drag and drop* on the substation folder as illustrated in Figure 6.12 below.

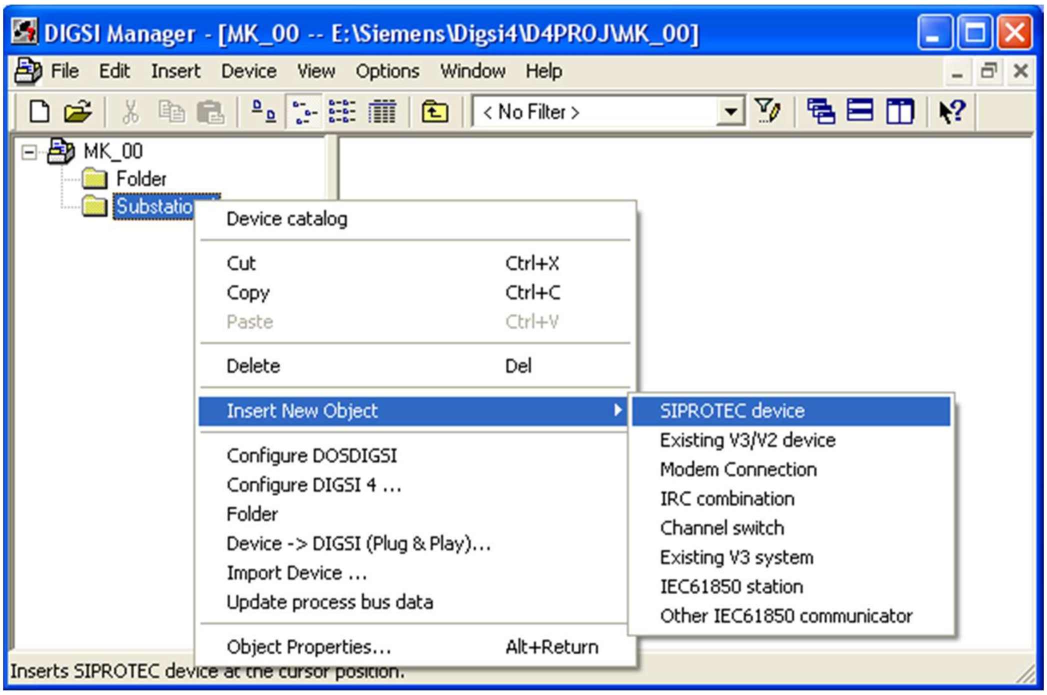
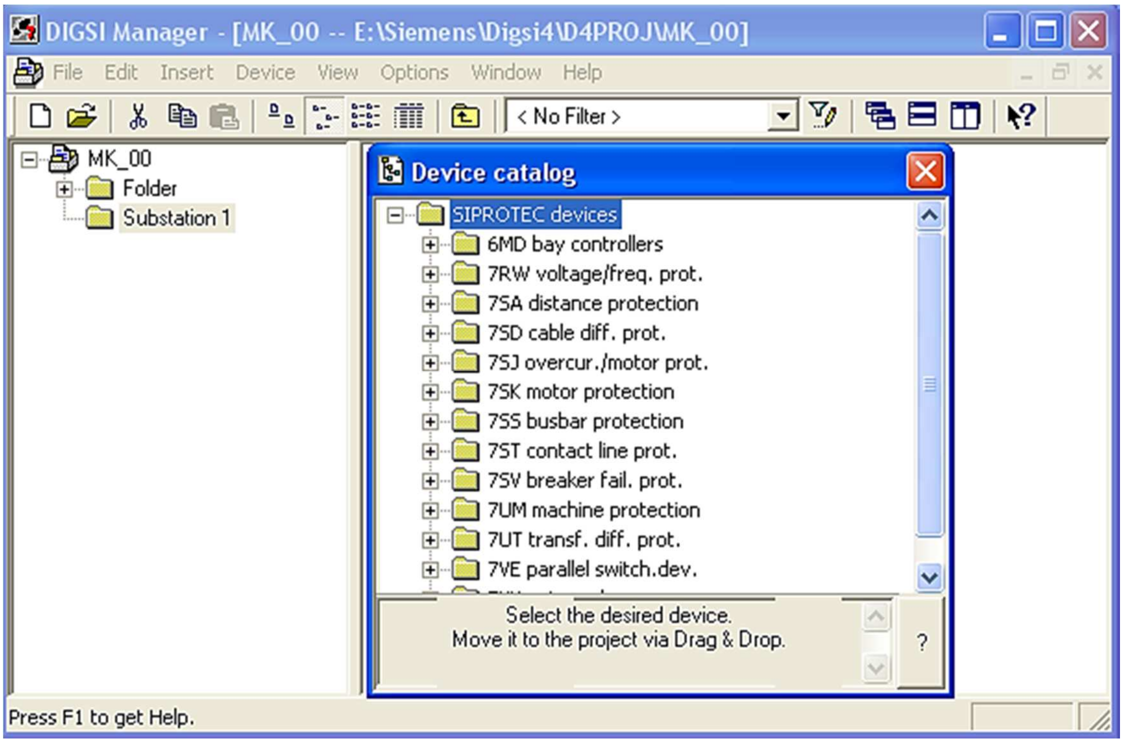
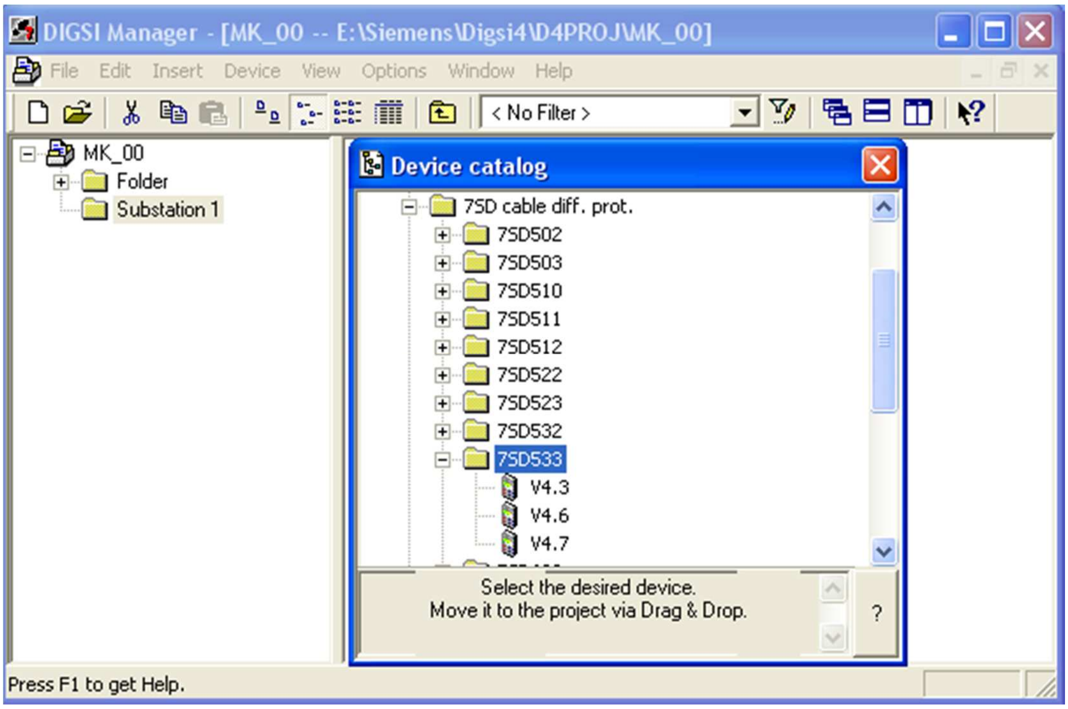


Figure 6.10: Inserting devices on DIGSI manager



(a) Device catalog



(b) Device catalog, selection of the 7SD533 IED

Figure 6.11: Selecting device on DIGSI manager

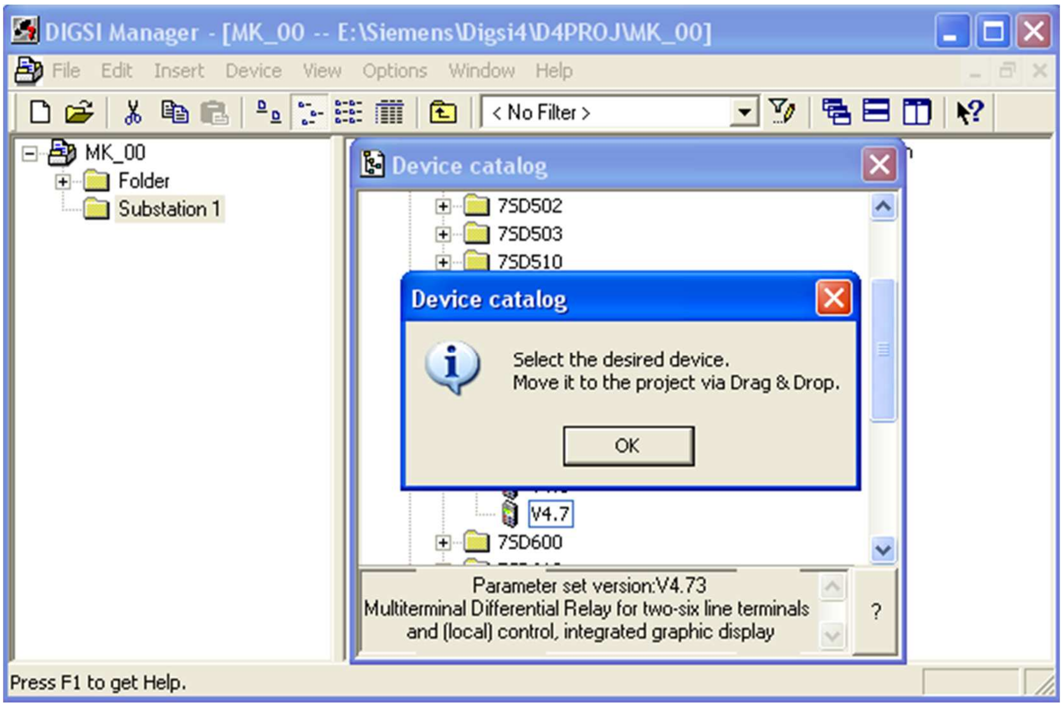
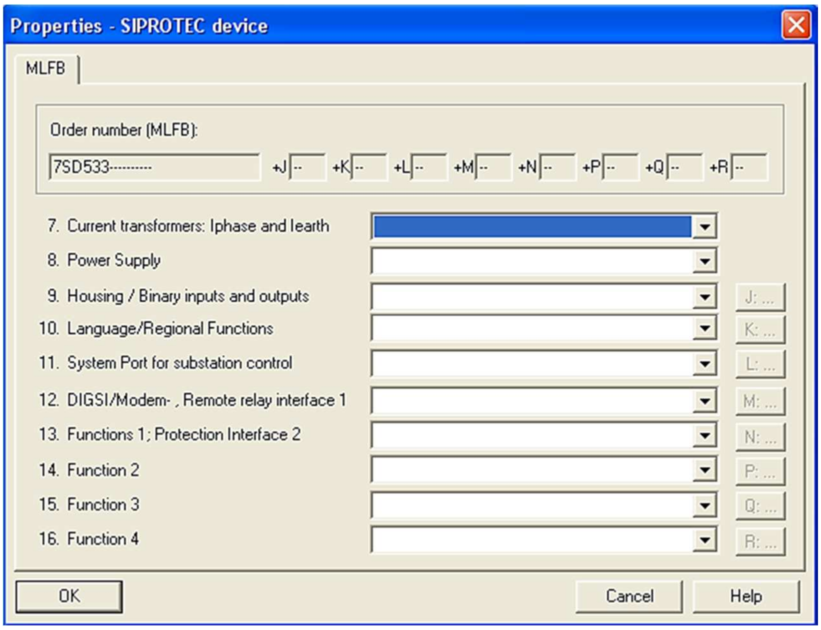


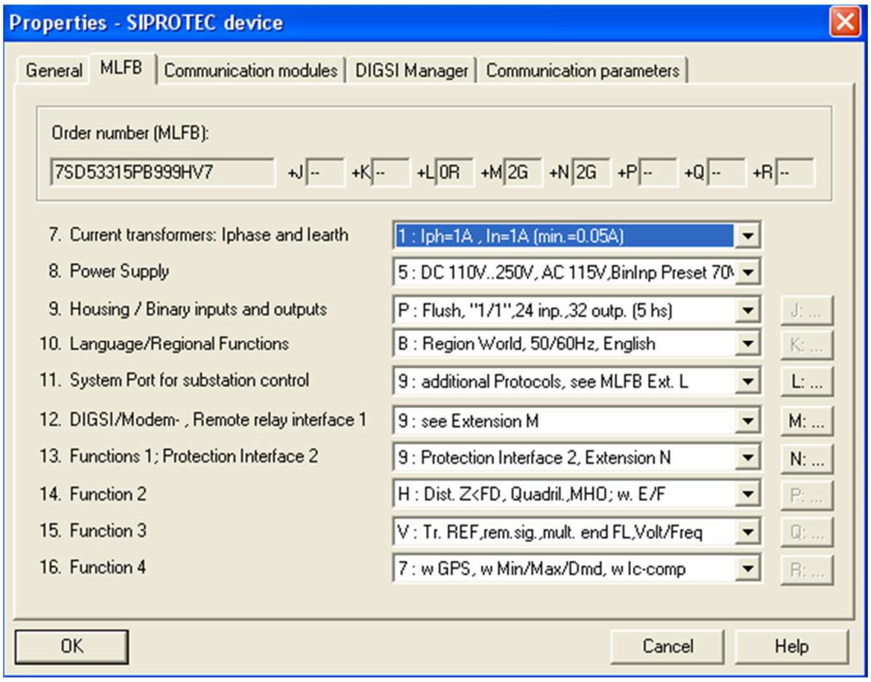
Figure 6.12: Choosing device on DIGSI manager

5. Once the selection of the device is completed, the unique device function needs to be entered in the device Machine Readable Product Code called the MLFB properties. Initial state of the MLFB presents a blank dialog

(Figure 6.13 (a)) which needs to be populated. The complete device MLFB number can be found on the device nameplate according to the order number. When the MLFB number is completed on the dialog, it will be represented as shown in Figure 6.13 (b). This process shall be repeated for inserting any other SIPROTEC device on the substation.



(a) Incomplete device MLFB file



(b) Complete device MLFB file

Figure 6.13: Device MLFB properties

6. After completing the inserting of IEDs, the IEC 61850 station which should be used for mapping the devices shall be inserted on the substation as shown in Figure 6.14 below.

Each device can now be configured for communication via Ethernet and to provide special device identity names such as IED 1 and IED 2. The initial step is to first link the host HMI 1 with the DIGSI4 device manager using *Configure DIGSI4* (Figure 6.14) and configure the Ethernet IP address to 192.168.1.1 as described in Table 6.1 above and shown in Figure 6.15 below. The communication port which is used for direct (serial) communication with the device is identified from the Windows control panel - *Computer Management – Device manager - Ports* which displays all ports being used on the HMI station.

When the above is completed, the connection to the device can be completed via *Initialize device – Direct* connection with the *PC interface* selected to the correct communication port number. When configuration is completed, all configured properties must be uploaded to the physical device via *DIGSI -> device* as shown in Figure 6.16

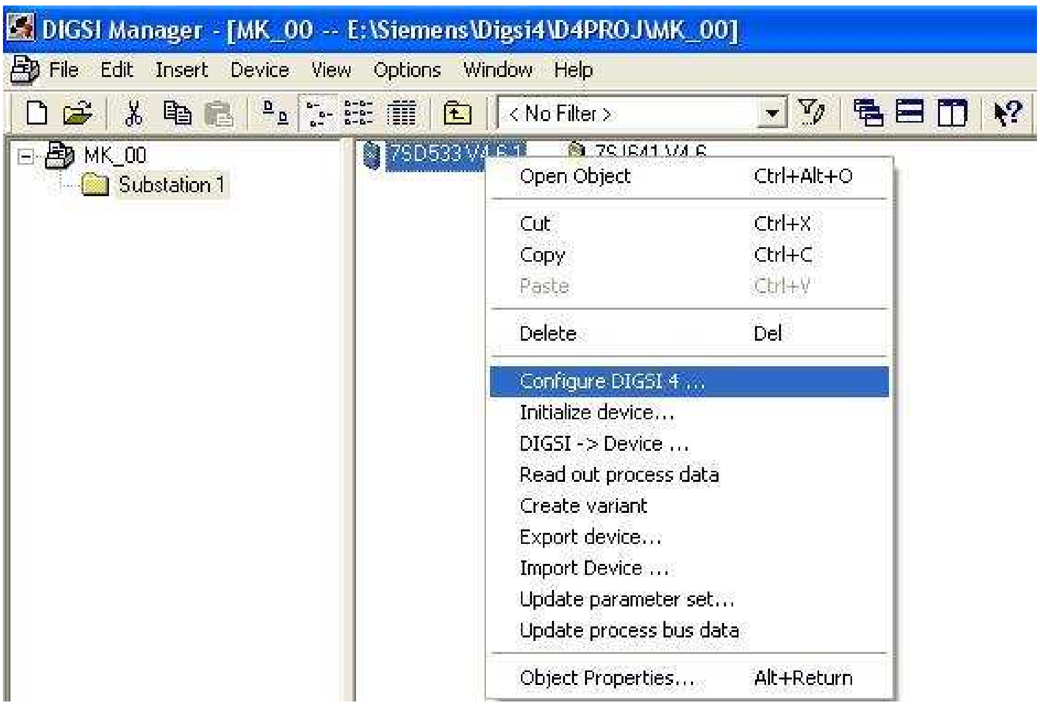


Figure 6.14: Configuring 7SD5 device parameters

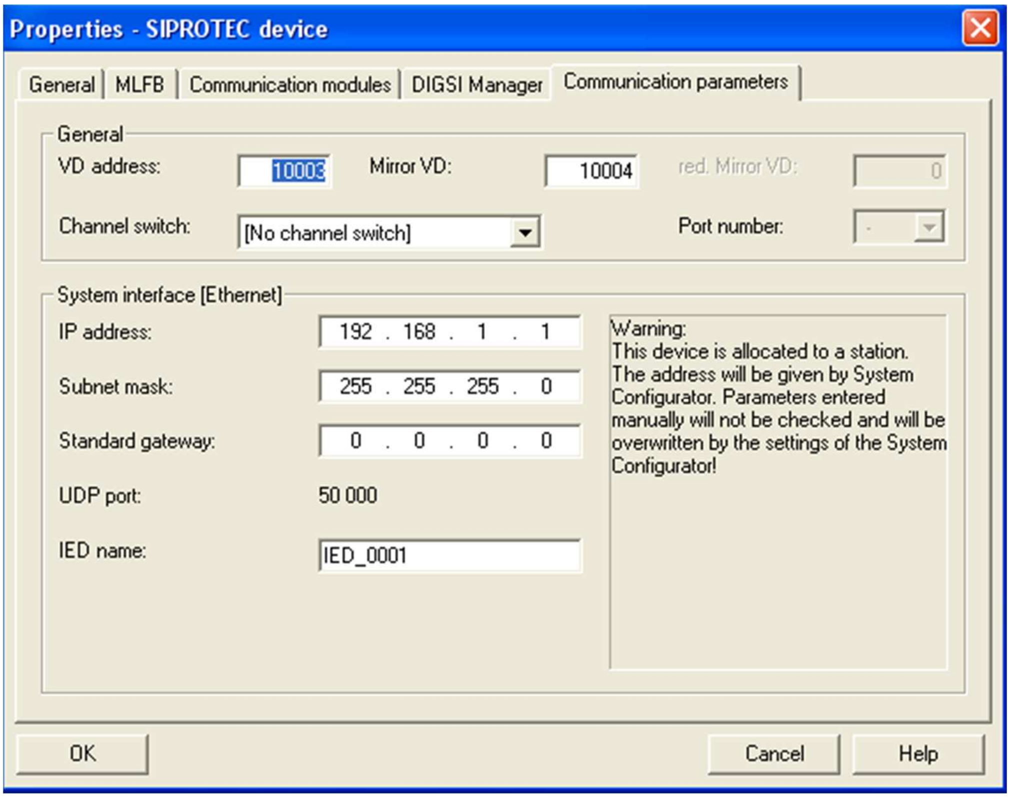


Figure 6.15: Configuring 7SD5 device IP address

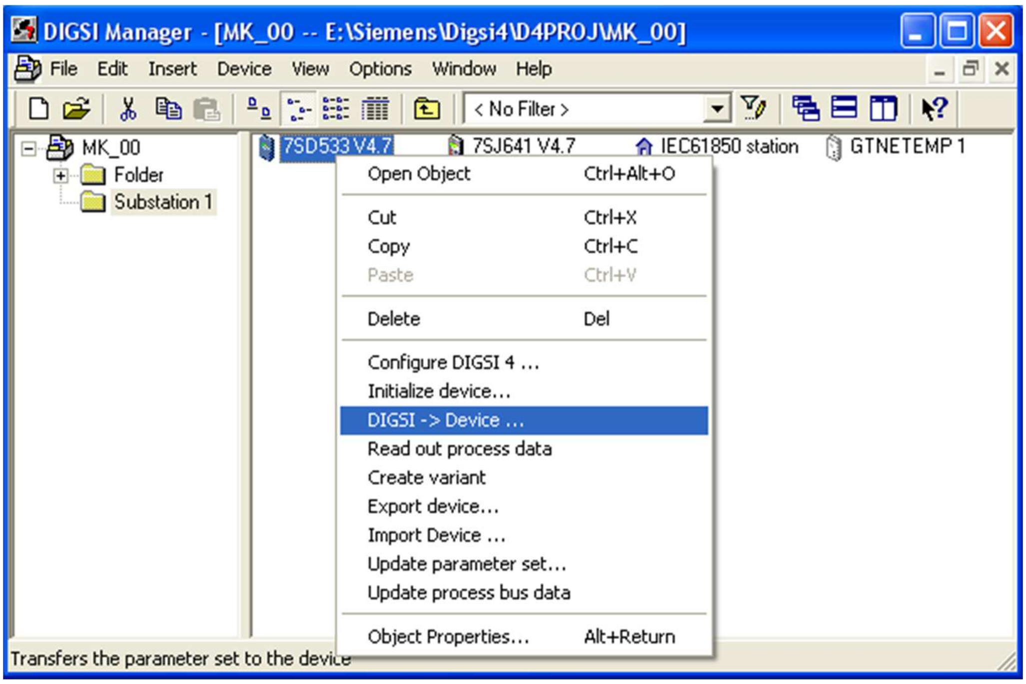
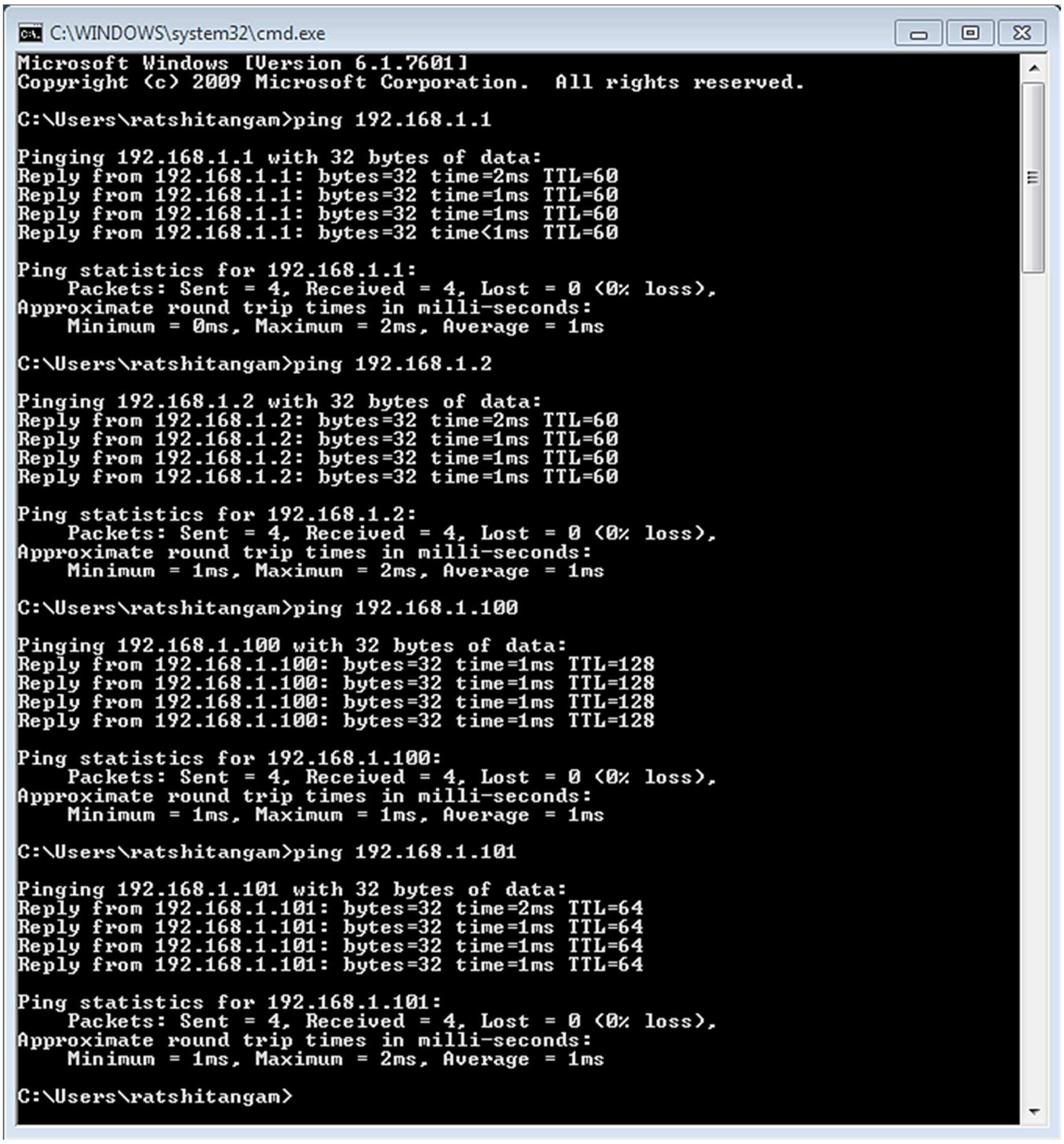


Figure 6.16: Writing the configured parameters and properties of the 7SD5 to the physical device

After completing the 7SD5 device configuration, all the steps are repeated when inserting and configuring the 7SJ64 device. When writing to all devices is completed, the Windows command prompt can be used to verify communication connectivity of each device using ping command as shown in Figure 6.17. This method confirms whether all devices are connected on the same network.



```
C:\WINDOWS\system32\cmd.exe
Microsoft Windows [Version 6.1.7601]
Copyright (c) 2009 Microsoft Corporation.  All rights reserved.

C:\Users\ratshitangam>ping 192.168.1.1

Pinging 192.168.1.1 with 32 bytes of data:
Reply from 192.168.1.1: bytes=32 time=2ms TTL=60
Reply from 192.168.1.1: bytes=32 time=1ms TTL=60
Reply from 192.168.1.1: bytes=32 time=1ms TTL=60
Reply from 192.168.1.1: bytes=32 time<1ms TTL=60

Ping statistics for 192.168.1.1:
    Packets: Sent = 4, Received = 4, Lost = 0 (0% loss),
Approximate round trip times in milli-seconds:
    Minimum = 0ms, Maximum = 2ms, Average = 1ms

C:\Users\ratshitangam>ping 192.168.1.2

Pinging 192.168.1.2 with 32 bytes of data:
Reply from 192.168.1.2: bytes=32 time=2ms TTL=60
Reply from 192.168.1.2: bytes=32 time=1ms TTL=60
Reply from 192.168.1.2: bytes=32 time=1ms TTL=60
Reply from 192.168.1.2: bytes=32 time=1ms TTL=60

Ping statistics for 192.168.1.2:
    Packets: Sent = 4, Received = 4, Lost = 0 (0% loss),
Approximate round trip times in milli-seconds:
    Minimum = 1ms, Maximum = 2ms, Average = 1ms

C:\Users\ratshitangam>ping 192.168.1.100

Pinging 192.168.1.100 with 32 bytes of data:
Reply from 192.168.1.100: bytes=32 time=1ms TTL=128
Reply from 192.168.1.100: bytes=32 time=1ms TTL=128
Reply from 192.168.1.100: bytes=32 time=1ms TTL=128
Reply from 192.168.1.100: bytes=32 time=1ms TTL=128

Ping statistics for 192.168.1.100:
    Packets: Sent = 4, Received = 4, Lost = 0 (0% loss),
Approximate round trip times in milli-seconds:
    Minimum = 1ms, Maximum = 1ms, Average = 1ms

C:\Users\ratshitangam>ping 192.168.1.101

Pinging 192.168.1.101 with 32 bytes of data:
Reply from 192.168.1.101: bytes=32 time=2ms TTL=64
Reply from 192.168.1.101: bytes=32 time=1ms TTL=64
Reply from 192.168.1.101: bytes=32 time=1ms TTL=64
Reply from 192.168.1.101: bytes=32 time=1ms TTL=64

Ping statistics for 192.168.1.101:
    Packets: Sent = 4, Received = 4, Lost = 0 (0% loss),
Approximate round trip times in milli-seconds:
    Minimum = 1ms, Maximum = 2ms, Average = 1ms

C:\Users\ratshitangam>
```

Figure 6.17: Command ping results via Ruggedcom RS900G

When the workstation setup is completed, communication should be shared between all devices. The workstation should be ready for hardware-in-the-loop simulation with each device connected via the Ethernet network. The final hard wiring and communication structure is shown in Figure 6.18. Measurement of currents are sent to IEDs via hard wiring cables from the RSCAD CTs. Trip command from IED 1 is sent to the RTDS via hard wiring cables to the RTDS while the trip command of IED 2 is sent via Ethernet GOOSE messaging to the

RTDS for processing. The RTDS processed information (trip signal and status changes) is monitored in the HMI2 via the Ethernet. Table 6.2 shows the signals matrix between devices.

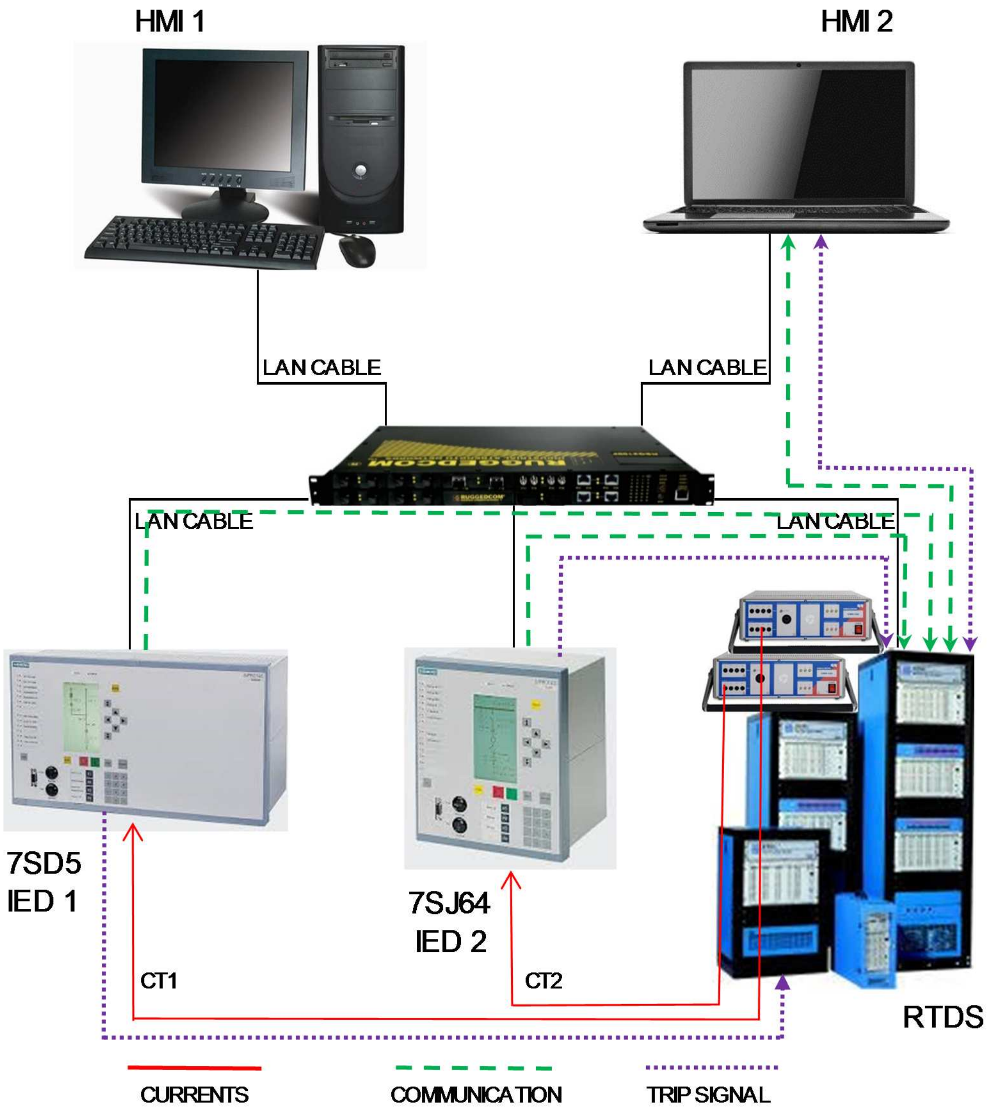


Figure 6.18: Workstation operation diagram

Table 6.2: Type of signals in the test workstation

	HMI 1	HMI 2	7SD5	7SJ64	RTDS
HMI 1	-	-	-	-	-
HMI 2	-	-	Control / Monitoring	Control / Monitoring	-
7SD5	-	-	-	-	Trip (H/W)
7SJ64	-	-	-	-	Trip (GOOSE)
RTDS	-	-	CT1 Currents (H/W)	CT2 Currents (H/W)	-

6.6 HARDWARE-IN-LOOP CONTROL WITH RTDS

As opposed to DIgSILENT where the entire simulation was completed on software, the RSCAD-RTDS provides added advantage of hardware-in-loop simulation. This method interfaces the RTDS with hardware devices such as protection IEDs for either testing the operation of the IEDs or performing closed-loop operations. In closed-loop, the response of the device IED is sent back to the RTDS simulator in order to complete a specific purpose such as breaker opening within the simulator runtime. The setup of the network intake substation is configured in the manner as described below.

6.6.1 Incomer Feeder Breaker 1 Control Using Hardwire

6.6.1.1 GTAO card configuration.

Breaker 1 protects CPUT busbar for any short circuit faults at the bus. The current passing through this breaker in the RSCAD RTDS model of the incomer substation is measured through current transformer CT1 and sent to the external protection IED SIPROTEC 7SD5 (IED 1) via the RTDS analog output card GTAO3 (shown in Figure 6.19) which writes the input signals to a high precision analogue card. Six voltages and six current digital/analogue inputs can be enabled on the GTAO3. In this case, the six current for the two breakers are enabled as shown in Figure 6.20 while the voltage inputs remain unused (input 4-6, and input 10-12).

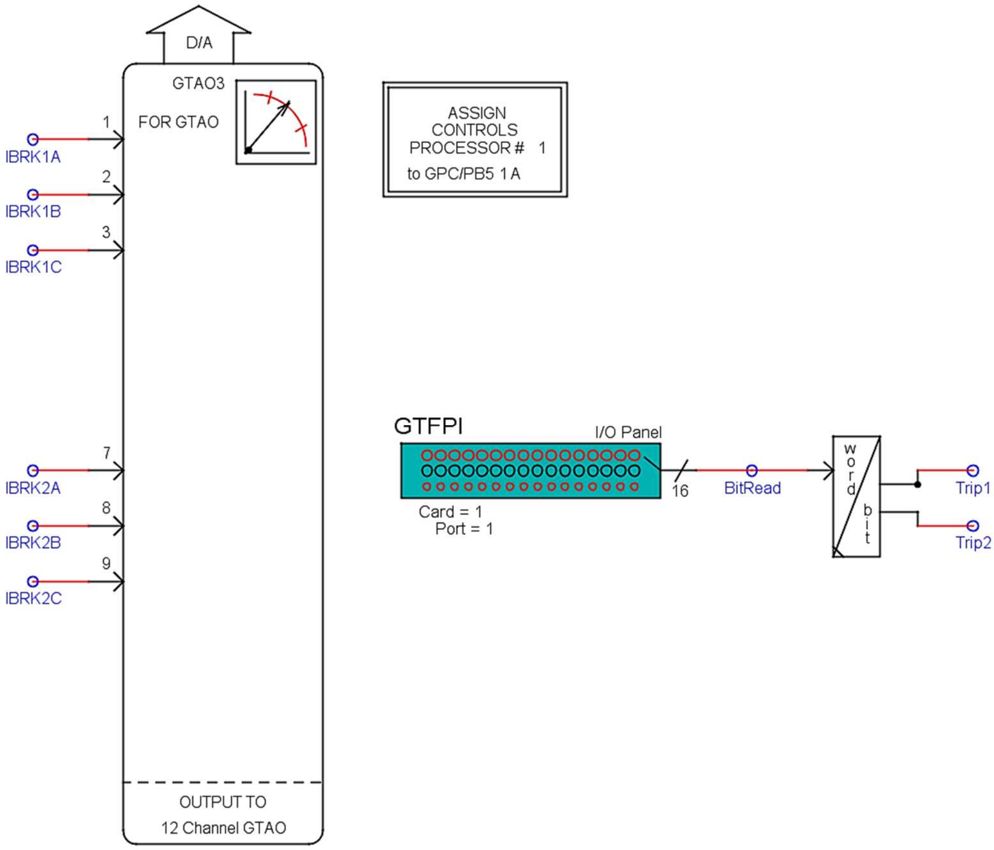
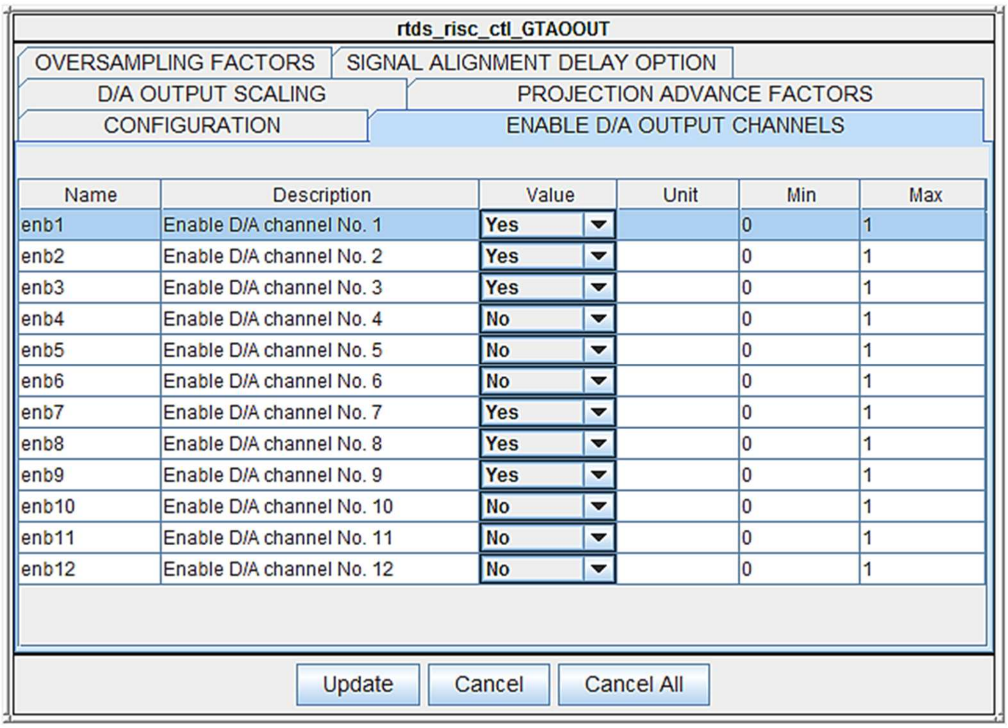


Figure 6.19: GTAO Breaker 1 & 2 input signals and GTFPI outputs.



Name	Description	Value	Unit	Min	Max
enb1	Enable D/A channel No. 1	Yes		0	1
enb2	Enable D/A channel No. 2	Yes		0	1
enb3	Enable D/A channel No. 3	Yes		0	1
enb4	Enable D/A channel No. 4	No		0	1
enb5	Enable D/A channel No. 5	No		0	1
enb6	Enable D/A channel No. 6	No		0	1
enb7	Enable D/A channel No. 7	Yes		0	1
enb8	Enable D/A channel No. 8	Yes		0	1
enb9	Enable D/A channel No. 9	Yes		0	1
enb10	Enable D/A channel No. 10	No		0	1
enb11	Enable D/A channel No. 11	No		0	1
enb12	Enable D/A channel No. 12	No		0	1

Figure 6.20: GTAO Breaker 1 & 3 Current input signals configuration.

CT1 currents are sent to channels 1, 2, & 3 of the GTAO3 and CT2 currents are sent to channels 7, 8 & 9 of the GTAO card as shown in Figure 6.20. The measured currents are sent from the GTAO to the amplifier which is connected to the RTDS. The amplifier's outputs are then correspondingly sent to the external protection IED's current input connections. The external IED's trip command then are sent back to the RTDS via the front of the GTFPI I/O panel (shown on Figure 6.19) on the RTDS rack. Digital input number 7 on the GTFPI is used as a breaker IED 1 trip command input and digital input number 9 is used as a breaker IED 2 trip command signal. A simple basic flow diagram for control hardware in loop real-time simulation is shown in Figure 6.21 below.

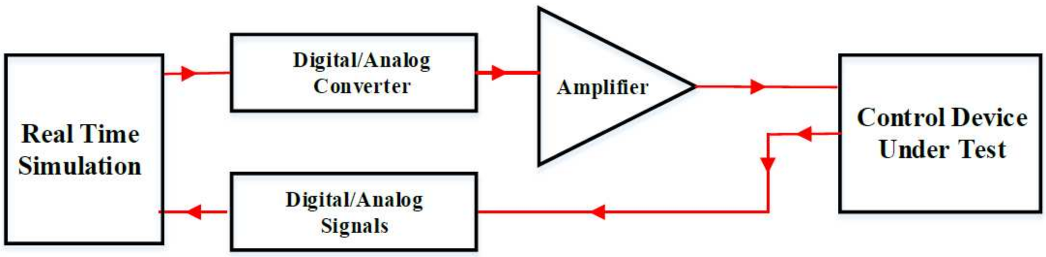
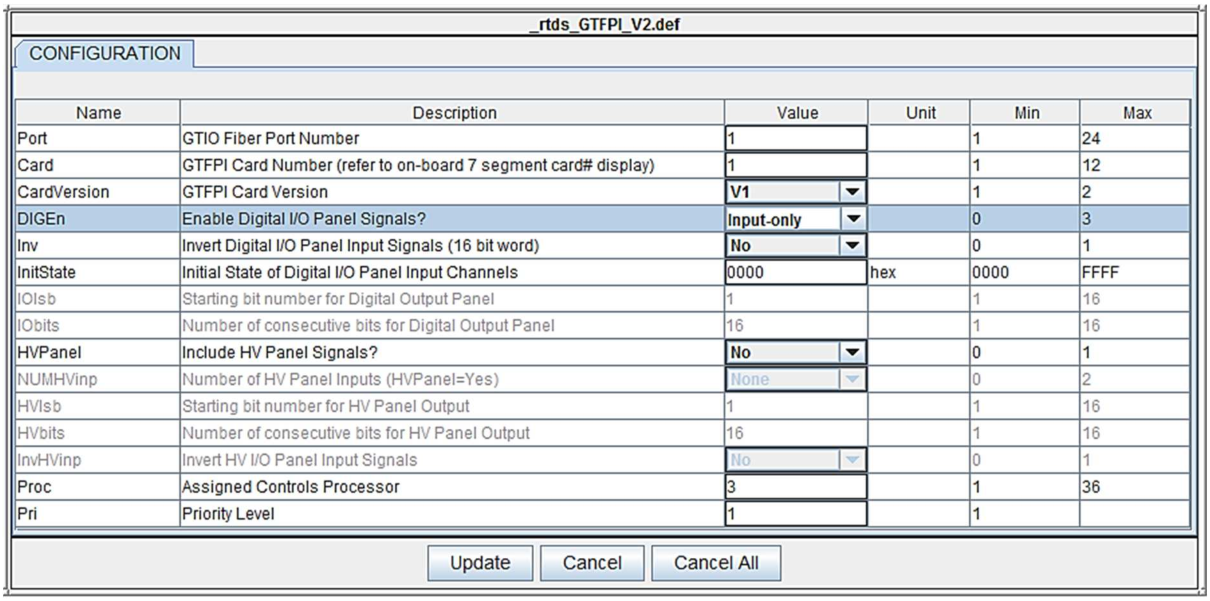


Figure 6.21: Closed-Loop hardware in loop simulation.

6.6.1.2 GTFPI configuration

The GTFPI needs to be configured as per Figure 6.22 below. It has to be ensured that the digital I/O panel signals are enabled as "Input-only" and not "invert" the signals. This allows panels signals as inputs only, taking binary outputs from the external IEDs. In addition, the HV panel is not included in the considered case.



_rtds_GTFPI_V2.def

CONFIGURATION

Name	Description	Value	Unit	Min	Max
Port	GTIO Fiber Port Number	1		1	24
Card	GTFPI Card Number (refer to on-board 7 segment card# display)	1		1	12
CardVersion	GTFPI Card Version	V1		1	2
DIGEn	Enable Digital I/O Panel Signals?	Input-only		0	3
Inv	Invert Digital I/O Panel Input Signals (16 bit word)	No		0	1
InitState	Initial State of Digital I/O Panel Input Channels	0000	hex	0000	FFFF
IOlsb	Starting bit number for Digital Output Panel	1		1	16
IObits	Number of consecutive bits for Digital Output Panel	16		1	16
HVPanel	Include HV Panel Signals?	No		0	1
NUMHVinp	Number of HV Panel Inputs (HVPanel=Yes)	None		0	2
HVlsb	Starting bit number for HV Panel Output	1		1	16
HVbits	Number of consecutive bits for HV Panel Output	16		1	16
InvHVinp	Invert HV I/O Panel Input Signals	No		0	1
Proc	Assigned Controls Processor	3		1	36
Pri	Priority Level	1		1	

Update Cancel Cancel All

Figure 6.22: GTFPI configuration

6.6.1.3 Breaker 1 control logic

Since IED's automatic reclosing is not enabled in this case, a control logic which enables manual closing of the breaker is developed and shown in Figure 6.23.

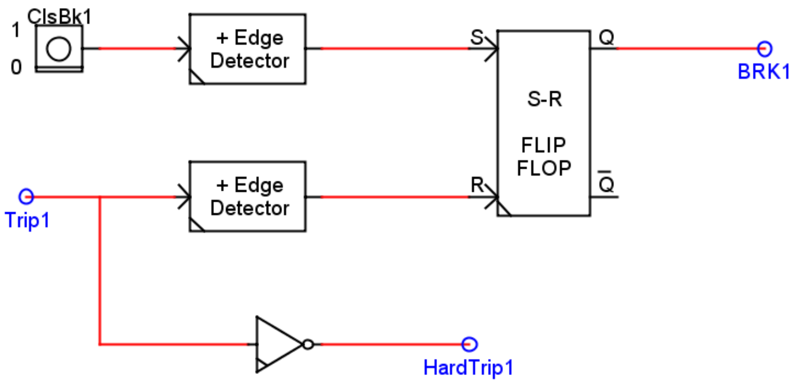


Figure 6.23: Breaker 1 Control logic diagram.

When a single-phase, phase-phase, or three-phase to ground short-circuit fault occurs on the feeder bus, IED 1 is expected to issue a trip command which is sent back to RTDS to open the Breaker 1 within RSCAD runtime.

6.6.2 Outgoing Feeder 2 Breaker Control Using Hardwire

Section 6.6.1.1 and 6.6.1.2 configurations above are enabled for both IED 1 and IED 2. The developed control logic for Breaker 2 is described below in 6.6.2.1

6.6.2.1 Breaker 2 control logic

Breaker 2 is controlled by control logic in Figure 6.24 shown below. The circuit compares two trip commands namely hard-wired trip (similar to IED 1) and GOOSE message trip. Channels 7, 8, & 9 read CT2 currents which are sent to IED 2 (SIPROTEC 7SJ64) via hard wiring similar to IED 1 as described above. When the IED 2 issues a trip command, the hardwiring binary output and the Ethernet GOOSE both send their signals out for processing. For the control logic below, the signal which gets past the flip-flop faster passes the OR gate first to trip the RSCAD breaker whose status is monitored on "*Runtime*" in real-time. For this case, the time taken by the two methods is compared.

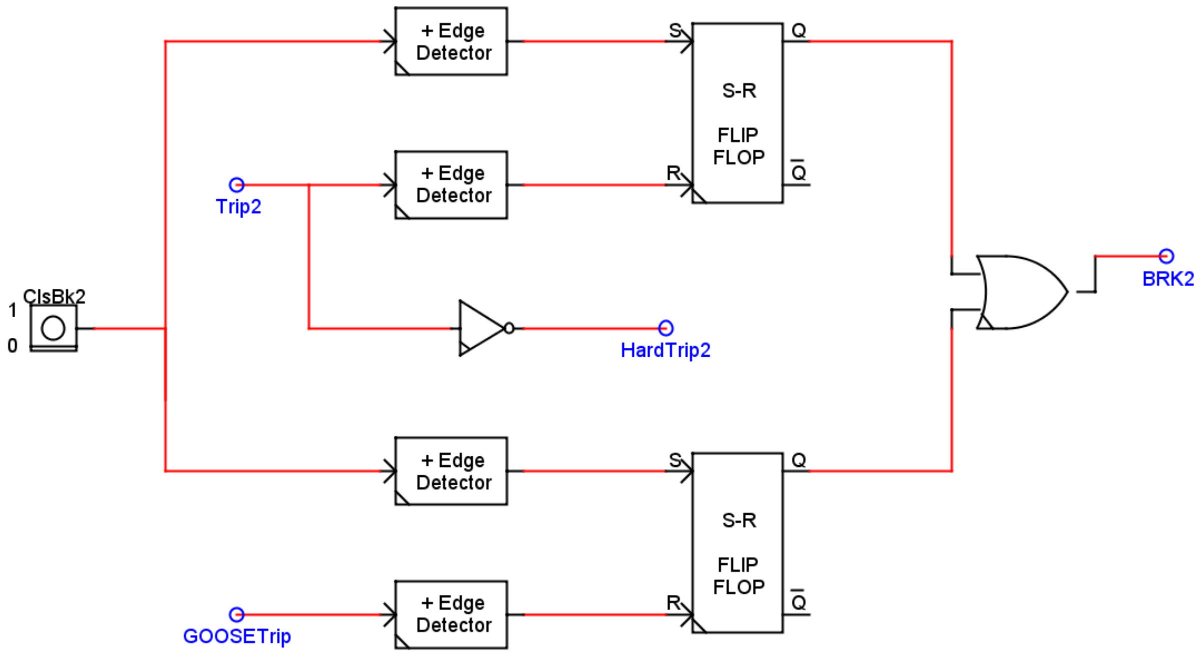


Figure 6.24: Breaker 2 Control logic diagram

6.6.2.2 Outgoing Feeder 2 Breaker Control Using GOOSE messages

The goal of the IEC 61850 standard is to provide interoperability between substation IEDs. Conformance to the standard guarantees that the IEDs from different vendors can communicate to each other. To setup GOOSE communication, one needs to create special files in a format defined by IEC 61850. These files shall be downloaded into all devices which are meant to communicate with each other. It is usual practice for IED manufacturers to provide their customers with their *IED configuration tool* which is specifically designed to create the files needed by their IEDs (RTDS, 2008).

In order for IEC 61850-compatible devices to be able to send to or receive data from one another, they need to be connected in the same Local Area Network (LAN). The RTDS GTWIF card, the GTNET card, the external IED 7SD5 and the control computer should each have a physical connection to the LAN. For this case each device must have a unique Internet Protocol Address (IP Address).

The following IP Addresses were setup at each device as shown in Table 6.1.

Host computer: 192.168.1.100
IED 1 – 7SD5: 192.168.1.1
IED 2 – 7SJ64: 192.168.1.2
IED 3 – RTDS internal library relay model.
RTDS Rack 1: 192.168.1.101 (location of GTNET card)

To complete the devices communication configuration, it is necessary to insert each device into the SIPROTEC device manager DIGSI Manager as shown in Figure 6.25 below. The DIGSI manager manages the changing of properties for all SIPROTEC devices. IED 1 and IED 2 have to be inserted into the device manager and into the IEC 61850 station which manages the mapping of IEDs to complete the GOOSE communication. The GTNET card has to be inserted to receive the GOOSE message published by the IED 2.

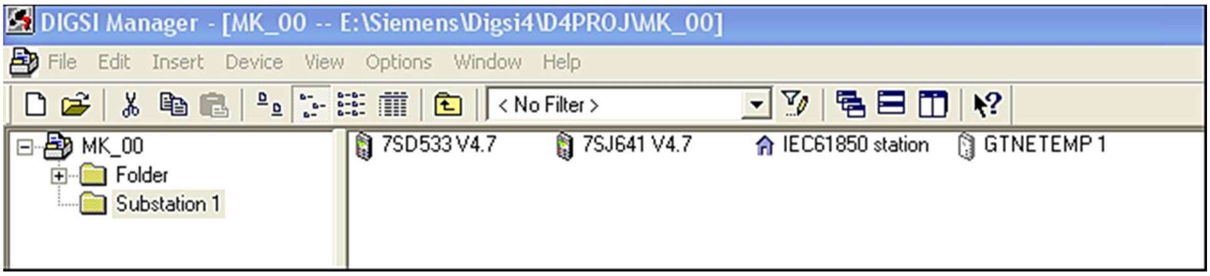


Figure 6.25: DIGSI 4 device manager

The IEDs which have been loaded into the DIGSI manager can be mapped in the IEC 61850 station by adding the IEDs from the "*Available IEC 61850* *devices"* into the "*IEC 61850 station communicator"* as shown in Figure 6.26 below.

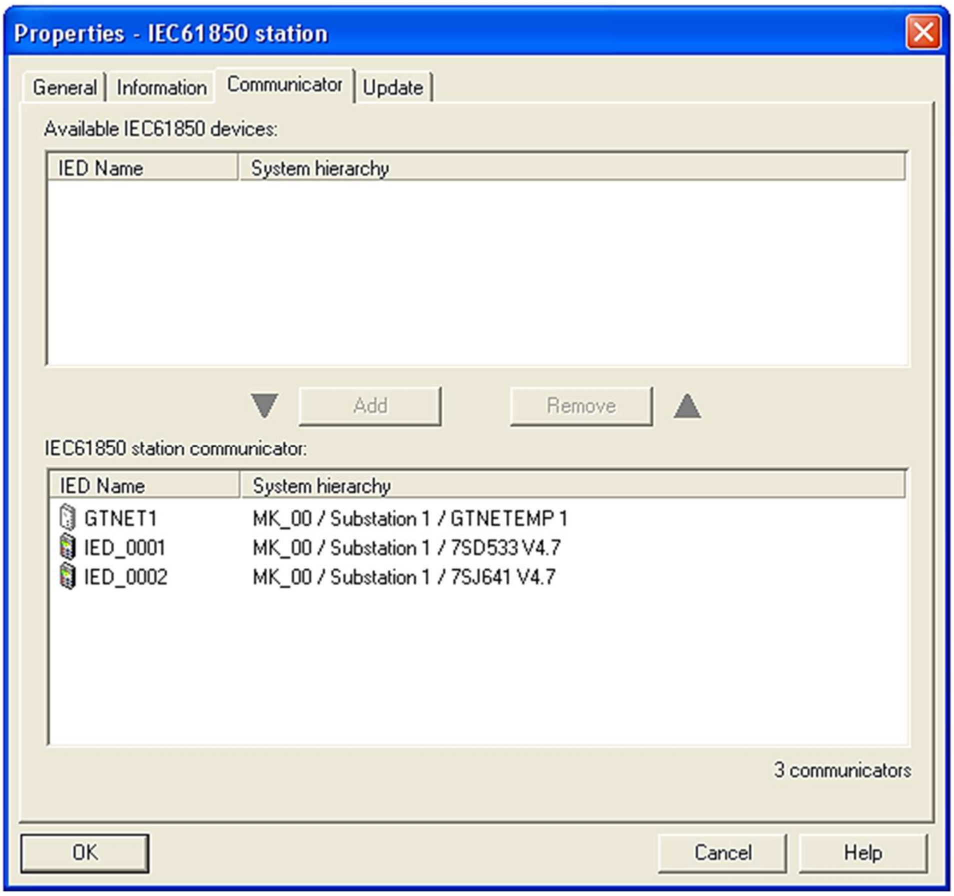


Figure 6.26: DIGSI 4 IEC 61850 station communicator

When the adding of the devices is complete, all parameters must be updated on the station (Figure 6.27) and then sent back to each device on the substation for each device to be updated with new properties. When update is complete, the *update report* should present a message stating that "*All IEC 61850 communicators were updated – 0 fault(s), 0 warning(s)"* as shown in Figure 6.28 below. This means all parameter have been loaded without any errors that will prevent communication between the devices.

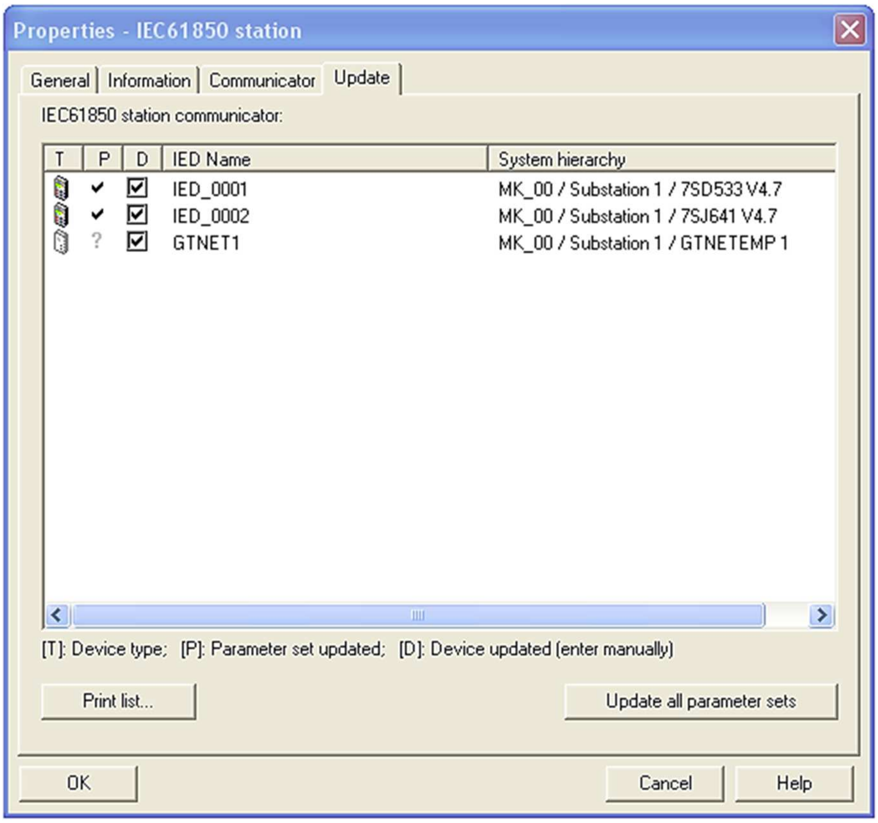


Figure 6.27: DIGSI 4 IEC 61850 station communicator update

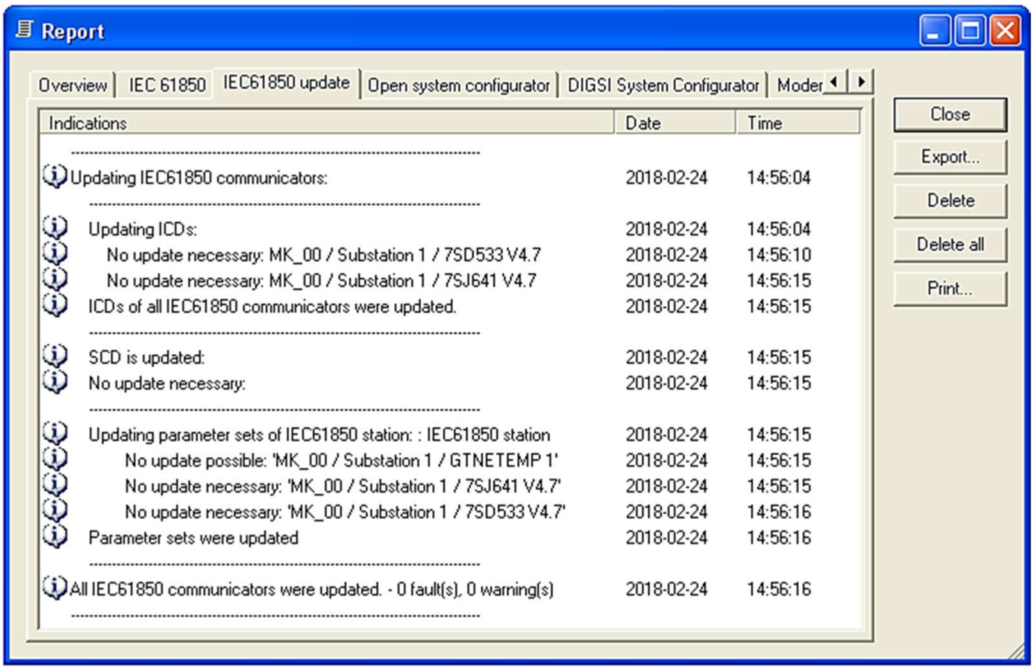


Figure 6.28: DIGSI 4 IEC 61850 station communicator report

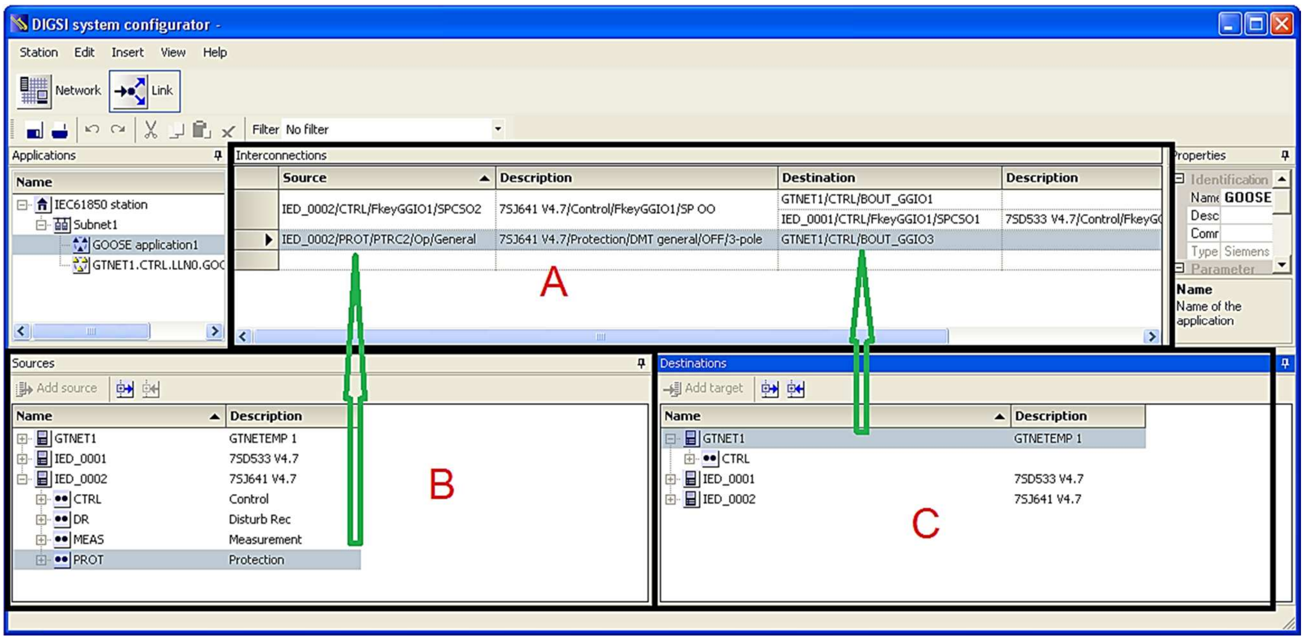


Figure 6.29: DIGSI 4 IEC 61850 station system configurator

The completed the IEC 61850 GOOSE communication mapping in DIGSI 4 is shown in Figure 6.29 above. Part A displays the logical nodes of the publishing IED linked to the subscribing logical nodes of other IEDs. The outputs of the IEDs are obtained from the part B. These outputs are imported from their IED Capability Description (ICD), Configured IED Description (CID), and/or Substation Configuration Description (SCD) files. Part C lists the inputs of the IEDs which need to subscribe the GOOSE messages. Once the mapping is completed, then the *system configurator* must be saved and the DIGSI parameters must be sent to each IED publishing or subscribing GOOSE messages.

6.6.2.3 GTNET card configuration

For GOOSE communication messages to be published via the Ethernet network, the RTDS uses the GTNET-GSE card as shown in Figure 6.30. The GOOSE messages can be published by the sender to any receiving device. For Breaker 2 GOOSE control, the short-circuit fault is injected in RSCAD runtime which then gets measured through the external IED 2. The IED 2 initiates a trip command which is published to the IEC 61850 Ethernet based network. The GTNET mapping receives this GOOSE message and sends the *GOOSETrip* to the Breaker 2 control logic (Figure 6.24 above) to trip the breaker in RSCAD *runtime.* An illustrative diagram is shown in Figure 6.31 below.

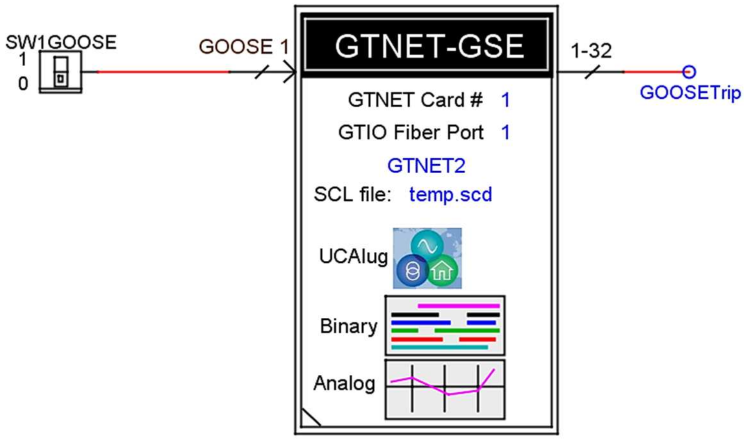


Figure 6.30: Breaker 2 GOOSE control function

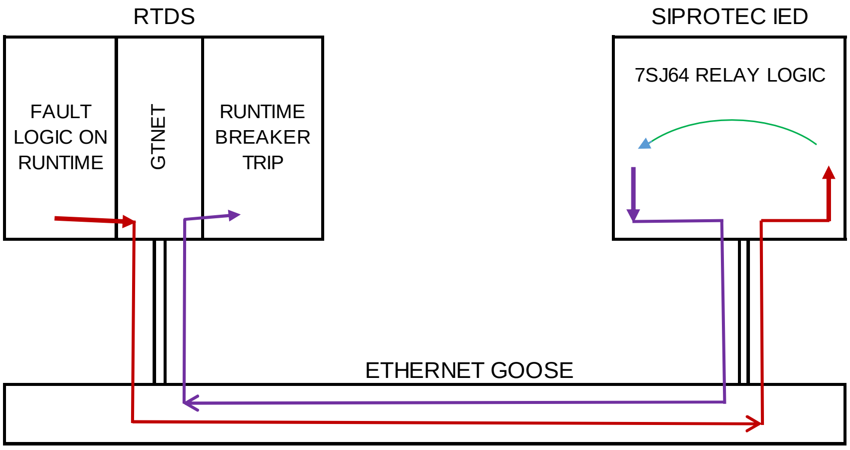


Figure 6.31: Breaker 2 GOOSE control setup

The GTNET component *_rtds_GTNET_GSE_v2.def* needs to be configured to publish GOOSE. Therefore the *type of processor* must be set to “GTNET” and the *communication protocol* set to “GOOSE” as shown in Figure 6.32 below. All other parameters such as fibre port number, card number and controls processor must be assigned according to the location in the rack. Under GOOSE configuration on the tab, the *name of the SCL file* needs to be defined together with the *GTNET iedName.* These names shall be unique to avoid duplications and contradiction of functions on the same network. After completing the changes, the component may be updated for changes to take effect.

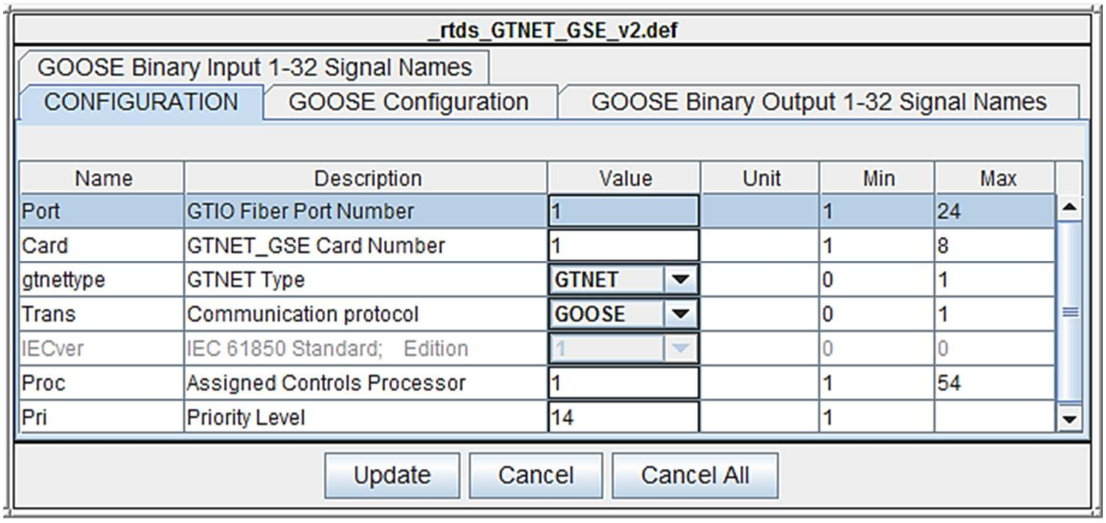


Figure 6.32: Configuration tab for GTNET component

To complete the IEC 61850 GOOSE communication in RSCAD, Figure 6.34 shows that Substation Configuration Description (SCD) file (path through Figure 6.33 below) must be edited to complete the mapping.

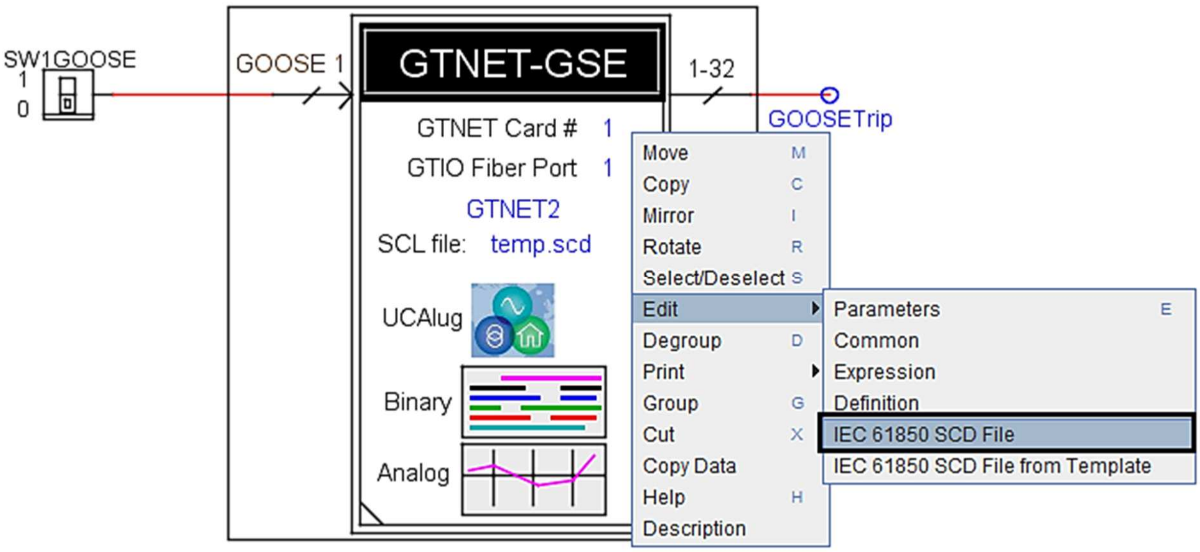


Figure 6.33: Editing the IEC 61850 SCD file

In Figure 6.34, part A is where the inputs of the GTNET are linked to the outputs of the other IEDs. This linking is called mapping. The outputs of the IEDs are obtained from part B. These outputs are imported from DIGSI4 via their IED Capability Description (ICD), Configured IED Description (CID), and/or SCD files which in the considered case is the IEC 61850 station. Part C lists the properties of the IED which needs to be mapped to the GTNET. Once the mapping is completed, then the *runtime* must be compiled.

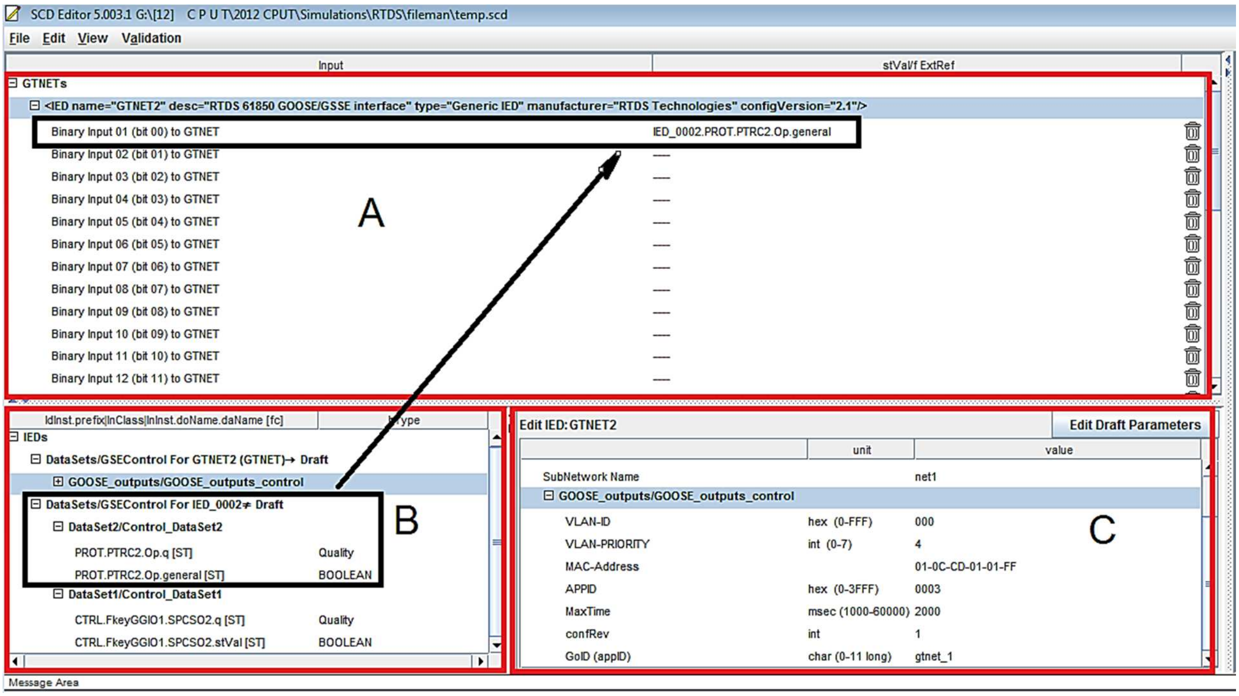


Figure 6.34: Mapping of logical nodes

At this point it is assumed that all parameters in DIGSI4 have been loaded in the IEDs from DIGSI4 manager and the GTNET GOOSE interface mapping is completed and compiled successfully. Once the mapping is completed, the RSCAD Runtime supervisory and data acquisition is ready for design and simulation. The results are shown in Chapter 7 later.

6.6.3 Outgoing Feeder 3 Breaker Control Using RTDS

The goal is to simulate breaker control using the RSCAD library overcurrent relay. This relay can be found on the protection & automation library. This multi-function overcurrent relay is suitable for providing protection functions on single breaker transmission feeder lines with three pole tripping and reclosing schemes (RTDS, 2008). The reclosing feature is not required for use on this network. The developed Breaker 3 control circuit is shown in Figure 6.35 below.

6.6.3.1 Breaker 3 control logic

Relay configuration was set up according to Figure 6.35. The instantaneous overcurrent relay elements are enabled as shown in Figure 6.36. Both voltages and current must be assigned for the relay model to function. These magnitudes shall be taken from the instrument transformers connected to the line which the relay is protecting. All other relay parameters are configured as shown in Figure 6.37 – Figure 6.38.

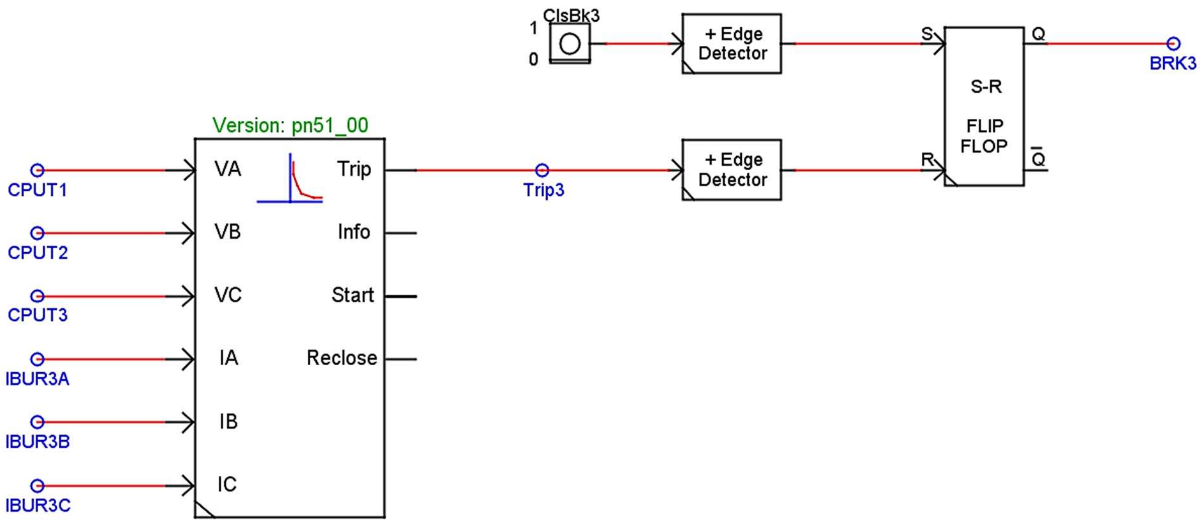
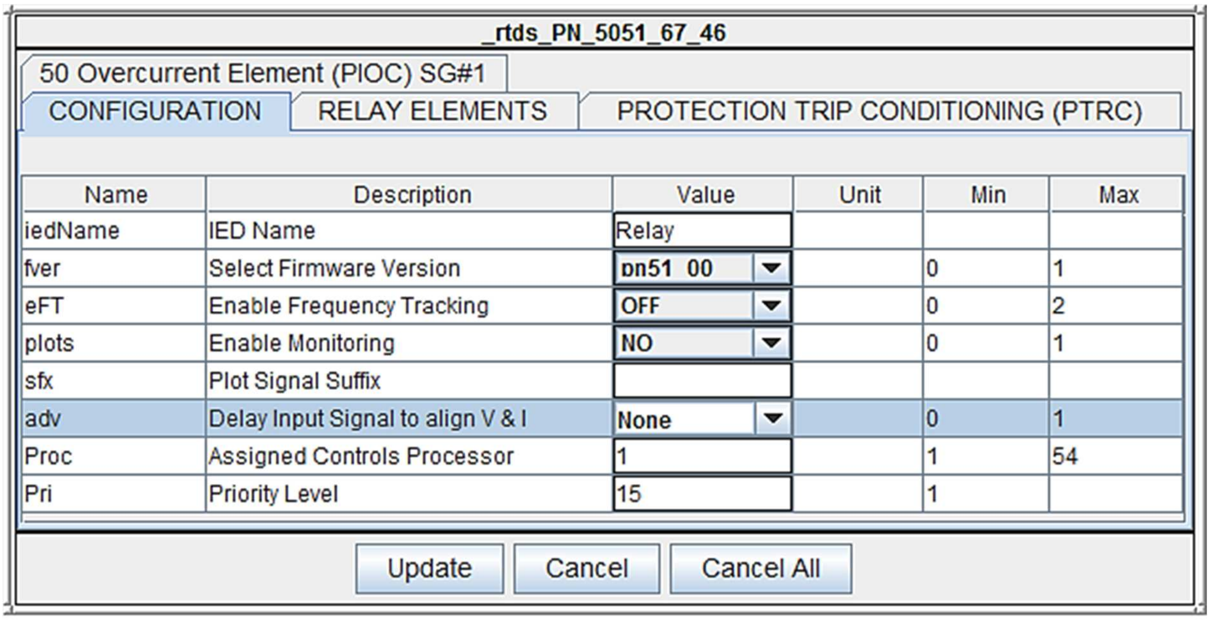


Figure 6.35: Feeder 3 Breaker control diagram



_rtds_PN_5051_67_46

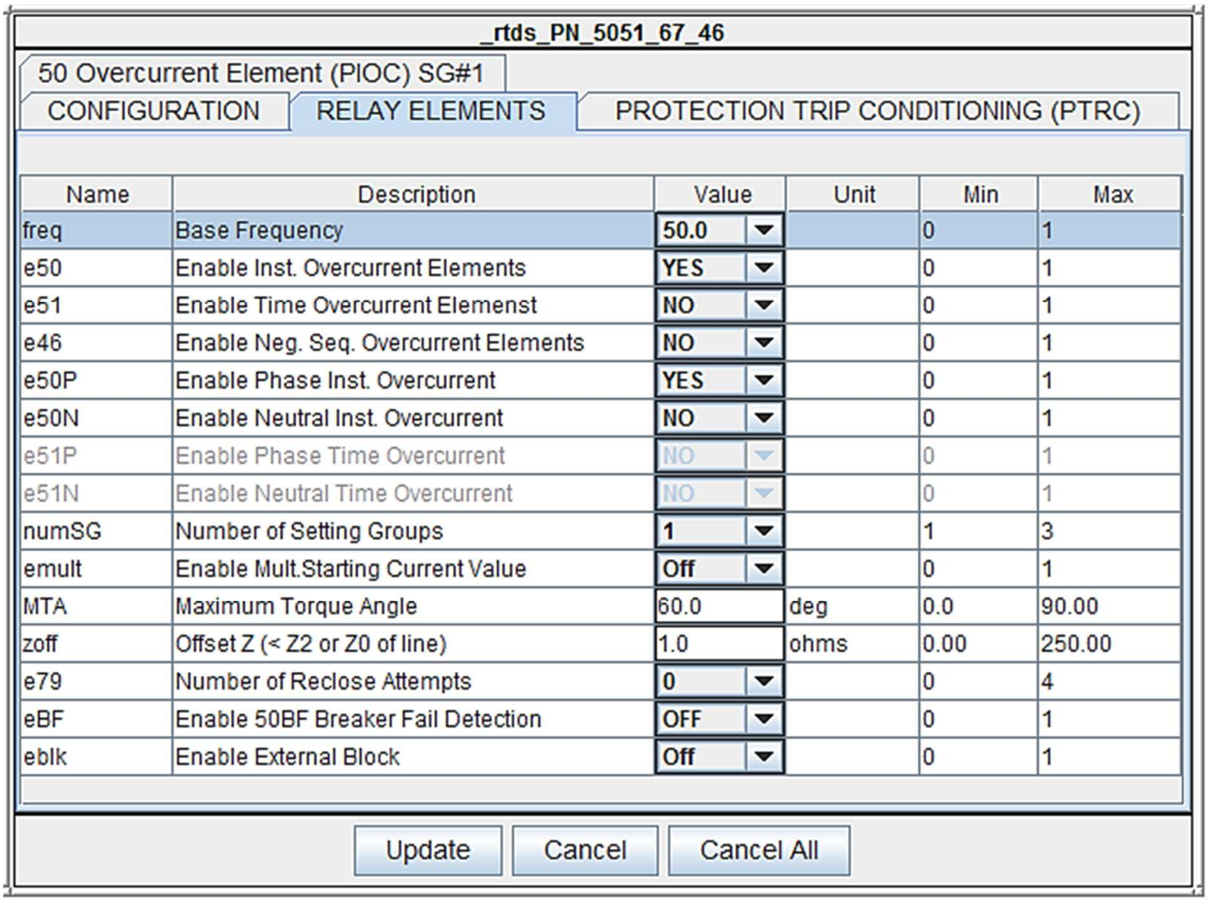
50 Overcurrent Element (PIOC) SG#1

CONFIGURATION | RELAY ELEMENTS | PROTECTION TRIP CONDITIONING (PTRC)

Name	Description	Value	Unit	Min	Max
iedName	IED Name	Relay			
fver	Select Firmware Version	pn51_00		0	1
eFT	Enable Frequency Tracking	OFF		0	2
plots	Enable Monitoring	NO		0	1
sfx	Plot Signal Suffix				
adv	Delay Input Signal to align V & I	None		0	1
Proc	Assigned Controls Processor	1		1	54
Pri	Priority Level	15		1	

Update | Cancel | Cancel All

Figure 6.36: Feeder 3 IED 3 configuration



_rtds_PN_5051_67_46

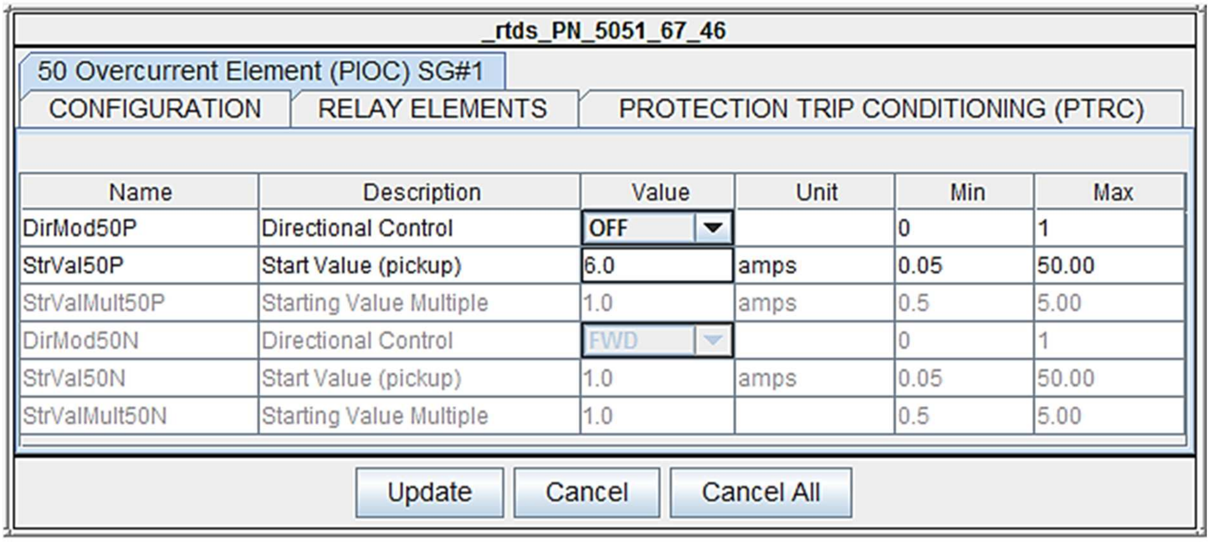
50 Overcurrent Element (PIOC) SG#1

CONFIGURATION | RELAY ELEMENTS | PROTECTION TRIP CONDITIONING (PTRC)

Name	Description	Value	Unit	Min	Max
freq	Base Frequency	50.0		0	1
e50	Enable Inst. Overcurrent Elements	YES		0	1
e51	Enable Time Overcurrent Elemenst	NO		0	1
e46	Enable Neg. Seq. Overcurrent Elements	NO		0	1
e50P	Enable Phase Inst. Overcurrent	YES		0	1
e50N	Enable Neutral Inst. Overcurrent	NO		0	1
e51P	Enable Phase Time Overcurrent	NO		0	1
e51N	Enable Neutral Time Overcurrent	NO		0	1
numSG	Number of Setting Groups	1		1	3
emult	Enable Mult.Starting Current Value	Off		0	1
MTA	Maximum Torque Angle	60.0	deg	0.0	90.00
zoff	Offset Z (< Z2 or Z0 of line)	1.0	ohms	0.00	250.00
e79	Number of Reclose Attempts	0		0	4
eBF	Enable 50BF Breaker Fail Detection	OFF		0	1
eblk	Enable External Block	Off		0	1

Update | Cancel | Cancel All

Figure 6.37: Feeder 3 relay elements



_rtds_PN_5051_67_46

50 Overcurrent Element (PIOC) SG#1

CONFIGURATION | RELAY ELEMENTS | PROTECTION TRIP CONDITIONING (PTRC)

Name	Description	Value	Unit	Min	Max
DirMod50P	Directional Control	OFF		0	1
StrVal50P	Start Value (pickup)	6.0	amps	0.05	50.00
StrValMult50P	Starting Value Multiple	1.0	amps	0.5	5.00
DirMod50N	Directional Control	FWD		0	1
StrVal50N	Start Value (pickup)	1.0	amps	0.05	50.00
StrValMult50N	Starting Value Multiple	1.0		0.5	5.00

Update | Cancel | Cancel All

Figure 6.38: Feeder 3 Overcurrent pick up

6.6.4 Short-circuit Fault Control RSCAD Logic

Figure 6.39 shows the control logic for any type of short-circuit fault. The *GrFltType* is a seven segment dial which is linked to the RSCAD/Runtime short-circuit fault type selection listed below with any of them applied when the *ApplyGrFlt* push button is pressed. *FaultDur* slider is used to set the time after the short-circuit fault at which the breaker open signal is given.

The dial values correspond with the following short-circuit fault

1. A phase to ground
2. B phase to ground
3. A-B phase to ground
4. C phase to ground
5. A-C phase to ground
6. B-C phase to ground
7. 3 Phase to ground.

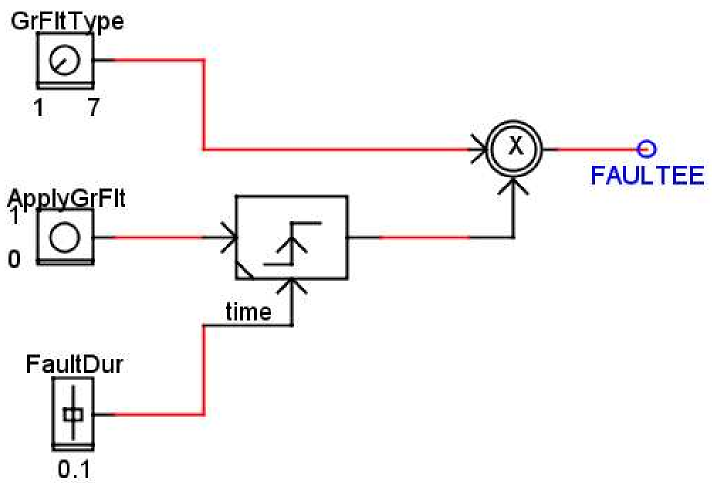


Figure 6.39: Short-circuit fault selection control logic diagram

The controls in Figure 6.39 require associated runtime controls switches, dialler etc. to enable required short-circuit fault logic. Adjustment of the dial position enables changing of short-circuit fault type as described in the dial controls description box. Therefore, for a three-phase to ground short-circuit fault, the dial must be positioned on number 7 before the fault is applied. Similarly, a single-phase to ground short-circuit fault on line C will be enabled by position 4. Figure 6.40 shows the signal controls for each point of the short-circuit fault on the CPUT incomer substation. Three locations for short-circuits are chosen at

CPUT incomer substation, Electrical Engineering substation (EE) and Substation 2 downstream

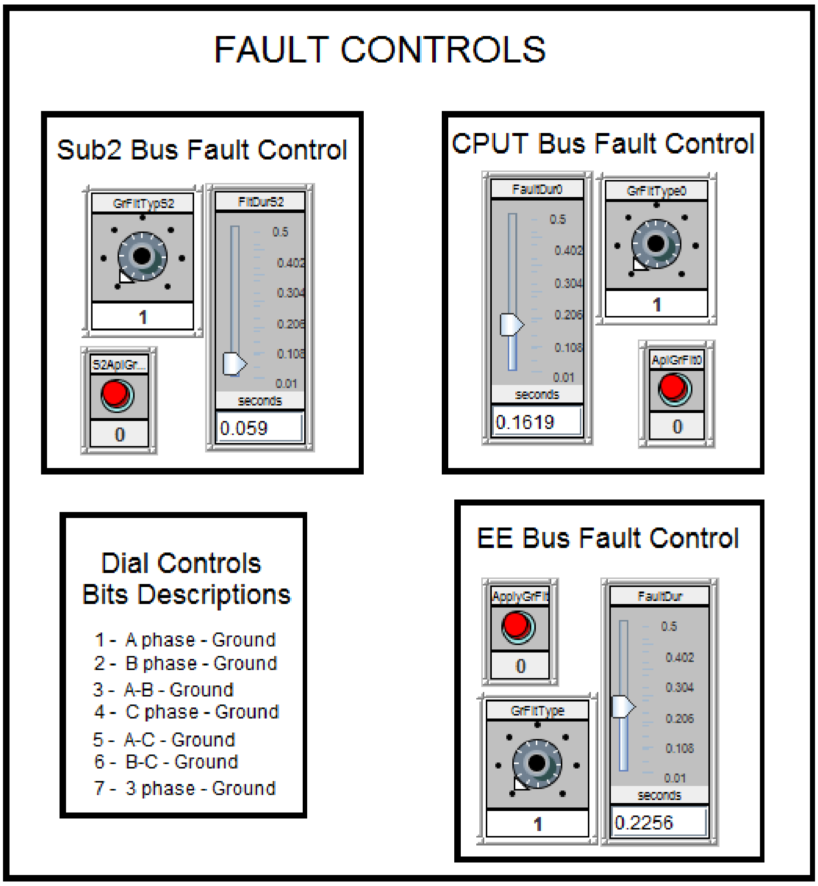


Figure 6.40: Short-circuit fault Controllers for CPUT sub, EE sub and Sub2

6.6.5 GOOSE Messages Monitoring

When GOOSE is being published, the message attributes can be monitored using programs which monitor IEC 61850 GOOSE messages via the network. Such programs are Wireshark and GOOSE Inspector.

Wireshark software inspects and captures multiple protocols published at the same time. They could be analysed offline. It is a network packet analyser which captures the live network packets and displays them as detailed as possible. When a GOOSE message is transmitted from one device to another, a status of a Boolean number on the status window has to change from *"false to true".* At the same time, the sequence number of the message has to reset to zero. The GOOSE logical node and the time at which the time stamp occurred can be viewed on the captured attribute. Figure 6.41 highlights the Wireshark capturing window.

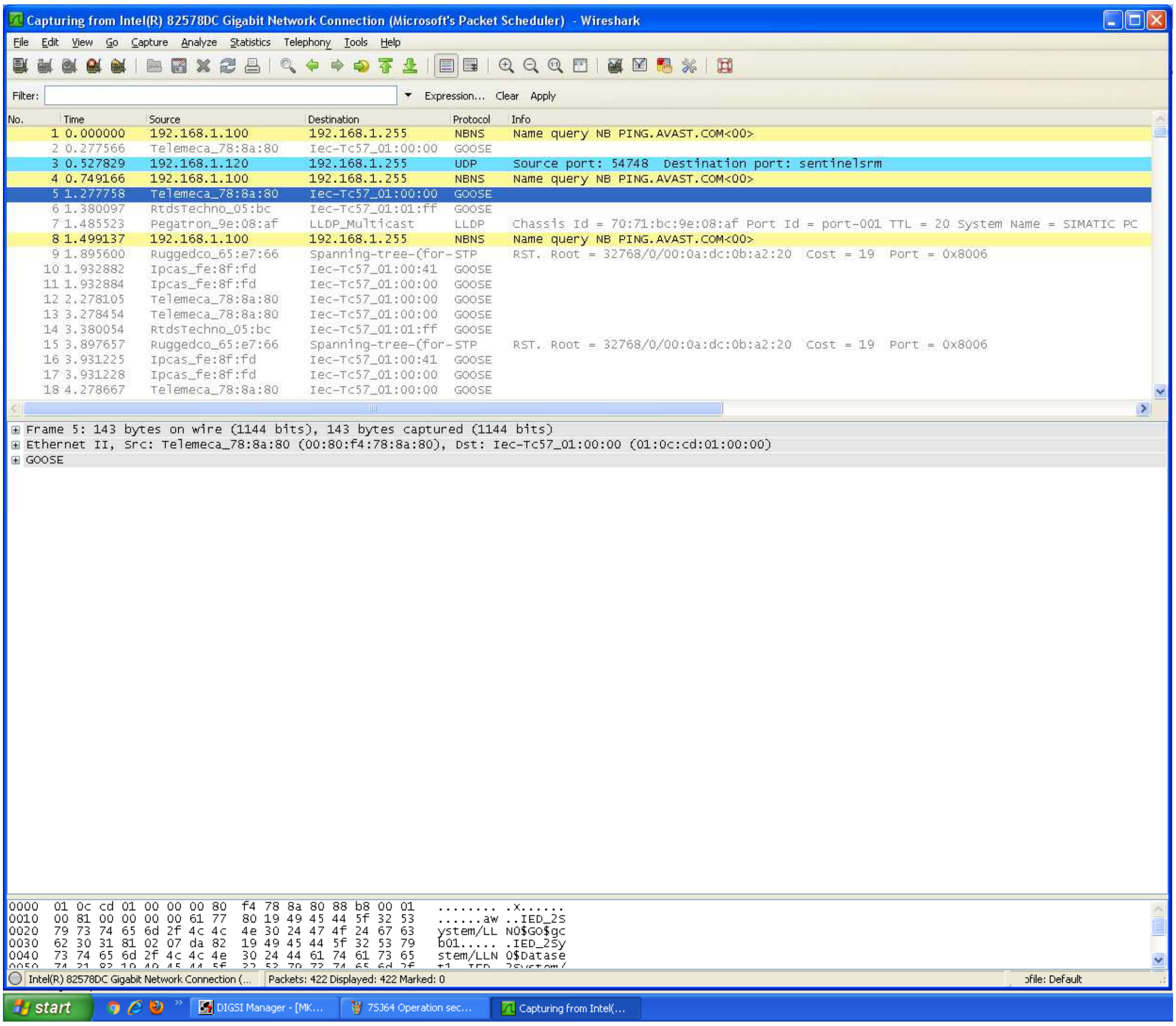


Figure 6.41: Wireshark data packets capturing window

GOOSE Inspector allows monitoring and capturing of IEC 61850 substation automation protocols messages via the network. The IEC 61850 packets are decoded with the exception of GSE and Sample Values, checked, displayed, filtered, and saved in the Log.lg6 circular buffer file. Furthermore, the program monitors GOOSE transmission via the network and displays the current status in GOOSE monitor table. An example can been seen in Figure 6.42 below.

The packets are shown in two windows which are *Main Window and the Detailed View*. Elements of the main Window can be seen in Figure 6.42

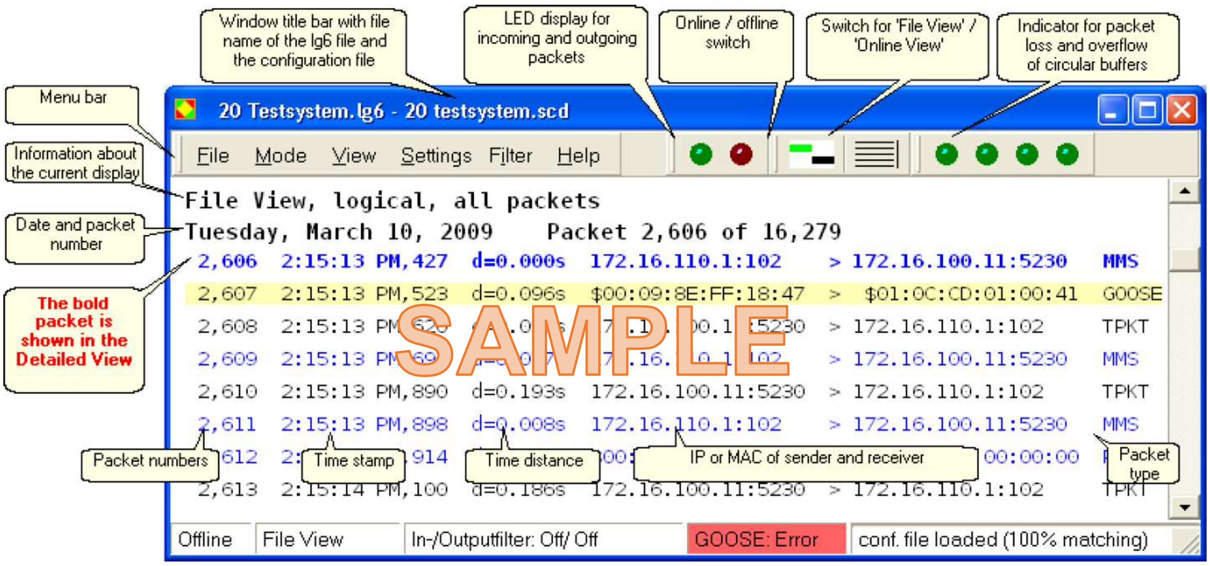


Figure 6.42: Example of the "File View" in the "Main Window" (Boeser and Consultants, 2017)

Similarly as in Wireshark, time stamps, Boolean status, sequence number are details which could be used to determine whether GOOSE message has been published/transmitted and subscribed/received.

6.7 CONCLUSION

The objective of this chapter was to design and setup a test bench of a closed-loop testing of the hardware-in-loop with SIPROTEC IEDs tripping the software circuit breakers on the power system network. The chapter highlighted IEC 61850 GOOSE mapping on SIPROTEC device manager DIGSI4 and RSCAD. The configurations were highlighted in detail in various areas of the study such as:

- Settings up and modelling of the power system on RSCAD software package,
- Modelling and building of short-circuits and respective circuit breaker control logic diagrams
- Steps required when configuring the IEDs for overcurrent and GOOSE mapping
- GOOSE messages mapping according to IEC 61850

The next chapter presents the simulation results and monitoring of network events including device monitoring. This included capturing and monitoring of the power system network results or events via RSCAD based runtime.

CHAPTER

7. REAL-TIME SIMULATION, MONITORING AND CONTROL WITH RSCAD

7.1 INTRODUCTION

This chapter presents the results and analysis for the power reticulation network modelled and simulated on RSCAD. This chapter also presents the simulation performed and behaviour of short circuits monitored and other related events captured either on various parts of the network within RSCAD runtime or via the external IEDs. The model and configuration of the network for HIL RTDS simulation has been covered in Chapter 6.

7.2 SIMULATION, MONITORING AND CONTROL OF THE CPUT INCOMER SUBSTATION

The runtime is used for running simulations, control and monitoring and can be customised entirely for each simulation by creating meters, plots, sliders, push buttons, switches and dials. Controls of switches can be done while the system is in operations and data captured in real-time. Plots are automatically updated during each state change of the control functions. A condition drawing such as in Figure 7.2 below is made to make the runtime canvas intuitive. An illustrative diagram of the runtime window is shown in Figure 7.1 below. Since the main protection of the reticulation network is at the main intake substation, switches located at various substations are used to enable isolation of loads at various locations on the CPUT reticulation network.

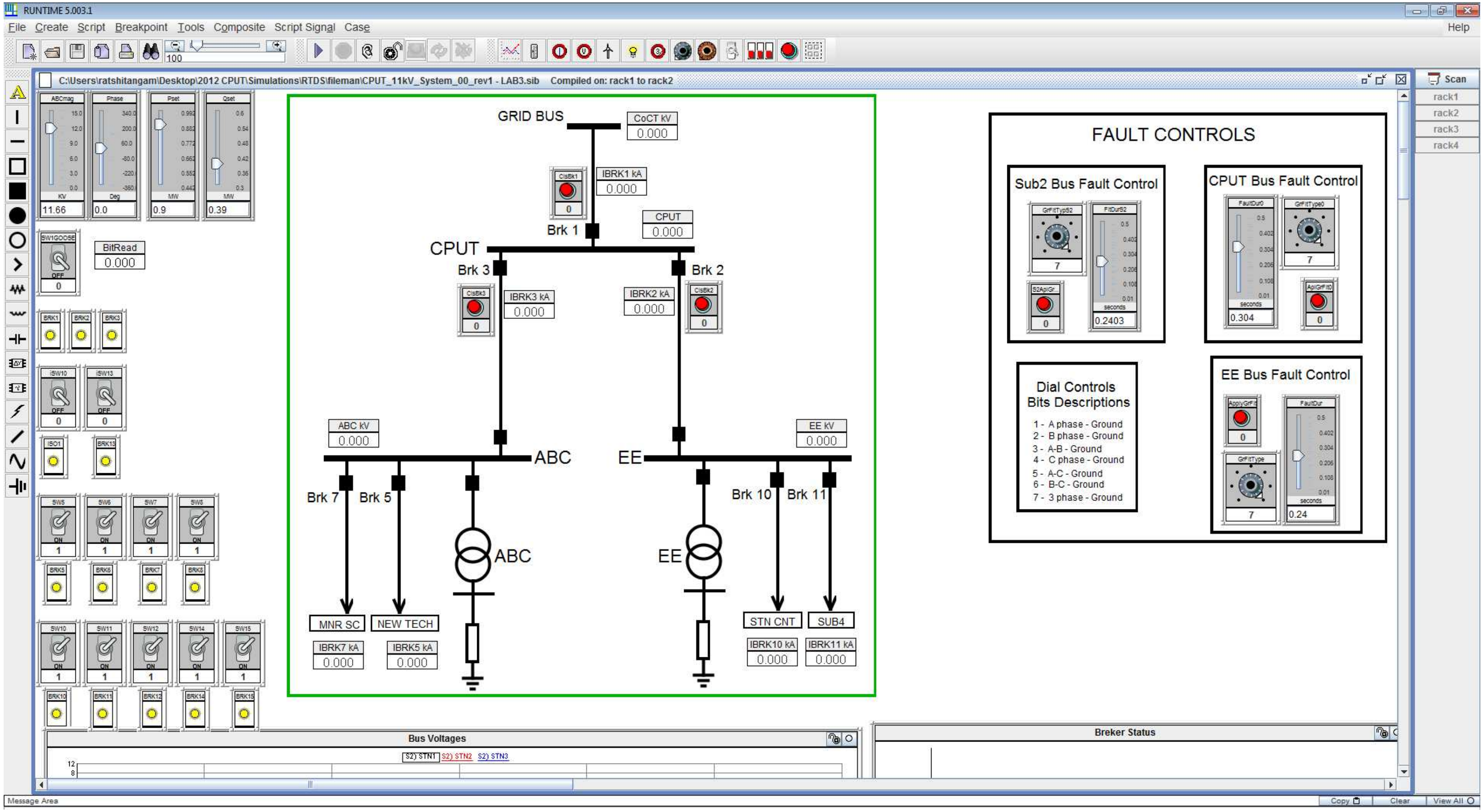


Figure 7.1: RSCAD Runtime window illustrative diagram

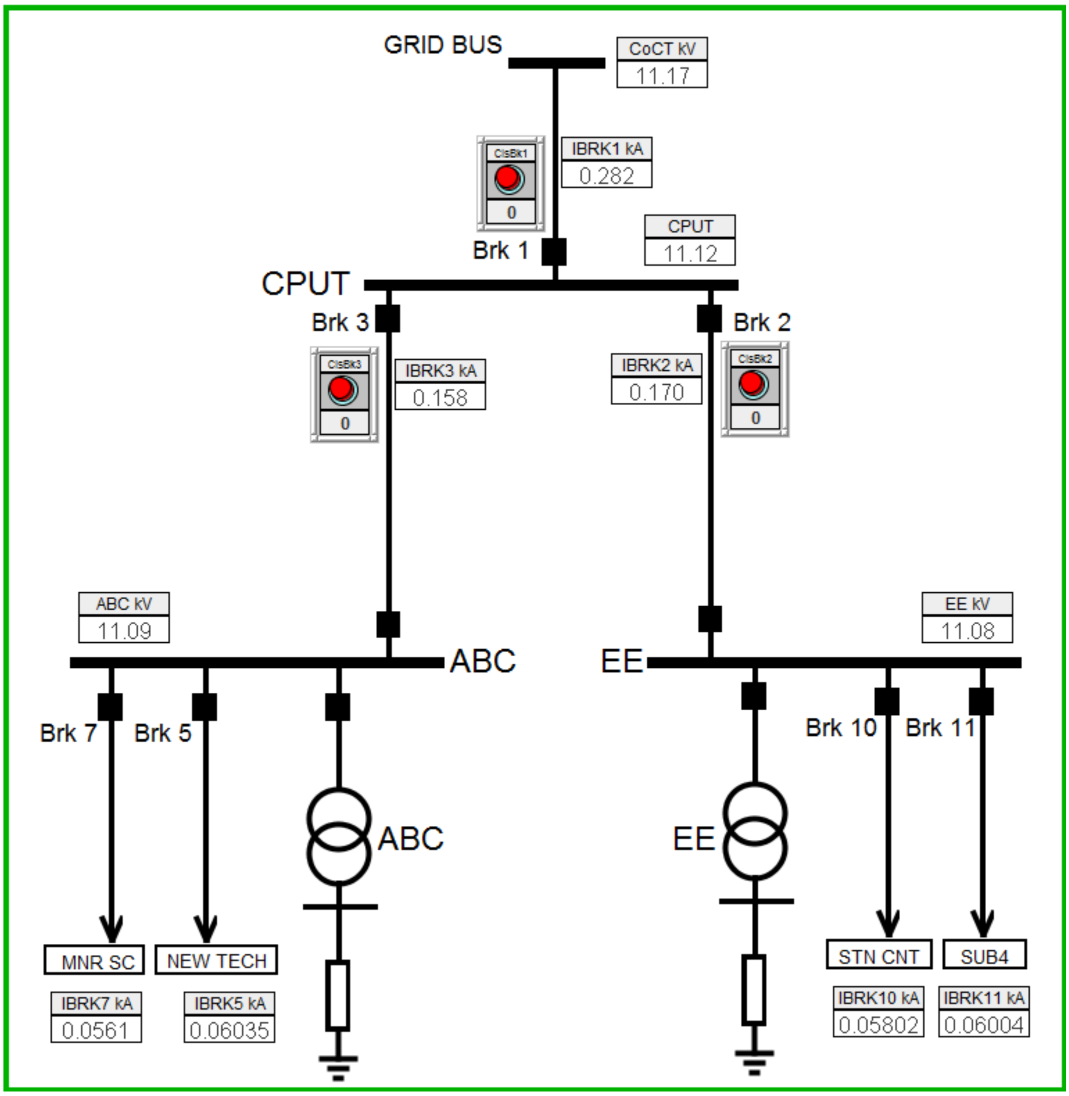


Figure 7.2: Runtime real-time monitoring of CPUT Incomer substation

The measurements on the runtime meters could also be confirmed with the IED measurements to see if these match. For this case, the CT ratio of 1000:1 was applied on the IEDs in order to present an ease of identification between primary measurements between runtime and on the IEDs. Figure 7.3 to Figure 7.6 illustrate IED measurements confirming similarities with measurements monitored in RSCAD.

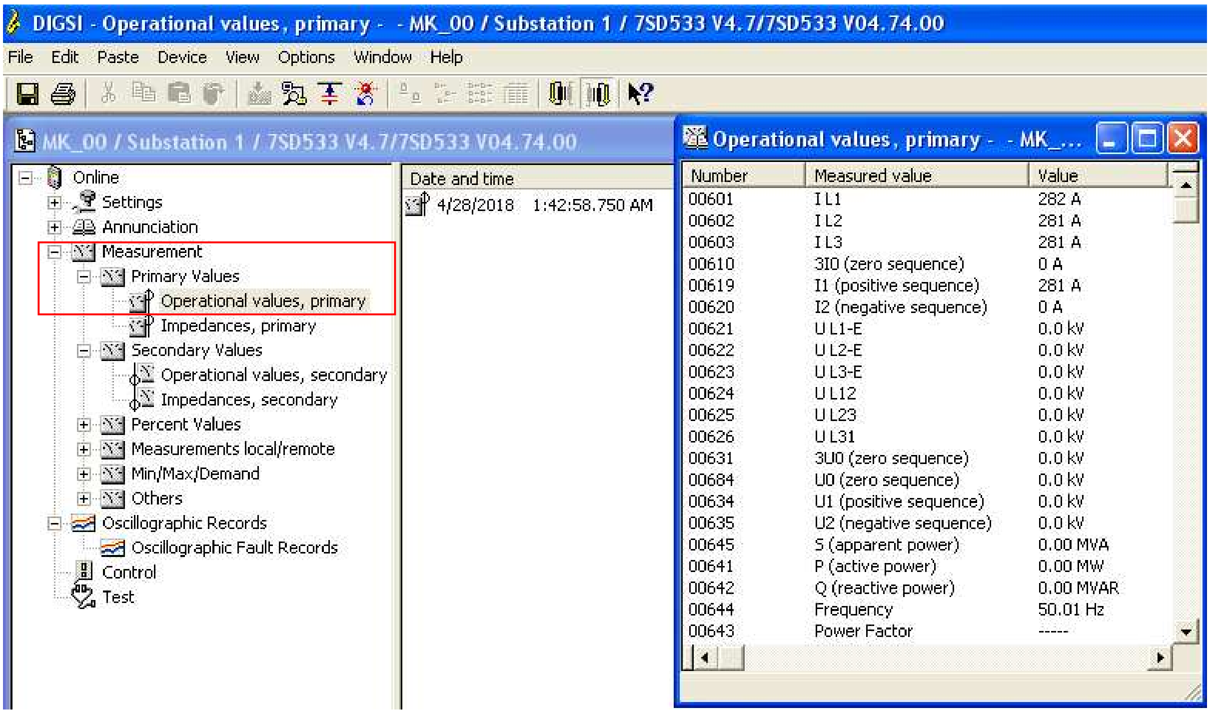


Figure 7.3: IED 1 primary measurements under normal conditions

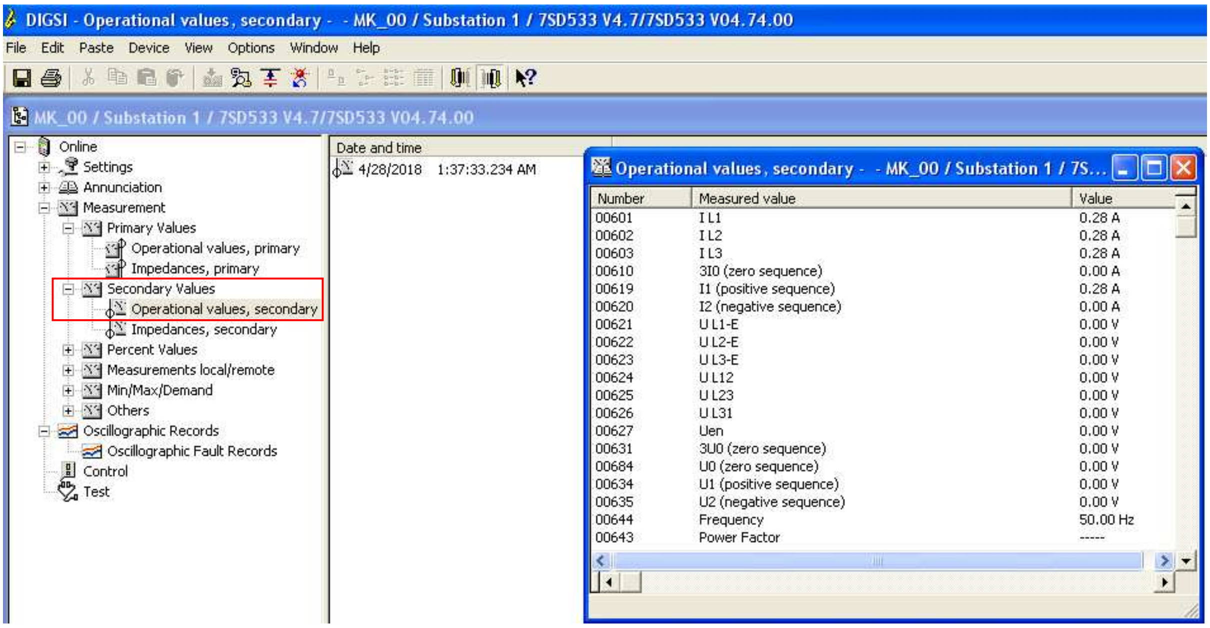


Figure 7.4: IED 1 secondary measurements under normal conditions

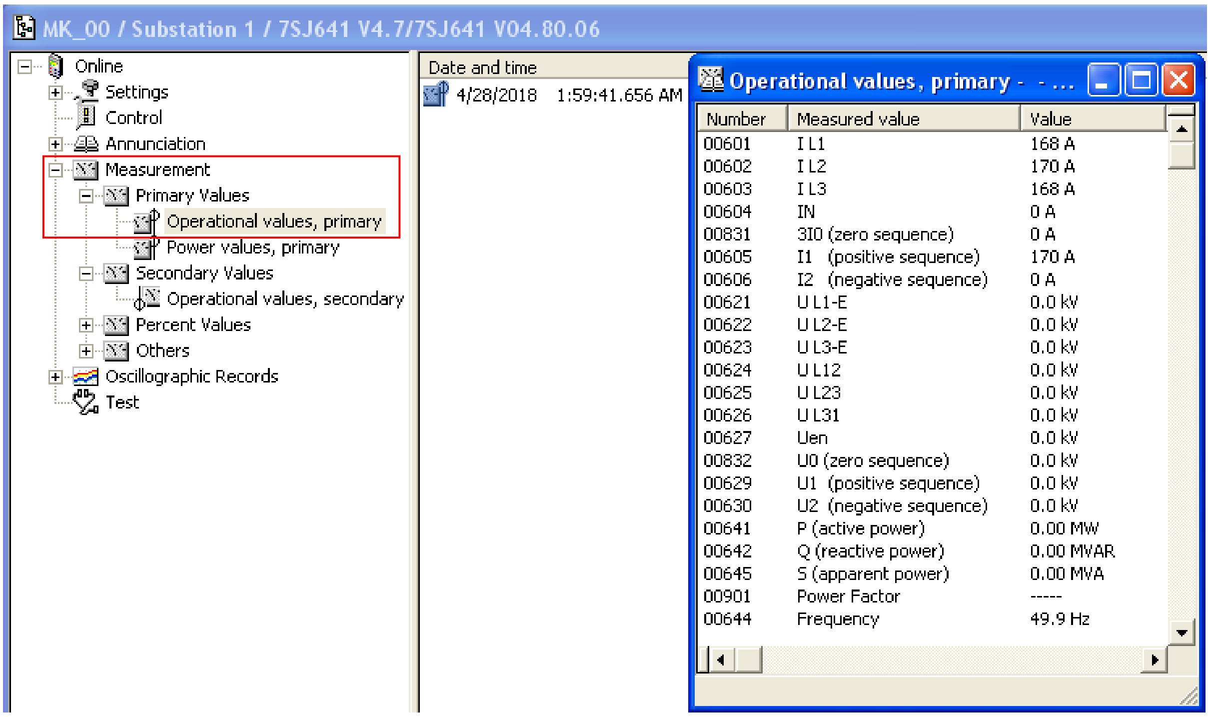


Figure 7.5: IED 2 primary measurements under normal conditions

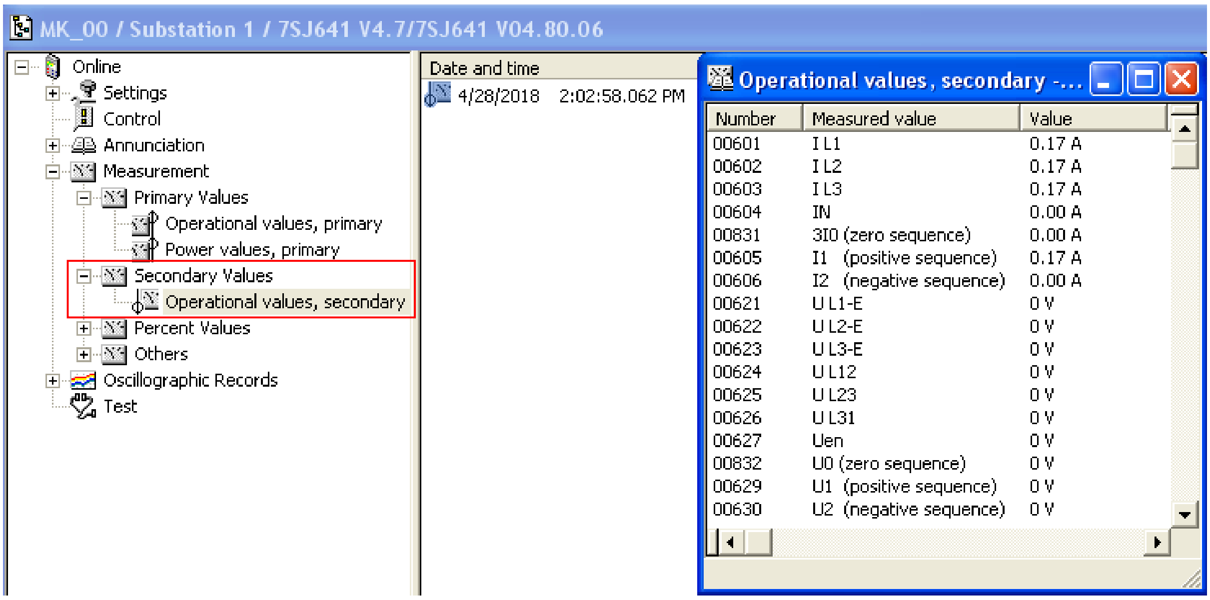


Figure 7.6: IED 2 secondary measurements under normal conditions

7.2.1 Single Phase Short-Circuit Fault on EE Substation Busbar

When a single phase short-circuit fault is introduced on the EE substation busbar or any other downstream substation, the CT measurements are obtained as shown in Figure 7.7 below. This illustrates that CT2 sees a short-circuit fault and later the IED 2 issues a trip command for breaker 2 to open.

However during the same period, CT3 sees a voltage dip which reduces the amount of current supplied towards downstream load of CT3. IED 3 does not see a short-circuit fault during this period and hence no trip command issued. CT1 however sees the short-circuit fault as this is on the incomer side of the bus. During the said period, IED 1 time grading prevents the IED from issuing a trip command thereby allowing continuity of supply to the other side of the loads through CT3. If however IED 2 fails to issue a trip command within maximum required time, then IED 1 should act as backup and open Breaker 1

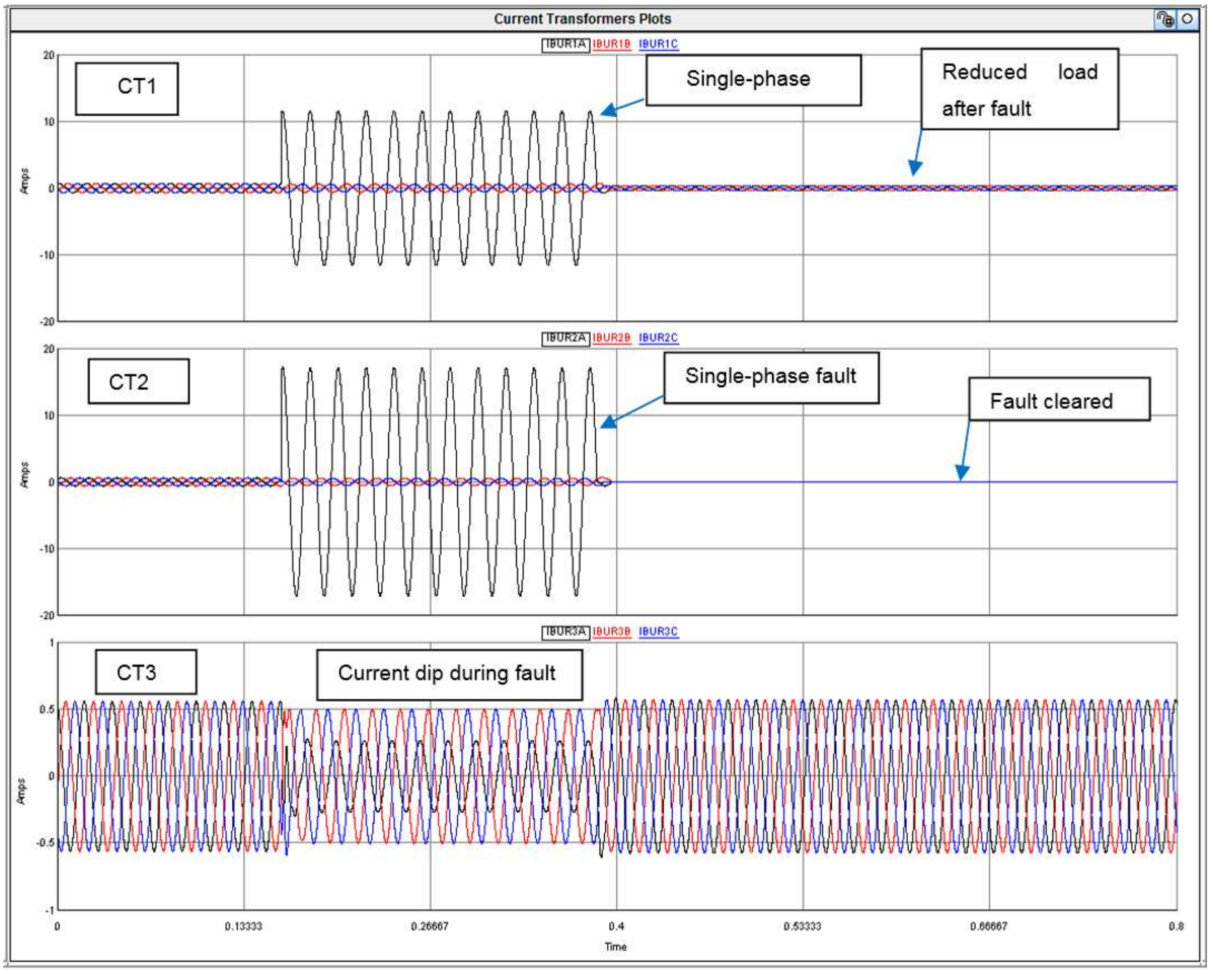


Figure 7.7: CT measurements during single-phase short-circuit fault at the EE substation bus

During this period, a comparison of the hard-wiring tripping time and the GOOSE message tripping time was conducted. When the GOOSE trip has been initiated, the breaker opens immediately while the hard-wiring trip has a delay time of approximately 7.55 ms. This is illustrated in Figure 7.8 and Figure 7.9 below.

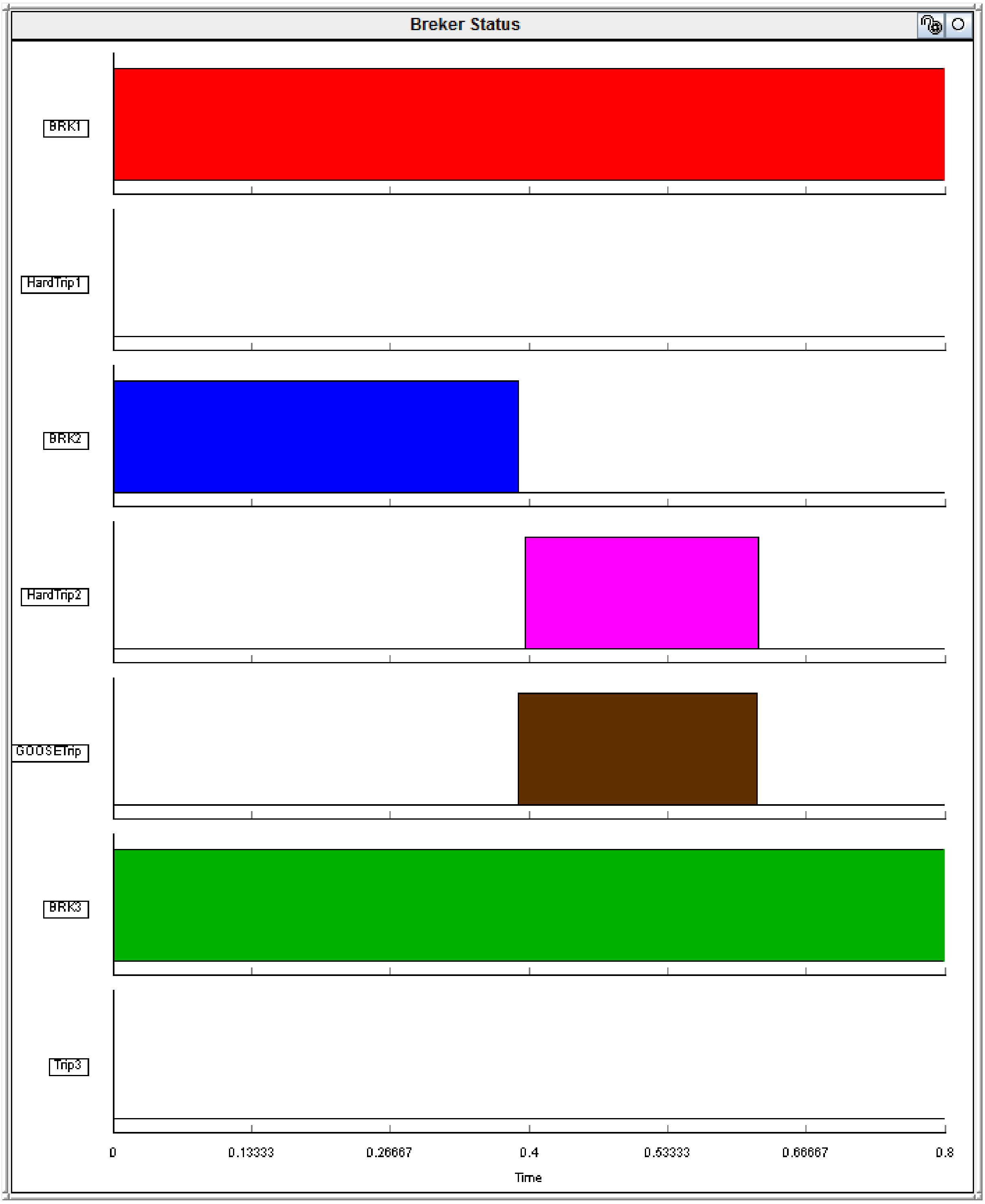


Figure 7.8: GOOSE vs. Hard-wiring trip time during single-phase short-circuit fault at EE substation bus

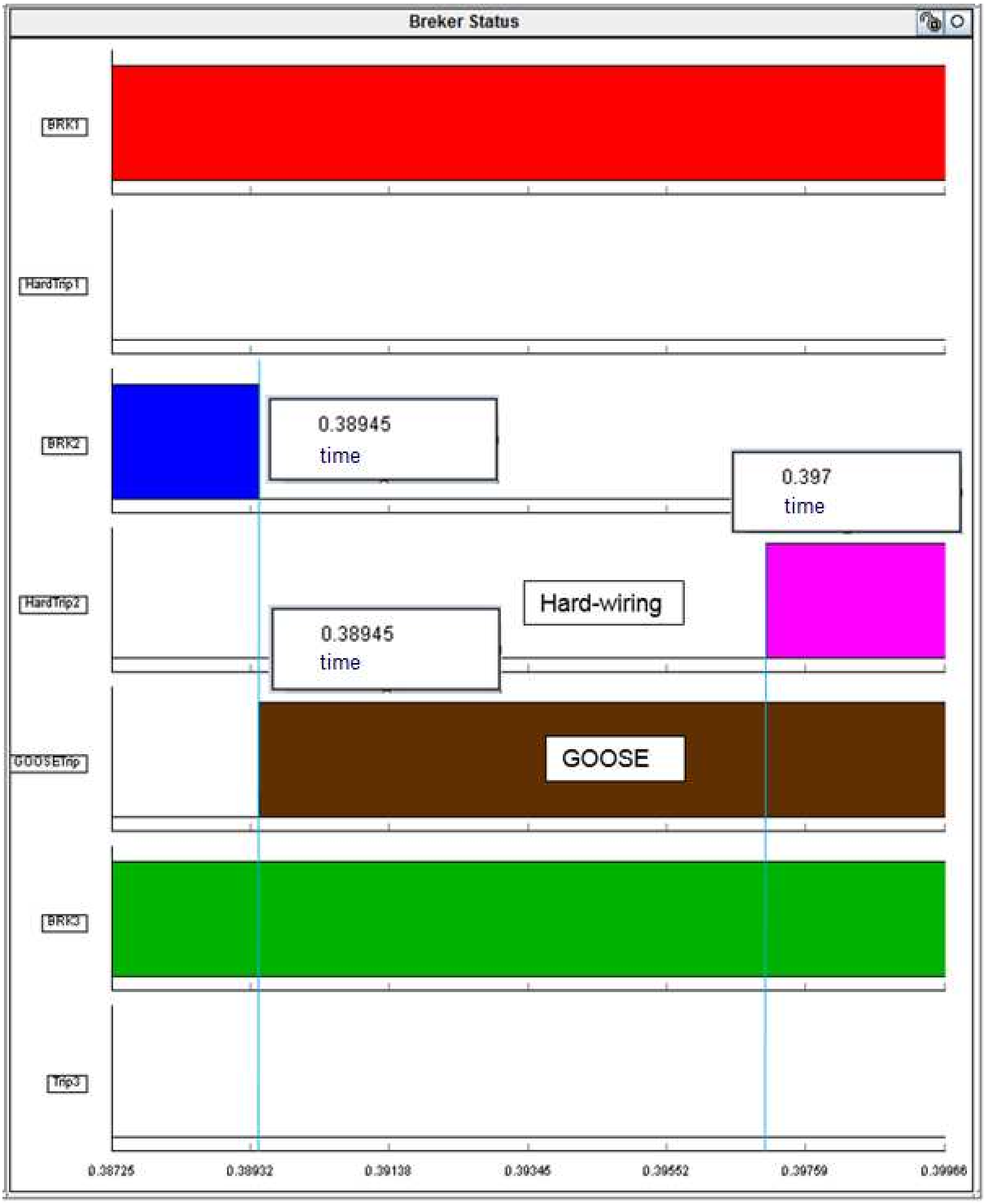


Figure 7.9: GOOSE vs. Hard-wiring trip time during single-phase short-circuit fault at EE substation busbar (Zoomed in)

The single-phase short-circuit fault is fully cleared after 5.8 ms from the time of initiating breaker open signal from GOOSE message. In addition, this short-circuit fault is cleared 1.75 ms before the hard-wiring signal has activated. This has been compared between Figure 7.9 above and Figure 7.10 below.

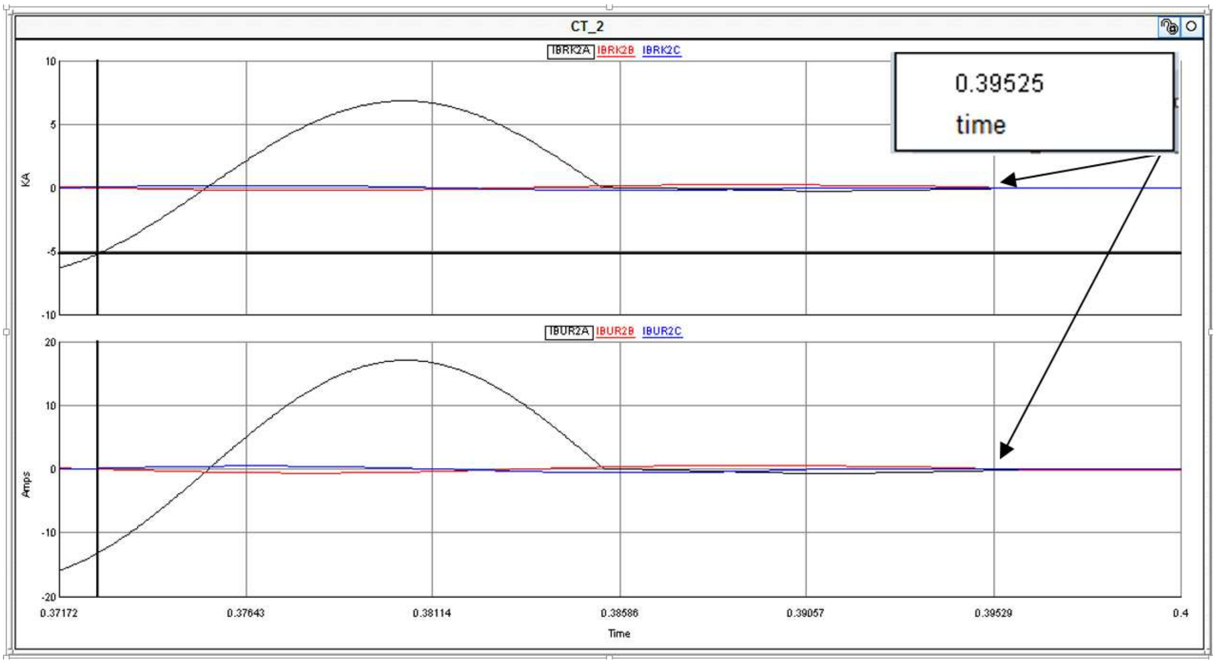


Figure 7.11: CT2 short-circuit fault clearance plots

The IED event and trip logs could also be extracted from the IED software DIGSI4 which then highlight the actual times at which events are triggered and length of such events if measureable. Figures 7.12 and 7.13 show the event and trip log respectively.

Event Log - - MK_00 / Substation 1 / 7SJ641 V4.7/7SJ641 V04.80.06

Number	Indication	Value	Date and time	Initiator	Cause
01815	I> TRIP	OFF	24.03.2018 16:50:47.477	Com.Issued=AutoLocal	Spontaneous
01791	Time Overcurrent TRIP	OFF	24.03.2018 16:50:47.477	Com.Issued=AutoLocal	Spontaneous
00301	Power System fault	42 - OFF	24.03.2018 16:50:47.477	Com.Issued=AutoLocal	Spontaneous
	Reset LED	ON	24.03.2018 16:51:27.509	Command Issued=Local	Spontaneous
00301	Power System fault	43 - ON	24.03.2018 17:04:50.366	Com.Issued=AutoLocal	Spontaneous
01791	Time Overcurrent TRIP	ON	24.03.2018 17:04:50.587	Com.Issued=AutoLocal	Spontaneous
01815	I> TRIP	ON	24.03.2018 17:04:50.587	Com.Issued=AutoLocal	Spontaneous
01815	I> TRIP	OFF	24.03.2018 17:04:50.817	Com.Issued=AutoLocal	Spontaneous
01791	Time Overcurrent TRIP	OFF	24.03.2018 17:04:50.817	Com.Issued=AutoLocal	Spontaneous
00301	Power System fault	43 - OFF	24.03.2018 17:04:50.817	Com.Issued=AutoLocal	Spontaneous
	Reset LED	ON	24.03.2018 18:08:35.518	Command Issued=Local	Spontaneous

Figure 7.12: 7SJ64 Event log during single phase short-circuit fault at EE substation bus

Trip Log - 000043 / 3/24/2018 5:04:50.366 PM - MK_00 / Substation 1 / 7SJ641 V...

Number	Indication	Value	Date and time
00301	Power System fault	43 - ON	24.03.2018 17:04:50.366
00302	Fault Event	43 - ON	24.03.2018 17:04:50.366
00501	Relay PICKUP	ON	0 ms
01761	Time Overcurrent picked up	ON	0 ms
01765	Time Overcurrent Earth picked up	ON	0 ms
01834	IE> picked up	ON	0 ms
01831	IE>> picked up	ON	0 ms
01762	Time Overcurrent Phase L1 picked up	ON	6 ms
01810	I> picked up	ON	6 ms
01800	I>> picked up	ON	16 ms
00511	Relay GENERAL TRIP command	ON	221 ms
01791	Time Overcurrent TRIP	ON	221 ms
01815	I> TRIP	ON	221 ms
00533	Primary fault current IL1	0.13 kA	252 ms
00534	Primary fault current IL2	0.04 kA	252 ms
00535	Primary fault current IL3	0.02 kA	252 ms
01123	Fault Locator Loop L1E	ON	257 ms
01117	Flt Locator: secondary RESISTANCE	0.00 Ohm	257 ms
01118	Flt Locator: secondary REACTANCE	0.00 Ohm	257 ms
01114	Flt Locator: primary RESISTANCE	0.00 Ohm	257 ms
01115	Flt Locator: primary REACTANCE	0.00 Ohm	257 ms
01119	Flt Locator: Distance to fault	0.0 km	257 ms
01120	Flt Locator: Distance [%] to fault	0.00 %	257 ms
01800	I>> picked up	OFF	441 ms
01765	Time Overcurrent Earth picked up	OFF	451 ms
01762	Time Overcurrent Phase L1 picked up	OFF	451 ms
01810	I> picked up	OFF	451 ms
01761	Time Overcurrent picked up	OFF	451 ms
01834	IE> picked up	OFF	451 ms
01831	IE>> picked up	OFF	451 ms
00301	Power System fault	43 - OFF	24.03.2018 17:04:50.817

Figure 7.13: 7SJ64 Trip log during single phase short-circuit fault at EE substation bus

7.2.1.1 GOOSE messages monitoring

As described in section 6.6.5 in Chapter 6, when GOOSE is being published, the attributes can be monitored using programs which monitor IEC 61850 GOOSE messages via the network. Such programs are Wireshark and GOOSE Inspector.

The GOOSE logical node and the time at which the time stamp occurred can be viewed on the captured attribute. Figures 7.14 and 7.15 shows the capturing of GOOSE message before and after the trip command message has been transmitted via Ethernet. Before the control GOOSE message is published, the status of the Boolean number is “False” (Figure 7.14) and changes to “True” when the trip logic GOOSE is published (Figure 7.15). The GOOSE message sequence number resets from 429 before the GOOSE trip and restarts the count from zero (Figures 7.14 and 7.15).

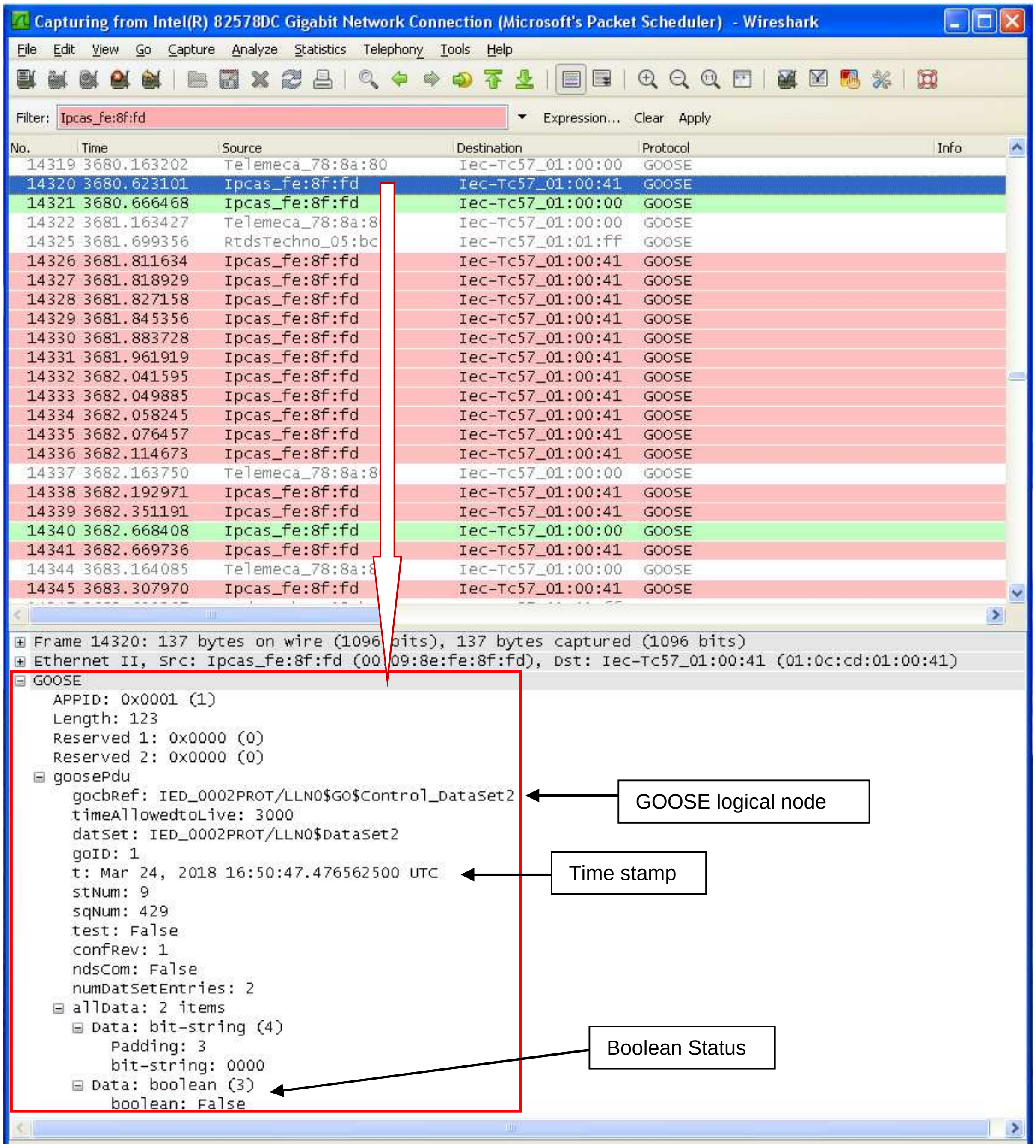


Figure 7.14: Wireshark packets before transmission of GOOSE trip messages

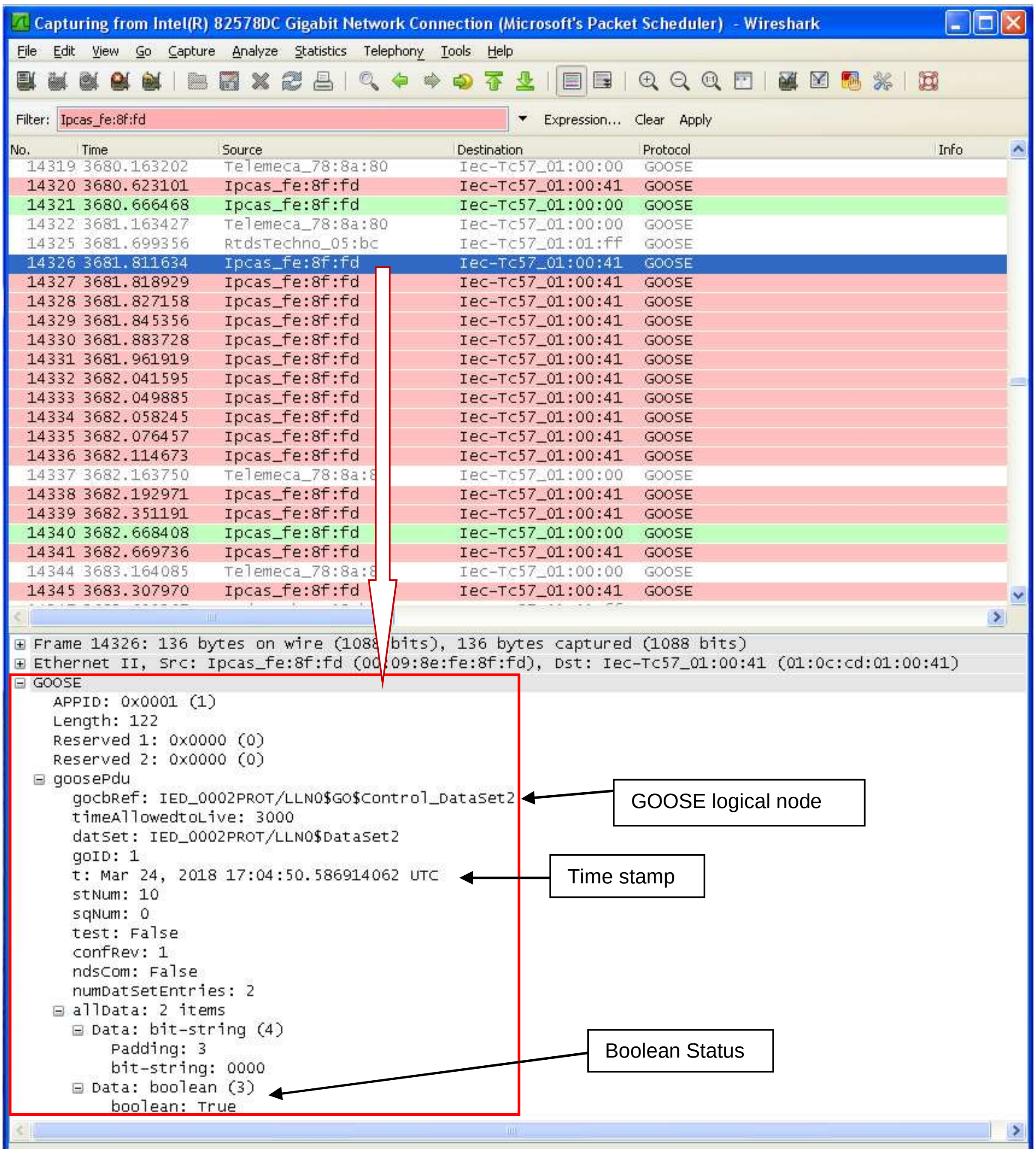


Figure 7.15: Wireshark packets during GOOSE trip message

As described in Chapter 6, GOOSE Inspector allows monitoring and capturing of IEC 61850 substation automation protocols via the network. The IEC 61850 packets are decoded with the exception of GSE and Sample Values, checked, displayed, filtered, saved in the Log.lg6 circular buffer file. Furthermore, the program monitors GOOSE transmission via the network and displays the current status in GOOSE monitor table and a sample example can be seen in Figure 6.42 in Chapter 6.

The packets are shown in two windows which are Main Window and the Detailed View. Elements of the main Window can be seen in Figure 7.16

Figure 7.16 below shows one of the last GOOSE packet sniffed before the GOOSE trip message is transmitted. The packet number 133, associated with time stamp at 16:56 and the mac address of the sending and receiving devices and the message type (GOOSE) are shown in the File View pane. The Detailed View pane right of the File View provides the additional information about the chosen packet. In this view, the GOOSE protection logical node can be identified to confirm the logical nodes which was defined in the respective IED. Sequence number and the Boolean status can also be identified.

Figure 7.17 below shows the completion of the transmitted trip command via GOOSE message. This is identified via the reset of the sequence number and the change in the Boolean status.

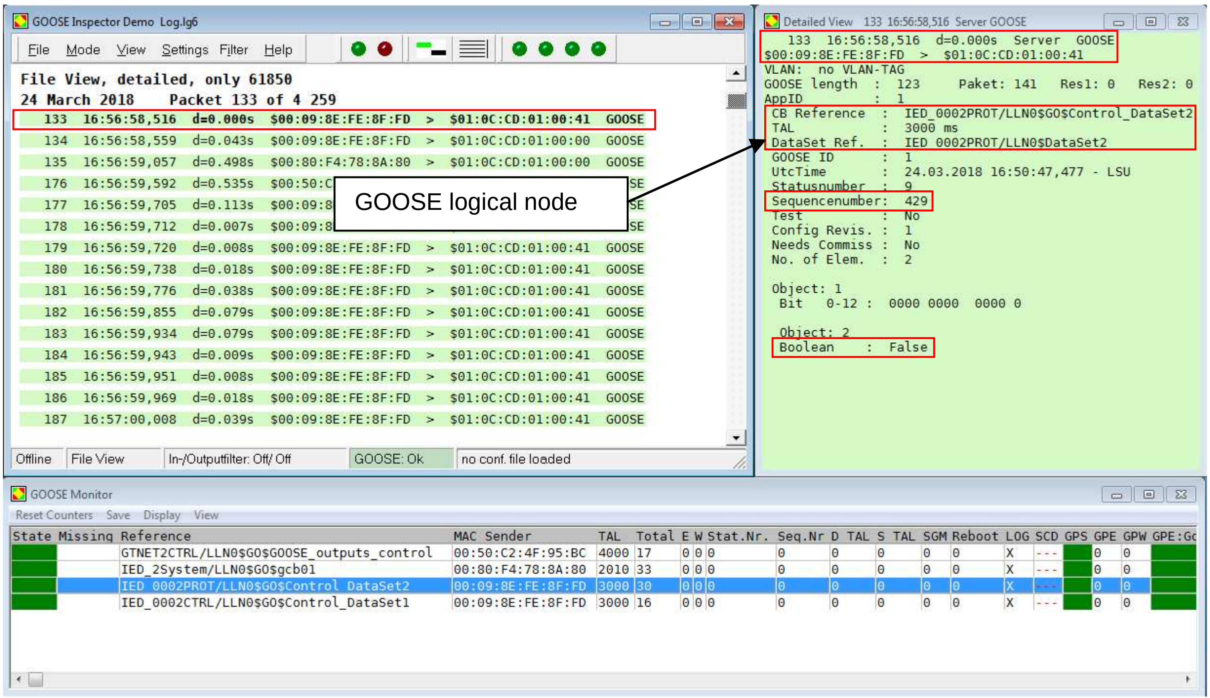


Figure 7.16: GOOSE Inspector captured information before the single-phase short-circuit fault

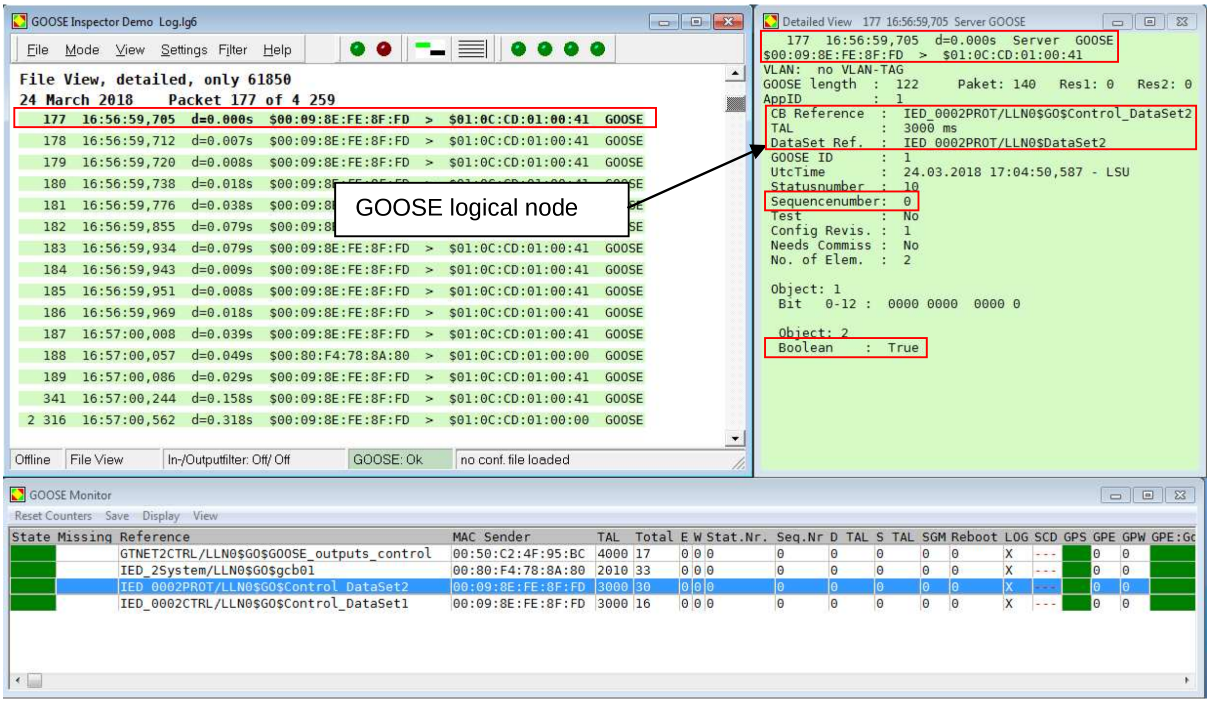


Figure 7.17: GOOSE Inspector captured information when single phase short-circuit fault is cleared

It could also be programmed on the runtime that when the breaker is assumed to be open, such event must also change the state of the single-line network diagram symbol. This has been done via the colour change and the no-fill of the breaker symbol as highlighted in the Figure 7.18 below.

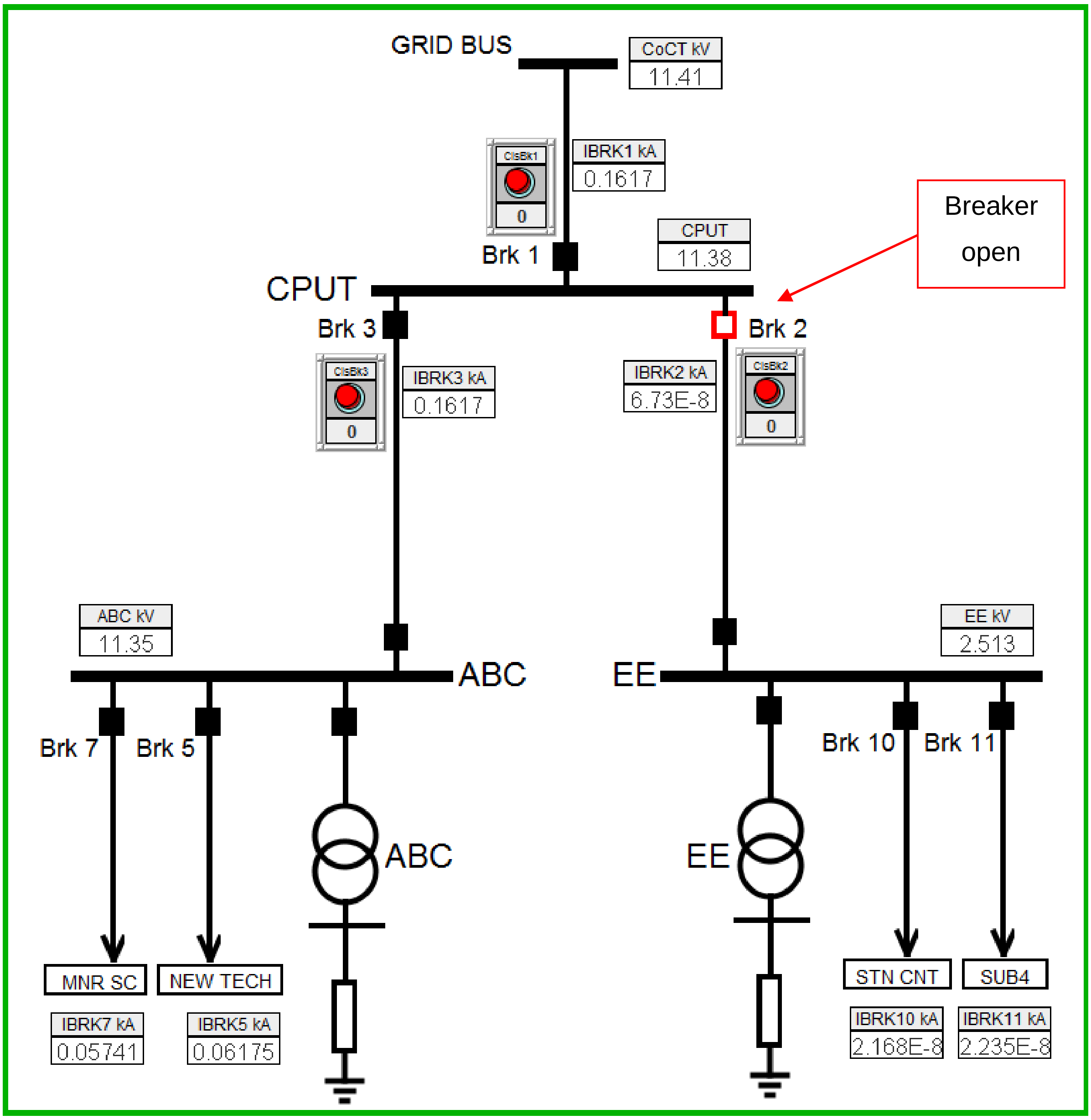


Figure 7.18: Monitoring of Incomer bus during single-phase short-circuit fault at EE

7.2.2 Three Phase Short-Circuit Fault at EE Substation Bus

When a three-phase to ground short-circuit fault is injected at EE substation bus by changing the dial control to logic number 7 and then "apply" ground short-circuit fault, CT measurements were recorded. Figure 7.19 illustrates that CT2 sees a short-circuit fault and later the IED 2 issues a trip command for the breaker 2 to open. However during the same period, CT3 sees a voltage dip which reduces the amount of current supplied towards downstream load of CT3. IED 3 does not see a short-circuit fault during this period and hence no trip command issued (see Figure 7.20). CT1 however sees the short-circuit fault as this is on the incomer side of the bus which is upstream of CT2. During the said period, IED 1 time grading prevents the IED from issuing a trip command thereby allowing continuity of supply to the other side of the loads through CT3. If however IED 2 fails to issue a trip command within maximum required time, then IED 1 should act as backup and open Breaker 1 when its minimum trip time has been reached.

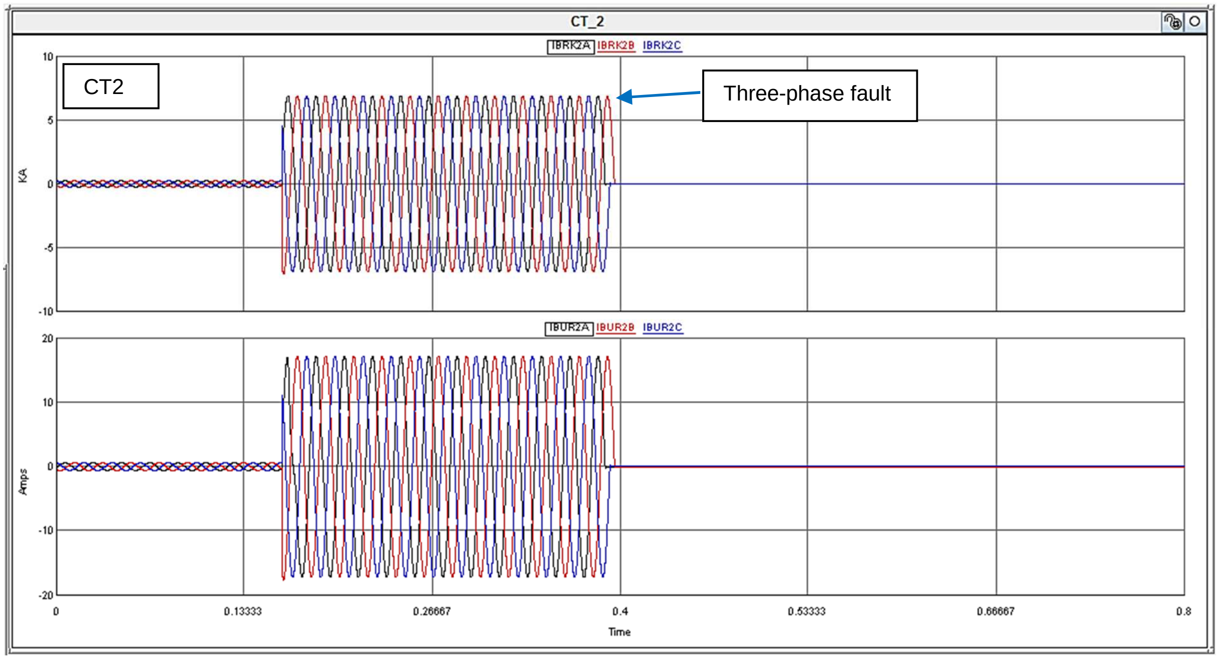


Figure 7.19: Measurements of three-phase short-circuit fault at EE substation bus

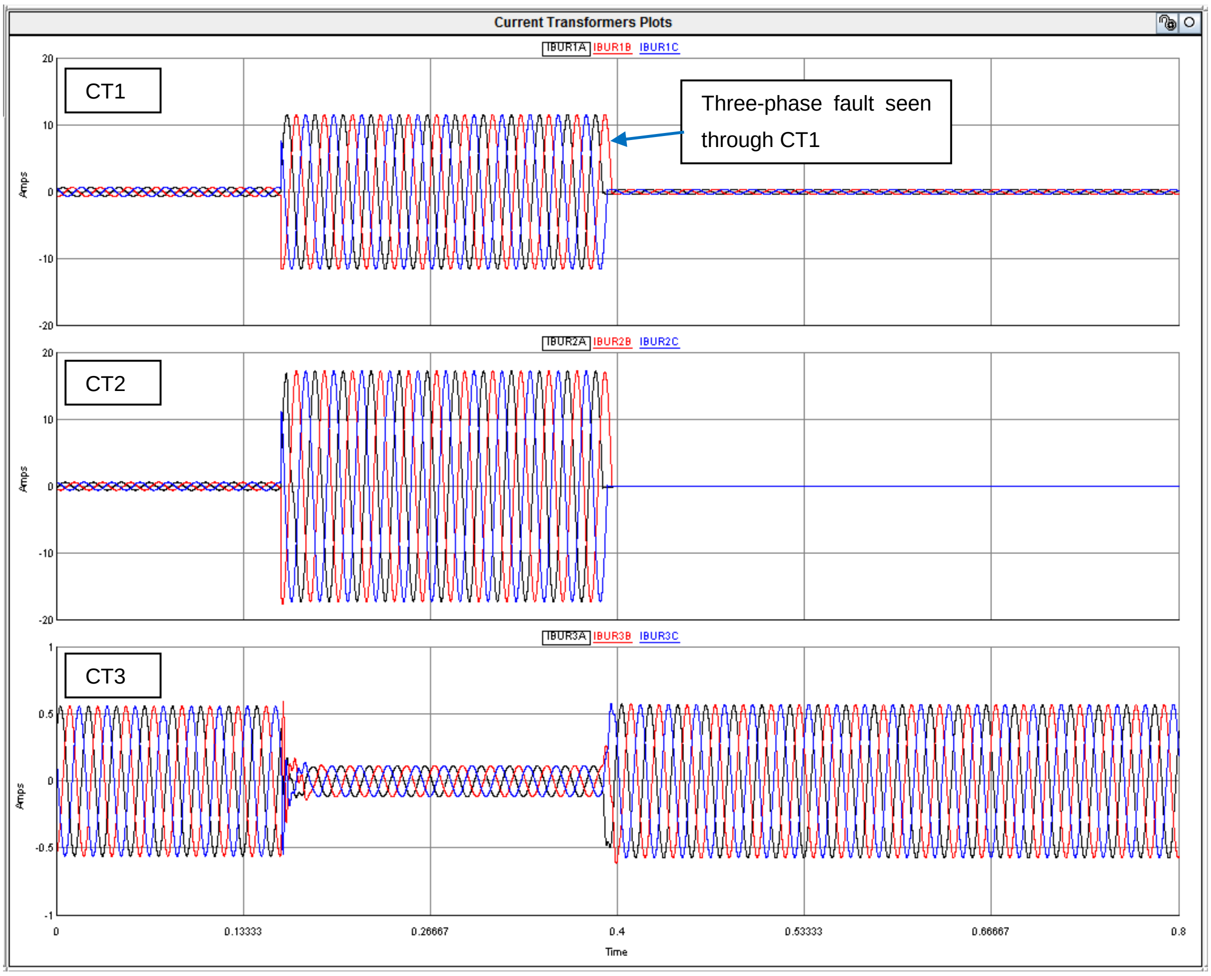


Figure 7.20: Measurement of three phase short-circuit fault through all CTs

During this period of three-phase to ground short-circuit fault, a comparison of the hard-wiring tripping time and the GOOSE message tripping time was conducted. When the GOOSE trip has been initiated, the breaker opens immediately while the hard-wiring trip has a delay time of approximately 7.55ms. This is illustrated in Figure 7.21 and 7.22 below. As expected, CT1 does measure the short-circuit fault however the IEDs associated with it does not initiate a trip command.

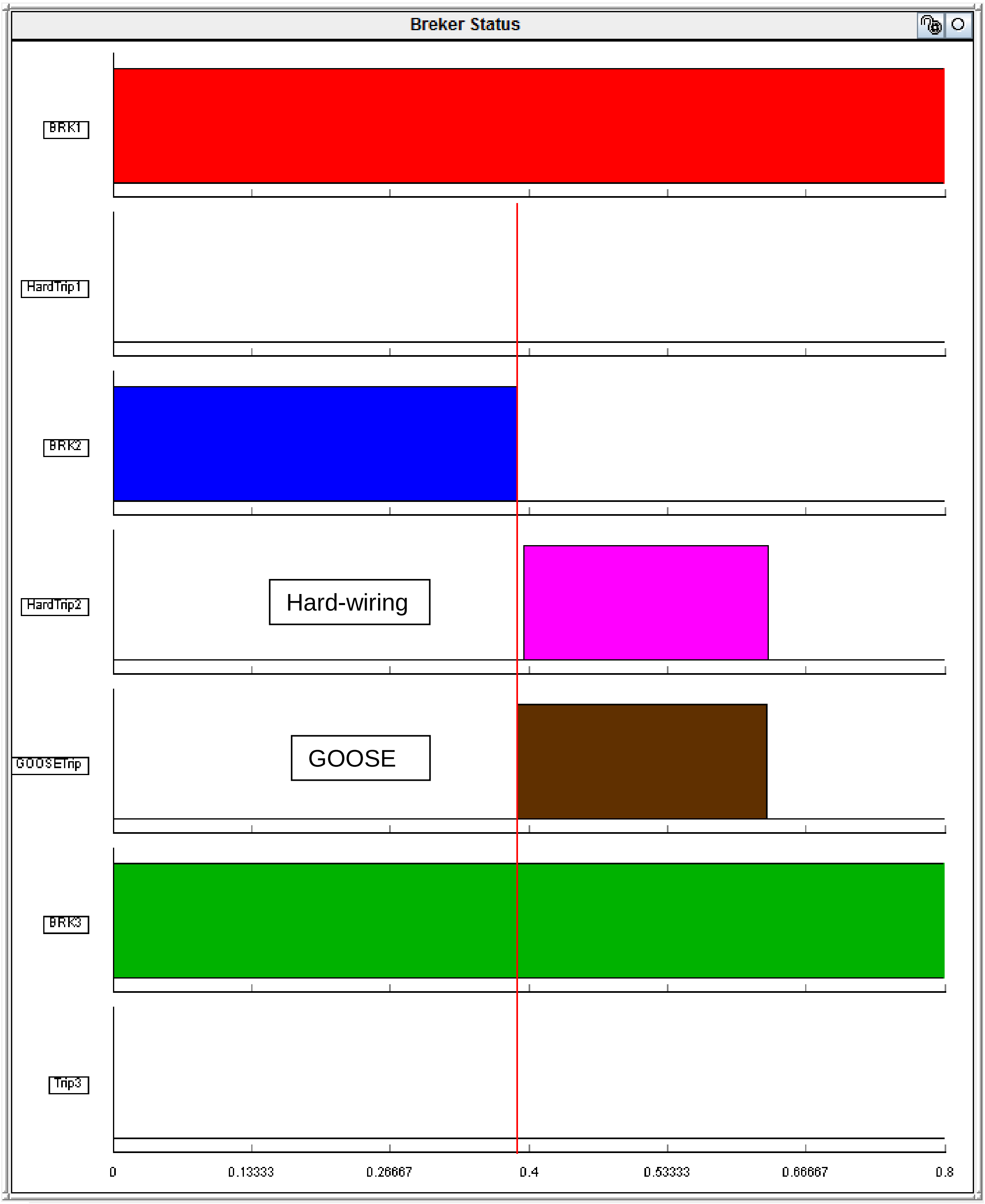


Figure 7.21: GOOSE vs. Hard-wiring during three-phase short-circuit fault

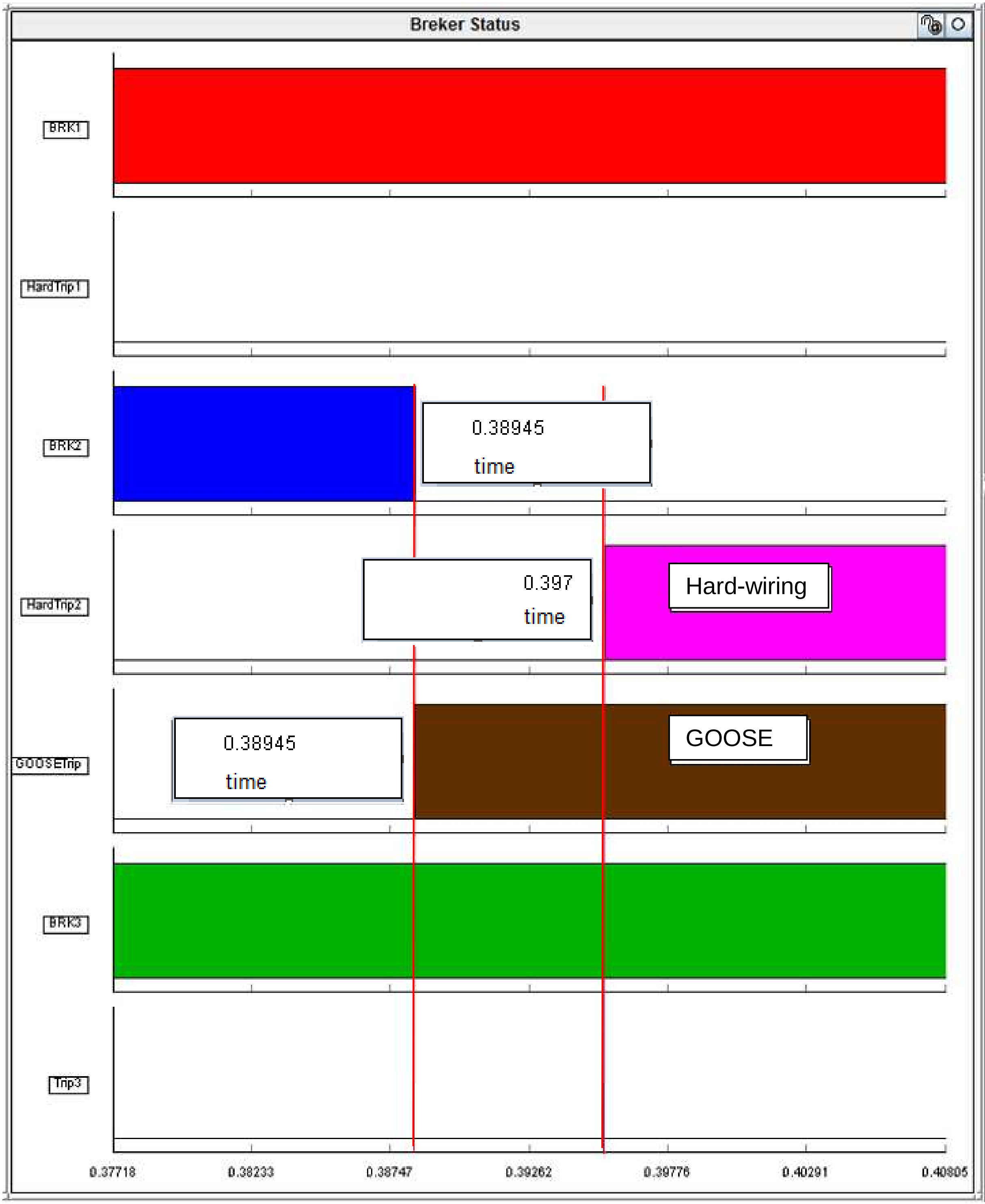


Figure 7.22: GOOSE vs. Hard-wiring zoomed in view of Figure 7.21

Figure 7.23 below shows the behaviour of voltage waveforms for various CPUT network substations during the three phase fault at EE substation busbar. A voltage dip is experienced at all other substations while EE substation is removed from the supply to clear the fault.

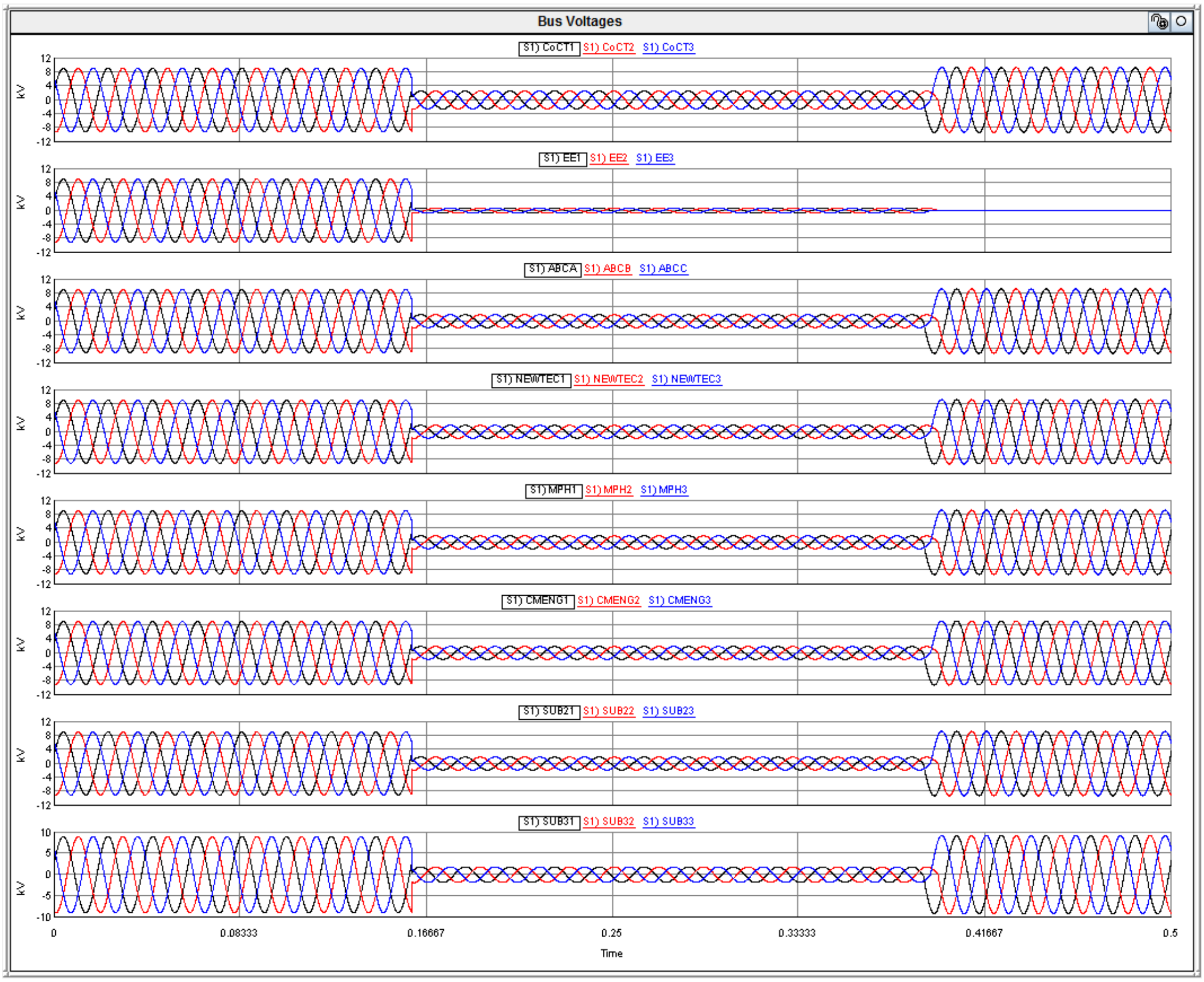


Figure 7.23: Voltage dip as experienced at various substations during three phase fault

Figure 7.24 shows one of the last GOOSE packet sniffed before the GOOSE trip message is transmitted. The packet number 405, associated time stamp at 16:25, and the mac address of the sending and receiving devices and the message type (GOOSE) are shown in the File View pane. The Detailed View pane right of the File View provides the additional information about the chosen packet. In this view, the GOOSE protection logical node can be identified to confirm the logical nodes which are defined in the respective IED. Sequence number and the Boolean status can also be identified.

Figure 7.25 show the completion of the transmitted trip command via GOOSE message. This is identified via the reset of the sequence number and the change in the Boolean status.

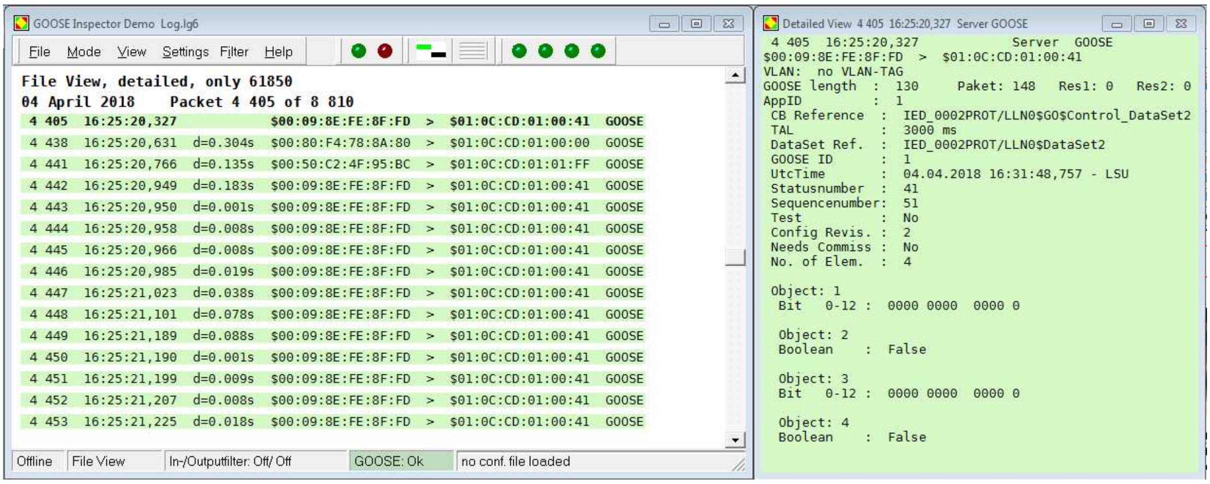


Figure 7.24: GOOSE data packets before three-phase short-circuit at EE substation bus

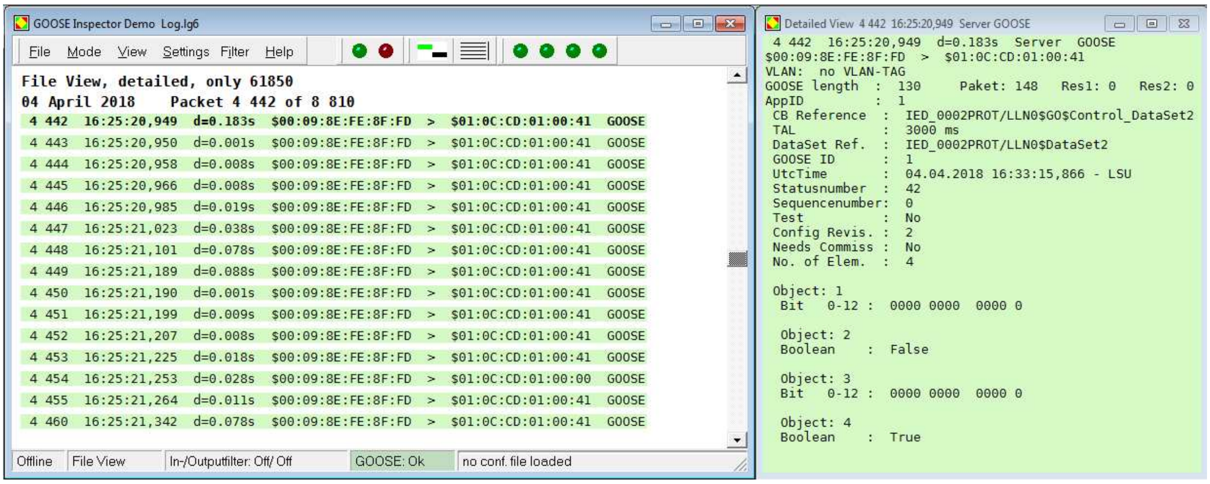
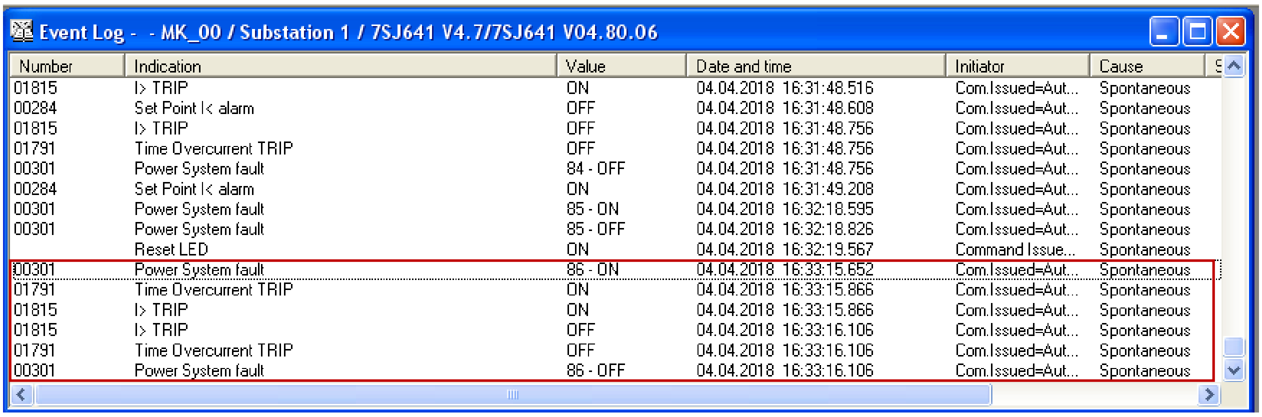


Figure 7.25: GOOSE data packets during clearance of the three-phase short circuit at EE substation bus

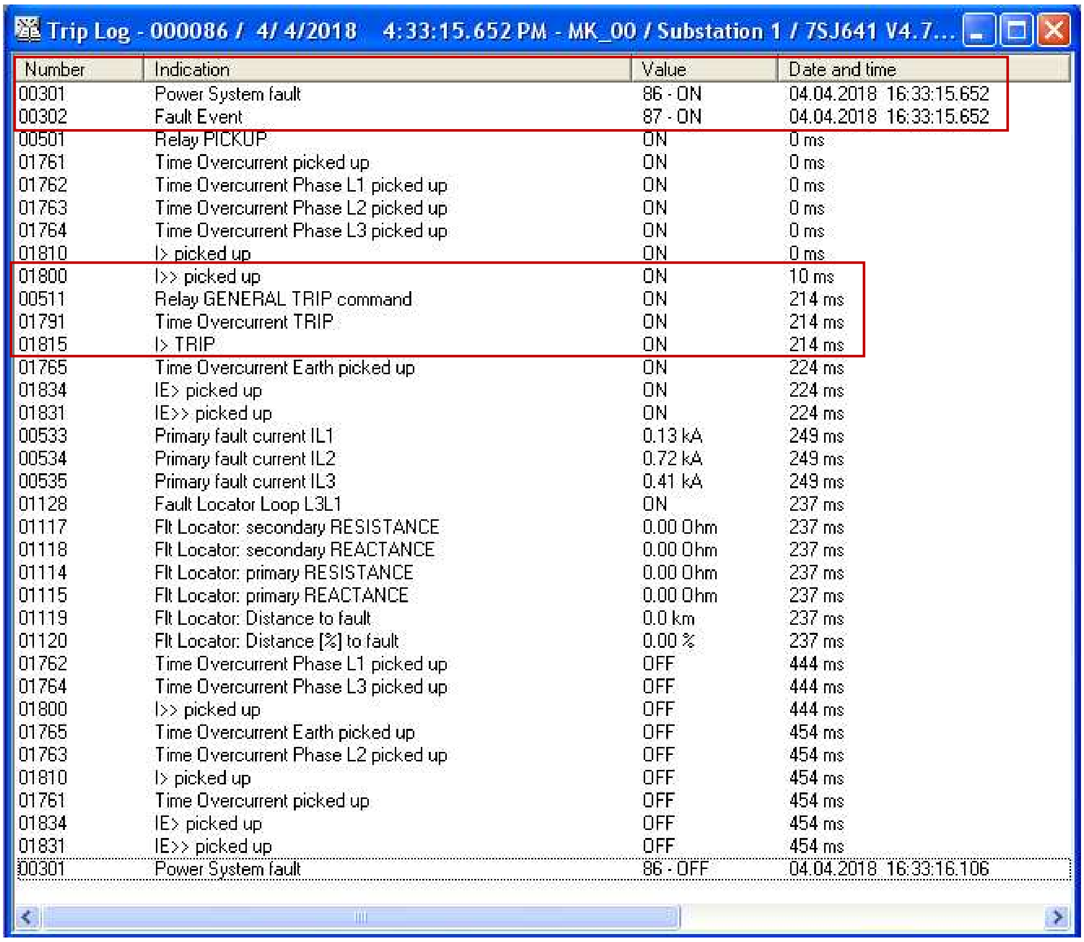
The IED event and trip logs could also be extracted from the IED software DIGSI4 which then highlight the actual times at which events are triggered and length of such events if measureable. Figures 7.26 and Figure 7.27 show the event and trip log respectively. These figures show the function description followed by the corresponding event log status with the date and time of when the event occurred with the duration of the event as shown on the trip log.



Event Log - - MK_00 / Substation 1 / 7SJ641 V4.7/7SJ641 V04.80.06

Number	Indication	Value	Date and time	Initiator	Cause
01815	I> TRIP	ON	04.04.2018 16:31:48.516	Com.Issued=Aut...	Spontaneous
00284	Set Point I< alarm	OFF	04.04.2018 16:31:48.608	Com.Issued=Aut...	Spontaneous
01815	I> TRIP	OFF	04.04.2018 16:31:48.756	Com.Issued=Aut...	Spontaneous
01791	Time Overcurrent TRIP	OFF	04.04.2018 16:31:48.756	Com.Issued=Aut...	Spontaneous
00301	Power System fault	84 - OFF	04.04.2018 16:31:48.756	Com.Issued=Aut...	Spontaneous
00284	Set Point I< alarm	ON	04.04.2018 16:31:49.208	Com.Issued=Aut...	Spontaneous
00301	Power System fault	85 - ON	04.04.2018 16:32:18.595	Com.Issued=Aut...	Spontaneous
00301	Power System fault	85 - OFF	04.04.2018 16:32:18.826	Com.Issued=Aut...	Spontaneous
	Reset LED	ON	04.04.2018 16:32:19.567	Command Issue...	Spontaneous
00301	Power System fault	86 - ON	04.04.2018 16:33:15.652	Com.Issued=Aut...	Spontaneous
01791	Time Overcurrent TRIP	ON	04.04.2018 16:33:15.866	Com.Issued=Aut...	Spontaneous
01815	I> TRIP	ON	04.04.2018 16:33:15.866	Com.Issued=Aut...	Spontaneous
01815	I> TRIP	OFF	04.04.2018 16:33:16.106	Com.Issued=Aut...	Spontaneous
01791	Time Overcurrent TRIP	OFF	04.04.2018 16:33:16.106	Com.Issued=Aut...	Spontaneous
00301	Power System fault	86 - OFF	04.04.2018 16:33:16.106	Com.Issued=Aut...	Spontaneous

Figure 7.26: 7SJ64 Event log during three phase short-circuit fault at EE substation bus



Trip Log - 000086 / 4/ 4/2018 4:33:15.652 PM - MK_00 / Substation 1 / 7SJ641 V4.7...

Number	Indication	Value	Date and time
00301	Power System fault	86 - ON	04.04.2018 16:33:15.652
00302	Fault Event	87 - ON	04.04.2018 16:33:15.652
00501	Relay PICKUP	ON	0 ms
01761	Time Overcurrent picked up	ON	0 ms
01762	Time Overcurrent Phase L1 picked up	ON	0 ms
01763	Time Overcurrent Phase L2 picked up	ON	0 ms
01764	Time Overcurrent Phase L3 picked up	ON	0 ms
01810	I> picked up	ON	0 ms
01800	I>> picked up	ON	10 ms
00511	Relay GENERAL TRIP command	ON	214 ms
01791	Time Overcurrent TRIP	ON	214 ms
01815	I> TRIP	ON	214 ms
01765	Time Overcurrent Earth picked up	ON	224 ms
01834	IE> picked up	ON	224 ms
01831	IE>> picked up	ON	224 ms
00533	Primary fault current IL1	0.13 kA	249 ms
00534	Primary fault current IL2	0.72 kA	249 ms
00535	Primary fault current IL3	0.41 kA	249 ms
01128	Fault Locator Loop L3L1	ON	237 ms
01117	Flt Locator: secondary RESISTANCE	0.00 Ohm	237 ms
01118	Flt Locator: secondary REACTANCE	0.00 Ohm	237 ms
01114	Flt Locator: primary RESISTANCE	0.00 Ohm	237 ms
01115	Flt Locator: primary REACTANCE	0.00 Ohm	237 ms
01119	Flt Locator: Distance to fault	0.0 km	237 ms
01120	Flt Locator: Distance [%] to fault	0.00 %	237 ms
01762	Time Overcurrent Phase L1 picked up	OFF	444 ms
01764	Time Overcurrent Phase L3 picked up	OFF	444 ms
01800	I>> picked up	OFF	444 ms
01765	Time Overcurrent Earth picked up	OFF	454 ms
01763	Time Overcurrent Phase L2 picked up	OFF	454 ms
01810	I> picked up	OFF	454 ms
01761	Time Overcurrent picked up	OFF	454 ms
01834	IE> picked up	OFF	454 ms
01831	IE>> picked up	OFF	454 ms
00301	Power System fault	86 - OFF	04.04.2018 16:33:16.106

Figure 7.27: 7SJ64 Trip log during three phase short-circuit fault at EE substation bus

7.2.3 Three-Phase Short-Circuit With Shorter Duration

For a short time duration of the fault it may not be expected that any IED will issue a trip command to the circuit breakers. This event could be such that the fault was not continuous for long and therefore the duration of it does not instruct the IED to proceed with protection.

For this case, a short time duration of less than 200 milliseconds is set and the fault is then applied to monitor whether there would be any actions from the IEDs. Figures 7.28 and 7.29 below illustrates the set duration.

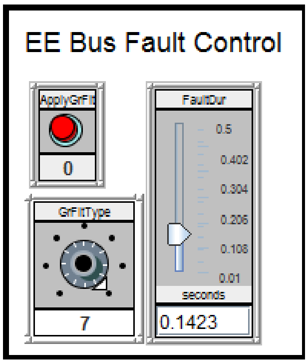


Figure 7.28: Setting EE substation busbar to shorter fault duration

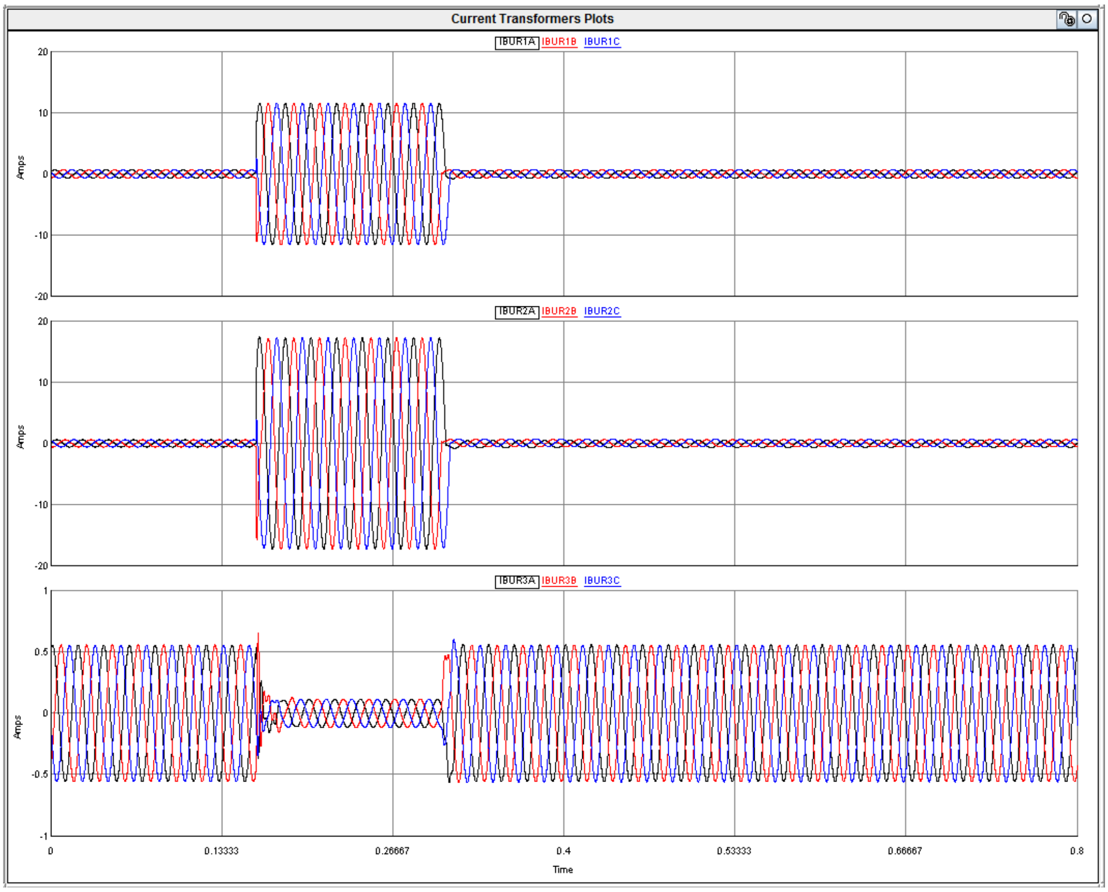


Figure 7.29: CT measurements during a short duration fault at EE substation busbar

The Figure 7.30 below shows voltage disturbances at other substations due a three-phase fault at EE substation. The fault does not last long and the circuit breaker does not trip. After the fault has passed, the system returns to steady state condition at all substations.

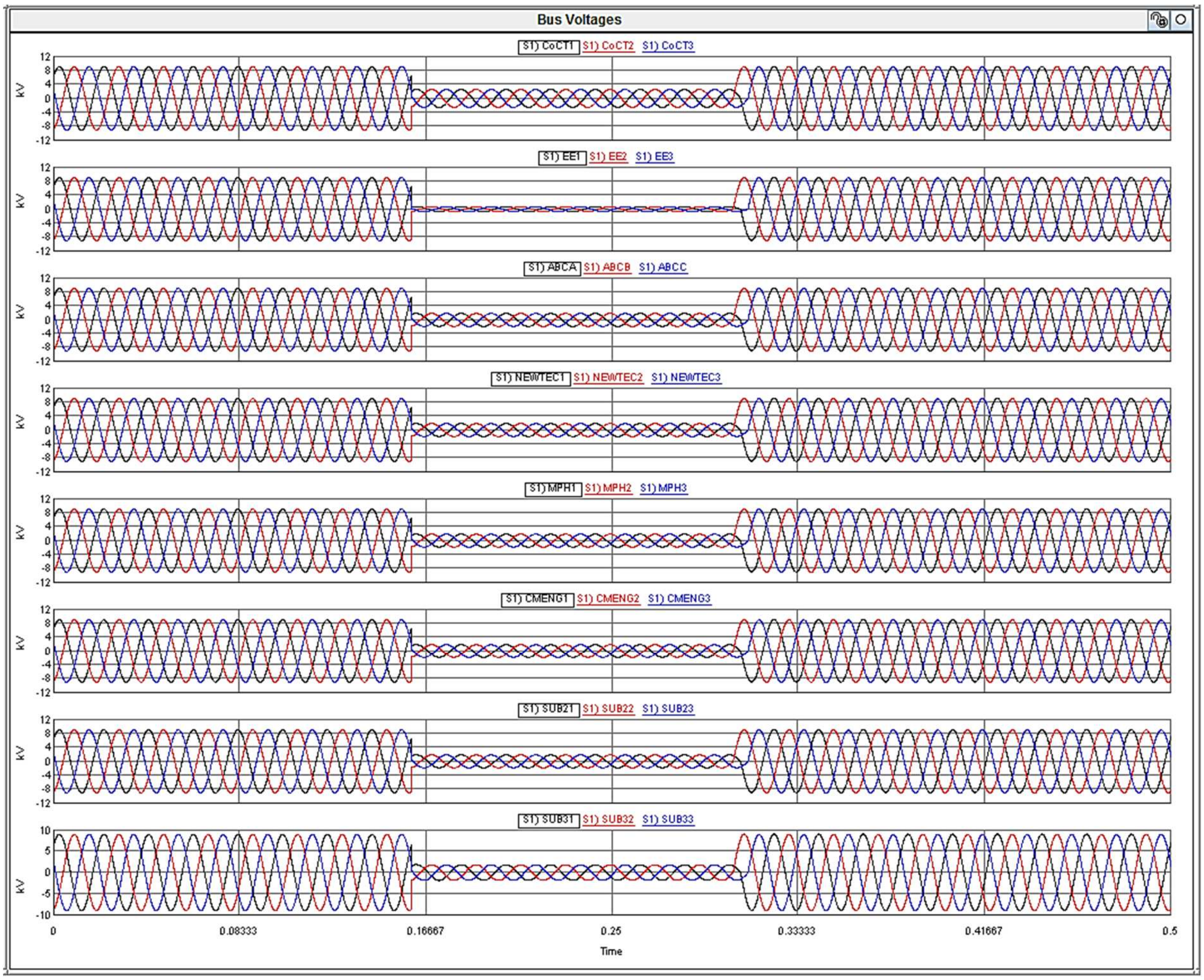


Figure 7.30: Response of voltages at other substations

7.3 ANALYSIS OF THE RESULTS

Closed-loop testing of the SIPROTEC protection IED was conducted and GOOSE message versus the hard-wiring through IED's binary inputs and outputs was completed. The test was to compare the speed of trip command between these two methods. A power system network similar to the one in Chapter 4 was built on RSCAD draft in order to model the closed-loop testing. Minor disadvantage with RSCAD was that each sub-system had a limitation of 72 nodes. These nodes comprise of all network equipment such as source, cable models, transformers, loads, circuit breakers and current transformers. In addition, when one subsystem is full in nodes, connection to the next subsystem required a modelling of a transmission line (T-line) of Bergeron type. This type of line makes the low voltage a little unrealistic as it introduces transients on the system. However since the objectives of the study was more on protection testing, the T-line had little impact on the results.

For simulation of short circuits, short-circuit fault control logic were built and breaker control logics were also built to clear these short-circuit faults. The IEC 61850 GOOSE communication was tested and compared with the traditional hard-wiring to determine the faster method between the two considering the application on low voltage power system network. The desired results were achieved. The devices sharing and receiving the GOOSE messages were the physical IED hardware and the RSCAD GTNET card. The IED sends the GOOSE message while the GTNET receives it. The sent message is the trip command initiated during short circuit conditions on the power system. The received message is intended on opening the software circuit breaker on the same power system network on RSCAD environment. This exercise was conducted through IED 2 and the associated circuit breaker.

IED 1 completed the experiment via hard-wiring in order to open associated circuit breaker in RSCAD software. IED 3 is the RSCAD internal library overcurrent relay model. The conducted tests were described in detail in the sections of this chapter of the study such as:

- Single phase short circuits at the EE substation busbar
- Three phase short circuits at the EE substation busbar
- Capturing and monitoring of the power system network results or events via RSCAD runtime.

Table 7.1: GOOSE vs. Hard-wiring

FAULT TYPE	LOCATION	GOOSE	HARD WIRING
Single-phase to ground	EE Substation	221 ms	228.55 ms
Three-phase to ground	EE Substation	214 ms	221.55 ms

7.4 CONCLUSION

The developed methods for the protection scheme shall be compatible with the CPUT power reticulation network. This protection and communication based on the IEC 61850 GOOSE shall provide benefits such as centralised monitoring of substation events and control of substation equipment from the central control location.

The objective of this chapter was closed-loop testing of the designed, developed and implemented hardware-in-loop workstation using SIPROTEC IEDs tripping the software circuit breakers on the power system network in the RSCAD environment. The chapter tested two IEDs based on traditional hard-wiring and IEC 61850 GOOSE messages.

The next chapter is the last of the thesis and provides the conclusion of the entire scope and recommends any future work necessary.

CHAPTER

8. CONCLUSIONS

8.1 INTRODUCTIONS

The present power system network arrangement is a natural starting point for planning purposes. The various types of the power system network equipment, their location, electrical and thermal loading and mechanical conditions are all factors to be taken into account when considering future developments. Economies which are developing are now changing even the architecture of their electricity supply networks and performance due to concerns which are; safety and security of the network, global warming and greenhouse gas emissions, and competition internationally. Network studies are to be carried out or else it may not possible to assess the overall technical capability of any network to determine its performance during steady-state conditions or under load, or short-circuit fault conditions.

Proposed solution to achieve a controlled and automated network is influenced by the growth and alteration of the network, nature of the loads, primary system failures, secondary system failures, and network source impedance. The thesis analysed some of the requirements and also the current loading profile of the power system network. The thesis also made analysis of protection requirements and for the protection of the power system network to be successful it is important to carry out the requirements for: Selectivity, Stability, Sensitivity, and Speed. To meet all of these requirements, protection must be reliable, meaning that the protection scheme must trip when called upon and must not trip when it is not required. Analysis of these findings were completed using DIgSILENT PowerFactory.

Chapter 6 highlighted the development and configuration of the test bench for the real-time implementation of the hardware-in-the-loop of the designed protection scheme using RTDS real-time simulation. These included:

- network configurations,
- IED configurations,
- Modelling of breaker control logic diagrams on the RTDS RSCAD software environment.
- Mapping of the intended GOOSE messages and
- Introduction to monitoring the GOOSE messages with various software packages.

In chapter 7, the thesis also analysed the hardware-in-loop testing of the protection IED and presented the results obtained when simulating the power system network on real time digital simulator RSCAD. Current were injected on SIPROTEC IEDs from RSCAD via binary inputs and the IED sent back the trip commands via binary outputs and the use of Ethernet.

Future work will involve completely eliminating the use of binary inputs/outputs and make use of Ethernet communication completely. Another method could be the use of sampled value message compatible IEDs in comparison with direct sending and receiving of GOOSE logical nodes. Future technology is to completely eliminate hard-wring and transmit/receive data via Ethernet or Fibre optic communication.

8.2 THESIS DELIVERABLES

The main deliverables for the thesis are summarised as follows

8.2.1 Literature Review

The literature review in Chapter 2 presented the methods previously used for automation of power reticulation networks, protection and control. This also included whether the use of SCADA monitoring system were in place or are proposed for future use. The use of IEC 61850 substation communication was reviewed and in addition, closed-loop testing of protection IEDs has been reviewed.

8.2.2 Modelling Of Power Reticulation Network

The CPUT reticulation network was considered as a case study. The power reticulation network was modelled and simulated on DIgSILENT and RSCAD software packages. Each software package was used specifically within its capabilities. DIgSILENT simulation was more focussed on analysis of short-circuit faults and identifying maximum and minimum short-circuit currents. RSCAD software was more focused on the real-time implementation of the developed protection scheme and its testing.

8.2.3 Modelling Of Power Reticulation Network on DIgSILENT

DIgSILENT was used to conduct power flow studies of the network and also the protection performance of the network. General equipment parameters were configured for the source, lines, substation busbars, transformers and loads.

8.2.4 Load Flow Analysis

Load flow studies were completed on DIgSILENT to determine whether the power reticulation network is not under loading stress at any point of the system, either underground cables or transformers.

8.2.5 Analysis Of Short-Circuit Fault on the Power Reticulation Network

The short-circuit fault currents were simulated and analysed. This provides parameters required to determine the IED limits. Different short-circuit faults such as three-phase and single-phase were analysed and simulated. These faults were simulated at different locations of the power reticulation network to determine the lowest and highest fault magnitudes which may be measured by the protection IEDs. The analysis was completed on DIgSILENT and the relay curves were plotted and analysed during short-circuit fault conditions.

8.2.6 Modelling Of Power Reticulation Network on RSCAD Software Environment

The power reticulation was modelled in RSCAD for the real-time implementation of the protection scheme described for the incomer substation. The GTAO card on RTDS racks enables the transmission of voltages and current through the amplifier to the external IEDs. The short-circuit fault control logic diagrams were built so that when a short-circuit fault is applied on the reticulation network, the currents are sent to the protection IEDs for fault measurement and action.

8.2.7 Monitoring and Control of the Power Reticulation Network

The RSCAD runtime was used to build a monitoring and control platform. Plots, light, meters, control switches and others are created and assigned to a required attribute. Waveforms of voltages and current are also viewed and as soon as there is a change of events on the power reticulation network, all plots are updated with applicable changes and shown for a defined period. Various events for the protection testing were created and analysed.

8.2.8 IED Configuration for IEC 61850 Substation Communication

Two SIPROTEC IEDs were used for the HIL RTDS workstation. Both IEDs were configured for measurement of currents and sending trip commands under short-circuit fault conditions. The second IED which is on the outgoing feeder was configured for GOOSE communication. This GOOSE message was linked to the RSCAD GTNET card which has capabilities of sampling/processing the

IEC 61850 GOOSE or GSE messages. The configuration of both IEDs and the GTNET card were completed and mapped in the IEC 61850 station in DIGSI4 software and also in the RSCAD GTNET's IEC 61850 SCD files. When mapping was completed on both sides, the compiling of each SCD/ICD file was performed for publishing of the GOOSE messages.

8.2.9 Hardware-In-Loop Configurations (HIL)

The test bench was set-up for hardware in loop configuration as highlighted in Chapter 6. The advantage of the HIL lies with the testing of protection IEDs and other intelligent device which are external to computers or software packages. This means these physical devices could be tested for scheme set-up functionalities and capabilities. The aim of this test method was:

- Implementation of the designed protection scheme in real-time
- Testing of the hardware IEDs performance
- Comparison between communication based and hard wiring based protection scheme.

8.2.10 GOOSE versus Hard-Wiring

The two methods GOOSE and hard-wiring were tested and compared on the speed of interrupting the short-circuit faults. The approach of replacing the traditional hard-wiring for protection with the IEC 61850 GOOSE communication was successful. There is a speed difference and the GOOSE messaging takes the lead in opening of circuit breakers. This method will be applied for implementation of the future (upgraded) CPUT power reticulation network and any other utility smart substations and reticulation networks

8.2.11 Tabulating Of the Developed Software Objectives

The complete list of software packages used is shown in Table 8.1 below. These packages are applied to develop specific functions for the modelling and simulation of the CPUT reticulation network, its testing, IEDs setting determination, communication configuration, and real-time implementation.

Table 8.1: Software packages utilised on the project

SOFTWARE PACKAGE	DESCRIPTION OF FUNCTIONS USED
DIgSILENT PowerFactory	Power flow analysis
	Short-circuit analysis
RTDS RSCAD	Breaker control logic implementation
	Short-circuit analysis
	IEC 61850 mapping
	HIL comparison between GOOSE and hard-wiring trip times
	Monitoring of simulated substation events in real-time
DIGSI4	SIPROTEC device configuration
	IEC 61850 mapping
Wireshark	GOOSE monitoring
GOOSE inspector	GOOSE monitoring

8.3 APPLICATION TO ACADEMIA

The thesis provided the scope which could be covered and considered for future smart substations. These smart substations would require centralised monitoring and control of equipment, status of the reticulation network, and the setup of the communication networks within substations.

Very few academics has taken an initiative to work or do research on real-time simulated projects. The knowledge obtained from this thesis will be used to build further the knowledge base and transfer of such to academics and researchers who intend to further their studies in protection, monitoring, communication and control of substations and reticulation networks.

Closed-loop hardware testing could further be added in more research projects within the Centre of Substation Automation and Energy Management System (CSAEMS) at

CPUT. These tests could be conducted for GOOSE or traditional hard-wiring types of communications.

8.4 APPLICATION FOR DEVELOPMENT OF THE UPGRADE AND IEC 61850 STANDARD-BASED AUTOMATION OF THE CPUT RETICULATION NETWORK

The research output of this thesis is presently accepted by the CPUT management. The decision was made to start with the implementation of the general network upgrades and the implementation of the IEC 61850-based automation system. A technical documentation for the full network upgrade, design and procurement is budgeted in multi-stages due to limited funds available in a fiscal year.

8.5 POSSIBLE FUTURE RESEARCH WORK

The current work was based on comparing the speed of GOOSE versus hardwiring in substations and all others as described in various chapters of the thesis. Future work may involve the modelling and analysis of performance of smart substations with the application of IEC 61850 standard. These smart substation could be linked to small or medium scale embedded generations such as photovoltaic solar systems, but not limited to. The smart substation could communicate exclusively on GOOSE messages to all equipment. Testing of such substations could be developed from methods similar to the ones highlighted in this thesis which may include a test bench with multiple IEDs in real-time. In this case, there could only be one cable connected to each device either the Ethernet or Fibre optics communication to transmit all relevant data across the substation devices or two depending on redundancy and criticality of the network.

In addition, not only the speed but the cyber security of such substations could be looked at and analysed and aspects of reliability.

8.6 PUBLICATIONS

Ratshitanga M, Mnguni MES, Prof Tzoneva R (2018). Implementation of the Hardware-In-The-Loop Testing for the CPUT Reticulation Network Upgrades sent to Journal of Electrical Engineering Technology (JEET), September 2018

CHAPTER

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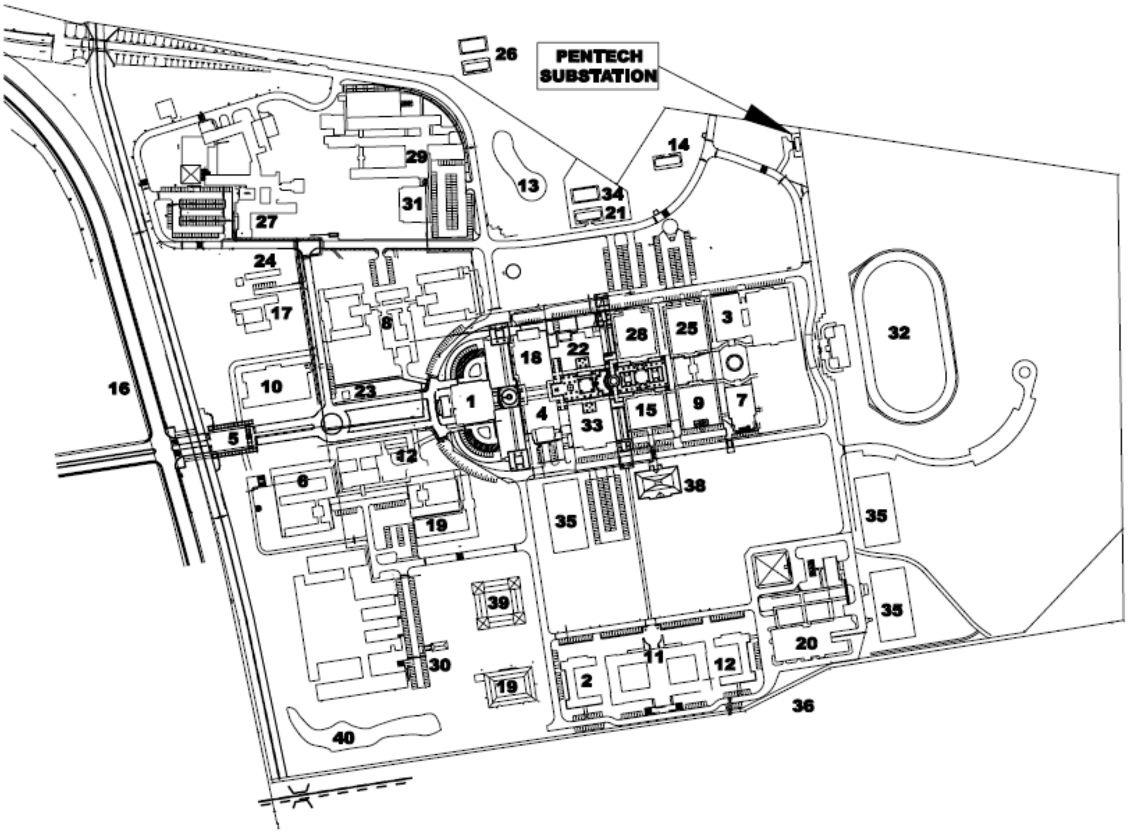
10. APPENDICES

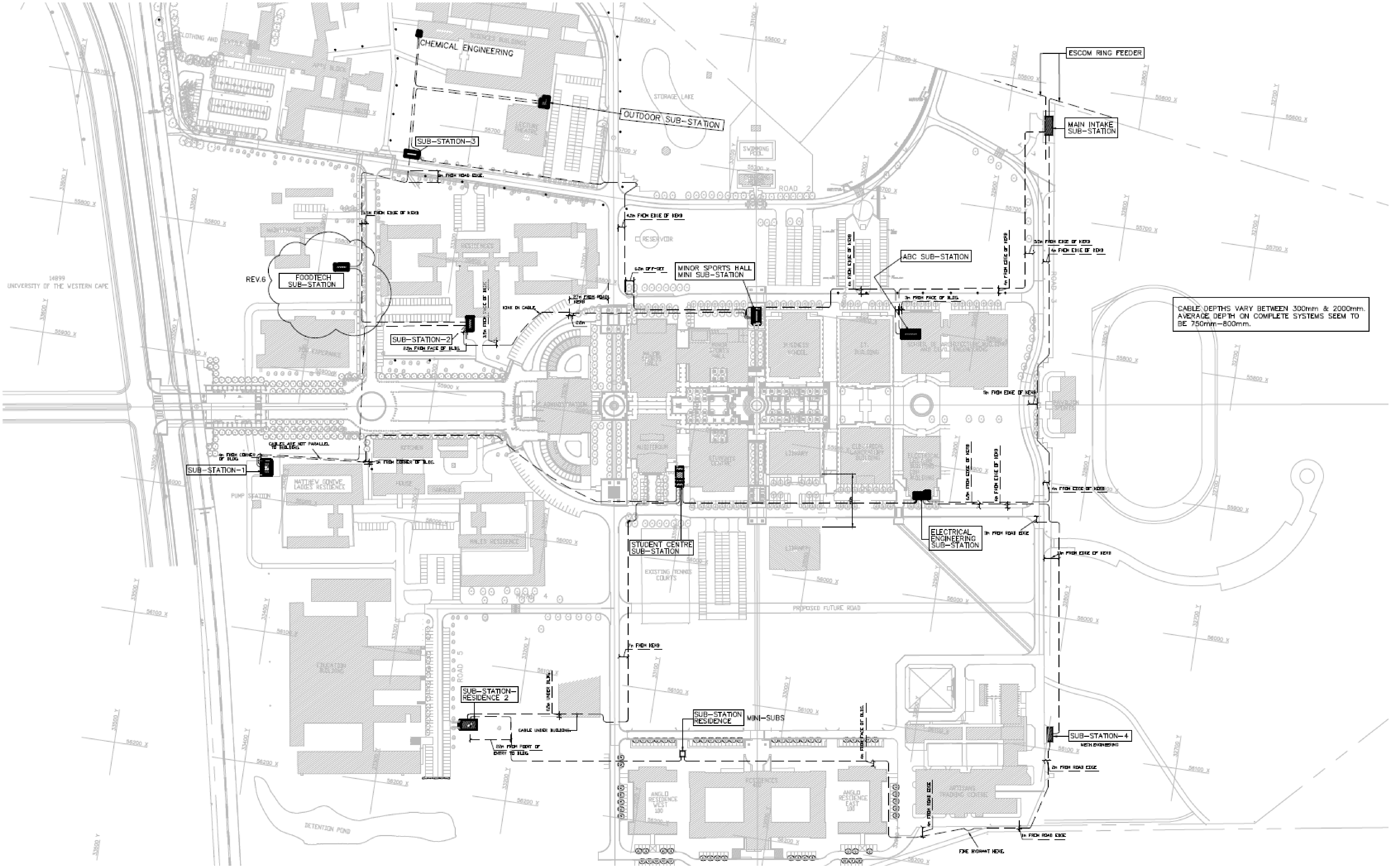
APPENDIX A: SURVEY LAYOUT OF THE CPUT CAMPUS



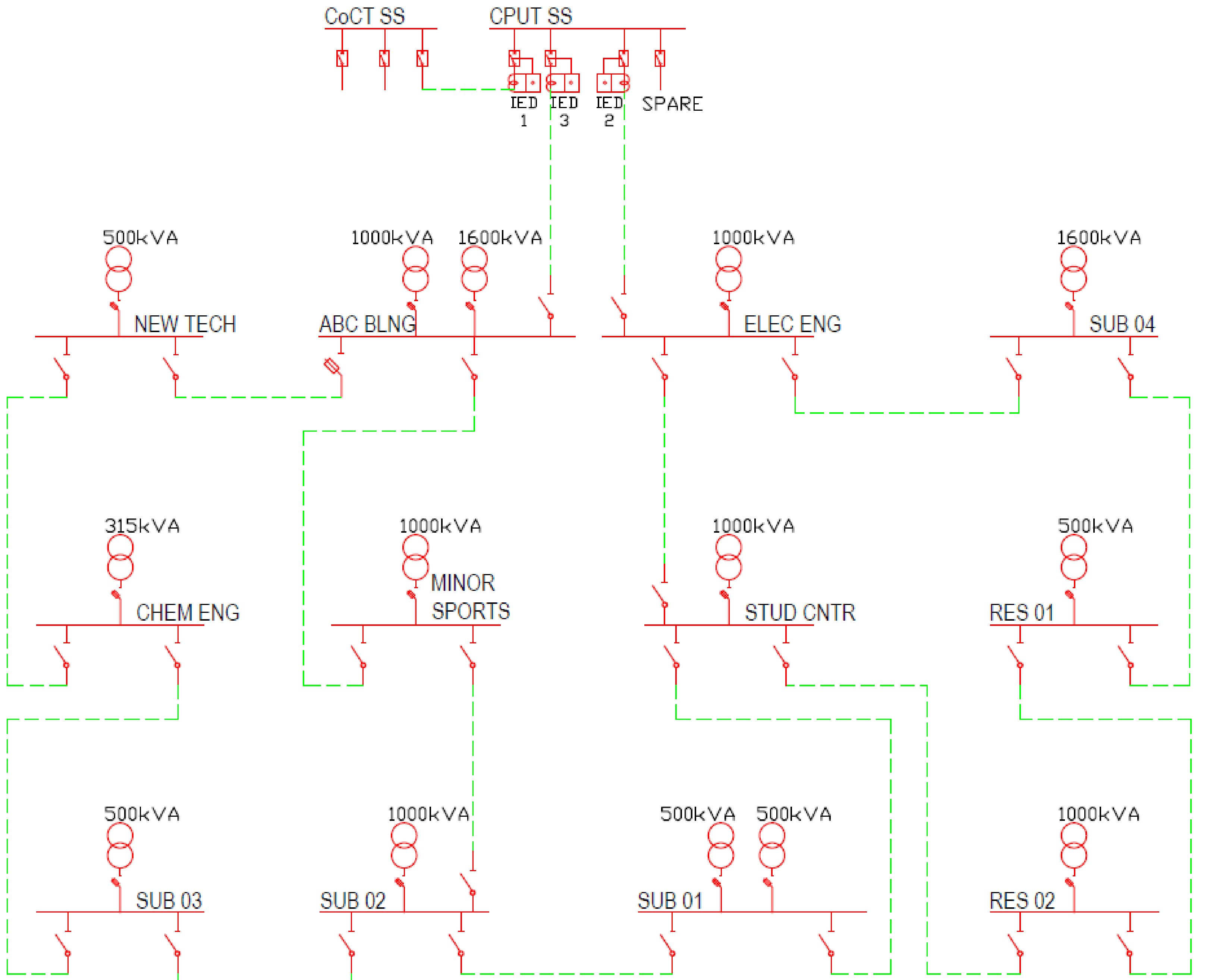
LEGEND

1. ADMINISTRATION
2. ANGLO RESIDENCE
3. ABC BUILDING - ENGINEERING
4. AUDITORIUM
5. MAIN ENTRANCE
6. MGR 2 RESIDENCE
7. ELECTRICAL ENGINEERING
8. RICHARD SACCO ENGINEERING
9. ELECTRICAL ENGINEERING
10. HORTICULTURE AND FOOD TECHNOLOGY
11. FREEDOM SQUARE RESIDENCE
12. DE BEERS RESIDENCE
13. LAKE
14. NURSERY
15. LIBRARY
16. SYMPHONY WAY
17. SCIENCE
18. MAJOR SPORTS HALL
19. MGR 2
20. MECHANICAL ENGINEERING
21. POOL HOUSE
22. SPORT CENTRE
23. INFORMATION CENTRE
24. OLD MAINTENANCE BUILDING
25. INFORMATION TECHNOLOGY CENTRE
26. NEW MAINTENANCE BUILDING
27. ART AND DESIGN BUILDING
28. BUSINESS FACULTY
29. SCIENCE FACULTY
30. EDUCATION BUILDING
31. NEW SCIENCE BUILDING
32. ATHLETIC STADIUM
33. STUDENT CENTRE
34. SWIMMING POOL
35. TENNIS COURTS
36. PENTECH STATION
37. HEROES HOUSE RESIDENCE
38. LIBRARY EXTENSION
39. POST GRAD RESIDENCE
40. DETENTION POND

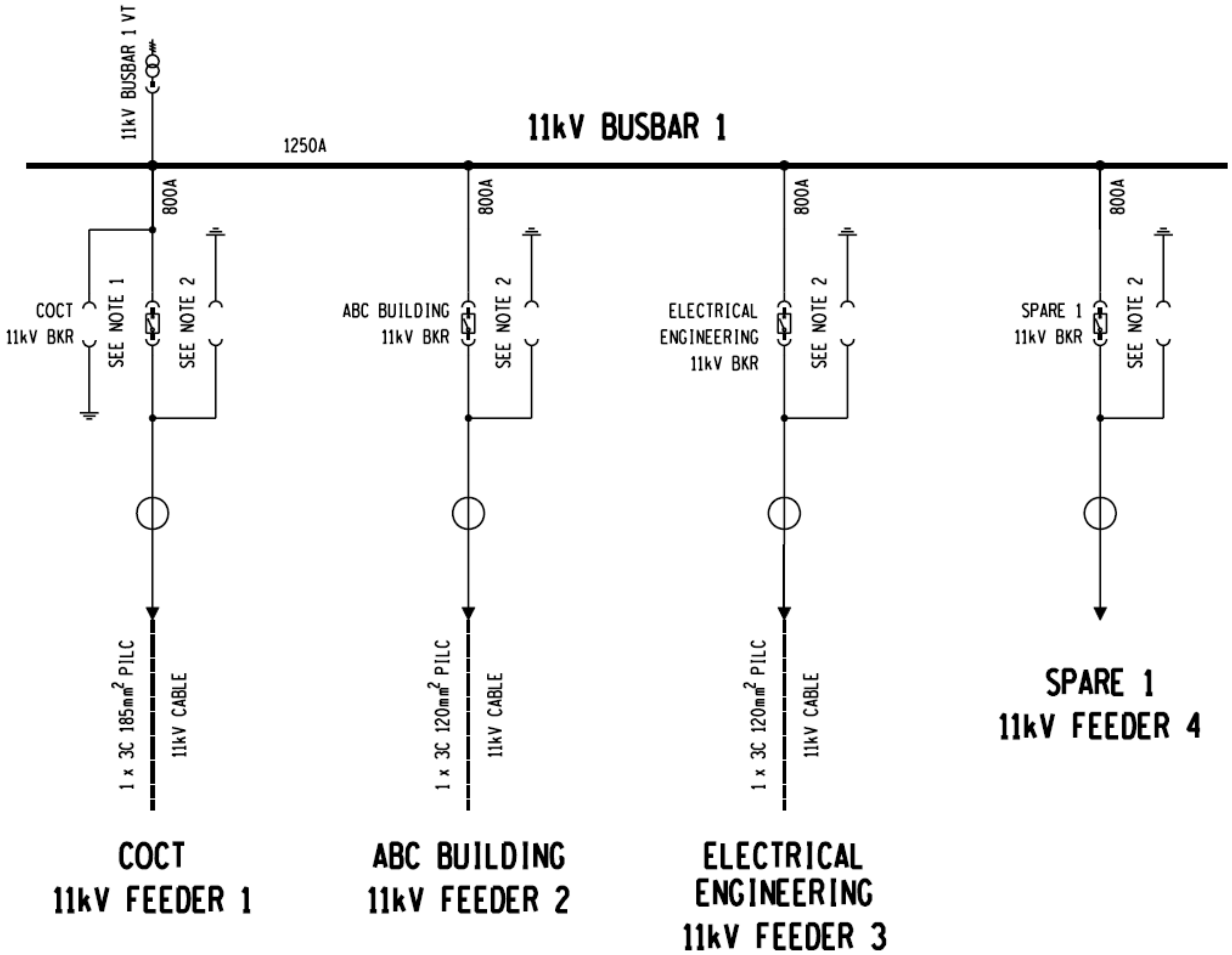
APPENDIX B: HIGH TENSION NETWORK LAYOUT



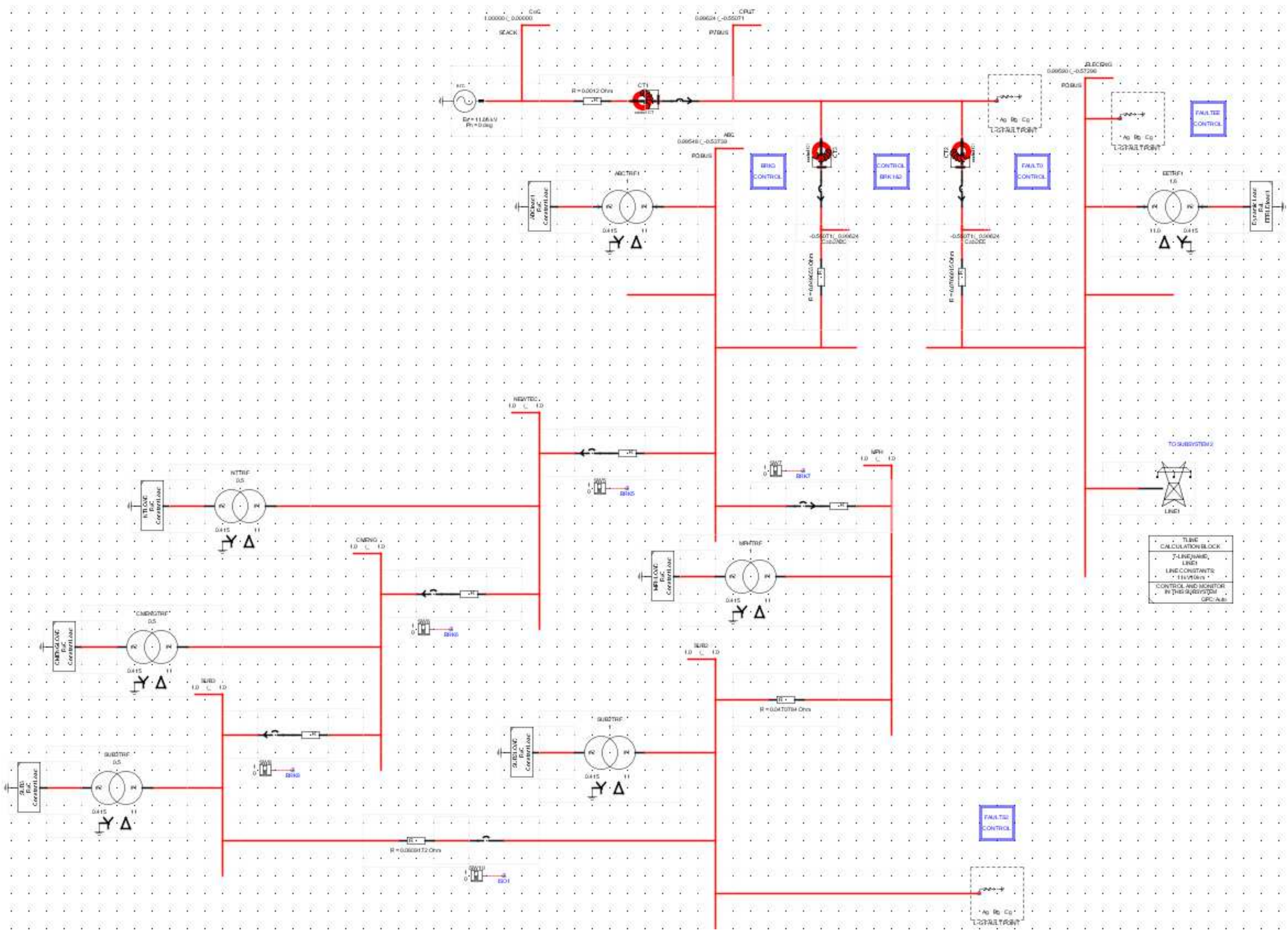
APPENDIX C: CPUT RETICULATION SINGLE LINE DIAGRAM WITH IED POSITIONS



APPENDIX D: CPUT MAIN INCOMER SUBSTATION CURRENT LAYOUT



APPENDIX E: CPUT RSCAD SINGLE-LINE DIAGRAM (SUBSYSTEM 1)



APPENDIX F: CPUT RSCAD SINGLE-LINE DIAGRAM (SUBSYSTEM 2)