Fault detection and location on 22kV and 11kV distribution feeders

Ryszard Orlowski

**Thesis submitted for the Doctorate of Philosophy Degree
to the School of Electrical Engineering,
Victoria University of Technology,
Footscray Park Campus**

March 2006

SYNOPSIS

AGL Electricity (AGLE) is one of the four privately owned electricity distribution companies in the Australian State of Victoria. Due to its operations in a regulated environment, AGLE's objective is to meet the distribution network performance standards set by the Victorian government's Essential Services Commission (ESC). Two performance measures are of major importance: average minutes off supply per customer and average number of interruptions per customer. These performance measures are adversely impacted by unplanned outages caused by faults occurring mainly on overhead distribution feeders. To improve these two performance measures, there has been a need to implement a scheme on AGLE's overhead distribution network that would contain long term effects of a fault within the feeder section that directly experienced the fault, leaving the remaining feeder sections and their customers on supply. To achieve this goal a means of fault detection and location, augmented by automatic isolation of the faulty feeder section, is required.

To that extent, AGLE was faced with a dilemma presented by typical fault detection and location scheme applications on complex distribution networks, i.e. reliable fault location resolution versus affordable implementation and maintenance costs. This dilemma was resolved through the extensive feasibility study carried out by the author of this thesis. The study concluded that the fault detection and location scheme, with the desired fault location accuracy of 100 metres, could not be economically justified in the regulatory environment determined by ESC at the time. Instead, an affordable performance reliability of a fault location scheme could be achieved by accepting a major distribution feeder switching section as a sufficient degree of fault location resolution. This conclusion is based on the proposed solution utilising two 'in line' reclosers installed at the boundaries of the major switching sections of a distribution feeder and, if required, relying on blocking schemes.

The implemented fault detection and location scheme is a scalable solution capable of deployment on both an 'as per need' basis and/or on a large-scale implementation at an affordable price. The progressive deployment of 'in line' reclosers allows AGLE to maintain the required Reliability of Supply standards in a controlled fashion thus delivering the principal goal undertaken by the author of this thesis. As a result, the achieved average percentage reduction in combined MAIFI and SAIDI for the years 2003, 2004 and 2005 was 9%, 11% and 24% respectively. The knowledge about the real time parameters along distribution feeders was also greatly advanced.

ACKNOWLEDGMENTS

The author would like to thank Victoria University of Technology, Footscray Park Campus, Melbourne, Australia and Agility Pty Ltd, Melbourne, Australia for their continuous support in this project. Grateful acknowledgments are made to AGLE for their generous funding and continuation with the automation strategy set as a result of this project. On a personal note, I wish to thank my supervisor, Professor Akhtar Kalam, and Messrs Edmund Pegiel and Stephen McGregor from Agility for helping me to make this project possible. Special thanks are extended to my wife Jolanta and son Christian for their unwavering support and understanding in the difficult moments of my work.

DOCTOR OF PHILOSOPHY DECLARATION

"I, Ryszard Orlowski, declare that the PhD thesis entitled 'Fault detection and location on 22kV and 11kV distribution feeders' is no more than 100,000 words in length, exclusive of tables, figures, appendices, references and footnotes. This thesis contains no material that has been submitted previously, in whole or in part, for the award of any other academic degree or diploma. Except where otherwise indicated, this thesis is my own work".

[redacted]

Signature

30 June 2006

Date

TABLE OF CONTENTS

LIST OF PUBLICATIONS

(1) Orlowski R, Kalam A, 'Fault detection and location on distribution feeders (22kV & 11kV)', *Proceedings of the Australasian Universities Power Engineering Conference, AUPEC'99*, Darwin, NT, Australia, 26-29 September 1999, pp. 168-172.

(2) Orlowski R, Kalam A, 'Communications considerations for automation schemes in existing Zone Substations', *Proceedings of the CIGRE 2003, Study Committee B5 Colloquium*, Paper No 101, Sydney, NSW, Australia, 30 September–1 October 2003.

(3) Orlowski R, Kalam A, 'Applications of reclosers on urban distribution networks' *Proceedings of the Distribution 2003 Conference*, Paper No 170, Adelaide, SA, Australia, 16–19 November 2003.

(4) Orlowski R, Kalam A, 'Power System Communications Challenges in a Privatised Environment', *Proceedings of the CIGRE 2005, Study Committee B5 Colloquium*, Paper No 202, Calgary, Alberta, Canada, 8-16 September 2005.

LIST OF GENERAL ABBREVIATIONS

Access Point	A device that connects wireless communication devices together to form a wireless network.
ACR	Automatic Circuit Recloser, another name for a recloser.
AGL	The Australian Gas Light Company, an Australian energy company in operation since 1837.
AGLE	AGL Electricity Limited, one of AGL family companies.
AI	Artificial Intelligence.
ANN	Artificial Neural Network.
ANSI	American National Standards Institute.
ASCII	American Standard Code for Information Interchange, a character encoding based on English alphabet.
CAIDI	Customer Average Interruption Duration Index, a measure of the average interruption duration for those customers interrupted during a year.
CB	Circuit Breaker, a device with fault breaking capability.
CBD	Central Business District.
DNP3	Distributed Network Protocol.
DMS	Distribution Management System.
DT	Definite Time.
E/F	Earth fault also referred to as ground fault.

ESC	Essential Services Commission.
GPRS	General Packet Radio Service.
GPS	Global Positioning System.
GPU	GPU Electric, an American utility company.
GVR27	The brand name of a Whipp & Bourne recloser with 27kV rating.
IOServer	An interface to multiple protocols through a single server. It enables remote control and monitoring of IO devices.
KPI	Key Performance Indicator.
LAN	Local Area Network.
MAIFI	Momentary Average Interruption Frequency Index, expressed as momentary interruptions per customer per year, is a measure of the average number of momentary electric service interruptions for each customer during the time period.
MDS	Microwave Data Systems, a vendor for iNET900 radios.
MOXA	A brand name of a Terminal Server.
NGK	NGK STANGER, a joint venture company founded in 1993 with the shareholders being NGK Insulators and Energy Support Corporation.
O/C	Overcurrent.
OSI model	Open System Interconnection model that defines a networking framework for implementing protocols in seven layers.
R1	Upstream recloser.
R2	Downstream recloser.

RS232 In telecommunications, RS232 is a standard for serial binary data interconnection between a *DTE* (Data Terminal Equipment) and a *DCE* (Data Communication Equipment). A similar ITU-T standard is V.24. RS is an abbreviation for 'Recommended Standard'.

RS485 In telecommunications, RS485 is an OSI Model physical layer electrical specification of a two-wire, half-duplex, multipoint serial connection.

R_X Receiving terminal (in communications).

SAIDI System Average Interruption Duration Index, denoting a total number of minutes, on average, that a customer on a distribution network is without electricity in a year.

SAIFI System Average Interruption Frequency Index, denoting an average number of times a customer's supply is interrupted per year.

SCADA Supervisory Control and Data Acquisition.

SEF Sensitive Earth Fault.

SEL Schweitzer Engineering Laboratories based in Pullman, WA, USA.

SER Sequential Event Recorder.

SIXNET A brand name of an Ethernet Switch.

SNMP Simple Network Management Protocol.

STP Simple Time Protocol.

TCP Transmission Control Protocol, one of the core protocols of the Internet protocol suite. It is associated with the transport layer of the OSI communications model.

TCP/IP Transmission Control Protocol/Internet Protocol, the suite of communications protocols used to connect hosts on the Internet.

TDR Time Domain Reflectometer.

T_X Transmitting terminal (in communications).

UDP User Datagram Protocol, one of the core protocols of the Internet protocol suite. It is associated with the transport layer of the OSI communications model.

WAN Wide Area Network.

LIST OF ANSI PROTECTION ACRONYMS USED BY SEL351P AND SEL351S RELAYS [1]

51G2	Residual ground current above pick up setting for residual ground time-overcurrent element 51G2T used in testing and control functions
51G2T	Residual ground time-overcurrent element time out used in tripping functions
51N1T	Neutral ground time-overcurrent time out used in tripping functions
51P1T	Phase time-overcurrent element time out used in tripping functions
51P2	Maximum phase current above pick up setting for phase time-overcurrent element 51P2T used in control functions
51P2T	Phase time-overcurrent element time out used in tripping functions
67N1T	Level 1 neutral ground definite-time overcurrent element timed out used in tripping functions
67N3T	Level 3 neutral ground definite-time overcurrent element timed out used in tripping functions
67P1T	Level 1 phase definite-time overcurrent element timed out used in tripping functions
79CY	Reclosing relay in the reclose cycle state used in control functions
79RS	Reclosing relay in the reset state used in control functions
CLOSE	Close output logic asserted used in output contact assignment
IN 101	Opto-isolated input used in control and status functions
MB8A	Mirrored Bits communications Channel A implemented between the 'in line' reclosers

MB8B	Mirrored Bits communications channel B implemented between the upstream recloser and the Zone Substation circuit breaker reclosers
LT1	Latch bit 1 asserted used in protection enabled functions
LT5	Latch bit 5 asserted used in remote enabled functions
OC	Open Command used in tripping and control functions
PB9	Trip push button function used in control functions
RMB1A	Channel A, received bit 1 used in Mirrored Bits reception
RMB1B	Channel B, received bit 1 used in Mirrored Bits reception
RXDFLT	The default state of Mirrored Bits used in received RMB1A-RMB8A communication condition
SV1	Control equation variable timer input SV1 asserted used in testing functions
SV1T	Control equation variable timer output SV1T asserted used in control functions
SV2	Control equation variable timer input SV2 asserted used in testing functions
SV2DO	Control equation variable drop out timer SV2DO used in control functions
SV2PU	Control equation variable pick up timer SV2PU used in control functions
SV2T	Control equation variable timer output SV2T asserted used in control functions
SV3	Control equation variable timer input SV3 asserted used in testing functions

SV3DO Control equation variable drop out timer SV3DO used in control functions

SV3PU Control equation variable pick up timer SV3PU used in control functions

SV3T Control equation variable timer output SV3T asserted used in control functions

TMB1A Channel A, transmit bit 1 used in Mirrored Bits transmission

TMB1B Channel B, transmit bit 1 used in Mirrored Bits transmission

TRIP Trip logic output asserted used in output contact assignment

LIST OF FIGURES

LIST OF TABLES

CHAPTER 1

INTRODUCTION

1.1 Introduction to the operating environment

Following the privatisation of the Electricity Supply Industry in Victoria in 1995 [2], Solaris Power emerged as one of the privately owned electricity distribution companies in Victoria covering the industrialised north-western region of Melbourne. The newly emerged distribution company was co-owned by The Australian Gas Light (AGL) company and a US based company GPU. One of the Key Performance Indicators (KPIs) set for Solaris Power by the then Office of the Regulator-General was the improvement of Reliability of Supply with its two major components impacting on performance indices, i.e. the duration customers are off-supply and the frequency of customer supply interruptions. Solaris Power addressed the Reliability of Supply issues through the gradual implementation of standardised procedural enhancements and the introduction, on a small scale, of remotely controlled load break switches.

In September 1997, GPU purchased a transmission company Powernet Victoria, and as a consequence of that acquisition, GPU had to withdraw their interests from electricity distribution in Victoria. As a result, in January 1998 AGL purchased the remaining share of Solaris Power thus establishing The Australian Gas Light Electricity Limited (AGLE). The change of ownership did not alter the focus on the improvement of Reliability of Supply standards set by the then Office of the Regulator-General later, in 2002, superseded by the Essential Services Commission. Further programs aimed at the improvement of Reliability of Supply indices were put in place through Agility, AGLE's subsidiary established in the year 2000 as a management arm of AGLE. However, the procedural enhancements were already largely exhausted and in order to meet the continuous improvement in the distribution network performance targets, set by the Essential Services Commission, a wider introduction of automated field devices on the AGLE distribution network became necessary.

Consequently, progressive automation of the AGLE distribution feeder network, i.e. mainly 22kV and 11kV, was adopted as a means of improving the Reliability of Supply. An absolute prerequisite for safe Distribution Feeder Automation is a reliable fault detection and fault location scheme because it facilitates the determination of the fault type, fault location on a feeder as well as the fault severity. As a result, the development of an economically viable fault detection and location scheme was perceived by AGLE as a preliminary but essential step that, with time, would lead to progressive implementation of Distribution Feeder Automation.

1.2 Background

A reliable fault detection scheme that detects and locates feeder faults under fault conditions can facilitate dynamic but safe network re-configuration aimed at the minimisation of the fault impact on customers. The restoration time itself could be reduced to a bare minimum due to accurate fault location within the line affected by the fault and consequently minimise patrolling time. For the above reasons the research on fault location and detection schemes has been continuing worldwide for nearly as long as electrical power transmission, sub-transmission and distribution systems have been serving the industrial age. Elaborate fault detection and location schemes, aiming at high fault location resolution, are still a major area of research [3].

Whereas practical applications of fault detection and location schemes have met with reasonable success on transmission and sub-transmission systems, the same cannot be said about their applications on distribution systems. This is due to the usually complex and frequently reconfigured distribution network topology, and hostile power line environment resulting in the need for cost prohibitive fault detection and location infrastructure. For these reasons no practical, large-scale fault detection and location schemes have been installed on distribution networks in Australia so far. Achieving this objective however, could ultimately result in a dramatic improvement in the Reliability of Supply and it would enhance the knowledge about the distribution network condition following the fault occurrence. This knowledge is invaluable for optimising the distribution network operation.

In 1999, the author of this thesis, currently an Agility employee, undertook a task to research and implement on a pilot basis an economically viable, safe and reliable fault detection and location scheme suitable for a scalable implementation on AGLE's 22kV and 11kV distribution feeders. An implementation of an overarching remote control and monitoring program on a large scale was to be carried out in conjunction with the work on the fault detection and location scheme.

1.3 Significance of originality

The reliable fault detection and location is the fundamental part of any automation system and its true significance can be fully appreciated when automatic distribution feeder re-configuration is considered. This may occur as a result of a fault occurrence or pre-planned or emergency load redistribution/shedding. Irrespective of circumstances, smooth network re-configuration is a prerequisite for a high standard energy delivery depicted by the Reliability of Supply indices strictly monitored by the Essential Services Commission. One of the major benefits that can be introduced by the implementation of the fault detection and location scheme is the minimised risk level associated with the re-configuration of the distribution network under fault condition.

At present, the restructured power industry in Victoria is under scrutiny from the customers and community in general to limit power interruptions to the bare minimum. Manual network switching cannot support this requirement. Automation of distribution networks is implied and its significance is fully appreciated by AGLE. The only automation aspect that remains in question is the degree of automation that is absolutely necessary, but constrained by the implementation and running costs, to achieve the desired distribution network performance goals.

The underestimation of the distribution feeder automation importance over the past decades can be attributed to many factors. The main ones are the conservative attitude of protection engineers, lack of incentive in a non-competitive environment and high implementation cost. As a result, successful large-scale distribution feeder automation systems have not been implemented in Australia yet.

The distribution feeder reticulation by its nature is complex because its main task is to safely distribute electrical energy to customers with diverse need profiles. This reticulation is of an overhead bare wire construction, multi-branched in most of the cases, populated with a large number of high voltage switching devices and distribution substations. Overhead power lines are extremely vulnerable to faults as they are exposed to different sorts of human activity and 'Acts of God' [4]. In addition, implementation of distribution feeder automation systems in urban areas is increasingly desired, as that is where the biggest benefits can be gained by application of fault detection and location schemes. Under these circumstances public safety is a prime consideration.

A cost-effective implementation of a safe and reliable fault detection and location scheme on AGLE urban and rural distribution feeders was regarded by AGLE as breaking new grounds way of addressing the Reliability of Supply issues present on any distribution network. The notion of fault containment within the feeder section directly experiencing the fault was an old one. However, the employment of emerging and vastly disparate technologies to achieve this fault containment on a complex distribution feeder, with the acceptable level of resolution, is an innovative one.

1.4 Organisation of thesis

Chapter 1 sets the scene necessitating the implementation of a practical fault detection and location system on distribution feeders by an electrical distribution business operating in a privatised environment in the Australian state of Victoria. A short explanation as to why the Reliability of Supply issues experienced by electrical distribution businesses remained unaddressed in Victoria until the privatisation era is given. In addition, this chapter describes AGLE distribution network, including customer base, outlining the existing infrastructure characteristics presenting the greatest challenge. AGLE switching policy is defined clearly as it constitutes the cornerstone for the implementation of the proposed fault detection and location scheme. Reliability of Supply performance measures are explained as they are the key performance targets to be addressed by this work. Thesis' work flow is also outlined in this chapter.

Chapter 2 overviews the investigative work done on fault detection and location schemes applicable to distribution feeders worldwide showing clearly different categories of proposed systems and approaches. General recommendations and justification points are made with respect to the recloser project objectives. Final conclusions, drawn by the author from his feasibility study, culminating in the recommendation to implement the indirect fault location and detection scheme are presented in this chapter.

Chapter 3 clearly outlines AGLE's objectives for the recloser project and the associated performance stipulations. Emphasis was put on showing that to minimise the capital outlay necessary for the implementation stage, the solution was tailored to fit the current network model. It also examines the adopted indirect fault detection and location scheme, including the principle of operation of full and partial blocking schemes, which are necessary when protection coordination cannot be achieved. An in depth explanation of the impact of a full blocking scheme on Reliability of Supply indices and a general implementation plan for the project are also given.

Chapter 4 explains the importance of protection grade communications for full and partial blocking schemes. It is stressed in this chapter that a wide spread availability of protection grade communications can be achieved through a coherent approach to communications within the whole company. This can only be ensured through a firmly established Communications Business Strategy leveraging, to a great extent, off other than protection communications applications. The testing of Ethernet based communication technologies, for recloser specific communication applications, is thoroughly covered in this chapter.

Chapter 5 presents the implementation stage in detail. The vendor selection process and explanation of the protection philosophy are considered as integral parts of this stage. A strong emphasis has been put on the explanation of the core principles of operation pertinent to blocking schemes implemented on the downstream and upstream reclosers and on the Zone Substation circuit breaker. In particular, transmitted and received mirrored bits are explained in full detail. An extensive series of fault scenarios is presented to further reinforce the understanding of the mirrored bits operation. Full logic diagrams are given for control, TRIP and Mirrored Bits variables.

Chapter 6 covers extensive testing and commissioning of a full blocking scheme as implemented on the AGLE distribution feeder BD7. The principles of testing are explained and test results are analysed. This chapter encompasses the work experience gained while testing a full blocking scheme on a fully operational distribution network.

Chapter 7 describes challenges encountered particularly during the implementation and testing of the full blocking scheme. The impact of these challenges, on the future recloser design and the overall project progress, is documented in this chapter. It is also shown how hardware failures and instances of force majeure influenced Agility's policies pertinent to recloser applications on distribution feeders.

Chapter 8 concludes the thesis and presents future directions for recloser technology developments that evolved as a result of the work on this project. A strong emphasis is put on the improvements of recloser hardware as a result of the demand created by a privatised environment.

Following Chapter 8 is the bibliography with extensive, up to date, professional references and supplementary reading references.

In Appendices 'A', 'B' and 'C' the procedures applicable to a full blocking scheme testing are examined in detail, with focus on R2 to R1, R1 to CB and R2 to CB blocking respectively.

In Appendix 'D' the AGLE coverage area is depicted from a Victorian perspective. The understanding of a typical AGLE distribution feeder topology is also enhanced due to the enclosed single line diagrams.

Appendix 'E' elaborates further on fault scenarios for reasons of completeness.

Appendix 'F' outlines technical specifications for GVR27 reclosers utilised in this project.

Appendix 'G' presents a copy of a formal report from Whipp & Bourne regarding the investigations into SEL351P relays recording residual current and voltage traces after tripping the GVR27 reclosers.

Appendix 'H' presents publications that resulted from the work on the project. They are shown in a chronological order to document clearly the evolution the project underwent from its initial, purely theoretical stages, to the final product applicable to any distribution network.

1.5 AGLE distribution network

1.5.1 Customer base

AGLE distribution network supplies electrical energy mainly to well established residential and industrialised areas of outer north-western suburbs of Melbourne as shown in Appendix 'D', Figure D.1. As of March 2006, there have been approximately 291,000 customers on AGLE distribution network. Residential and small business customers constitute 46% and large businesses 54% of the total customer base [5] located in a coverage area of approximately 1,000 km^2. Electricity distributed by AGLE is approximately 4,174 GWh.

1.5.2 General network characteristics

AGLE distribution network comprises 10,285 kilometres of Low Voltage and High Voltage reticulation. Within this reticulation, there are 203 High Voltage feeders. 10 of these feeders are classified as short rural feeders and 193 are classified as urban feeders.

The distribution feeder categories, as defined by ESC, are presented in Table 1-1.

Table 1-1 Distribution feeder category definitions

Feeder category	Description
CBD	feeder supplying Melbourne CBD determined from zone substation coverage maps
Urban	feeder, which is not a CBD feeder, with a load density greater than 0.3 MVA/km
Short rural[1]	feeder, which is not a CBD or urban feeder, with a total length less than 200 km
Long rural	feeder, which is not a CBD or urban feeder, with total length greater than 200 km

AGLE distribution feeders are mainly of overhead construction. Rural feeders operate typically in radial configuration. The configuration of urban feeders allows for loop schemes and consequent load transfers. These feeders operate predominantly at 22kV and 11kV. Although there are still a small number of distribution feeders operating at 6.6kV, they are not considered for the implementation of the fault detection and location applications as they are to be phased out in the near future. Due to the gradual development over the years, the existing overhead high voltage feeder reticulation comprises a variety of aging construction types employing overhead bare conductors.

[1] Short rural feeders include feeders in urban areas with low load densities.

Only new residential developments are planned to have underground high voltage reticulation installed. This overhead construction type makes the distribution feeders extremely vulnerable to faults caused by adverse weather conditions, insulator contamination resulting in current tracking, vegetation and fauna interference and road accidents. In rural areas, bushfires are a recognised hazard and special operational practices are applied in bushfire mitigation areas as shown in Appendix 'D', Figure D.2.

As majority of AGLE's distribution feeders are distributed in the urban area, the safety aspect during feeder normal operation as well as under fault condition is of paramount importance. Thus protection equipment needs to be highly reliable and fault-clearing times must be fast. Post-fault back-feeding of the healthy feeder section can be carried out only after it is ensured that it is safe to do so. This implies that the faulty feeder section must be found and isolated first. Following that, the remaining feeder sections, located upstream relative to the faulted section, need to be patrolled for secondary faults, which result from heavy fault currents. Patrolling time can be accounted for the majority of the time lost. Depending on the length of the feeder, the fault type and human resources available, the feeder patrolling time can easily reach 45 minutes thus contributing to the 'customer minutes off-supply' index. As a result Reliability of Supply, monitored by the Essential Services Commission vigilantly, is adversely affected.

1.5.3 Urban distribution feeder characteristics

AGLE's urban distribution feeders are radial, relatively short but heavily loaded. Most of the feeders are well designed for load transfers between adjacent feeders through strategically placed normally open interconnection points. A significant number of these interconnection points are equipped with NGK load break switches either already remotely controlled or capable of being remotely controlled. Fault currents, depending on the fault location with respect to source, can reach levels of up to 13kA.

The load distribution along feeders can be 'lumpy' due to the presence of high voltage customers that require large amounts of energy for their operations. Despite these adverse characteristics, a uniform approach to all distribution feeders has been advocated. AGLE distribution feeder switching policy manifests that approach. However, these distribution feeder characteristics present a particularly difficult task for the introduction of an accurate fault location scheme. The task is even more difficult on feeders where Neutral Earthing Resistors have been installed to limit the phase to ground fault currents and where the distribution feeders have multi-branched reticulation.

1.5.4 Feeder switching policy

To facilitate a comprehensive approach to Distribution Feeder Automation, AGLE developed the distribution feeder switching policy. It calls for each feeder to be split into three major switching sections by two remotely controlled and monitored switching devices as designated in Figure 1.1. Each section is characterised by a load of around 3MVA. Feeders are inter-connected with adjacent feeders via normally open switches. In general, the main target of this policy is to ensure that there is 3MVA stand-by capacity, available on each of the distribution feeders under normal operating condition, to absorb a load transfer of one switching section from an adjacent feeder under emergency condition.

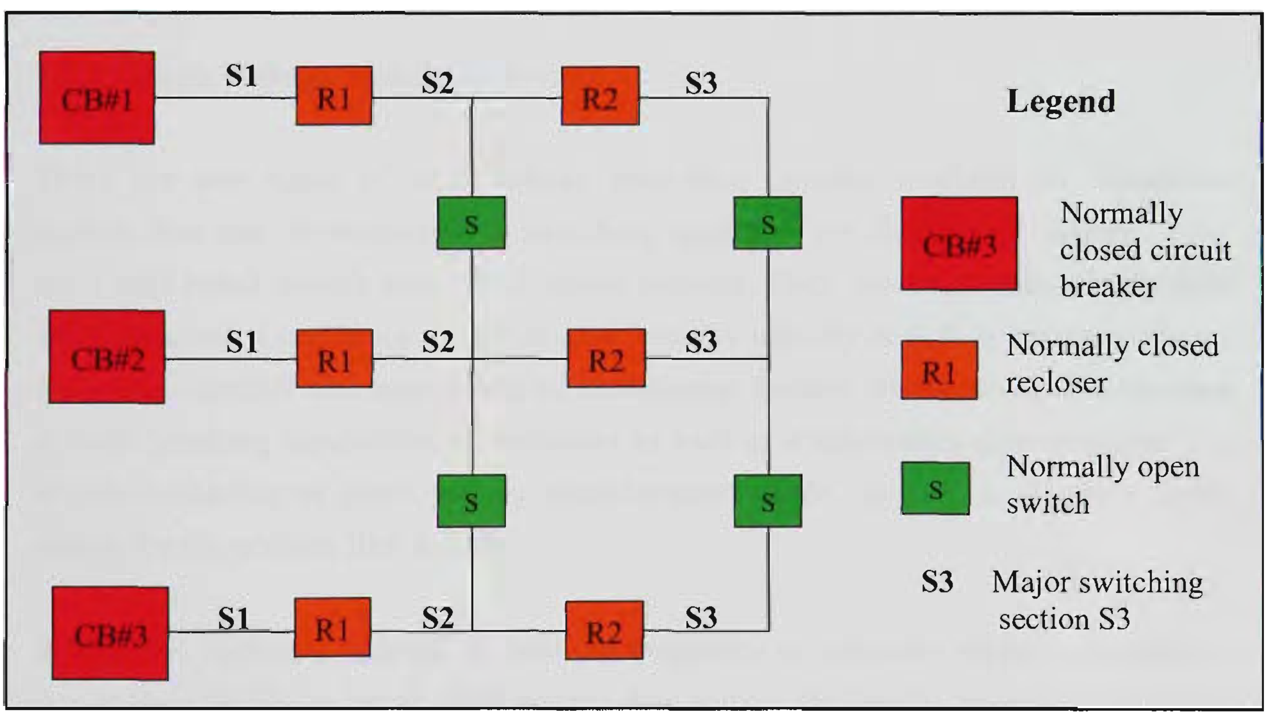


Figure 1.1 Major switching sections

Remotely controlled and monitored 22kV or 11kV switchgear is being gradually installed at the boundaries of the major switching sections. As a result rapid load transfers can be achieved under normal operating conditions. In the event of a fault occurring within a particular section of a feeder, the whole 3 MVA major switching section can be rapidly isolated by remote control. The isolation of a faulty feeder section relies heavily on accurate fault location. After the isolation of the faulty feeder section, the healthy feeder sections can be re-energised by closing remotely the normally open points located on the boundaries with the adjacent feeders not affected by the fault.

Current AGLE's approach to normally open points is to utilise load break switches associated by the switch controllers. However, this approach may be changed once feeder loop configurations are technically matured for automation. In such an event reconfigurable reclosers will be used on open points.

Splitting distribution feeders into three major switching sections by two 'in line' reclosers was undertaken to maximise the short-term and long-term benefits that will result from the incorporation of the fault location on recloser hardware. This in itself is a novel approach to the issue of fault detection and location as it significantly reduces the number of complexities presented by an average distribution feeder. As a result of this approach, only the feeder section affected by the fault is analysed to determine the exact location of the fault within the faulty feeder section.

1.5.5 High Voltage switching devices

There are two types of high voltage switching devices, available in Australian market, that can be employed as switching apparatus on distribution feeders. They are a load break switch and a fault break recloser. Both can be remotely controlled and monitored. Load break switches were initially used by AGLE as primary devices for remote control and monitoring of distribution feeders. However, recent increase in fault breaking capabilities of reclosers as well as a substantial cost reduction due to new technologies employed by manufacturers made 'in line' reclosers a viable option for the utilities like AGLE.

In addition, reclosers address the issue of frequency of customer supply interruptions due to their ability to break fault current thus saving the healthy feeder section(s) in the event of the fault occurrence downstream from the recloser. Another taken for granted feature of reclosers is their ability to clear intermittent faults thus saving 'customer minutes off-supply' that would have been lost otherwise.

These recloser features have ensured change in their typical application. Whereas, in the past reclosers were predominantly used in rural areas, at present there are increasing numbers of them installed in urban areas where savings in 'customer minutes off-supply' and frequency of customer supply interruptions are much more profound due to a large number of customers affected. This application change has introduced new challenges for electrical and communications engineers as the characteristics of urban distribution feeders are vastly different from rural feeders.

1.6 Reliability of Supply performance measures

The Essential Services Commission (ESC) established a set of Reliability of Supply performance measures for comparison and performance reporting purposes [6]. They are referred to as Reliability Indices. Their description and definitions are presented in Table 1-2. The improvement in the Reliability of Supply performance measures, meeting the annual targets set by ESC, constitutes the overall goal for this work.

Table 1-2 Reliability of Supply performance measures

Index	Measure/description	Definition
SAIDI System Average Interruption Duration Index	Total number of minutes, on average, that a customer on a distribution network could expect to be without electricity in a year.	The sum of the duration of each customer interruption, in minutes, divided by the total number of connected customers averaged over a year. SAIDI excludes momentary interruptions, defined as less than 1 minute, but it comprises planned and unplanned interruptions.
SAIFI System Average Interruption Frequency Index	Average number of times a customer's supply is interrupted per year	The total number of customer interruptions, divided by the total number of connected customers averaged over the year. SAIFI excludes momentary interruptions.
CAIDI Customer Average Interruption Duration Index	Average duration of each interruption	The sum of the duration of each customer's interruption, in minutes, divided by the total number of customer interruptions, i.e. SAIDI divided by SAIFI. CAIDI excludes momentary interruptions.
MAIFI Momentary Average Interruption Frequency Index	Average number of momentary interruptions per customer per year	The total number of customer interruptions of less than 1 minute in duration, divided by the total number of connected customers averaged over the year.

CHAPTER 2

LITERATURE REVIEW

2.1 Introduction

The literature review has been carried out to investigate the latest developments in the fault detection and location technology. The literature searches continued throughout the research program allocated for this project to keep abreast with the new developments. The emphasis has been placed on fault location as the still not quite resolved aspect of the distribution networks' operation.

One of the most comprehensive works, on the development of fault location methods, has been carried out by Diaz and López [7]. They have produced a literature survey pertinent to strategic work done on fault location systems applicable mainly to distribution systems. Comparative statistical analysis is given covering fault location developments up to the year 2005. This analysis has shown, that most of the fault location methods were developed for transmission networks thus, they are not suitable for radial distribution networks applications. Increasing research is noted, particularly in the area of signal analysis. This is due to the rapid development of microprocessor based technologies particularly suitable for the analysis of high frequency components. General classification of fault location techniques is given in their survey [7]. However, the technique presented by the author of this thesis is not accounted for in this classification.

The results of this literature review indicate that fault location techniques, for application on distribution networks, can be classified according to two main approaches adopted in the up-to-date research and developments, i.e. a direct and an indirect approach. Combinations of techniques, belonging either to one or the other classification, are quite a common occurrence.

2.1.1 Direct approach techniques

In the direct approach, the fault location methodologies focus on signal measurements, either single-ended or double-ended, and the consequent analyses with the ultimate aim of locating the fault point on the feeder.

2.1.1.1 Signal analysis techniques

The literature research [7] demonstrates that generally practical direct fault detection and location can be achieved with a varying degree of accuracy by employing techniques grouped into the following main categories:

- Fundamental frequency techniques based on line impedance measurements.

- High frequency components techniques based on travelling wave measurements and harmonic.

All these techniques have their specific shortcomings as far as distribution feeder applications are concerned. These shortcomings are mainly due to a complex and dynamically changing distribution network reticulation, unbalanced loads, a variety of fault types that can occur on a distribution feeder, large number of feeder elements and substations, non-uniform conductor gauges, multi-branched feeder reticulation, switching operations and topological changes due to network expansion or maintenance works.

2.1.1.1.1 Fundamental frequency techniques

Fundamental frequency techniques rely on measurements of power frequency quantities. Measurements are provided by protection grade instrumentation such as current transformers, voltage transformers and protection relays located either at Terminal Stations, Zone Substations or in the field. The quantities obtained are used in sequence components analysis to determine fault types, faulty phases as well as the fault location estimates.

2.1.1.1.1.1 Impedance based techniques

Impedance based fault detection and location process involves analysis of post- and/or pre- fault voltage and current data at the selected check point(s) on the feeder to provide accurate information about the fault type and its location relative to the check point(s). Currently there are four basic varieties of the impedance approach to fault detection and location:

- Triggering the voltage and current measurements at the inception of the fault at one end of the feeder usually at the feeder circuit breaker to cover the whole feeder.

- Triggering the voltage and current measurements at the inception of the fault at both ends (two terminals) of the feeder thus ensuring much better accuracy for fault location.

- Collecting the voltage and current information at one feeder end by continuously sampling the respective waveforms under normal feeder operating condition and storing them in a circular buffer for comparison purposes when the fault occurs i.e. pre- and post-fault data collection.

- Collecting the voltage and current information at both feeder ends (two terminals) by continuously sampling the respective waveforms under normal feeder operating condition and storing them in a circular buffers for comparison purposes when the fault occurs i.e. pre- and post-fault data collection.

Analogue single terminal and two terminal methods can be reasonably inaccurate when employed on distribution feeders. Errors in fault distance calculations, based on voltages and currents measured at the sending end are usually attributed to the fault impedance and to the effect of the load supplied by the feeder at the time of the fault occurrence [8]. Knowing the line impedance per km, the distance to the fault site can be determined. Several factors influence the accuracy of the fault location schemes though. The most important are [9,10]:

- Combined effect of the load current and fault resistance, the value of which may be particularly high for ground faults i.e. reactance effect.

- Insufficient accuracy of the line model, i.e. presence of shunt capacitance/reactance.

- Uncertainty about line parameters such as zero sequence components.

- Measurement errors.

As a result, the accuracy for fault location is usually limited to approximately 2-3% of the total line length.

Single-terminal and two-terminal algorithms have been developed to overcome the aforementioned problems. Two-terminal approach results in much higher accuracy for various system conditions and in general the post fault analysis allows for the fault resistance determination. In addition, this approach does not require high-speed communications as all data transmission and calculations can take place after the fault has been cleared [10]. These two-terminal methods, previously handicapped by the limited accuracy of analogue fault recording, were further enhanced by the employment of digital relays capable of providing more accurate data [12]. These relays store filtered pre- and post-fault data at a fixed rate thus representing instantaneous voltages and currents of a particular disturbance.

Most common faults on distribution feeders, i.e. up to 90%, are phase to ground faults. This implies unbalanced situations. Consequently sequence components need to be employed in the relevant calculations. The fault location problem requires the single solution of a circuit equation system. Such equations are presented in terms of impedance or admittance of the elements that form the circuit voltage and current values. The following launching equations can be used to calculate the distance to the fault site [8]:

- For the phase to ground fault $V_P + V_N + V_Z = [\ I_P + I_N + I_Z\ ]Z_F$.

- For the phase to phase fault $V_P - V_N = [I_P - I_N]\ Z_F$.

- For the three phase fault $V_P = I_P\ Z_F$.

where: V_P, V_N, V_Z, I_P, I_N and I_Z are respective voltage and current positive, negative and zero sequence components and Z_F is the fault impedance.

Due to the lower cost involved, single-terminal impedance measurements have been preferred by the industry, especially in applications on rural radial feeders where accuracy of fault location is not highly critical [11]. No requirement for communications promoted one terminal approach even further. With the introduction of remote control on High Voltage switchgear installed along the urban distribution feeders, two-terminal impedance measuring techniques gradually become more cost effective due to the possibility of communication infrastructure sharing. Remotely controlled 'in line' reclosers, designed for the applications on urban feeders, are even more suitable for the impedance measurements intended to determine fault locations as their design relies on protection digital relays that can be equipped with impedance measuring capabilities.

The development of different approaches utilising fundamental frequency based techniques is outlined below.

Hong and Colwell [12] have introduced a fault locating system that utilises two-ended methodology to automatically confirm fault types and compute line fault locations based on real time operating data or off-line reports pertinent to transmission systems. In this system the pre-fault and post-fault data, provided by protection relays, is software filtered to provide only fundamental frequency components, as phasor quantities, using Fast Fourier Transformation. The fault location estimation is achieved by solving a complete, three phase network model. The fault location module models the faulted transmission line by a set of 15 real simultaneous equations using an iterative method to find the distance to the fault. Single phase to ground faults are computed by using negative sequence network models to the impact of mutual coupling. Combination of two-ended algorithm application along with protection grade communication technology, advanced mathematical techniques and mature software platform resulted in a low cost system capable of reasonable fault location estimations on transmission systems.

Girgis et al. [13] have presented a single-ended digital fault location technique for rural distribution feeders including single-phase, two-phase and three-phase laterals. This fault location technique accounts for the multi-phase laterals, unbalanced loads and the asymmetrical nature of distribution feeders by continuous updates of the fundamental frequency voltage and current vectors carried out by a recursive optimal estimation algorithm. Fault location point is estimated by a method based on the apparent impedance approach using the updated voltage and current vectors. The apparent impedance is defined as the ratio of selected voltage to selected current based on fault type and faulted phases. The change in magnitudes of the voltage and current phasors is used to classify the fault type and the faulted phases. The maximum change in amplitude of the current phasors is used as a reference. This fault location technique is reported to show reasonable performance as far as accuracy and calculation speed are concerned, even when applied to temporary faults lasting only for a few cycles.

Minfang et al. [14] have introduced the k-fault diagnosis theory for fault location applications on distribution networks. This technique identifies the faulty feeder section first, and then proceeds to locate the fault within the faulty section. However, the emphasis is put on the identification of the feeder section. The technique is capable of locating single-phase as well as multiple phase faults. The accuracy depends on the availability of voltage measurements at predetermined nodes. The technique for the location of faults within the faulty feeder section needs further refinements.

Choi et al. [15] have introduced a fault detection algorithm, called direct circuit analysis algorithm due to the process involved, specifically tailored for the application on unbalanced distribution networks. The performance of this algorithm on usually balanced transmission networks is reported to be also very effective. The proposed algorithm overcomes the limits of the conventional algorithms, which give accurate results only when applied to balanced networks. When tested against a balanced network orientated algorithm which uses a distribution factor based method, on a simulated unbalanced phase-ground fault, it is reported to give the maximum error, in distance to fault calculation, of 0.05%. The algorithm applying the distribution factor based method is reported to give maximum distance estimation errors in the order of 25%.

Zhang et al. [16] have presented a fault location approach for application on ungrounded or Peterson coil grounded distribution networks. Fault location task on these networks is difficult due to small fault currents flowing, as a leakage capacitance effect, without tripping the feeder. The system operation relies on the data feedback provided by protection relays, installed at substation ends, and remote ground-fault indicators to indicate faulted phase, feeder and affected by the fault feeder section as well as fault distance estimate. Two fault location techniques are utilised: on-line and off-line. In the on-line technique, a diagnostic signal generator is connected through a voltage transformer to inject a zero-sequence current signal, for several milliseconds, with a specific diagnostic frequency that is recognisable by the remote ground-fault indicators or hand held detectors. Summation of the three–phase currents and the signal generator current gives a non-zero residual current value for the network sections between the signal generator and the fault point. In network sections not affected by fault the residual current is zero. The impedance method, using zero-sequence voltages and currents, is used to provide the distance to the fault location. In the off-line technique, a direct current high voltage signal, not higher than 1.4 of the rated voltage for the feeder, is injected into the de-energised feeder to ensure insulation breakdown at the fault point. Following that, the on-line technique process is utilised to locate the fault.

Taalab et al. [17] have presented three enhancement techniques applicable to fault location algorithms used to determine radial distribution feeder faults. They are:

- Varying compensation current.
- Subtracting pre-fault currents.
- Unsynchronised shifting of current and voltage phasors.

Application of these enhancement techniques on two single–ended conventional fault location methods, such as apparent impedance method and reactive power method, produced reduced errors without any reliance on communications. It is reported that for the apparent impedance method, either reduction of compensation current by a factor of 1.0 to 1.1 or reduction of the fault current by 0.4 to 0.6 substantially enhanced the fault location accuracy. The unsynchronised shifting of current and voltage phasors technique used with the tap current reduced by a factor of 0.4-0.6 also produced enhanced fault location accuracy when applied to both the apparent impedance method and reactive power method.

However, AGLE's decision not to install voltage transformers at their recloser installations limited the relay inputs to current sensing only. Lack of voltage sensing renders the impedance measurements based methods unsuitable for the fault detection and location applications as one quantity, i.e. voltage, necessary for the impedance calculations is missing. The usage of the predetermined line impedance values cannot guarantee desired fault location resolution due to the frequent network/feeder reticulation changes.

Also, the lack of voltage sensing means inability to determine the actual direction of a fault current in situations where there is a capacitive discharge current involved. In this case, the capacitive current flowing towards the fault, as a result of the underground cables discharge, would be detected by the recloser relay that did not experience the actual fault current thus giving misleading location of the actual fault.

2.1.1.1.2 High frequency components techniques

By definition, high frequency components techniques encompass analysis of signals that are higher than the fundamental frequency signals, i.e. harmonics, natural oscillating frequencies and travelling waves. They can present a challenge when attempts are made to extract them from the fault composite signal due to their usually low magnitudes and the overpowering effect of background noise. Detailed review of the literature on the developments regarding the high frequency components techniques, applicable to the fault detection and location area in distribution networks, is presented below.

2.1.1.1.2.1 Harmonics and natural oscillating frequencies analysis

Yu and Khan [18] have presented a combined High Impedance and Low Impedance fault detection method for application on distribution networks. The technique utilises the following High Impedance fault characteristics resulting from modelling of a distribution feeder experiencing a High Impedance fault:

- Fault current magnitude.
- 3rd and 5th harmonic current magnitudes.
- The angle of 3rd harmonic current.
- The angle difference between the 3rd harmonic current and the fundamental voltage.
- Negative sequence of High Impedance fault current.
- Average (ambient) negative sequence load current.

In this approach, the magnitudes of the 3rd and 5th harmonic currents are examined to differentiate the characteristics typical for load switching, capacitor switching and/or arc producing devices from those of High Impedance faults. The average load current and the negative sequence currents are calculated and stored. For each phase, the measured r.m.s. load and negative sequence current are compared with the equivalent stored average values. If the comparison yields the difference exceeding an arbitrarily predetermined value of +/- 20% then this phase is selected as a the one experiencing a High Impedance fault. This technique makes the scheme more sensitive to low currents resulting from the High Impedance faults and prevents tripping during normal feeder operation. The Low Impedance faults are detected by the overcurrent relays.

Kachesov et al. [19] have presented an on-line approach to locate faults on underground distribution networks. It is based on the natural oscillation frequency, associated with the capacitive discharge on a faulty phase, dependent on network parameters. As an improvement on the first approach, Kachesov and Ovsyannikov [20] have proposed another fault location method based on the analysis of transient voltages occurring in the initial stage of the insulation breakdown. In this method, calculated maximum voltage derivative, representing a faulty phase, is utilised to locate phase-to-ground faults occurring on distribution networks. However, further work, supported by field trials, is necessary to confirm the viability of these two approaches.

2.1.1.1.2.2 Travelling wave techniques

The principle of operation for the travelling wave based techniques relies on the fact that a sudden change in voltage on a system generates a wide band of travelling waves covering the entire frequency range. These frequency components propagate away from the fault position in both directions as shown in Figure 2.1, representing the proposed AGLE feeder structure. As these travelling waves encounter on their way a number of different types of discontinuities along the feeder, they are reflected back towards the fault point.

The initial values of these waves mainly depend on the fault position on the feeder, the fault path resistance and the instance of fault occurrence [21]. The discontinuities may be in the form of:

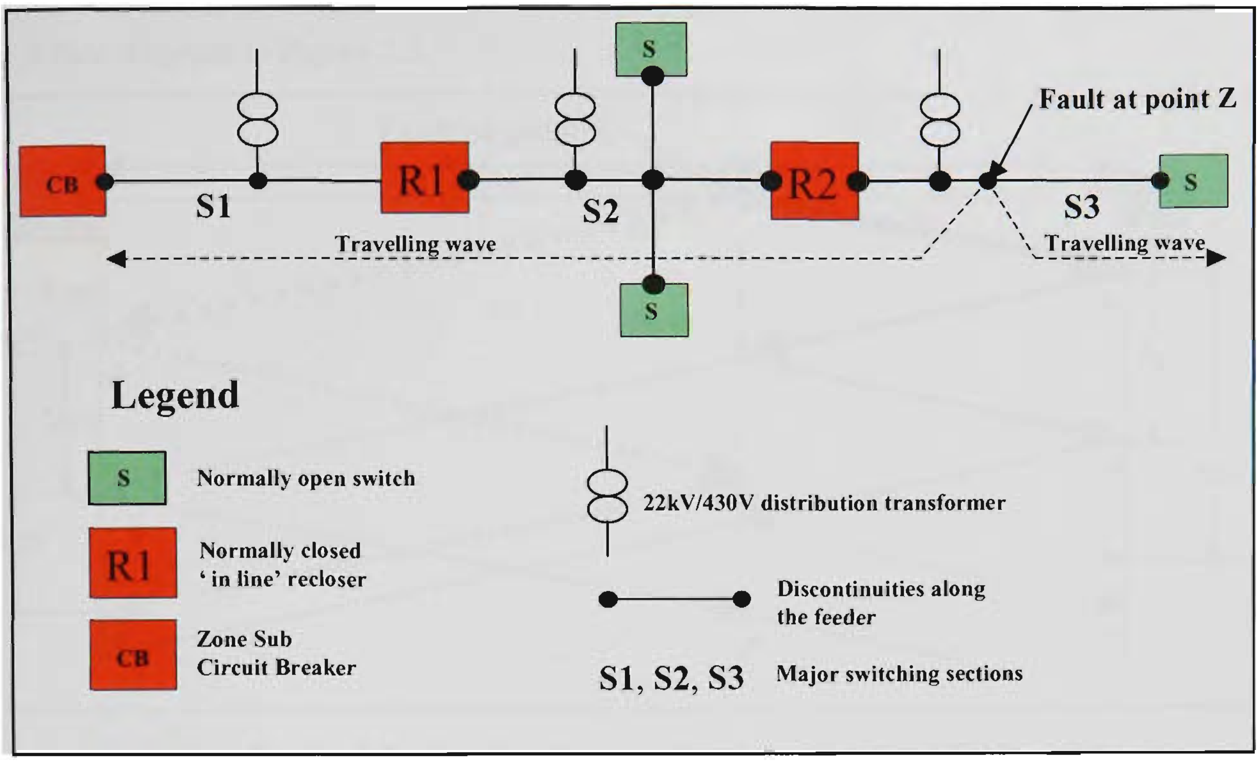


Figure 2.1 Travelling wave propagation due to a fault

- Tapped-off loads such as distribution transformers or feeder spur lines.

- High Voltage customer infrastructure.

- High Voltage switch gear irrespective whether acting as open or closed points changes in conductor gauge.

There are three types of reflected signals that can be measured. They are:

- The same polarity signal in the event of a post fault open circuit.

- An opposite polarity signal in the event of a short circuit.

- An opposite polarity signal with much smaller magnitude than the original signal generated by the fault due to reflections from feeder discontinuities [22,23].

Successive arrivals of travelling waves at both terminals, i.e the recloser R2 and switch S, are noted and identified providing time information necessary for distance calculations. The most useful are arrival times of the first and subsequent waves due to the relatively easy task of discrimination between the waves as shown by the lattice diagram in Figure 2.2.

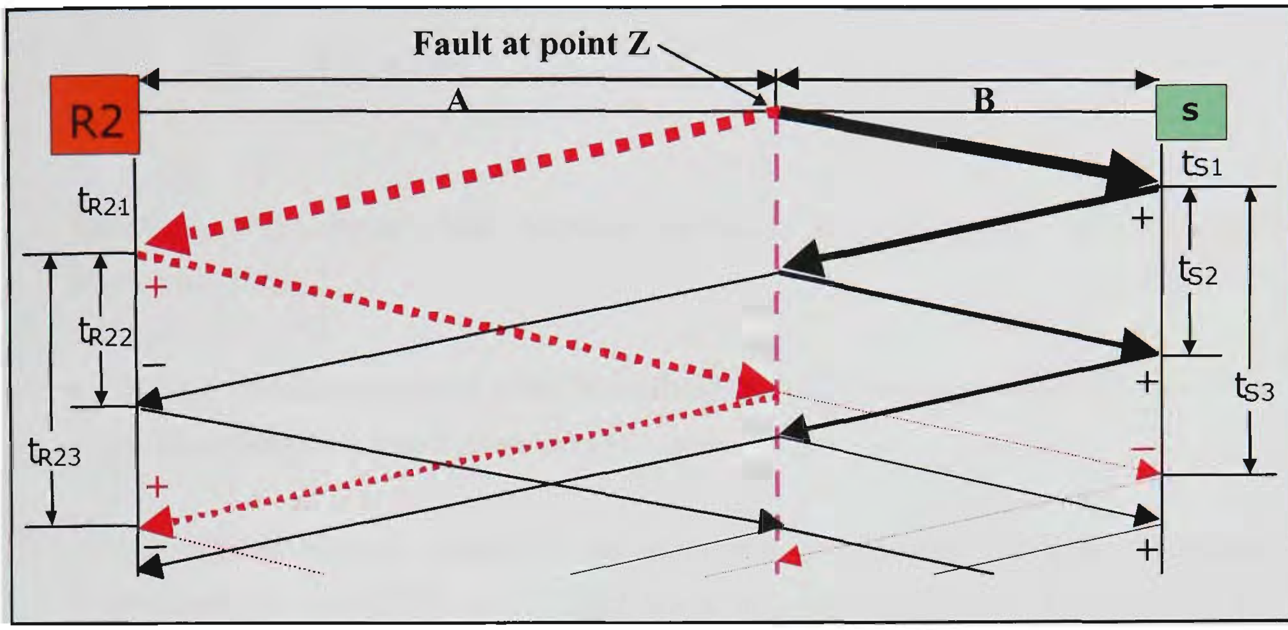


Figure 2.2 Lattice diagram for a single-phase fault

By examining Figure 2.2, it can be seen that at terminal R2 the waves reflected from terminal S will have opposite polarity to the waves generated by the fault or reflected from the fault position. Thus the waves generated by the fault and reflected from the opposite terminal can be discriminated at terminal R2.

The analysis of Figure 2.2 indicated that the location of the fault position, looking from terminal S, can be determined by [21]:

$$\text{Distance Z to S} = v * t_{S2} / 2$$

and looking from terminal R2 the fault position can be determined by:

$$\text{Distance Z to R2} = (A + B) - v * t_{R22} / 2$$

where:

v is the travelling wave velocity,

$(A + B)$ is the total length of the feeder with $A > B$,

t_{S2} is the time difference between the arrival time of the initial fault generated wave at terminal S and its first reflection,

t_{R22} is the time difference between the arrival of the initial fault generated wave at terminal R2 and the first reflection arriving from terminal S,

Z is the location of the fault.

Travelling wave based fault location methods are affected by the following shortcomings [21]:

- A fault may not generate many travelling wave components when it occurs at a voltage inception angle close to zero degree.

- For a fault located closely to the monitoring equipment, the time difference between the arrival of an incident wave and its reflection is too short to be detected as separate waves.

- The travelling wave measurements are adversely affected by the bandwidth limitations of current and voltage transformers employed as an interface devices between High Voltage conductors and the measuring equipment.

Conventional travelling wave fault locators can be grouped into two types [11]:

- Monitoring type; when time difference between the reflected waves produced as a result of the fault is detected at the terminals by the fault location equipment that is continuously analysing the waveforms at both ends of the line for 'abnormal', reflected waves.
- Post-fault pulse injection type; when a correlation is measured between a test pulse, usually launched from the upstream terminal after the fault has occurred, and its reflection from the faulty line component.

Both types represent purely reactive measures in addressing Reliability of Supply issues, i.e. the action is taken after a fault has occurred. Nevertheless methods based on travelling waves offer better accuracy than the impedance methods in particular in locating remote faults. Travelling wave methods can facilitate a partially proactive approach to fault detection and location as well. Although not much can be done about lightning strikes or road accidents proactively the issue of cross-arm fires can be addressed on proactive basis by continuous monitoring/searching for travelling wave signatures typical for current tracking on wooden cross-arms.

Detailed literature survey reveals the following developments in the area of travelling waves techniques applications for fault location.

For underground Low Voltage distribution networks, Navaneethan et al. [24] developed a Time Domain Refractometer (TDR) based technique to locate faults on three-phase cables automatically. In this technique, the diagnostic TDR signals are pre-processed to eliminate reflections due to tee-offs. Adaptive filtering is utilised to minimise the difference between the diagnostic TDR signals, affected by cable attenuation, and the phase characteristics obtained in the pre-processing stage. The resulting error signals arriving from the adaptive filter are compared with the pre-determined threshold values, derived to reflect typical cable characteristics, to localise key departures in the reflected signals that serve for fault location purposes. In this way, the accuracy of locating three-phase open or short-circuit faults on underground cables is enhanced. A significant advantage of this method is the utilisation of commercially available TDRs and reduced skill set requirement to operate them.

Hizam et al. [25] have presented a study wherein a single-ended method for fault location on underground and overhead distribution feeders is discussed. The method relies on successive comparisons between each relative distance of the fault initiated travelling wave peaks with the predetermined reflection points in distribution feeders. The resultant fault location data is utilised by the transient power system simulator to model the actual network. Its output signal is then cross-correlated with the transient signals captured on the real network. For the correct location of the fault, the cross-correlation process yields a high positive value.

Thomas et al. [26] have presented an attempt at an experimental single and double-ended fault location system, based on travelling waves techniques, for applications on distribution systems. The voltages are estimated using the line modelling method whilst the distance to the fault is computed using cross-correlation function. The system senses the fault generated transient currents, at either one or two terminals with a current probe, having high-pass transfer characteristic, attached to a standard medium-voltage protection relay current transformer achieving bandwidth in excess of 500kHz. Following the modifications of the system [27], the cross-correlation function is not used due to the requirement for measured voltage values. In both cases, the transients are sampled at a rate of 1.25 MHz with 8 bit resolution. It is reported that fault location accuracy achieved with this sample rate is approximately 240 metres, in spite of the complexities introduced by discontinuities present on multiple distribution feeders, with the double-ended approach yielding better results as expected.

Xiangjun et al. [28] developed a two-ended system that relies on the Global Positioning System (GPS) time tagging for location of faults on both transmission and distribution lines. Fault positions are calculated by the tagged travelling wave arrival times. The system comprises current travelling wave sensors, voltage travelling wave sensors, the sampling unit and the main fault-locating unit. The current travelling wave sensor is installed on the ground side of capacitive equipment such as transformer bushing or capacitive voltage transformer to capture current travelling waves flowing from the equipment to ground. By doing so, it suppresses power-frequency signals amplifying frequencies above 10kHz. The voltage travelling wave sensor is a resistor divider installed at the zero sequence winding of a voltage transformer to capture voltage travelling waves in all three phases. The sampling unit detects the abrupt signal change, initiated due to the fault, calculates the variation rate and amplitude of the received signal and transforms it into a square wave. The abrupt change of the square wave is saved and communicated to the fault locator unit where the distance calculations are carried out. The precision of this fault location system is dependent on the sampling rate (200MHz used), the quality of GPS time tagging and reliable communications between the two ends sensing travelling waves. Reported accuracy of the fault location system is approximately 300 metres.

2.1.1.1.2.2.1 Wavelet transform techniques

Magnago and Abur [29] presented a single-ended method that allows for fault location determination in radial distribution feeders with multiple laterals where the measurements are available only at the substation. The method is based on the analyses of the transient signal wavelet transforms, phasor measurements obtained in the substation and network topology. It identifies the fault path using the information provided by the high frequency components of the recorded travelling waves initiated by the fault. The multiphase transient signals are decomposed into their modal components first, followed by the modal signal decomposition into their wavelet components to obtain the corresponding wavelet coefficients. The special properties of wavelet coefficients allow the system to differentiate between faults occurring along different laterals of the same main feeder. Thus, the lateral subjected to fault is identified. This process involves voltage signals decomposition in a frequency spectrum of 12 to 25kHz. Consequently, voltage transducers with a bandwidth of 50kHz are utilised. After the faulty feeder lateral is identified, the post-fault steady state phasors, along with the simplified network model, are used to determine more exact fault location.

Nouri et al. [30] have introduced a double-ended fault location technique for distribution feeders with tapped loads utilising Global Positioning System (GPS) clock and reliable communications system. The technique is based on wavelet transforms. In this approach, fault transient detectors, installed at the local and remote busbars as well as at the remote feeder terminals, transform the voltage signals into their modal components using Clark's transformation matrix. Ground mode deals with ground faults and aerial mode deals with other fault types. Modal transformation is carried out ensure the technique works correctly for both symmetrical and asymmetrical faults. These mode signals are analysed using wavelet transforms and, as a result, the instant of their arrival is time-tagged by synchronised GPS clocks at the busbars and feeder terminals. The fault location is estimated by using the equation shown below:

$$x = \frac{L_{AB} - v * t_d}{2} = \frac{L_{AB} - v * (t_B - t_A)}{2}$$

where:

t_A is the time at which the signal wavelet coefficient shows its peak as recorded at terminal A, equivalent to the signal spike,

t_B is the time at which the signal wavelet coefficient shows its peak as recorded at terminal B, equivalent to the signal spike,

t_d is the time delay between node B and node A, i.e. $t_d = t_B - t_A$,
L_{AB} is the distance between terminals A and B,

v is the travelling wave velocity,

x is the distance to the fault from terminal B.

From the set of given solutions, the longest distance is the correct one.

Qianli et al. [31] have presented a single-ended scheme for the fault line selection applicable to distribution networks. The scheme utilises typical wavelet transform based techniques. The logic basis for fault location relies on the following principles:

- The amplitudes of the initial travelling waves, on the line effected by the fault compared to ones captured on healthy lines, are of opposite polarity.

- The travelling wave amplitudes in healthy lines have similar characteristics.

- The amplitude of the first current travelling wave in the line effected by the fault is usually higher than the corresponding amplitudes captured on healthy lines.

The proposed fault location algorithm senses phase currents on all phases to provide the characteristic model components instead of the usual phase components. Then, the polarity and amplitude is determined for the travelling waves in all phases followed by the summation of wavelets representing high frequency components on faulty and healthy phases to detect the highest wavelet coefficient. The line found with the highest coefficient and reverse polarity to others is defined as a faulty line. The accuracy of this method is not effected by the load or by the types of neutral point grounding.

Moshtagh and Aggarwal [32] have presented an off-line single-ended approach to fault location applicable to single core underground distribution cables. The principle of operation is based on two techniques employed:

- Wavelet transform analysis, implemented to recognise a sudden change in voltage and current signals due to reflection of a wave from the fault point, which in turn indicates the fault distance and wave propagation velocity.

- Fuzzy set logic, implemented to identify and locate the fault location through pattern recognition.

The advantageous feature of a wavelet transform is its ability to analyse signals containing short lived high frequency components superimposed on power frequency signals. Whereas fuzzy logic techniques offer fast implementation of adaptable conceptual rules using natural language. Combination of these two techniques offers an enhanced reliability approach to locating faults on single core underground cables.

Four types of underground cable faults can be determined by this approach. They are:

- Core open-circuit fault.

- Core and sheath open-circuit fault.
- Core with sheath short-circuited fault.
- Core and sheath to ground short-circuit fault.

The reported test results show satisfactory performance in terms of fault location accuracy.

Tag El Din et al. [33] have presented a double ended fault location scheme for aged power line cables on distribution networks. Underground aged power cables present specific problems for fault location due to the change of manufacturing parameters over the years. The main problem is the change in the three-phase positive, negative and zero-sequence capacitance effecting the travelling wave propagation velocity. The scheme utilises synchronised three-phase voltage measurements taken at both sides of the cable. The principle of operation relies on the successive identification of the first travelling high frequency signal. The signals generated by the fault are first converted into aerial modal signals by modal transformation to extract sufficient fault transient information. Clark's transformation is used to decouple the phase signals. Following that process, wavelet transformation is applied to produce a specific band of high frequency components allowing extraction of the travelling waves needed for the recognition of characteristic signatures corresponding to the discontinuity points on the line. On the arrival of the first travelling wave with spiky magnitude, signifying a fault, a series of key transient sequences is recorded and the relationship between these sequences is analysed to determine the fault position. The scheme can be applied on any cable, independently from the cable manufacturing parameters, provided its length is known. It is not effected by faults occurring on or very close to the zero-crossing points. The reported accuracy is approximately 365 metres.

2.1.1.1.2.2.2 Wavelet packets technique

A novel approach has been proposed by Yan et al. [34] in which theoretical single-ended technique, using wavelet packets to locate faults on multi-branched distribution networks, is presented. The wavelet packet technique has been applied as it offers a better representation of the information embedded in high frequency components than the wavelet transform method. It relies on detection, by the fault locator installed at the substation end, of high frequency transient composite signals.

These composite signals are generated by the fault and the signals reflected from discontinuities present along the feeder including the signals reflected from the fault point itself. The technique is based on the high frequency content reconstructed by the wavelet packet coefficients of the signal. An eigenvector matrix is constructed representing the local energies of the signal. Firstly, the faulty section is found by comparing local energies in the eigenvector matrix with a given threshold. Secondly, the fault point is found according to the maximal relativity of the two reflected waves.

2.1.2 Indirect approach

In the indirect approach, the estimates of fault location points, in principle, are derived from the devices' status data provided by SCADA and protection relays and, when available Distribution Management Systems. Heuristic knowledge of the system operators, whether or not augmented by knowledge-based systems, is also utilised for the fault location estimation. The indirect approach can be categorised as follows:

- Operational techniques incorporating SCADA and protection relay derived status information, augmented by system operators' knowledge of the network.

- Knowledge based systems techniques mainly based on Artificial Intelligence algorithms.

2.1.2.1 Operational techniques

The strategies regarding fault location vary from basic ones to very advanced ones advocating the utilisation of fully integrated Distribution Management Systems. Usually, they are application specific dictated by the gradual development that has taken place over the years. Samples are given below.

Willis [35] has presented a suite of fault location techniques and management principles applicable to fault finding in shielded, lead shielded or armoured medium voltage class, extruded solid dielectric cables. The discussed techniques are visual inspection, megohmmeter test and sectionalisation, Murray loop resistance bridge, capacitance bridge, Time Domain Reflectometer method and impulse method. The general conclusion reached is that the fault location method or methods to use must depend on evaluation of the merits and disadvantages of each as related to the particular circumstances of the cable fault.

Verho et al. [36] have presented a set of fault location strategies developed for distribution networks. Improved fault location management through the integrated feeder automation, relay protection and SCADA system within one Distribution Management System is indicated as the evolving management approach to the operation of distribution networks. A concept of a total Distribution Management System, with full integration of network related databases, advanced network monitoring and fault management and employing a knowledge-based system to account for heuristic knowledge related to fault location, is advocated. Special focus is placed on the proactive approach to fault location of high impedance faults evolving gradually into permanent faults causing health and safety hazards.

Kiessling and Schwabe [37] have presented an approach focused on the software solution for fault record analysis based on records produced by digital relays installed on both transmission and distribution networks. The reduced impact of high impedance faults, mutual coupling, frequency variations, unbalanced loads, inhomogeneous distribution lines and effects of arc resistance on fault location accuracy is discussed in the light of the capabilities presented by the full integration of protection relay data into this software. The notion of a double-ended positive sequence algorithm, reflecting the fault events at both ends of the effected line, is shown as having the advantages of provisioning precise grid data and invariance to arc resistance and mutual coupling.

2.1.2.1.1 Fault indicator techniques

Fault indicators are usually installed on the laterals of distribution feeders to indicate fault paths. They alone cannot prevent outages as they represent purely a reactive measure to a fault. When equipped with radio communications, such as GPRS, fault indicators can help in the identification of problem areas of a distribution network and reduce crew patrol time significantly. They are an inexpensive means of improving reliability of supply, used essentially as a means of reducing outage duration rather than frequency of supply interruptions.

A study on the applications of fault indicators on distribution systems, presented by Krajnak [38], indicates that they can have a significant impact on the reliability of supply indices. Apart from the fact that they are used as a tool for outage response, fault indicators might be also applied to flag occurrences of momentary faults. According to the study, improved performance of modern fault indicators, equipped with current transformers, eliminated false tripping due to fault conditions on adjacent circuits such as inrush currents caused be recloser operations or other transients. Current transformer sensing, in conjunction with low pass filtering, allows elimination of false tripping due to cable outrush capacitive currents. An inrush restraint feature prevents from false tripping due to inrush currents. Modern fault indicators equipped with a feature to sense a rate of change in currents makes them versatile as no specific trip setting needs to be applied. As reliability indices such as SAIFI, SAIDI, CAIDI and MAIFI are becoming more prevalent in the regulator's assessment of utility performance, the role of modern fault indicators equipped with communications, used as an inexpensive remedial measure, is envisaged to increase in the future. An indicative SAIDI and CAIDI measurement comparison, presented by the study for a base case scenario with no fault indicators and a scenario with fault indicators, has shown that for the feeder with the fault indicators installed, the improvement in SAIDI and CAIDI can be of the order of 15%. It has been noted by the study that this order of improvement may not be sufficient to meet utility's SAIDI and CAIDI improvement goals.

2.1.2.1.2 Techniques based on 'in line' switches and sectionalisers

In 1995-96, an American based company, EnergyLine [39,40], devised a faulty section location scheme, for applications on distribution loop-feed feeder configurations. A typical loop-feed feeder configuration is comprised of two distribution feeders each having up to three 'in line' load break / fault make automatic switches installed in the feeder backbone. The two feeders are tied at a normally open paralleling point featuring a load break / fault make automatic switch to provide a means of backfeeding. This switch is of the same type as those installed in the feeder backbones. The switch controllers communicate with each other on peer-to-peer basis informing each other about their status. SCADA communications is not absolutely necessary as the preferred scheme application is in a stand-alone configuration. It is an example of Distribution Automation implementation in the field, without relying on first automating Zone Substation or depending on SCADA. In this scheme, the switches take automatic action under three conditions:

- A line segment experienced a fault.
- A circuit breaker opened at the Zone Substation end.

- A single-phase condition occurred.

When a fault occurs on one feeder segment, it is cleared by the relevant Zone Substation circuit breaker. The scheme identifies the affected by fault section by interrogating all the switches and checking for switches that recorded overcurrent and 'loss of supply'. The switch that recorded overcurrent and the adjacent switch that recorded 'loss of supply' are identified as the isolation points for the faulty feeder section. Then, the scheme back-feeds the healthy loop sections automatically to minimise the outage duration. Healthy feeder segments adjacent to the normally open point, if any, are classified as 'preferred transfer segments' and they get energised first. The disadvantage of this scheme is the requirement for the switches to be equipped with both current and voltage sensing and the fact that the switches cannot break fault currents. The reliance on fault clearing by zone substation circuit breakers means that all customers on the feeder are affected by the fault.

Sectionalisers can also be used to locate the faulty feeder section. Their function is not to interrupt the fault currents but instead count the fault occurrences on the line, and upon a predefined number of counts, open up when the line is de-energised. The fault current interrupting device, allowing the counting action, is either an upstream recloser or a Zone Substation circuit breaker. This is a disadvantage in cases where there are critical loads and reduction in MAIFI is important. Sectionalisers are often used where coordination with other devices is difficult.

Switches and sectionalisers yield no overall improvement in the SAIFI as they do not automatically segment the distribution feeder.

2.1.2.1.3 Techniques based on 'in line' reclosers

Reclosers are designed to interrupt both load and fault currents and reclose on a fault repeatedly in a predefined sequence in an attempt to clear the fault. When installed in an 'in line' configuration, reclosers present an approach that can address both SAIFI and SAIDI reliability indices [41,42]. This is because, in many cases, fault clearing is not carried out by Zone Substation circuit breakers but by reclosers installed 'in line' along the feeder. Thus, in most cases, customers on the upstream sections of the feeder do not experience the effect of faults that took place in the downstream sections of the feeder.

Goodin et al. [43] have presented a study on the impact different switch gear stand-alone configurations, installed on a radial distribution feeder, have on the reliability indices such as SAIDI, SAIFI and MAIFI. The resultant summary of reliability percentage improvements is shown in Table 2-1.

Table 2-1 Percentage reliability improvement summary as per ABB study

Switch gear type	Configuration	SAIFI % improvement	SAIDI % improvement	MAIFI % improvement
Zone Sub circuit breaker only	Radial feeder, base case	–	–	–
Zone Sub circuit breaker and a load break switch	Radial, midpoint switch	None	10	None
Zone Sub circuit breaker and a sectionaliser	Radial, mid point sectionaliser	19	19	-3
Zone Sub circuit breaker and a recloser	Radial, midpoint recloser	19	19	26
2 Zone Sub circuit breakers and a load break switch per each feeder	Looped, midpoint switches with a tie switch	None	11	None
2 Zone Sub circuit breakers and a sectionaliser per each feeder	Looped, midpoint sectionalisers with a tie switch	19	30	-6
2 Zone Sub circuit breakers and a recloser per each feeder	Looped, midpoint reclosers with a tie switch	19	29	29
2 Zone Sub circuit breakers and a recloser per each feeder	Looped, midpoint reclosers with an automatic tie-point recloser	38	38	23

Single phase switching has been included in this study although it does not apply in Australia. In essence, the study has presented a quantitative answer to a typical utility dilemma regarding how to increase reliability at the lowest possible cost. Load break switches, sectionalisers and reclosers, installed in different configurations, are analysed in this study.

It is evident that all devices, considered in Table 2-1, offer a degree of improvement in reliability. However, reclosers can simultaneously address both SAIFI and SAIDI indices to the highest degree, especially operating in a loop scheme with an automatic tie-point recloser.

Elder and O'Sullivan [44] have presented an optimised economic approach for recloser applications on rural distribution networks operating in Australian environment. In this approach reclosers are located on feeders so that it takes no more than 1 second to clear faults in their protection zone, thus minimising the fire risk. Upstream reclosers have around twice the pick up current of downstream reclosers to maximise cover and minimise cascading. The result is a fully optimised feeder protection policy applicable anywhere in rural areas regardless of the supply voltage.

In 2004, Hataway [45] from Schweitzer Engineering Laboratories introduced a network autosectionalising scheme based on the SEL651 protection relay advanced recloser controls applied to distribution feeders operating in a loop configuration. This scheme relies on peer-to-peer communications between all reclosers in a loop utilising Schweitzer proprietary protocol called Mirrored Bits. Typical communications media include fibre optic cables and digital spread-spectrum radios between recloser controllers. In this scheme, the operation of a recloser and the subsequent lock out are detected followed by the isolation of the faulty feeder section. Then the scheme finds and closes the normally open point to energise the healthy feeder sections that may have been de-energised when the fault was cleared. The scheme relies on 3 phase current sensing and 6 phase voltage sensing to ensure safe and secure loop-feed automation. In addition, the SEL651R can provide fault location estimation [46] using fault type, replica line impedance settings and fault condition information. It does not require special communications channels, special instrument transformers or pre-fault information. The fault locator itself requires the connection of 3 phase voltage inputs.

2.1.2.2 Knowledge based systems

A number of knowledge based systems have evolved over the years targeting specific faults types. In general, knowledge based systems can be categorised as based on mathematical techniques and Artificial Intelligence techniques.

2.1.2.2.1 Mathematical techniques

A probabilistic method, to address the difficulties with fault location for very high resistance single-phase earth faults is presented by Hänninen et al. [47]. It is applicable to radial operated distribution networks. The method can facilitate a proactive approach to intermittent high resistance fault incidents, such as a tree branch touching a phase line, the aim of which is to prevent intermittent faults from developing into permanent ones. In this method, two independent algorithms called neutral-voltage analysis and residual-current analysis are utilised. The effectiveness of these analyses is reliant on a degree of integration with the SCADA system providing protection and status data from zone substations and remote feeder terminal units. The neutral-voltage analysis determines the fault impedance and the fault current in terms of the phasor sum of the measured voltages, positive-sequence component of the phase voltage in the faulted phase and the zero-sequence impedance of the network. The residual-current analysis compensates for the effect of earth-phase capacitancies and outputs compensated zero-sequence current of the faulted feeder. Combining the outputs of both analyses provides the means for location of a faulty feeder and the faulty feeder section. In case of very high resistance faults, the magnitudes of the compensated feeder zero-sequence currents are small. Thus, due to the voltage and current measurement errors, there is a risk of not being able to select the compensated zero-sequence current of the highest magnitude, i.e. the criterion for a faulty feeder. Therefore, a probabilistic approach has been introduced whereby the compensated zero-sequence current and the estimated fault current are regarded as random variables obeying normal distribution. When applying probabilistic methods, difficulties may arise when the compensated zero-sequence current distribution is very narrow or when its deviation is too big. Despite of these shortcomings, this method is able to detect and locate resistive earth faults up to the value of 220 kΩ.

Wang et al. [48] have proposed a mathematical concept for fault location applications that relies on the formation of matrices representing relations between nodes and sections as well as voltage sensors present on a distribution network. The technique is reported to have the advantages such as:

- Identification of a faulty section or faulty area using the status of voltage sensors and the topological structure of the network.
- Reduced number of voltage sensors compared to conventional approaches and the resultant low capacity communications required.
- Effective in detection of single and multiple faults.

The drawback of this method is the assumption that all the feeder sections are protected by fuses and circuit breakers which is not a reflection of a typical distribution network. The need for an adequate number of monitored voltage sensors installed at feeder tee-offs is a disadvantage as mainly current sensing has been commonly installed on distribution networks.

2.1.2.2.2 Artificial Intelligence techniques

The Artificial Intelligence techniques encompass:

- Expert systems dealing mainly with alarm identification and their selection resulting in subsequent decision regarding fault location [49,50].

- Systems relying on application of fuzzy logic in an attempt to target the inherent uncertainties associated with faults, an example of which may be passive high impedance faults [51].

- Systems employing artificial neural networks [52,53] and genetic algorithms.

These systems are characterised by a heavy reliance on heuristic knowledge, encompassing all possible network configurations, loading limits and typical fault types as well as their signatures [54].

Special challenge for the Artificial Intelligence techniques is presented by high impedance faults as it is the knowledge based systems that present the greatest potential to deal with the problem. The detection and location of high impedance faults has been the most persistent and difficult challenge facing the power industry and for that reason they attracted additional attention in this review.

High impedance faults result from an unwanted contact of a conductor with objects that provide path to earth with current levels limited to the extent that they are not detectable by the protection equipment [54]. There are two types of high impedance faults:

- Active.

- Passive.

Active high impedance faults are characterised by electric arcs resulting in generation of wide band signals. They can be addressed by the signal analysis techniques although with not quite reliable results. Passive high impedance faults are not associated by electric arcs. There is no indication readily available about the hazardous condition of the feeder [18]. Thus, they are even more difficult to detect and locate than the active high impedance faults.

To address the problem of passive high impedance faults a high frequency impulse is injected at the feeder terminal at predetermined time intervals. High frequency signal makes the method insensitive to the phase unbalance and noisy loads. The resultant reflected travelling waves are sampled at high sampling rates to provide all the feeder signature information. Each response signal is processed, converted to frequency domain and stored in a database. During the fault the system compares the incoming fault signatures with the high impedance fault reference signatures stored in the database. The correlation of these signatures results in deviations that are classified as small, medium and large and represented as fuzzy numbers [51]. The analysis of the pulse response signals is carried out in three stages:

- The analysis of frequency response signals where the real and imaginary components of the sampled response signals are subjected to the predetermined selection rules. These rules are the most representative for the high impedance pre- and post-fault conditions which result in variable frequency coherence.

- Averaging variable frequency coherence and reference frequency coherence resulting in sample coherence. As there are a number of samples taken, a single reference coherence is derived by calculating the average of sample coherences.

- Final inference applied to reference coherences according to predetermined rules that reflect the characteristics of high impedance faults. This process results in the high impedance fault identification and location.

Detailed review of the literature on the implementation of knowledge based systems, in fault detection and location area, is presented below. It shows the research undertaken and developments that followed.

2.1.2.2.2.1 Expert systems

Eickhoff et al. [50] have presented a generic set of guidelines applicable to a newly established knowledge based system for application on distribution networks with limited number of monitoring points. Meshed distribution networks are given as examples in their work. The emphasis is put on the integration of different types of telemetry and control systems, protection devices as well as the ability to analyse information, characterised by a high degree of uncertainty, related to the post-fault topological status of the distribution network. This, in turn, has an impact on the fault location abilities of the system. Characteristic complexities, associated with distribution networks, are described in detail with the focus on the inadequate information content that has to be dealt with by the inference engine of the knowledge based system. Inadequate saturation of distribution networks with protection devices is listed as one of the technical constraints generally faced. When available, the system can incorporate the following protection functions:

- Differential protection.
- Distance protection.
- Overcurrent protection with or without time delay and directional indication.
- Single-phase fault indication using time delay and directional components.
- Overload protection.

Within these guidelines, a rule based fault location prototype system has been described in terms of general fault analysis. It can be applied to phase-phase and earth faults. Due to the limited number of monitoring/protection points on the network, fault location estimates are given in terms of probable and plausible fault locations. In case of complex networks, a set of possible fault locations can be given by the described knowledge system.

Girgis and Johns [55] have introduced a hybrid expert system capable of identifying bus faults, faulty line sections and fault sections in the common area of a specific bus or line. This expert system has been developed with transmission applications in mind and it represents an early stage of hybrid expert system developments. The expert system combines numeric algorithms with rule based algorithms in one scheme albeit implemented in four stages. The first stage determinates the faulty section of the power system. The second stage plays the role of an interface between the expert system and a database containing real-time phasor measurements including protection relays and circuit breakers' status. The third stage is employed to classify faults by utilising the phasor quantities. The fourth stage interfaces the expert system with fault location algorithms best suited to cater for a specific fault. The rules developed for this expert system operate in the following order of priority:

- Determine if a bus experienced a fault.
- If yes, then determine if the fault effected the common bus and line area.
- If it is not the bus then determine the faulty line section.

The numeric algorithms estimate the fundamental frequency components sourced from the recorded post-fault waveforms and expressed as phasor voltage and current quantities. The pre-fault current and voltage phasors are calculated from the pre-fault data sourced from the protection relays. Reliable communications between phasor data sources and the expert system is critical in this process. The pre and post-fault phasor data is stored in a fault specific file for comparison purposes. The change between the pre and post-fault current values is used for the fault type classification while the change in magnitude of voltage and current phasors and the zero-sequence currents are used for fault location computation. Two groups of fault location algorithms are available: one applicable to single terminal measurements and the other applicable to multi-terminal measurements. The fault location accuracy is greatly increased when the multi-terminal approach is feasible, in particular, when applied to high impedance faults.

Hsu et al. [56] have presented a rule based expert system designed to locate faults on complex laterals of a distribution system. This approach is particularly valuable as faults on the feeder laterals are usually cleared by non monitored fuses. Thus, no change in feeder status is detected at the control centre end. As a result, trouble calls from affected customers are the only source of outage information. The system comprises the knowledge base, the inference engine and the man-machine interface serving as a communications medium between the user and the expert system. To facilitate the operation of this expert system, a set of heuristic rules, reflecting expert knowledge gathered over the years, has been developed and embedded in the rule base. Operation of the inference engine is based on three major logical processes: the dynamic searching, backtracking and set intersection operation. Through these processes it implements deductive reasoning on the production rules and controls the derivation of new facts. The reported success rate, when tested under real-time conditions on the underground distribution network over a period of one year, is reported to be 17 successfully located fault events out of 19 events experienced.

Momoh et al. [57] have introduced a rule based support system that is focused on single-phase to ground fault detection occurring in Δ-Δ connected distribution systems. This type of faults, as well as the high-impedance single-phase to ground faults occurring in Y-grounded distribution systems, cannot be detected and located by standard methods. It is because in Δ-Δ connected networks, due to the inherent capacitance forming a Y-grounded high impedance path to ground, low fault ground currents flow under fault condition. The low magnitude of the fault ground current prevents the protection devices from detecting it and clearing the fault. The rule-based support system has been designed to be used for fault detection, faulted feeder identification, fault type classification, fault location and impedance classification. The knowledge base for this system has been established by empirical studies carried out on a specific network by the authors. As the system performance differs for different types of faults, fault classification has been established as follows:

- Type 1 – single-phase to ground fault with conductor intact, i.e. shunt fault.

- Type 2 – single-phase to ground fault with conductor broken and source end on the ground, load end hanging in the air.

- Type 3 - single-phase to ground fault with conductor broken with load end on the ground and source end hanging in the air.

- Type 4 – open conductor with neither end making contact with ground.

The system has been designed with the following major modules:

- Fault Detector Module detecting faults based on an increase in the negative or zero sequence components of the feeder currents.

- Feeder Identifier Module identifying the faulty feeder based on the largest negative and zero sequence components of the feeder currents with priority given to negative sequence component.

- Fault Type and Phase Classifier Module identifying fault types and faulty phases by rule matrices developed for specific fault types.

- Fault Locator Module designed to detect the proximity of series or combined types of faults.

- Fault Impedance Evaluator Module operating on voltage magnitudes and implemented only for Type 1 and 2 faults.

The system success rates are reported as:

- Feeder identification - 100% for all fault types.

- Phase and fault type classification – 100% for Fault Type 1, approximately 90% for Fault Types 2, 3 and 4.

- Fault location – not very satisfactory (although carried out only for Fault Types 2 and 4). Fault location is reported to be most successful either at the very end of the line or nearest to the bus. In other parts of the feeder fault location is reported as ineffective.

- Fault impedance estimation – very successful for Fault Types 1 and 2.

2.1.2.2.2.2 Fuzzy logic techniques

Järventausta et al. [58] have introduced a fault location method based on a fuzzy set theory that is focused on the utilisation of heuristic expertise of the SCADA centre controllers operating distribution networks with long and complex radial feeders. The aim of the proposed method is to enhance the knowledge base pertinent to faults and consequently support informed decision making by the controllers who are ultimately in control of the distribution network. The principle of the fault location operation relies on the grades of membership functions of alternative hypotheses. Zero fault resistance approach has been adopted for the short circuit current calculations. The ensuing uncertainties are taken care of by fuzzy logic. The decision making process utilises maximum selection, α-level and the relative cardinality of a switching zone to locate the faulty feeder section. In addition, the elimination rule is used in cases when logical outcomes or SCADA inputs are mutually exclusive.

Faulted zone is determined first followed by calculations to locate the fault within the faulted zone. Performance details are not known. However, the effective use of the proposed method calls for an advanced distribution automation system.
Furthermore, Järventausta et al. [59] have developed a practical expert system for fault location on medium voltage distribution networks. This expert system is an integral part of the Distribution Management System (DMS) that is highly dependent on the interoperability with other distribution management databases and systems. It applies different Artificial Intelligence (AI)–based techniques to capitalise on their strengths in favourable applications. Thus, the object-orientated approach and the blackboard technique have been effective in building flexible connections between different data systems and combining different problem solving methods. They are essential in building the network entity platform reflecting the real-time state of the network. Fuzzy set theory and decision tree have provided the methods to model the expert knowledge and the uncertainty. The absolute mean accuracy for fault location is reported as 800 metres for the year 1995. The fault location response time is reported to have been 10–30 seconds including data transmission and DMS processing times.

Zhong and Liu [60,61] have published two papers describing the same fuzzy set method for fault location on distribution feeders. The fault location algorithm employed by this method encompasses two phases. In the first phase, sensor signals, SCADA provisioned fault related information and heuristic rules, defined by codifying operators' experiences, are used to form the basic possible faulted zone. In the second phase, the fuzzy set method is applied to effectively reduce the margin for the fault location within the basic possible faulted zone or provide the priority list of the possible faulted line sections. The definition of membership functions is of crucial importance in this method. Two types are used: an on-line calculated membership function and an off-line defined membership function. The on-line calculated membership function is determined by matching the fault currents provided by the SCADA system with the fault currents calculated by the short circuit analysis. The off-line defined membership function is determined by assigning different weighting to line sections to reflect their susceptance to faults as defined by expert operators. The most likely location of a fault is based on the grades of considered membership functions. This method presents a great potential for the implementation on any distribution network facilitated by a mature real-time SCADA system.

Chang et al. [62] have developed a fuzzy logic approach, albeit presented for transmission line applications, that takes into account the uncertainties associated with the post fault network status information. These uncertainties occur due to the circuit breaker and protection relay failures as well as the communications system failures. In this approach, fuzzy set theory is applied to determine the most likely faulty section(s) of the network and systematically model the uncertainties with an additional outcome being the provision of calculated uncertainty confidence levels. Fault models are based on the post-fault status of the circuit breakers and protection relays only effected by the fault(s). This technique offers a more expedient expert knowledge modelling with reduced number of rules needed for the inference processes. As a result, the knowledge database, memory space and computation times are reduced to the point that it could be regarded as fast enough for real-time applications. With modifications reflecting the distribution system characteristics this fuzzy logic expert system could have a potential for applications on distribution networks.

2.1.2.2.2.3 Artificial Neural Networks techniques

Glinkowski and Wang [63] have presented a fault location technique, based on Artificial Neural Networks (ANNs), that is designed to locate and classify faults occurring on underground networks, encompassing both distribution and Low Voltage network reticulations with varying interconnections and topologies. This approach utilises both the pattern recognition feature of ANNs and the emerging capabilities of modern protection relays. The technique is based on the assumption that under fault conditions, just prior to the fault clearance, the voltages and currents measured contain fault signature characteristic enough for the ANNs to determine the fault location on the network and classify its type. The accuracy of the system is dependent on the extent of simulation carried out for a particular distribution network configuration to train the ANN in question. Thus, the system is more suitable for fault location applications on static networks rather than dynamic ones. Unfortunately, typical distribution networks are dynamic by nature. This fact implies that a considerable effort would have to be invested in the reticulation specific ANNs training processes to be able to learn about the predetermined network reticulation variants and thence maintain the expected fault locating accuracy levels.

Li et al. [64] have presented an enhanced application of the artificial neural network (ANN) technique for locating faults that have infeed sources at both ends of the transmission line. This method is renowned for fast learning and its ability to recognise the learnt behavioural patterns of a power system whereby functional relationships, under fault conditions, are difficult to define. The speed performance is due to the use of the Nguyen-Widrow method to find the initial conditions further augmented by the use the Levenberg-Marquardt approximation to optimise training speed, albeit at the cost of an increased demand for computer processing power. The required input by the ANN is the pre-fault active and reactive power and measured impedance during the fault. The output, i.e. fault location and fault resistance, is given in the form of percentage line length from each line terminal and the calculated value of fault resistance. This technique can estimate locations of faults and fault resistance for line-earth faults with the accuracy of approximately 1 % of line length and fault resistance accuracy of approximately 1 Ω with the exception of high resistance faults. Although it is designed primarily with transmission applications in mind, there is scope for its future use on distribution networks with implemented distributed generation. However, further refinements would be necessary to reflect the complexities of distribution networks.

Eberl et al. [65] have presented a study on the performance comparison between the artificial neural network (ANN) method, wavelet algorithm and differential equation algorithm for transient based ground fault location applied to radial distribution networks with unearthed, partially compensated and compensated neutrals. In these networks fundamental frequency techniques cannot be used for the fault location purposes. The study is based on the charge transients as the most useful component for fault location diagnosis. In the ANN approach special focus is given to scaling of the input data to enable an ANN to perform fault distance estimations in distribution networks of different sizes. The wavelet algorithm method firstly determines the maximum wavelet coefficients of the current including amplitude, frequency and location of the wavelet. Then, using the frequency, the equivalent fault inductances are calculated. The mean value of these inductances is used to determine the fault distance. The method, employing the differential equation algorithm on iterative basis, solves the line inductance in time domain using three pairs of current and voltage samples, producing the average inductance values associated with statistical deviations. The inductance with the smallest statistical deviation is used for the fault distance estimation. It is documented in the study that the performance of the ANN technique is comparable with the performance of conventional algorithms with better results achieved when dealt with very low resistance faults, i.e. the mean error of 1 kilometre. In addition, it is shown that the wavelet and differential equation algorithms perform better with faults characterised by higher resistances, i.e. the mean error of approximately 2 kilometre. As the transient based ground fault location performance is restricted by the transient attenuation, directly proportional to the distances involved on the complex distribution network, the highest fault resistance, proven to deliver acceptable fault distance estimates, was found to be 50 Ω.

Considering different earthing systems, the differential equation algorithm delivers better results when applied to partially compensated and unearthed networks. The ANN and wavelet methods are more accurate when applied to compensated networks.

As in the paragraph above, Hänninen and Lehtonen [66] have presented a transient based earth fault location method, applicable to radial distribution networks, by using an Artificial Neural Network (ANN) approach. In this approach, harmonic components of the neutral voltage transients are utilised for the earth fault distance computation. This method is particularly useful for fault location on distribution networks with high impedance grounding whereby single-phase fault currents are usually too small to give effective input for reliable fault distance estimation. The key issue in this method is to extract the charge transient from other parts of the measured signal. This is achieved, firstly, by the removal of the fundamental frequency component followed by spectrum analysis to estimate the charge transient frequency and finally low-pass filtering to remove the higher frequency components. To train the ANN, the Backpropagation method is used with the Levenberg-Marquart training algorithm to facilitate fast but stable training process and a sufficient error decrease for the ANN. The presented test results show that a harmonic trained ANN provides comparable accuracy levels for fault location as the current/voltage trained ANNs. The mean error in absolute terms, achieved in field trials with assumed zero fault resistance, is approximately 1 kilometre. The drawback of this method is that with higher fault resistances the transients are attenuated resulting in drastically accentuated errors, i.e. fault resistances above 50 Ω render the fault detection ineffective.

Momoh et al. [67] have introduced a hybrid package for fault diagnosis in either grounded or ungrounded distribution networks. It utilises rule-based schemes and the Artificial Neural Network (ANN) approach to detect, classify and locate faults. Fault diagnosis can be provided for Y-grounded and Δ-Δ connected distribution systems. The ANN, used in both modules, is a clustering based algorithm that separates the input data into different classes of clusters representing distinct input patterns. As with any ANN systems extensive training is required usually by utilising fault simulation techniques. It has been demonstrated by this hybrid approach that both the rule based scheme and the ANN based scheme can achieve success rates of 100% for the classification of the faulted feeder and faulted phase as well as for fault location when applied to Δ-Δ connected networks. Success rates for the classification of the faulted feeder and faulted phase achieved with the Y-grounded distribution network simulation data are shown as more modest, i.e. between 81% and 85% depending on the simulated fault type. Most importantly, fault location ability has not been tested with reference to Y-grounded networks. Irrespective of the fault location performance on Y-grounded networks, this hybrid approach to fault location is not applicable to Australian distribution networks as they are built in Δ-Y configuration. In addition, the level of complexity is excessive implying costly implementation and maintenance.

2.2 Literature review summary

The overall conclusion, reached after the completion of this literature review, is that in general the researched fault location techniques and systems cannot provide levels of accuracy required by urban Distribution Feeder Automation Schemes. This is due to the complexities and uncertainties pertinent to the distribution networks in general. Safety standards demanded from the fault location schemes, by the automation applications in urban areas, cannot be met in an economical way at the current development stage of these techniques and systems. For these reasons the author of this research has not considered any of the techniques and systems as reliable enough or economically viable for practical implementation on urban distribution networks. In particular, accurate location of high impedance faults on radial urban distribution feeders is still an unresolved issue.

Working experience of the author and the up to date literature survey indicate, that the only exception from the above reached conclusion is the Schweitzer SEL651 advanced recloser control for loop-feed schemes. However, this scheme is not regarded as cost effective in the current Australian utility operating environment due to its requirement for voltage sensing and protection grade communications all along distribution feeders. Thus, the author of this thesis has not found a fault location scheme readily available for deployment on urban distribution feeders in Australia. Consequently, a need for the development of an approach suitable for Australian utility environment arose.

The researched fault location techniques have been classified by the author of this thesis and presented in Figure 2.3 to illustrate the overall complexity of the fault location issue as well as the interdependencies of these techniques.

The literature review indicates that a number of different fully developed fault detection schemes are available for applications on sub-transmission and transmission networks. It is noted that a steady progress is being made in the area of fault location for distribution network applications with the future developments focusing on hybrid systems that incorporate some of the discussed techniques as one solution.

2.3 Recommendation and justification

Considering the preliminary AGLE's stipulation not to implement voltage sensing and the results of the literature review, a general conclusion has been reached that a direct approach to fault detection and location is incapable of fulfilling the project's scope. In reaching this conclusion the following aspects have been considered:

- High implementation cost due to the lack of the 'off the shelf' products.
- Long implementation timeframe.
- Less than desired fault location resolution on complex distribution feeders.
- Expected poor reliability due to the harsh environment and frequent network reticulation changes.
- High maintenance costs and a requirement for specialist skills resource matrix.

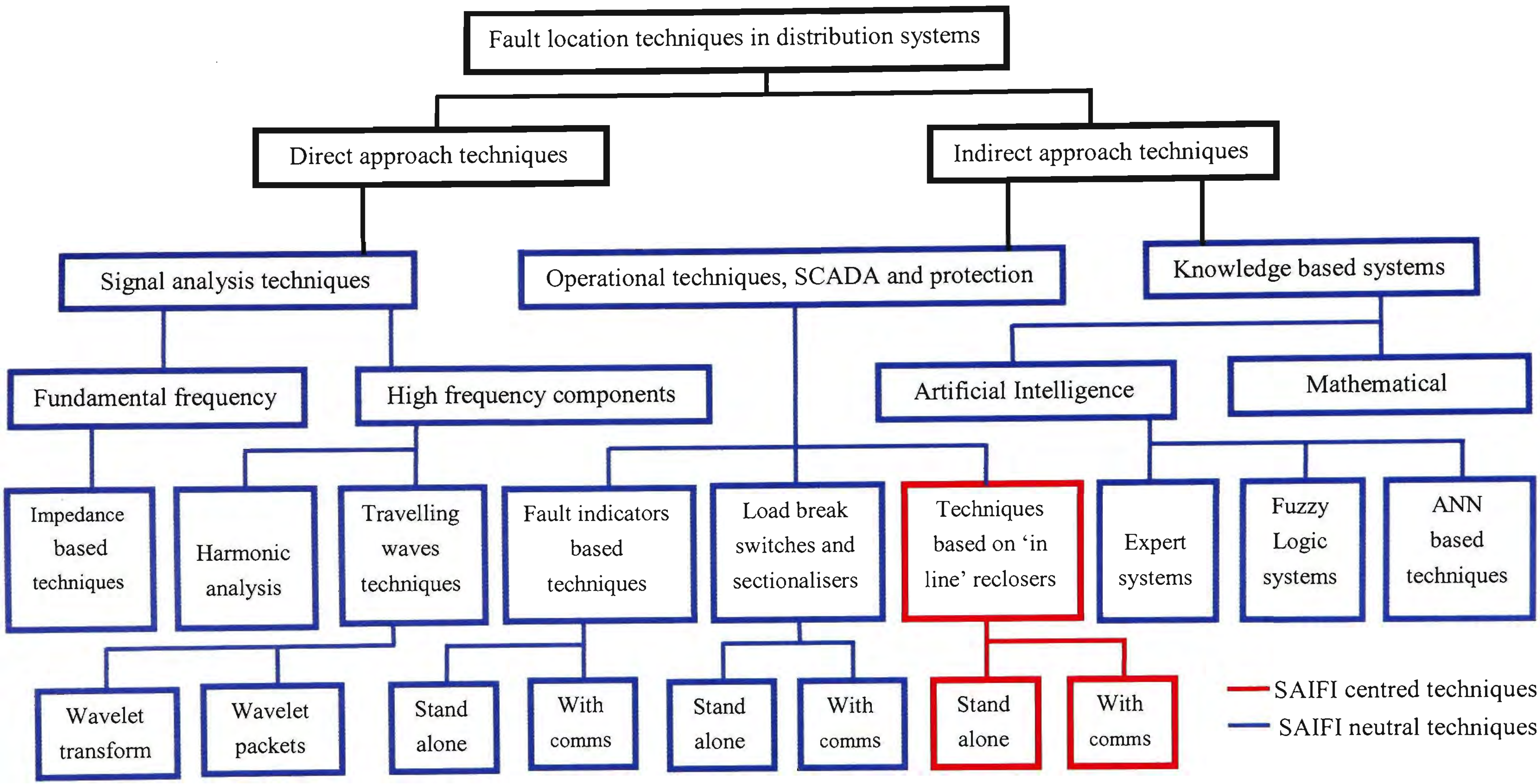


Figure 2.3 Classification of fault location techniques for distribution system application

Thus, an indirect approach to fault location and detection, based on 'in line' reclosers, has been recommended for implementation on AGLE distribution network by the author of this thesis.

The most decisive factor, in recommending this fault detection and location approach for a large scale implementation, has been its ability to help AGLE effectively address the Reliability of Supply issues on time by a scalable implementation of a much more cost effective and technically simpler scheme than any of those surveyed in the literature review. In essence, AGLE needs to be able to minimise the capital expenditure associated with the investment necessary to meet the Reliability of Supply requirements by an allocation of only an incremental capital outlay to address issues on 'as per needs' bases. The recommended indirect fault detection and location approach addresses that need as it naturally lends itself for a staged implementation.

In addition, the 'in line' recloser scheme could be implemented at a much lower cost, with predominantly 'off the shelf' hardware and within much shorter implementation time frame. It has offered an acceptable degree of fault location resolution under current circumstances. The fault location resolution can be significantly improved if the network owner opts to implement voltage sensing on reclosers. The implementation of the indirect fault detection and location scheme based on 'in line' reclosers could be undertaken as part of the implementation of the remote control and monitoring program that is in turn based on a coherent network communication strategy adopted by AGLE.

CHAPTER 3

AGLE'S OBJECTIVE DEFINITION AND STIPULATIONS

3.1 Introduction

The primary target of this research has been to develop and pilot test **a practical, safe and economically viable** fault detection and location scheme with the aim of being ready for a large-scale deployment on AGLE distribution network at any time. AGLE's objective has been to have a system and a process, readily available for implementation, with the help of which dynamic focus could be applied to efforts aimed at meeting the Reliability of Supply indices set by the Essential Services Commission. Essential task, within this primary target, has been addressing the SAIFI performance measure on AGLE distribution network. However, improvement in SAFI usually results in a collateral improvement in SAIDI and CAIDI. Thus, a general improvement in Reliability of Supply performance measures has been implied by the scope of this work. The dynamic nature of the required improvements, resulting mainly from weather dependency or random fauna/flora interference, implied a gradual approach targeting the most vulnerable parts of AGLE's distribution network first.

The secondary target of AGLE has been to proceed with the large-scale implementation of remote control and monitoring program covering pole-top devices across the whole of AGLE supply area. Although the large-scale implementation of this program was not part of this research initially, with time the intricate interdependence of the fault detection and location scheme with remote control and monitoring program has been recognised. As a result, the implementation of remote control and monitoring program, covering the pole-top devices only but excluding interfacing with the SCADA host located in the Central Business District of Melbourne, has been included as part of the research covering fault detection and location scheme.

The most profound in consequence technical stipulation, made for this research program by AGLE, was not to implement voltage sensing for the fault detection and location scheme. This stipulation has limited fault detection inputs to current sensing only and as such has posed a severe restriction on the achievable level of fault location resolution. This decision was made due to the prohibitive cost associated with the purchase and installation of three-phase, protection grade voltage transformers operating at distribution voltages of 22kV and 11kV.

Another important stipulation has been to deploy 'off the shelf' configurable hardware preferably supplied by a single vendor. This requirement highlighted the need for a long-term relationship with a well established and reliable vendor. Consequently, vendor research and vendor selection processes have been included as part of this project.

AGLE has been committed to provide all equipment and facilities needed for the full testing and implementation of the fault detection and location scheme. The author of this thesis was put in direct control of human and material resources allocated to this project. In addition, the hardware vendor selection and vendor relationship maintenance processes were put under the jurisdiction of the author of this thesis.

3.2 Adopted approach to fault detection and location

Due to the AGLE's objectives characterised by the need for the immediate as well as long-term improvements in the area of Reliability of Supply, the research on fault detection and location schemes were split into two generic categories:

- Indirect fault detection and location approach using 'in line' reclosers that narrow the fault location down to a major switching section.

- Direct fault detection and location approach that would determine the fault type and its location within the major switching section.

As the reliable fault detection and fault type identification can be accurately achieved with the help of the relay equipment employed currently by the power industry, the research focus was placed on the fault location component of the scheme with the emphasis on its applications on distribution feeders.

A two-prong approach was adopted by AGLE in relation to the research on fault location. To enjoy relatively quick benefits as far as the improvement of supply reliability is concerned, the indirect fault detection and location approach was chosen as the first implementation stage. The research target of this stage was to prove the concept of 'in line' reclosers in applications on distribution networks and the overall benefits of the switching policy advocating the use of 'in line' reclosers.

Direct fault detection and location was nominated to be the subject of the second stage. Due to AGLE's stipulations, particularly regarding economic viability and the expected degree of difficulty, a feasibility study on the subject of direct fault location was to be carried out first. The expected outcomes of this feasibility study were:

- Availability and cost of the necessary infrastructure.
- Performance characteristics/reliability.
- Benefits' comparison between the indirect approach and direct approach to fault detection and location.

3.3 Indirect fault detection and location overview

The indirect fault detection and location can be introduced by the implementation of a recloser scheme on an urban distribution feeder with two reclosers in series, i.e. two 'in line' recloser scheme. In this scheme, the concept of upstream and downstream reclosers is used. In general terms, a downstream recloser is electrically further away from the Zone Substation, the energy source, than the upstream recloser. The reclosers are located at the boundaries of the major switching sections. In the event of a fault occurring on the last feeder section, i.e. past the downstream recloser, the fault current is detected by the feeder Circuit Breaker (CB) relay at the Zone Substation and by both reclosers' protection relays. Due to the difficulties with the protection discrimination, frequently experienced on short and heavily loaded distribution feeders, there is a requirement for a fast blocking scheme that would prevent the upstream recloser, and/or the feeder CB at the Zone Substation, from operation. This is because the objective is to limit the adverse effect of the fault to the feeder section that directly experienced the fault. This objective is achieved by opening only the recloser that is closest to the actual fault location and continuing to supply power to customers connected to the upstream feeder section(s) that did not experience the fault directly.

In some cases where two 'in line' reclosers are installed on a feeder, protection coordination between the two 'in line' reclosers and the Zone Substation circuit breaker can only be achieved if protection is slowed to an undesirable degree. In these situations blocking schemes can resolve the protection coordination difficulties and permit faster clearing times. Faster fault clearance has the benefit of reducing the probability of secondary faults therefore increasing the chances of successful reclose attempts.

To reflect the varying degree of acceptable protection discrimination available along distribution feeders and the cost effectiveness of the proposed solutions, the blocking schemes were split into the full blocking schemes and partial blocking schemes. A full blocking scheme was defined as a protection scheme whereby protection grade communications is implemented between the downstream recloser, upstream recloser and the feeder CB at the Zone Substation with the aim of preventing the, 'uninvolved directly' in fault, upstream devices from unnecessary tripping. A partial blocking scheme is defined as a protection scheme whereby protection grade communications is implemented between the downstream recloser and upstream recloser only. The partial blocking scheme reflects a common scenario whereby the difficulties with the protection discrimination are experienced in the downstream part of the feeder and whereby cost justification for the installation of protection grade communications is unattainable.

3.4 Full blocking scheme – principle of operation

A full blocking scheme comprises of two partial blocking schemes, i.e. one implemented between the Zone Substation circuit breaker and the upstream recloser and the other between the upstream recloser and the downstream recloser. The purpose of the full blocking scheme is to contain long-term effects of a fault within the feeder section that directly experienced the fault, by isolating the faulty section, and continuing to supply electrical energy to the 'healthy' feeder sections and their customers.

Under normal operating conditions, the full blocking scheme is in a 'ready' state by having 8 mirrored bits 'circulating', with unchanged status, between the downstream recloser and the upstream recloser as well as between the upstream recloser and the Zone Substation circuit breaker. A status change in one or more mirrored bits is interpreted as the receipt of a blocking signal at the receiving end.

Standard application of a full blocking scheme under fault condition is depicted in Figure 3.1.

There are 3 fault cases to be considered. In Case 1, a fault has occurred at the switching section S3. Both 'in line' reclosers and the Zone Substation CB#1 detect the fault but only the downstream recloser, R2, should trip to de-energise the faulty feeder section as it is adjacent to the faulty section. The aim is to leave customers, fed off switching sections S1 and S2, on supply. To prevent the upstream recloser, R1, and the Zone Substation CB#1 from tripping, a blocking signal is sent by the downstream recloser, R2, to the upstream recloser, R1. Recloser R1, in turn, passes this blocking signal over to the Zone Substation CB#1. The normally open switch at the end of the feeder needs to remain open to have the faulty feeder section isolated until the feeder's faulty infrastructure is repaired.

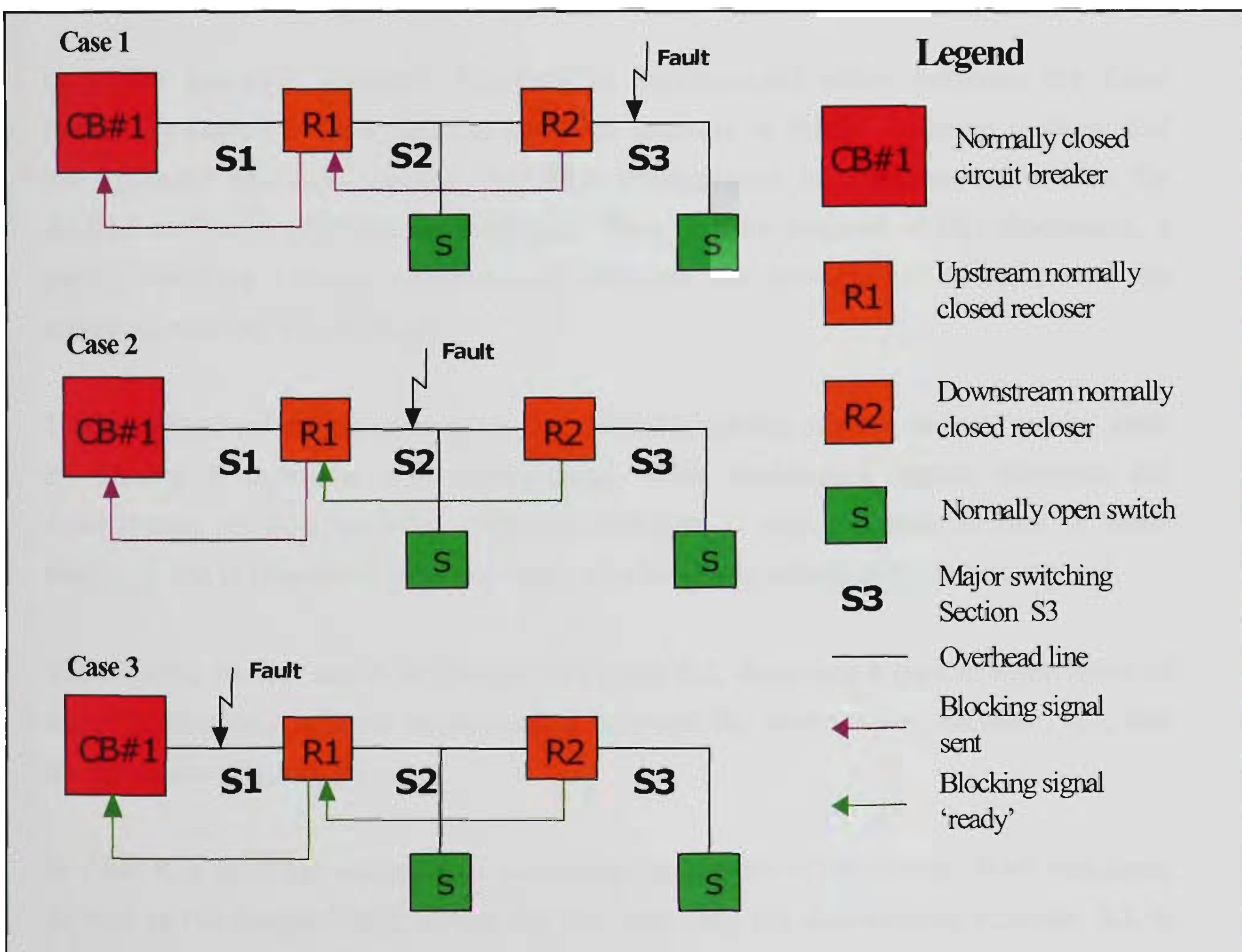


Figure 3.1 Standard application of a full blocking scheme

In Case 2, a fault has occurred at the switching section S2. Both the upstream recloser, R1, and the Zone Substation CB#1 detect the fault but only the upstream recloser, R1, should trip as it is adjacent to the faulty section. To prevent the Zone

Substation CB#1 from tripping, a blocking signal is sent, by the upstream recloser, R1, to the Zone Substation CB#1 indicating that the fault has been detected by R1 and R1 will trip. In this way, switching section S1 is saved from being off supply and switching section S3 can be backfed once R2 has been opened to isolate the faulty switching section S2.

In Case 3, the switching section S1 is subjected to a fault. However, no blocking is required as only the Zone Substation CB#1 detects the fault and it is meant to trip. Thus, the full blocking scheme is in 'ready' state although all three switching sections are off supply. Switching sections S2 and S3 can be backfed once R1 has been opened to isolate the faulty switching section S1.

3.5 Partial blocking scheme – principle of operation

In partial blocking schemes, blocking is implemented either between the Zone Substation circuit breaker and the upstream recloser or the downstream recloser and the upstream recloser. Usually the latter arrangement is implemented due to the desired cost savings in communications. Thus, for the purpose of this discussion, a partial blocking scheme implemented between the downstream recloser and the upstream recloser is considered.

Under normal operating conditions, the partial blocking scheme is in a 'ready' state by having 8 mirrored bits 'circulating', with unchanged status, between the downstream recloser and the upstream recloser. A status change in one or more mirrored bits is interpreted as the receipt of a blocking signal at the receiving end.

Three cases, № 4, 5 and 6, are shown in Figure 3.2, depicting a typical application of a partial blocking scheme implemented between the downstream recloser, R2, and the upstream recloser R1.

In Case 4, a fault has occurred in switching section S3 of the feeder. Both reclosers, as well as the feeder CB#2, detect the fault but only the downstream recloser, R2, is permitted to trip as it is adjacent to the faulty switching section S3. To prevent the upstream recloser, R1, from tripping, a blocking signal is sent by the downstream recloser, R2, indicating that it has detected the fault and it will trip. The feeder CB#2 at the Zone Substation should not trip, despite of detecting the fault current and not being blocked, because protection discrimination between the feeder CB#2 and both of the 'in line' reclosers has been ensured and reflected by the respective protection settings.

In Case 5, a fault has occurred in switching section S2. Both, the upstream recloser, R1, and the Zone Substation CB#2 detect the fault but only the upstream recloser, R1, should trip as it is adjacent to the faulty switching section S2. Again, the feeder CB#2 at the Zone Substation should not trip, despite of the detected fault current and not being blocked, because protection discrimination between the feeder CB#2 and both of the 'in line' reclosers has been ensured by the application of appropriate protection settings. The partial blocking scheme remains in the 'ready' state until a fault happens in the switching section S3.

In Case 6, a fault has occurred in switching section S1. The Zone Substation CB#2 detects the fault and it should trip, in accordance with the protection discrimination implemented in the feeder CB#2 protection setting file, as it is adjacent to the faulty switching section S1. The partial blocking scheme remains in the 'ready' state until a fault happens in the switching section S3.

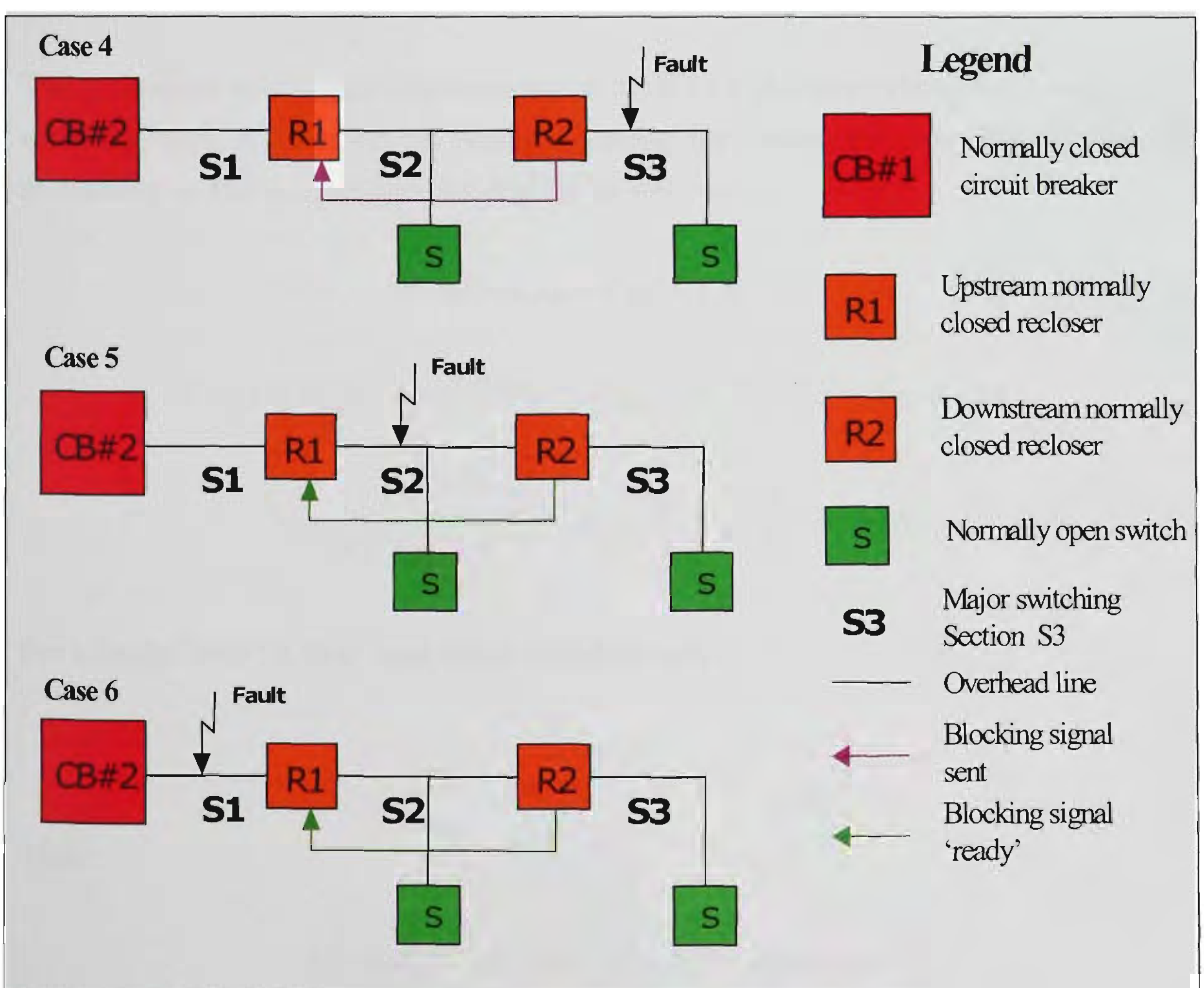


Figure 3.2 Standard application of a partial blocking scheme

3.6 Full blocking scheme versus Reliability of Supply

The impact of a full blocking scheme on the Reliability of Supply indices can be explained with the help of three basic fault scenarios, presented by 'Fault A', 'Fault B' and 'Fault C' in Figure 3.3, Figure 3.4 and Figure 3.5 respectively. The scenarios rely on an assumption that the capacity of Zone Substation Y is sufficient to take over the load of two feeder sections that normally are fed from Zone Substation X. However, under normal operating environment, the load transfer practice is governed by the feeder switching policy.

In particular, the improvement in the SAIFI index has been considered in these examples: SAIFI being a measure of the average number of times that the average customer experienced a sustained interruption to supply. The improvement in the SAIFI index is understood as the savings achieved in comparison with the feeders employing two 'in line' fault break reclosers in place of two 'in line' load break switches. With only load break switches employed, the whole feeder would have to experience an interruption to supply due to the circuit breaker fault clearing at the Zone Substation end whenever 'Fault A', 'Fault B' or 'Fault C' occurred.

The theoretical percentage improvement in SAIFI for the three above fault scenarios, assuming even distribution of customers along the feeder and even distribution of probability of faults, is derived by Agility as follows:

$$C = C_{FA} + C_{FB} + C_{FC}$$

$$C = p(S3)\, C_{S3} + p(S2)\, (C_{S3} + C_{S2}) + p(S1)\, (C_{S3} + C_{S2} + C_{S1})$$

$$C = \frac{1}{3}\left(\frac{N}{3}\right) + \frac{1}{3}\left(\frac{2N}{3}\right) + \frac{1}{3}\left(\frac{3N}{3}\right) = \frac{2N}{3} \approx 0.67N$$

For a feeder with 'in line' load break switches only:

$$C = N$$

Thus:

$N - 0.67N = 0.33N$, i.e. 33% improvement where:

C is the total number of customers affected by the fault(s) on a feeder with two 'in line' fault break reclosers deployed

C_{FA}, C_{FB} and C_{FC} are the customers affected by 'Fault A', 'Fault B' and 'Fault C'

$p(S3)$, $p(S2)$ and $p(S1)$ are the probabilities of faults happening in section S3, S2 and S1 respectively, i.e. assumed to be $\frac{1}{3}$ for each

N is the total number of customers on a feeder

C_{S3}, C_{S2} and C_{S1} represent the number of customers fed by sections S3, S2 and S1 respectively, i.e. assumed to be $\frac{N}{3}$ for each

The discussions regarding the three fault scenarios are presented below.

'Fault A' scenario, presented in Figure 3.3, illustrates that customers on two thirds of the feeder can be saved from an interruption to supply if a blocking scheme is implemented between reclosers $R2_X$ and $R1_X$ as well as the CB at Zone Substation X. This would be reflected in an improvement in SAIFI. Under this scenario, reclosers $R1_X$, $R2_X$ and the Zone Substation circuit breaker all detect the fault current but only recloser $R2_X$ opens, blocking recloser $R1_X$ and the Zone Substation circuit breaker from operation.

As a result the feeder section $S3_X$, between recloser $R2_X$ and the normally open high voltage switch, is isolated as depicted by their open status in green colour. The impact of this fault is localised within $S3_X$ feeder section. Overall, two feeder sections are not affected by the fault and one section is permanently affected. An improvement in CAIDI will also be achieved because the location of the fault has been narrowed to one feeder section and a result a smaller number of customers were taken off supply.

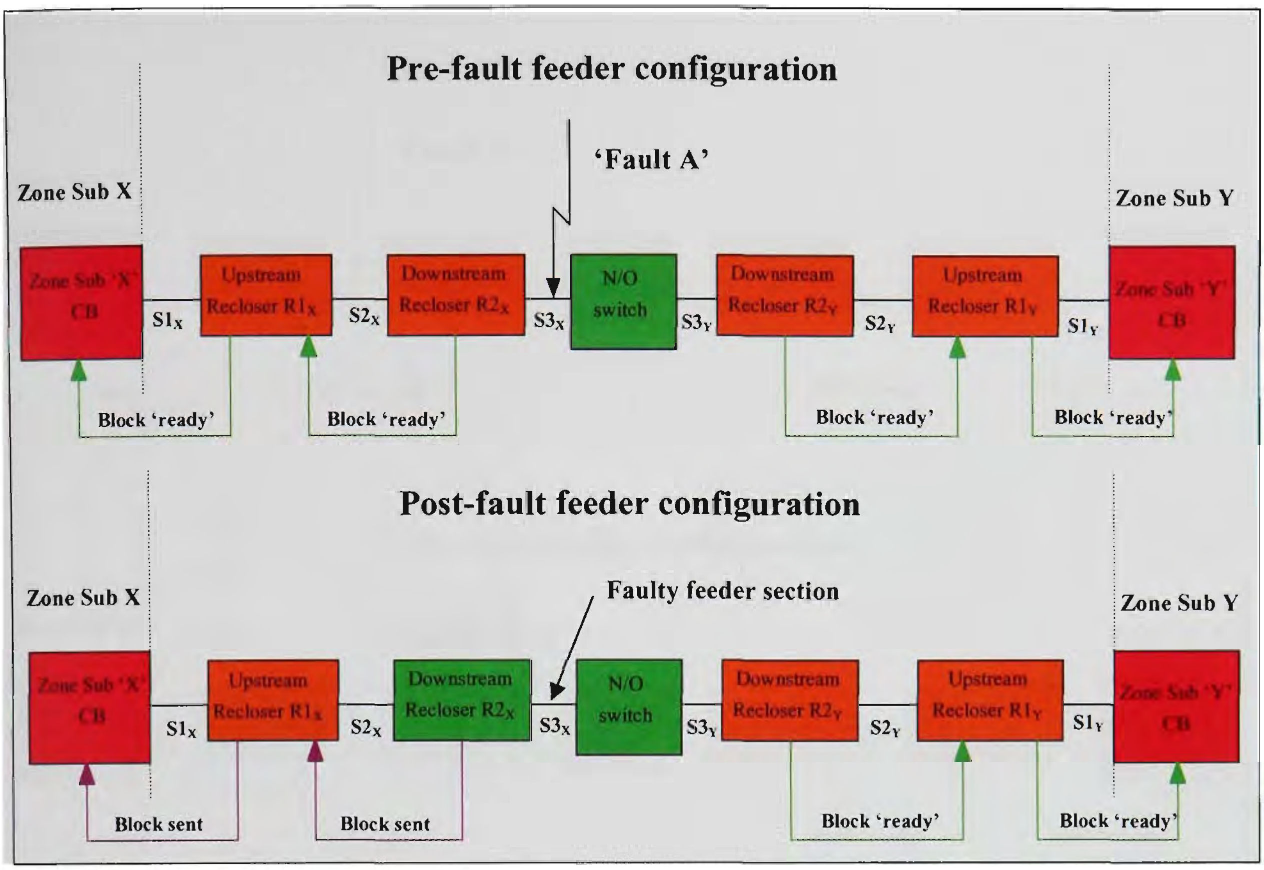


Figure 3.3 Fault 'A' scenario - saving $S1_X$ and $S2_X$ switching sections from the impact of a permanent fault in $S3_X$

'Fault B' scenario, presented in Figure 3.4, illustrates that customers on one third of a feeder, i.e. section $S1_X$, do not experience the interruption to supply. This is due to the blocking scheme implemented between recloser $R1_X$ and the CB at Zone Substation X. The fault is localised in section $S2_X$ after recloser $R2_X$ is opened via remote control. Customers on the feeder section $S3_X$ do experience an interruption to supply. However, it is as short as the time required to close the otherwise normally open switch to backfeed section $S3_X$ from Zone Substation Y.

The overall improvement in SAIFI is less significant than in the 'Fault A' scenario as more customers experience the interruption to supply. CAIDI performance however, is further improved by virtue of the fact that although more customers are impacted by the fault, because supply is restored quickly, the CAIDI measure for the overall network is improved. In 'Fault B' scenario one feeder section, $S1_X$, is not affected by the fault, one feeder section, $S3_X$, is temporarily affected and one feeder section, $S2_X$, is permanently affected.

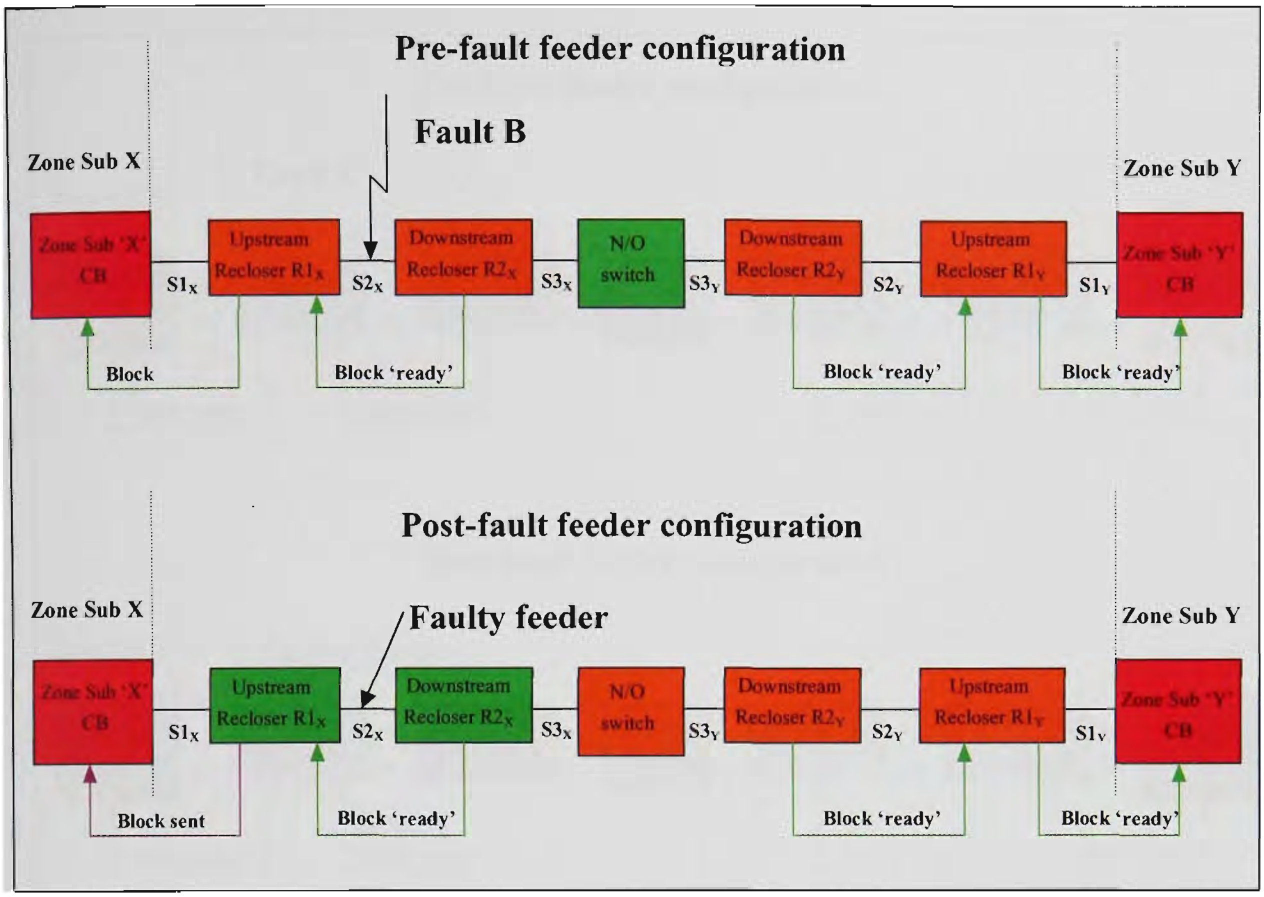


Figure 3.4 'Fault B' scenario - saving $S1_X$ switching section from the impact of a permanent fault in $S2_X$ followed by the restoration of supply to $S3_X$

'Fault C' scenario, presented in Figure 3.5, illustrates that customers on all three feeder sections are affected by the feeder fault. This is because the fault is cleared by the Zone Substation X circuit CB. Once recloser $R1_X$ is opened via remote control, the fault is localised in section $S1_X$. Following the fault containment, feeder sections $S2_X$ and $S3_X$ are backfed from the Zone substation Y by closing the otherwise normally open switch.

There is no improvement in SAIFI as all feeder sections experience the interruption to supply. CAIDI performance is even better than in the 'Fault B' scenario because more customers have their supply restored quickly following the fault.

Overall, two feeder sections, $S2_X$ and $S3_X$, are temporarily affected by the fault and one section, $S1_X$, is permanently affected.

It is evident that the availability of fast and reliable communications links servicing protection signalling is a basic prerequisite for the implementation of blocking schemes.

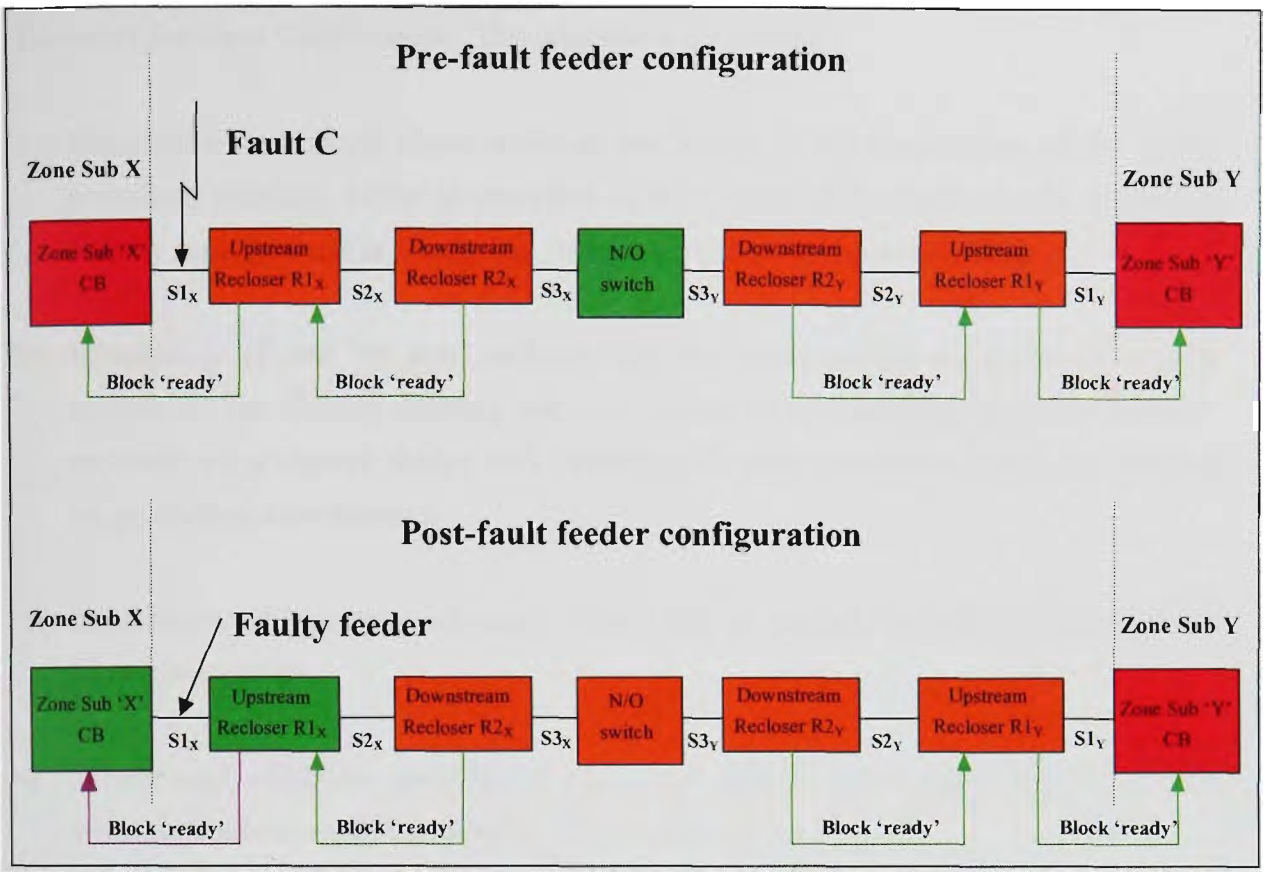


Figure 3.5 'Fault C' scenario - restoration of $S2_X$ and $S3_X$ switching sections

3.7 Adopted solution and the implementation plan

As a result of the feasibility study and the following recommendation, AGLE adopted the indirect fault detection and location scheme as a basic innovative unit for implementation on AGLE's urban distribution network. The implementation of the scheme was incorporated as an integral part of the program aimed to improve the Reliability of Supply indices for AGLE's urban distribution feeders at affordable cost.

Typically, the adopted scheme comprises two 'in line' reclosers installed on a feeder backbone dividing the feeder load into three equal load sections. The reclosers' positions reflect the major switching sections' boundaries. The need for blocking schemes, either full or partial, is mandated by the difficulties of protection coordination experienced on urban distribution feeders that are short and heavily loaded.

Due to the scalable nature of the indirect fault detection and location scheme, a staged implementation approach was adopted to reap most of the benefits at the early implementation stages to meet the Reliability of Supply requirements imposed by the Essential Services Commission. The adopted stages were :

1. Installation of a stand alone recloser per feeder at the boundaries of the major switching sections, either at one third or two thirds of the feeder loads, operating only in pure protection mode, i.e. relying on protection coordination.

2. Installation of two 'in line' recloser sets per feeder either by adding a second recloser to the already existing one on a feeder or by installing two new 'in line' reclosers on a chosen feeder still operating in pure protection mode, i.e. relying on protection coordination.

3. Installation of blocking schemes, either full or partial, on selected feeders via fibre optic cables.

4. Where cost effective, installation of remote control and monitoring via guided communications media preferably fibre optic cables.

5. Installation of AGLE owned radio network covering whole of the AGLE coverage area for the purpose of remote control and monitoring of pole top devices including reclosers.

6. Implementation of the DNP3 protocol, at the SCADA host located in the Control Centre in the Central Business District of Melbourne, for remote control and monitoring of reclosers.

CHAPTER 4

COMMUNICATION SOLUTION

4.1 Introduction

To fulfil their role dictated by fault location schemes, reclosers need to operate in two modes. Firstly, in a recloser specific mode, when recloser operation is governed by the events on a feeder resulting in actions triggered by recloser protection relays. Secondly, reclosers need to be capable of operating in a remote control and monitoring mode when standard network re-configuration needs to be carried out. Consequently, there are two aspects of recloser communications, i.e. recloser protection signalling, characterised by response times in the order of milliseconds, and communications facilitating remote control and monitoring/remote event records retrieval with response time measured in seconds. Both of these communication types are of paramount importance in the area of Distribution Feeder Automation involving reclosers as a rule. However, the requirements for the performance standards for these communication types are significantly different. Due to the high speed and reliability, required by protection applications, the choice of a suitable communications medium is quite often limited to fibre optics. In urban areas, the implementation of communication solutions based on fibre optics can be difficult logistically. Also, it is not cost effective when implemented for recloser needs only.

On the other hand, the performance standards for communications, facilitating remote control and monitoring on reclosers, are more relaxed in comparison with those of protection signalling. Response times in the order of 1 second are quite acceptable when specific control functions are considered. Diagnostic functions, such as retrievals of event log files or oscillographic disturbance records can take up to a few minutes.

Overall, specific communication solutions can only address specific communication applications. As a result, two distinct communication approaches need to be adopted when considering communications with reclosers, i.e. guided communications predominantly for protection signalling and radio communications for remote control and monitoring / remote event records retrieval, when the implementation of guided communications is not justifiable. In cases where guided communication is available, joint implementation of both protection signalling and communication for remote control and monitoring / remote event records retrieval is the obvious solution.

4.2 Recloser communication considerations and requirements definition

In line with protection relay technology developments, modern recloser protection relays incorporate basic communication functions within the relay [68]. This approach leaves the internal process control with the relay's Central Processing Unit (CPU). Due to the stringent processing time constraints, measured in cycles referenced to the frequency of supply, it is crucial for the CPU to give the first priority to processes catering for protection functions.

Out of the four distinct CPU process categories, i.e. protection parameter calculations, protection signalling, communications covering remote control and monitoring as well as remote event records retrieval, the latter two have the low priority so that the relay's CPU does not get overburdened with non-protection tasks at protection critical times. Interfacing with the outside world is usually implemented via a number of serial communication ports. Protection signalling is implemented over dedicated ports. Theoretically, this approach eliminates the need for external Remote Terminal Units (RTUs) implying cost savings.

In practice, however, there is still a need for a communication platform, between field devices and the operational centre, to transport existing/legacy protocols [69]. This communication platform needs to be sufficiently flexible to accommodate the introduction of newer relay types equipped to run with higher communication speeds. Network diagnostics and network re-configuration are the basic features expected from such a platform. Consequently, the installation of additional communications hardware is required in the recloser controller to fulfil the communication needs of modern remote control and monitoring as well as remote event records retrieval. Only a uniform approach to network communications, such as the extension of Ethernet based communications to field devices including reclosers, can address the aforementioned requirements. A prerequisite for that is the implementation of Ethernet based communications on recloser protection relays, i.e. Ethernet cards, a task the manufacturers of recloser protection relays have not widely embraced yet.

Ethernet based communication is not the only solution available for communications with reclosers. However, it is a solution that has the potential to simplify existing network complexities arising from a wide variety of legacy communication protocols used by existing field devices. Due to the high bandwidth requirement of Ethernet based communications, only fibre optic and spread spectrum radio solutions could be considered.

With all the aforementioned considerations in mind, and the outcomes of the communications market research, carried out worldwide, the following general recloser communication functions were stipulated for implementation:

- Remote control and monitoring using protocol such as DNP3.
- Remote retrieval of event reports using SEL ASCII protocol.
- Protection grade communication interface for blocking schemes.

4.2.1 Ethernet radio considerations

When fibre optic communications is not available at a recloser location, then the only plausible solution available for the Ethernet based communications is the spread spectrum radio. Its practical applications are restricted to remote control and monitoring as well as remote event reports retrieval. Ethernet spread spectrum radio can be used for protection applications under special circumstances. In general, however, protection signalling over the spread spectrum radio, does not offer the reliability required by protection applications. In urban areas, the ultra high frequency (UHF) signal penetration is often unequally distributed, as the 'line of sight' cannot always be guaranteed due to tall buildings etc, thus obstructing signal paths and resulting in inadequate radio signal strength at recloser locations. When fibre optic communication is not available the coordination of protection systems on reclosers has to rely on current and time discrimination.

4.2.2 The benefits of recloser remote control and monitoring

The primary benefit of remote control and monitoring on reclosers is network switching, whether under fault conditions or during planned network re-configuration, commanded from the operational centre. Reliable status and alarm monitoring allows for informed decision making under any circumstance. Remotely controlled and monitored reclosers also increase the degree of knowledge about network parameters along the feeders. They allow for pro-active as well as reactive remedial actions to be taken by a Distribution Network owner. A feature enabling pro-active action is sensitive earth fault (SEF) monitoring. In this application, increasing SEF current levels, compared with the bench-marked SEF current levels, can be met with remedial action before reaching the pre-set trip level. A typical example is when a tree grows into power lines and the resultant intermittent current leakage raises an SEF alarm.

The tree branches can be cleared well before the SEF trip level is reached, averting customer outages and reducing the risk of fire. Reclose operations and post fault network switching are examples of reactive remedial actions.

Without remote control and monitoring on reclosers the only option for the distribution network owner is to rely on time consuming reactive remedial actions. A typical example is a feeder recloser that tripped and went to lockout due to a fault that took place at night. Because of light feeder loading at night, the recloser trip may go unnoticed by the operational centre staff until notified by irate customer(s). This notification may come hours after the fault occurrence.

4.2.3 The benefits of remote event reports retrieval

The post fault analyses require reliable remote event log file downloads. Retrieving event reports may use manufacturer specific protocols for each recloser relay type. When the number of reclosers on the network is significant and when they are spread over a large area, efficient downloading, file storage and subsequent access for analysis purposes becomes a complicated and costly exercise. The issue is exacerbated if legacy protocols are involved. For this reason the implementation of an Ethernet based communication solution, capable of providing a transportation platform for serial protocols and widely accepted by the communications industry, has been of significant importance for the network owner as it could bring benefits in terms of reduced maintenance costs.

4.2.4 Requirements for protection grade communication facilitating blocking schemes

To devise a communication solution for reclosers supporting blocking schemes, a number of requirements had to be considered. The general requirements were:

- The ability to support protocols for protection applications.
- The communications medium had to be secure and reliable.
- The communications solution itself had to be affordable.

The literature review and feasibility study, undertaken as part of this thesis, identified the existence of one readily available protection grade protocol, i.e. SEL Mirrored Bits protocol, suitable for applications on blocking schemes. Due to the fact that the protocol was proprietary, its application on the SEL351 relay family was implied. There were two SEL recloser relays identified as available for blocking scheme applications, i.e. SEL351P and SEL351R. Both were equipped with the Mirrored Bits protocol interface. In addition, another relay belonging to the SEL351 relay family, i.e. SEL351S equipped with Mirrored Bits protocol interface, was also identified as readily available for blocking scheme applications at the Zone Substation end.

For security and reliability reasons the communication medium for the Mirrored Bits communication application was restricted, by the AGLE protection practice guidelines, to fibre optic cables.

The need for a cost effective communications solution implied selective applications of blocking schemes in areas where fibre optic cables were already present or where the application of blocking schemes, and the required installation of fibre optic cables, could be justified as absolutely necessary.

4.3 Recloser communication platform selection

As the hybrid radio – fibre optic communication solution was imposed by economic considerations, it was necessary to devise a solution that would encapsulate all the protocols, supported by the recloser relay of choice, within a single protocol. This approach ensured consistency across the network and simplified integration into other systems. One protocol suite that allowed this functionality is TCP/IP. An Ethernet based TCP/IP solution also has the following advantages:

- It is competitively priced due to the widespread use of Ethernet and its availability.

- It is non proprietary as there are a large number of vendors manufacturing Ethernet compatible products. This feature negates the risks associated with a single supplier and licensing.

- It is a perfect solution for networks that demand scalability as Ethernet is designed for expansion.

- It is easy to use due to its 'Plug and Play' design philosophy.

- It is versatile to accommodate Transmission Control Protocol (TCP) and User Datagram Protocol (UDP) across radio and fibre optic networks. It also permits the use of Simple Network Management Protocol (SNMP) and Simple Time Protocol (STP) allowing remote management and diagnosis of the network.

The commonality across both radio and fibre optic network is the use of terminal servers, over an Ethernet IP based network, which act as Ethernet to serial / serial to Ethernet communication converters.

As a result, Ethernet based TCP/IP communication solution suite was chosen for reclosers as the AGLE standard. Consequently, all the subsequent investigations were focused on the particular Ethernet based TCP/IP solutions.

The application of the Ethernet spread spectrum radio solution, with its requirement for the 'line of sight' to ensure reliable transmission, implied the need for the establishment of a network of spread spectrum radio base stations to provide radio signal coverage throughout the AGLE area. The resulting cost implications had to be accounted for in the overall AGLE communications policy and the Power System Communications Network Asset Management Plan.

4.3.1 Testing of communication technologies

To accommodate typical utility needs, the fibre optic and radio media were investigated for their possible application in communications with reclosers. The basis for the solution was the use of terminal servers on an Ethernet IP based network. Both radio and fibre optic approaches were tested for their suitability to provide reliable and secure:

- Remote control and monitoring using the DNP3 protocol.
- Remote retrieval of event reports using the SEL ASCII protocol.
- Blocking between reclosers and/or between Zone Substation circuit breaker and recloser(s) using the SEL Mirrored Bits protocol.

The radio chosen for this application was MDS iNET900 spread spectrum Ethernet radio with the inbuilt terminal server. The fibre optic solution employed, required an Ethernet switch with two fibre ports and a separate terminal server with two RS232 communications ports. All terminal servers had both TCP and UDP capabilities.

4.3.2 Testing of the DNP3 and ASCII over Ethernet radio

Three MDS iNET900 spread spectrum Ethernet radios were tested in configuration depicted in Figure 4.1. One radio, an Access Point equipped with an omnidirectional antenna, was utilised as a master at the radio base station. Two dual remote radios, equipped with directional Yagi antennas and with two serial ports each, were utilised as slaves in the recloser controllers. The Access Point was connected to a PC running as an IOServer.

The PC was configured as a DNP3 master with each remote radio connected as a virtual COM port using the TCP based port redirector software which redirected the port specific applications transparently.

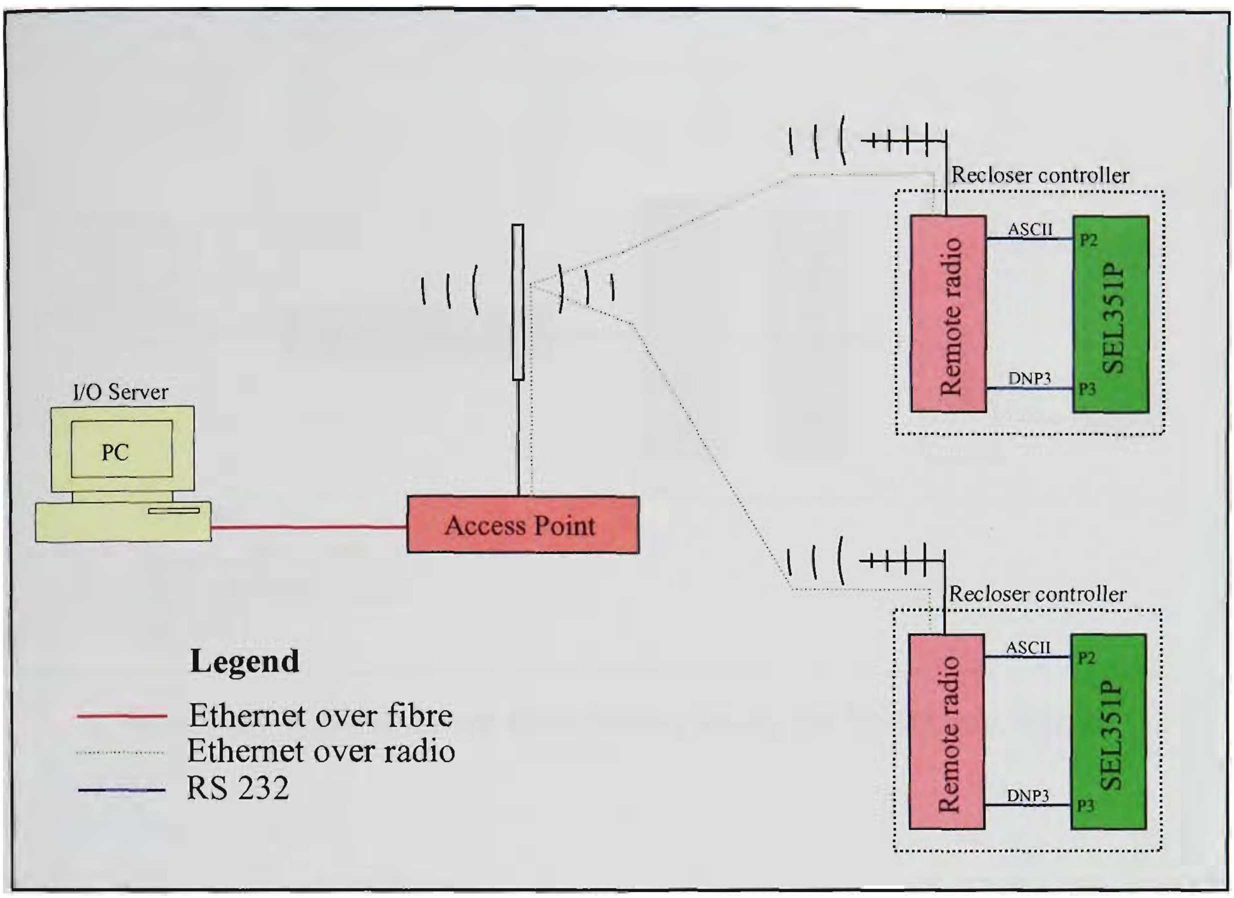


Figure 4.1 Ethernet radio testing set up for DNP3 and ASCII protocols

4.3.3 Testing of the DNP3 and ASCII over Ethernet on fibre

The general configuration for DNP3 and ASCII testing was as depicted in Figure 4.2. The recloser's SEL351P relay was connected to a PC via a terminal server, an Ethernet Switch and two media converters. The PC was configured as a DNP3 master running IOServer. Connection to the recloser was as virtual COM port using port redirector software.

The terminal server provided IP addressing capability, necessary when dealing with multiple recloser numbers, and Ethernet to serial / serial to Ethernet conversion. The Ethernet switch provided switching function based on the IP addressing system. Media converters served as interfaces between electrical and fibre optic media.

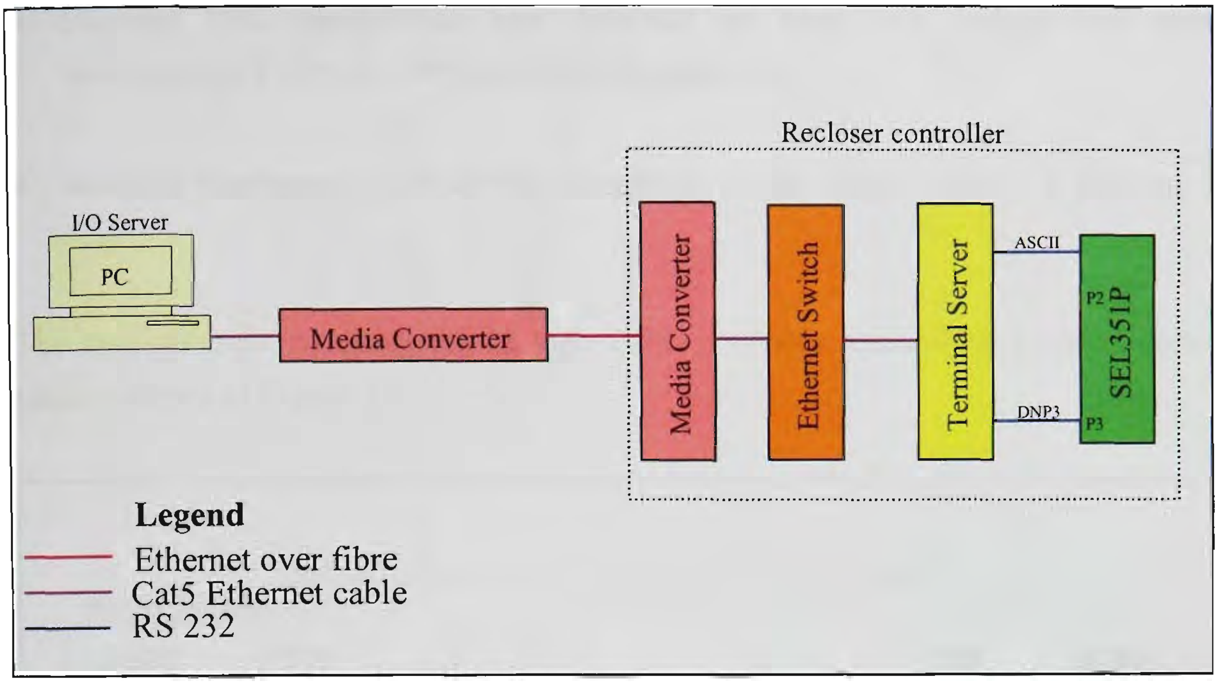


Figure 4.2 Ethernet over fibre testing set up for DNP3 and ASCII

4.3.4 Ethernet radio and Ethernet on fibre test results

The test results for both Ethernet radio and Ethernet on fibre proved that:

- Communications applied for the remote control and monitoring functions performed successfully up to a rate of 19.2 kbps using the DNP3 protocol.

- Communications applied for the retrieval of SEL351P relay event reports performed successfully up to a rate of 38.4 kbps using ASCII. The download time, for a standard size 15 cycle event report over radio, was 1 minute and 10 seconds. A local download, carried out directly at the SEL351P relay, took 1 minute and 40 seconds on the average.

4.3.5 Mirrored Bits Protocol testing

To investigate the achievable reliability levels for the required protection grade transmission of the Mirrored Bits Protocol, three distinctly different communication technologies were tested. They were:

- Mirrored Bits transmission over Ethernet radio, carried out only for comparison purposes

- Mirrored Bits transmission over Ethernet on fibre with independent tests involving the TCP and UDP transmission protocols.

- Mirrored Bits transmission directly over fibre, i.e. not using Ethernet technology.

The configuration covering the Mirrored Bits Protocol application over Ethernet radio is shown in Figure 4.3.

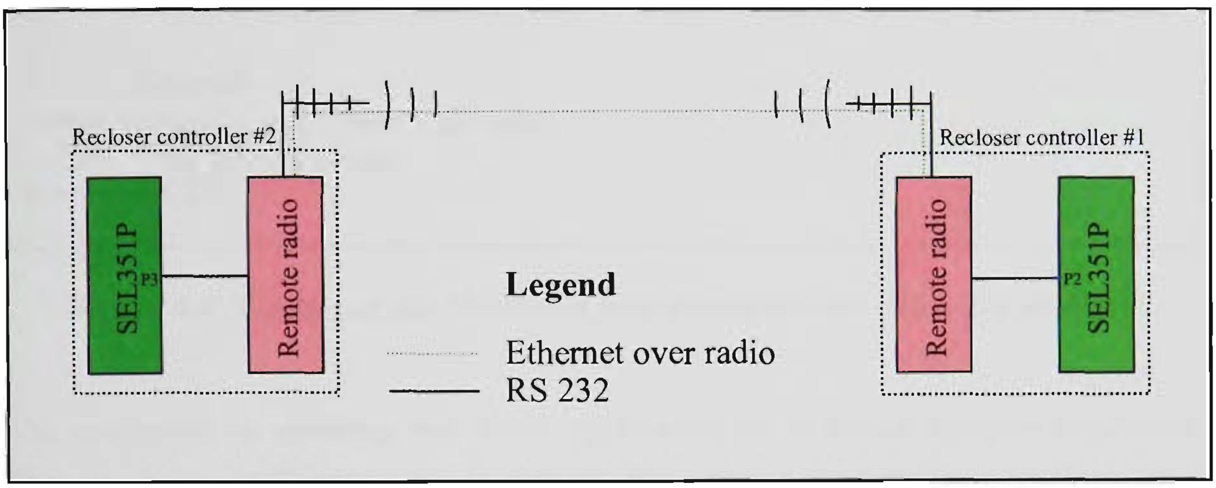


Figure 4.3 Testing of the Mirrored Bits Protocol over Ethernet radio

The testing was carried out on peer to peer basis, i.e. one remote radio communicating directly with another remote radio without the radio base station. The aim was to investigate the minimum signal return trip time without any repeating stages. Passing this testing stage could only warrant further testing involving radio base stations.

The configuration covering the Mirrored Bits Protocol application over Ethernet on fibre is shown in Figure 4.4. In this configuration Mirrored Bits Protocol over two transport protocols, TCP and UDP, was tested in two separate tests.

The Mirrored Bits Protocol testing over Ethernet on fibre had a very important implication regarding fibre utilisation planning as it was designed to show whether a single pair of fibres could be utilised for remote control and monitoring, event reports retrieval and Mirrored Bits communication for application on blocking schemes.

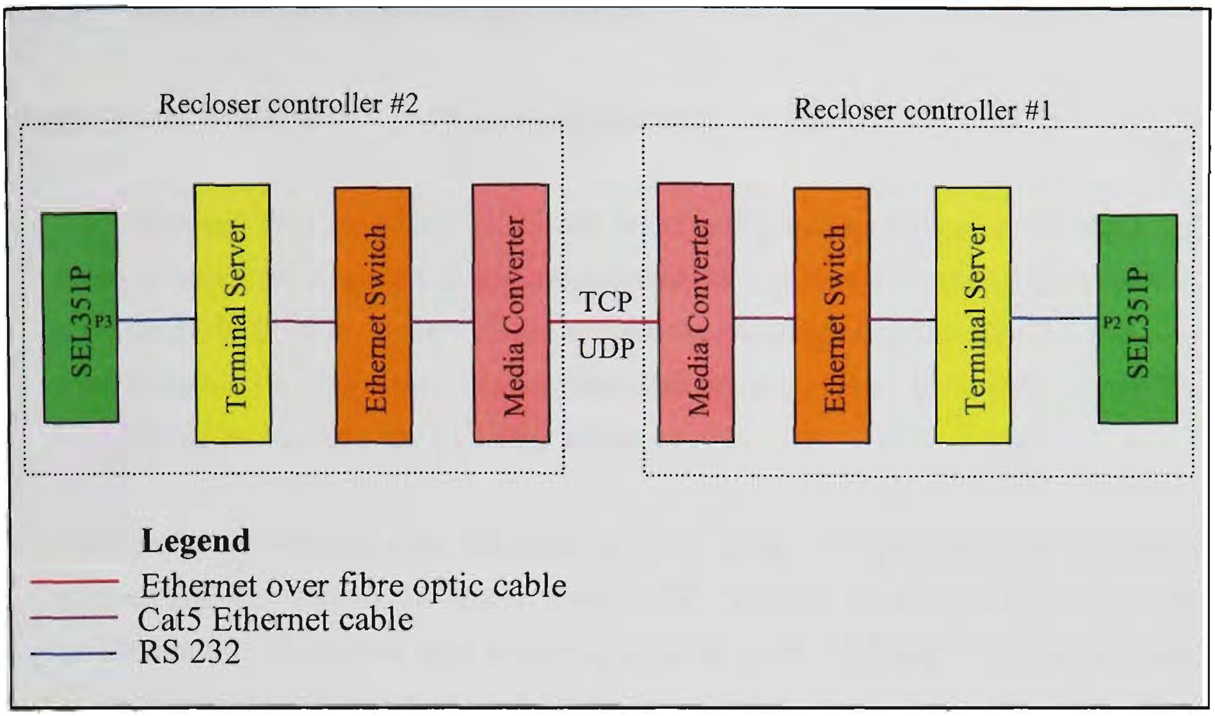


Figure 4.4 Testing of the Mirrored Bits Protocol over Ethernet on fibre

The configuration covering the direct application of Mirrored Bits Protocol over fibre, is shown in Figure 4.5. In this configuration a separate pair of fibres was allocated to be utilised only by blocking schemes. Remote control and monitoring as well as the event report retrievals required an additional pair of fibres in this approach.

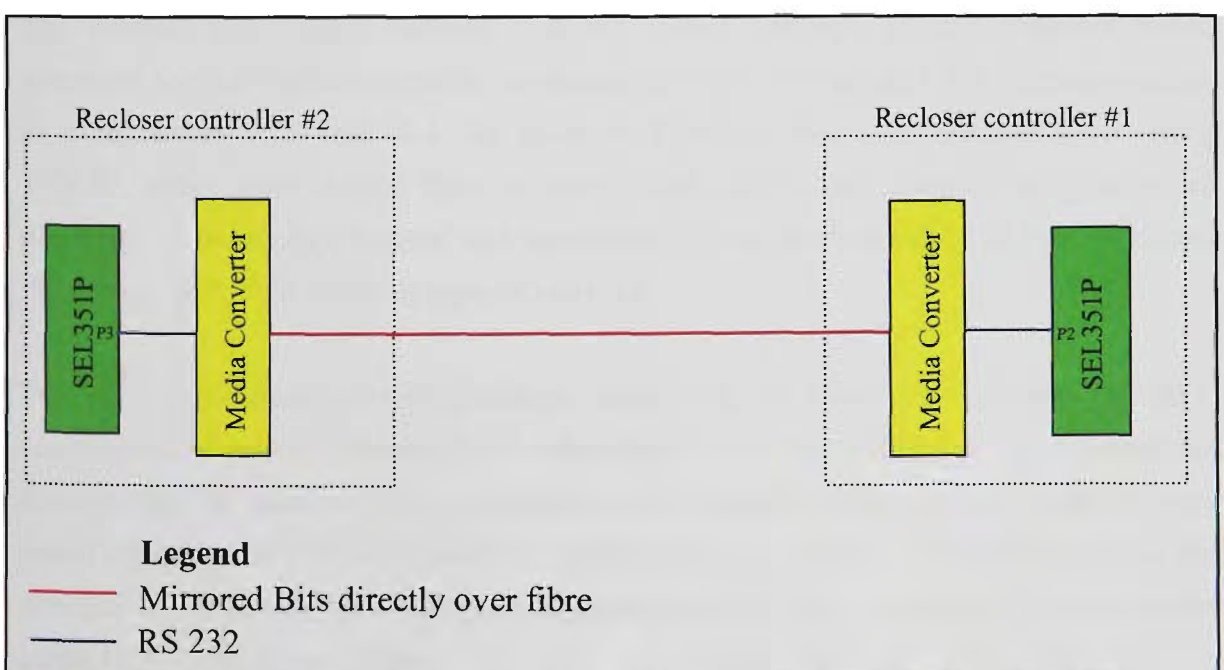


Figure 4.5 Testing of the Mirrored Bits Protocol directly over fibre

4.3.5.1 Mirrored Bits Protocol test results

The Mirrored Bits protocol test results proved that:

- The Mirrored Bits protocol could not be reliably transported over the Ethernet radio at any rate over 2.4 kbps irrespective of whether the transport protocols, such as TCP or UDP, were utilised or not. At these speeds, the signal return trip time between reclosers was greater than 300 ms and it was, therefore, deemed as too slow to be suitable for blocking schemes.

- Mirrored Bits protocol over Ethernet on fibre using TCP proved to be unreliable at rates above 2.4 kbps. However, using UDP, with its smaller packet overheads, reliable communications was achieved at rates up to 19.2 kbps. UDP was found to be unreliable at the rate of 38.4 kbps.

- Mirrored Bits protocol directly over fibre was limited only by the speed of the RS232 port interface, i.e. 34.8 kbps. Using this configuration not a single error was detected during continuous testing over a period of 6 days.

4.3.6 Communications testing summary and developed design criteria

The overall test results verified that the initial concept, to use Ethernet based solutions for the recloser specific communications, was suitable for implementation as summarised in Table 4-1. In essence, Ethernet based communications using TCP/IP, either over shared fibre or radio, was proven and adopted as a universal platform for the remote control and monitoring of reclosers using DNP3 protocol and the remote SEL ASCII event reports retrieval.

For protection grade communications, applicable to blocking schemes, the SEL Mirrored Bits protocol transmission directly over dedicated fibres, i.e. without the involvement of Ethernet, was adopted as the standard. This design philosophy was based on the good protection practice guidelines, enforced by AGLE, in spite of the acceptable performance of the Mirrored Bits protocol when transmitted over Ethernet using UDP over shared fibres.

Table 4-1 Suitability of the tested solutions for recloser communications

Communications solution	Spread Spectrum Radio	Fibre
DNP3 for Remote Control & Monitoring over Ethernet	Yes	Yes
SEL ASCII for event report retrieval over Ethernet	Yes	Yes
Mirrored Bits over TCP over Ethernet	No	No
Mirrored Bits over UDP over Ethernet	No	Yes
Mirrored Bits without Ethernet and any transport protocol	No	Yes

Due to the testing outcomes and AGLE good protection practice guidelines the following design criteria were developed for recloser specific communications:

1. For recloser locations with economically justified access to fibre optic cables:

   - DNP3 communications for the remote control and monitoring of reclosers should be implemented over Ethernet on shared fibre pairs.

   - SEL ASCII communications for the event report retrieval applications should be implemented over Ethernet on shared fibre pairs.

   - The SEL Mirrored Bits protocol, if required for blocking scheme applications, should be implemented directly, i.e. no Ethernet involved, over the dedicated to blocking schemes only, fibre pairs.

2. For recloser locations where access to fibre optic cables cannot be economically justified, in general, and the implementation of blocking schemes along the whole feeders is not regarded as essential:

   - DNP3 communications for the remote control and monitoring of reclosers should be implemented over Ethernet spread spectrum radio.

   - SEL ASCII communications for the event report retrieval applications should be implemented over Ethernet spread spectrum radio.

- The SEL Mirrored Bits protocol, for blocking scheme applications, should not be implemented.

3. For recloser locations where access to fibre optic cables cannot be economically justified, in general, and the implementation of partial blocking schemes, at the downstream feeder sections, is regarded as essential on protection grounds:

   - DNP3 communications for the remote control and monitoring of reclosers should be implemented over Ethernet spread spectrum radio.

   - SEL ASCII communications for the event report retrieval applications should be implemented over Ethernet spread spectrum radio.

   - The fibre optic cables will be installed between the downstream and upstream reclosers. The SEL Mirrored Bits protocol, for blocking scheme applications, should be implemented directly, i.e. no Ethernet involved, over the dedicated to blocking schemes only, fibre pairs.

4. For recloser locations where access to fibre optic cables cannot be economically justified, in general, and the implementation of partial blocking schemes, at the upstream feeder sections, is regarded as essential on protection grounds:

   - The fibre optic cables should be installed between the upstream reclosers and Zone Substation CBs. DNP3 communications for the remote control and monitoring of the upstream reclosers should be implemented over Ethernet on shared fibre pairs. DNP3 communications for the remote control and monitoring of the downstream reclosers should be implemented over Ethernet spread spectrum radio.

   - SEL ASCII communications for the event report retrievals from the upstream reclosers should be implemented over Ethernet on shared fibre pairs. SEL ASCII communications for the event report retrievals from the downstream reclosers should be implemented over Ethernet spread spectrum radio.

- The SEL Mirrored Bits protocol, for blocking scheme applications, should be implemented directly, i.e. no Ethernet involved, over the dedicated to blocking schemes only fibre pairs.

Another design criterion, adopted for recloser communications over fibre optic cables, is the redundant loop topology applied for the DNP3 based remote control and monitoring as well as the SEL ASCII based event reports retrieval. Under normal operating conditions, one of the ports at the Ethernet switch will be in blocking mode as shown in Figure 4.6. In this configuration, the loop is effectively a 'bus' beginning at the non-blocking port and finishing at the blocking port.

If a break occurs in the recloser communications loop, the Ethernet switch will unblock the formerly blocking port, thus re-establishing contact with all the reclosers. Under this situation, the reclosers adjacent to the faulty fibre section will go to a loopback configuration and the original redundant fibre loop will be effectively split into two 'buses' as shown in Figure 4.7.

When the faulty fibre section is repaired and communication is restored, one of the ports will return to the blocking mode and the system will go back to the normal configuration as shown in Figure 4.6.

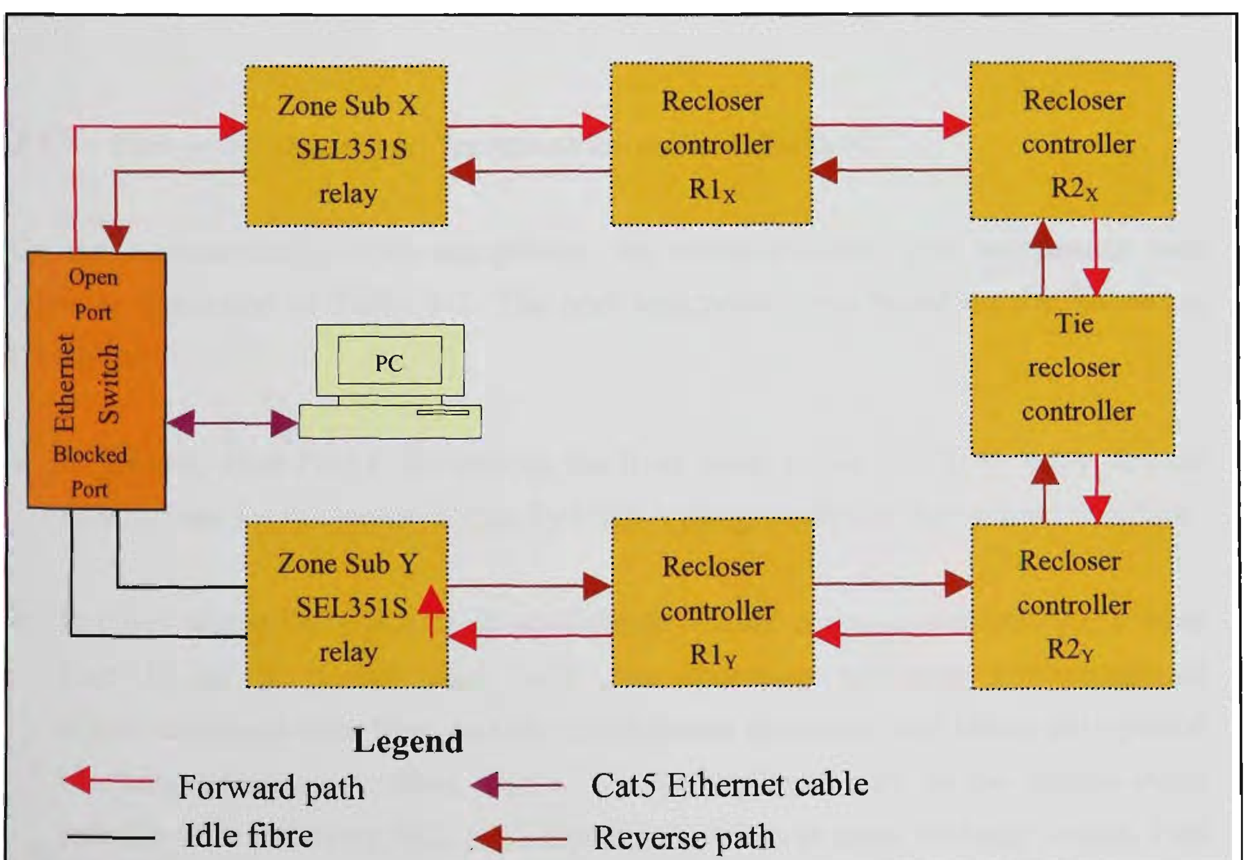


Figure 4.6 Recloser communications loop in normal configuration

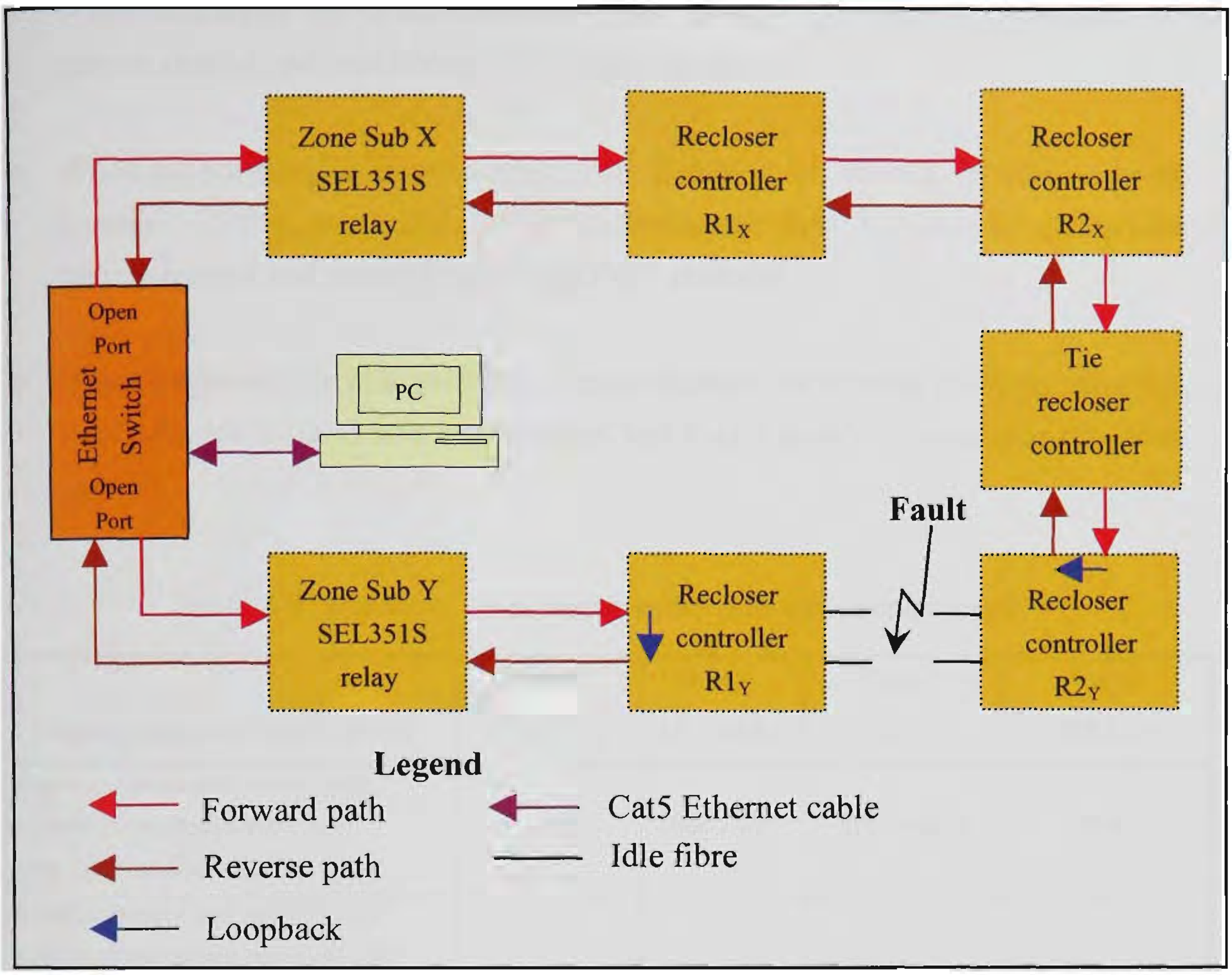


Figure 4.7 Recloser communications loop in loopback configuration

4.3.7 Port assignments and transmission rates definition

On the communication tests completion, the communication port assignment was made as illustrated in Table 4-2. The port assignment was based on the following principles:

- In general, front Port F, located on the front panel of the SEL351P relay, should be allocated for the laptop access by High Voltage testers at the recloser location.

- In cases where there is a need to facilitate remote communications by the front Port F, as it is the case with the upstream reclosers facilitating all communications over fibre and the downstream reclosers facilitating only partial blocking schemes over fibre, Port F is to be employed only for the remote event records retrieval, using SEL ASCII protocol. When in need for local access, Port F should be used, permitting the interruption of the remote event records retrieval as this is the least significant interruption to recloser remote communications.

- When employed for communications over fibre, Port 1 should be utilised for remote control and monitoring using DNP3 protocol.

- When no blocking is implemented, Port 2 should be utilised for remote event records retrieval, using SEL ASCII protocol, and Port 3 should be utilised for remote control and monitoring using DNP3 protocol.

- When employed for Mirrored Bits communication, facilitating blocking schemes, Port 2 should be used as a sending port and Port 3 should be used as a receiving port.

Table 4-2 Recloser relay communication port assignments

Communication application	Port F (RS232)	Port 1 (RS485)	Port 2 (RS232)	Port 3 (RS232)
Remote control and monitoring, remote event record retrieval over radio or fibre. No blocking.	Local	Not used	SEL ASCII	DNP3
Remote control and monitoring, remote event record retrieval and blocking schemes over fibre only. Downstream recloser application. Partial or full blocking scheme.	Local	DNP3	Mirrored Bits MB8A[1]	SEL ASCII
Remote control and monitoring, remote event record retrieval and blocking schemes over fibre only. Upstream recloser application. Partial blocking scheme.	Local	DNP3	Mirrored Bits MB8B[2]	SEL ASCII
Remote control and monitoring, remote event record retrieval and blocking schemes over fibre only. Upstream recloser application. Full blocking scheme only.	SEL ASCII	DNP3	Mirrored Bits MB8B[2]	Mirrored Bits MB8A[1]
Remote control and monitoring and remote event record retrieval over radio. Partial blocking schemes on fibre. Downstream recloser applications.	SEL ASCII	Not used	Mirrored Bits MB8A[1]	DNP3

[1] Channel A [2] Channel B

As an outcome of the communication tests, the following communication channel specifications were defined for the SEL ASCII, DNP3 and Mirrored Bits protocol transmissions:

- SEL ASCII: 38,400 bps, 8 data bits, no parity, 1 stop bit.
- DNP3: 19,200 bps, 8 data bits, no parity, 1 stop bit.
- MB8A, i.e. the communication Channel A between the downstream and upstream reclosers: 19,200 bps.
- MB8B, i.e. the communication Channel B between the upstream recloser and the Zone Substation CB: 19,200 bps.

4.4 Recloser controller with full blocking

The maximum benefits can be achieved when the 'in line' reclosers are equipped with remote control and monitoring as well as protection signalling implemented for blocking purposes over fibre optic cables. Depending on the specific feeder requirements, protection signalling can be implemented as a partial blocking scheme or as a full blocking scheme.

For demonstration purposes, the explanation of the full blocking scheme operation, installed on the upstream recloser, is most appropriate. This is because the communication hardware and software configuration of the upstream recloser, i.e. $R1_X$, is most elaborate as it encompasses two combined partial blocking schemes.

To illustrate the complexity involved, the full blocking scheme communication hardware and the Ethernet based communication hardware, utilised for the remote control and monitoring as well as for the remote event reports retrieval, is shown in Figure 4.8. In essence, the Ethernet based communication covering remote control and monitoring as well as remote event records retrieval are implemented over a self-healing fibre optic loop comprising two fibres. This fibre optic loop begins and ends at the Ethernet switch at Zone Substation X, which is part of the inter-Zone Substation Wide Area Network (WAN). The WAN facilitates communications with the operational centre. Along this fibre optic loop, recloser $R1_X$, recloser $R2_X$, remotely controlled switch, recloser $R2_Y$, recloser $R1_Y$ and Zone Substation Y are connected as per Figure 4.6. If need be, other devices may be connected anywhere on the loop. The fibre optic cable path, providing the forward link between Zone Substation X and Zone Substation Y via $R1_X$, $R2_X$, tie recloser controller, $R2_Y$ and $R1_Y$, is physically diverse from the fibre optic cable path, providing the reverse link between Zone Substation Y and Zone Substation X, to ensure self-healing capability over the entire loop.

Under normal circumstances, the incoming data arrives at the recloser $R1_x$ controller via the forward fibre connected to the receiving terminal of the optical/electrical media converter M1. Then, the data is passed onto the local Ethernet switch where it gets switched according to its encoded address. Data destined for recloser $R2_X$, remotely controlled switch, recloser $R2_Y$, recloser $R1_Y$ and Zone Substation Y is forwarded through the transmitting terminal of M1. Data destined for recloser $R1_X$ is passed to the Internet Protocol (IP) addressable terminal server from where it is communicated serially to the appropriate relay port.

There are two relay communication ports assigned for non-protection duties. Port, P1, is for remote control and monitoring using DNP3 protocol. The other port, FP, facilitates the remote event reports retrieval using the relay manufacturer's specific SEL ASCII protocol.

In the event of a fibre optic cable break-down between Zone Substation X and recloser $R1_X$, both the forward and reverse fibre optic cable paths are used to maintain communications. Under this scenario, the incoming data arrives at the recloser $R1_X$ controller via the fibre connected to the receiving terminal of the optical/electrical media converter M2. The data is then passed onto the local Ethernet switch where it gets switched according to its encoded address. The data destined for the recloser $R1_X$ is passed onto the terminal server from where it is communicated serially to the appropriate relay port. The data, not destined for the recloser $R1_X$, is passed on via the fibre connected to the transmitting terminal of the optical/electrical media converter M2.

Two partial blocking schemes are implemented through the dedicated optical/electrical media converters M3 and M4. The M3 converter facilitates circuit breaker blocking and the M4 converter receives blocking signals from the downstream recloser. These blocking schemes utilise Schweitzer philosophy and techniques developed specifically for protection applications [70-73].

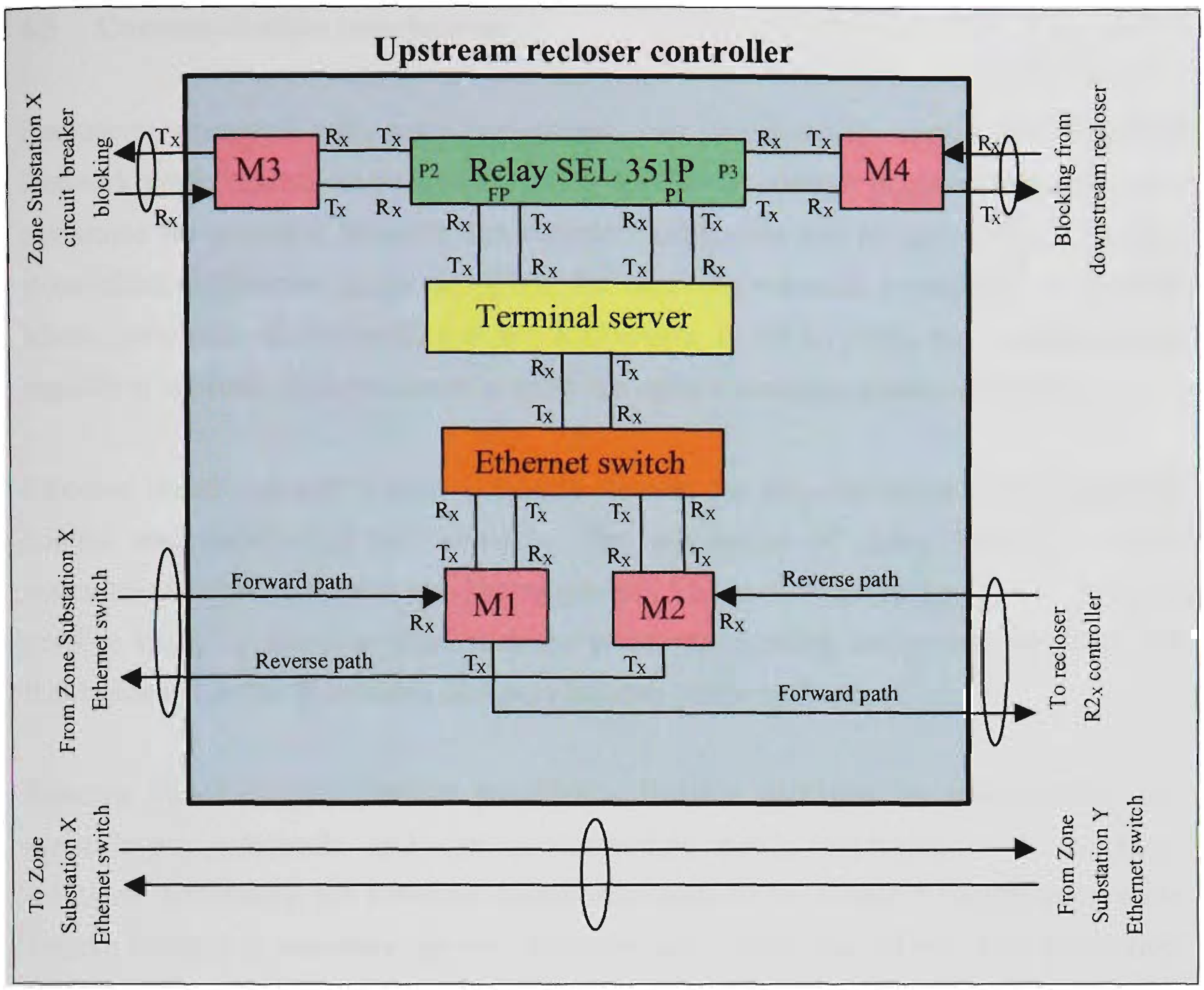


Figure 4.8 Upstream recloser controller communications hardware

The communication hardware components used for the above upstream recloser controller are:

- M1, M2, M3 and M4 single mode optical/electrical media converters, OSD 139 AML

- Terminal server MOXA NPort 5210 or 5230 when used with RS485 communications port for DNP3 applications

- Ethernet switch SIXNET ET-GT-5ES-5SC

The communications hardware of recloser $R1_X$, depicted in Figure 4.8, can be easily modified for radio remote control and monitoring as well as remote record file retrieval needs. An MDS iNet900 Ethernet spread spectrum radio, with two RS232 ports, could be connected directly to the recloser relay offering instant Ethernet capabilities.

4.5 Communication conclusions

Reclosers, equipped with communications, can significantly improve Distribution Network performance, in particular, when applied to combat unplanned outages. To maximise the potential benefits that reclosers offer, fast and reliable communication is essential. Protection grade signalling for blocking schemes is required on feeders where protection discrimination is not achievable. In urban areas, modern protection signalling is practically restricted to the fibre optic communications solution.

Ethernet based communication is highly desired for the implementation of remote control and monitoring on reclosers. The advantage of using Ethernet is that communication with the devices is transparent. The user does not know, and does not need to know, if the connected recloser is communicating via a radio or fibre. All that is needed is the IP address and port number of the recloser.

Ethernet based communication provides a flexible platform for transportation of some legacy protocols and can accommodate newly emerging communication solutions. Extending the Ethernet communications to the Control Centre allows the System Control to remotely operate reclosers, i.e. 'open' and 'close', turn protection 'on' and 'off' and check load information. Current readings from reclosers could be used to improve the accuracy of the Distribution Management System (DMS). Connectivity into the corporate LAN is also possible, allowing the authorised parties to access information from the reclosers. In addition, the communications self-monitoring system can be implemented by the introduction of the Ethernet based network management solution such as the Simple Network Management Protocol.

The implementation of the Ethernet based communications at field devices not having access to optical fibres is still a challenge. Spread spectrum radio offers these field devices access to Ethernet based communications albeit only for remote control and monitoring as well as remote event reports retrieval. As the Ethernet based spread spectrum radio provides limited signal coverage, a network of local base stations is necessary.

As a result of the carried out feasibility study and the subsequent testing of the preselected Ethernet based communication solutions, a hybrid, Ethernet based, recloser specific communication solution has been designed, tested and successfully accredited for a large scale implementation on AGLE distribution network.

This design is based on the premise that in recloser locations where fibre optic cables are available, all recloser communications, not related to blocking schemes, will be implemented over Ethernet on fibre. Separate fibres will be allocated to protection grade communications, implemented for blocking schemes directly over fibre, as per AGLE protection practice guidelines in force.

In recloser locations devoid of fibre optic cables, the recloser specific communications will be implemented over Ethernet radio excluding protection grade communications for blocking schemes. Should there be a need for blocking schemes in these recloser locations, fibre optic cables will be installed there to facilitate, most likely, only partial blocking schemes, subject to AGLE justification processes.

CHAPTER 5

IMPLEMENTATION STAGE

5.1 Introduction

Following the completion of the initial research stage of the project and the subsequent acceptance of the indirect fault detection and location scheme as the preferred solution, the overall project direction was set. However, the ongoing research continued throughout the doctoral work covering the implementation stages of the project and bringing about continuous technical and procedural enhancements.

To continue with the project, AGLE provided the financial support, whereas Agility assured the provision of the required manpower, hardware/software, test equipment and facilities for the testing as well as the necessary procedural support for the 'on line' implementation of the indirect fault detection and location schemes.

5.2 Recloser specifications and vendor selection

In 1999, extensive feasibility study and market research was carried out, by the author of this thesis, to assess and select recloser hardware and software available on the market at the time. This study defined the selection criteria for the reclosers planned for the implementation on AGLE distribution network. The most desired general technical specifications for the prospective reclosers to have were defined as:

1. Fault break current not smaller than 12kA.

2. Operating voltage 22kV to cover both 22kV and 11kV distribution feeders.

3. Lightning impulse withstand not smaller than 150kV.

4. Current making and breaking by vacuum interrupters with a magnetic actuator.

5. No sulphur hexafluoride (SF6) gas used for insulation purposes.

6. Semiconductor based current transformer (CT) open circuit protection.

7. Hardware and software supporting reliable communications over protection grade protocol(s) such as, SEL Mirrored Bits Protocol or similar, to facilitate the implementation of blocking schemes.

8. Communications supporting Distributed Network Protocol (DNP3) to facilitate remote control and monitoring.

9. Ability to remotely install and modify protection settings.

10. Compatibility with the existing AGLE protection platform.

11. Support for hardware and software available in Australia.

As a result of the market research, carried out worldwide, it became evident that there was only one recloser vendor, offering 'off the shelf' recloser products, which could meet most of the desired recloser's technical specifications. This was Hawker & Siddeley Switchgear Pty Ltd and specifically its subsidiary company Whipp & Bourne based in Manchester, England. The selected recloser was GVR27. Its technical specifications are enclosed in Appendix 'F'.

The most decisive factor in the selection of the GVR27 recloser for AGLE distribution network was the Schweitzer 351P relay, incorporated within the GVR27 recloser unit, and its capability to support blocking schemes by utilising the SEL Mirrored Bits Protocol.

Although, the GVR recloser did not conform to AGLE's stipulation referring to the non-utilisation of the SF6 gas, this departure from the initial technical specifications was accepted because, at the time, there was no recloser brand available on the market that could meet the 150kV lightning impulse withstand stipulation. Another accepted non-conformance point, was a lack of the semiconductor based CT open circuit protection. These two shortcomings became a subject to further research continuing on recloser hardware and software while installing the first reclosers under a pilot program.

In 2000, the author of this thesis, inspected Whipp & Bourne manufacturing plant in Rochdale, England and witnessed the type testing of the modifications introduced on the GVR27 recloser by AGLE. These modifications encompassed the installation of interposing CTs in the recloser tank, as a temporary measure, to address the non-conformance of the CT open circuit protection. Subsequent to this work an alliance agreement was signed between Hawker & Siddeley Pty Ltd, the mother company of Whipp & Bourne, and AGLE. Thus, the path for a long-term cooperation was established and the GVR27 recloser became the workhorse unit for AGLE's future automation program. In 2005, as a result of this cooperation, the semiconductor based CT open circuit protection was introduced on GVR27 reclosers.

The GVR27 recloser's typical installation is shown in Figure 5.1.

Figure 5.1 GVR27 recloser switch unit and the recloser controller

5.3 Protection philosophy for full blocking schemes on AGLE's network

As the 'in line' reclosers and blocking schemes had not been installed on AGLE distribution networks so far, there was a need for a set of standards and procedures pertaining specifically to the novel introduction of reclosers in urban areas, characterised by more stringent safety measures. The development of these standards was gradual and influenced mainly by the performance analysis carried out on the reclosers installed under the pilot program.

During the AGLE Protection Forum, held on 6 October 2003, covering 'Hazard and operability study on recloser and circuit breaker blocking schemes', the following guidelines were adopted as AGLE's standard for the design and implementation of blocking schemes on AGLE's urban distribution network. These guidelines stated that:

1. Blocking will be applied for any phase or ground time overcurrent element.

2. No blocking shall be sent from the downstream recloser to the upstream recloser or the circuit breaker for Sensitive Earth Faults (SEF). In all situations time grading for SEF will be used in lieu of blocking schemes. The SEF elements shall be independent and non-blocked.

3. A non-blocked, slower and independent backup overcurrent element (51P2T) shall be used at the Zone Substation circuit breaker (CB). This will be slower than the normal Zone Substation CB protection but will be faster than the backup Zone Substation bus protection.

4. At the Zone Substation CB, the fast instantaneous overcurrent and the SEF elements shall be independent and non-blocked.

5. For any feeder re-configuration, protection and blocking shall be disabled.

6. Three setting groups shall be utilised at each protection device:

    - Main Settings (Group 1) – for protection with blocking.

    - Alternate Settings (Group 2) – for protection without blocking (slower than Group 1).

- Live Line Sequence Settings (Group 3) – fast protection with no blocking.

7. When Live Line Sequence (Group 3) is invoked, no blocking signals shall be sent from or acted upon at that protection device.

8. Alternate Settings (Group 2) shall be used when the blocking scheme is out of service. These settings will provide discrimination but will be slower to clear faults.

9. Automatic change-over between protection setting groups, i.e. Group 1, Group 2 and Group 3, shall be disallowed.

10. Multiple faults shall be cleared safely and reliably although they may be slightly slower to clear with the blocking scheme in place. An assessment will be carried out as experience is gained.

11. Testing shall replicate the operation of the full blocking scheme. In house testing shall be done with a dummy CB and two recloser simulators first. In-field testing shall involve real Zone Substation circuit breaker and two recloser simulators. Both tests shall use secondary injections and simulate:

    - Sensitive earth faults (SEFs).

    - Phase to phase faults.

    - Phase to ground faults.

    - Three phase to ground faults.

    - Simultaneous multiple faults.

12. Protection setting philosophy shall be given with the setting files in plain English.

In addition, two further enhancements, reflecting safety features developed during the 'in house' testing, were also incorporated into AGL protection standards. They stipulate that:

13. The ‘in line’ reclosers shall have recloser breaker failure timers incorporated in their protection logic design to prevent the possibility of blocking signal transmission to continue for more than 200ms, in case of the recloser circuit breakers failure to clear the fault within the specified time.

14. Zone Substation circuit breakers and upstream reclosers, i.e. devices capable of receiving blocking signals, shall have communications drop out timers incorporated in their protection logic design to overcome the effect of the momentary, i.e. <40ms, loss of communication signalling.

These guidelines were introduced to reflect AGLE’s switching philosophy, operational needs, priorities and Health and Safety practices. They are subject to regular reviews by AGLE’s Protection Forums to ensure that all emerging developments in the applications of the ‘in line’ reclosers are taken into account by protection standards.

5.4 Logic design implementation for the blocking schemes

The core feature of the indirect fault detection and location scheme is the full blocking scheme or its truncated version, the partial blocking scheme. As the full blocking scheme encompasses all operational aspects of the partial blocking scheme, then the detailed logic design of the full blocking scheme only is discussed below.

Both full and partial blocking schemes rely heavily on reliable, protection grade communications implemented over fibre optic cables. As faults have to be cleared as quickly as possible, the communication between the protection devices needs to be fast. This was achieved by using Schweitzer’s proprietary Mirrored Bits protocol available on the reclosers’ SEL351P relays and on the Zone Substation circuit breaker’s SEL351S relay. The protocol exchanges the state of eight bits between two devices in a minimal time. Two separate Mirrored Bit channels were established. Channel MB8A was established between the upstream and downstream reclosers. Channel MB8B was established between the upstream recloser and the Zone Substation circuit breaker. The configuration is shown in Figure 5.2.

For the downstream recloser to indicate to the upstream recloser that it has detected a fault, one of the Mirrored Bits in channel MB8A is set and sent to the upstream recloser. The upstream recloser in turn sends the signal to the Zone Substation circuit breaker via channel MB8B. Similarly, for the upstream recloser to indicate to the Zone Substation circuit breaker that it has detected a fault, one of the Mirrored Bits in channel MB8B is set and sent to the Zone Substation circuit breaker.

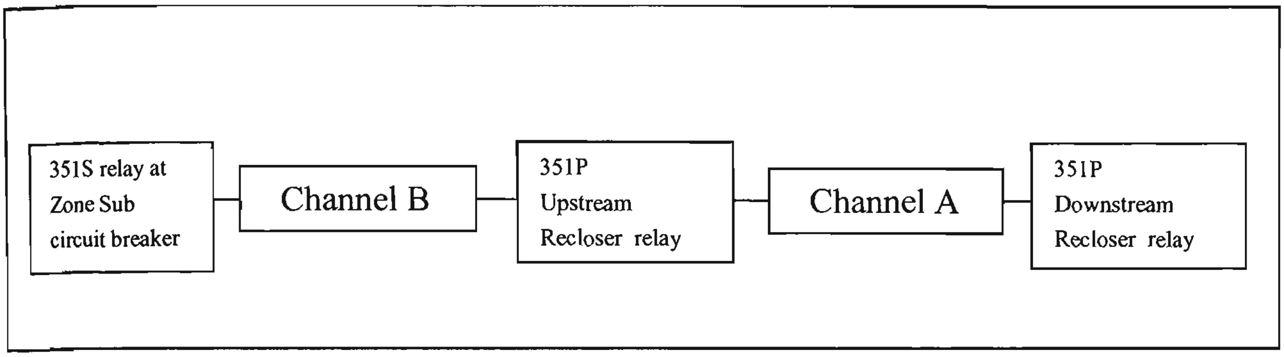


Figure 5.2 Mirrored Bits channels

Each blocking signal is characterised by two Mirrored Bits variables to reflect transmitted and received states. For a blocking signal between the downstream recloser and the upstream recloser, i.e. over Channel A, variables TMB1A and RMB1A were used. For a blocking signal between the upstream recloser and the Zone Substation circuit breaker, i.e. over Channel B, TMB1B and RMB1B were used. Mirrored Bit '1' is set, for the above Mirrored Bits variables, when phase or ground overcurrent condition occurs and protection is enabled on the device.

Detection of either phase fault or ground fault or both is reflected by the asserted variable SV2. Receipt of a blocking signal is reflected by the asserted variable SV3. The S1 variable, when asserted, depicts the presence of either local or remote trip command. It is included in the detailed discussion below because it is an integral component of the TRIP variable although it does not participate in the generation of an automatic trip signal referred to as auto trip.

Drop out timers were implemented at each, the upstream recloser's relay, labelled as T4, and the Zone Substation circuit breaker's relay, labelled as T1. Pick up timers, both labelled as T3, were implemented on each, the downstream recloser and the upstream recloser.

Each blocking signal, sent over channels MB8A or MB8B, used a respective dropout timer output, SV3T, at its destination relay. The dropout timer setting, SV3DO, was set to 2 cycles, i.e. equivalent to 40ms in case of 50Hz supply. It allows for momentary loss of communications between protection relays and also ensures the upstream protection relay(s) has/have time to reset properly before the blocking signal is removed. The minimum and maximum reset times for the over-current elements vary by up the 0.6 cycles. The 2 cycle drop out delay was used to account for these discrepancies between the reset times of the protection relays as well as multiple momentary signal losses.

The pick up timer output, SV2T, was used to remove the blocking signal sent to the upstream recloser's relay and/or the Zone Substation circuit breaker's relay in the event of the downstream breaker failure to clear the fault within the specified time. The pickup timer setting, SV2PU, sets the amount of allowable time for the downstream recloser to trip before the blocking signal is removed in the event of breaker failure. Its value was set to 10 cycles which is equivalent to 200ms in case of 50Hz supply. When the downstream recloser or the upstream recloser attempts to trip for a time equal to or longer than 200ms but fails, then the pickup timer output SV2T gets asserted and the blocking signal is nullified by the inverse of SV2T, the variable !SV2T.

This operation is explained by the timing diagram in Figure 5.3 which illustrates the downstream circuit breaker failure. The blocking signal is received by the upstream recloser through RMB1A, while the Zone Substation circuit breaker receives the blocking signal through RMB1B. At both locations the blocking signal is assigned to variable SV3. Although both reclosers detect a fault condition (SV2), the upstream recloser will not trip until the received blocking signal expires due to the downstream recloser circuit breaker failure time out. A received blocking signal is also used to create an entry in the sequential event recorder.

The blocking signal variables, i.e. TMB1A, RMB1A, TMB1B and RMB1B were incorporated in the TRIP equations for Group 1 protection settings of each protection relay. As per AGLE protection guidelines, tripping on phase and ground faults is permitted only if a blocking signal has not been received and a fault has been detected. When this occurs, a blocking signal is sent to the upstream protection relay(s). If a fault occurs in the feeder section S3 the downstream recloser, the blocking signal is passed on to the Zone Substation circuit breaker's relay, from Mirrored Bits channel A to channel B.

The only exceptions from this logic are the instantaneous overcurrent element 67P1T and the time delayed back up element 51P2T, though still faster than the bus protection, which are not blocked at the Zone Substation circuit breaker's relay.

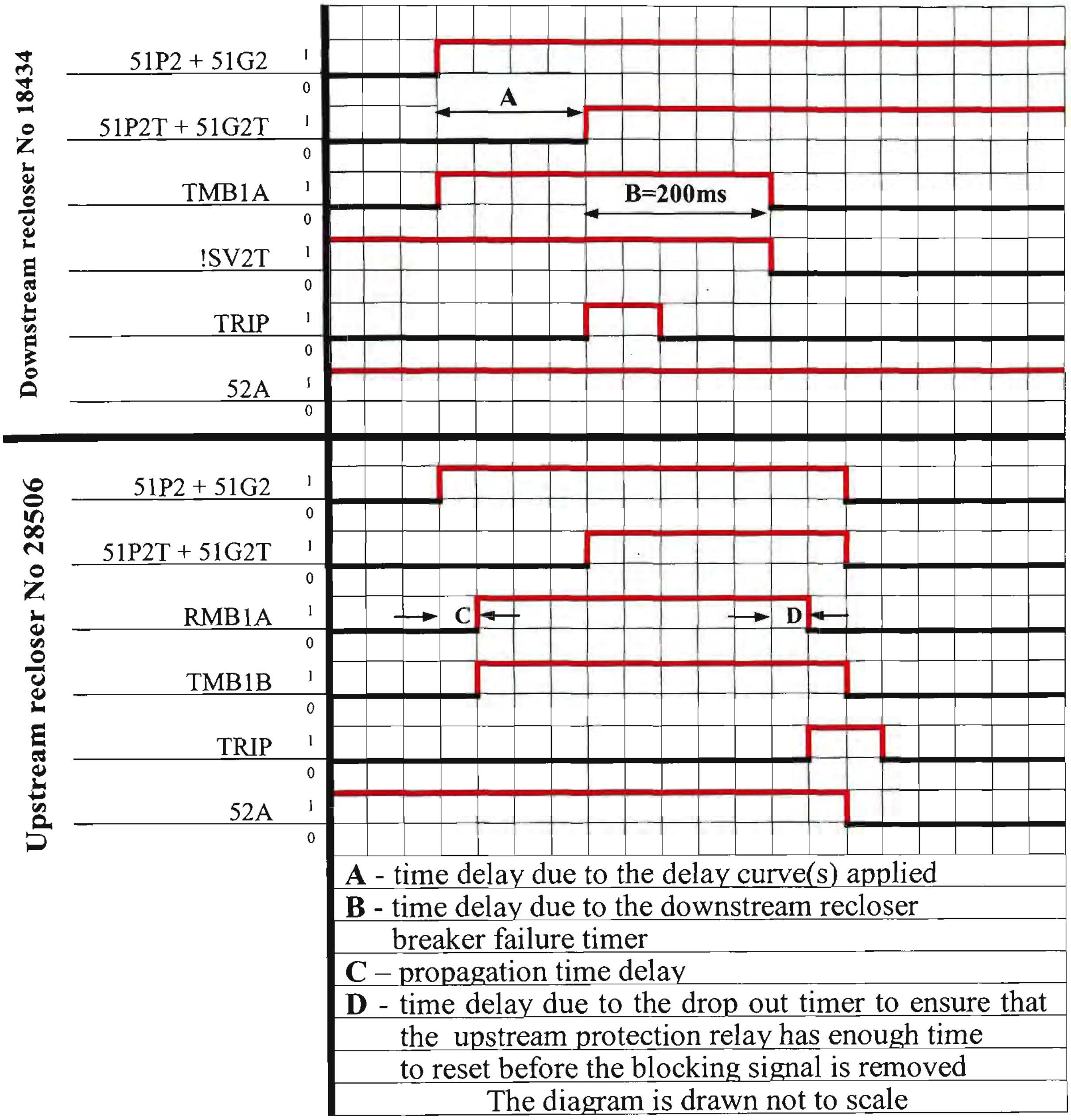


Figure 5.3 Timing diagram for R2 circuit breaker failure

The purpose of each protection input and output, relevant to blocking signals, at the downstream recloser, upstream recloser and Zone Substation circuit breaker is discussed in detail in the following sections. In a similar fashion, the RMB1A, RMB1B intputs and TMB1A and TMB1B outputs, reflecting blocking signals' operation, are discussed. The summary of equations defining the blocking schemes is listed in Table 5-1.

Table 5-1 Summary of equations defining blocking schemes

Equation function	Downstream recloser	Upstream recloser	Zone Substation circuit breaker
Remote or local TRIP	SV1=(PB9*!LT5)+(OC+/IN101)*LT5	SV1=(PB9*!LT5)+(OC+/IN101)*LT5	Not applicable. Done independently from the blocking schemes logic
Non blocked TRIP	SV2=51P2T+51G2T	Not applicable	Not applicable
Blocked TRIP	Not applicable. TRIP not blocked.	SV2=(51P2T+51G2T)* !SV3T	SV2=(51PT+51N1T)*!SV3T
Blocking sent	TMB1A=LT1*(51P2+51G2)* !SV2T	TMB1B=LT1*(51P2+51G2)*! SV2T+RMB1A	Not applicable
Blocking received	Not applicable	RMB1A=SV3	RMB1B=SV3
TRIP	TRIP=SV1+LT1*(SV2+67N3T)	TRIP=SV1+LT1* (SV2+67N3T)	TRIP=SV2+67P1T+67N1T+5 1P2T

5.5 Downstream recloser No 18434 – blocking and trip logic operation

The design principles covering the operation of block signalling and tripping, for the downstream recloser No 18434, are discussed below. The logic diagram, including the representative equations, is illustrated in Figure 5.4.

Blocking signalling, implemented at the downstream recloser, was designed to prevent the upstream recloser and the Zone Substation circuit breaker from tripping in the event of P/F and/or E/F occurring in section S3 of the distribution feeder. If unblocked, the upstream recloser and/or the Zone Substation circuit breaker could clear the detected fault(s) independently, as they simultaneously detect the same fault(s), causing an interruption to supply to more customers than absolutely necessary.

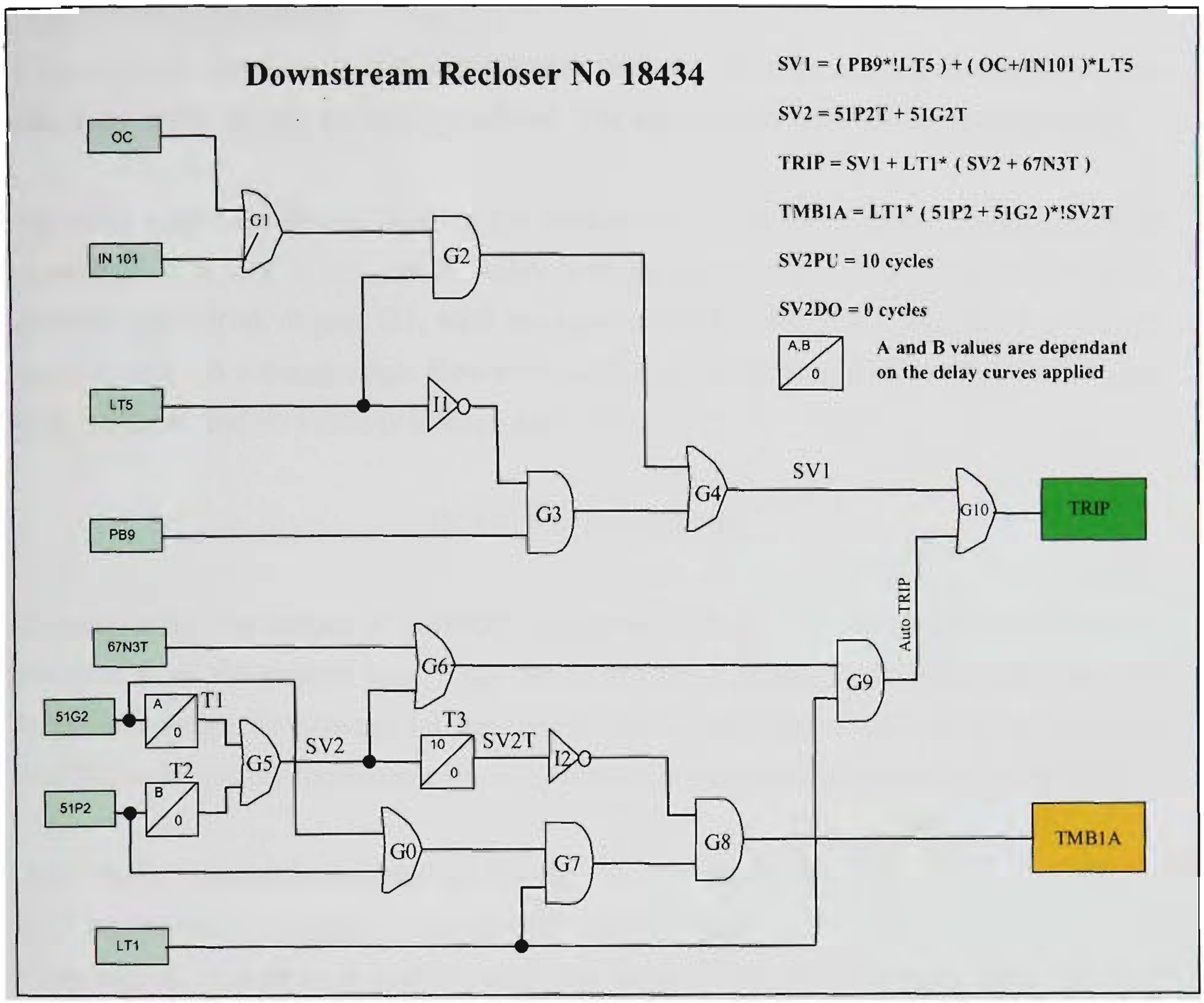


Figure 5.4 Downstream recloser's logic diagram for the TMB1A and TRIP condition

5.5.1 Control variable SV1

Task - To enable either local or remote trips.

Inputs - OC, open command used via serial port to remotely trip recloser's circuit breaker.

- IN 101, optoisolated input used to trip the recloser's circuit breaker from other devices such as mimic panels at Zone Substations.
- LT5, latch bit 5 enabling operations triggered by remote commands when asserted. It can be toggled from the control panel at the recloser.
- PB9, trip push button used for local recloser circuit breaker tripping when asserted.

Description of operation

When LT5 is asserted at the downstream recloser, the remote trip function for the remote, usually SCADA, host is enabled. The open command, OC, is implemented

via serial communications, linking the remote host with the recloser. When the open command is issued from the SCADA host at the control centre, the OC input is asserted and ORed, at gate G1, with the optoisolated input IN 101 designed to trigger gate G1 only on a rising edge. However, with the 'in field' reclosers the IN 101 input is not utilised and its value is always zero, i.e.

IN 101 = 0 (deasserted)

Consequently, the output of gate G1 is asserted only when open command has been received from the remote host. This output is then ANDed, at gate G2, with the LT5 to provide either the passage for the remote open command when remote operation is enabled or to nullify the remote open command when remote operation is disabled.

Also, the LT5 input is inverted, at inverter I1, and then ANDed, at gate G3, with the PB9 input used for local tripping. This logic excludes the possibility of a local trip when remote operation is enabled and vice versa. Then, the outputs of gates G2 and G3 are ORed, at gate G4, to allow either local trip command or remote trip command to pass through as control variable SV1. The summary of SV1 logic outputs is given in Table 5-2.

Table 5-2 Downstream recloser - logic outputs for control variable SV1

IN 101	LT5	OC	PB9	G2	G3	G4=SV1
	0	0	0	0	0	0
0		1	1	0	1	1
	1	0	0	0	0	0
		1	1	1	0	1

Outcomes

The SV1 variable is asserted either when remote operation is disabled and local trip command is issued or when remote operation is enabled and remote open command is issued. This is a standard function implemented on Schweitzer 351P relays by Schweitzer Engineering Laboratories.

5.5.2 Control variable SV2

Task - Detection of sustained phase and/or ground faults, generation of blocking signals.

Inputs - 51G2, residual ground current above pick up setting for residual ground time-overcurrent element 51G2T used to detect E/F.
- 51P2, maximum phase current above pick up setting for phase time-overcurrent element 51P2T used to detect P/F.

Description of operation

When an ground fault is detected and the value of 51G2 lasts long enough for the timer T1 to time out on the applied time delay curve and, assert its output then

51G2T = 1 (asserted)

When a phase fault is detected and the value of 51P2 lasts long enough for the timer T2 to time out on the applied time delay curve and, assert its output then

51P2T = 1 (asserted)

51P2T and 51G2T outputs are ORed at gate G5, the output of which is the variable SV2. The summary of SV2 logic outputs is given in Table 5-3.

Table 5-3 Downstream recloser - logic outputs for control variable SV2

Fault type(s)	51P2T	51G2T	G5 output = SV2
Only phase fault (P/F)	1	0	1
Only ground fault (E/F)	0	1	1
Both P/F and E/F	1	1	1
Neither P/F nor E/F	0	0	0

Outcomes

SV2 is asserted when sustained P/F or E/F or both is/are detected, i.e. tripping and blocking signals are generated when sustained P/F or E/F or both is/are detected.

5.5.3 Transmitted mirrored bit 1, TMB1A

Task - Transmission of blocking signals from the downstream recloser to the upstream recloser following the detection of sustained and transient P/F and/or E/F.

Inputs - SV2, control variable reflecting, when asserted, the presence of sustained P/F and/or E/F and, generating blocking signals.
- LT1, latch bit 1 enabling recloser relay protection when asserted. It is used to enable or suppress recloser's protection.
- 51G2, residual ground current above pick up setting for residual ground time-overcurrent element 51G2T used to detect E/F.
- 51P2, maximum phase current above pick up setting for phase time-overcurrent element 51P2T used to detect P/F.

Description of operation

The 51P2 and 51G2 are used to detect P/Fs or E/Fs respectively and to generate blocking signals to reflect the occurrences of P/Fs or E/Fs before it is determined whether the fault(s) is/are of sustained nature. This means that in case of transient faults blocking signals are generated but tripping signals are not. In addition, the 51P2 and 51G2 provide input signals for timers T2 and T1 which define sustained faults by timing out on the applied protection relay's time delay curve(s). Subsequent to the continuous fault(s) presence, up to the time when T1 and/or T2 time(s) out, tripping and blocking signals are generated, at gate G5, to reflect the detection of sustained P/F and/or E/F.

The outputs from 51P2 and 51G2 are ORed, at gate G0, to provide common blocking signals reflecting detection of transient P/Fs and/or E/Fs and, if the fault duration is sufficiently long, sustained P/Fs and/or E/Fs. These blocking signals are generated immediately after faults' detection and, before determining whether the P/F and/or E/F is/are sustained.

At gate G7, the output of gate G0 is ANDed with LT1 input, the latch bit 1 that defines the status of recloser's protection. Whenever protection is suppressed, LT1 is deasserted and blocking signals, if generated, are nullified. Whenever protection is enabled, LT1 is asserted and, under fault condition, the passage of blocking signals is allowed. The output of gate G7 is deasserted when P/F and/or E/F is/are not detected and protection is enabled.

Variable SV2, generating tripping and blocking signals due to sustained P/F and/or E/F, is fed into the recloser's circuit breaker failure timer, T3, with the pick up time setting, SV2PU, set to 200ms. Following the detection of sustained P/F and/or E/F, meaning asserted variable SV2, the output of timer T3, variable SV2T, remains deasserted until the pick up value of SV2PU expires and timer T3 times out. Once the continuous fault duration of the 200ms time-out is reached, the SV2T variable gets asserted, inverted at inverter I2 and, at gate G8, the inverted SV2T, variable !SV2T, nullifies the blocking signal coming from gate G7 if protection is enabled. This feature covers for an inadvertent downstream recloser's circuit breaker failure to clear the fault within the predetermined time of 200ms. If the downstream recloser's circuit breaker failure occurs, the upstream recloser should clear the fault. The summary of TMB1A logic outputs is given in Table 5-4.

Outcomes

The 'transmit bit 1' on Channel A, i.e. TMB1A implemented for blocking the upstream recloser's protection and the Zone Substation circuit breaker's protection, is asserted only in two cases. The first case is when a transient P/F or a transient E/F or both is/are detected and protection is enabled. The second case is when a sustained P/F or a sustained E/F or both is/are detected and protection is enabled and the circuit breaker failure timer is timing.

Table 5-4 Downstream recloser - logic outputs for TMB1A

Time	Faults	G0	LT1	G7	SV2	SV2T	!SV2T	TMB1A
<200ms	No transient faults	0	0	0	0	0	1	0
			1	0	0	0	1	0
	transient P/F or E/F or both	1	0	0	0	0	1	0
			1	1	0	0	1	1
	No sustained faults	0	0	0	0	0	1	0
			1	0	0	0	1	0
	sustained P/F or E/F or both	1	0	0	1	0	1	0
			1	1	1	0	1	1
>200ms	sustained P/F or E/F or both	1	0	0	1	1	0	0
			1	1	1	1	0	0

5.5.4 Trip variable

Task - To facilitate either automatic tripping on the detection of sustained P/F, E/F and SEF or tripping on local/remote open command.

Inputs - SV1, control variable that enables either local or remote trips.
- SV2, control variable reflecting the presence or absence of sustained P/Fs and /or E/Fs and generating tripping and blocking signals.
- 67N3T, neutral ground definite-time overcurrent element used to detect sustained sensitive earth faults (SEF).
- LT1, latch bit 1 enabling recloser relay protection when asserted, used to enable or suppress recloser's protection.

Description of operation

The tripping of the downstream recloser, effected by variable SV1, results when the utility personnel decide to open this recloser either locally or remotely from the SCADA host. It is not a direct result of faults automatically detected by the recloser's relay. In contrast with variable SV1, variable SV2 effects recloser tripping, when sustained P/F and/or E/F are automatically detected by the downstream recloser's relay.

The 67N3T element is used to detect SEFs and generate tripping signals but it does not generate blocking signals for the upstream devices as required by AGLE protection guidelines. Its output is ORed, at gate G6, with the SV2 variable which provides signalling reflecting the occurrences of P/Fs and/or E/Fs. The output of gate G6 provides common, automatically generated, tripping signal due to the occurrence of either SEF or P/F or E/F or any combination of them. The output from gate G6 is ANDed, at gate G9, with LT1, the protection enable input, to either pass the automatically generated tripping signal through if recloser protection has been enabled or nullify this tripping signal if recloser protection has been suppressed.

The output of gate G9 is ORed, at gate G10, with variable SV1 to provide combined tripping signals generated due to automatically detected SEFs, P/Fs and E/Fs as well as locally or remotely issued open commands. The output of gate G10 is the trip signal. The summary of TRIP logic outputs is given in Table 5-5.

Table 5-5 Downstream recloser - logic outputs for TRIP variable

<table>
<tr><th>67N3T</th><th>SV2</th><th>G6</th><th>LT1</th><th>G9</th><th>SV1</th><th>G10=TRIP</th></tr>
<tr><td rowspan="2">0</td><td>0</td><td>0</td><td rowspan="4">0</td><td rowspan="4">0</td><td rowspan="2">0</td><td rowspan="2">0</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="2">1</td><td>0</td><td>1</td><td rowspan="2">1</td><td rowspan="2">1</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="3">0</td><td rowspan="2">0</td><td rowspan="2">0</td><td rowspan="5">1</td><td rowspan="2">0</td><td>0</td><td>0</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td>1</td><td>1</td><td rowspan="3">1</td><td rowspan="2">0</td><td rowspan="2">1</td></tr>
<tr><td rowspan="2">1</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>1</td><td>1</td><td>1</td></tr>
</table>

Outcomes

When protection is suppressed at the downstream recloser, the only TRIP signals are generated as a result of remote or local open commands issued either from the SCADA host or from the downstream recloser's control panel. When protection is enabled, the TRIP signals are automatically generated as a result of detection of sustained SEF or P/F or E/F or any combination of the three fault types. Also, when protection is enabled, TRIP signals are generated as a result of remote or local open commands issued either from the SCADA host or from the downstream recloser's control panel.

5.6 Upstream recloser No 28506 – blocking and trip logic operation

The design principles covering the operation of blocking and tripping, at the upstream recloser No 28506, are discussed below. The logic diagram, including the representative equations, is illustrated in Figure 5.5.

Blocking signalling, implemented at the upstream recloser's relay, was designed primarily to prevent the Zone Substation circuit breaker from tripping in the event of P/Fs and/or E/Fs occurring in section S2 of the distribution feeder. In addition to the above design specification, blocking signalling was implemented to prevent the Zone

Substation circuit breaker from clearing detected faults in the event of the downstream recloser's circuit breaker failure to clear the P/Fs and/or E/Fs occurring in section S3 of the distribution feeder. In both cases, if unblocked, the Zone Substation circuit breaker would clear the detected fault(s) independently, as it simultaneously detects the same fault(s), causing an interruption to supply to more customers than absolutely necessary.

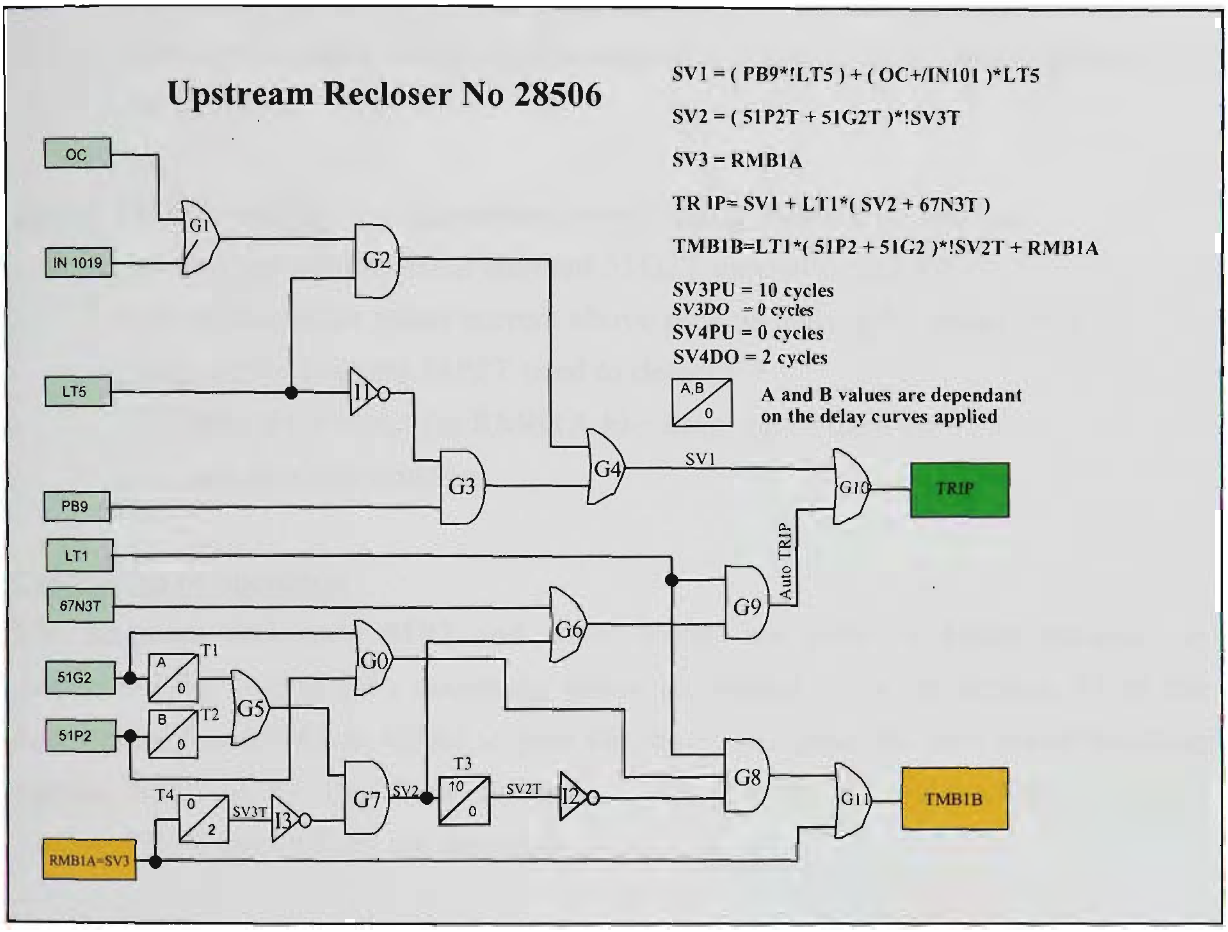


Figure 5.5 Upstream recloser - logic diagram for RMB1A and TMB1B mirrored bits

5.6.1 Control variable SV1

The logic design of the SV1 variable for the upstream recloser is exactly the same as in the case of the downstream recloser. For that reason, the discussion of this variable is not given below. For discussion details on variable SV1 please refer to Chapter 5, section 5.5.1.

5.6.2 Control variable SV2

Task - To block automatic tripping of the upstream recloser on detection of sustained P/F and/or E/F in feeder section S3. To pass through triggering signals for automatic tripping of the upstream recloser on detection of sustained P/F and/or E/F in feeder section S2. To facilitate a passage for locally generated blocking signals destined for the Zone Substation circuit breaker on detection of sustained P/F and/or E/F in feeder sections S2 and S3.

Inputs - 51G2, residual ground current above pick up setting for residual ground time-overcurrent element 51G2T used to detect E/F.
- 51P2, maximum phase current above pick up setting for phase time-overcurrent element 51P2T used to detect P/F.
- Variable SV3 being the RMB1A blocking signal received from the downstream recloser.

Description of operation

The upstream recloser's 51P2 and 51G2 inputs are used to detect transient or sustained P/Fs and/or E/Fs occurring either in section S2 or in section S3 of the distribution feeder. When ORed at gate G0, they also generate, non-timed blocking signals, destined for the Zone Substation circuit breaker, when transient and/or sustained P/Fs and/or E/Fs are detected.

Thus, when 51P2 input detects a P/F lasting long enough for the timer T2, the time delay of which is defined by the delay curve type applied in the protection settings file, to time out then an occurrence of a sustained P/F is determined and

$$51P2T = 1$$

When 51G2 input detects an ground fault lasting long enough for the timer T1, the time delay of which is defined by the delay curve type applied in the protection settings file, to time out then an occurrence of a sustained E/F is determined and

$$51G2T = 1$$

The outputs of timers T1 and T2, i.e. 51G2T and 51P2T respectively, are ORed at gate G5 to provide a common signal reflecting the presence, when asserted, or absence, when deasserted, of sustained P/Fs and/or E/Fs.

The blocking signal, received by the upstream recloser as asserted RMB1A, is equated with variable SV3. This signal is fed into the T4 timer whose drop out setting, SV3DO, has been set to 2 cycles, i.e. 40ms in case of 50Hz supply. The purpose of the T4 timer is to maintain the presence of a blocking signal during a momentary loss of communications, commonly referred to as a glitch, which can happen during adverse communications conditions. As long as the loss of communications in Channel A, whilst the asserted TMB1A is being sent by the downstream recloser, does not exceed 40ms the output of timer T4 will remain asserted, i.e. meaning the continuous receipt of the blocking signal from the downstream recloser. Thus

$$SV3T = 1$$

When communications loss exceeds the 40ms drop out threshold, the T4 timer drops out leaving its output deasserted. Under this circumstance

$$SV3T = 0$$

The SV3T output is inverted at inverter I3 giving as a result variable !SV3T. Then, at gate G7, the !SV3T variable is ANDed with the output of gate G5 reflecting, when asserted, the presence a locally generated tripping signal due to detection of sustained P/F and/or E/F. Output of gate G7 is the control variable SV2. This variable has an effect on locally generated trip signals. In addition, the SV2 variable effects the transmission of locally generated blocking signals destined for the Zone Substation circuit breaker.

Below, there are four selected scenarios depicting the performance of the SV2 variable.

In scenario 1, either sustained P/F or sustained E/F or both occur(s) in section S2 of the distribution feeder and no blocking signal is received from the downstream recloser. This is a normal situation in which variable SV2 gets asserted thus allowing a passage for the locally generated trip signal to automatically trip the upstream recloser. The passage of the locally generated blocking signal destined for the Zone Substation circuit breaker is allowed, at gate G8, until either, the upstream recloser clears the fault or the 200ms upstream recloser's circuit breaker failure time-out is reached and the Zone Substation circuit breaker clears the fault.

In scenario 2, either sustained P/F or sustained E/F or both occur(s) in section S2 of the distribution feeder and a blocking signal is received due to communications hardware failure. This is an abnormal situation in which the SV2 variable gets deasserted, thus nullifying the trip signal locally generated to automatically trip the upstream recloser. As the blocking signal is held on due to communications hardware failure, it will have to be cleared by a default state of Mirrored bits, the RXDFLT. The passage of the blocking signal destined for the Zone Substation circuit breaker is allowed, at gate G8, until either, the RXDFLT clears the abnormally asserted RMB1A and the upstream recloser clears the fault or the Zone Substation circuit breaker clears the fault.

In scenario 3, either sustained P/F or sustained E/F or both occur(s) in section S3 of the distribution feeder and a blocking signal is received from the downstream recloser. This is a normal situation in which variable SV2 gets deasserted, thus nullifying the trip signal locally generated to automatically trip the upstream recloser. The passage of the locally generated blocking signal destined for the Zone Substation circuit breaker is allowed, at gate G8, until either, the downstream recloser clears the fault or the 200ms downstream recloser's circuit breaker failure time-out is reached and the upstream recloser clears the fault.

In scenario 4, either sustained P/F or sustained E/F or both occur(s) in section S3 of the distribution feeder and no blocking signal is received from the downstream recloser. The absence of the blocking signal RMB1A can be caused by either Channel A communications failure or the downstream recloser's circuit breaker failure timer time-out. This is an abnormal situation in which variable SV2 gets asserted, allowing the passage for the locally generated trip signal to automatically trip the upstream recloser. The passage of the locally generated blocking signal destined for the Zone Substation circuit breaker is allowed, at gate G8, until the upstream recloser clears the fault.

The summary of TRIP logic outputs is given in Table 5-6.

Table 5-6 Upstream recloser - logic outputs for control variable SV2

Fault in		Fault type(s)	51P2T	51G2T	G5	RMB1A Glitches < 40ms	!SV3T	SV2
Scenario 1	Section S2	Only P/F	1	0	1			1
		Only E/F	0	1	1	0*	1	1
		Both P/F and E/F	1	1	1			1
		Neither P/F nor E/F	0	0	0			0
Scenario 2	Section S2	Only P/F	1	0	1			0
		Only E/F	0	1	1	1**	0	0
		Both P/F and E/F	1	1	1			0
		Neither P/F nor E/F	0	0	0			0
Scenario 3	Section S3	Only P/F	1	0	1			0
		Only E/F	0	1	1	1*	0	0
		Both P/F and E/F	1	1	1			0
		Neither P/F nor E/F	0	0	0			0
Scenario 4	Section S3	Only P/F	1	0	1			1
		Only E/F	0	1	1	0***	1	1
		Both P/F and E/F	1	1	1			1
		Neither P/F nor E/F	0	0	0			0

* Situation normal

** Situation abnormal, blocking signal received and held on due to communications hardware failure to be cleared by the default state of Mirrored bits, RXDFLT

*** Situation abnormal due to Channel A communications failure or the downstream recloser's circuit breaker failure timer time-out

Outcomes

On the receipt of the blocking signal the SV2 variable is deasserted thus nullifying the trip signal generated locally due to the detection of sustained P/F and/or E/F.

When the blocking signal is not received from the downstream recloser, the SV2 variable is asserted thus allowing passage of the trip signal generated locally due to the detection of sustained P/F and/or E/F.

The passage of the locally generated blocking signal destined for the Zone Substation circuit breaker is allowed, until the fault is cleared.

5.6.3 Transmitted mirrored bit 1, TMB1B from R1

Task - transmission of blocking signals from the upstream recloser to the Zone Substation circuit breaker or passage of blocking signals from the downstream recloser to the Zone Substation circuit breaker following the detection of sustained P/F and/or E/F.

Inputs - SV2, control variable reflecting the presence or absence of the trip signal as a result of the detected sustained P/F and/or E/F in feeder sections S2 or S3 or both and, facilitating generation of blocking signals.
- LT1, latch bit 1 enabling recloser relay protection when asserted, used to enable or suppress recloser's protection.
- 51P2, maximum phase current above pick up setting for phase time-overcurrent element used to detect P/F.
- 51G2, residual ground current above pick up setting for residual ground time-overcurrent element used to detect E/F.
- variable SV3 being the RMB1A blocking signal received from the downstream recloser.

General description of operation

The 51P2 and 51G2 elements are ORed, at gate G0, to provide instant blocking signals reflecting the occurrence of P/F and/or E/F, i.e. not timed on the time delay curves. The output of gate G0 is fed into gate G8.

Also, the 51G2 and 51P2 elements provide inputs for timers T1 and T2 respectively. The output of timer T1, the 51G2T variable, provides a predetermined, by the selected protection curve, time delayed response to E/Fs. The output of timer T2, the 51P2T variable, provides a predetermined, by the selected protection curve, time delayed response to P/Fs.

The 51G2T and 51P2T variables are ORed, at gate G5, to provide a common output reflecting the presence or absence of P/F and/or E/F.

The blocking signal, received by the upstream recloser as RMB1A, is equated with variable SV3. This signal is fed into the T4 timer whose drop out setting, SV3DO, has been set to 2 cycles, i.e. 40ms in case of 50Hz supply. The purpose of the T4 timer is to maintain the presence of a blocking signal during a momentary loss of communications, commonly referred to as a glitch, which can happen during adverse communications conditions. As long as the loss of communications does not exceed 40ms the output of timer T4 will remain asserted, i.e.

SV3T = 1 (asserted)

When communications loss has exceeded the 40ms drop out threshold, the T4 timer drops out leaving its output deasserted. Under this circumstance

SV3T = 0 (deasserted)

The output of gate G5 is ANDed, at gate G7, with the inverted, at inverter I3,output of timer T4, the variable !SV3T. The output of gate G7, i.e. the trip/blocking variable SV2, is fed into the upstream recloser's circuit breaker failure timer, T3, with its pick up time setting, SV2PU, set to 10 cycles, i.e. equivalent to 200ms in case of 50Hz supply. Then, the output of timer T3, the variable SV2T, is inverted at inverter I2 the output of which is variable !SV2T.

At gate G8, the output of gate G0, !SV2T are ANDed together with LT1, the latch bit 1 that defines the status of recloser's protection. Whenever protection is suppressed, LT1 is deasserted and generation of a blocking signal, TMB1B, is nullified. Whenever protection is enabled, LT1 is asserted and, under a fault condition, the generated blocking signal, TMB1B, is allowed to be transmitted. During times when 51P2 and/or 51G2 elements have picked up, but sustained P/F and/or E/F have not been detected, and with protection enabled, the output of gate G8 is asserted. This means that a blocking signal is generated without waiting for a time out due to the time delay curves.

Following the detection of sustained P/F and/or E/F in feeder section S2, i.e. when SV2 = 1, the SV2T variable remains deasserted until the pick up value of SV2PU expires and timer T3 times out. Once the 200ms time out is reached, the SV2T variable gets asserted and the inverted SV2T, !SV2T, nullifies the transmission of a blocking signal due to a fault detected by the upstream recloser. This feature covers for an inadvertent upstream recloser's circuit breaker failure to break the fault current within the expected time of 200ms. If the upstream recloser's circuit breaker failure occurs, the Zone Substation's circuit breaker should clear the fault.

The output of gate G8 is ORed with the received blocking signal, RMB1A, to enable the passage of this blocking signal, as TMB1B, to the Zone Substation circuit breaker in case of a fault in the feeder section S3.

For further study of eleven selected fault scenarios and the associated TMB1B logic states the reader is referred to Appendix 'E'.

5.6.4 Trip variable

Task - to facilitate either automatic tripping on the detection of P/F, E/F and SEF or tripping on local/remote open command.

Inputs - SV1, control variable that enables either local or remote trips.
- SV2, control variable reflecting the presence or absence of phase and /or ground fault(s).
- 67N3T, neutral ground definite-time overcurrent element used to detect sustained sensitive earth faults (SEF).
- LT1, latch bit 1 enabling recloser relay protection when asserted. It is used to enable or suppress recloser's protection.

Description of operation

The SV1 variable enables local or remote tripping of the recloser. The tripping, facilitated by the SV1 variable, is a result of actions taken by the utility personnel to configure the network reticulation. It is not a direct result of faults automatically detected by the recloser's relay. In contrast with the SV1 variable, the variable SV2 facilitates recloser tripping when sustained P/F and E/F faults are automatically detected by the recloser relay. The 67N3T element is used to detect SEFs but does not facilitate the issue of blocking signals for the upstream devices as per Guideline 2 recommended by AGLE Protection Forum.

The 67N3T element is ORed, at gate G6, with the SV2 variable which provides signalling reflecting the occurrences of P/Fs and/or E/Fs. The output of gate G6 provides tripping signal due to the occurrence of either SEF or P/F or E/F or any combination of them. The output from gate G6 is ANDed, at gate G9, with LT1, the protection enable input, to either pass the automatically generated trip signal if recloser protection has been enabled or nullify this trip signal if recloser protection has been suppressed.

Then the output of gate G9 is ORed, at gate G10, with variable SV1 to provide combined trip signalling due to automatically detected SEFs, P/Fs and E/Fs as well as local or remote open commands. The output of gate G10 is the trip signal. The summary of TRIP logic outputs is given in Table 5-7.

When protection is suppressed, the TRIP signal can only be issued as a result of remote or local open command. When protection is enabled, the TRIP signal is issued as a result of SEF or P/F or E/F or any combination of the three faults or as a result of remote or local open command.

Table 5-7 Upstream recloser - logic outputs for TRIP variable

<table>
<tr><th>67N3T</th><th>SV2</th><th>G6</th><th>LT1</th><th>G9</th><th>SV1</th><th>G10=TRIP</th></tr>
<tr><td rowspan="2">0</td><td>0</td><td>0</td><td rowspan="4">0</td><td rowspan="4">0</td><td rowspan="2">0</td><td rowspan="2">0</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="2">1</td><td>0</td><td>1</td><td rowspan="2">1</td><td rowspan="2">1</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="4">0</td><td rowspan="2">0</td><td rowspan="2">0</td><td rowspan="8">1</td><td rowspan="2">0</td><td>0</td><td>0</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="2">1</td><td rowspan="2">1</td><td rowspan="2">1</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="4">1</td><td rowspan="2">0</td><td rowspan="2">1</td><td rowspan="2">1</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>1</td></tr>
<tr><td rowspan="2">1</td><td rowspan="2">1</td><td rowspan="2">1</td><td>0</td><td>1</td></tr>
<tr><td>1</td><td>1</td></tr>
</table>

5.7 Zone Substation circuit breaker

The logic diagram for the Zone Substation CB relay application is presented in Figure 5.6. This diagram does not incorporate the remote and local control of the CB as these controls were implemented independently of the SEL351S protection relay. Only the principles of operation covering the control variable SV2 and the Trip variable are presented in the following paragraphs.

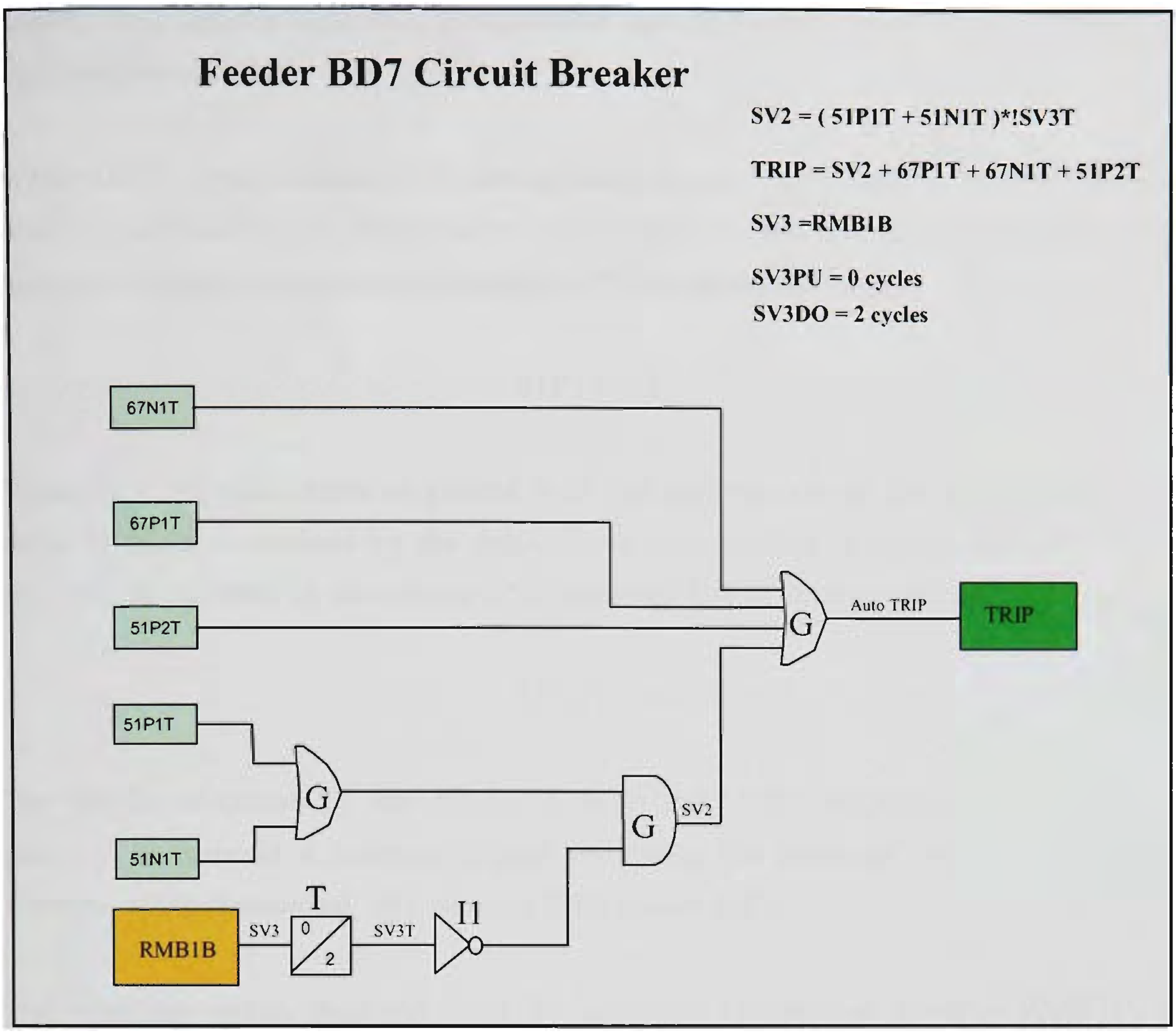


Figure 5.6 BD7 CB – logic diagram for RMB1B and TRIP condition

5.7.1 Control variable SV2

<u>Task</u> - To block automatic tripping of the CB on detection of sustained P/F and/or E/F in feeder section S2 or S3.

<u>Inputs</u> - 51N1T, neutral ground timed-overcurrent element used to detect E/F.
- 51P1T, phase timed-overcurrent element used to detect P/F.
- Variable SV3 being the RMB1B blocking signal received from the upstream recloser.

<u>Description of operation</u>

The BD7 feeder CB's 51P1T and 51N1T inputs are used to detect sustained P/Fs and/or E/Fs occurring either in section S1, S2 or in section S3 of the distribution feeder. They are the only two elements that can be blocked on the BD7 CB's SEL-351S protection relay.

When 51P1T input detects a P/F lasting long enough for its timer, the time delay of which is defined by the delay curve type applied in the protection settings file, to time out then an occurrence of a sustained P/F is determined and

$$51P1T = 1$$

When 51N1T input detects an ground fault lasting long enough for its timer, the time delay of which is defined by the delay curve type applied in the protection settings file, to time out then an occurrence of a sustained E/F is determined and

$$51N1T = 1$$

The outputs of timers T1 and T2, i.e. 51G2T and 51P2T respectively, are ORed at gate G5 to provide a common signal reflecting the presence, when asserted, or absence, when deasserted, of sustained P/Fs and/or E/Fs.

The blocking signal, received from the upstream recloser as asserted RMB1B, is equated with variable SV3. This signal is fed into the T1 timer whose drop out setting, SV1DO, has been set to 2 cycles, i.e. 40ms in case of 50Hz supply. The purpose of the T1 timer is to maintain the presence of a blocking signal during a momentary loss of communications, commonly referred to as a glitch, which can happen during adverse communications conditions. As long as the loss of communications in Channel B, whilst the asserted TMB1B is being sent by the upstream recloser, does not exceed 40ms the output of timer T1 will remain asserted, i.e. meaning the continuous receipt of the blocking signal from the downstream recloser. Thus

$$SV3T = 1$$

When communications loss exceeds the 40ms drop out threshold, the T1 timer drops out leaving its output deasserted. Under this circumstance

$$SV3T = 0$$

The SV3T output is inverted at inverter I1 giving as a result variable !SV3T. Then, at gate G7, the !SV3T variable is ANDed at G2 with the output of gate G1 reflecting, when asserted, the presence a locally generated tripping signal due to detection of sustained P/F and/or E/F. Output of gate G2 is the control variable SV2. This variable has an effect on locally generated trip signals.

Below, there are four selected scenarios depicting the performance of the SV2 variable.

In scenario 1, either sustained P/F or sustained E/F or both occur(s) in section S1 of the distribution feeder and no blocking signal is received from the downstream recloser and upstream recloser. This is a normal situation in which variable SV2 gets asserted thus allowing a passage for the locally generated trip signal to automatically trip the CB.

In scenario 2, either sustained P/F or sustained E/F or both occur(s) in section S1 of the distribution feeder and a blocking signal is received due to communications hardware failure. This is an abnormal situation in which the SV2 variable gets deasserted, thus nullifying the trip signal locally generated to automatically trip the CB. As the blocking signal is held on due to communications hardware failure, it will have to be cleared by a default state of Mirrored bits, the RXDFLT. In the meantime, depending on the type of fault, the fault is cleared by one or more of the unblocked elements, i.e. 51P2T, 67P1T or 67N1T.

In scenario 3, either sustained P/F or sustained E/F or both occur(s) in section S2 or S3 of the distribution feeder and a blocking signal is received from the upstream recloser. This is a normal situation in which variable SV2 gets deasserted, thus nullifying the trip signal locally generated to automatically trip the CB. The reception of RMB1B continues, until either, the downstream/upstream recloser clears the fault or the 200ms downstream/upstream recloser's circuit breaker failure time-out is reached and the CB clears the fault.

In scenario 4, either sustained P/F or sustained E/F or both occur(s) in section S3 or S2 of the distribution feeder and no blocking signal is received from the upstream recloser. The absence of the blocking signal RMB1B can be caused by either Channel A/B communications failure or the downstream/upstream recloser's circuit breaker failure timer time-out. This is an abnormal situation in which variable SV2 gets asserted, allowing the passage for the locally generated trip signal to automatically trip the CB. The summary of TRIP logic outputs is given in Table 5-8.

Table 5-8 BD7 CB - logic outputs for control variable SV2

Fault in		Fault type(s)	51P1T	51N1T	G1	RMB1B Glitches < 40ms	!SV3T	SV2
Scenario 1	Section S1	Only P/F	1	0	1	0^{*}	1	1
		Only E/F	0	1	1			1
		Both P/F and E/F	1	1	1			1
		Neither P/F nor E/F	0	0	0			0
Scenario 2	Section S1	Only P/F	1	0	1	1^{**}	0	0
		Only E/F	0	1	1			0
		Both P/F and E/F	1	1	1			0
		Neither P/F nor E/F	0	0	0			0
Scenario 3	Section S3/S2	Only P/F	1	0	1	1^{*}	0	0
		Only E/F	0	1	1			0
		Both P/F and E/F	1	1	1			0
		Neither P/F nor E/F	0	0	0			0
Scenario 4	Section S3/S2	Only P/F	1	0	1	0^{***}	1	1
		Only E/F	0	1	1			1
		Both P/F and E/F	1	1	1			1
		Neither P/F nor E/F	0	0	0			0

* Situation normal

** Situation abnormal, blocking signal received and held on due to communications hardware failure to be cleared by the default state of Mirrored bits, RXDFLT

*** Situation abnormal due to Channel A/B communications failure or the upstream/downstream recloser's circuit breaker failure timer time-out

<u>Outcomes</u>

On the receipt of the blocking signal the SV2 variable is deasserted thus nullifying the trip signal generated locally due to the detection of sustained P/F and/or E/F.

When the blocking signal is not received from the upstream recloser, the SV2 variable is asserted thus allowing passage of the trip signal generated locally due to the detection of sustained P/F and/or E/F.

5.7.2 TRIP variable

Task - to facilitate either automatic tripping on the detection of P/F, E/F and SEF.

Inputs - SV2, control variable reflecting the presence or absence of phase and /or ground fault(s).
- 67N1T, unblocked Level 1neutral ground definite-time overcurrent element used to detect sustained sensitive ground faults (SEF).
- 67P1T, unblocked Level 1 instantaneous phase definite-time overcurrent element used to detect phase faults.
- 51P2T, unblocked phase time-overcurrent element that is quicker than the bus protection but slower than the normally blocked phase O/C timed element 51P1T.

Description of operation

The SV2 variable facilitates blockable recloser tripping when sustained P/F and E/F faults are automatically detected by the CB relay. The unblocked 67N1T timed element is used to detect SEFs. The unblocked timed elements such as 67P1T and 51P2T are used to detect P/Fs. They are all ORed at gate G3. The output of gate G3 provides tripping signal, due to the occurrence of either SEF or P/F or E/F or any combination of them, for the CB protecting the feeder.

The protection suppression and remote or local control of the CB is not considered here as it is implemented directly on the CB. When protection is suppressed, the TRIP command cannot be issued. When protection is enabled, the TRIP command is issued as a result of SEF or P/F or E/F or any combination of the three faults or as a result of remote (SCADA) or local open command.

5.8 Implementation of the blocking schemes

To assess performance under normal operating conditions, two pilot installations were chosen for field testing on 22kV feeders. The first installation, implemented on the TT8 feeder, was designated to prove the working concept of a partial blocking scheme. The configuration of this feeder, encompassing the partial blocking scheme, is shown in a single line diagram presented in Appendix 'D', Figure D.3. The second, BD7 feeder installation, was designated to prove the operation of a full blocking scheme. The configuration of BD7 feeder, encompassing the full blocking scheme, is shown in a single line diagram presented in Appendix 'D', Figure D.4. It is the BD7 full blocking scheme that was subjected to extensive testing. The tests performed on this scheme were able to verify the operation of both partial and full blocking schemes. An approximate number of customers directly effected by this work was 4,695 and 2,248 for the BD7 and TT8 feeders respectively. The coverage area, affected by the BD7 and TT8 feeder tests, is shown in Appendix 'D', Figure D.5. Commissioning was followed by the ongoing performance monitoring of both installations constituted the core component of this research.

CHAPTER 6

TESTING AND COMMISSIONING

6.1 Introduction

The full blocking scheme was installed on the BD7 feeder emanating from the Broadmeadows Zone Substation. From the operational point of view, it was imperative that the BD7 feeder continued to supply electrical power to customers, fed off this feeder, without any interruptions to supply during the 'in field' blocking tests. Due to the enforcement of the 'business as usual' policy, special testing procedures had to be developed to accommodate the testing needs as well as the requirement for uninterrupted supply.

'In house' testing of the full blocking scheme was carried out first to fine tune the system and to ensure the overall interoperability between communications and protection system components. Once the acceptable confidence level in operational expediency of the testing regime was achieved, the 'in field' testing followed.

To prevent an inadvertent operation of a recloser under test and to ensure general safety standards when working on the 'live' BD7, feeder the umbilical cables, linking recloser breakers with their respective recloser controllers, were disconnected from the recloser controllers. In their place recloser simulators, developed by Agility for the recloser project, were connected to simulate the operation of recloser breakers. A 'dummy circuit breaker' was used to simulate the BD7 circuit breaker operation in most of the tests. Some tests, however, were carried out with the real BD7 circuit breaker in order to test the interoperability between the circuit breaker and reclosers. In these cases, the supply for the BD7 feeder was switched around the BD7 circuit breaker to provide continuous supply to customers.

Two Doble current injection test sets, 2200 series, were used to inject secondary currents into the protection relays simulating faults. Current injections at the reclosers and BD7 circuit breaker were synchronised via satellite communications to simulate a fault experience by the devices under test. Due to the functional limitations of the Doble test set, however, it was not possible to interrupt the fault simulating currents and show that there was no current flowing after the recloser simulator trip. For this reason, all diagrams, obtained from the Doble test set, do show fault currents flowing after the relay tripped albeit it does not reflect the real life system's performance.

Three sets of blocking tests were devised to verify the correct operation of the blocking scheme. They were:

- Test set 'A' – encompassing blocking from the downstream recloser No 18434, referred to as R2, to the upstream recloser No 28506, referred to as R1.

- Test set 'B' – encompassing blocking from R1 to the BD7 feeder CB.

- Test set 'C' – encompassing blocking from R2 to the BD7 feeder CB.

6.1.1 Test set 'A', blocking from R2 to R1

Test set 'A' comprised six tests as shown in Table 6-1.

Table 6-1 Blocking from R2 to R1

Test No	Purpose
A1	Phase O/C on R2 blocks Phase O/C on R1
A2	Phase O/C on R2 blocks Ground O/C on R1
A3	Ground O/C on R2 blocks Ground O/C on R1
A4	Ground O/C on R2 blocks Phase O/C on R1
A5	SEF on R2 does not block Phase O/C or Ground O/C on R1
A6	Ground O/C on R2 blocks Phase O/C and Ground O/C on R1 and tests breaker fail scenario at R2

Tests A1–A4 were carried out by first subjecting R1 to a known fault current to establish a base line. Without blocking, R1 would trip after a known time determined by the appropriate time-overcurrent curve. R1 was then subjected to fault currents again, except this time R2 was also subjected to a fault current simultaneously, causing it to send a blocking signal to R1. In the latter case, R1 should not trip in the time observed in the former scenario.

Test A5 was carried out in a similar manner to A1-A4 except in this case a blocking signal should not be sent. This is because SEF faults should not be blocked at all. In this case, R1 should trip in the same time as for the cases with and without blocking.

Test A6 was carried out in the same way as Tests A1-A4, with the addition of breaker fail feature. To test this scenario, the fault current was continued at R2 for at least 200ms after the R2 issued a trip command to its local breaker. The expected result was for the blocking signal, issued by R2, to deassert 200ms after a trip command was issued by R2, allowing R1 to clear the fault.

The summary of test set 'A' results is presented in Table 6-2.

Table 6-2 Results for the test set 'A' at the upstream recloser R1

Test	Results	Trip without blocking in seconds	Trip with blocking in seconds
A1	Expected Result	2.970	No trip
	Observed Result	2.885	No trip
A2	Expected Result	3.375	No trip
	Observed Result	3.284	No trip
A3	Expected Result	3.375	No trip
	Observed Result	3.289	No trip
A4	Expected Result	2.970	No trip
	Observed Result	2.890	No trip
A5	Expected Result	0.281	Trip in 0.285s
	Observed Result	0.285	Trip in 0.285s
A6	Expected Result	0.281	Trip in 0.663s[1]
	Observed Result	0.285	Trip in 0.700s

[1] Downstream recloser (R2) trips in 0.463s + 0.200s for breaker failure = 0.663s

Detailed test results, covering test set 'A', are presented in Appendix 'A'.

6.1.2 Test set 'B', blocking from R1 to BD7 feeder CB

Test set 'B' comprised seven tests as shown in Table 6-3.

Table 6-3 Blocking from R1 to BD7 feeder CB

Test No	Purpose
B1	Phase O/C on R1 blocks Phase O/C on CB
B2	Phase O/C on R1 blocks Ground O/C on CB
B3	Ground O/C on R1 blocks Ground O/C on CB
B4	Ground O/C on R1 blocks Phase O/C on CB
B5	SEF on R1 does not block Phase O/C or Ground O/C on CB
B6	Phase O/C or Ground O/C on R1 does not block Instantaneous O/C on CB
B7	Ground O/C on R1 blocks Phase O/C and Ground O/C on CB and tests breaker fail at R1

Tests B1–B4 were carried out by first subjecting CB to a known fault current. Without blocking, CB would trip after a known time determined by the appropriate time-overcurrent curve. CB was then subjected to the same fault current again, except this time R1 was also subjected to a fault current simultaneously, causing it to send a blocking signal to CB. In the latter case, CB should not trip in the time observed in the former scenario.

Test B5 was carried out in a similar manner to B1-B4 except in this case a blocking signal should not be sent. However, CB should trip in the same time as for the cases with and without blocking.

Test B6 was carried out in a similar manner to B1-B4 except in this case, although a blocking signal is sent, the instantaneous overcurrent element at CB should not be blocked. In this case, CB should trip in the same time for both cases.

Test B7 was carried out in the same way as Tests B1-B4, with the addition of breaker fail feature. To test this scenario, the fault current was continued at R1 for at least 200ms after R1 issued a trip command to its local breaker. The expected result was for the blocking signal to deassert 200ms after a trip command was issued by R1, allowing CB to clear the fault.

The summary of test set 'B' results is presented in Table 6-4.

Table 6-4 Results for the test set 'B' at the BD7 feeder CB

Test	Results	Trip without blocking in seconds	Trip with blocking in seconds
B1	Expected Result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[1]
	Observed Result	0.910s	Trip due to the back up element at 1.085s, i.e. in additional 0.175s
B2	Expected Result	3.279s	No trip
	Observed Result	3.279s	No trip
B3	Expected Result	3.279s	No trip
	Observed Result	3.279s	No trip
B4	Expected Result	1.096s	Trip due to the back up element in 1.286s, i.e. in additional 0.190s[2]
	Observed Result	0.910s	Trip due to the back up element in 1.095s, i.e. in additional 0.185s
B5	Expected Result	0.765s	No blocking
	Observed Result	0.800s	No blocking
B6	Expected Result	0.100s	No blocking
	Observed Result	0.110s	No blocking
B7	Expected Result	0.255s	0.575[2]
	Observed Result	0.260s	0.620

[2] Downstream (R1) trips in 0.375s + 0.2s for breaker failure = 0.575s

Detailed test results, covering test set 'B', are presented in Appendix 'B'.

6.1.3 Test set 'C', blocking from R2 to BD7 feeder CB

Test set 'C' comprised seven tests as shown in Table 6-5.

Table 6-5 Blocking from R2 to the BD7 feeder CB

Test Number	Purpose
C1	Phase O/C on R2 blocks Phase O/C on CB
C2	Phase O/C on R2 blocks Ground O/C on CB
C3	Ground O/C on R2 blocks Ground O/C on CB
C4	Ground O/C on R2 blocks Phase O/C on CB
C5	SEF on R2 does not block Phase O/C or Ground O/C on CB
C6	Phase O/C or Ground O/C on R2 does not block Instantaneous O/C on CB
C7	Ground O/C on R2 blocks Phase O/C and Ground O/C on CB and tests breaker fail at R2

Tests C1–C4 were verified by first subjecting CB to a known fault current. Without blocking, CB would trip after a known time determined by the appropriate time-overcurrent curve. CB was then subjected to the same fault current again, except this time R2 was also subjected to a fault current simultaneously, causing it to send a blocking signal to CB. In the latter case, CB should not trip in the time observed in the former scenario.

Test C5 was verified in a similar manner to C1-C4 except in this case a blocking signal should not be sent. In this case, CB should trip in the same time as for the cases with and without blocking.

Test C6 was verified in a similar manner to C1-C4 except in this case, although a blocking signal is sent, the instantaneous overcurrent element at CB should not be blocked. In this case, CB should trip in the same time for both cases.

Test C7 was verified in the same way as Tests C1-C4, with the addition of the breaker fail feature. To test this, the fault current was continued at R2 for at least 200ms after R2 issued a trip command to its local breaker. The expected result was for the blocking signal to deassert 200ms after a trip command was issued by R2, allowing CB to clear the fault.

The summary of test set 'C' results is presented in Table 6-6.

Table 6-6 Results for the test set 'C' at the BD7 feeder CB

Test	Results	Trip without blocking in seconds	Trip with blocking in seconds
	Expected Result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[1]
	Observed Result	0.899s	Trip due to the back up element at 1.095s, i.e. in additional 0.196s
C2	Expected Result	3.279s	No trip
	Observed Result	3.272s	No trip
C3	Expected Result	3.279s	No trip
	Observed Result	3.279s	No trip
C4	Expected Result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[3]
	Observed Result	0.911 s	Trip due to the back up element at 1.096s, i.e. in additional 0.185s
C5	Expected Result	0.765s	No blocking
	Observed Result	0.769s	No blocking
C6	Expected Result	0.100s	No blocking
	Observed Result	0.115s	No blocking
C7	Expected Result	0.255s	Trip in 0.560s[3]
	Observed Result	0.260s	Trip in 0.625s

[3] Downstream (R2) trips in 0.360s + 0.200s for breaker failure = 0.560s

Detailed test results, covering test set 'C', are presented in Appendix 'C'.

6.1.4 Results Analysis

A representative analysis of the obtained results is presented below for test 'A6' only. This test is the most illustrative as it covers both the blocking scheme and circuit breaker failure scenarios.

The observed results were verified by analysing the event reports and Sequential Event Recorder (SER) from reclosers R2 and R1.

Test 'A6_1'

Figure 6.1 shows R1 being subjected to a ground fault (51G2). After approximately 14 cycles (0.28s) the ground element times out (51G2T is asserted) and a trip is initiated (TRIP).

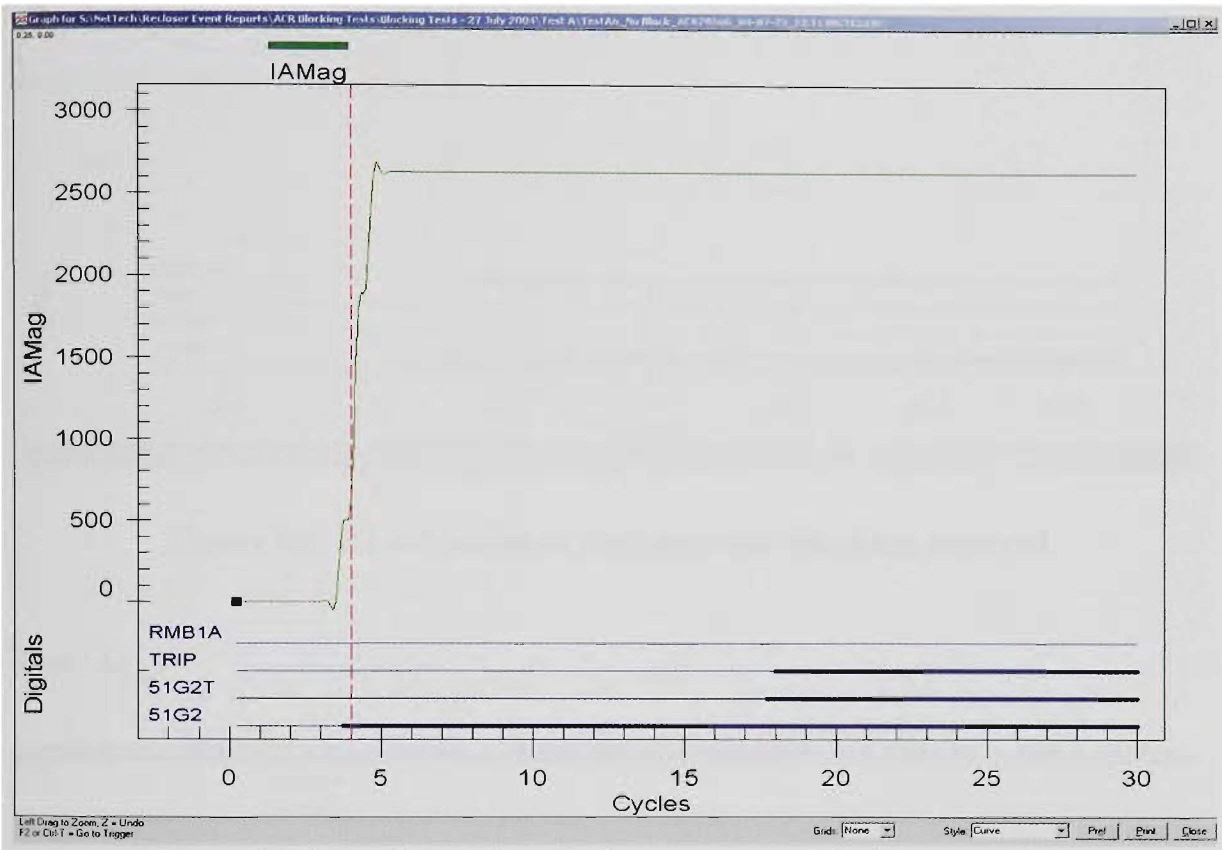


Figure 6.1 R1 subjected to fault current, no blocking received

Test 'A6_2'

Figure 6.2 shows R1 being subjected to a ground fault (51G2) as in Figure 6.1. This time a blocking signal is received (RMB1A) and no trip (TRIP) is initiated. This proves that R1 is being successfully blocked, and will not trip.

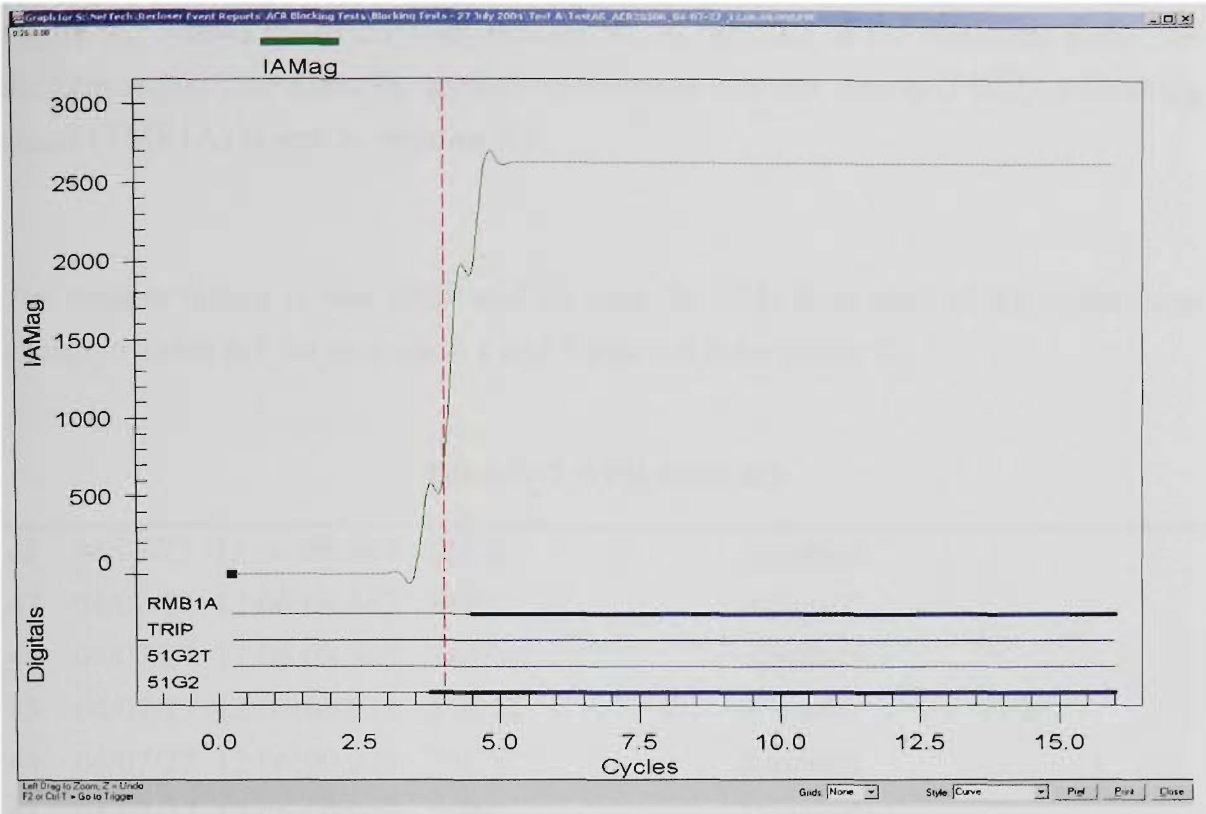


Figure 6.2 R1 subjected to fault current, blocking received

Test 'A6_3'

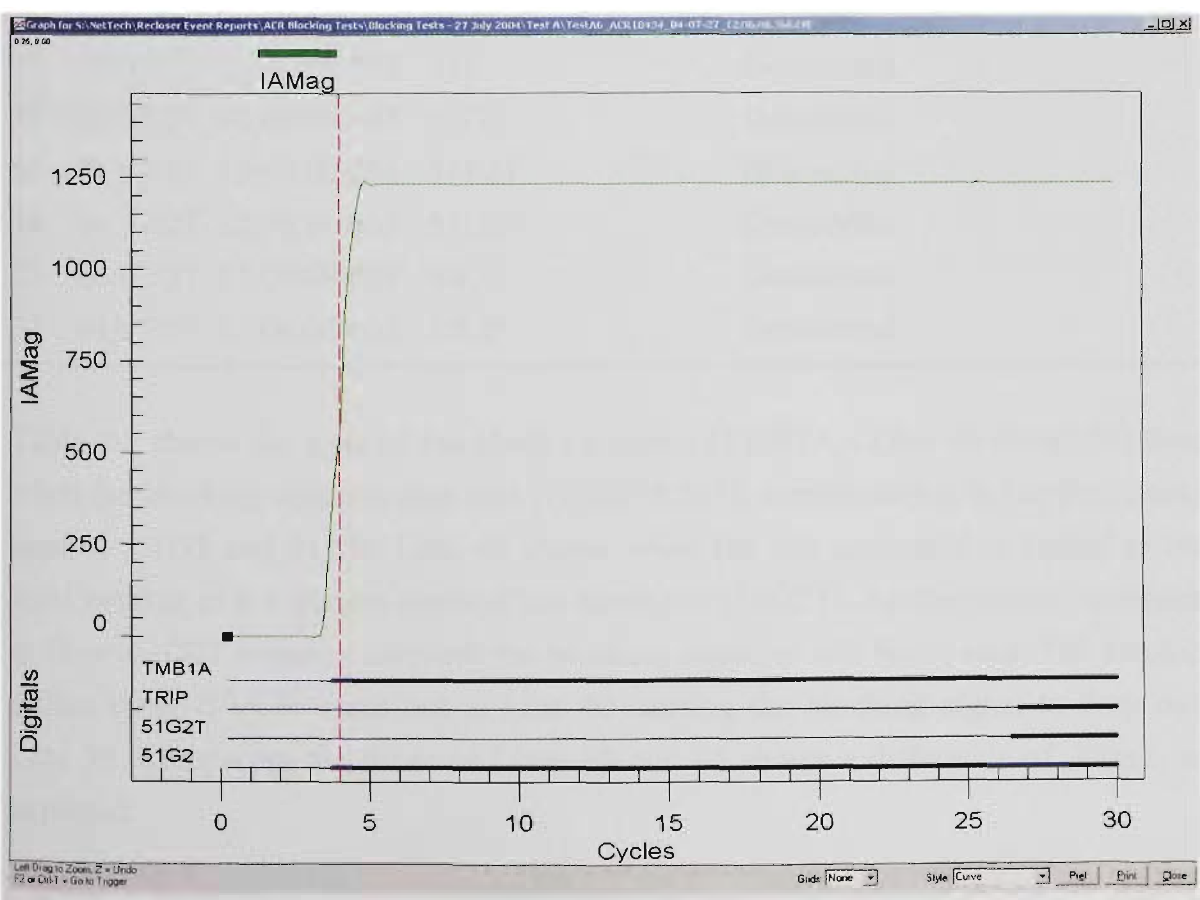


Figure 6.3 Event from downstream recloser R2

Figure 6.3 shows the event from recloser R2 at the start of the simulated fault. The diagram shows that when the ground overcurrent element asserts (51G2), a blocking signal (TMB1A) is sent to recloser R1.

The breaker failure is best illustrated through the SER from each of the reclosers as shown in Table 6-7 for recloser R2 and Table 6-8 for recloser R1.

Table 6-7 SER from R2

48	04/07/27	12:06:08.563	51G2	Asserted
47	04/07/27	12:06:08.563	51P2	Asserted
46	04/07/27	12:06:08.563	TMB1A	Asserted
45	04/07/27	12:06:09.018	51G2T	Asserted
44	04/07/27	12:06:09.023	79CY	Asserted
43	04/07/27	12:06:09.023	79RS	Deasserted
42	04/07/27	12:06:09.023	TRIP	Asserted
41	04/07/27	12:06:09.063	52A	Deasserted
40	04/07/27	12:06:09.218	SV2T	Asserted
39	04/07/27	12:06:09.218	TMB1A	Deasserted
38	04/07/27	12:06:09.388	51P2T	Asserted
37	04/07/27	12:06:09.578	51P2	Deasserted
36	04/07/27	12:06:09.583	51G2	Deasserted
35	04/07/27	12:06:09.598	51P2T	Deasserted
34	04/07/27	12:06:09.603	51G2T	Deasserted
33	04/07/27	12:06:09.603	SV2T	Deasserted
32	04/07/27	12:06:09.608	TRIP	Deasserted

Table 6-7 shows the state of the blocking signal (TMB1A). Line 46 shows the time when the blocking signal is first sent (12:06:08.563), corresponding to the fault being applied (51G2 and 51P2). Line 42 shows when the trip command is issued to the local breaker as the ground element has timed out (51G2T). As the current continues to flow (51G2T remains asserted) the blocking signal is still being sent. The breaker failure timer (SV2T) times out in Line 40 causing the blocking signal to drop out, Line 39. Comparing the times of Lines 39 and 45 shows a difference of 200ms, as expected.

Table 6-8 SER from R1

86	04/07/27	12:06:08.308	51G2	Asserted
85	04/07/27	12:06:08.308	51P2	Asserted
84	04/07/27	12:06:08.308	TMB1B	Asserted
83	04/07/27	12:06:08.323	RMB1A	Asserted
82	04/07/27	12:06:08.588	51G2T	Asserted
81	04/07/27	12:06:08.843	51P2T	Asserted
80	04/07/27	12:06:08.978	RMB1A	Deasserted
79	04/07/27	12:06:09.008	79CY	Asserted
78	04/07/27	12:06:09.008	79RS	Deasserted
77	04/07/27	12:06:09.008	TRIP	Asserted
76	04/07/27	12:06:09.038	52A	Deasserted
75	04/07/27	12:06:09.203	SV2T	Asserted
74	04/07/27	12:06:09.203	TMB1B	Deasserted
73	04/07/27	12:06:09.328	51G2	Deasserted
72	04/07/27	12:06:09.328	51P2	Deasserted
71	04/07/27	12:06:09.348	51G2T	Deasserted
70	04/07/27	12:06:09.348	51P2T	Deasserted

Table 6-8 shows the blocking signal being received from R2 (RMB1A). RMB1A is first asserted when R2 detects a fault condition (Line 84). Both the phase and ground elements time out (51P2T and 51G2T) but no trip is initiated as the blocking signal is asserted. After the breaker fails at R2, the blocking signal is dropped and is recorded at R1 (Line 80). A trip is initiated immediately after (Line 77) which proves the correct operation of the breaker failure feature.

CHAPTER 7

CHALLENGES ENCOUNTERED

7.1 Conductor clashing

Due to the very high fault currents flowing along the feeders under fault conditions, secondary faults were observed on some feeders in the feeder sections located upstream from the fault location. These secondary faults manifested themselves mainly as conductor clashing. They were due to the overhead lines construction practices followed by the network owners preceding AGLE. These practices did not take into account the application of 'in line' reclosers on urban distribution feeders and the effects they might cause as it was not the practice at the time.

It became evident that some of the urban overhead distribution feeders were of substandard construction for the application of the 'in line' reclosers only after these reclosers were installed on these feeders as part of the recloser installation program. The occurrences of secondary faults were due to the fact that with the introduction of the 'in line' reclosers, at one third and two thirds of the average feeder loads, existing overhead distribution lines, of inadequate construction standards for 'in line' reclosers, ended up upstream from these newly installed reclosers. As a result, when subjected to high fault currents the conductors clashed, wrapped with each other and/or got dislodged from the insulators causing secondary faults. Faster reclose times introduced by the 'in line' reclosers on urban distribution feeders also contributed to the problem. Before the installation of the 'in line' reclosers these problems were not evident as normally there are no overhead lines, upstream from the Zone Substation circuit breaker, built to distribution feeder standards.

Remedial action plan was put in place in order to rectify the problems with the feeders characterised by substandard construction. This action plan was implemented by AGLE in the order of priority given below:

- Survey of all urban distribution feeders that were designated for the 'in line' recloser installations.

- Cross-arm replacements with cross-arms of an improved construction, i.e. bigger spacing between phases, insulators of an improved construction.

- Installation of intermediate H.V. poles to reduce bay conductor length (if permissible).

- Installation of H.V. spreaders (not preferred).

As a result, as of the time of writing of this thesis, all AGLE urban distribution feeders with 'in line' reclosers installed have been surveyed and corrective actions were implemented on feeders found in need of H.V. line construction upgrades. A procedure was established for the future 'in line' recloser installations to have the urban distribution feeders surveyed prior to the 'in line' recloser installation(s).

Consequently, the secondary faults occurring purely due to the presence of 'in line' reclosers on urban distribution feeders were eliminated. The secondary faults do still occur on these feeders, due to a variety of fault types affecting the feeders, but they are much less frequent than before the implementation of the remedial plan depicted above.

7.2 Recloser damage due to a lightning strike

On 04 January 2004 recloser No 28506, located in Ripplebrook Drive, was hit by a lightning strike. This recloser was a part of the pilot full blocking scheme implemented on BD7 feeder to validate the theoretical work carried out by the author of this thesis on the indirect fault detection and location scheme. The event log files were salvaged from the recloser controller on 28 January 2004. A representative event with post fault signature waveform is shown in Figure 7.1.

The damaged recloser was de-installed and sent to the Whipp & Bourne assembly plant in Brisbane for joint investigations into the incident to ensure that the nature of the incident is well understood. Agility's investigative committee, comprising the author of this thesis and another Agility representative, participated in these joint investigations with Whipp & Bourne in Brisbane on 27 February 2004. The verdict of the committee confirmed a direct lightning strike and classified it as a force de majoure event. The damaged recloser was beyond repairs as illustrated in a series of photographs in Figure 7.2.

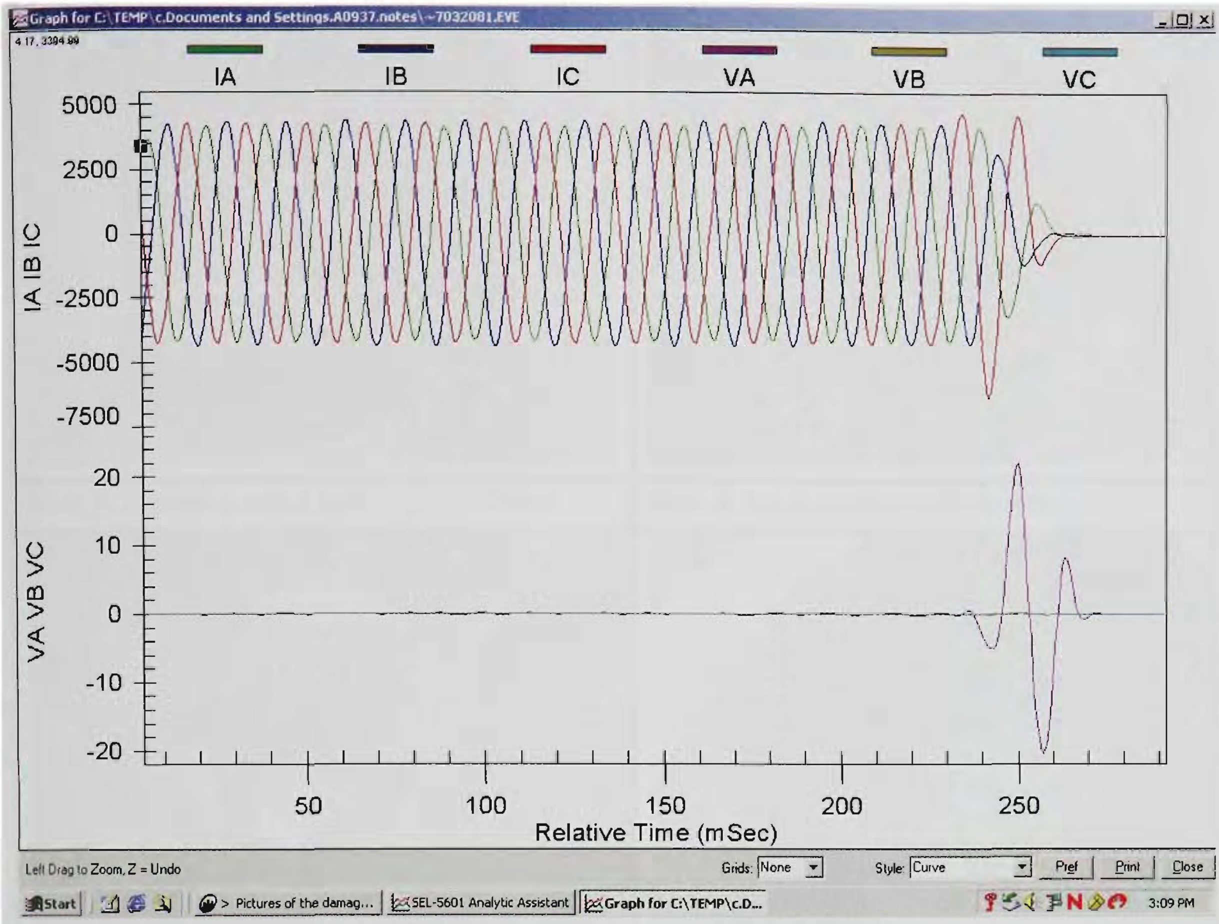
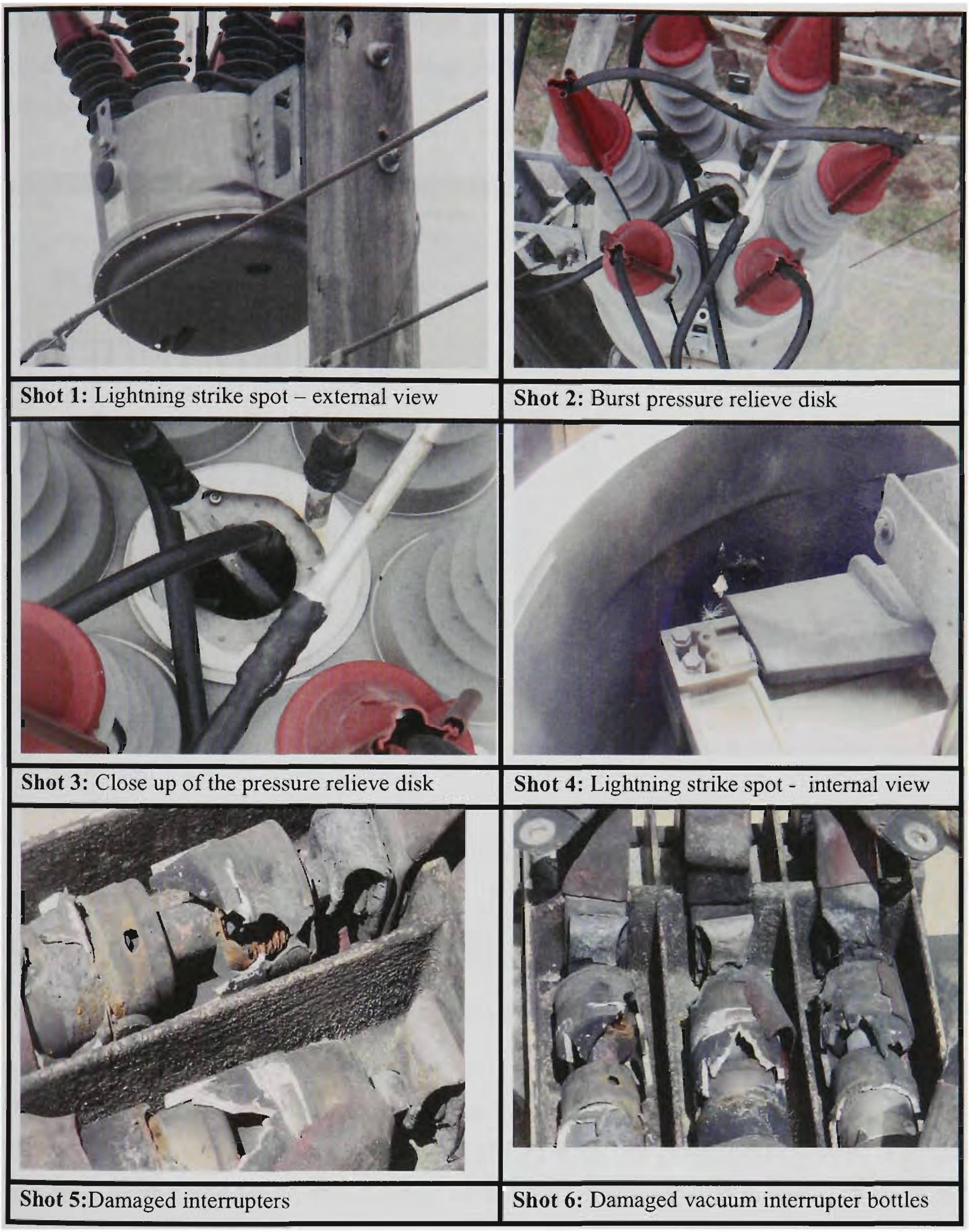


Figure 7.1 Recloser No 28506 – waveform subsequent to a lightning strike

The consequence of this event had an adverse effect on the overall progress with the recloser installation program as additional funds were required: to purchase and install a replacement recloser, to resplice the fibre optic connections and reprogram the protection settings. These works were completed in the year 2004, i.e. the project experienced a delay of 11 months.



Shot 1: Lightning strike spot – external view

Shot 2: Burst pressure relieve disk

Shot 3: Close up of the pressure relieve disk

Shot 4: Lightning strike spot - internal view

Shot 5: Damaged interrupters

Shot 6: Damaged vacuum interrupter bottles

Figure 7.2 Photographs of the recloser damaged by a lightning strike

7.3 Residual currents and voltages phenomenon occurring after recloser tripping

On 13 October 2003 during a routine monthly scrutiny of the recloser event files it was noted that recloser's No 14432 trip operation, dated from 10 September 2003, showed residual current and voltage signatures present subsequent to a recloser trip operation as shown in Figure 7.3. These residual current and voltage continued for a time much longer than expected subsequent to the trip time indicated on the diagram below by a vertical dashed line.

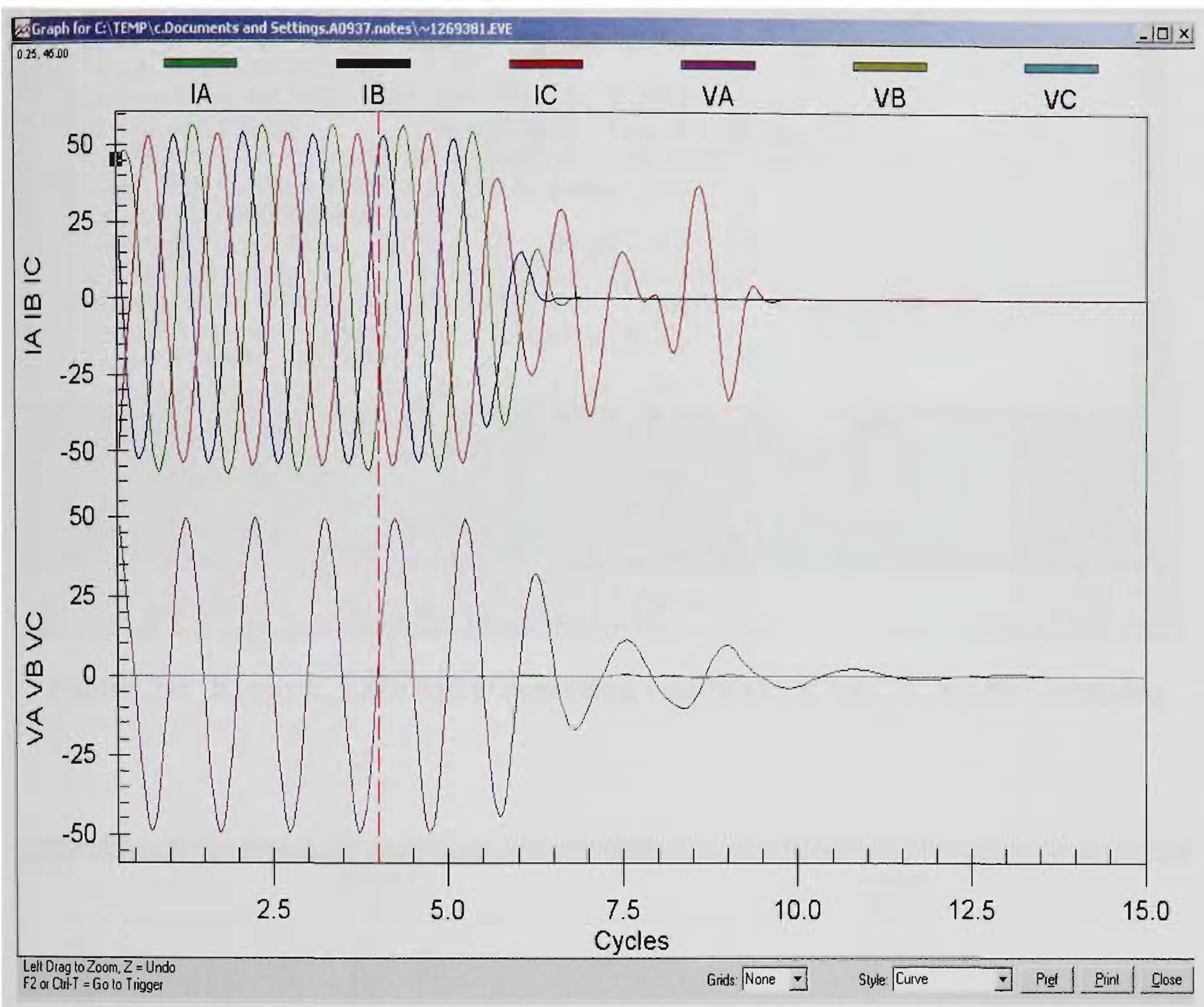


Figure 7.3 Residual current and voltage waveforms after tripping

The event log file entry, shown in Figure 7.4, indicated that the trip operation was due to a low-level sensitive ground fault (SEF) with the magnitude of 19A. Further scrutiny of the signature waveforms, as shown in Figure 7.5, revealed that these residual current and voltage were present in Phase C and Phase A respectively. Currents in Phase B and Phase C and voltages in Phase B and Phase C were not effected by this phenomenon as shown in Figure 7.6.

Further recloser hardware analysis indicated the possibility of Phase C vacuum interrupter not interrupting the current flow correctly. It was suspected that the vacuum bottle seal failed letting SF6 insulating gas in and allowing for residual current flow. To ensure that this was an isolated case of the vacuum interrupter failure a thorough investigation of all available recloser event log files was launched.

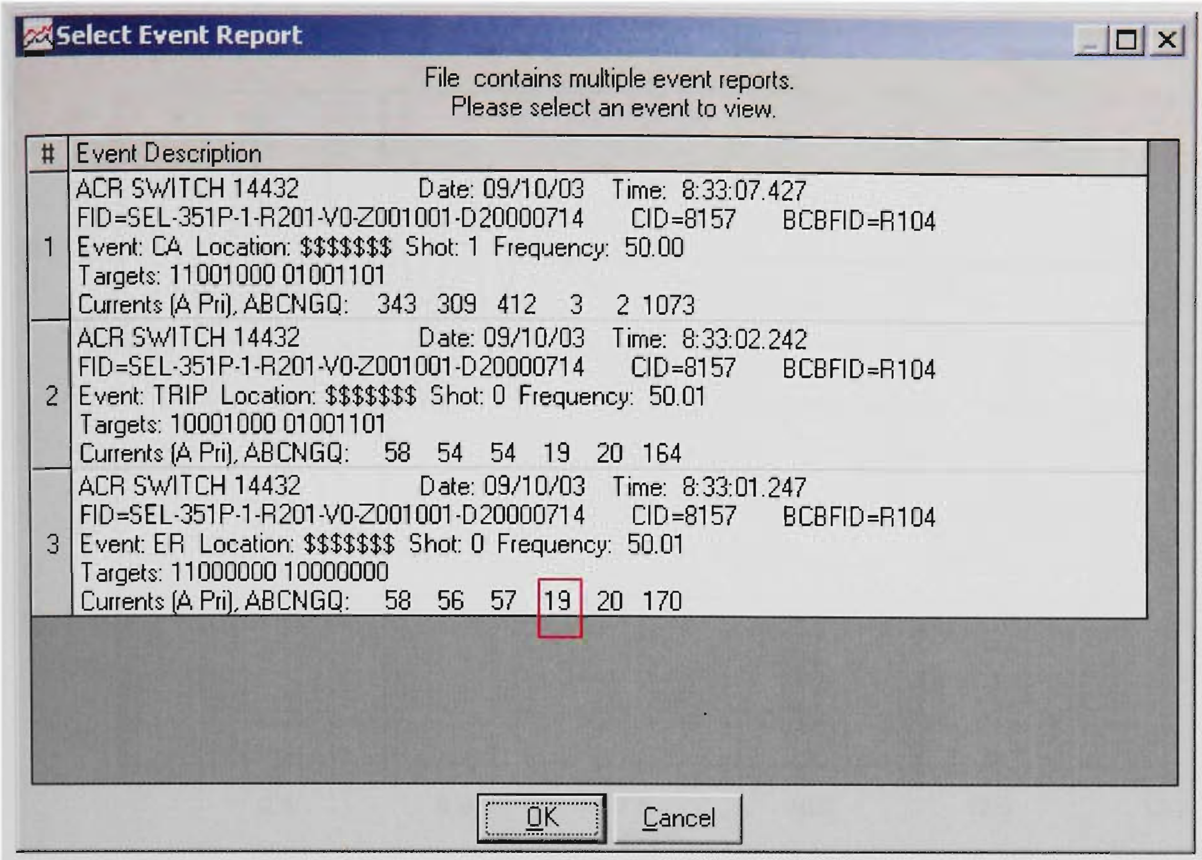


Figure 7.4 Event log file entry depicting residual current flow after tripping

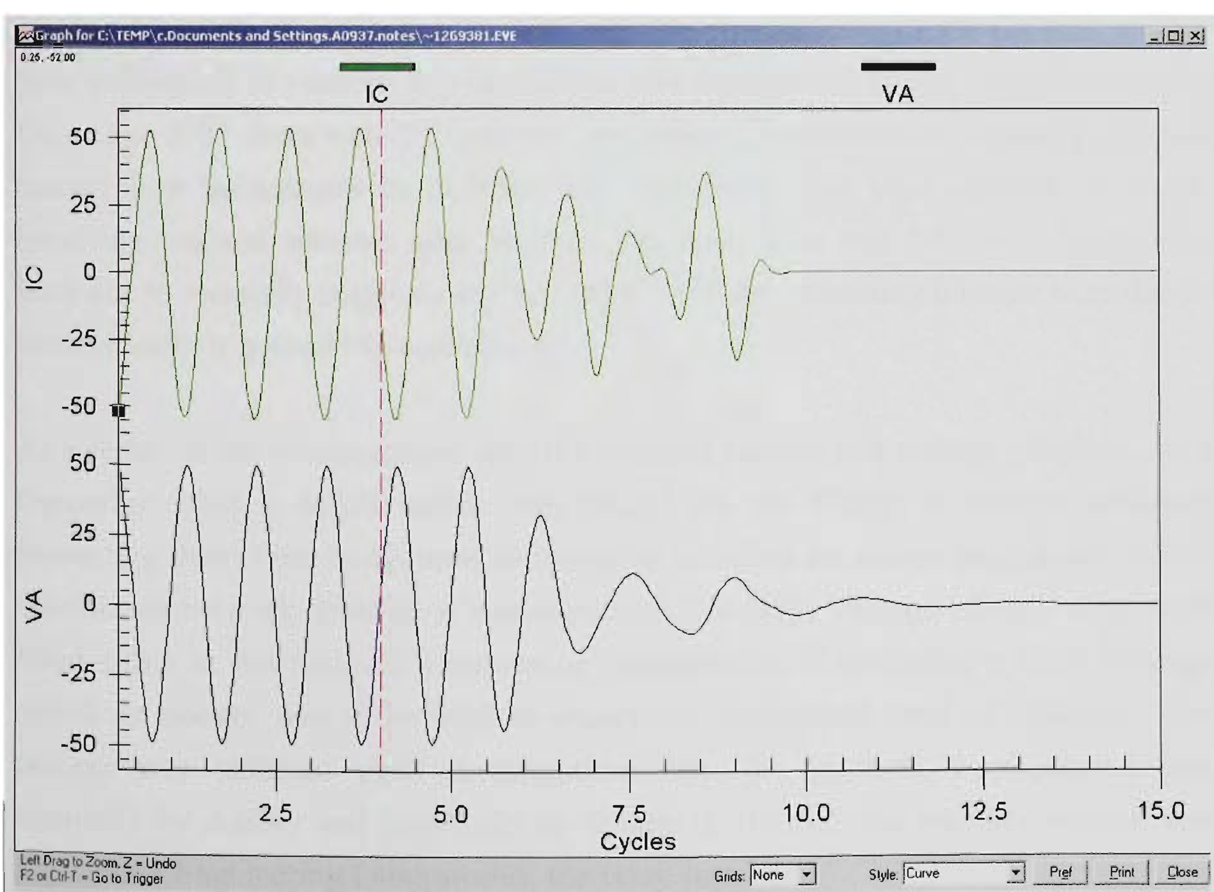


Figure 7.5 Residual current flow in Phase C and voltage presence in Phase A

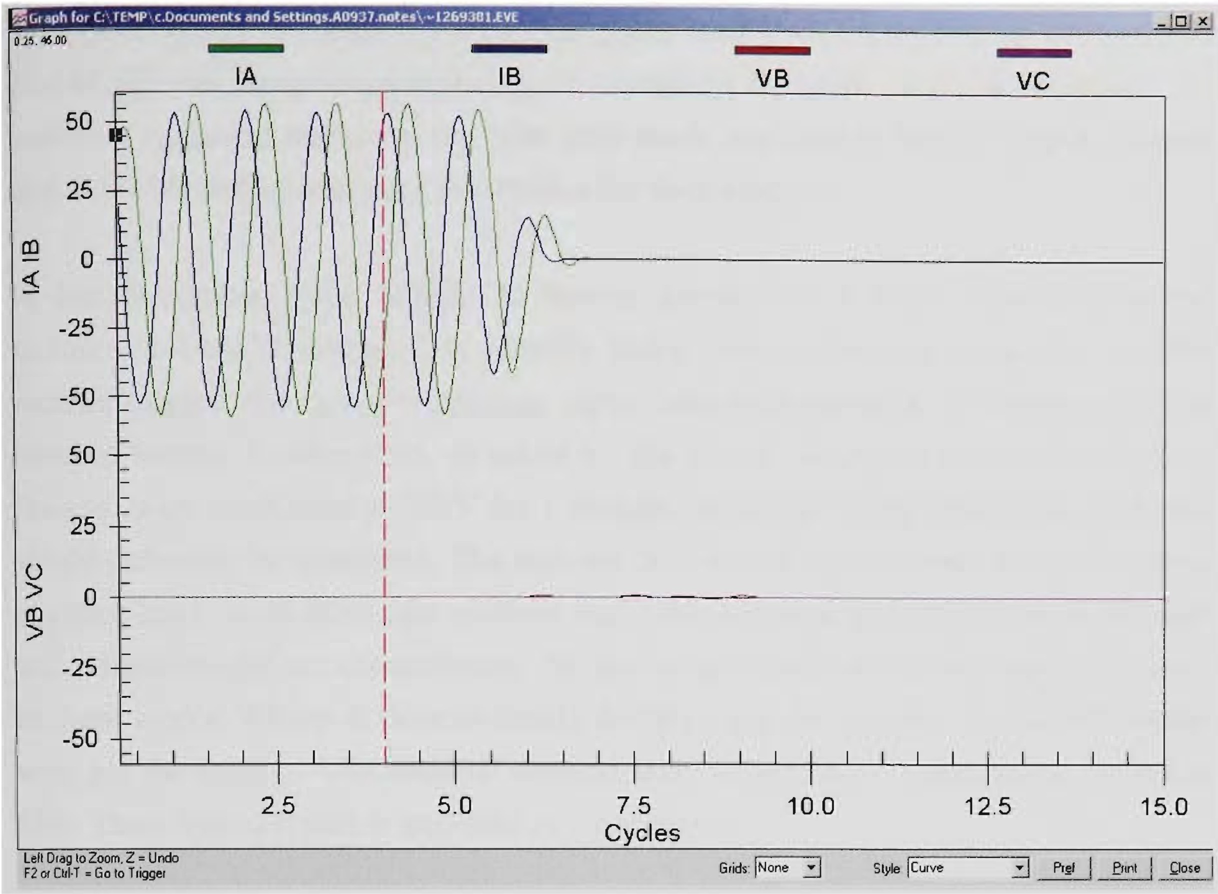


Figure 7.6 Absence of residual currents in Phases A, B and voltage in Phases B, C

The results of the investigation showed that the phenomenon of the residual current flow subsequent to recloser trip operations was widespread. It was identified that by December 2003 there were 17 reclosers with signature waveforms depicting residual current flow subsequent to recloser trip operations. The total number of events involving residual currents after recloser trip operations was fifty-two. Thirty-nine were due to manually triggered trip operations and the remaining thirteen were due to automatically triggered trip operations.

As a result of the investigations into the residual current and voltage problem, on 8 December 2003 a defect notice was placed on all Whipp & Bourne reclosers preventing them from being used as points of isolation for access permits on AGLE distribution network. Instead, it was stipulated that High Voltage bridges were to be lifted either at the recloser locations or upstream or, if available, a High Voltage switch or isolator was to be used to ensure the guaranteed level of isolation. This process was enforced until investigations into the problem were carried out, internally by Agility and externally by Whipp & Bourne, the recloser vendor, and Schweitzer Engineering Laboratories, the relay supplier.

To enable Whipp & Bourne staff to carry out their own investigations the recloser No144232 was de-installed and shipped to Whipp & Bourne plant in Brisbane. All available signature waveform log files were made available to both Whipp & Bourne and Schweitzer Engineering Laboratories for their analyses.

In late December 2004, Whipp & Bourne carried out a 42kV flash test on the recloser No144232 designed to identify leaky vacuum interrupter bottles and the recloser passed the test without any signs indicating potential problems with the vacuum bottles. Further tests, as asked by the United Kingdom office of Whipp & Bourne, were conducted at 70kV for 1 minute, as at this voltage level a faulty bottle would definitely be identified. The recloser No 144232 again passed the test without any problems. In addition, the recloser tank was degassed and the inside of the tank was scrutinised for arc contaminants. No arc contaminants were found and as a result of these works, Whipp & Bourne finally declared that the vacuum interrupter bottles were not the source of the residual currents and voltages as recorded in the event log files. Their formal report is enclosed in Appendix 'G'.

On 13 February 2004, Agility on its own accord, carried out live investigative tests on recloser No 12723, i.e. one of the reclosers effected by the phenomenon. The aim of the tests was to determine the origin of the currents recorded in the SEL 351P relay subsequent to the recloser trip operation. Two High Voltage feeders on AGLE distribution network were paralleled, with recloser No 12723 as a paralleling point, so that the tests could be carried out without supply interruptions to customers. The tests covered 'on load' and 'off load' recloser switching aimed to record the phenomenon of residual currents and voltages under controlled conditions. The 'on load' tests were carried out under various loading conditions.

The currents throughout all tests were simultaneously recorded:

- By the SEL 351P relay itself.
- At the CT secondary circuits.
- At the primary conductors.

The currents recorded by the SEL351P relay were monitored using a laptop computer and the SEL 5601 Analytic Assistant software. The CT secondary currents were monitored and recorded using Hioki recorders connected into the CT secondary links in the recloser controller. The primary currents were monitored using an Amp Stick attached to the end of a switch stick with a readout device at ground level.

The test plan comprised the following steps:

- Taking out 'Sanction for Testing'.
- Installation of instrumentation and checking correlation between instruments.
- Configuration of the network to ensure about 50 A load current in the recloser.
- Opening the recloser to break a parallel between feeders and observing/recording current changes.
- Closing the recloser and observing/recording current changes.
- Repeating steps 4 and 5 up to five times, if necessary, until the phenomenon is observed.
- Opening the recloser and then opening isolators 18625 and checking that the section of overhead between the recloser and the isolator is de-energised
- Repeating steps 4 and 5 up to 5 times and observing/recording current changes until the phenomena is observed.
- Analysis of information and repeating tests as required.
- Removal of instrumentation and cancellation 'Sanction for Testing'.

Although the tests carried by Agility alone did not fully resolve the problem, Agility was able to confirm that there was not a problem with the vacuum interrupter contacts. There was no corresponding current detected in the primary conductor by an independent current measuring device placed on the load side of the recloser after it was opened. The problem was narrowed down to the CT secondary circuit picking up interference signals that the SEL351P relay interpreted as a small current when the recloser was open.

As a result of Agility's investigations, Whipp & Bourne reclosers were deemed to be fully compliant with the AGLE High Voltage operational standards and could be used as points of isolation for works under access permits subject to the formal explanation of the phenomenon by Whipp & Bourne and Schweitzer Engineering Laboratories. The standard practice of testing the isolated line before earthing applied as usual.

The defect notice remained in force until Whipp & Bourne and Schweitzer Engineering Laboratories produced formal reports, explaining the phenomenon, on 17 May 2004 and 20 May 2004 respectively. The reports confirmed that the recordings of residual currents and voltages after recloser tripping were due to interference signals and erroneous scaling factors applied by the SEL 5601 Analytic Assistant software when dealing with very small currents. These reports, explaining the phenomenon in detail, are enclosed in Appendix 'F' titled 'Reports on investigations into 351P relays recording residual current and voltage traces after tripping the GVR27 reclosers'.

The remaining unresolved issue, although of collateral nature, was related to the ability of the Whipp and Bourne recloser to act as an effective isolator following the failure of a vacuum interrupter bottle. Concern existed as to the breakdown strength of a vacuum interrupter bottle that had lost its vacuum and as a result absorbed SF6 gas. In order to resolve this issue Agility approached Whipp & Bourne seeking information on the size of the break in the vacuum interrupter bottle and the dielectric strength of SF6 gas at the pressure it is used at in the GVR27 recloser. Whipp & Bourne advised that the contacts in the vacuum interrupters when in the open position have a separation of 14mm. They have also advised that conservatively the dielectric strength of the SF6 at atmospheric pressure is 6kV/mm. This meant that a vacuum bottle that had lost its vacuum and drawn in the SF6 gas would be expected to have minimum breakdown strength of 85kV, i.e. a sufficient level of isolation to serve as an isolation point for works under access permit.

With the establishment of the dielectric strength maintained across 14mm gap when filled with the SF6 gas, an adequate level of comfort and confidence with the recloser switch unit was achieved and the final issue was closed. It was proven during the investigations that the oscillographic records, provided by the SEL351P relays, were misleading and that special care needed to be taken when interpreting signature waveforms involving small currents and voltages using the SEL 5601 Analytic Assistant software. This combined with Agility's standard access permit procedures was formally deemed as sufficient to ensure the safety of any work party utilising a

Whipp & Bourne GVR27 recloser as an isolation point. Consequently, the defect notice, placed on GVR27 reclosers on 8 December 2003, was removed on 21 May 2004.

Although the origin of the phenomenon was clarified to the satisfaction of all parties involved nevertheless the recloser project suffered a delay of 6 months.

CHAPTER 8

FUTURE DIRECTIONS AND CONCLUSION

8.1 Future directions

At the conclusion of this project, a number of innovative ideas were promoted combining the author's work experience and knowledge gained during the project implementation. They can be categorised into two main themes, i.e. hardware innovation and distribution network automation.

8.1.1 Hardware innovation

The recloser vendors that plan to expand their business or the emerging ones that plan to enter a conservative and yet very competitive recloser market need to present a new generation of reclosers characterised by compelling differentiating factors and meeting, at the same time, operational and environmental standards and pressures. A special challenge presents an implementation of a new recloser platform on a distribution network already equipped with a particular brand of reclosers. It is very difficult for a utility company to introduce a new recloser type not only because of engineering issues, such as an overall system's interoperability, but mainly because of commercial and philosophical reasons.

These differentiating factors for the new generation reclosers at this point in time are listed below. They are the main areas for future research and hardware development:

- Solid insulation, i.e. no SF6 gas, with phase to ground BIL of 150kV.

- Lightweight under cross-arm construction, i.e. it minimises the installation costs and increases the radio antenna installation height needed to achieve a 'line of sight'.

- Manual close mechanism, capable of safe operations even when inadvertently closing on a fault, to be able to close a recloser when its controller is inoperational. This feature is very important in urban applications where by-pass switches are not installed and minutes off supply cost dearly.

- Magnetic actuator to reduce the battery size and prolong its life.

- Vacuum interruptors with the fault current breaking capability of minimum 12.5 kA.

- Solid state (triacs) open CT protection circuitry fitted in the recloser tank rather than in the controller box. This allows communications technicians to work safely on the recloser controllers in full compliance with regulations. It also eliminates the issues with variable lengths of umbilical cable when recloser tank is equipped with conventional interposing CTs.

- Scalable protection platform to be able to target both crude and sophisticated protection requirements.

- Recloser relays capable of Ethernet communications.

- Recloser relays capable of protection grade peer to peer communications, i.e. suitable for blocking scheme applications.

8.1.2 Distribution network automation

Distribution network automation is heavily dependant on four factors:

- Accurate fault location.

- Capable fault breaking switch hardware installed at critical points on the feeders.

- Protection grade communications.

- Capable SCADA system equipped with Distribution Management System (DMS).

The distribution network automation can be introduced gradually targeting the most critical areas first which was the approach adopted by the author of this thesis. The approach needs to offer appropriate scalability and commercial or regulatory incentives. For these reasons, the recommended approach to the distribution network automation in the future is to:

- Install 'in line' reclosers in feeder backbones in preparation to the introduction of looped schemes augmented by protection grade communications.

- Install fault indicators, with affordable radio communications, on distribution feeders in strategic locations such as at the spur points.

- Install reclosers on normally open points in preparation for rapid network reconfigurations.

- Control and monitor the above listed devices by an expedient SCADA host capable of utilising advanced fault detection and location techniques in conjunction with the protection data supplied from the field locations.

All the aforementioned challenges require significant commitment to research and development and they constitute the basis for future work on the improvement of distribution networks operation.

8.2 Conclusion

As a result of this project 53 reclosers were installed on AGLE distribution network. There are 3 partial blocking schemes and one full blocking scheme in operation. There is also one hybrid scheme wherein two reclosers are installed on a feeder in 'Y' configuration with the two reclosers independently blocking the Zone Substation CB. The overall approach to communications has been revised with the focus being on leveraging off the protection grade communications when installing other types of communications applications.

The overall system's operation is monitored on regular basis to provide data for its performance assessment. An audit, carried out in year 2005 on AGLE distribution network, proved that the recloser project has been by far the best measure of improving Reliability of Supply, mainly SAIFI and SAIDI, indices which are reported to the Essential Services Commission on regular basis. The most compelling evidence of the system's performance is provided by the comparison of the improvement in SAIFI and MAIFI indices over the years 2002, 2003, 2004 and

2005. This comparison is presented in Table 8-1. In conclusion it can be declared, that the achieved results prove the investment made is bringing regular returns and that the system performs according to its design specifications. The scalability of the system allows for its expansion on as per need basis thus incurring the minimum capital expenditure.

Table 8-1 Average % reduction in AGLE MAIFI and SAIFI

Index	Year 2002[A]	Year 2003[B]	Year 2004[C]	Year 2005[D]
AGLE MAIFI reduction	0.140*	0.1255	0.1275	0.2850
AGLE SAIFI reduction	0.017*	0.0530	0.0752	0.1657
Combined AGLE MAIFI and AGLE SAIFI	0.157*	0.1785	0.2027	0.4507
ESC target MAIFI	0.56	0.53	0.52	0.51
ESC target SAIFI	1.44	1.4	1.37	1.35
Combined ESC MAIFI and SAIFI	2	1.93	1.89	1.86
Average % reduction in combined MAIFI and SAIFI	7%*	9%	11%	24%

* half yearly results

[A] 31 reclosers operational throughout the year

[B] 37 reclosers operational throughout the year

[C] 51 reclosers operational throughout the year

[D] 54 reclosers operational throughout the year

BIBLIOGRAPHY

References

1. *SEL-351P Recloser Control Manual 20021119* 4th ed. 2350 NE Hopkins Court, Pullman, WA, USA: Schweitzer Engineering Laboratories, 2002.

2. Beder S, *Power Play: the fight for control of the world's electricity*. Melbourne, Victoria, Australia: Scribe Publications Pty Ltd, 2003, pp. 223-274.

3. Kalam A, Spicer A, Coulter R, Klebanowski A, Biasizzo C, McDonald H, *Power System Protection* 3rd ed. Melbourne, Victoria, Australia: Victoria University of Technology, 1997, Chapter 15, pp.1-34.

4. Kalam A, Klebanowski A, Bell H, *Power System Protection Short Course Program*. Melbourne, Victoria, Australia: Victoria University of Technology, 1993.

5. *The Australian Gas Light Company Concise Annual Report 2005*. Sydney, New South Wales, Australia: The Australian Gas Light Company, 2005.

6. *Electricity Distribution Price Determination 2001 – 2005, Statement of Purpose and Reasons*. Melbourne, Victoria, Australia: Essential Services Commission, September 2000, Volume 1.

7. Diaz HR, López MT, 'Fault location techniques for electrical distribution networks: a literature survey', *Proceedings of the Fifth IASTED International Conference on Power and Energy Systems*, Benalmadena, Spain, 15-17 June 2005, pp. 311-318.

8. Reineri CA, Alvarez C, 'Load research for fault location in distribution feeders', *IEE Proceedings. Generation, Transmission & Distribution*, Volume 146, Issue 2, March 1999, pp. 115–120.

9. Tang Y, Wang HF, Aggarwal RK, Johns AT, 'Fault indicators In Transmission and Distribution Systems', *Proceedings of the International Conference on Electric Utility Deregulation and Restructuring and Power Technologies*, London, UK, 4-7 April 2000, pp. 238-243.

10. Novosel D, Hart DG, Udren E, Saha MM, 'Fault Location Using Digital Relay Data', *IEEE Computer Applications in Power*, Volume 8, Issue 3, July 1995, pp. 45–50.

11. Bengiamin NN, Jensen CA, McMahon H, 'PC-Based Fault Finder', *IEEE Computer Applications in Power*, Volume 6, Issue 3, July 1993, pp. 22–26.

12. Hong HW, Colwell DH, 'Intelligent System Identifies and Locates Transmission Faults', *IEEE Computer Applications in Power*, Volume 10, Issue 2, April 1997, pp. 31–35.

13. Girgis AA, Fallon CM, Lubkeman DL, 'A fault location technique for rural distribution feeders', *IEEE Transactions on Industry Applications*, Volume 29, Issue 6, November-December 1993, pp. 1170-1175.

14. Minfang P, Yigang H, Yi T, Hongli H, Xueyi S, 'Line Fault Location in a Distribution Network Based on K-fault Diagnosis Method', *Proceedings of the 2003 IEEE International Conference on Robotics, Intelligent systems and signal processing*, Changsha, China, October 2003.

15. Choi MS, Lee SJ, Lee DS, Jin BG, 'A new fault location algorithm using direct circuit analysis for distribution systems', *IEEE Transactions on Power Delivery*, Volume 19, Issue 1, January 2004, pp. 35-41.

16. Zhang HF, Pan ZC, Sang ZZ, 'Fault locating in ungrounded and compensated systems', *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection, 2004*, Volume 2, Amsterdam, Holland, 5-8 April 2004, pp. 469-472.

17. Taalab AI, Darvish HA, Alam MA, Elkhazendar M, Aly GE, 'Novel approaches enhancing accuracy of fault location algorithms for distribution feeders', *Proceedings of the 2004 International conference on Electrical, Electronic and Computer Engineering, ICEEC'04*, Cairo, Egypt, 5-7 September 2004, pp. 858-863.

18. Yu DC, Khan SH, 'An Adaptive High and Low Impedance Fault Detection Method', *IEEE Transactions on Power Delivery*, Volume 9, Issue 4, October 1994, pp. 1812–1820.

19. Kachesov VE, Ovsajnnikov AG, Lavrov VU, 'Outcomes of overvoltage monitoring and fault location in underground distribution networks', *Proceedings of the Sixth Russian-Korean International Symposium on Science and Technology, 2002. KORUS-2002*, Novosibirsk, Russia, 24-30 June 2002, pp. 447-451.

20. Kachesov VE, Ovsajnnikov A, 'On-line fault locating in distribution networks', *Proceedings of the Seventh Korea-Russia International Symposium on Science and Technology, 2003. KORUS 2003,* Volume 2, Ulsan, Korea, 28 June-6 July 2003, pp. 484-488.

21. Bo ZQ, Weller G, Redfern MA, 'Accurate fault location technique for distribution system using fault-generated high frequency transient voltage signals', *IEE Proceedings. Generation, Transmission & Distribution*, Volume 146, Issue 1, January 1999, pp. 73–79.

22. Navaneethan S, Soraghan JJ, Siew WH, Muirhead R, Livie J, 'An Automatic Fault Detection and Location Technique in Low Voltage Distribution Networks', *Proceedings of the International Conference on Energy Management and Power Delivery, 1998. EMPD'98*, Volume 2, Singapore, 3-5 March 1998, pp. 732-736.

23. Navaneethan S, Soraghan JJ, Siew WH, McPherson F, Gale PF, 'Automatic Fault Location Using Intelligent Processing', *Proceedings of the International Conference on Electric Power Engineering, 1999. PowerTech Budapest 99*, Budapest, Hungary, 29 August – 2 September 1999, p. 29.

24. Navaneethan S, Soraghan JJ, Siew WH, McPherson F, Gale PF, 'Automatic Fault Location for Underground Low Voltage Distribution Networks', *IEEE Transactions on Power Delivery*, Volume 16, Issue 2, April 2001, pp. 346-351.

25. Hizam H, Crossley A, Gale PF, Bryson G, 'Fault section Identification and Location On A Distribution Feeder Using Travelling waves', *Proceedings of the Power Engineering Society Summer Meeting, 2002 IEEE*, Volume 3, Chicago, IL, USA, July 2002, pp. 1107-1112.

26. Thomas DWP, Carvalho RJO, Pereira ET, 'Fault Location in Distribution Systems Based on Travelling Waves', *Proceedings of the 2003 IEEE Bologna Power Tech Conference*, Volume 2, Bologna, Italy, 23-26 June 2003, p. 5.

27. Thomas DWP, Christopoulos C, Carvalho RJO, Pereira ET, 'Single and double ended travelling-wave fault location on a MV system', *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection, 2004*, Volume 1, Amsterdam, Holland, 5-8 April 2004, pp. 200-203.

28. Xiangjun Z, Li KK, Zhengyi L, Xianggen Y, 'Fault Location Using Travelling Wave for Power Networks', *Conference Record of the 2004 IEEE Industry Applications Conference, 2004. 39th IAS Annual Meeting*, Volume 4, Seattle, WA, USA, 3-7 October 2004, pp. 2426-2429.

29. Magnago FH, Abur A, 'A new fault location technique for radial distribution systems based on high frequency signals', *Proceedings of the IEEE Power Engineering Society Summer Meeting, 1999*, Volume 1, Edmonton, Alberta, Canada, 18-22 July 1999, pp. 426-431.

30. Nouri H, Wang C, Davies T, 'An accurate Fault Location Technique for Distribution Lines with Tapped Loads Using Wavelet Transform', *Proceedings of the 2001 IEEE Power Tech Conference*, Volume 3, Porto, Portugal, 10-13 September 2001.

31. Qianli S, Xinzhou D, Shenxing S, Bin S, Jiali H, 'A new principle of fault selection for distribution', *Proceedings of the Seventh IEE International Conference on Developments in Power Systems Protection, 2001*, Amsterdam, Holland, 9-12 April 2001, pp. 379-382.

32. Moshtagh J, Aggarwal RK, 'A new approach to Fault Location in a single core underground cable system using combined fuzzy logic and wavelet analysis', *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection, 2004*, Volume 1, Amsterdam, Holland, 5-8 April 2004, pp. 228-231.

33. Tag El Din ES, Gilany M, Abdel Azziz MM, Ibrahim DK, 'A wavelet-Based Fault Location technique for Aged Power Cables', *Proceedings of the Power Engineering Society General Meeting, 2005, IEEE*, Volume 3, San Francisco, USA, 12-16 June 2005, pp. 2485-2491.

34. Yan F, Chen Z, Liang Z, Kong Y, Li P, 'Fault Location Using Wavelet Packets', *Proceedings of the 2002 PowerCon. International Conference on Power System*

Technology, 2002, Volume 4, Kunming, China, 13-17 October 2002, pp. 2575-2579.

35. Willis OL, 'A review of fault locating techniques in medium voltage power cable', *Record of Conference Papers, Industry Applications Society 38th Annual Petroleum and Chemistry Industry Conference, 1991*, Toronto, Ontario, Canada, pp. 225-228.

36. Verho P, Nikander A, Järventausta P, 'Aspects on development of distribution network fault location and management', *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection, 2004*, Volume 2, Amsterdam, Holland, 5-8 April 2004, pp. 784-787.

37. Kiessling G, Schwabe S, 'Software solution for fault record analysis in power transmission and distribution', *Proceedings of the Eighth IEE International Conference on Developments in Power System Protection, 2004*, Volume 1, Amsterdam, Holland, 5-8 April 2004, pp. 192-195.

38. Krajnak DJ, 'Faulted circuit indicators and system reliability', *Proceedings of the Rural Electric Power Conference*, Louisville, KY, USA, 7-9 May 2000, pp. A4/1-A4/4.

39. *IntelliTEAM™. A revolutionary peer-to-peer auto-reconfiguration system*, EnergyLine Systems, Incorporated, 1135 Atlantic Avenue, Alameda, CA, USA, 94501, 1995-1996.

40. Marks J, 'New technology improves loop-feeder schemes', *Electrical World*, February 1997, McGraw-Hill Companies.

41. Orlowski R, Kalam A, 'Fault detection and location on distribution feeders (22kV & 11kV)', *Proceedings of the Australasian Universities Power Engineering Conference, AUPEC'99*, Darwin, NT, Australia, 26-29 September 1999, pp. 168-172.

42. Orlowski R, Kalam A, 'Applications of reclosers on urban distribution networks' *Proceedings of the Distribution 2003 Conference*, Paper No 170, Adelaide, SA, Australia, 16–19 November 2003.

43. Goodin RE, Fahey TS, Hanson A, 'Distribution Reliability using reclosers and sectionalisers', ABB Incorporated, Lake Mary, Florida, USA. Portions of this paper are from the ABB paper 'The Application of Reclosers on Future Distribution Systems', ABB Incorporated, January1999.

44. Elder LA, O'Sullivan B, 'Economic optimisation of an Australian rural electricity network using automatic circuit reclosers with remote monitoring & control', *Proceedings of the IEEE Transmission and Distribution Conference, 1999 IEEE*, Volume 1, New Orleans, LA, USA, 11-16 April 1999, pp. 310-313.

45. Hataway G, *Minimize Distribution Outages With High-Speed Automatic Network Reconfiguration Using SEL-651R Advanced Recloser Controls*, SEL Application Guide, Volume 3, AG2004-09, Schweitzer Engineering Laboratories, Pullman, WA, USA, Date Code 20040609.

46. *SEL-651R Advanced Recloser Control; Keeping the Power On With Improved Reliability and Control*, 651Rflyr 20050107 · PF00064, Schweitzer Engineering Laboratories, Pullman, WA, USA, Date Code 20050107.

47. Hänninen S, Lehtonen M, Pulkkinen U, 'A probabilistic method for detection and location of very high resistive ground faults', *Electric Power Systems Research*, Volume 54, Elsevier Science, June 2000, pp. 199-206.

48. Wang C, Nouri H, Davies TS, 'A Mathematical Approach for Identification of Fault Sections on the radial Distribution Systems: Voltage Sensor', *Proceedings of the Tenth Mediterranean Electrotechnical Conference, 2000. MELECON 2000*, Volume 3, Nicosia, Cyprus, 29-31 May 2000, pp. 882-886.

49. Montakhab MR, Adams RN, 'Intelligent system for fault diagnosis on low voltage distribution networks', *IEE Proceedings. Generation, Transmission & Distribution*, Vol. 145, Issue 5, September 1998, pp. 592-596.

50. Eickhoff F, Handschin E, Hoffman W, 'Knowledge based alarm handling and fault location in distribution networks', *IEEE Transactions on Power Systems*, Volume 7, Issue 2, May 1992, pp. 770-776.

51. Jota FG, Jota PRS, 'High impedance fault identification using a fuzzy reasoning system', *IEE Proceedings. Generation, Transmission & Distribution*, Volume 145, Issue 6, November 1998, pp. 656–662.

52. Keerthipala WWL, Wai CT, Siang KC, Peng HL, 'Implementation of neural network based fault classifier for power system protection', Proceedings of the *IEEE International Conference on Systems, Man and Cybernetics, 1995. 'Intelligent Systems for the 21st Century'*, Volume 2, Vancouver, British Columbia, Canada, 22-25 October 1995, pp. 1356–1361.

53. Vazquez E, Altuve HJ, Chacon OL, 'Neural network approach to fault detection in electric power systems', *Proceedings of the IEEE International Conference on Neural Networks, 1996*, Volume 4, Washington, DC, USA, 3-6 June 1996, pp. 2090-2095.

54. Patterson R, 'Signatures and Software Find High-Impedance Faults', *IEEE Computer Applications in Power*, Volume 8, Issue 3, July 1995, pp. 12–15.

55. Girgis AA, Johns MB, 'A hybrid expert system for faulted section identification, fault type classification and selection of fault location algorithms', *IEEE Transactions on Power Delivery*, Volume 4, Issue 2, April 1989, pp 978-985.

56. Yuan-Yin H, Lu FC, Chien Y, Liu JP, Lin JT, Yu PHS, Kuo RRT, 'An expert system for locating distribution system faults', *IEEE Transactions on Power Delivery*, Volume 6, Issue 1, January 1991, pp. 366-372.

57. Momoh JA, Dias LG, Thor T, Laird D, 'Rule Based Decision Support System for Single-Line Fault Detection in a Delta-Delta Connected Distribution system', *IEEE Transactions on Power Systems*, Volume 9, Issue 2, May 1994, pp.782-788.

58. Järventausta P, Verho P, Partanen J, 'Using fuzzy sets to model the uncertainty in the fault location process of distribution networks', *IEEE Transactions on Power Delivery*, Volume 9, Issue 2, April 1994, pp. 954-960.

59. Järventausta P, Verho P, Kärenlampi M, Partanen J, 'AI-based Methods in Practical Fault Location of Medium Voltage Distribution Feeders', Proceedings of the ISAP'96. International Conference on Intelligent Systems Applications to Power Systems, 1996, Orlando, FL, USA, 28 January-2 February 1996, pp. 164-169.

60. Zhong W, Liu WHE, 'Application of a fuzzy set method in distribution system fault location', *Proceedings of the 1996 IEEE International Symposium on*

Circuits and Systems, 1996. ISCAS'96. 'Connecting the World', Volume 1, Atlanta, GE, USA, 12-15 May 1996, pp. 617-620.

61. Liu WHE, Zhong W, 'A fuzzy set method for fault location identification in power distribution systems', *Proceedings of the 35th IEEE Conference on Decision and Control, 1996*, Volume 2, Kobe, Japan, 11-13 December 1996, pp. 2208-2212.

62. Chang CS, Chen JM, Srinivasan D, Wen FS, Liew AC, 'Fuzzy logic approach in power system fault section identification', *IEE Proceedings. Generation, Transmission & Distribution*, Volume 144, Issue 5, September 1997, pp. 406-414.

63. Glinkowski MT, Wang NC, 'ANNs pinpoint underground distribution faults', *IEEE Computer Application in Power*, Volume 8, Issue 4, October 1995, pp. 31-34.

64. Li KK, Lai LL, David AK, 'Application of Artificial Neural Network in Fault Location Technique', *Proceedings of the International Conference on Electric Utility Deregulation and Restructuring and Power Technologies, 2000, DRPT 2000*, London, UK, 4-7 April 2000, pp. 226-231.

65. Eberl G, Hänninen S, Lehtonen M, Schegner P, 'Comparison of Artificial Neural Networks and Conventional Algorithms in Ground Fault Distance Computation', *Proceedings of the IEEE Power Engineering Society Winter Meeting 2000*, Volume 3, Singapore, 23-27 January 2000, pp. 1991-1996.

66. Hänninen S, Lehtonen M, 'Earth Fault Distance Computation with Artificial Neural Network Trained by Neutral Voltage Transients', *Proceedings of the IEEE Power Engineering Society Summer Meeting 2001*, Volume 2, Vancouver, British Columbia, Canada, 15-19 July 2001, pp. 1187-1192.

67. Momoh JA, Dias LG, Laird DN, 'An Implementation of a Hybrid Intelligent Tool for Distribution System Fault Diagnosis', *Proceedings of the 1996 IEEE Transmission and Distribution Conference, 1996*, Los Angeles, CA, USA, 15-20 September 1996, pp. 123-128.

68. Orlowski R, Kalam A, 'Communications considerations for automation schemes in existing Zone Substations', *Proceedings of the CIGRE 2003, Study Committee*

B5 Colloquium, Paper No 101, Sydney, NSW, Australia, 30 September–1 October 2003.

69. Orlowski R, Kalam A, 'Power System Communications Challenges in a Privatised Environment', *Proceedings of the CIGRE 2005, Study Committee B5 Colloquium*, Paper No 202, Calgary, Alberta, Canada, 8-16 September 2005.

70. Schweitzer EO, Behrendt K, Lee T, 'Digital communications for power system protection: security, availability and speed', Schweitzer Engineering Laboratories, Pullman, WA, USA, 1998.

71. Dolezilek D, 'SEL communications and integration white paper', Schweitzer Engineering Laboratories, Pullman, WA, USA, Code Date 20011023.

72. Costello D, Fodero K, *Mirrored Bits™ Communications With Spread Spectrum Radios*, SEL Application Guide AG2000-02, Volume 2, Schweitzer Engineering Laboratories, Pullman, WA, USA, Date Code 20011002.

73. Behrendt K, Fodero K, *Implementing Mirrored Bits™ Technology Over Various Communication Media*, SEL Application Guide AG2001-12, Volume 2, Schweitzer Engineering Laboratories, Pullman, WA, USA, Date Code 20011016.

Reading bibliography

1. Schweitzer E, 'Evaluation and Development of Transmission Line Fault Locating Techniques Which Use Sinusoidal Steady State Information', *Proceedings of the Ninth Annual Western Protective Relay Conference*, Spokane, WA, USA, October 1982.

2. Kalam A, Spicer A, Coulter R, Klebanowski A, Biasizzo C, McDonald H, *Power System Protection* 3rd ed. Melbourne, Victoria, Australia: Victoria University of Technology, 1997.

3. Stevenson Junior WD, *Elements of Power Systems Analysis*, McGraw-Hill International, 3rd ed, 1982.

4. Schweitzer EO III, 'A Review of Impedance-based Fault Locating Experience', *Proceedings of the Fourteenth Annual Iowa-Nebraska System Protection Seminar*, Omaha, NE, USA, 16 October, 1990.

5. *LFL Fault Locating and Experience*, SEL Application Guide, Schweitzer Engineering Laboratories, Pullman, WA, USA, Date Code 930415.

6. Redfern MA, Bo ZQ, Kwong W, Roberts GV, 'An investigation into the characteristics of High Voltage distribution cable circuits for digital protection data communication', *Proceedings of the 25th Universities Power Engineering Conference*, Aberdeen, UK, September 1990.

7. Aucoin BM, Jones RH, 'High Impedance Fault Detection Implementation Issues' *IEEE Transactions on Power Delivery*, Volume 11, Issue 1, January 1996, pp. 139-148.

8. *Protective relays application guide*, GEC Alsthom Measurements Limited, 3rd ed. Stafford, UK, 1990.

9. Taylor V, Faulkner VM, Kalam A, Haydon AJ, 'Digital Simulation of Fault Location on EHV Lines Using Wideband Spread Spectrum Techniques', *IEE Proceedings. Generation, Transmission & Distribution*, Volume 142. Issue 1, January 1995, pp. 73–80.

10. Deepal P, Pahwa A, Boyer JE, 'Location of Outages in Distribution Systems Based on Statistical Hypothesis Testing', *IEEE Transactions on Power Delivery*, Volume 11, Issue 1, January 1996, pp. 546–551.

Appendix 'A'

Blocking from R2 to R1

Test set 'A'

Introduction

Test set 'A' comprised six tests as shown in Table A - 1.

Table A - 1 Blocking from R2 to R1

Test No	Purpose
A1	Phase O/C on R2 blocks phase O/C on R1
A2	Phase O/C on R2 blocks ground O/C on R1
A3	Ground O/C on R2 blocks ground O/C on R1
A4	Ground O/C on R2 blocks phase O/C on R1
A5	SEF on R2 does not block phase O/C or ground O/C on R1
A6	Ground O/C on R2 blocks phase O/C and ground O/C on R1 and tests breaker fail scenario at R2

Notes:

1. An SEF fault on any section should not block any protection element on an upstream device
2. A phase fault on any section should not block an SEF element on an upstream device
3. The instantaneous phase O/C element at the CB should not be blocked by any downstream device
4. A downstream device will stop transmitting a blocking signal 200ms after issuing a trip command (to cater for breaker failure)

The configuration used during the testing is shown in Figure A below.

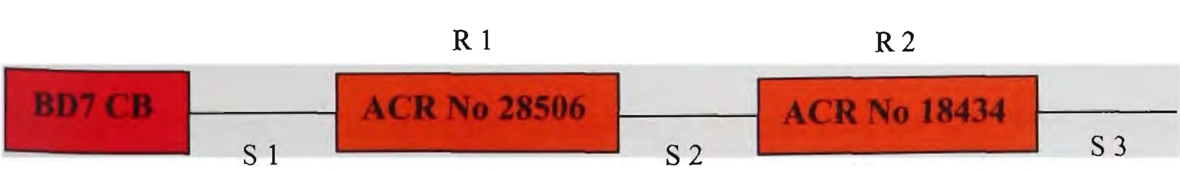


Figure A Configuration for BD7 feeder testing

A1 testing regime

Task

To block the upstream recloser No 28506, from tripping due to the phase O/C pick up, with the blocking signal sent by downstream recloser No18434 due to its phase O/C pick up.

The testing set up is shown in Table A - 2.

Table A - 2 Set up for 'A1' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	2 times the O/C setting	4 A	2.97 s	E/F and O/C element blocked by ACR No 18434. No tripping
R2 18434	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	1.8 A	12.825 s	Trip after 12.825 s and reclose.

A1 testing

Test A1_1

Secondary fault current of 4A was injected into the SEL351P relay at recloser No 28506, referred to as R1, to simulate a fault in section 3 of the feeder.

There are two events, No 1 and No 2, in this test. This is because the SEL 351P software is capable of displaying only 30 cycles at a time, i.e. approximately 600 ms. As the upstream recloser, without blocking, is expected to trip in 2.97 seconds, a second event needs to be presented.

Figure A1_1_Event 1, illustrates the first event in which the phase O/C 51P2 element on the upstream recloser picked the fault current and the mirorred bit TMB1B was transmitted to block the Zone Substation circuit breaker. No blocking signal RMB1A was received from the downstream recloser. The phase time O/C 51G2T element did not pick up as it has not timed out yet. The recloser breaker 52A status remained asserted signifying that the recloser breaker has not opened yet.

Figure A1_1_Event 2, illustrates the second event in which the phase time O/C 51G2T element picked up followed by a trip. No blocking signal RMB1A was received from the downstream recloser. The recloser breaker 52A status changed to deasserted signifying that the recloser breaker has opened.

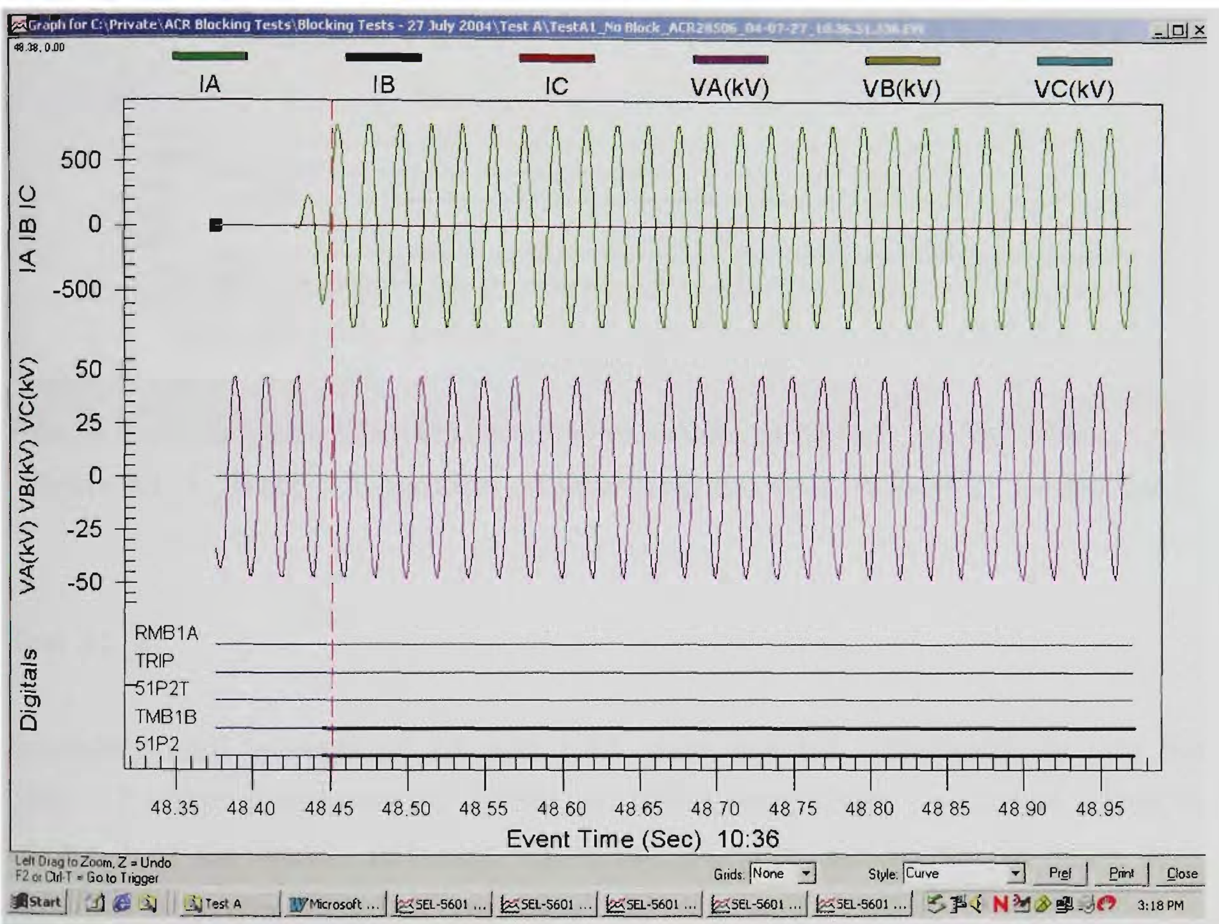


Figure A1_1_Event 1 Upstream recloser, phase O/C pick up, no blocking

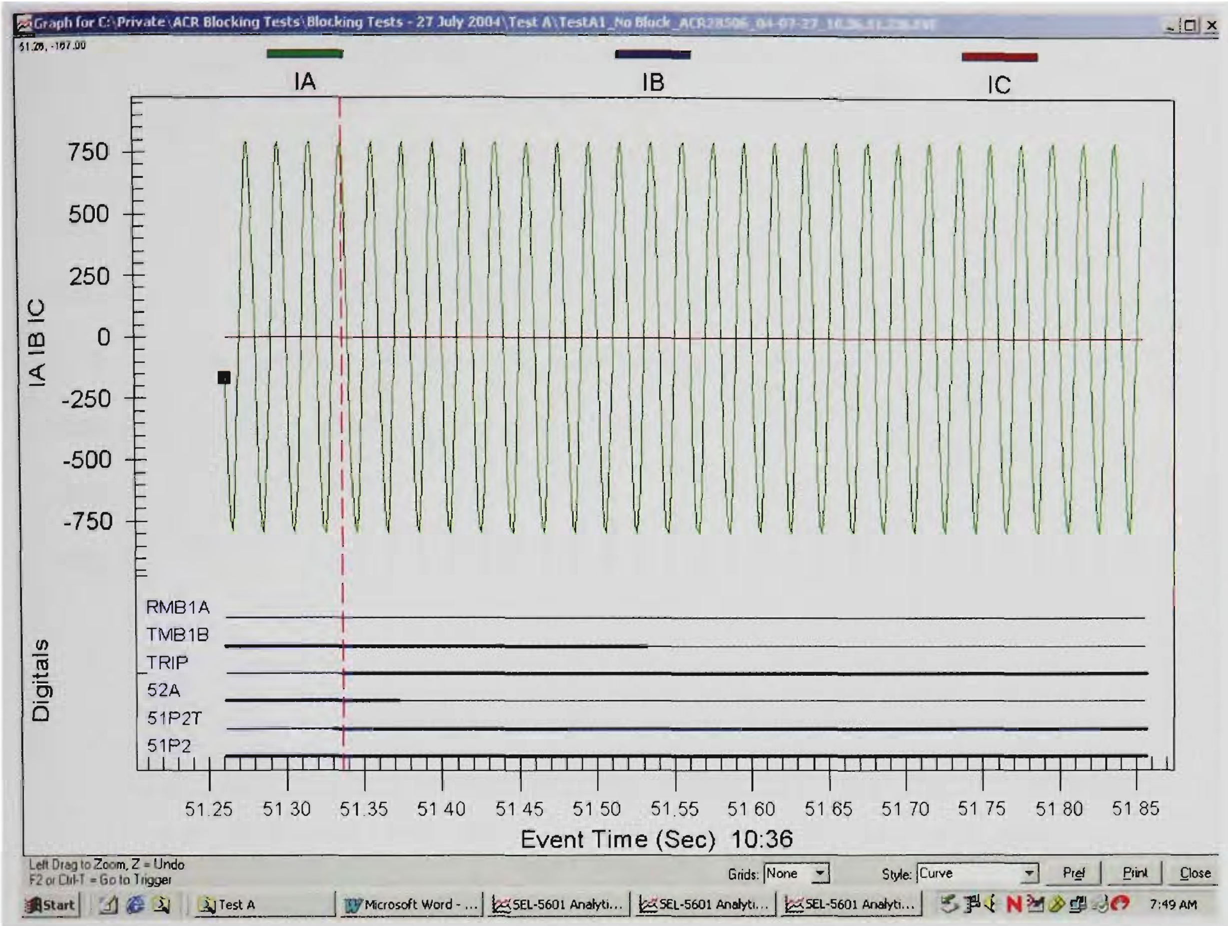


Figure A1_1_Event 2 Upstream recloser, trip due to a phase O/C, no blocking

Test A1_2

Secondary fault currents of 2A and 1.8A were injected simultaneously into the SEL351P relays at reclosers No 28506 and 18434 respectively to simulate a fault in section 3 of the feeder. Although under the 'real life' conditions the same fault current is experienced by both reclosers when the fault occurs in feeder section 3, two different current magnitudes were chosen to make the operation of a blocking scheme evident. This is because there is some discrimination built into the protection settings.

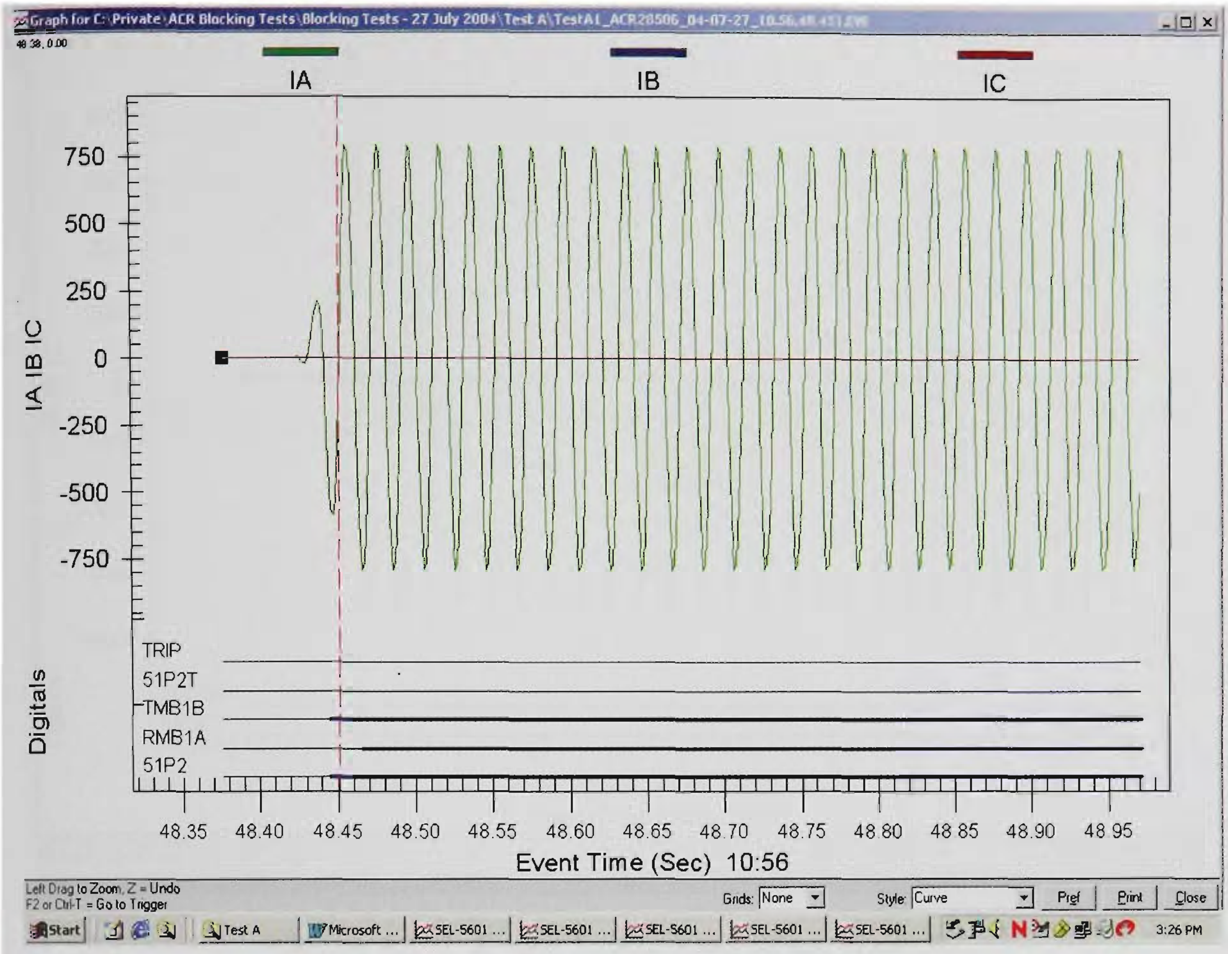


Figure A1_2_Event 1 Blocking of Recloser 28506 on phase O/C

The upstream recloser phase O/C 51P2 element picked up the fault current followed by sending a blocking signal TMB1B destined to the Zone Substation circuit breaker. Because a blocking signal RMB1A was received from the downstream recloser, there was no trip and no upstream recloser breaker status change.

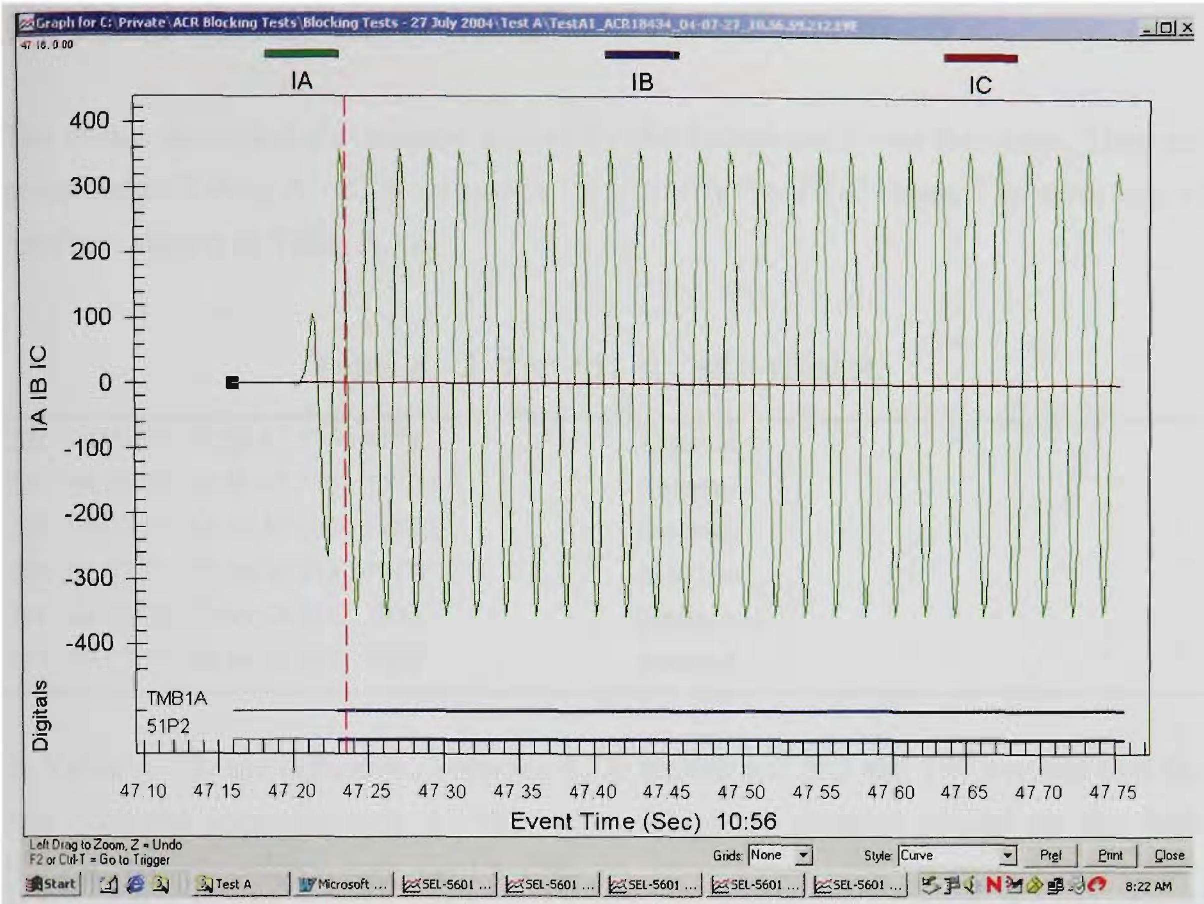


Figure A1_2_Event 2 Blocking signal from R2

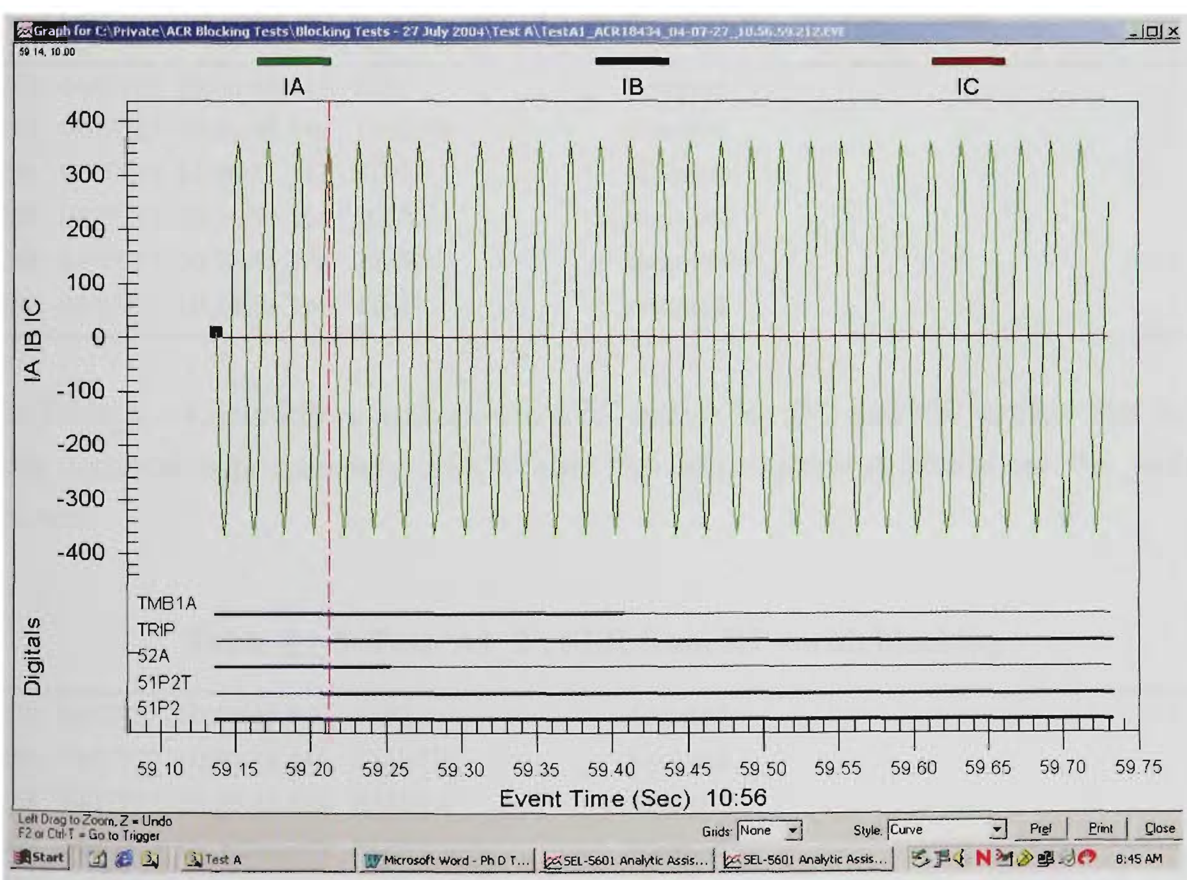


Figure A1_2_Event 3 Tripping of R2

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 3, A - 4 and A - 5 to verify the TRIP times. The summary of results is shown in Table A - 6.

Table A - 3 Test 'A1_2', SER from R2

202	04/07/27	10:56:47.230	51P2	Asserted
201	04/07/27	10:56:47.230	TMB1A	Asserted
200	04/07/27	10:56:59.207	51P2T	Asserted
199	04/07/27	10:56:59.212	79CY	Asserted
198	04/07/27	10:56:59.212	79RS	Deasserted
197	04/07/27	10:56:59.212	TRIP	Asserted

In Table A - 3, the difference between SER entries No 202 and 197 verifies that the trip occurred approximately 11.982s after the phase element picked up the fault current. The expected result was 12.825s.

Table A - 4 Test 'A1_1', SER from R1 - no blocking

292	04/07/27	10:36:48.446	51P2	Asserted
291	04/07/27	10:36:48.446	TMB1B	Asserted
290	04/07/27	10:36:51.331	51P2T	Asserted
289	04/07/27	10:36:51.336	79CY	Asserted
288	04/07/27	10:36:51.336	79RS	Deasserted
287	04/07/27	10:36:51.336	TRIP	Asserted

In Table A - 4, the difference between SER entries No 292 and 287 verifies that the trip occurred approximately 2.885s after the phase element picked up the fault current.

Table A - 5 Test 'A1_2', SER from R1 – with blocking

270	04/07/27	10:56:48.446	51P2	Asserted
269	04/07/27	10:56:48.446	TMB1B	Asserted
268	04/07/27	10:56:48.466	RMB1A	Asserted
267	04/07/27	10:56:51.335	51P2T	Asserted
266	04/07/27	10:56:58.448	51P2	Deasserted
265	04/07/27	10:56:58.468	51P2T	Deasserted
264	04/07/27	10:57:00.643	RMB1A	Deasserted
263	04/07/27	10:57:00.643	TMB1B	Deasserted

Table A - 5 shows the behaviour of R1 when a blocking signal is received. Although the phase overcurrent element times out (51P2T is asserted), no trip signal is issued.

Table A - 6 Results summary for testing 'A1'

Test No	Phase O/C on R2 blocks Phase O/C on R1		
Test A1		Without blocking	With blocking
	Expected Result	2.97s	No trip
	Observed Result	2.885	No trip

A2 testing regime

Task

To block the upstream recloser No 28506, from tripping due to the ground O/C pick up, with the blocking signal sent by downstream recloser No18434 due to its phase O/C pick up.

The testing set up is shown in Table A - 7.

Table A - 7 Set up for 'A2' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	2 times the E/F setting	2 A	3.375 s	E/F and O/C element blocked by ACR No 18434. No tripping
R2 18434	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	1.8 A	12.825 s	Trip after 12.825 s and reclose.

A2 testing

Test A2_1

Secondary fault current of 2 A was injected into the E/F element at the upstream recloser No 28506.

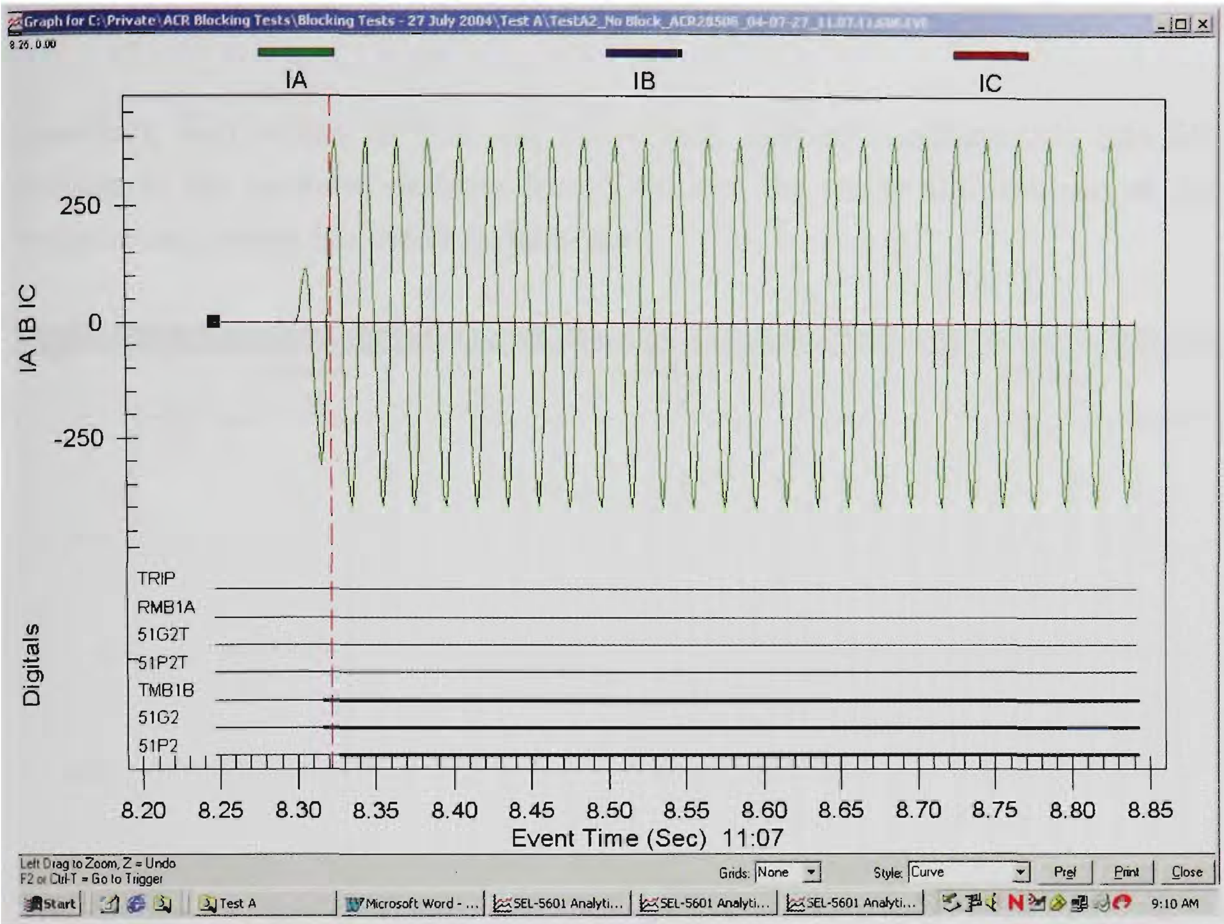


Figure A2_1_Event 1 Ground and Phase O/C pick up by R1, no blocking

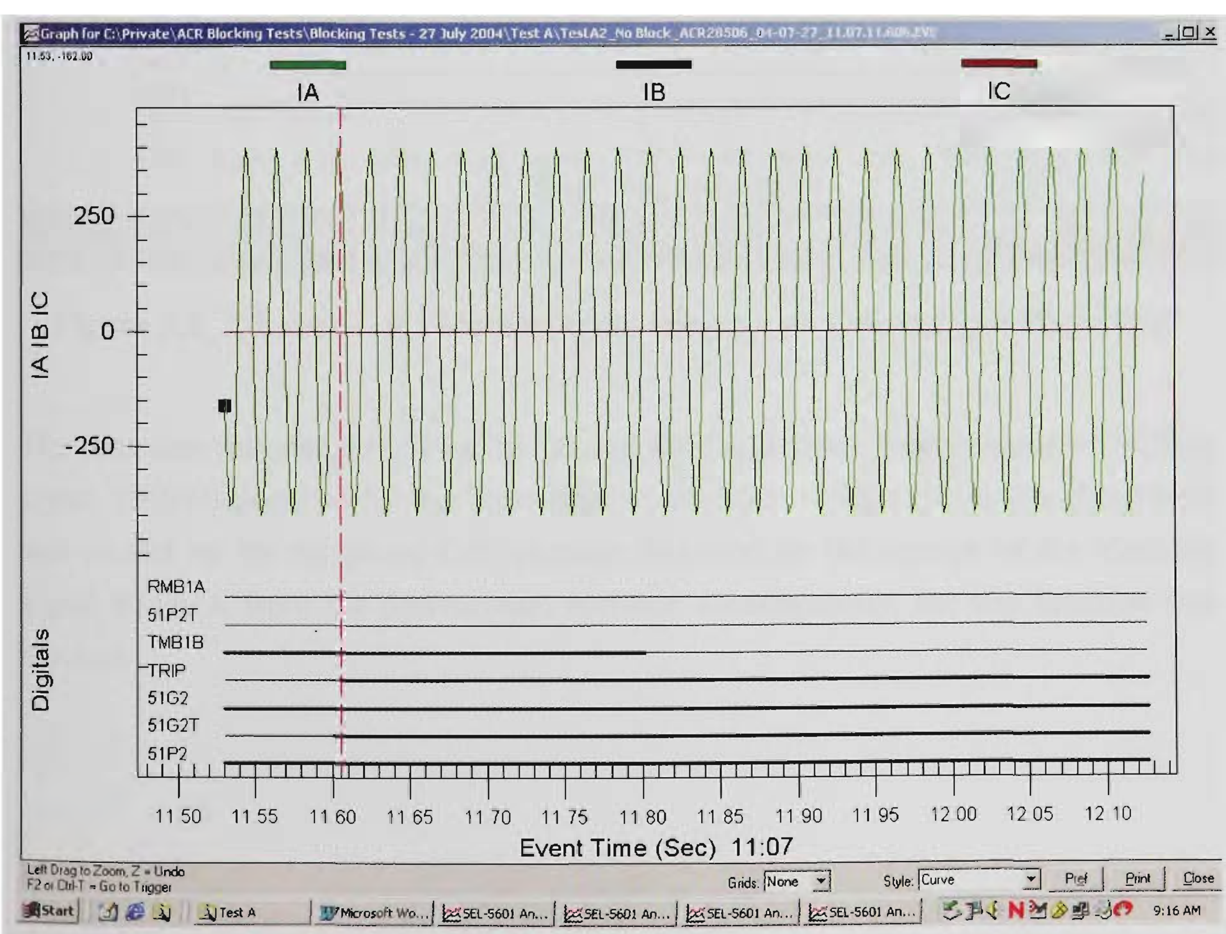


Figure A2_1_Event 2 Tripping of R1 on Ground O/C, no blocking

Test A2_2

Secondary fault current of 2 A and 1.8 A were injected simultaneously into E/F element at the upstream recloser No 28506 and the phase O/C element at the downstream recloser No 18434 respectively.

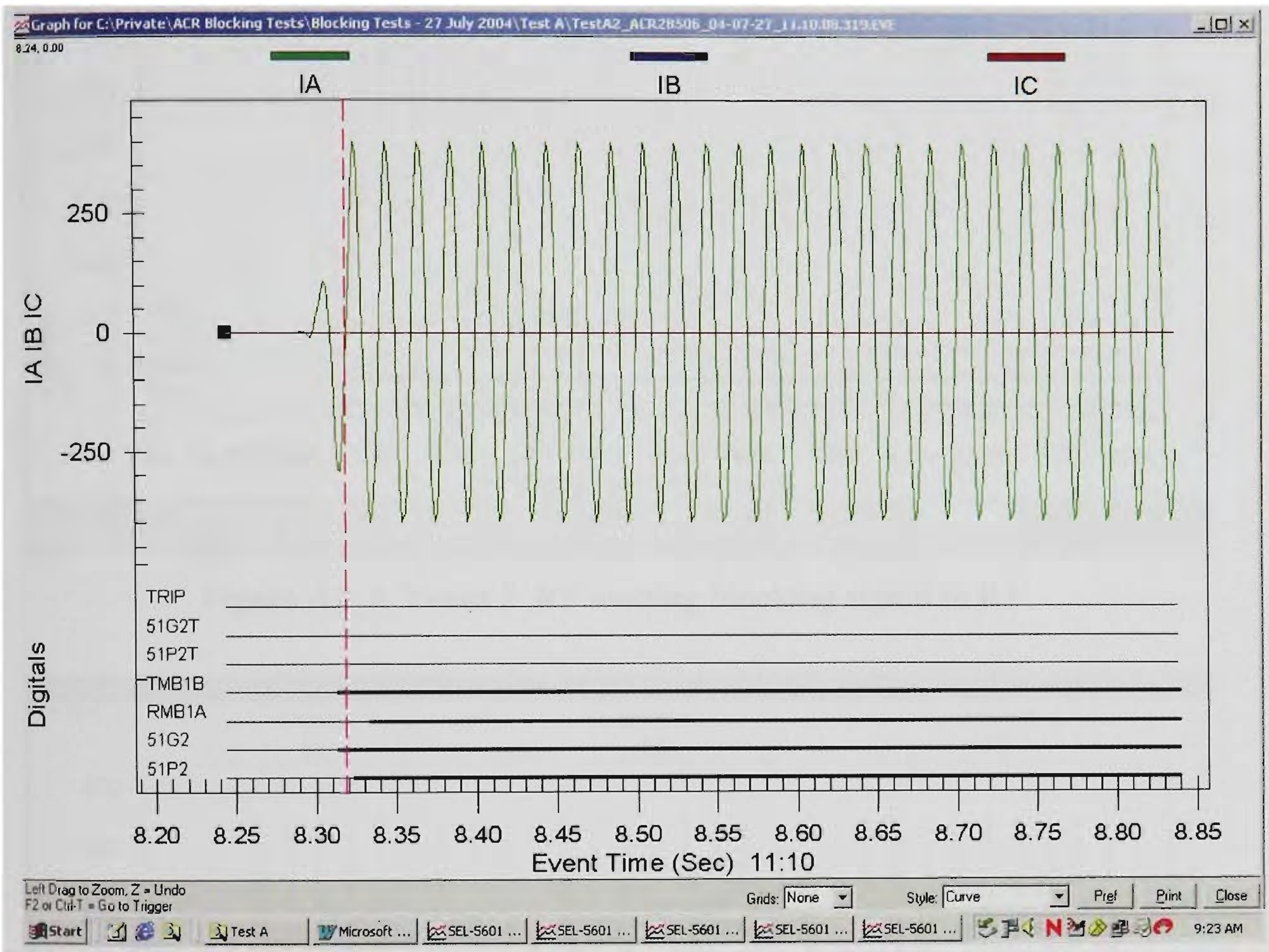


Figure A2_2_Event 1 R1 blocked from tripping on Ground and Phase O/C

The upstream recloser picked up the ground fault and immediately issued a blocking signal TMB1B destined for the Zone substation circuit breaker. Next, the phase fault was picked up by the phase O/C element followed by the receipt of the blocking signal RMB1A from the downstream recloser. Consequently, the trip function was blocked.

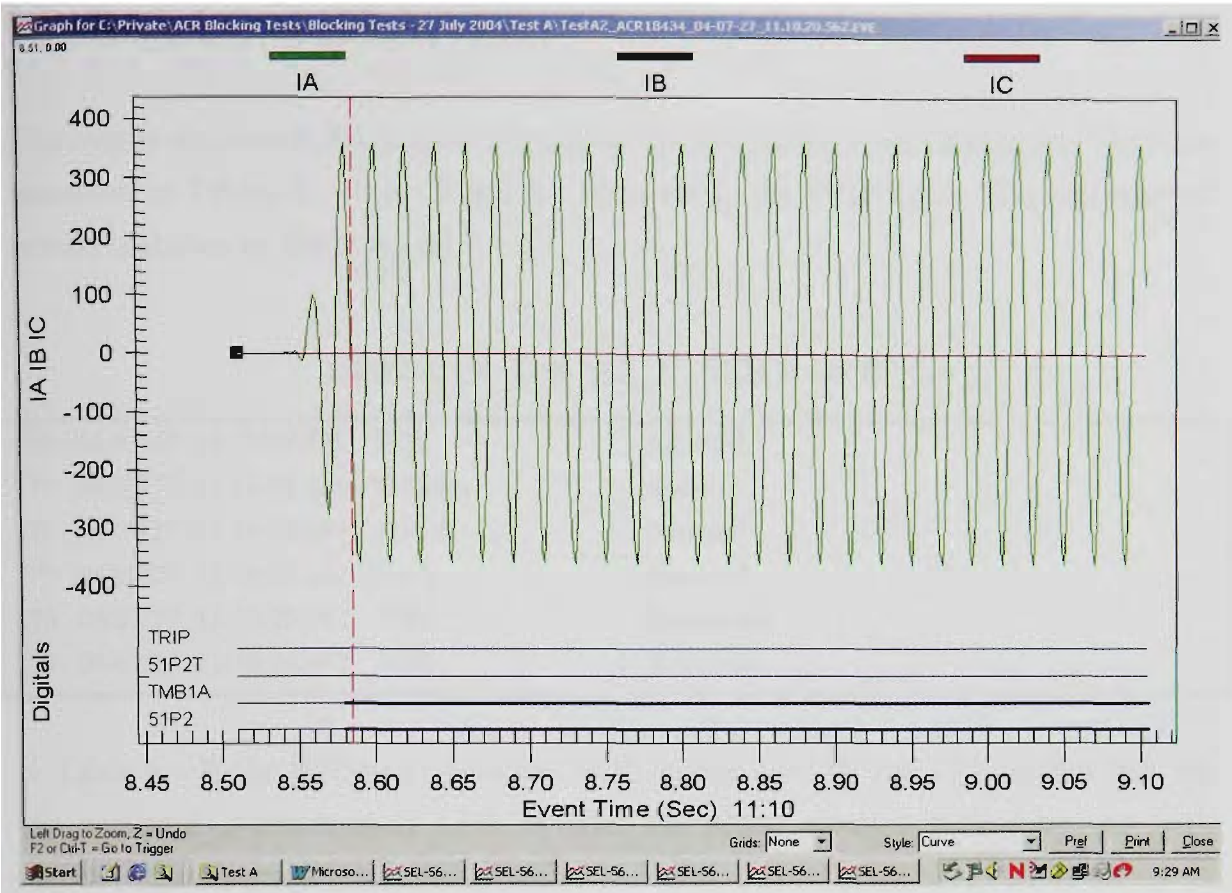


Figure A2_2_Event 2 R2 sending blocking signal to R1

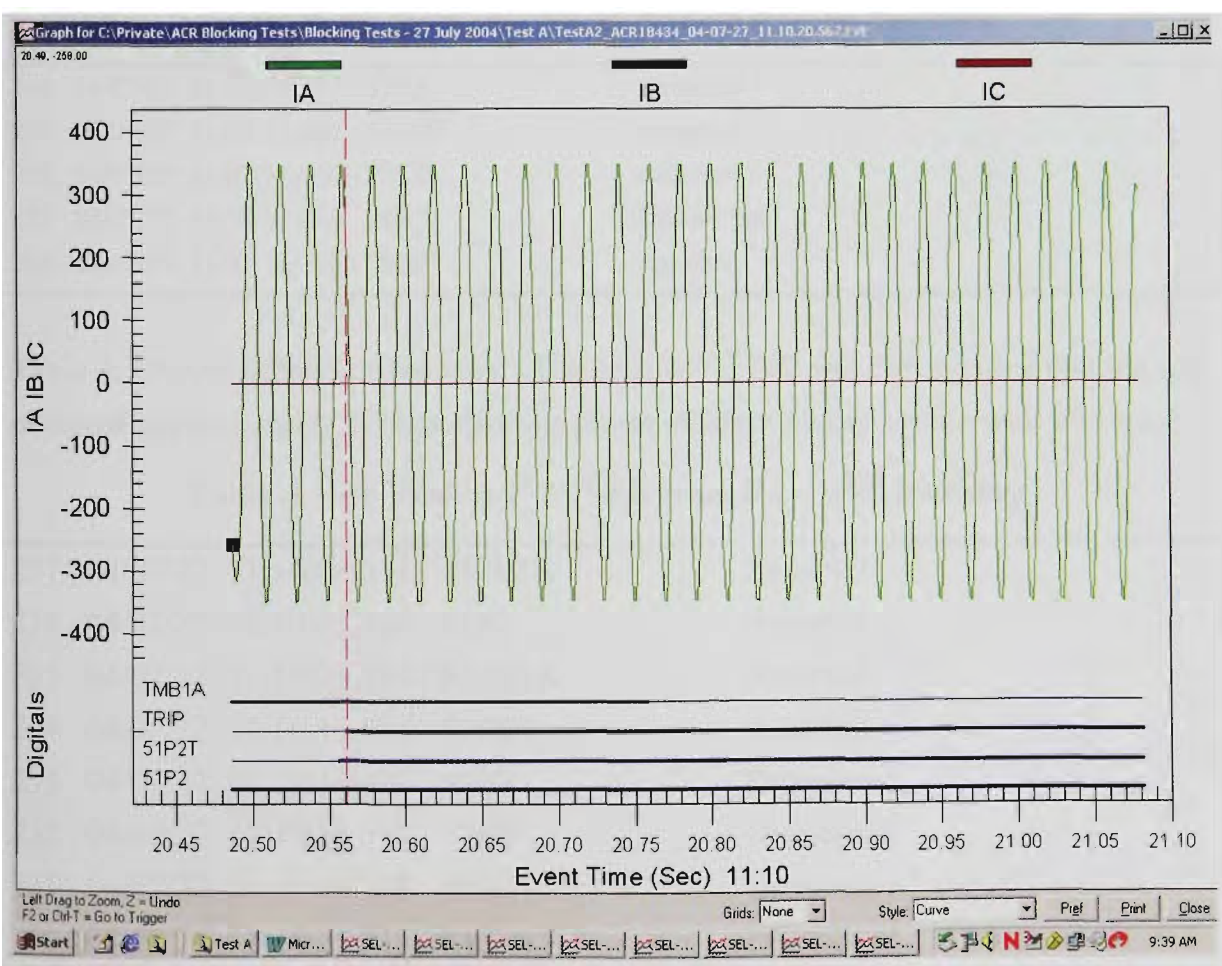


Figure A2_2_Event 3 R2 tripping on Phase O/C

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 8, A - 9 and A - 10 to verify the TRIP times. The summary of results is shown in Table A - 11.

Table A - 8 Test 'A2_2', SER from R2

180	04/07/27	11:10:08.580	51P2	Asserted
179	04/07/27	11:10:08.580	TMB1A	Asserted
178	04/07/27	11:10:20.557	51P2T	Asserted
177	04/07/27	11:10:20.562	79CY	Asserted
176	04/07/27	11:10:20.562	79RS	Deasserted
175	04/07/27	11:10:20.562	TRIP	Asserted

In Table A - 8, the difference between SER entries No 180 and 175 verifies that the trip occurred approximately 11.977s after the phase element picked up the fault current. The expected result was 12.825s.

Table A - 9 Test 'A2_1', SER from R1 - no blocking

260	04/07/27	11:07:08.327	51P2	Asserted
259	04/07/27	11:07:11.601	51G2T	Asserted
258	04/07/27	11:07:11.606	79CY	Asserted
257	04/07/27	11:07:11.606	79RS	Deasserted
256	04/07/27	11:07:11.606	TRIP	Asserted

Table A - 9, the difference between SER entries No 260 and 256 verifies that the trip occurred approximately 3.284s after the phase element picked up the fault current.

Table A - 10 Test 'A2_2', SER from R1 – with blocking

237	04/07/27	11:10:08.314	TMB1B	Asserted
236	04/07/27	11:10:08.324	51P2	Asserted
235	04/07/27	11:10:08.334	RMB1A	Asserted
234	04/07/27	11:10:11.604	51G2T	Asserted
233	04/07/27	11:10:18.302	51P2	Deasserted
232	04/07/27	11:10:18.317	51G2	Deasserted
231	04/07/27	11:10:18.337	51G2T	Deasserted
230	04/07/27	11:10:20.511	RMB1A	Deasserted
229	04/07/27	11:10:20.511	TMB1B	Deasserted

Table A - 10 shows the behaviour of R1 when a blocking signal is received. Although the phase and ground overcurrent elements time out (51P2T and 51G2T are asserted), no trip signal is issued.

Table A - 11 Results summary for test 'A2'

Test No	Phase O/C on R2 blocks Ground O/C on R1		
Test A2		Without blocking	With blocking
	Expected Result	3.375s	No trip
	Observed Result	3.284s	No trip

A3 testing regime

Task

To block the upstream recloser No 28506, from tripping due to the ground O/C pick up, with the blocking signal sent by downstream recloser No18434 due to its ground O/C pick up.

Testing set up is shown in Table A - 12.

Table A - 12 Set up for 'A3' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	2 times the E/F setting	2 A	3.375 s	E/F and O/C element blocked by ACR No 18434. No tripping
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.5 times the O/C setting	1.14 A	6.480 s	Trip after 6.48 s and reclose.

A3 testing

Test A3_1

Secondary fault current of 2 A was injected into the E/F element at the upstream recloser No 28506.

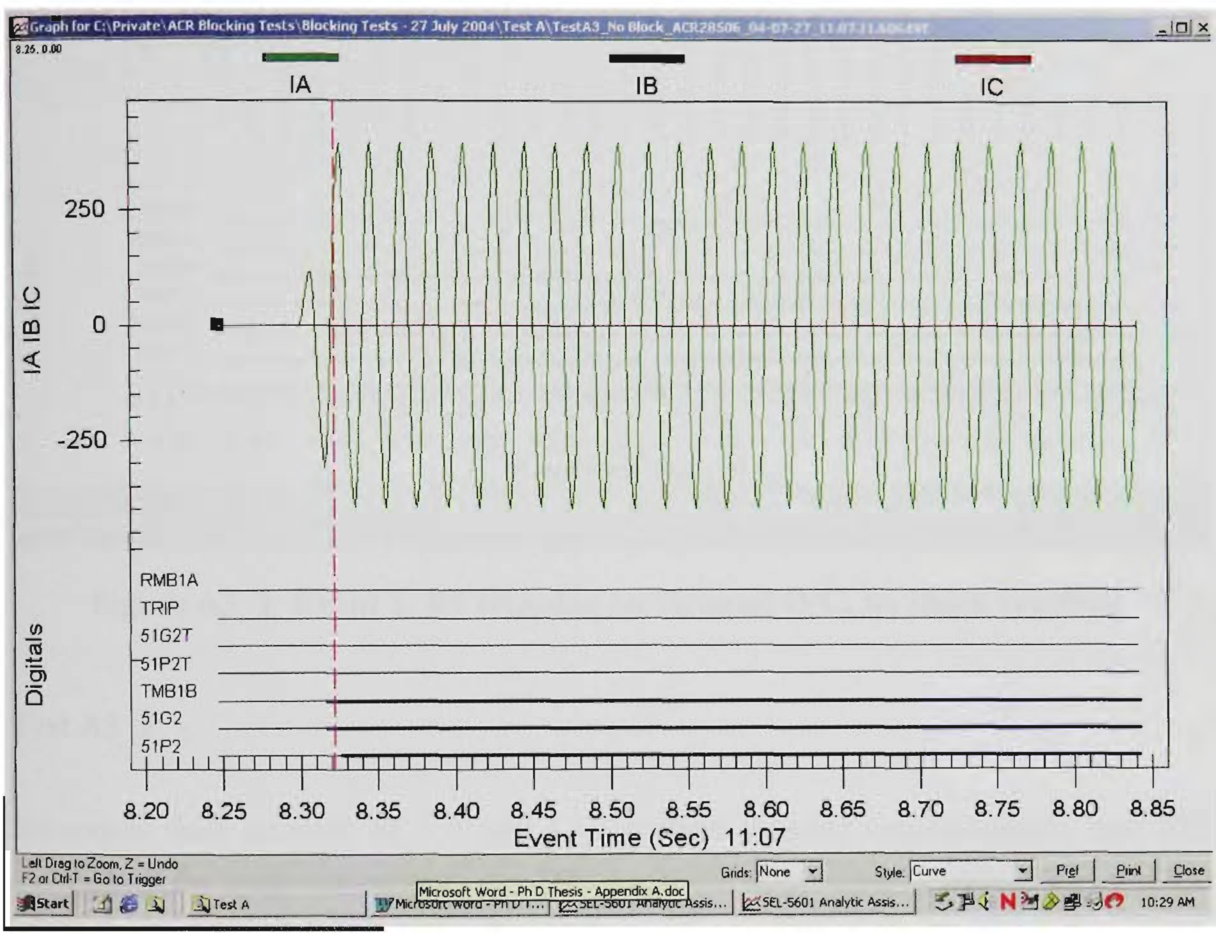


Figure A3_1_Event 1 Ground and Phase O/C pick up by R1, no block received

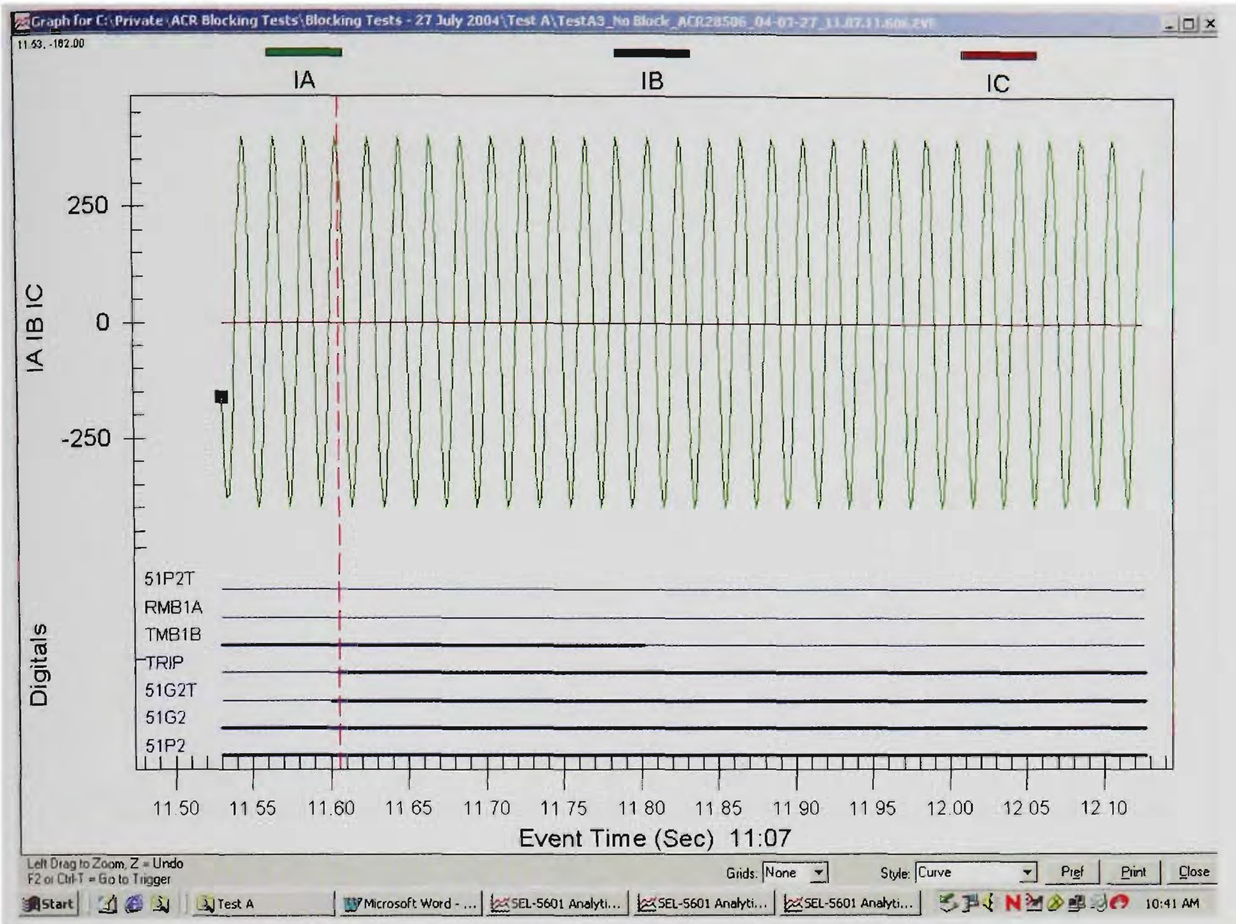


Figure A3_1_Event 2 R1 tripping on Ground O/C, no block received

Test A3_2

Secondary fault currents of 2 A and 1.14 A were injected simultaneously into E/F elements at the upstream recloser No 28506 and the downstream recloser No 18434.

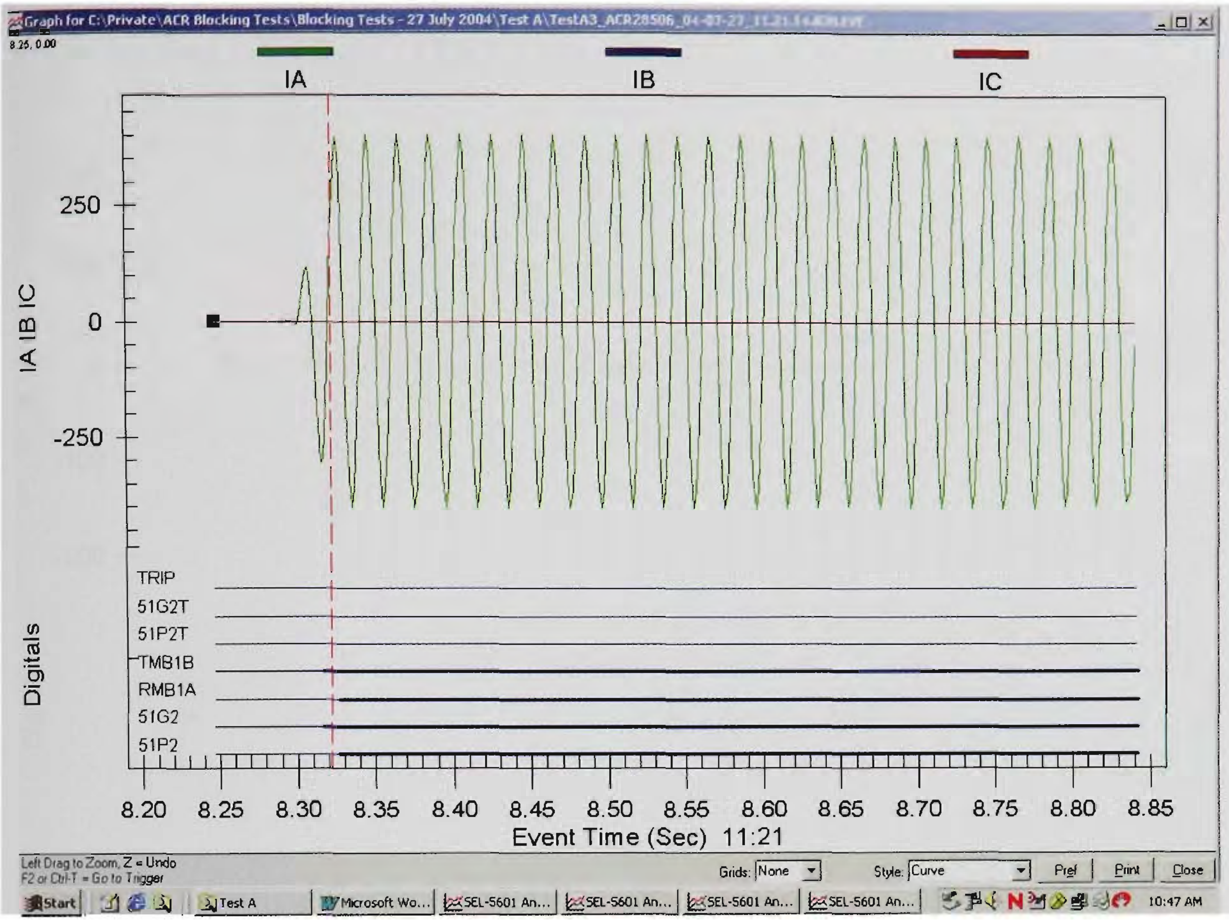


Figure A3_2_Event 1 R1 blocked from tripping on Ground and Phase O/C

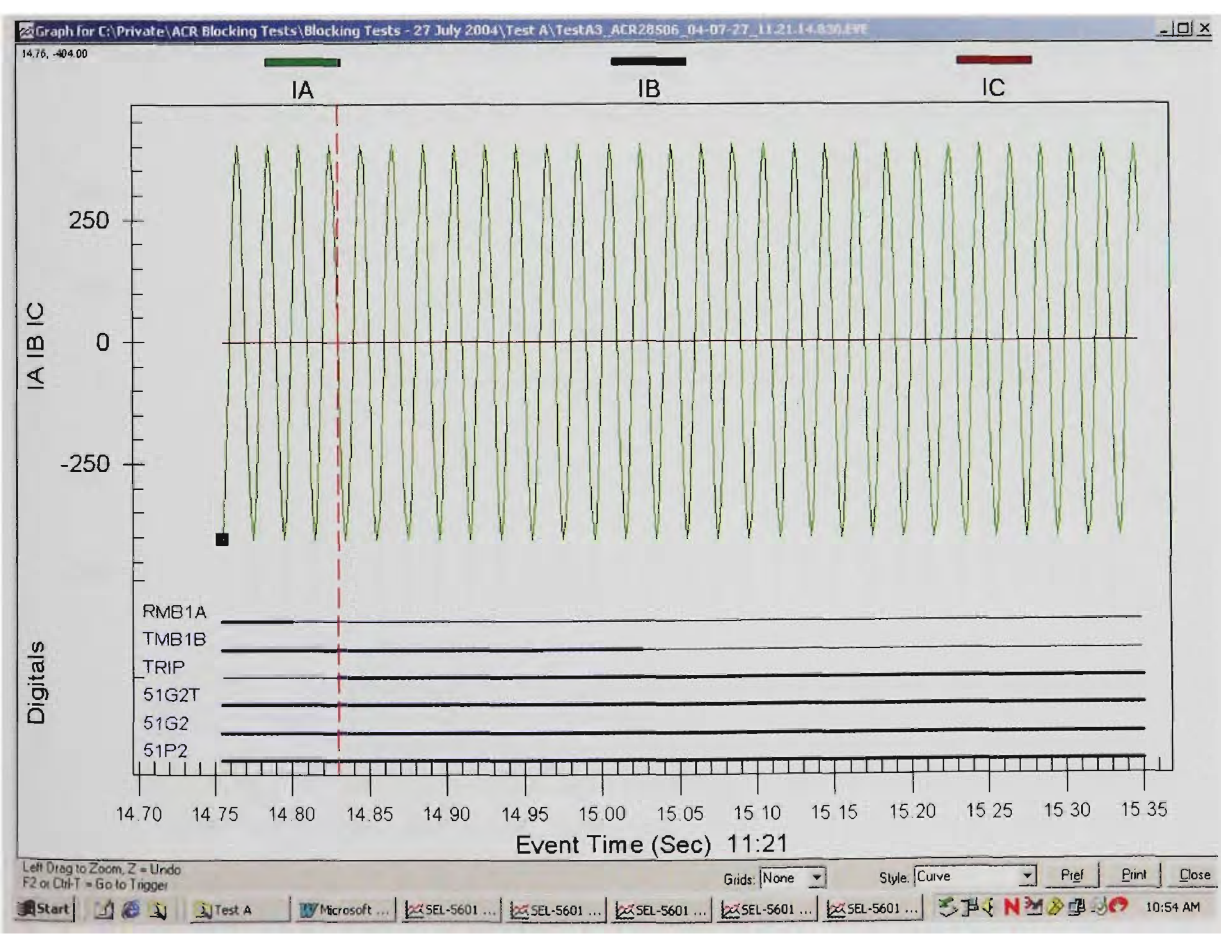


Figure A3_2_Event 2 R1 tripping on after blocking has ceased

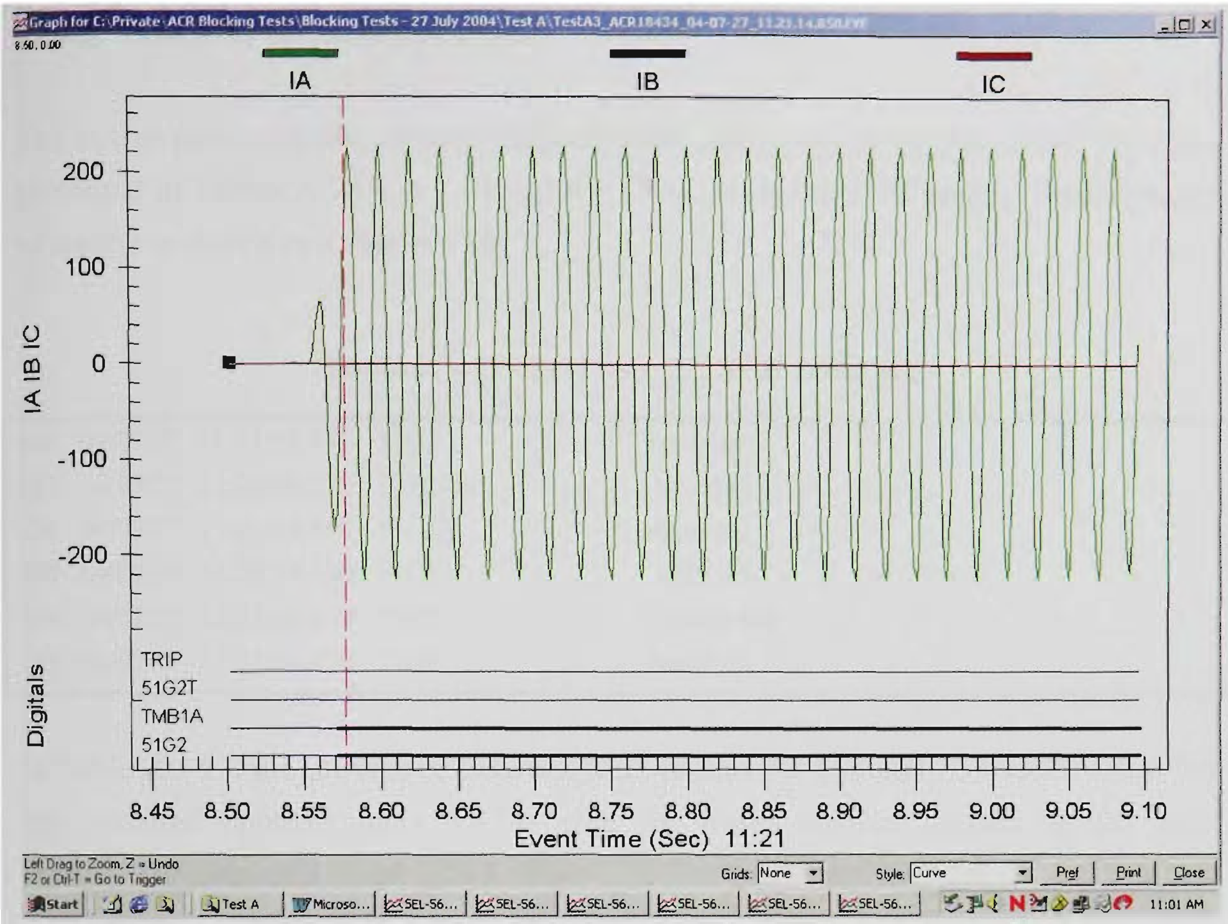


Figure A3_2_Event 3 R2 sending blocking signal to R1

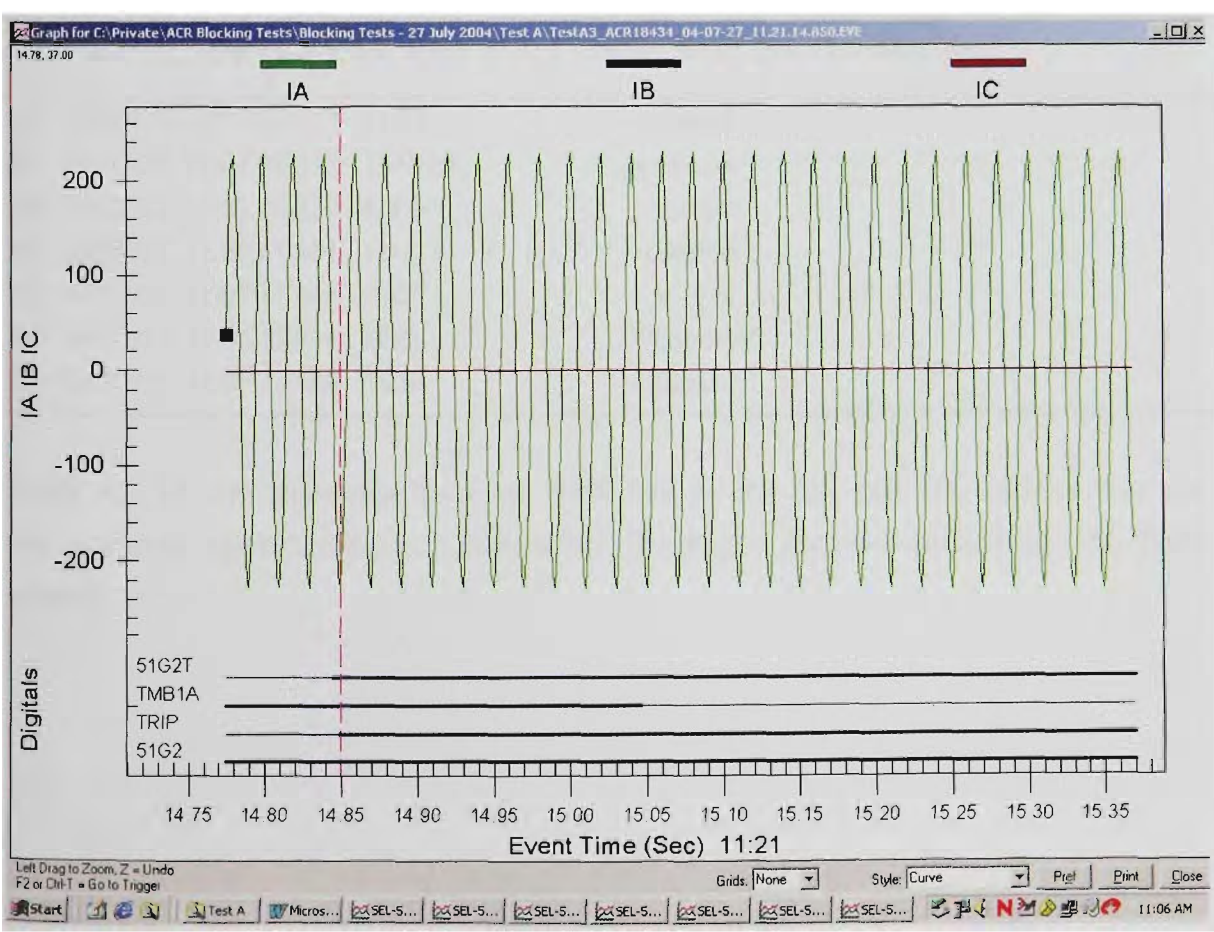


Figure A3_2_Event 4 R2 tripping on Ground O/C

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 13, A - 14 and A - 15 to verify the TRIP times. The summary of results is shown in Table A - 16.

Table A - 13 Test 'A3_2', SER from R2

158	04/07/27	11:21:08.572	51G2	Asserted
157	04/07/27	11:21:08.572	TMB1A	Asserted
156	04/07/27	11:21:14.845	51G2T	Asserted
155	04/07/27	11:21:14.850	79CY	Asserted
154	04/07/27	11:21:14.850	79RS	Deasserted
153	04/07/27	11:21:14.850	TRIP	Asserted

In Table A - 13, the difference between SER entries No 158 and 153 verifies that the trip occurred approximately 6.273s after the phase element picked up the fault current. The expected result was 6.480s.

Table A - 14 Test 'A3_1', SER from R1 - no blocking

262	04/07/27	11:07:08.317	51G2	Asserted
261	04/07/27	11:07:08.317	TMB1B	Asserted
260	04/07/27	11:07:08.327	51P2	Asserted
259	04/07/27	11:07:11.601	51G2T	Asserted
258	04/07/27	11:07:11.606	79CY	Asserted
257	04/07/27	11:07:11.606	79RS	Deasserted
256	04/07/27	11:07:11.606	TRIP	Asserted

Table A - 14, the difference between SER entries No 262 and 256 verifies that the trip occurred approximately 3.289s after the phase element picked up the fault current.

Table A - 15 Test 'A3_2', SER from R1 – with blocking

228	04/07/27	11:21:08.317	51G2	Asserted
227	04/07/27	11:21:08.317	TMB1B	Asserted
226	04/07/27	11:21:08.327	51P2	Asserted
225	04/07/27	11:21:08.327	RMB1A	Asserted
224	04/07/27	11:21:11.606	51G2T	Asserted
223	04/07/27	11:21:14.800	RMB1A	Deasserted
222	04/07/27	11:21:14.830	79CY	Asserted
221	04/07/27	11:21:14.830	79RS	Deasserted
220	04/07/27	11:21:14.830	TRIP	Asserted

Table A – 15 shows the behaviour of R1 when a blocking signal is received. Although the ground overcurrent element times out (51G2T is asserted), no trip occurs until the blocking signal is deasserted.

Table A - 16 Results summary for test 'A3'

Test No	Ground O/C on R2 blocks Ground O/C on R1		
Test A3		Without blocking	With blocking
	Expected Result	3.375s	No trip
	Observed Result	3.289s	No trip

A4 testing regime

<u>Task</u>

To block the upstream recloser No 28506, from tripping due to the phase O/C pick up, with the blocking signal sent by downstream recloser No18434 due to its ground O/C pick up.

The testing set up is shown in Table A – 17.

Table A - 17 Set up for 'A4' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	2 times the O/C setting	4 A	2.97 s	E/F and O/C element blocked by ACR No 18434. No tripping
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.5 times the O/C setting	1.14 A	6.480 s	Trip after 6.48 s and reclose.

A4 testing

Test A4_1

Secondary fault current of 4 A was injected into the phase element at the upstream recloser No 28506.

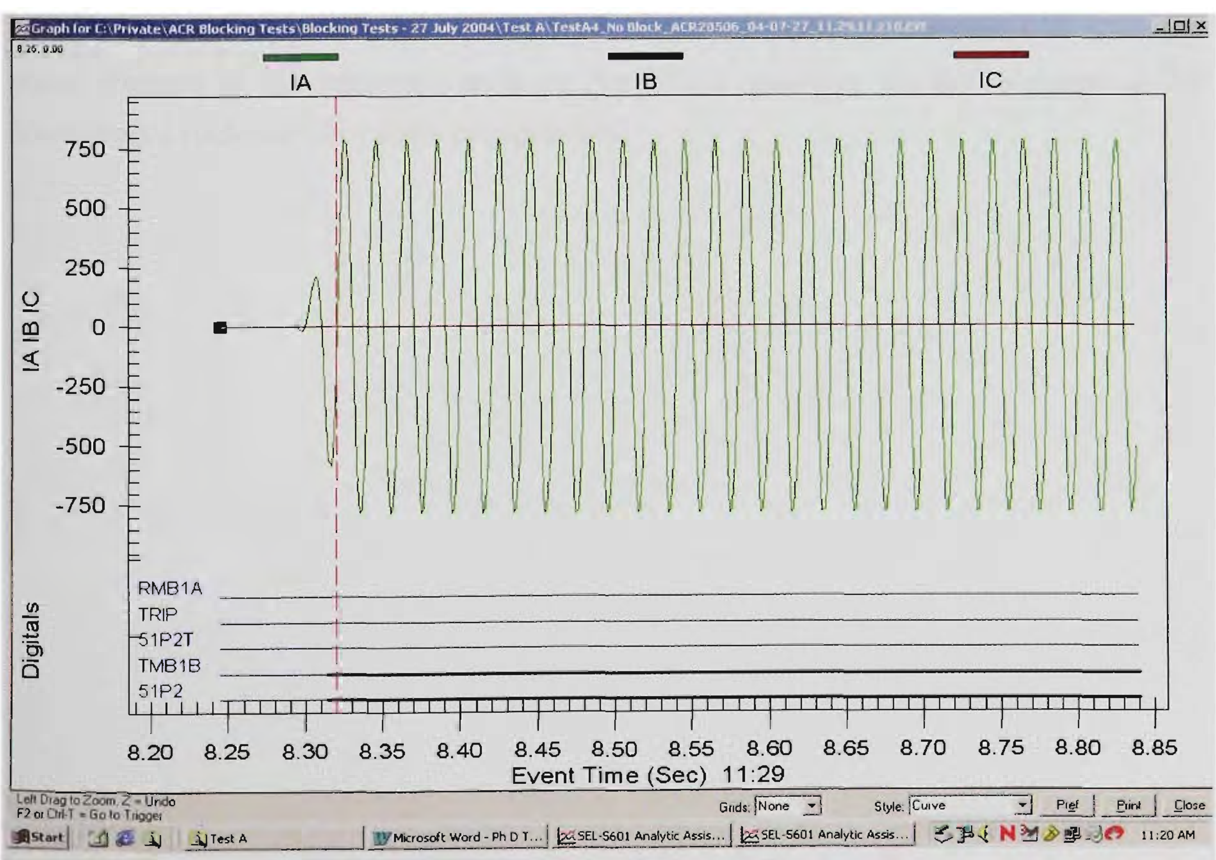


Figure A4_1_Event 1 Phase O/C pick up by R1, no block received

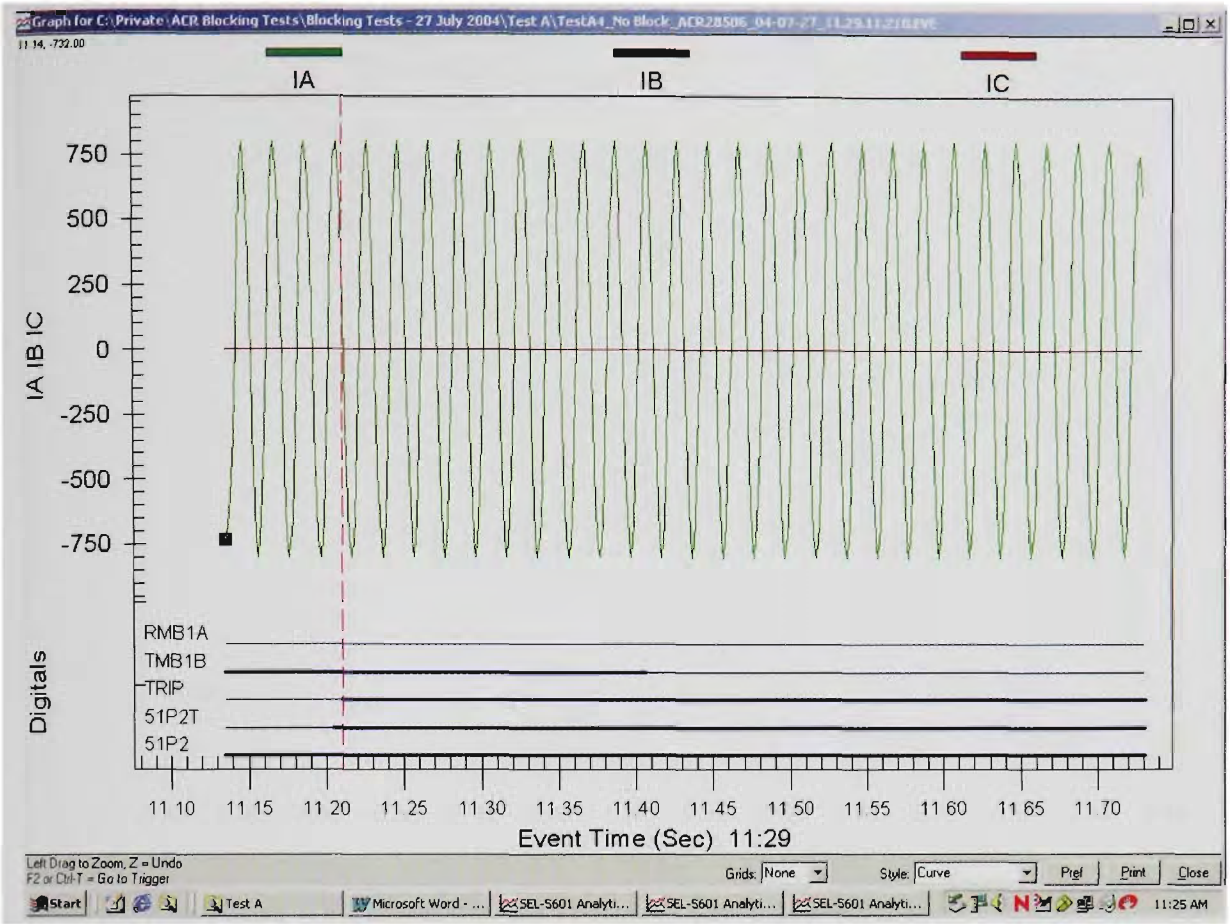


Figure A4_1_Event 2 R1 tripping on Phase O/C, no block received

Test A4_2

Secondary fault currents of 4 A and 1.14 A were injected simultaneously into the phase element at the upstream recloser No 28506 and into the E/F element at the downstream recloser No 18434 respectively.

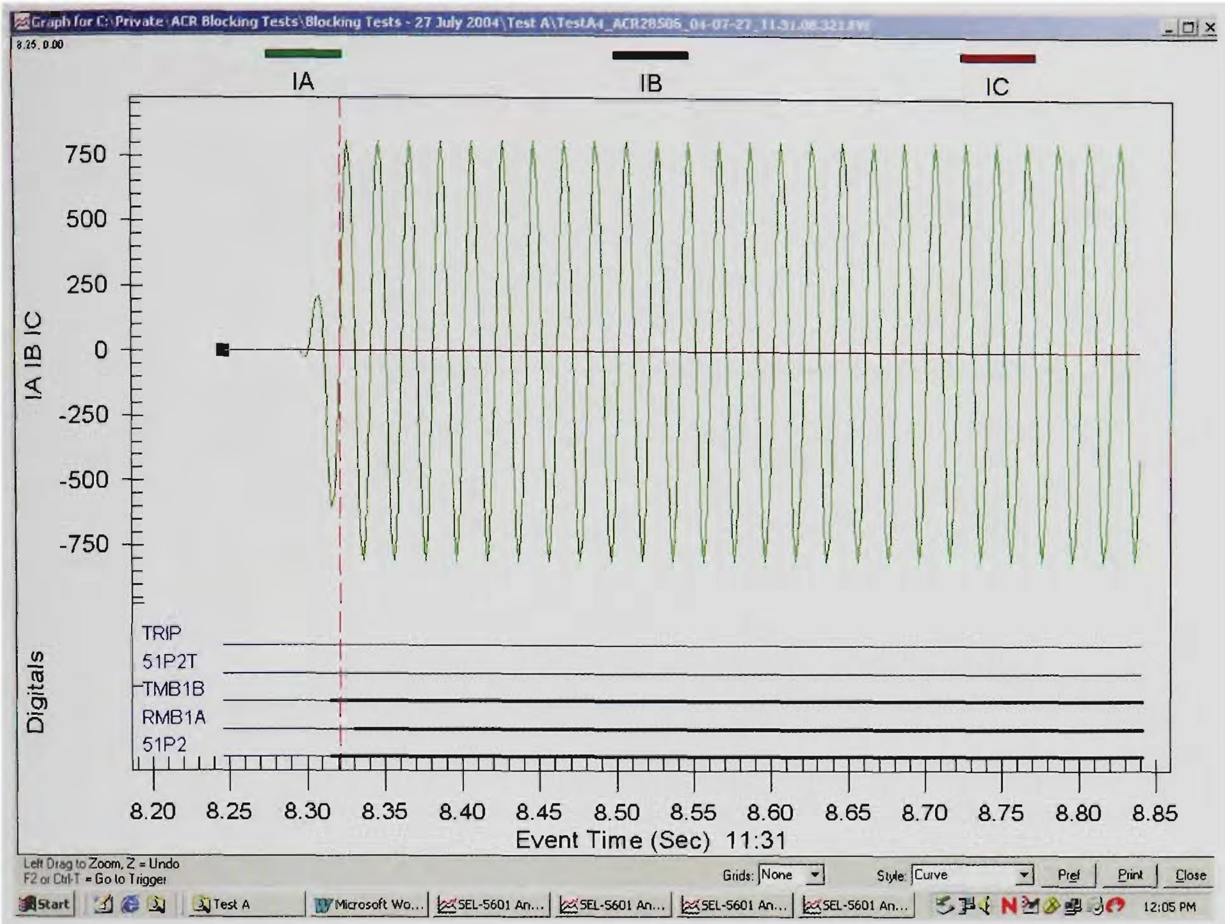


Figure A4_2_Event 1 R1 blocked from tripping on Phase O/C

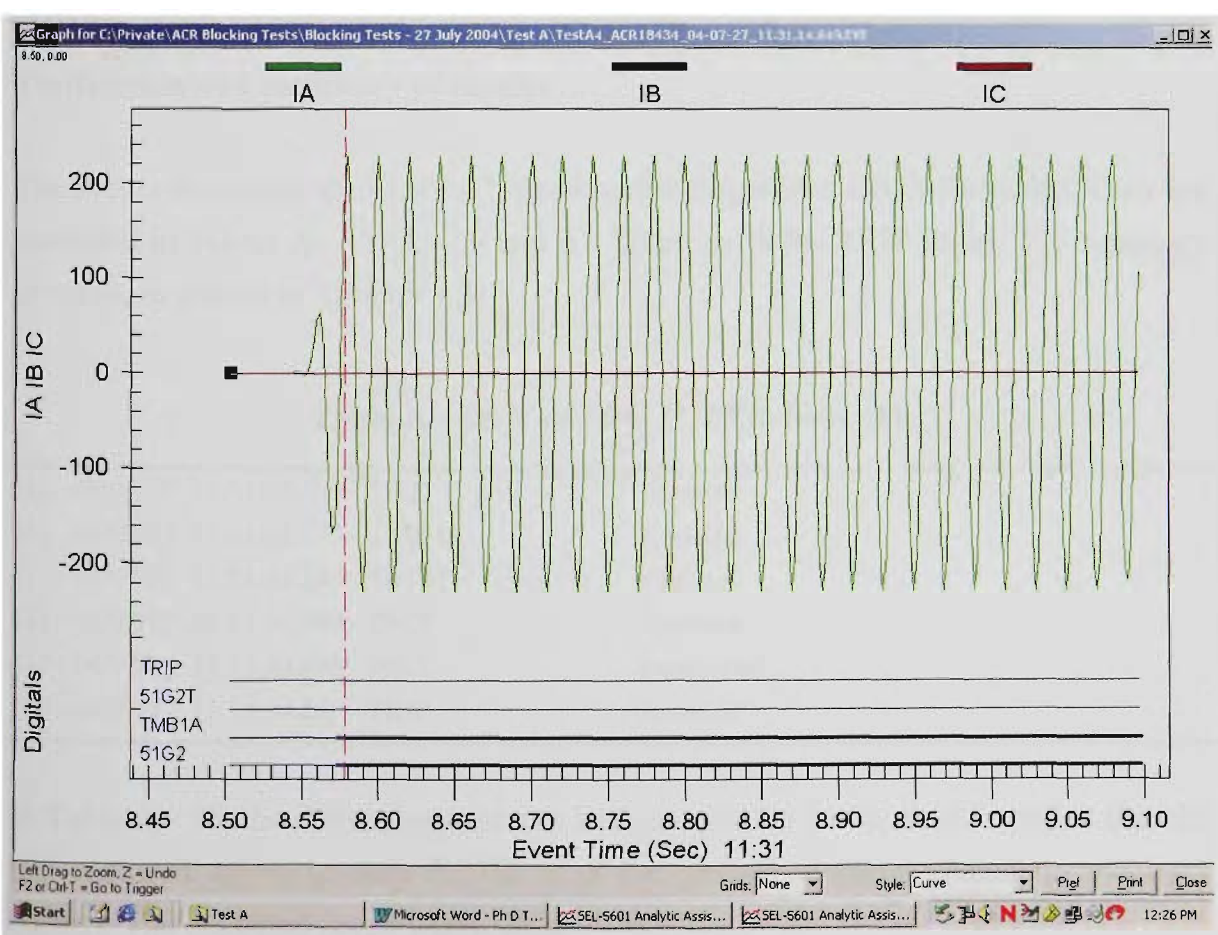


Figure A4_2_Event 2 R2 sending blocking signal to R1

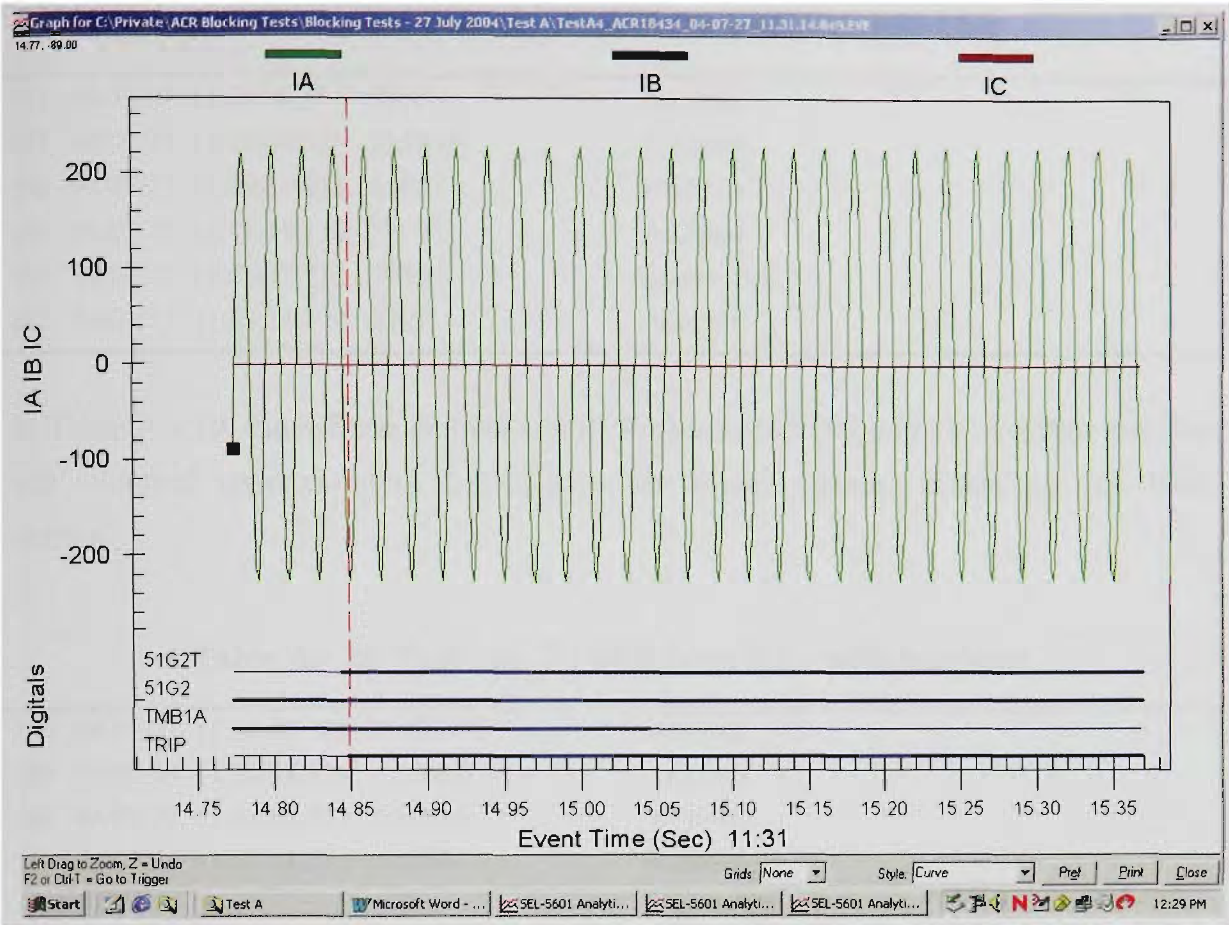


Figure A4_2_Event 3 R2 tripping on Ground O/C

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 18, A - 19 and A - 20 to verify the TRIP times. The summary of results is shown in Table A - 21.

Table A - 18 Test 'A4_2', SER from R2

114	04/07/27	11:31:08.573	51G2	Asserted
113	04/07/27	11:31:08.573	TMB1A	Asserted
112	04/07/27	11:31:14.844	51G2T	Asserted
111	04/07/27	11:31:14.849	79CY	Asserted
110	04/07/27	11:31:14.849	79RS	Deasserted
109	04/07/27	11:31:14.849	TRIP	Asserted

In Table A - 18, the difference between SER entries No 114 and 109 verifies that the trip occurred approximately 6.271s after the ground element picked up the fault current. The expected result was 6.480s.

Table A - 19 Test 'A_1', SER from R1 - no blocking

192	04/07/27	11:29:08.315	51P2	Asserted
191	04/07/27	11:29:08.315	TMB1B	Asserted
190	04/07/27	11:29:11.205	51P2T	Asserted
189	04/07/27	11:29:11.210	79CY	Asserted
188	04/07/27	11:29:11.210	79RS	Deasserted
187	04/07/27	11:29:11.210	TRIP	Asserted

In Table A - 19, the difference between SER entries No 192 and 187 verifies that the trip occurred approximately 2.890s after the phase element picked up the fault current.

Table A - 20 Test 'A4_2', SER from R1 – with blocking

170	04/07/27	11:31:08.316	51P2	Asserted
169	04/07/27	11:31:08.316	TMB1B	Asserted
168	04/07/27	11:31:08.331	RMB1A	Asserted
167	04/07/27	11:31:11.205	51P2T	Asserted
166	04/07/27	11:31:13.315	51P2	Deasserted
165	04/07/27	11:31:13.335	51P2T	Deasserted
164	04/07/27	11:31:14.805	RMB1A	Deasserted
163	04/07/27	11:31:14.805	TMB1B	Deasserted

Table A - 20 shows the behaviour of R1 when a blocking signal is received. Although the phase overcurrent element times out (51P2T is asserted), no trip occurs.

Table A - 21 Results summary for test 'A4'

Test No	Ground O/C on R2 blocks Phase O/C on R1		
Test A4		Without blocking	With blocking
	Expected Result	2.970s	No trip
	Observed Result	2.890s	No trip

A5 testing regime

Task

To verify that SEF on the downstream recloser does not block ground O/C on the upstream recloser with SEF OFF

The testing set up is shown in Table A - 22.

Table A - 22 Set up for 'A5' testing

ACR	ACR pushbuttons	Current leads	Fault current	Secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	13 times the E/F setting	13 A	0.281 s	E/F and O/C element blocked by ACR No 18434. No tripping
R2 18434	Prot ON Reclose ON E/F ON SEF ON CB Closed	SEF element	2 times the SEF setting	0.072 A	1.0 s	Trip on SEF after 1 s

A5 testing

Test A5_1

Secondary fault current of 13 A was injected into the ground element of the SEL 351P relay at the upstream recloser No 28506.

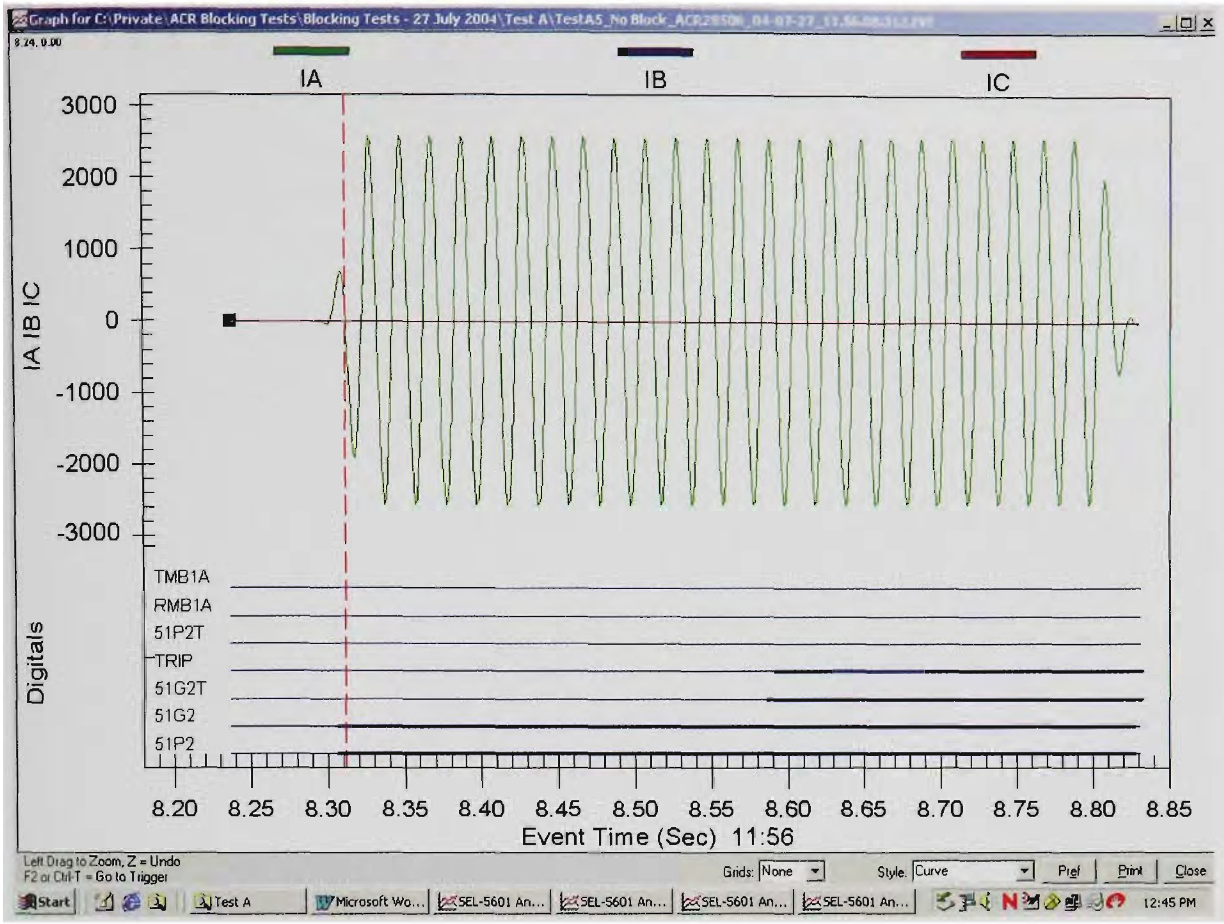


Figure A5_1_Event 1 Ground and Phase O/C pick up by R1, without blocking

Test A5_2

Secondary fault currents of 13 A and 0.072 A were injected simultaneously into the ground element of the SEL 351P relay at the upstream recloser No 28506 and into the SEF element of the SEL 351P relay at the downstream recloser No 18434 respectively.

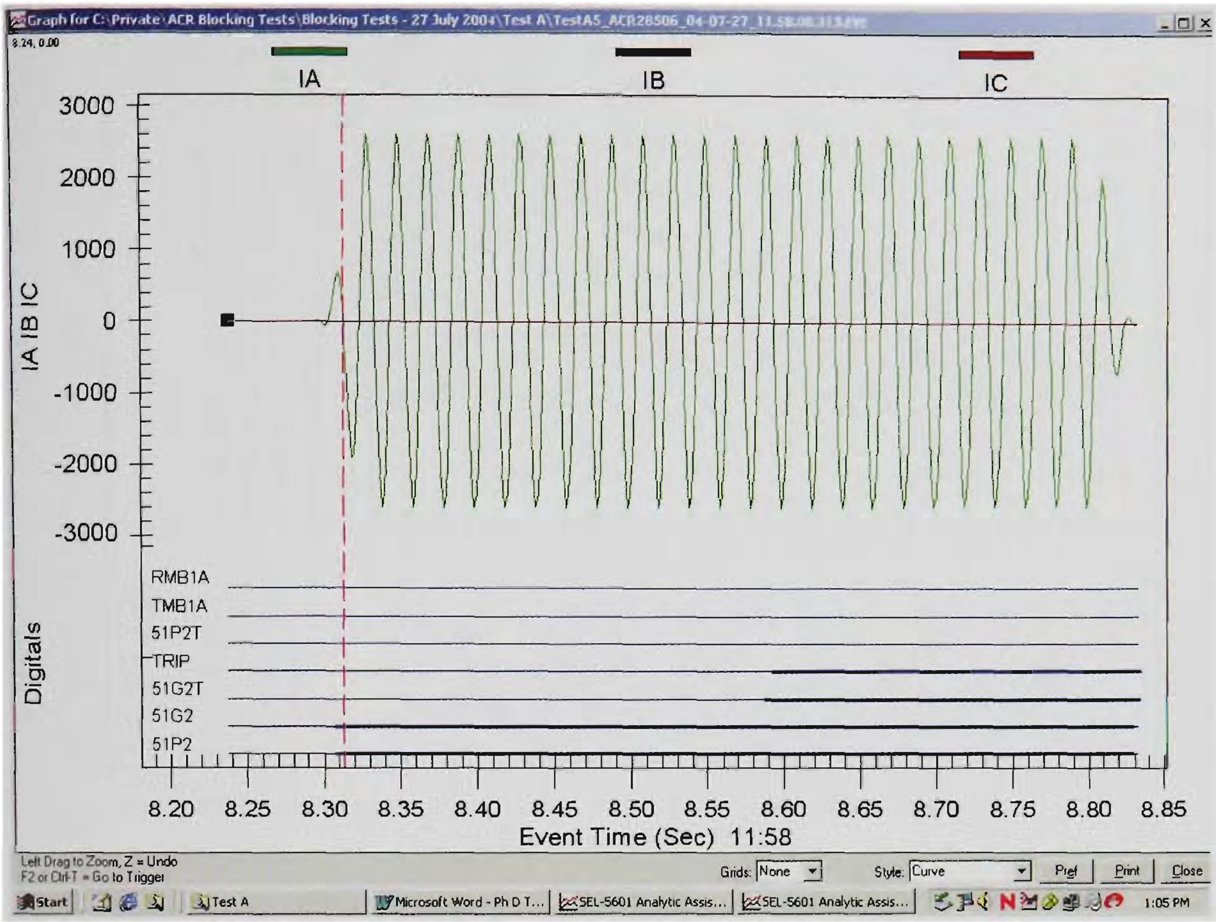


Figure A5_2_Event 1 SEF on R2 does not block Ground and Phase O/C elements on R1, no block received

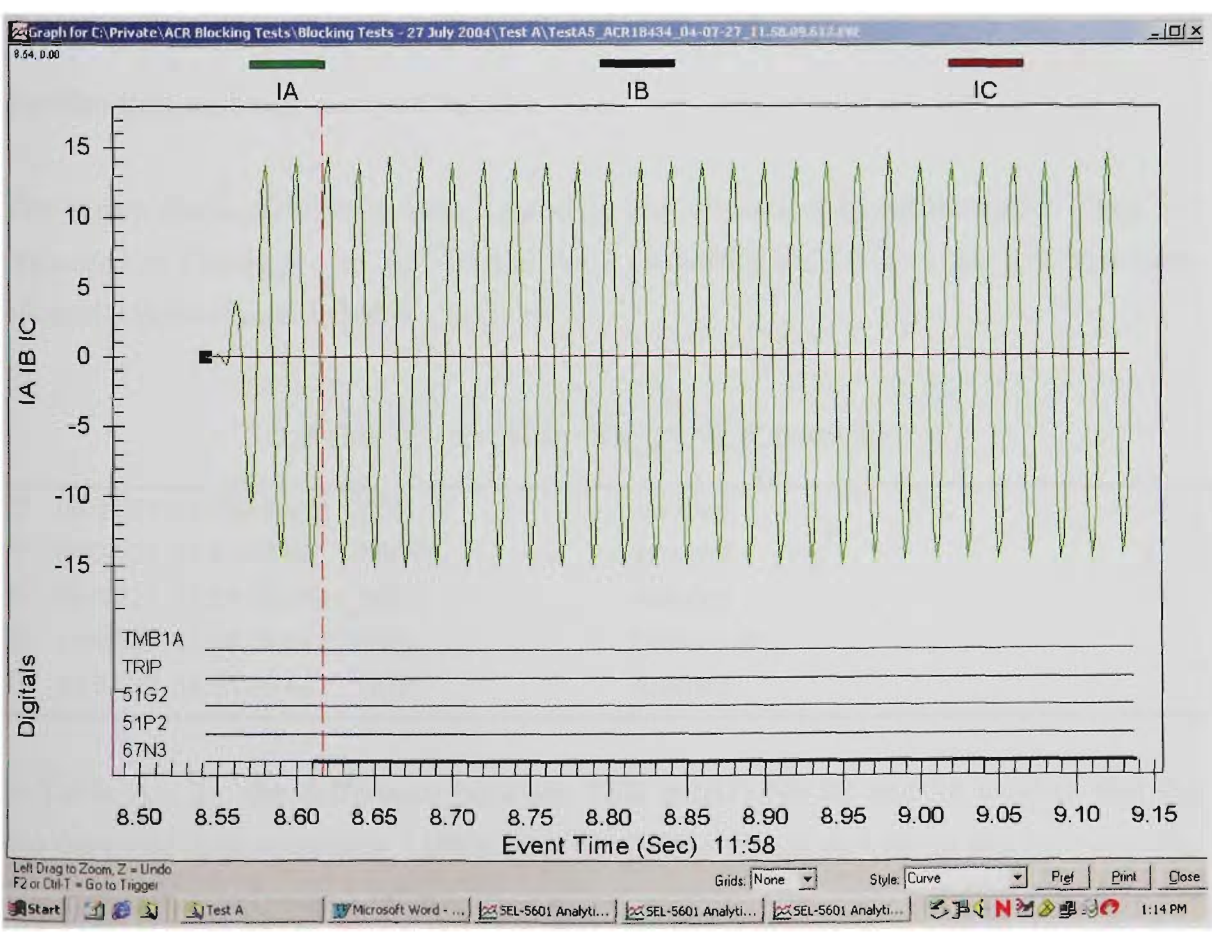


Figure A5_2_Event 2 SEF pick up by R2, no block transmitted

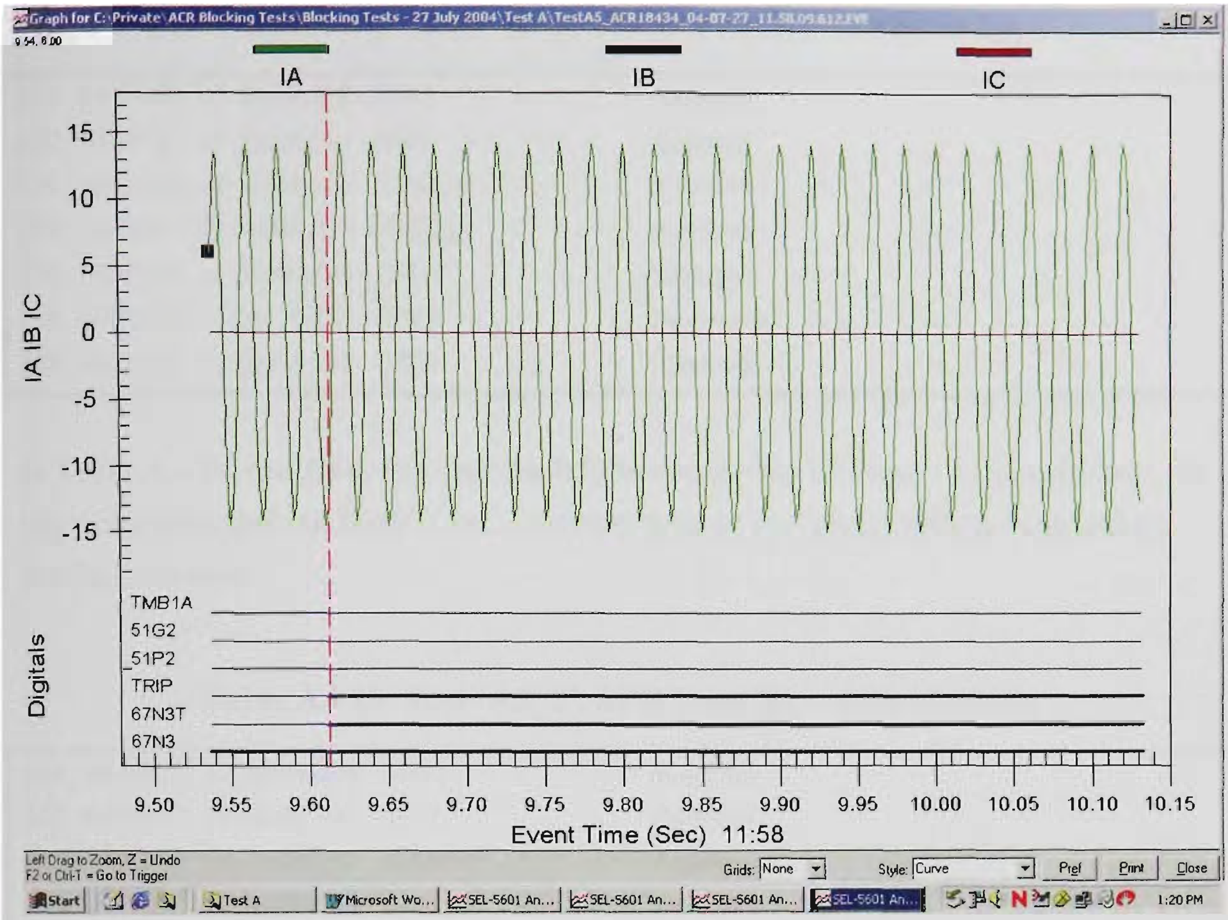


Figure A5_2_Event 3 R2 tripping on SEF, no block transmitted

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 23, A - 24 and A - 25 to verify the TRIP times. The summary of results is shown in Table A - 26.

Table A - 23 Test 'A5_2', SER from R2

92	04/07/27	11:58:08.612	67N3	Asserted
91	04/07/27	11:58:09.612	67N3T	Asserted
90	04/07/27	11:58:09.612	79CY	Asserted
89	04/07/27	11:58:09.612	79RS	Deasserted
88	04/07/27	11:58:09.612	TRIP	Asserted

In Table A - 23, the difference between SER entries No 92 and 88 verifies that the trip occurred approximately 1.000s after the SEF element picked up the fault current. The expected result was 1.000s.

Table A - 24 Test 'A5_1', SER from R1 - no blocking

138	04/07/27	11:56:08.307	51G2	Asserted
137	04/07/27	11:56:08.307	51P2	Asserted
136	04/07/27	11:56:08.307	TMB1B	Asserted
135	04/07/27	11:56:08.587	51G2T	Asserted
134	04/07/27	11:56:08.592	79CY	Asserted
133	04/07/27	11:56:08.592	79RS	Deasserted
132	04/07/27	11:56:08.592	TRIP	Asserted

In Table A - 24, the difference between SER entries No 138 and 132 verifies that the trip occurred approximately 0.285s after the ground and phase elements picked up the fault currents.

Table A - 25 Test 'A5_2', SER from R1 – with blocking

114	04/07/27	11:58:08.308	51G2	Asserted
113	04/07/27	11:58:08.308	51P2	Asserted
112	04/07/27	11:58:08.308	TMB1B	Asserted
111	04/07/27	11:58:08.588	51G2T	Asserted
110	04/07/27	11:58:08.593	79CY	Asserted
109	04/07/27	11:58:08.593	79RS	Deasserted
108	04/07/27	11:58:08.593	TRIP	Asserted

In Table A - 25, the difference between SER entries No 114 and 108 verifies that the trip occurred approximately 0.285s after the ground and phase elements picked up the fault currents, i.e no blocking occurred.

Table A - 26 Results summary for test 'A5'

Test No	SEF on R2 does not block Ground O/C or Phase O/C on R1		
Test A5		Without blocking	With blocking
	Expected Result	0.281s	Trip in 0.285s
	Observed Result	0.285s	Trip in 0.285s

A6 testing regime

Task

On the upstream recloser No 28506, to test E/F and phase O/C element operation with and without blocking. To verify the 200ms recloser breaker failure operation on the downstream recloser No 18434 and the upstream recloser No 28506.

The testing set up is shown in Table A - 27.

Table A - 27 Set up for 'A6' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	13 times the E/F setting	13 A	0.281 s	ACR 28506 O/C and E/F elements blocked by ACR 18434. ACR 28506 rips 200 ms after ACR 18434 is supposed to trip. Trip time = 0.463+200 = 0.663 ms.
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	8 times the E/F setting	6.08 A	0.463 s	Keep the current on for at least 200 ms.

A6 testing

Test A6_1

Current of 13A was injected on a single phase at the upstream recloser No 28506, referred to as R1, to simulate a fault in feeder section 3.

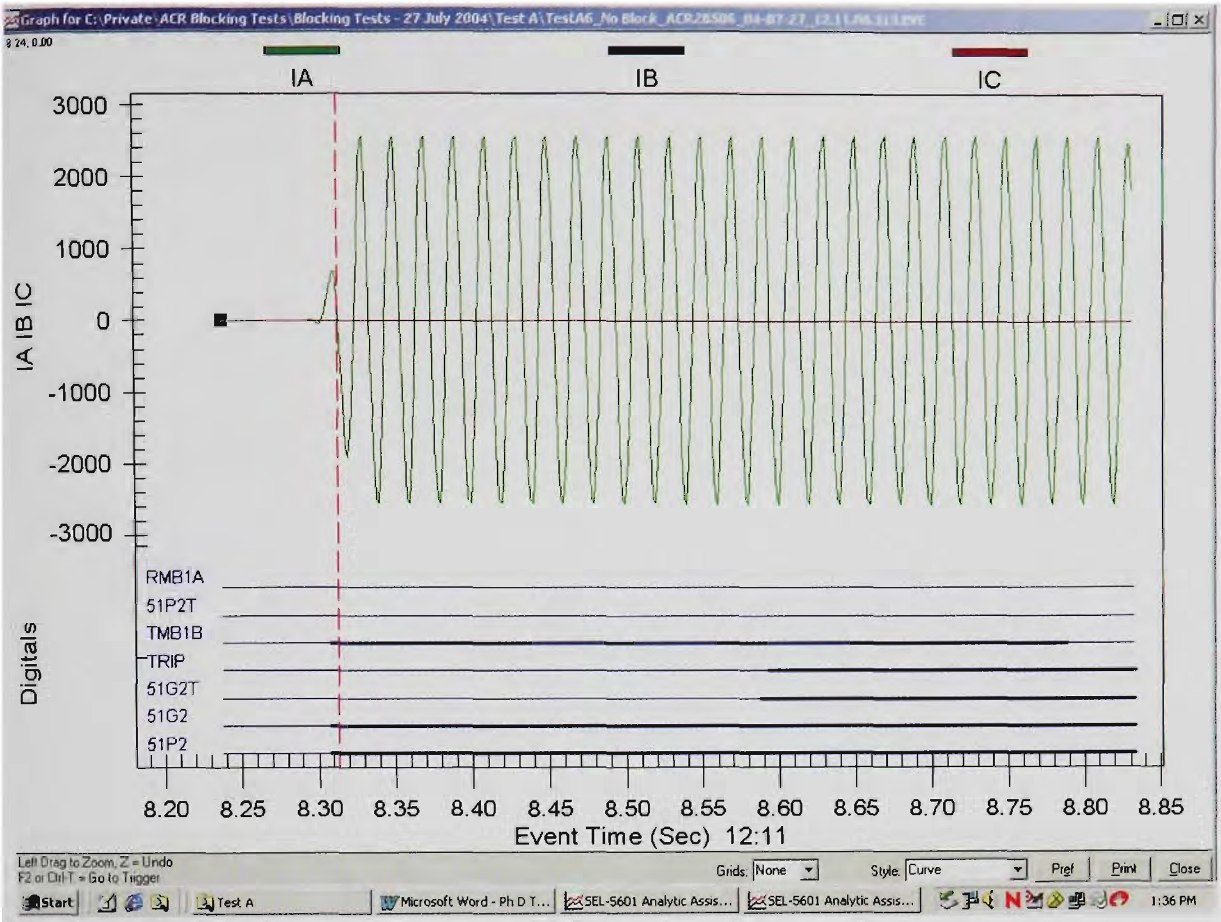


Figure A6_1_Event 1 R1 tripping on Ground O/C, no blocking

Test A6_2

Fault currents of 13A and 6.08A were injected simultaneously at the upstream recloser No 28506 and the downstream recloser No18434 to simulate a fault in feeder section 3. The downstream recloser breaker failure was simulated by injecting a fault current, at R1, for at least 200ms after R2 issued a trip command for its breaker.

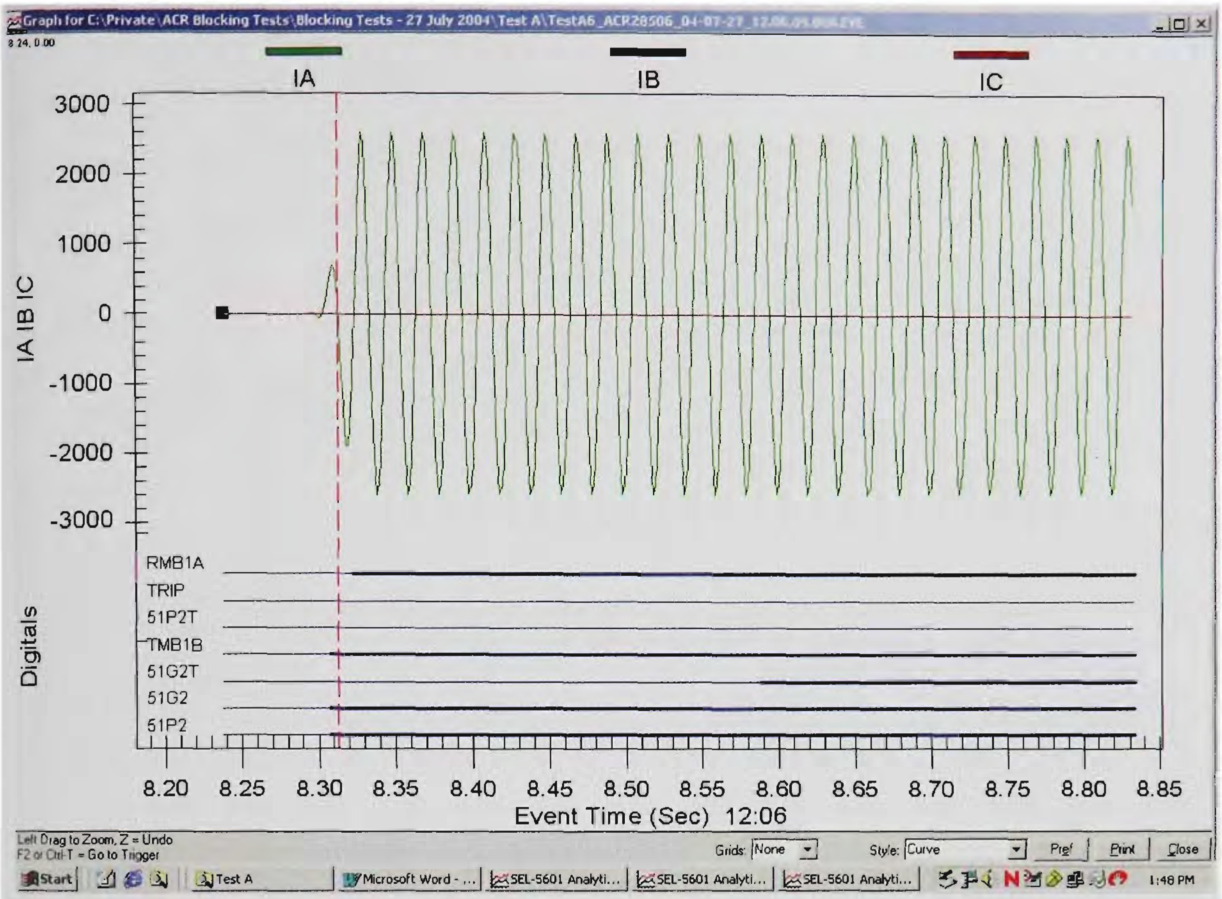


Figure A6_2_Event 1 Ground O/C pick up by R1, blocking received, no trip

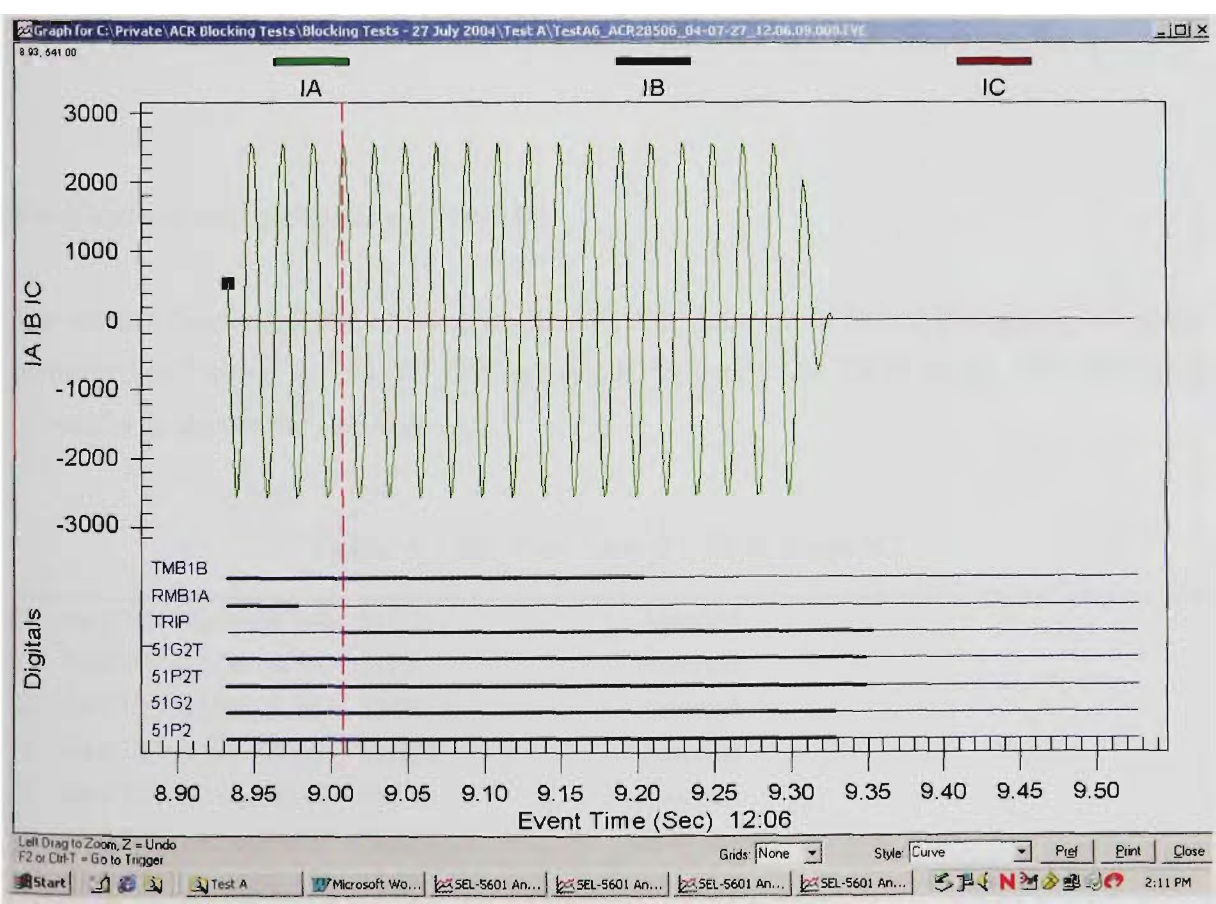


Figure A6_2_Event 2 R1 trips after blocking is removed by R2 due to its breaker failure

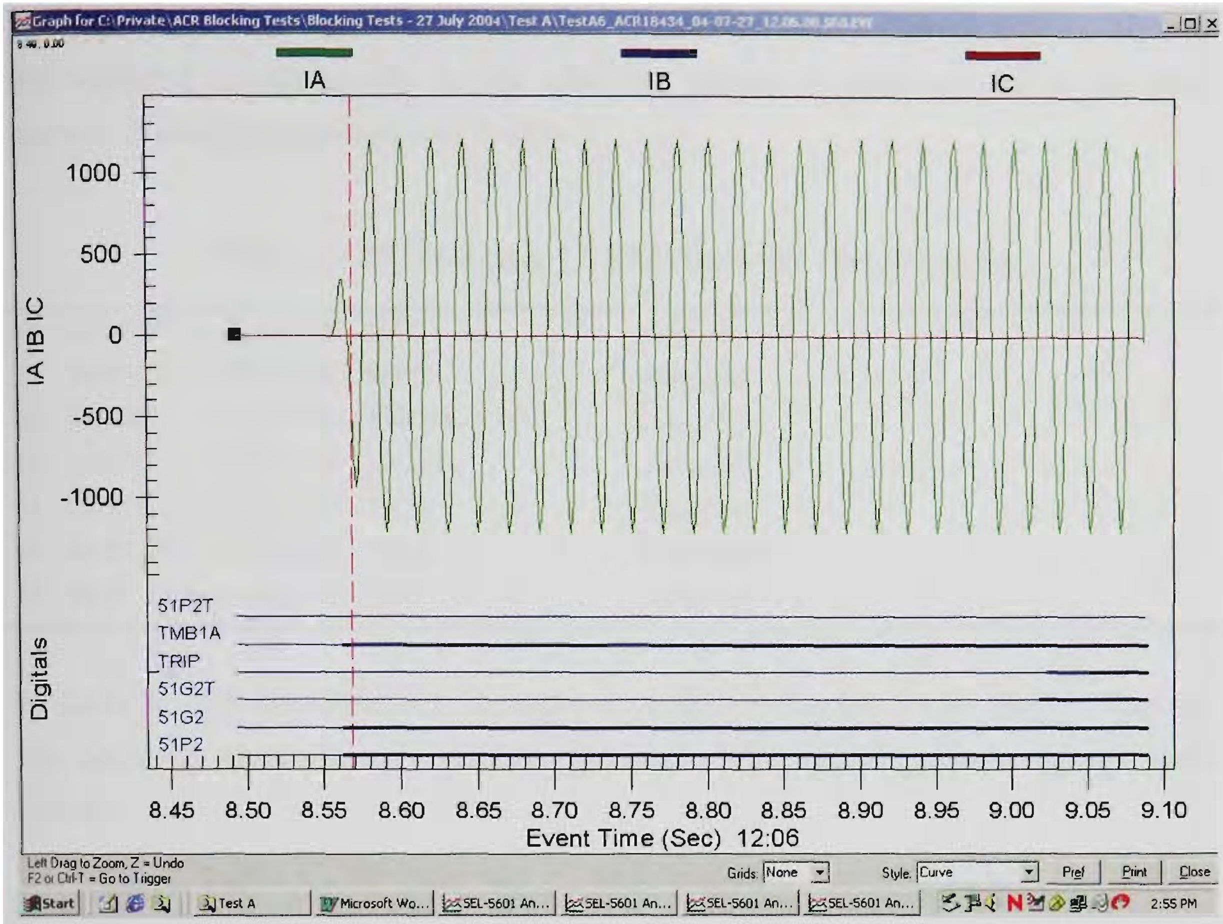


Figure A6_2_Event 3 Trip command issued by R2, for breaker failure scenario the fault current flows for at least 200ms before R1 clears the fault

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables A - 28, A - 29 and A - 30 to verify the TRIP times. The summary of results is shown in Table A - 31.

Table A - 28 Test 'A6_2', SER from R2

48	04/07/27	12:06:08.563	51G2	Asserted
47	04/07/27	12:06:08.563	51P2	Asserted
46	04/07/27	12:06:08.563	TMB1A	Asserted
45	04/07/27	12:06:09.018	51G2T	Asserted
44	04/07/27	12:06:09.023	79CY	Asserted
43	04/07/27	12:06:09.023	79RS	Deasserted
42	04/07/27	12:06:09.023	TRIP	Asserted

In Table A - 28, the difference between SER entries No 48 and 42 verifies that the trip occurred approximately 0.460s after the ground element picked up the fault current. The expected result was 0.463s.

Table A - 29 Test 'A6_1', SER from R1 - no blocking

58	04/07/27	12:11:08.308	51G2	Asserted
57	04/07/27	12:11:08.308	51P2	Asserted
56	04/07/27	12:11:08.308	TMB1B	Asserted
55	04/07/27	12:11:08.588	51G2T	Asserted
54	04/07/27	12:11:08.593	79CY	Asserted
53	04/07/27	12:11:08.593	79RS	Deasserted
52	04/07/27	12:11:08.593	TRIP	Asserted

In Table A - 29, the difference between SER entries No 58 and 52 verifies that the trip occurred approximately 0.285s after the phase element picked up the fault current.

Table A - 30 Test 'A6_2', SER from R1 – with blocking

86	04/07/27	12:06:08.308	51G2	Asserted
85	04/07/27	12:06:08.308	51P2	Asserted
84	04/07/27	12:06:08.308	TMB1B	Asserted
83	04/07/27	12:06:08.323	RMB1A	Asserted
82	04/07/27	12:06:08.588	51G2T	Asserted
81	04/07/27	12:06:08.843	51P2T	Asserted
80	04/07/27	12:06:08.978	RMB1A	Deasserted
79	04/07/27	12:06:09.008	79CY	Asserted
78	04/07/27	12:06:09.008	79RS	Deasserted
77	04/07/27	12:06:09.008	TRIP	Asserted

Table A - 30 shows the behaviour of R1 when a blocking signal is received. The time difference between SER entries No 86 and 77 verifies that the trip occurred approximately 0.700s after the phase and ground elements picked up the fault current.

Table A - 31 Test 'A6_2', SER from R2 – for R2 breaker failure scenario

48	04/07/27	12:06:08.563	51G2	Asserted
47	04/07/27	12:06:08.563	51P2	Asserted
46	04/07/27	12:06:08.563	TMB1A	Asserted
45	04/07/27	12:06:09.018	51G2T	Asserted
44	04/07/27	12:06:09.023	79CY	Asserted
43	04/07/27	12:06:09.023	79RS	Deasserted
42	04/07/27	12:06:09.023	TRIP	Asserted
41	04/07/27	12:06:09.063	52A	Deasserted
40	04/07/27	12:06:09.218	SV2T	Asserted
39	04/07/27	12:06:09.218	TMB1A	Deasserted
38	04/07/27	12:06:09.388	51P2T	Asserted
37	04/07/27	12:06:09.578	51P2	Deasserted
36	04/07/27	12:06:09.583	51G2	Deasserted

In Table A - 31, the time difference between SER entries No 39 and 45, i.e. 200 ms, proves that the breaker failure feature performed according to the design specification.

Table A - 32 Results summary for test 'A6'

Test No	Ground O/C on R2 blocks Phase and Ground O/C on R1 and tests breaker fail timer at R2		
Test A6		Without blocking	With blocking
	Expected Result	0.281s	0.663[A]
	Observed Result	0.285s	0.700s

[A] trip time = 0.463 + 0.200 = 0.663, i.e. the trip time of R2 without blocking + 200ms breaker failure delay timer time

Appendix 'B'

Blocking of BD7 feeder CB by R1

Test set 'B'

Introduction

Test set 'B' comprised seven tests covering blocking from the upstream recloser, R1, to the BD7 CB as outlined in Table B.

Table B - 1 Blocking from R1 to BD7 CB

Test No	Purpose
B1	Phase O/C on R1 blocks Phase O/C on CB
B2	Phase O/C on R1 blocks Ground O/C on CB
B3	Ground O/C on R1 blocks Ground O/C on CB
B4	Ground O/C on R1 blocks Phase O/C on CB
B5	SEF on R1 does not block Phase O/C or Ground O/C on CB
B6	Phase O/C or Ground O/C on R1 does not block Instantaneous O/C on CB
B7	Ground O/C on R1 blocks Phase O/C and Ground O/C on CB and tests breaker fail at R1

General design specifications:

5. An SEF fault on any section should not block any protection element on an upstream device.

6. A phase fault on any section should not block an SEF element on an upstream device.

7. The instantaneous phase O/C element at the CB should not be blocked by any downstream device.

8. A downstream device should stop transmitting a blocking signal 200ms after issuing a trip command (to cater for breaker failure).

The test set up deployed is shown in Figure B[2].

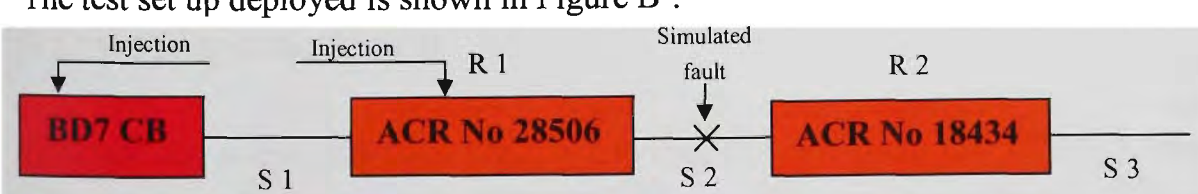


Figure B Test set 'B' set up for R1 blocking BD7 CB

[2] CT ratio for the BD7 CB is 700/5. CT ratio for R1 recloser for testing purposes is 200/1. For operational purposes, the effective CT ratio for R1 recloser is 400/1. This is due to the presence of interposing CTs in the recloser tank.

B1 testing regime

Task

To block the BD7 CB, from tripping due to its Phase O/C pick up, with the blocking signal sent by the upstream recloser, R1, due to its Phase O/C pick up.

The testing set up is shown in Table B - 2.

Table B - 2 Set up for 'B1' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	2.4 A	14.850s	Trips after 14.850s
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C OFF	Any phase element	4.0 times the O/C setting	17.0 A	1.096s	BD7 Inverse Time O/C element blocked. Trips on the back up element only.

B1 testing

Test B1_1, no blocking

Secondary fault current of 17A was injected into the Phase O/C element of the SEL351S relay at the BD7 CB.

There are two events, No 1 and No 2, in this test. This is because the SEL 351S relay software is capable of displaying only 30 cycles at a time, i.e. approximately 600 ms. As the BD7 CB, without blocking, is expected to trip in 1.096 seconds, a second event is needed to capture the TRIP.

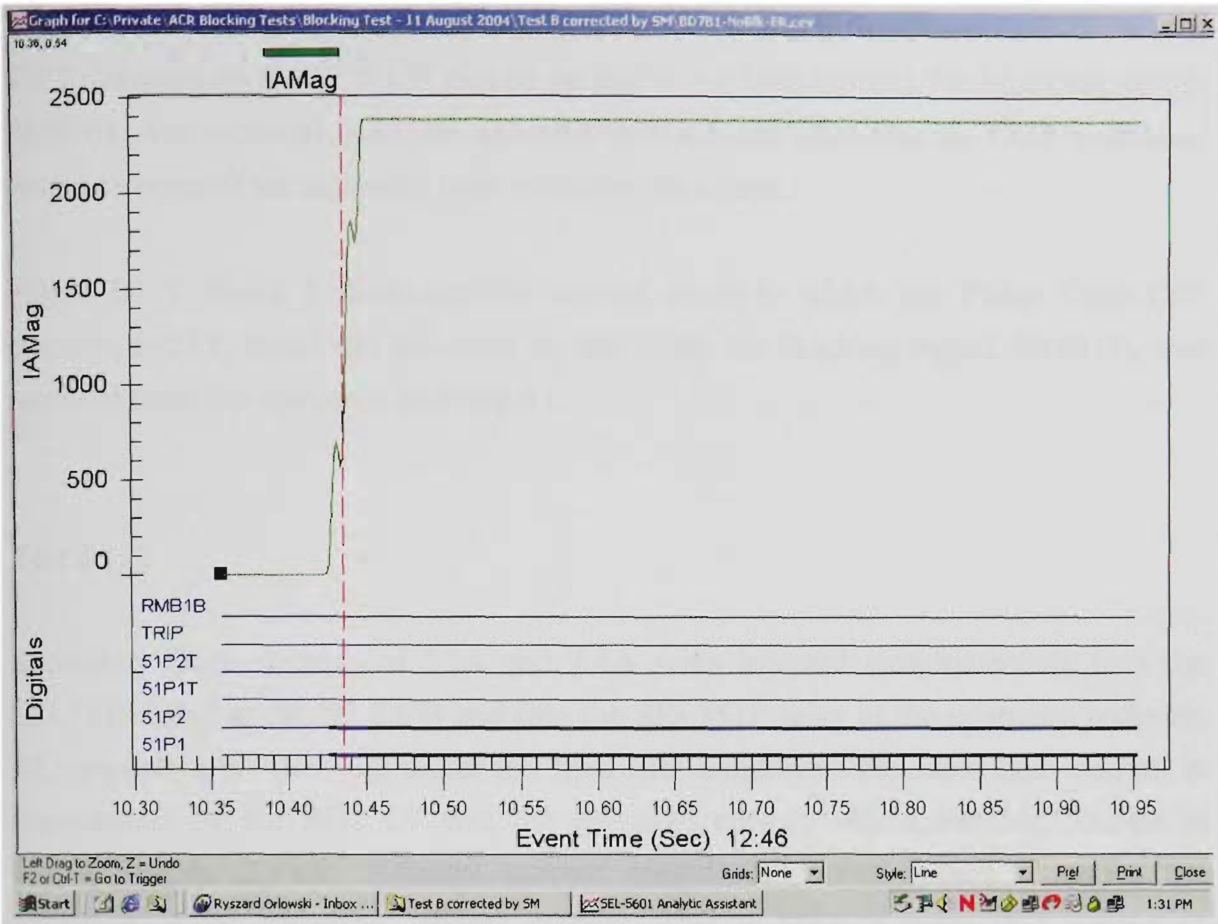


Figure B1_1_Event_1 BD7 CB, Phase O/C pick up, no blocking

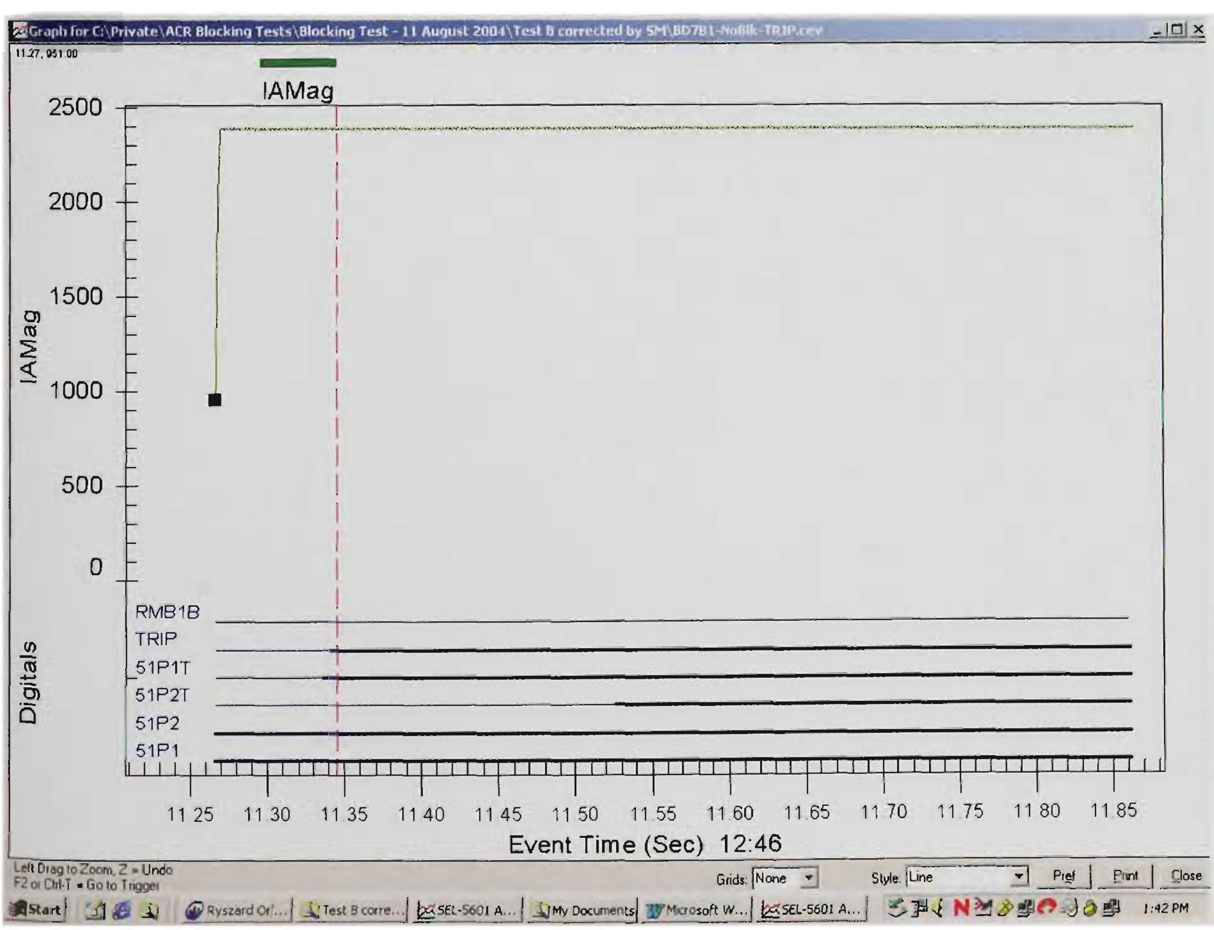


Figure B1_1_Event_2 BD7 CB, trip due to a Phase O/C, no blocking

Figure B1_1_Event_1, illustrates the first event in which the Phase O/C 51P1 and 51P2 elements on the BD7 CB picked up due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser and there was no TRIP command issued as none of the activated time elements timed out.

Figure B1_1_Event_2 illustrates the second event in which the Phase Time O/C element, 51P1T, timed out followed by the TRIP. No blocking signal, RMB1B, was received from the upstream recloser R1.

Test B1_2

Secondary fault currents of 17A and 2.4A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the upstream recloser, R1, respectively. Although under the 'real life' conditions the same fault current is experienced by the BD7 CB and the upstream recloser when the fault occurs in feeder Section 2, two different current magnitudes were chosen to make the operation of the blocking scheme evident. This is because there is a degree of discrimination built into the protection settings.

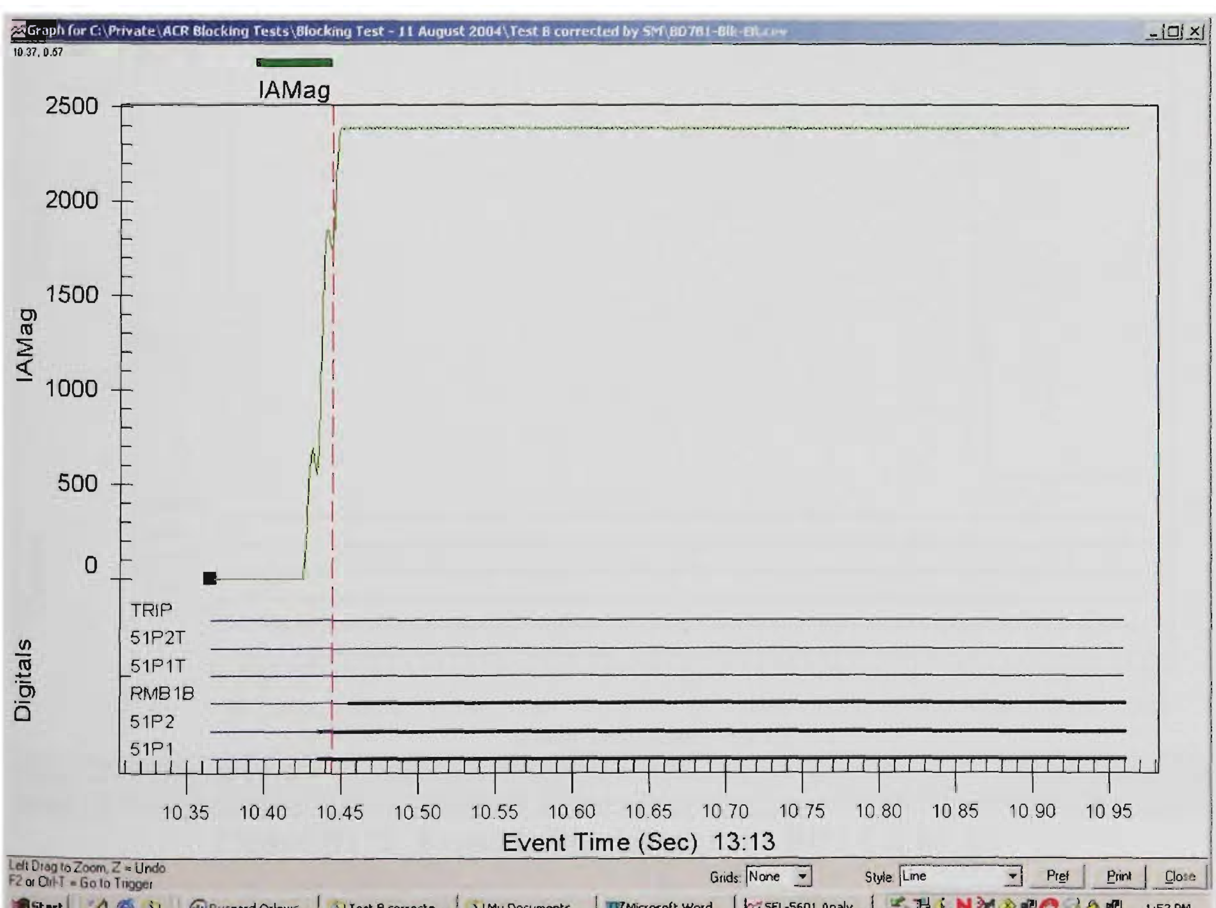


Figure B1_2_Event_1 Blocking of the BD7 CB on Phase O/C

Figure B1_2_Event_1 shows that the Phase O/C elements, 51P1 and 51P2, at the BD7 CB picked up the fault current. Because the Phase Time O/C elements, 51P1T and 51P2T, had not timed out yet and a blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not issue the TRIP command.

Figure B1_2_Event_2 illustrates that the faster Phase Time O/C element, 51P1T, timed out but the BD7 CB did not trip because the TRIP function was blocked by the received blocking signal, RMB1B, from the upstream recloser, R1. The TRIP operation occurred due to the time out of the slower back up Phase Time O/C element, 51P2T.

Figure B1_2_Event_3 illustrates that the Phase O/C element, 51P2, at the upstream recloser R1, picked up the fault and as a result a blocking signal, TMB1B, was transmitted to the BD7 CB to stop it from tripping.

Figure B1_2_Event_4 illustrates that the Phase Time O/C element, 51P2T, timed out at the upstream recloser R1, and as a result the upstream recloser, R1, tripped.

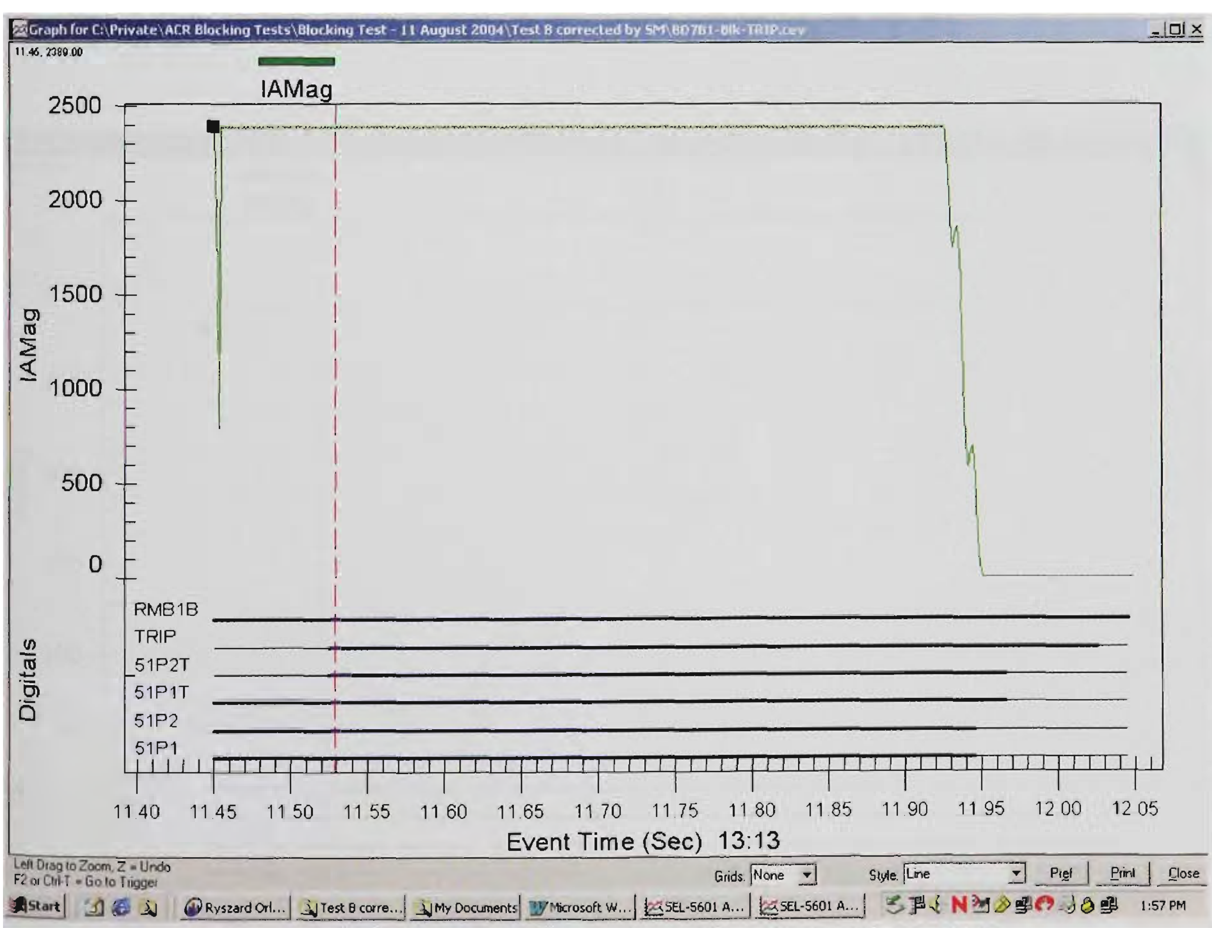


Figure B1_2_Event 2 Blocking of the BD7 CB by R1

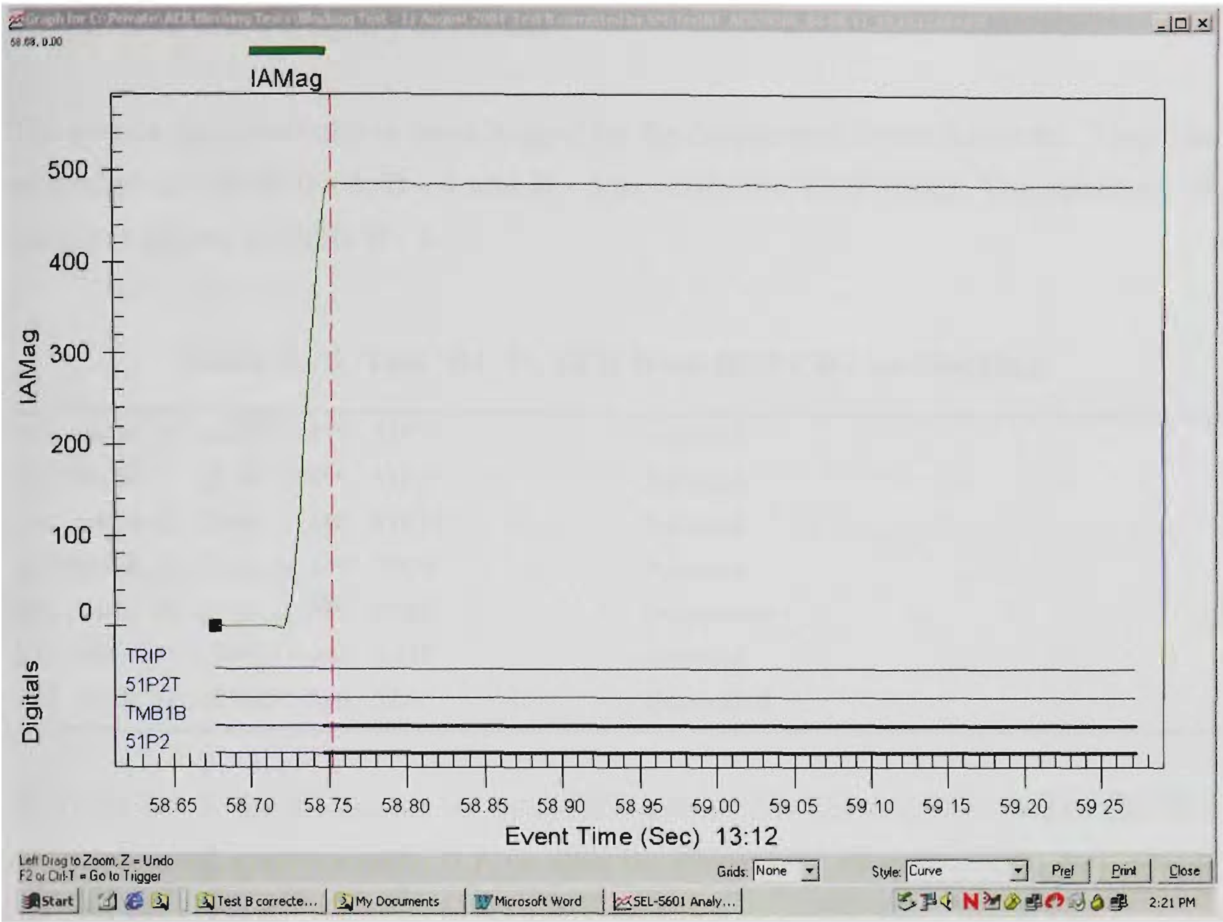


Figure B1_2_Event_3 Phase O/C pick up by R1

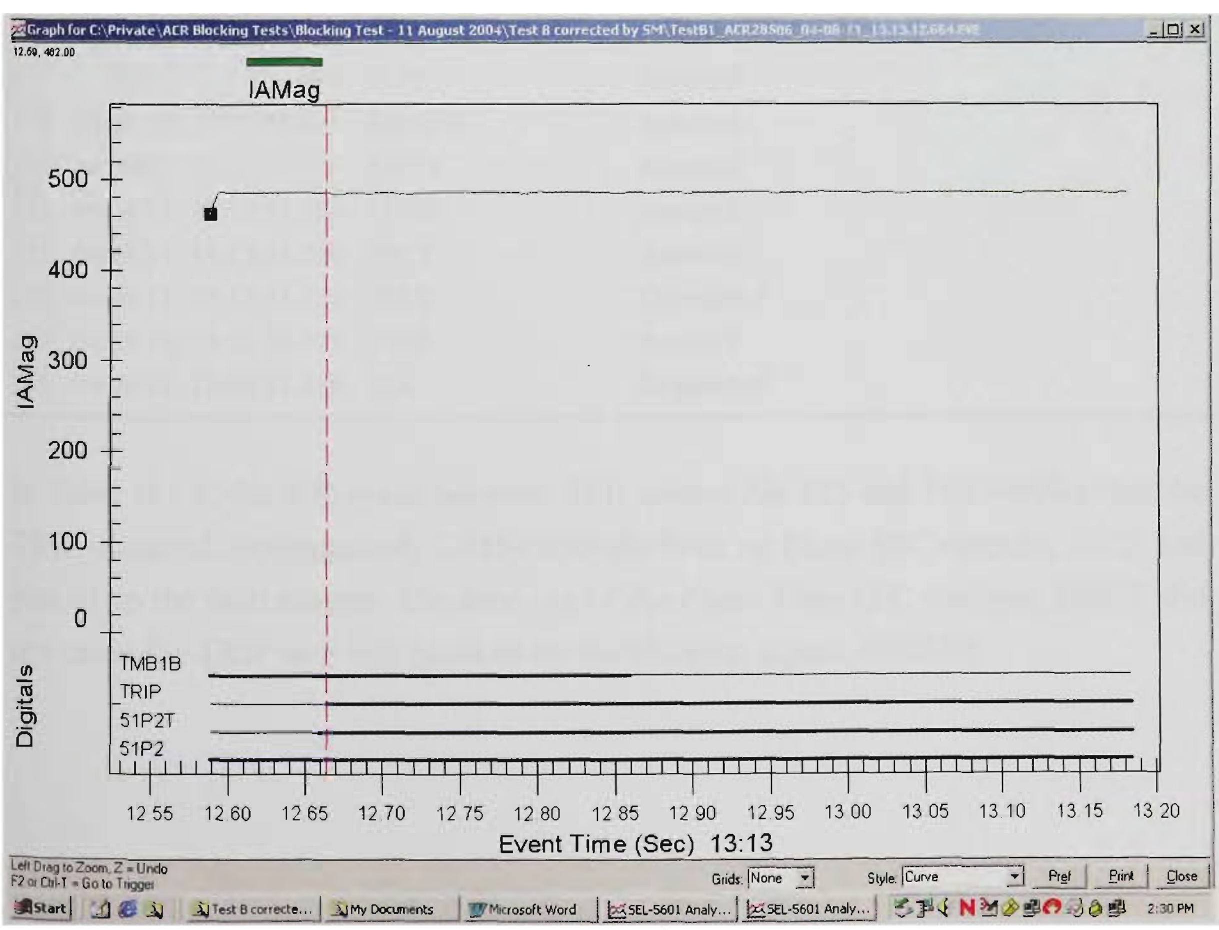


Figure B1_2_Event_4 Tripping of R1 due to the Phase O/C pick up

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 3, B - 4 and B - 5 to verify the TRIP times. The summary of results is shown in Table B - 6.

Table B - 3 Test 'B1_1', SER from BD7 CB - no blocking

226	04/08/11	12:46:10.435	51P1	Asserted
225	04/08/11	12:46:10.435	51P2	Asserted
224	04/08/11	12:46:11.340	51P1T	Asserted
223	04/08/11	12:46:11.345	79CY	Asserted
222	04/08/11	12:46:11.345	79RS	Deasserted
221	04/08/11	12:46:11.345	TRIP	Asserted
220	04/08/11	12:46:11.380	52A	Deasserted

In Table B - 3, the difference between SER entries No 226 and 221 verifies that the TRIP occurred approximately 0.910s after the Phase O/C element, 51P1, had picked up the fault current.

Table B - 4 Test 'B1_2', SER from BD7 CB - with blocking

176	04/08/11	13:13:10.444	51P1	Asserted
175	04/08/11	13:13:10.444	51P2	Asserted
174	04/08/11	13:13:10.459	RMB1B	Asserted
173	04/08/11	13:13:11.339	51P1T	Asserted
172	04/08/11	13:13:11.529	51P2T	Asserted
171	04/08/11	13:13:11.529	79CY	Asserted
170	04/08/11	13:13:11.529	79RS	Deasserted
169	04/08/11	13:13:11.529	TRIP	Asserted
168	04/08/11	13:13:11.564	52A	Deasserted

In Table B - 4, the difference between SER entries No 175 and 169 verifies that the TRIP occurred approximately 1.085s after the back up Phase O/C element, 51P2, had picked up the fault current. The time out of the Phase Time O/C element, 51P1T, did not cause the TRIP as it was blocked by the blocking signal, RMB1B.

Table B - 5 Test 'B1_2', SER from R1

154	04/08/11	13:12:58.747	51P2	Asserted
153	04/08/11	13:12:58.747	TMB1B	Asserted
152	04/08/11	13:13:12.659	51P2T	Asserted
151	04/08/11	13:13:12.664	79CY	Asserted
150	04/08/11	13:13:12.664	79RS	Deasserted
149	04/08/11	13:13:12.664	TRIP	Asserted
148	04/08/11	13:13:12.699	52A	Deasserted

In Table B - 5, the difference between SER entries No 154 and 149 verifies that the TRIP occurred approximately 13.917s after the Phase O/C element, 51P2, had picked up the fault current.

Table B - 6 Results summary for 'B1' testing

Test B1	Phase O/C on R1 blocks Phase O/C on BD7 CB		
BD7 CB results		Without blocking	With blocking
	Expected result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[1]
	Observed result	0.910s	Trip due to the back up element at 1.085s, i.e. in additional 0.175s
R1 results	Expected result	14.850s	
	Observed result	13.917s	

[1] Arbitrarily chosen value to be smaller than 200ms, i.e. for protection coordination this value needs to be smaller than the breaker failure time

B2 testing regime

Task

To block the BD7 CB, from tripping due to the Ground O/C pick up, with the blocking signal sent by the upstream recloser, R1, due to its Phase O/C pick up.

The testing set up is shown in Table B -7

Table B - 7 Set up for 'B2' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	2.4 A	14.850s	Trips after 14.850s
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	1.7 times the E/F setting	4.25 A	3.279s	BD7 CB Inverse Time E/F element blocked. No trip.

B2 testing

Test B2_1, no blocking

Secondary fault current of 4.25 A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

As in B1_1 test, there are two events in this test.

Figure B2_1_Event_1 illustrates the first event in which the Ground O/C element, 51N1, at the BD7 CB picked up due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1, and there was no TRIP command issued as the Ground Time O/C element, 51N1T, had not timed out yet.

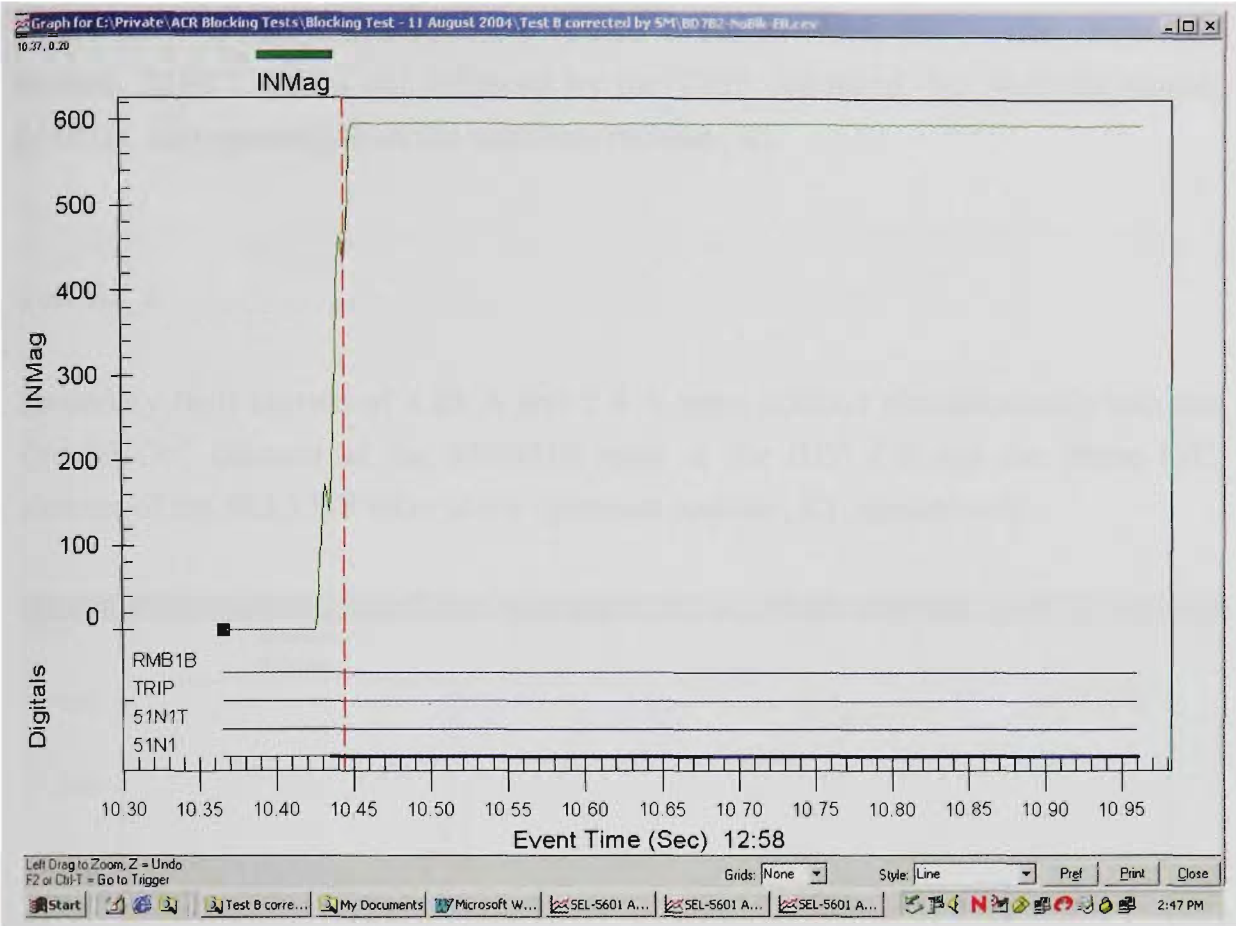


Figure B2_1_Event_1 Ground O/C pick up by the BD7 CB, no blocking

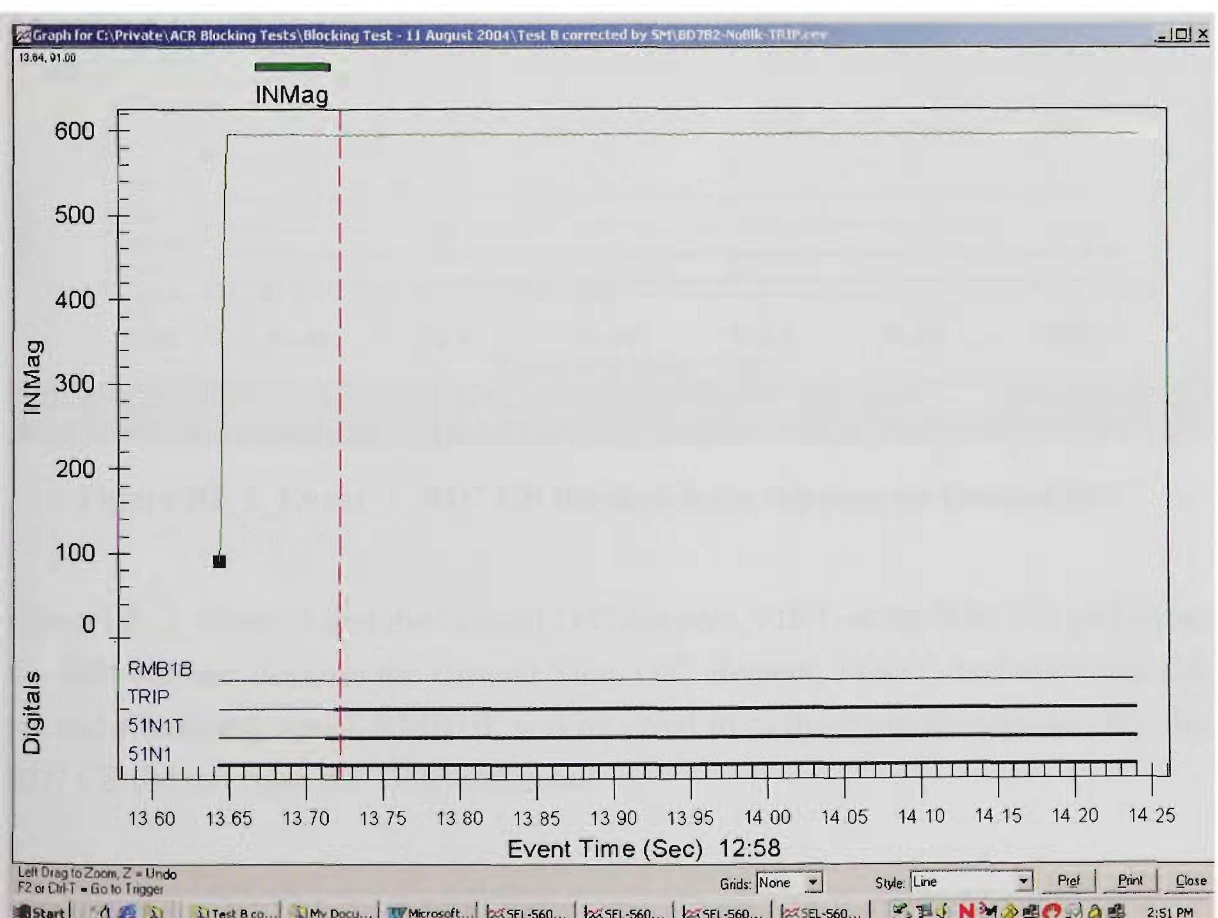


Figure B2_1_Event_2 Tripping of the BD7 CB on Ground O/C, no blocking

Figure B2_1_Event_2 illustrates the second event in which the Ground Time O/C element, 51N1T, timed out followed by the TRIP command. No blocking signal, RMB1B, was received from the upstream recloser, R1.

Test B2_2

Secondary fault current of 4.25 A and 2.4 A were injected simultaneously into the Ground O/C element of the SEL351S relay at the BD7 CB and the Phase O/C element of the SEL351P relay at the upstream recloser, R1, respectively.

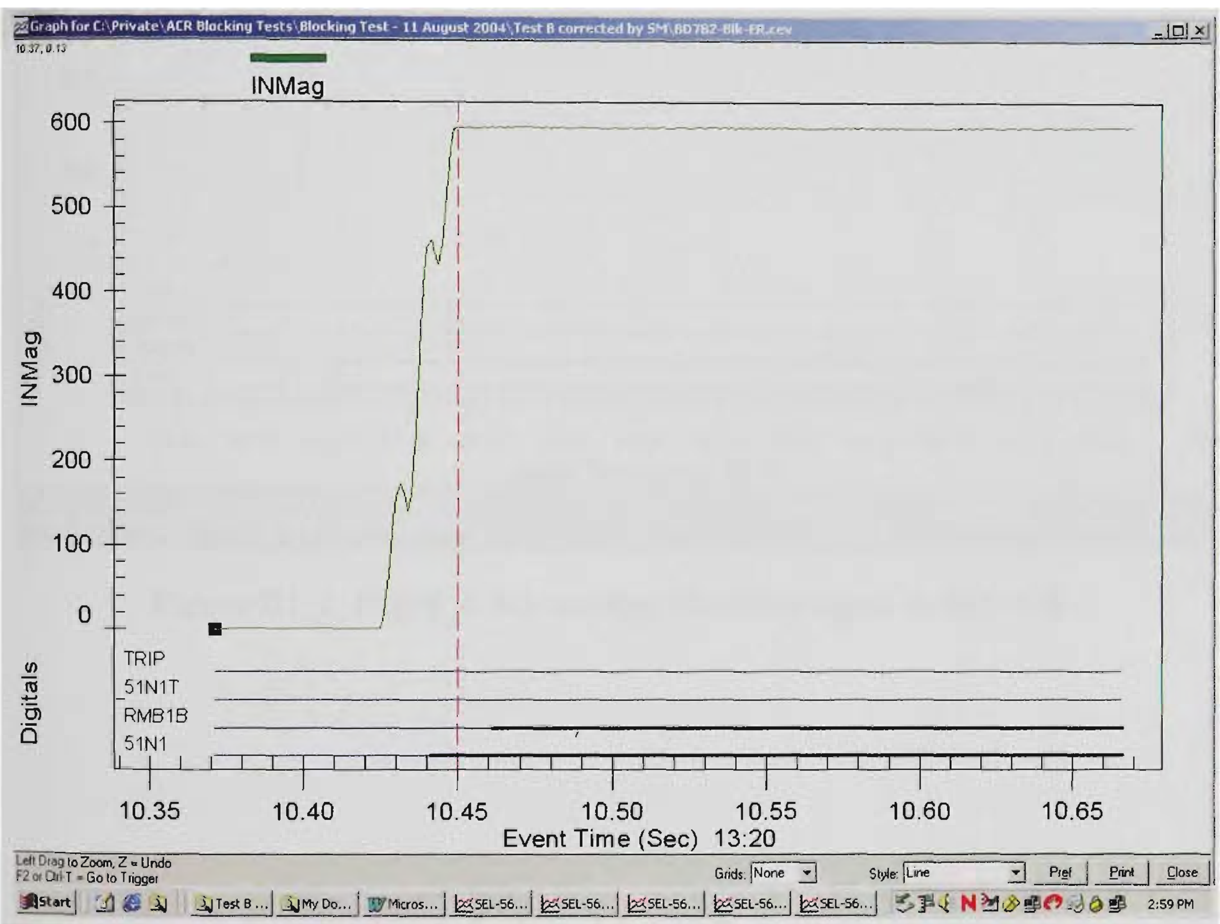


Figure B2_2_Event_1 BD7 CB blocked from tripping on Ground O/C

Figure B2_2_Event_1 that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current. Because the Ground Time O/C element, 51N1T, had not timed out yet and a blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not issue the TRIP command.

Figure B2_2_Event_2 illustrates that the Phase O/C element, 51P2, at the upstream recloser R1, picked up the fault and as a result a blocking signal, TMB1B, was transmitted to the BD7 CB to stop it from tripping.

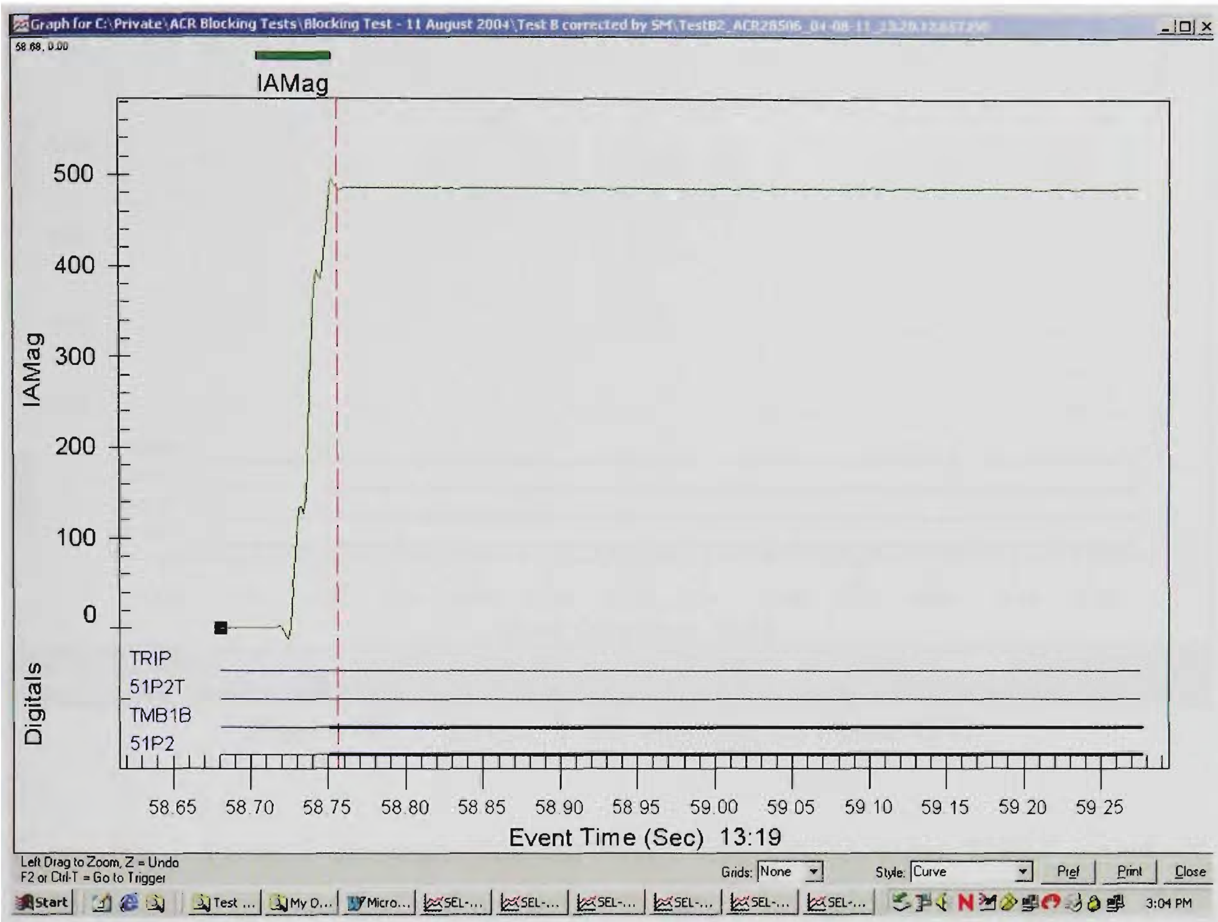


Figure B2_2_Event_2 R1 sending blocking signal to BD7 CB

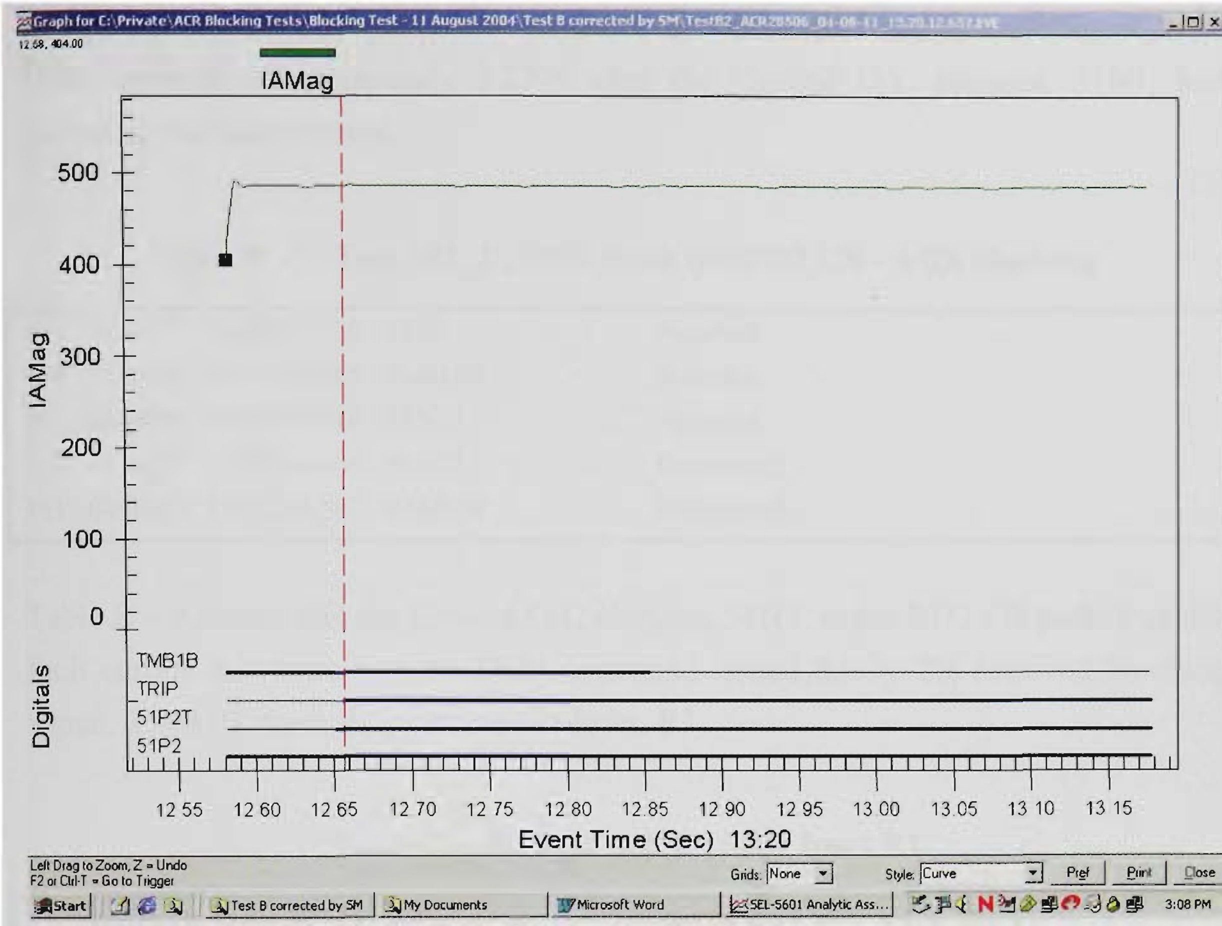


Figure B2_2_Event_3 R1 tripping on Phase O/C

Figure B2_2_Event_3 illustrates that the Phase Time O/C element, 51P2T, timed out at the upstream recloser R1, and as a result the upstream recloser, R1, tripped.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 8, B - 9 and B - 10 to verify the TRIP times. The summary of results is shown in Table B - 11.

Table B - 8 Test 'B2_1', SER from the BD7 CB - no blocking

207	04/08/11	12:58:10.444	51N1	Asserted
206	04/08/11	12:58:13.718	51N1T	Asserted
205	04/08/11	12:58:13.723	79CY	Asserted
204	04/08/11	12:58:13.723	79RS	Deasserted
203	04/08/11	12:58:13.723	TRIP	Asserted
202	04/08/11	12:58:13.758	52A	Deasserted

In Table B - 8, the difference between SER entries No 207 and 203 verifies that the TRIP occurred approximately 3.279s after the Ground O/C element, 51N1, had picked up the fault current.

Table B - 9 Test 'B2_2', SER from the BD7 CB - with blocking

155	04/08/11	13:20:10.450	51N1	Asserted
154	04/08/11	13:20:10.465	RMB1B	Asserted
153	04/08/11	13:20:13.714	51N1T	Asserted
152	04/08/11	13:20:14.464	51N1T	Deasserted
151	04/08/11	13:20:24.567	RMB1B	Deasserted

Table B – 9 shows that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current but there was no TRIP command issued due to the received blocking signal, RMB1B, from the upstream recloser, R1.

Table B - 10 Test 'B2_2', SER from R1

132	04/08/11	13:19:58.751	51P2	Asserted
131	04/08/11	13:19:58.751	TMB1B	Asserted
130	04/08/11	13:20:12.652	51P2T	Asserted
129	04/08/11	13:20:12.657	79CY	Asserted
128	04/08/11	13:20:12.657	79RS	Deasserted
127	04/08/11	13:20:12.657	TRIP	Asserted
126	04/08/11	13:20:12.692	52A	Deasserted

In Table B - 10, the difference between SER entries No 132 and 127 verifies that the TRIP occurred approximately 13.906s after the Phase O/C element, 51P2, had picked up the fault current.

Table B - 11 Results summary for test 'B2'

Test B2	**Phase O/C on R1 blocks Ground O/C on BD7 CB**		
BD7 results		Without blocking	With blocking
	Expected result	3.279s	No trip
	Observed result	3.279s	No trip
R1 results	Expected result	14.850s	
	Observed result	13.906s	

B3 testing regime

Task

To block the BD7 CB, from tripping due to the Ground O/C pick up, with the blocking signal sent by the upstream recloser, R1, due to its Ground O/C pick up.

The testing set up is shown in Table B -12.

Table B - 12 Set up for 'B3' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.2 times the E/F setting	1.2 A	16.875s	Trip after 16.875s
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	1.7 times the E/F setting	4.25 A	3.279s	BD7 CB Inverse Time E/F element blocked. No trip.

B3 testing

Test B3_1, no blocking

Secondary fault current of 4.25 A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB. This test procedure and results obtained are the same as in the test B2_1. Thus, for the test details, the reader is referred to the test B2_1.

Test B3_2

Secondary fault current of 4.25 A and 1.2 A were injected simultaneously into Ground O/C element of the SEL351S relay at the BD7 CB and into the Ground O/C element of the SEL351P relay at the upstream recloser, R1, respectively.

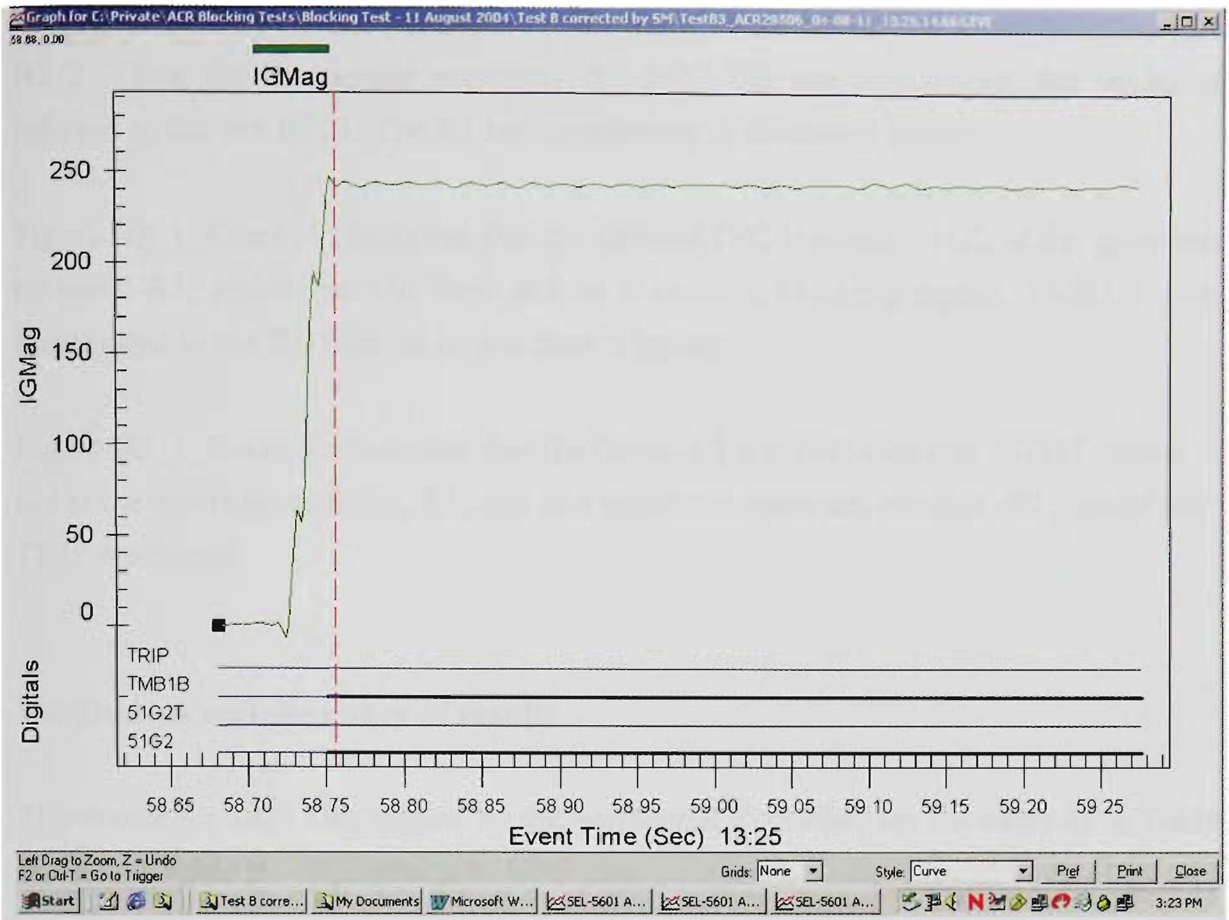


Figure B3_1_Event_1 Ground O/C pick up by R1, blocking signal transmitted

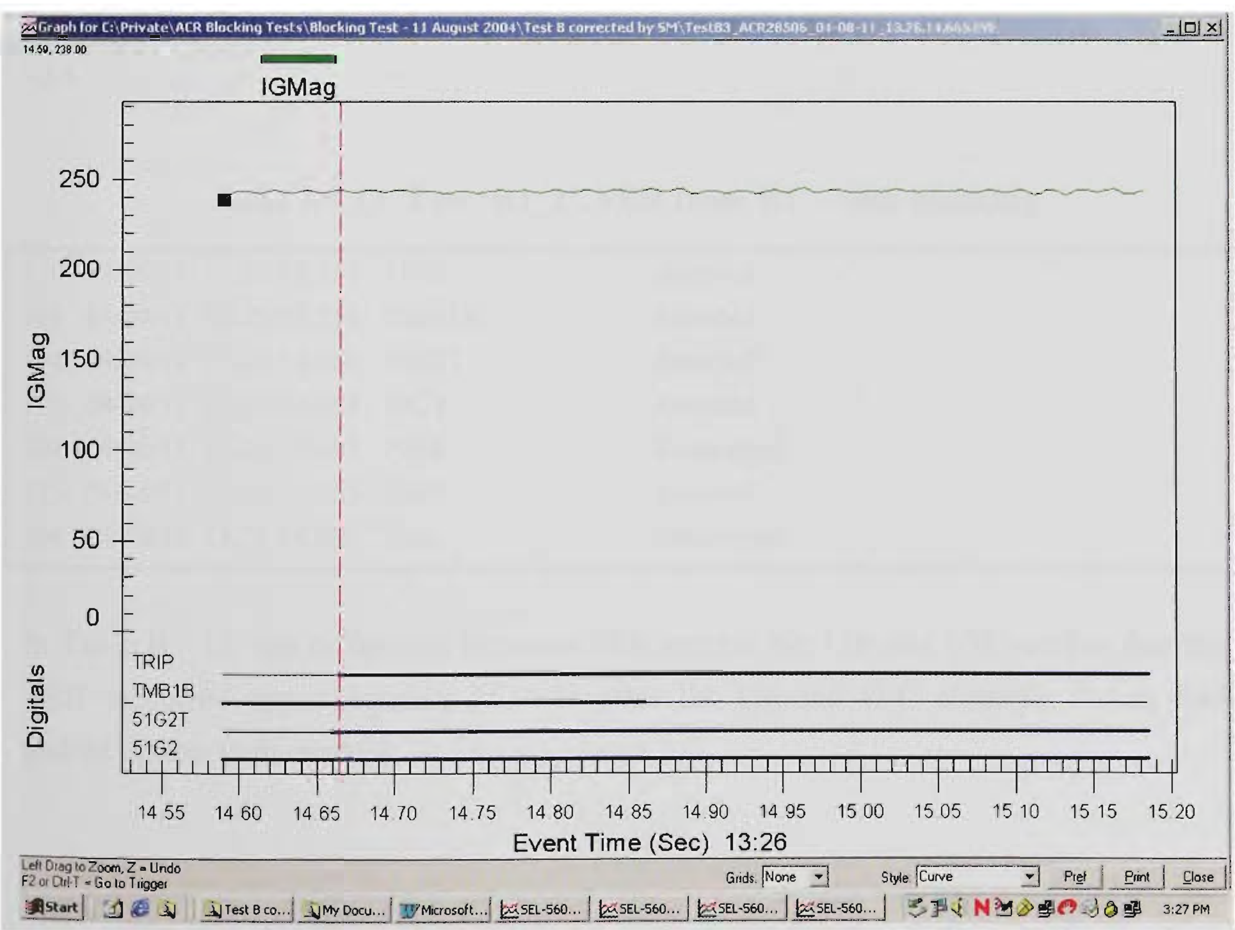


Figure B3_1_Event_2 R1 tripping on Ground O/C

For the BD7 CB, the test procedure and results obtained are the same as in the test B2_2. Thus, for the details regarding the BD7 CB test component, the reader is referred to the test B2_2. The R1 test component is discussed below.

Figure B3_1_Event_1 illustrates that the Ground O/C element, 51G2, at the upstream recloser, R1, picked up the fault and as a result a blocking signal, TMB1B, was transmitted to the BD7 CB to stop it from tripping.

Figure B3_1_Event_2 illustrates that the Ground Time O/C element, 51G2T, timed out at the upstream recloser, R1, and as a result the upstream recloser, R1, issued the TRIP command.

Verification and summary of results

The events for BD7 CB, logged by the Sequential Recorder, are the same as in Table B – 8 and Table B – 9 pertinent to BD7 CB.

The events pertinent to R1, logged by the Sequential Event Recorder, are presented in Table B – 13 to verify the TRIP time. The summary of results is shown in Table B - 14.

Table B - 13 Test 'B3_2', SER from R1 – with blocking

110	04/08/11	13:25:58.751	51G2	Asserted
109	04/08/11	13:25:58.751	TMB1B	Asserted
108	04/08/11	13:26:14.660	51G2T	Asserted
107	04/08/11	13:26:14.665	79CY	Asserted
106	04/08/11	13:26:14.665	79RS	Deasserted
105	04/08/11	13:26:14.665	TRIP	Asserted
104	04/08/11	13:26:14.700	52A	Deasserted

In Table B - 13, the difference between SER entries No 110 and 105 verifies that the TRIP occurred approximately 15.914s after the Ground O/C element, 51G2, had picked up the fault current.

Table B - 14 Results summary for test 'B3'

Test B3	Ground O/C on R1 blocks Ground O/C on BD7 CB		
BD7 CB results as per test B2		Without blocking	With blocking
	Expected result	3.279s	No trip
	Observed result	3.279s	No trip
R1 results	Expected result	16.875s	
	Observed result	15.914s	

B4 testing regime

<u>Task</u>

To block the BD7 CB, from tripping due to the Phase O/C pick up, with the blocking signal sent by the upstream recloser, R1, due to its Ground O/C pick up.

The testing set up is shown in Table B - 15.

Table B - 15 Set up for 'B4' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.2 times the E/F O/C setting	1.2 A	16.875s	Trips after 16.875s
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C OFF	Any phase element	4.0 times the Phase O/C setting	17 A	1.096s	BD7 CB Inverse Time Phase O/C element blocked. No trip.

B4 testing

Test B4_1, no blocking

Secondary fault current of 17 A was injected into the Phase O/C element of the SEL351S relay at the BD7 CB.

Figure B4_1_Event_1 illustrates the event, recorded by the BD7 CB SEL351S relay, in which the Phase Time O/C element, 51P1T, timed out followed by the TRIP. No blocking signal, RMB1B, was received from the upstream recloser, R1.

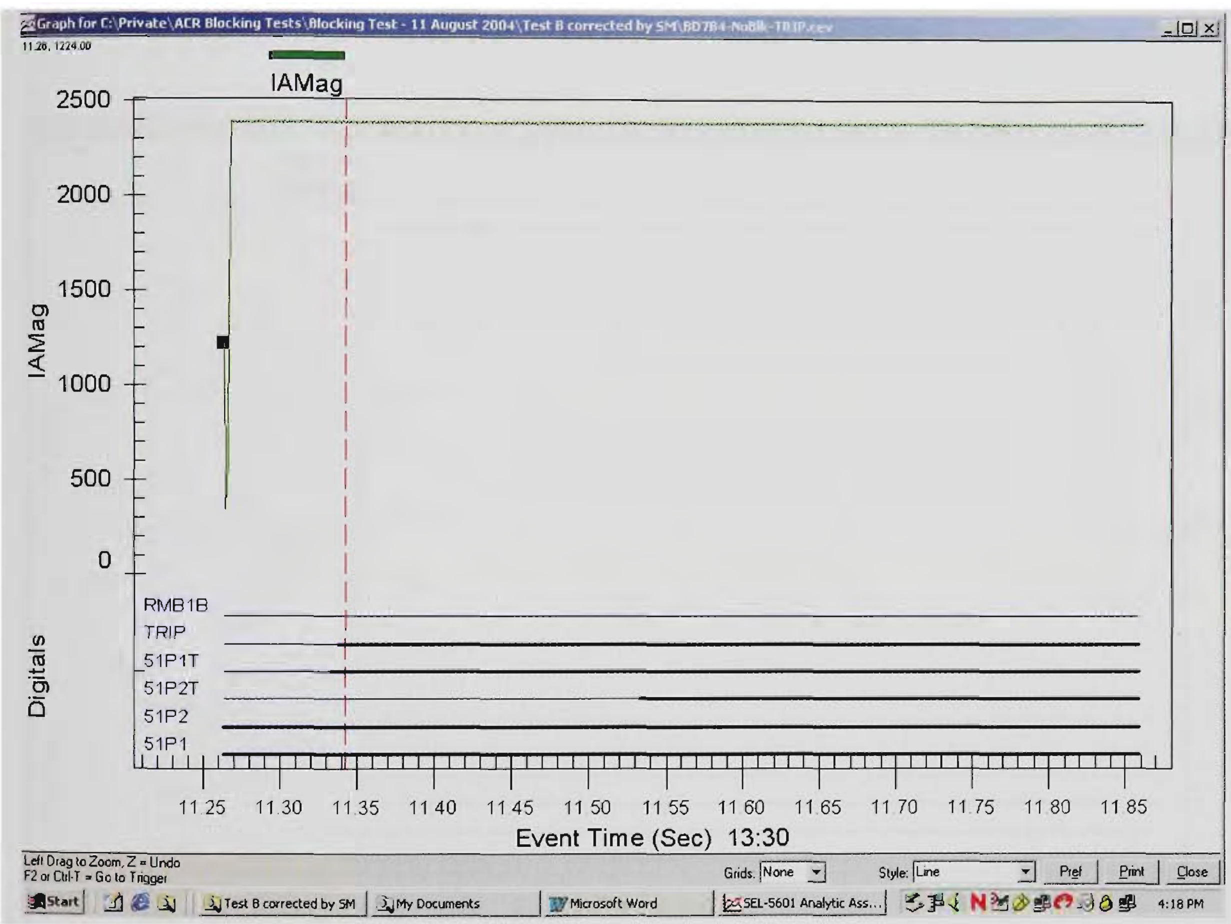


Figure B4_1_Event_1 Tripping of BD7 CB on Phase O/C, no blocking

Test B4_2

Secondary fault current of 17 A and 1.2 A were injected simultaneously into the Phase O/C element of the SEL351S relay at the BD7 CB and into the Ground O/C element of the SEL351P relay at the upstream recloser, R1, respectively.

Figure B4_2_Event_1 shows that the Phase O/C elements, 51P1 and 51P2, at the BD7 CB picked up the fault current. Because the Phase Time O/C elements, 51P1T and 51P2T, had not timed out yet and a blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not TRIP.

Figure B4_2_Event_2 illustrates that the Ground O/C element, 51G2, at the upstream recloser, R1, picked up the fault and as a result a blocking signal, TMB1B, was transmitted to the BD7 CB to stop it from tripping.

Figure B4_2_Event 3, presented below, illustrates that the Ground Time O/C element, 51G2T, timed out at the upstream recloser, R1, and as a result the upstream recloser issued the TRIP command to its local breaker.

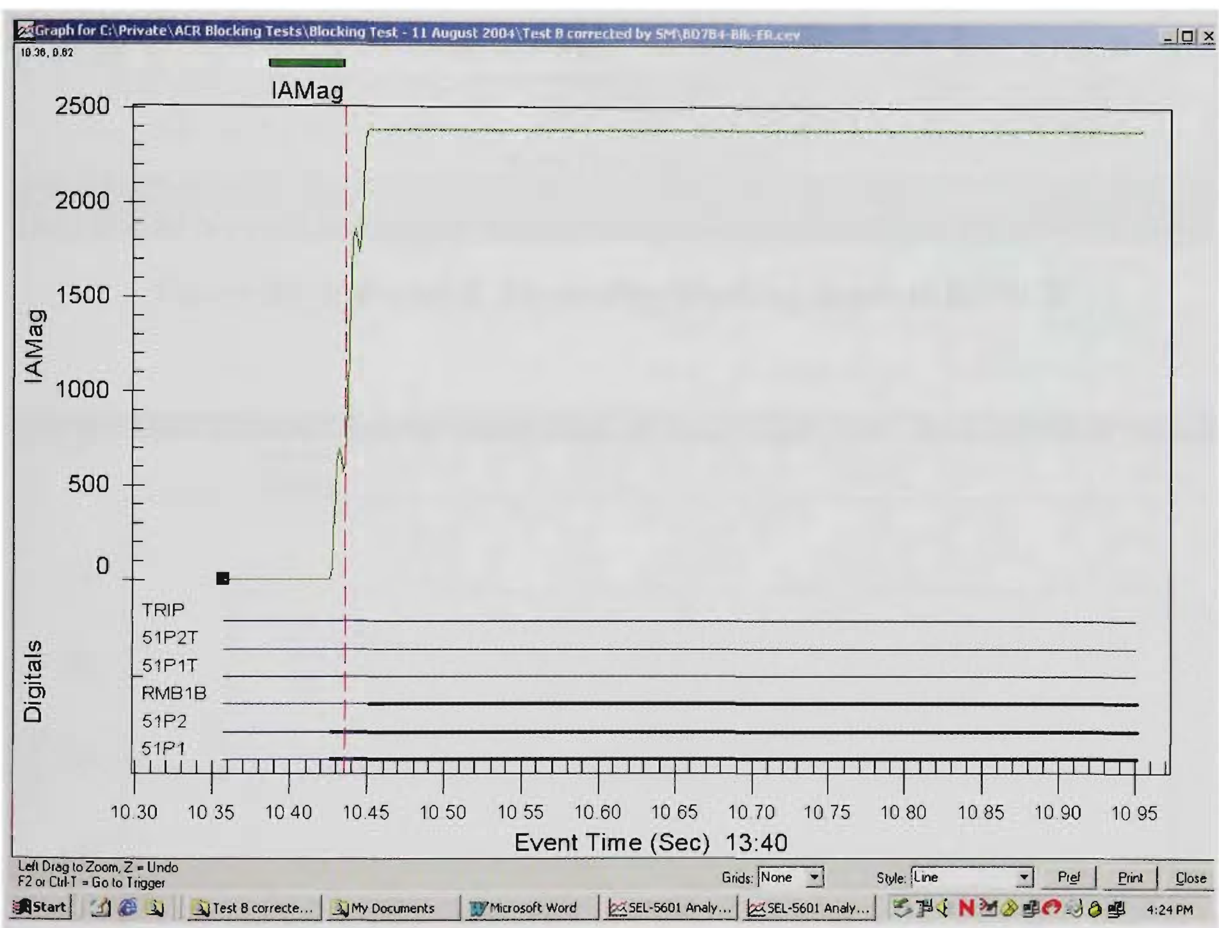


Figure B4_2_Event_1 BD7 CB blocked from tripping on Phase O/C

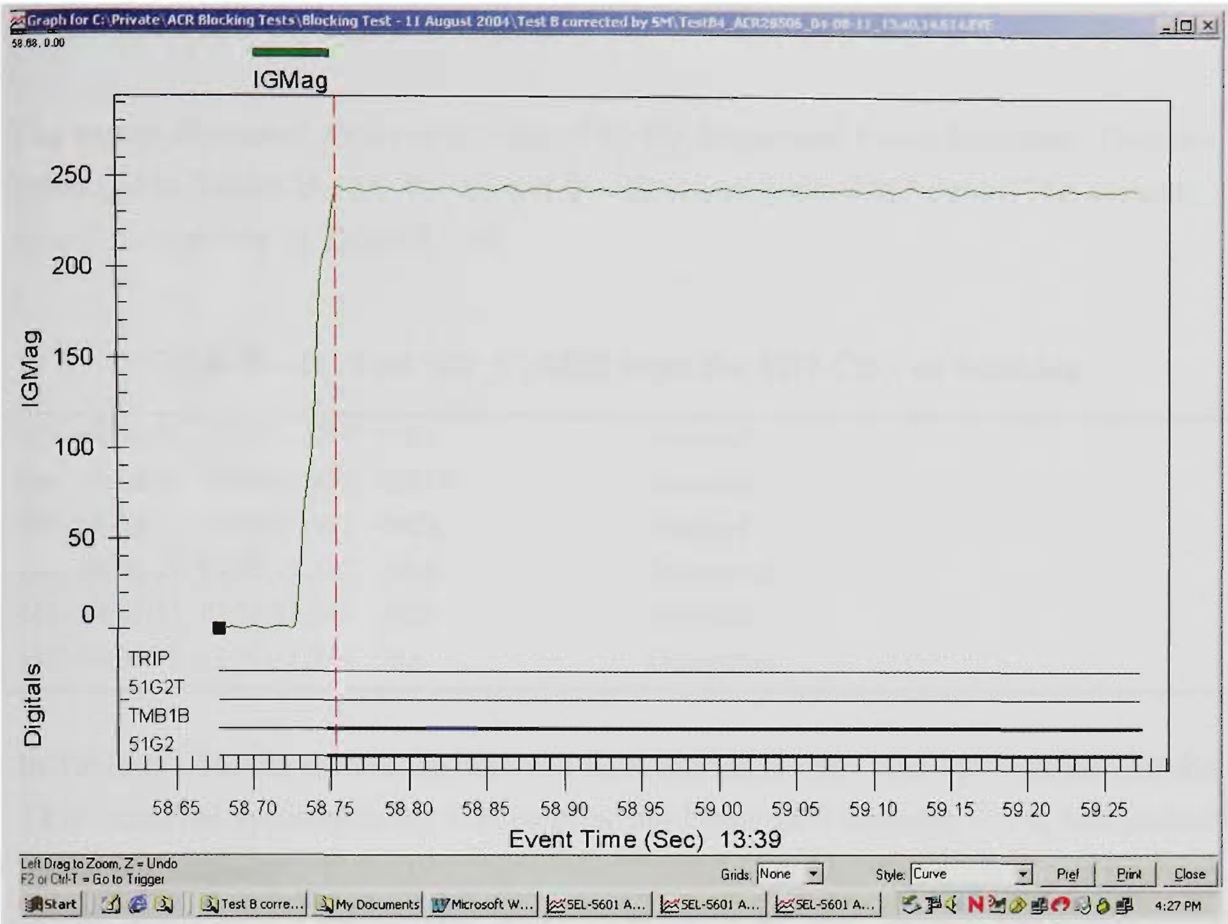


Figure B4_2_Event_2 R1 sending blocking signal to BD7 CB

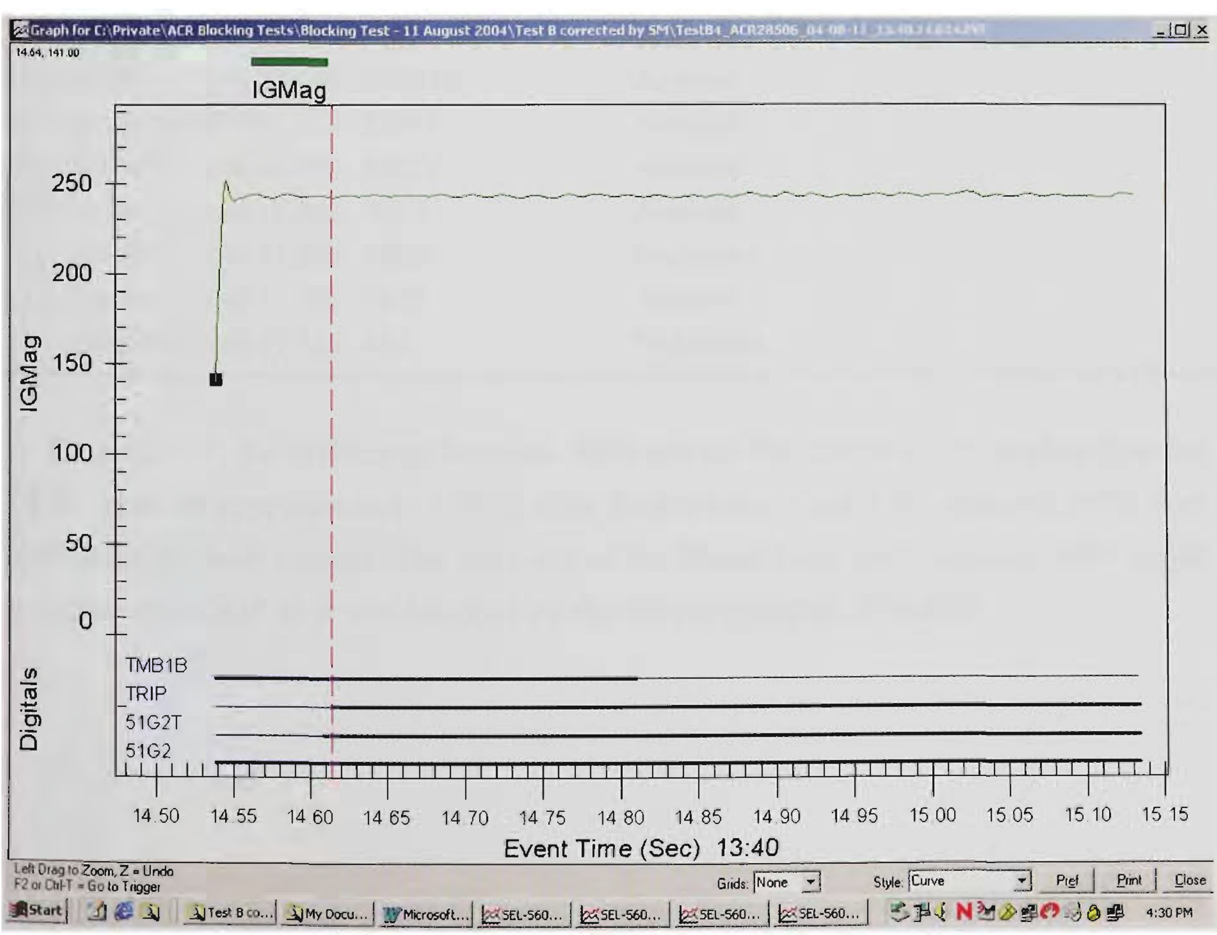


Figure B4_2_Event_3 R1 tripping on Ground O/C

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 16, B - 17 and B - 18 to verify the TRIP times. The summary of results is shown in Table B - 19.

Table B - 16 Test 'B4_1', SER from the BD7 CB - no blocking

147	04/08/11	13:30:10.432	51P1	Asserted
146	04/08/11	13:30:11.337	51P1T	Asserted
145	04/08/11	13:30:11.342	79CY	Asserted
144	04/08/11	13:30:11.342	79RS	Deasserted
143	04/08/11	13:30:11.342	TRIP	Asserted
142	04/08/11	13:30:11.377	52A	Deasserted

In Table B - 16, the difference between SER entries No 147 and 143 verifies that the TRIP occurred approximately 0.910s after the Phase O/C element, 51P1, had picked up the fault current.

Table B - 17 Test 'B4_2', SER from the BD7 CB - with blocking

130	04/08/11	13:40:10.435	51P1	Asserted
129	04/08/11	13:40:10.435	51P2	Asserted
128	04/08/11	13:40:10.455	RMB1B	Asserted
127	04/08/11	13:40:11.340	51P1T	Asserted
126	04/08/11	13:40:11.530	51P2T	Asserted
125	04/08/11	13:40:11.530	79CY	Asserted
124	04/08/11	13:40:11.530	79RS	Deasserted
123	04/08/11	13:40:11.530	TRIP	Asserted
122	04/08/11	13:40:11.565	52A	Deasserted

In Table B - 17, the difference between SER entries No 129 and 123 verifies that the TRIP occurred approximately 1.095s after the back up Phase O/C element, 51P2, had picked up the fault current. The time out of the Phase Time O/C element, 51P1T, did not cause the TRIP as it was blocked by the blocking signal, RMB1B.

Table B - 18 Test 'B4_2', SER from R1

88	04/08/11	13:39:58.748	51G2	Asserted
87	04/08/11	13:39:58.748	TMB1B	Asserted
86	04/08/11	13:40:14.609	51G2T	Asserted
85	04/08/11	13:40:14.614	79CY	Asserted
84	04/08/11	13:40:14.614	79RS	Deasserted
83	04/08/11	13:40:14.614	TRIP	Asserted
82	04/08/11	13:40:14.649	52A	Deasserted

In Table B - 18, the difference between SER entries No 88 and 83 verifies that the TRIP occurred approximately 15.866s after the Ground O/C element, 51G2, had picked up the fault current.

Table B - 19 Results summary for 'B4' testing

Test B4	Ground O/C on R1 blocks Phase O/C on BD7 CB		
BD7 CB results		Without blocking	With blocking
	Expected result	1.096s	Trip due to the back up element in 1.286s, i.e. in additional 0.190s[2]
	Observed result	0.910s	Trip due to the back up element in 1.095s, i.e. in additional 0.185s
R1 results	Expected result	16.875s	
	Observed result	15.866s	

[2] Arbitrarily chosen value to be smaller than 200ms, i.e. for protection coordination this value needs to be smaller than the breaker failure time

B5 testing regime

<u>Task</u>

To prove that SEF on R1 does not block Phase O/C and Ground O/C on the BD7 CB.

The testing set up is shown in Table B - 20.

Table B - 20 Set up for 'B5' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF ON CB Closed	SEF element	2 times the SEF setting	0.072 A	1.5s DT	Trip on SEF after 1.5s.
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	4.0 times the E/F setting	10.0 A	0.765s	Trip on E/F element after 0.765s. No blocking.

B5 testing

Test B5_1, no blocking

Secondary fault current of 10A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

Figure B5_1_Event 1 illustrates the event in which the Ground O/C element, 51N1, at the BD7 CB picked up due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1. The Ground Time O/C element, 51N1T, timed out followed by the TRIP.

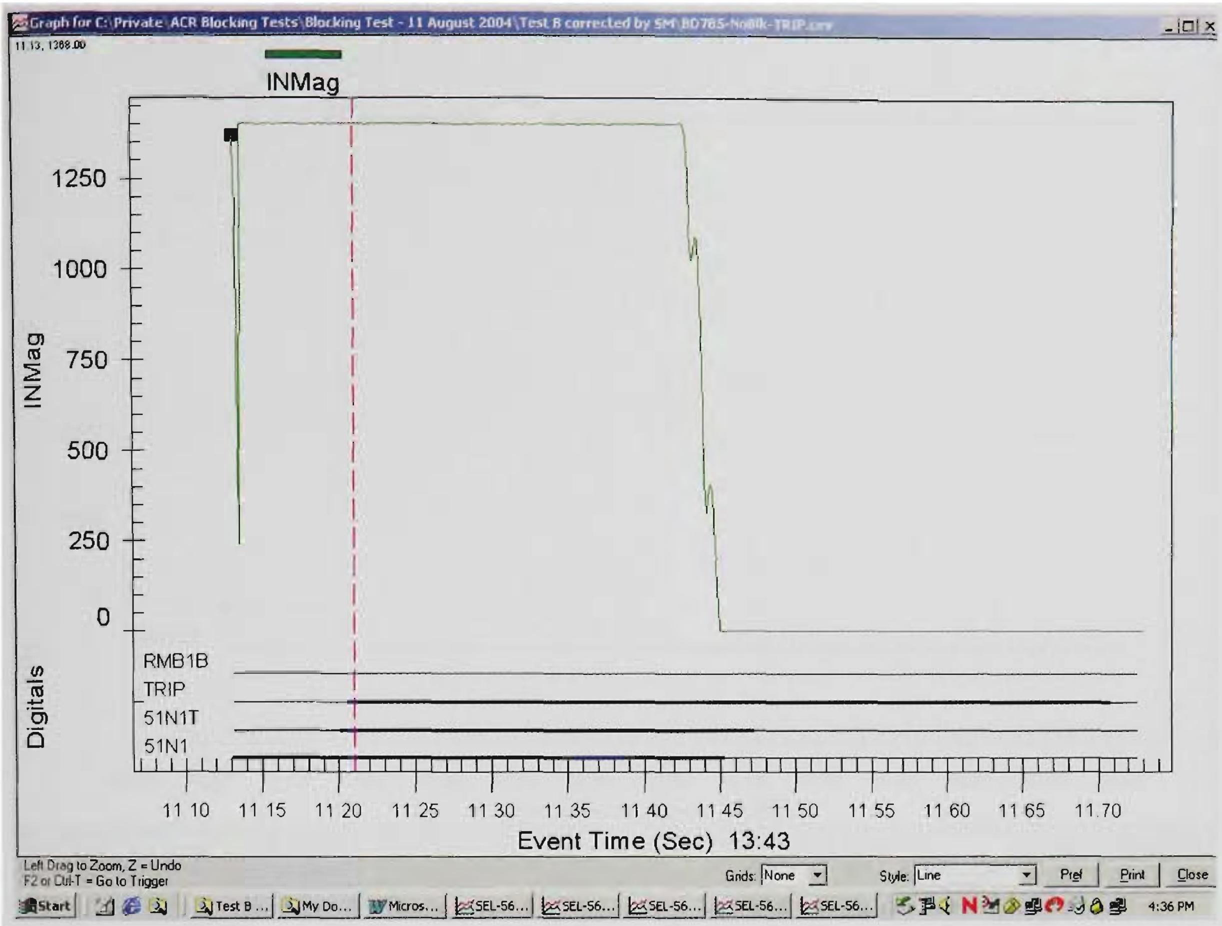


Figure B5_1_Event_1 BD7 CB, TRIP on Ground O/C, no blocking

Test B5_2

Secondary fault currents of 10A and 0.072A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the upstream recloser, R1, respectively.

Figure B5_2_Event_1 shows that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current. Because the Phase Time O/C element, 51N1T, had not timed out yet, there was no TRIP. Blocking signal, RMB1B, was not received from the upstream recloser, R1.

Figure B5_2_Event_2 illustrates that the Ground Time O/C element, 51N1T, timed out followed the TRIP. Blocking signal, RMB1B, was not received from the upstream recloser, R1.

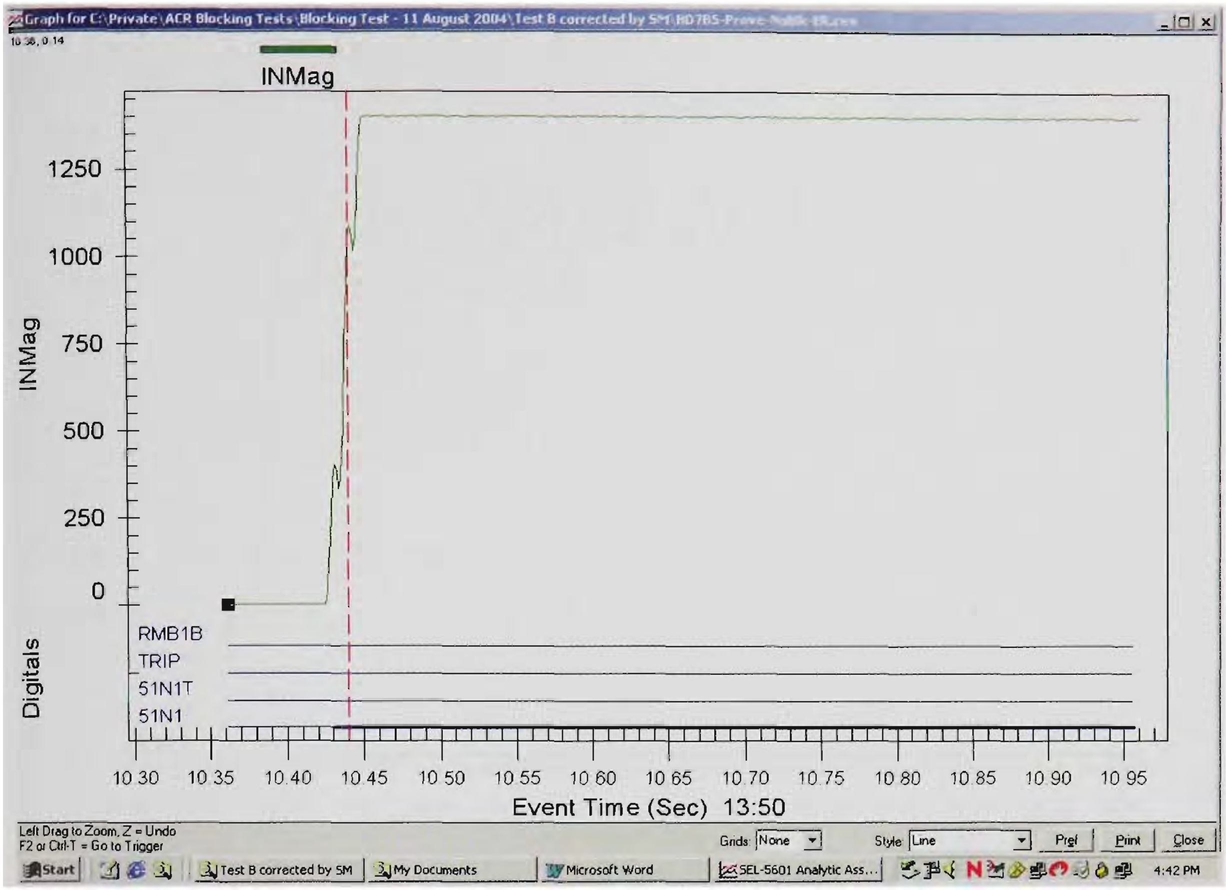


Figure B5_2_Event_1 Ground O/C pick up at BD7 CB, no blocking received

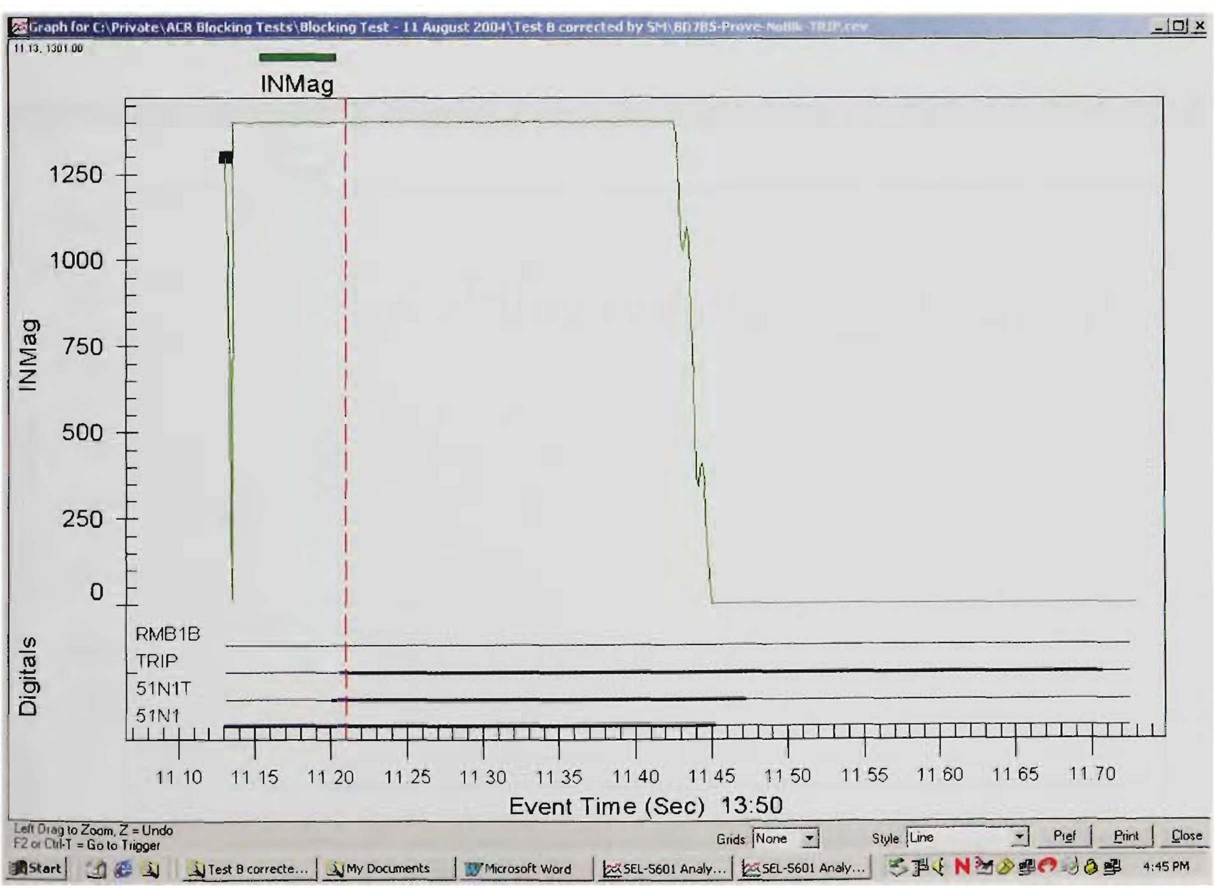


Figure B5_2_Event_2 TRIP of BD7 CB on Ground O/C, no blocking received

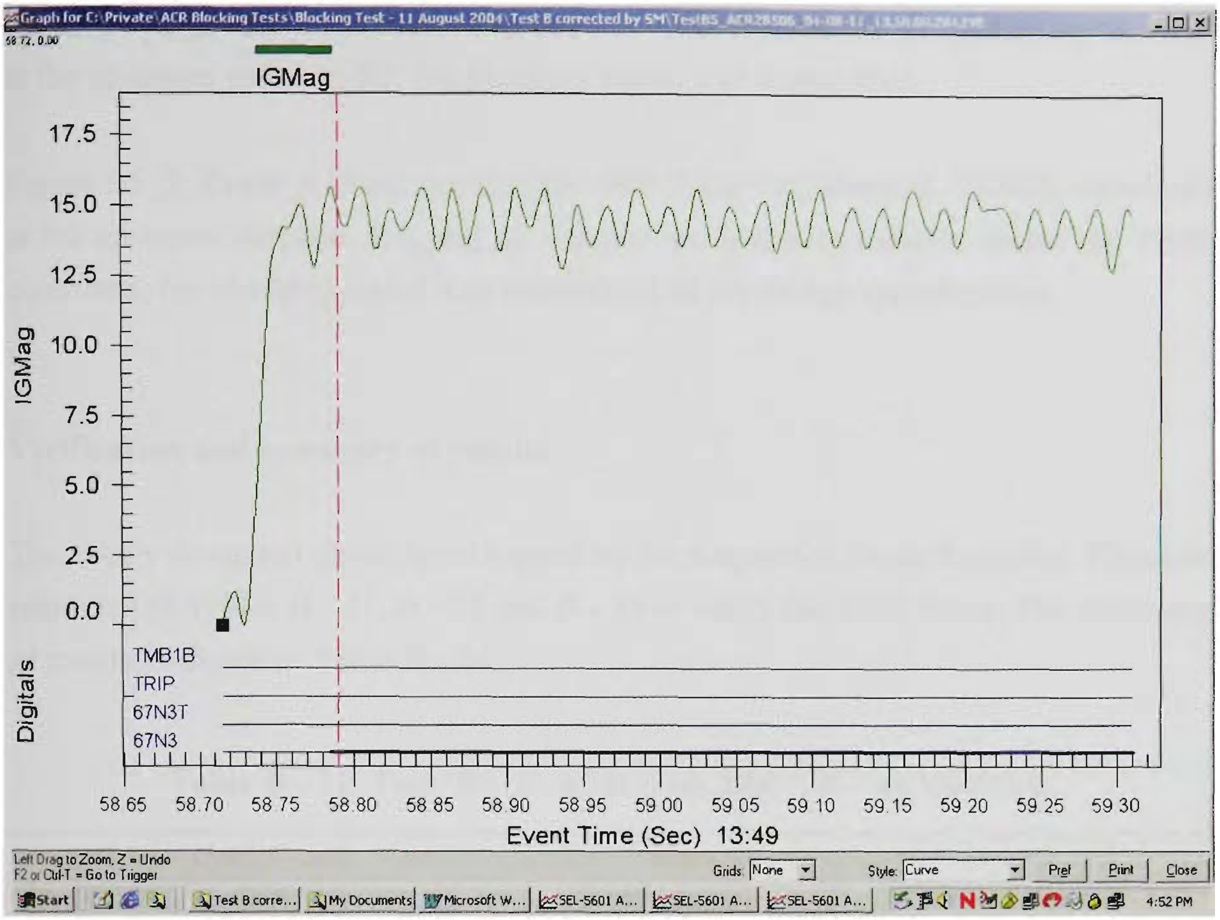


Figure B5_2_Event_3 SEF pick up by R1

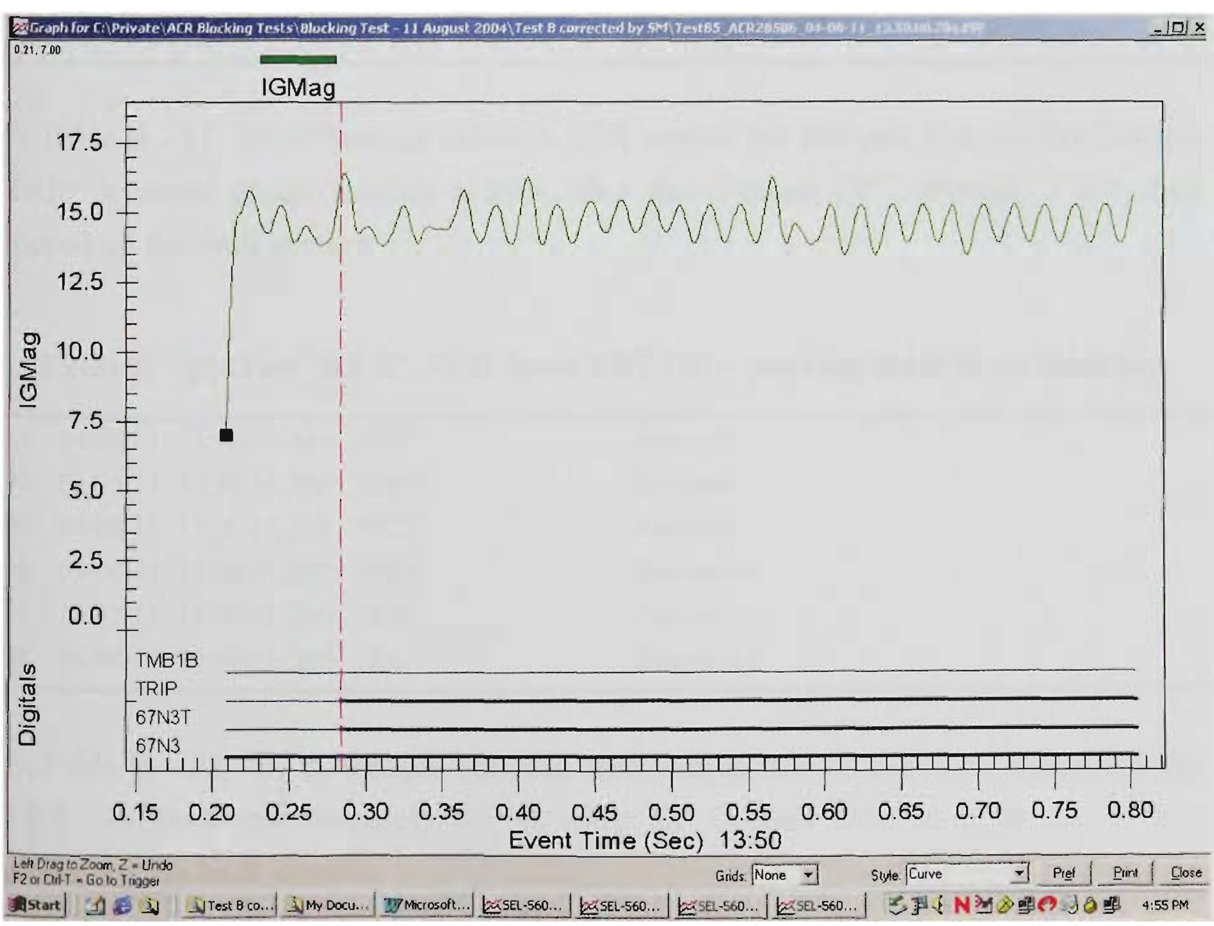


Figure B5_2_Event_4 Tripping of R1 due to the SEF

Figure B5_2_Event_3 illustrates that the SEF O/C element, 51N3, picked up the SEF at the upstream recloser, R1. No blocking signal was transmitted.

Figure B5_2_Event_4 illustrates that the SEF Time O/C element, 51N3T, timed out at the upstream recloser, R1, and as a result, the upstream recloser issued the TRIP command. No blocking signal was transmitted as per design specifications.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 21, B - 22 and B - 23 to verify the TRIP times. The summary of results is shown in Table B - 24.

Table B - 21 Test 'B5_1', SER from BD7 CB - no blocking

109	04/08/11	13:43:11.130	51N1	Asserted
108	04/08/11	13:43:11.205	51N1T	Asserted
107	04/08/11	13:43:11.210	79CY	Asserted
106	04/08/11	13:43:11.210	79RS	Deasserted
105	04/08/11	13:43:11.210	TRIP	Asserted
104	04/08/11	13:43:11.245	52A	Deasserted

In Table B - 21, the difference between SER entries No 109 and 105 verifies that the TRIP occurred approximately 0.800s after the Ground O/C element, 51N1, had picked up the fault current.

Table B - 22 Test 'B5_2', SER from BD7 CB – proving there is no blocking

93	04/08/11	13:50:10.440	51N1	Asserted
92	04/08/11	13:50:11.205	51N1T	Asserted
91	04/08/11	13:50:11.210	79CY	Asserted
90	04/08/11	13:50:11.210	79RS	Deasserted
89	04/08/11	13:50:11.210	TRIP	Asserted
88	04/08/11	13:50:11.245	52A	Deasserted

In Table B - 22, the difference between SER entries No 93 and 89 verifies that the TRIP occurred approximately 0.770s after the Ground O/C element, 51N1, had picked up the fault current.

Table B - 23 Test 'B5_2', SER from R1

66	04/08/11	13:49:58.785	67N3	Asserted
65	04/08/11	13:50:00.284	67N3T	Asserted
64	04/08/11	13:50:00.284	79CY	Asserted
63	04/08/11	13:50:00.284	79RS	Deasserted
62	04/08/11	13:50:00.284	TRIP	Asserted
61	04/08/11	13:50:00.319	52A	Deasserted

In Table B - 23, the difference between SER entries No 66 and 62 verifies that TRIP occurred approximately 1.499s after the SEF element, 67N3, had picked up the fault current.

Table B - 24 Results summary for 'B5' testing

Test B5	SEF on R1 does not block Ground O/C on BD7 CB		
BD7 CB results		Without blocking	With blocking
	Expected result	0.765s	No blocking
	Observed result	0.800s	No blocking
R1 results	Expected result	Trip in 1.500s	
	Observed result	Trip in 1.499s	

B6 testing regime

Task

To prove that Phase O/C or Ground O/C on R1 does not block Instantaneous O/C on the BD7 CB.

The testing set up is shown in Table B - 25.

Table B - 25 Set up for 'B6' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	2.5 times the Phase O/C setting	5.0 A	1.980s	Trip after 1.980s.
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C ON	Any phase element	Just above minop	45.0 A	0.100s DT	Trip on Inst O/C after 0.100s.

B6 testing

Test B6_1, no blocking

Secondary fault current of 45A was injected into the Instantaneous Phase O/C element of the SEL351S relay at the BD7 CB.

Figure B6_1_Event_1 illustrates the event in which the Instantaneous Phase O/C element, 67P1, at the BD7 CB picked up due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1. The Instantaneous Phase Time O/C element, 67P1T, timed out followed by the TRIP.

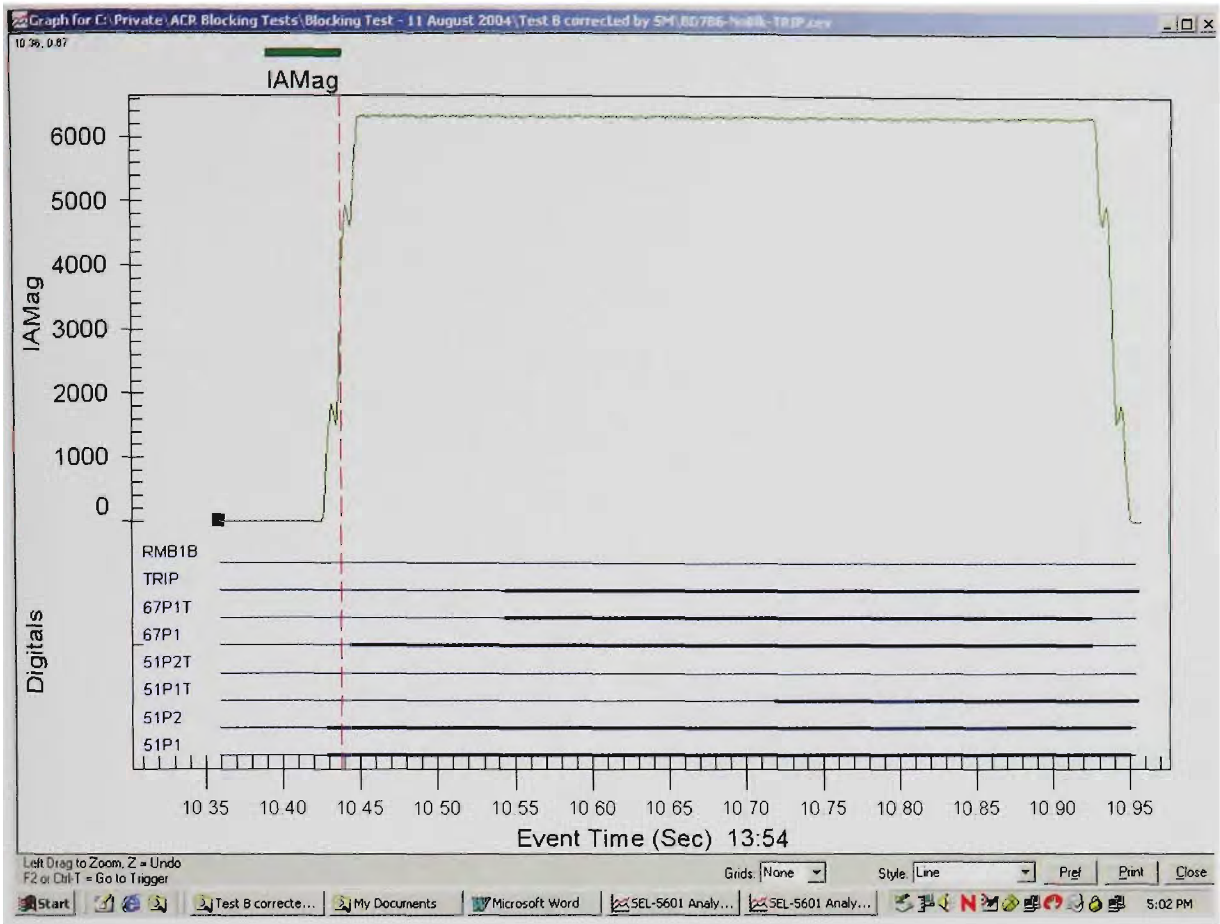


Figure B6_1_Event_1 BD7 CB, Instantaneous Phase O/C pick up and TRIP, no blocking

Test B6_2

Secondary fault currents of 45A and 5A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the upstream recloser, R1, respectively.

Figure B6_2_Event_1 shows that the Instantaneous Phase O/C element, 67P1, at the BD7 CB picked up the fault current. The Instantaneous Phase Time O/C element, 67P1T, timed out followed by a TRIP. Blocking signal, RMB1B, was received from the upstream recloser, R1, but it did not block the Instantaneous Phase O/C element.

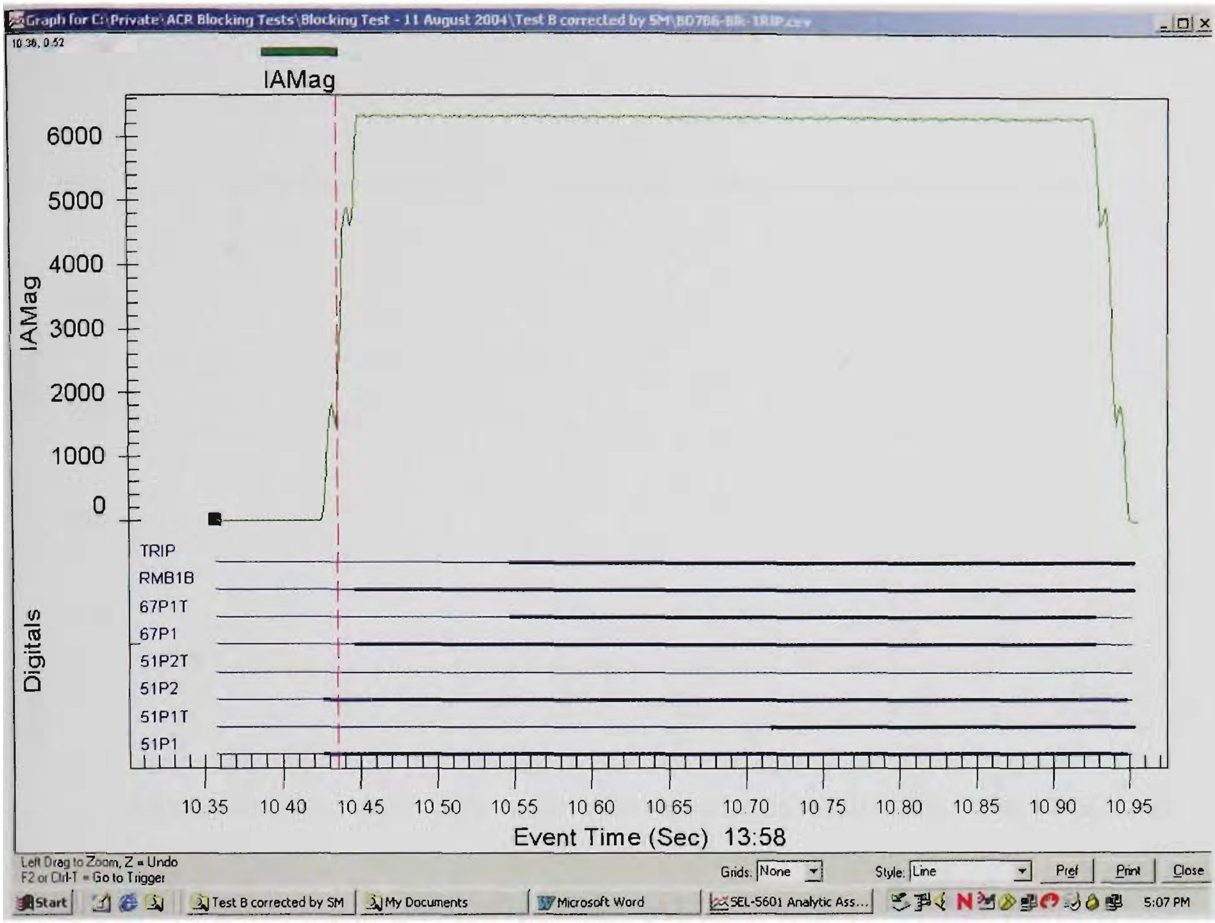


Figure B6_2_Event_1 Inst Phase O/C pick up and TRIP at BD7 CB

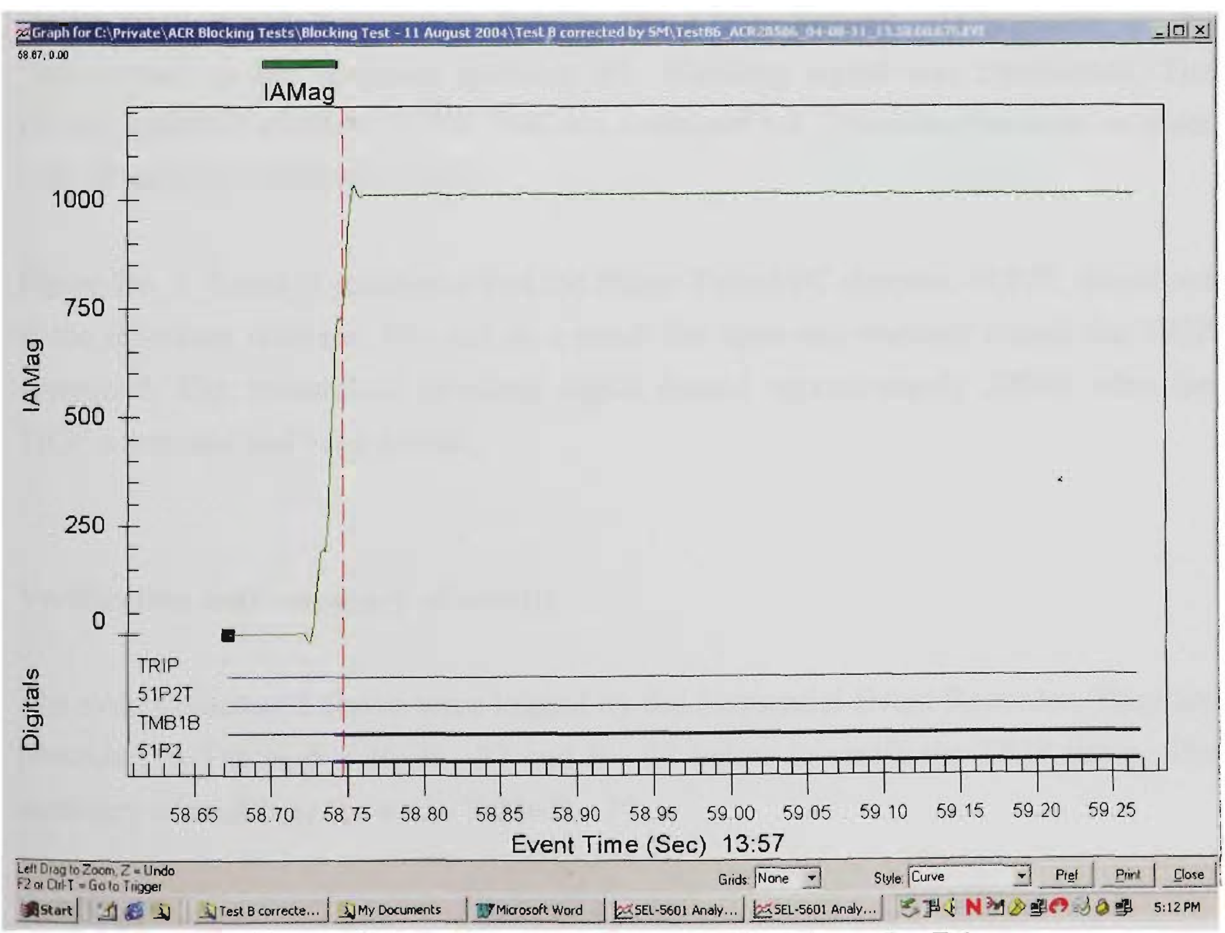


Figure B6_2_Event_2 Phase O/C pick up by R1

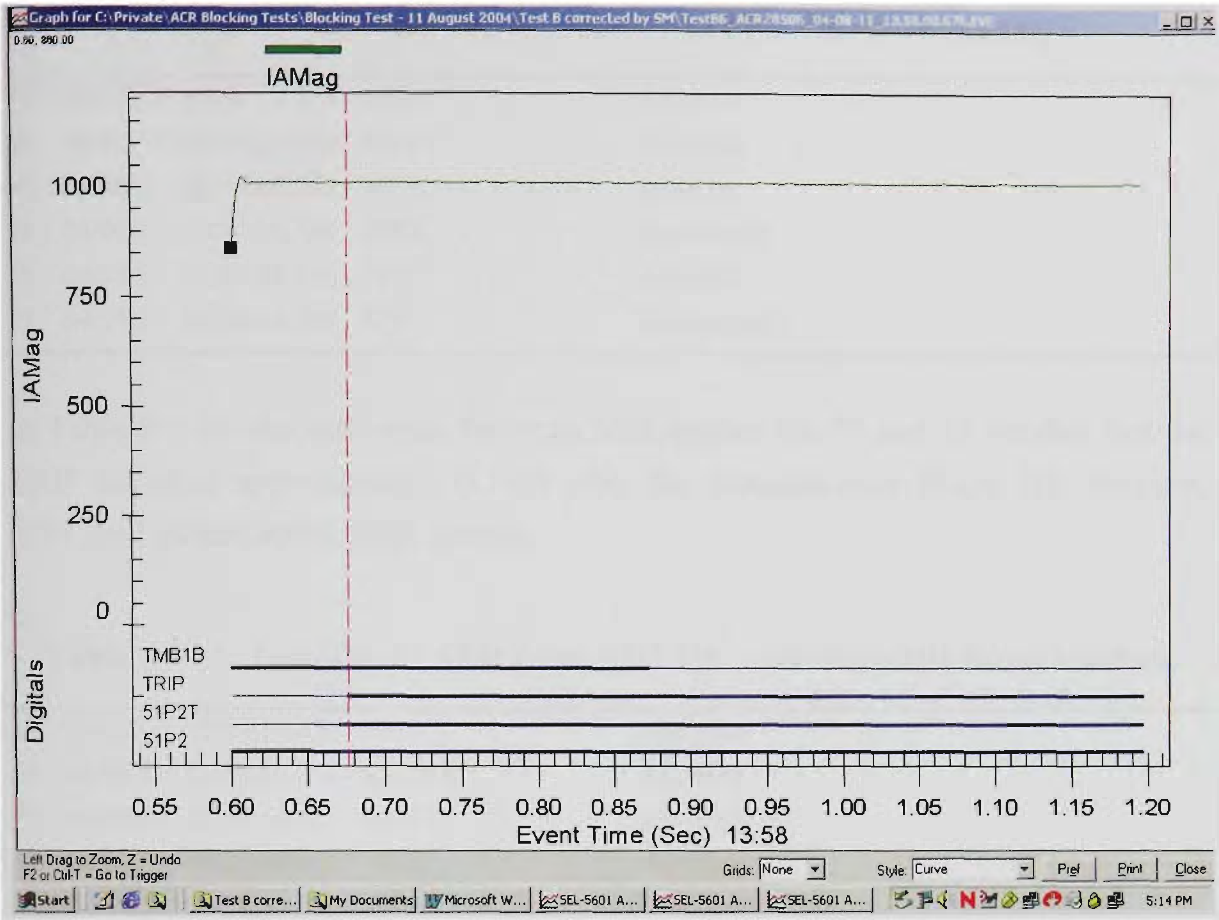


Figure B6_2_Event_3 Tripping of R1 due to the Phase O/C

Figure B6_2_Event_2 illustrates that the Phase O/C element, 51P2, picked up the fault current at the upstream recloser, R1. Blocking signal was transmitted. The Phase Time O/C element, 51P2T, had not timed out yet. Thus, the upstream recloser did not issue the TRIP command.

Figure B6_2_Event_3 illustrates that the Phase Time O/C element, 51P2T, timed out at the upstream recloser, R1, and as a result the upstream recloser issued the TRIP command. The transmitted blocking signal ceased approximately 200ms after the TRIP command had been issued.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 26, B - 27 and B - 28 below to verify the TRIP times. The summary of results is shown in Table B - 29.

Table B - 26 Test 'B6_1', SER from BD7 CB - no blocking

77	04/08/11	13:54:10.438	67P1	Asserted
76	04/08/11	13:54:10.548	67P1T	Asserted
75	04/08/11	13:54:10.548	79CY	Asserted
74	04/08/11	13:54:10.548	79RS	Deasserted
73	04/08/11	13:54:10.548	TRIP	Asserted
72	04/08/11	13:54:10.583	52A	Deasserted

In Table B - 26, the difference between SER entries No 77 and 73 verifies that the TRIP occurred approximately 0.110s after the Instantaneous Phase O/C element, 67P1, had picked up the fault current.

Table B - 27 Test 'B6_2', SER from BD7 CB – proving 67P1 is not blocked

59	04/08/11	13:58:10.436	67P1	Asserted
58	04/08/11	13:58:10.451	RMB1B	Asserted
57	04/08/11	13:58:10.551	67P1T	Asserted
56	04/08/11	13:58:10.551	79CY	Asserted
55	04/08/11	13:58:10.551	79RS	Deasserted
54	04/08/11	13:58:10.551	TRIP	Asserted
53	04/08/11	13:58:10.586	52A	Deasserted

In Table B - 27, the difference between SER entries No 59 and 54 verifies that the TRIP occurred approximately 0.115s after the Instantaneous Phase O/C element, 67P1, had picked up the fault current.

Table B - 28 Test 'B6_2', SER from R1

48	04/08/11	13:57:58.742	51P2	Asserted
47	04/08/11	13:57:58.742	TMB1B	Asserted
46	04/08/11	13:58:00.671	51P2T	Asserted
45	04/08/11	13:58:00.676	79CY	Asserted
44	04/08/11	13:58:00.676	79RS	Deasserted
43	04/08/11	13:58:00.676	TRIP	Asserted
42	04/08/11	13:58:00.711	52A	Deasserted

In Table B - 28, the difference between SER entries No 48 and 43 verifies that TRIP occurred approximately 1.934s after Phase O/C element, 51P2, had picked up the fault current.

Table B - 29 Results summary for 'B6' testing

Test B6	Phase or Ground O/C on R1 does not block Instantaneous Phase or Ground O/C on BD7 CB		
BD7 CB results		Without blocking	With blocking
	Expected result	0.100s	No blocking
	Observed result	0.110s	No blocking
R1 results	Expected result	Trip in 1.980s	
	Observed result	Trip in 1.934s	

B7 testing regime

Task

To prove that Ground O/C on R1 blocks Phase O/C and Ground O/C on the BD7 CB.

To test breaker fail feature at R1.

The testing set up is shown in Table B - 30.

Table B - 30 Set up for 'B7' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R1 28506	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	10 times the E/F setting	10 A	0.375s	Trip after 0.375s. However, the fault current is kept on for at least 200ms
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	10 times the E/F setting	25 A	0.255s	E/F element blocked by R1. Trip 200ms after R1 trips due to the blocking signal having been removed

B7 testing

Test B7_1, no blocking

Secondary fault current of 25A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

Figure B7_1_Event 1, illustrates the event in which the Ground O/C element, 51N1, at the BD7 CB picked up due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1. The Ground Time O/C element, 51N1T, timed out followed by the TRIP.

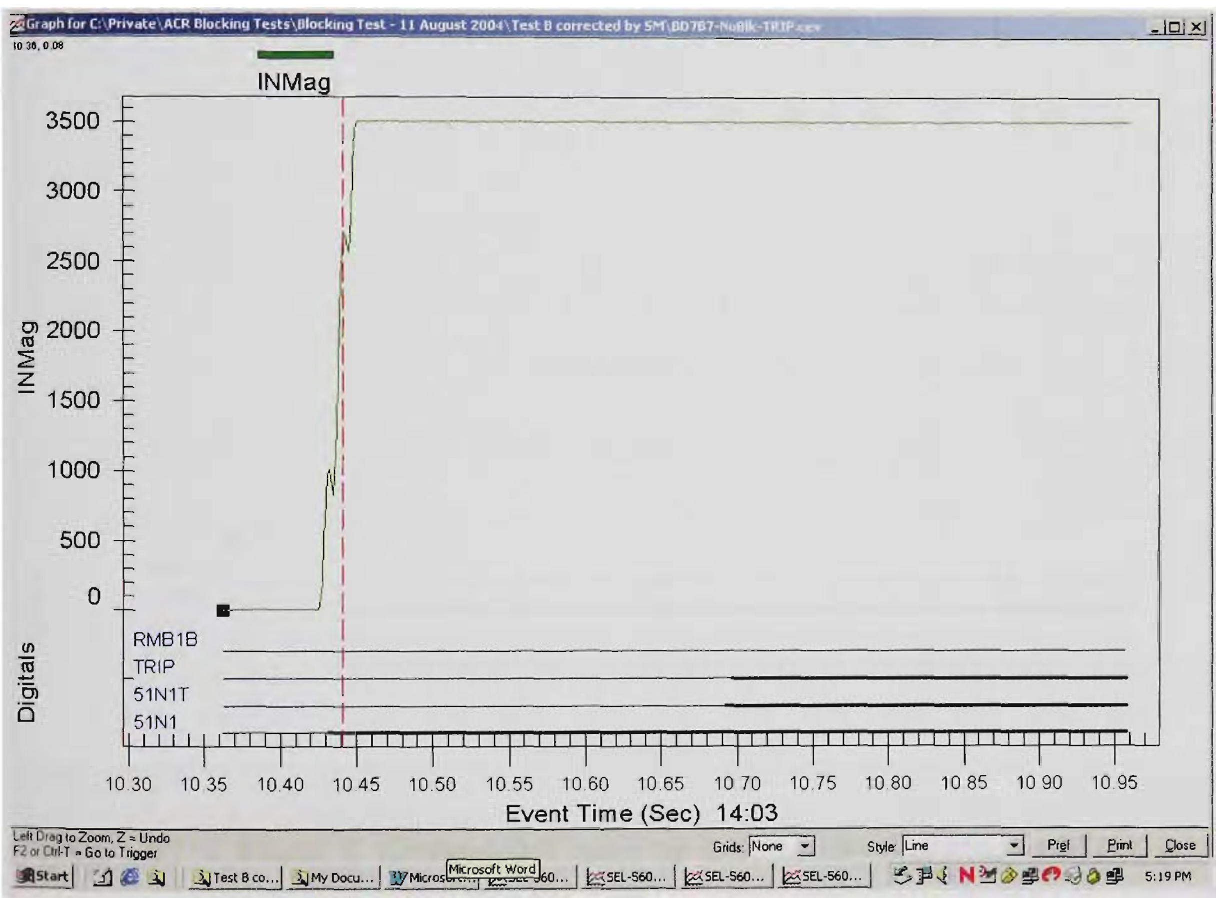


Figure B7_1_Event_1 BD7 CB, Ground O/C pick up and TRIP, no blocking

Test B7_2

Secondary fault currents of 25A and 10A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the upstream recloser, R1, respectively.

Figure B7_2_Event_1 shows that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current. The Ground Time O/C element, 51N1T, did time out but there was no TRIP due to the blocking signal, RMB1B, having been received from the upstream recloser, R1.

Figure B7_2_Event_2 illustrates that the Ground Time O/C element, 51N1T, timed out but the TRIP occurred only when the blocking signal, RMB1B, was removed by the upstream recloser, R1, due to its local breaker failure timer time out, i.e. after 200ms.

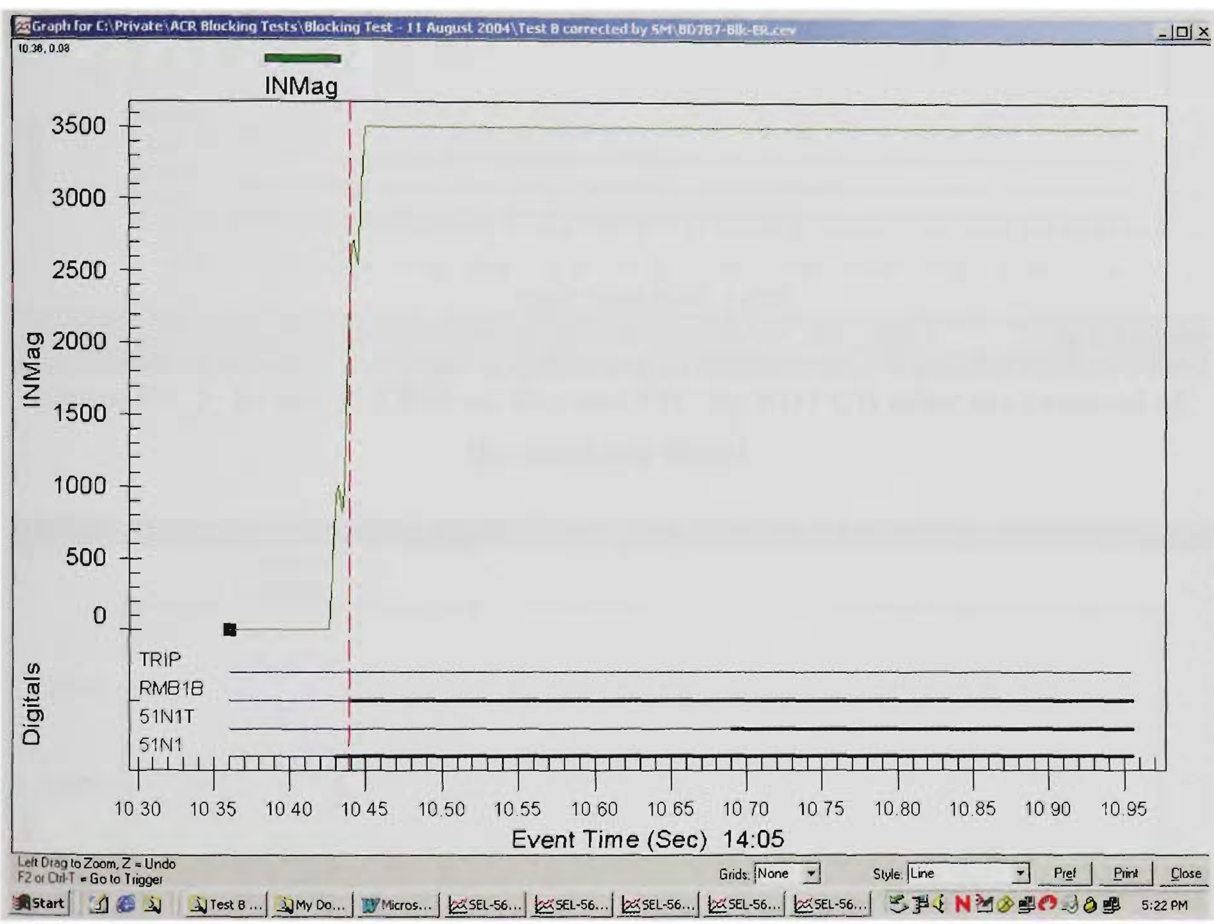


Figure B7_2_Event_1 Ground O/C pick up followed by blocking at BD7 CB

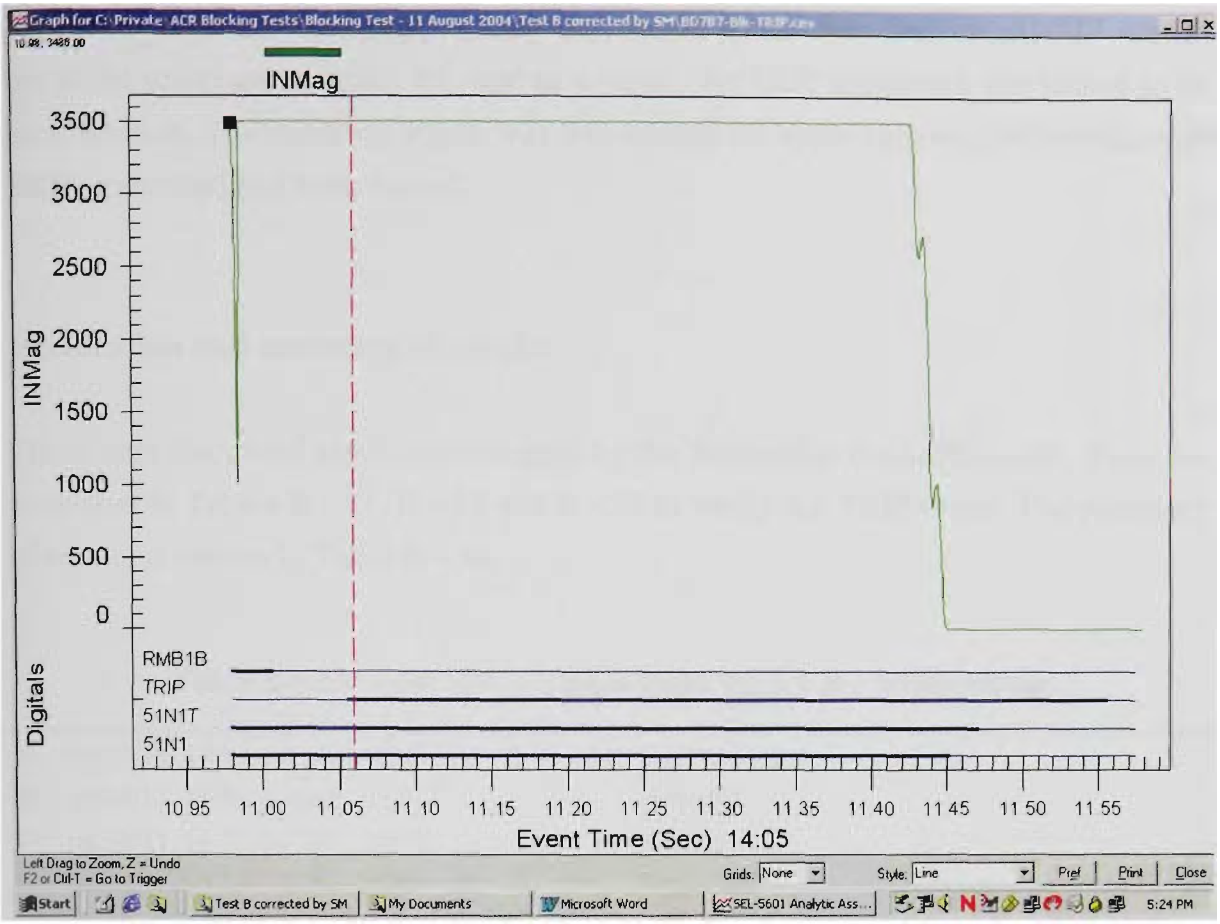


Figure B7_2_Event_2 TRIP on Ground O/C by BD7 CB after the removal of the blocking signal

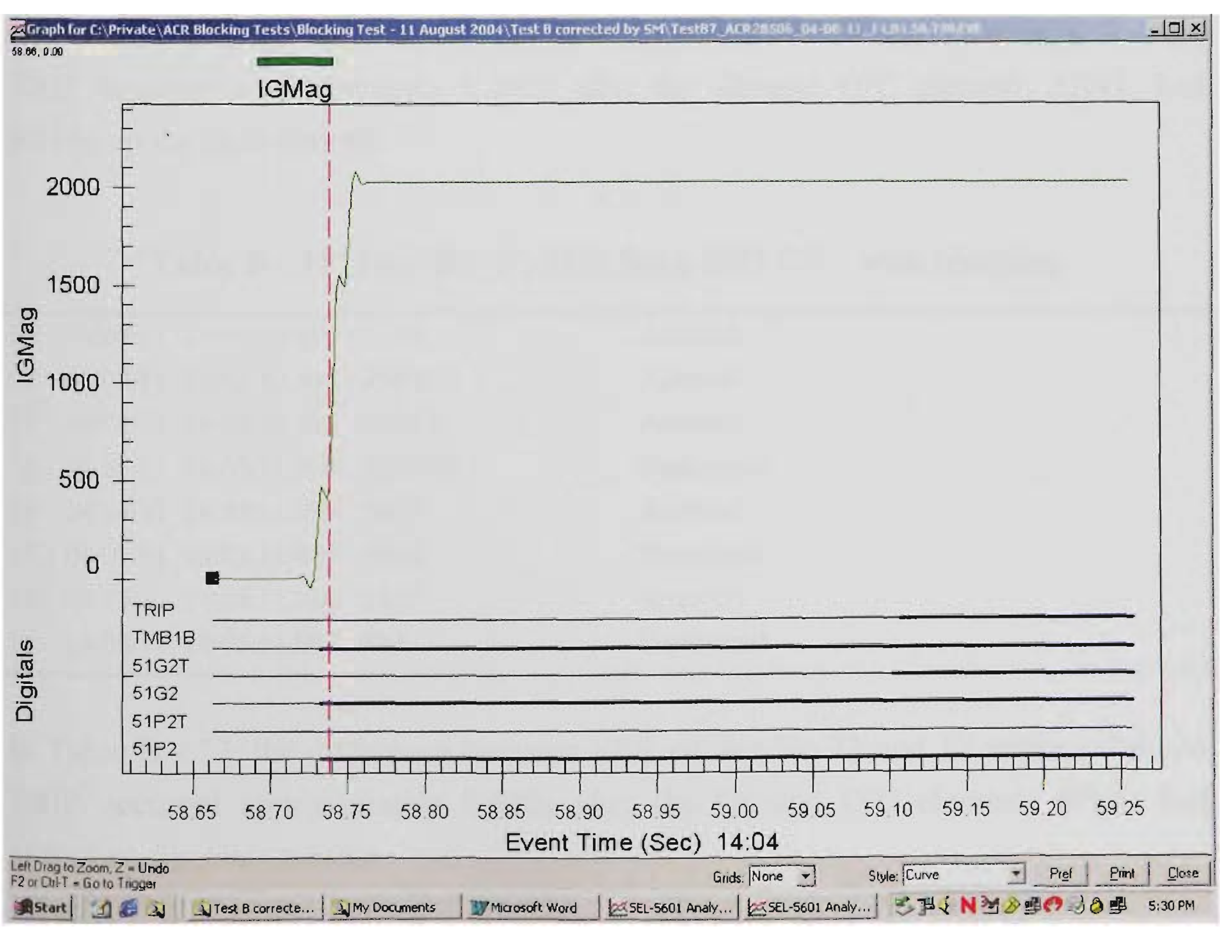


Figure B7_2_Event_3 Tripping of R1 due to the Ground O/C

Figure B7_2_Event_3 illustrates that the Ground Time O/C element, 51G2T, timed out at the upstream recloser, R1, and as a result, the TRIP command was issued to its local breaker. The blocking signal was transmitted for approximately 200ms after the TRIP command had been issued.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables B - 31, B - 32 and B - 33 to verify the TRIP times. The summary of results is shown in Table B - 34.

Table B - 31 Test 'B7_1', SER from BD7 CB - no blocking

39	04/08/11	14:03:10.441	51N1	Asserted
38	04/08/11	14:03:10.696	51N1T	Asserted
37	04/08/11	14:03:10.701	79CY	Asserted
36	04/08/11	14:03:10.701	79RS	Deasserted
35	04/08/11	14:03:10.701	TRIP	Asserted
34	04/08/11	14:03:10.736	52A	Deasserted

In Table B - 31, the difference between SER entries No 39 and 35 verifies that the TRIP occurred approximately 0.260s after the Ground O/C element, 51N1, had picked up the fault current.

Table B - 32 Test 'B7_2', SER from BD7 CB – with blocking

23	04/08/11	14:05:10.439	51N1	Asserted
22	04/08/11	14:05:10.444	RMB1B	Asserted
21	04/08/11	14:05:10.694	51N1T	Asserted
20	04/08/11	14:05:11.009	RMB1B	Deasserted
19	04/08/11	14:05:11.059	79CY	Asserted
18	04/08/11	14:05:11.059	79RS	Deasserted
17	04/08/11	14:05:11.059	TRIP	Asserted
16	04/08/11	14:05:11.094	52A	Deasserted

In Table B - 32, the difference between SER entries No 23 and 17 verifies that the TRIP occurred approximately 0.620s after the Ground O/C element, 51N1, had picked up the fault current.

Table B - 33 Test 'B7_2', SER from R1

26	04/08/11	14:04:58.733	51G2	Asserted
25	04/08/11	14:04:58.733	51P2	Asserted
24	04/08/11	14:04:58.733	TMB1B	Asserted
23	04/08/11	14:04:59.103	51G2T	Asserted
22	04/08/11	14:04:59.108	79CY	Asserted
21	04/08/11	14:04:59.108	79RS	Deasserted
20	04/08/11	14:04:59.108	TRIP	Asserted
19	04/08/11	14:04:59.143	52A	Deasserted
18	04/08/11	14:04:59.303	SV2T	Asserted
17	04/08/11	14:04:59.303	TMB1B	Deasserted
16	04/08/11	14:04:59.468	51P2T	Asserted
15	04/08/11	14:04:59.753	51G2	Deasserted
14	04/08/11	14:04:59.753	51P2	Deasserted
13	04/08/11	14:04:59.773	51G2T	Deasserted
12	04/08/11	14:04:59.773	51P2T	Deasserted
11	04/08/11	14:04:59.773	SV2T	Deasserted
10	04/08/11	14:04:59.778	TRIP	Deasserted

In Table B - 33, the difference between SER entries No 26 and 20 verifies that the TRIP command was issued approximately 0.375s after Ground O/C element, 51G2, had picked up the fault current. The difference between SER entries No 23 and 17 verifies that the breaker failure timer timed out after 200ms.

Table B - 34 Results summary for 'B7' testing

Test B7	Ground O/C on R1 blocks Phase and Ground O/C on BD7 CB and tests breaker failure feature at R1		
BD7 CB results		Without blocking	With blocking
	Expected result	0.255s	Trip in 0.575s[3]
	Observed result	0.260s	Trip in 0.620s
R1 results	Expected result	Trip in 0.375s	
	Observed result	Trip in 0.375s	

[3] Trip time = 0.375s + 0.200s = 0.575s

Appendix 'C'

Blocking of BD7 feeder CB by R2

Test set 'C'

Introduction

Test set 'C' comprised seven tests as outlined in Table C - 1.

Table C - 1 Blocking from R2 to BD7 feeder CB

Test No	Purpose
C1	Phase O/C on R2 blocks Phase O/C on CB
C2	Phase O/C on R2 blocks Ground O/C on CB
C3	Ground O/C on R2 blocks Ground O/C on CB
C4	Ground O/C on R2 blocks Phase O/C on CB
C5	SEF on R2 does not block Phase O/C or Ground O/C on CB
C6	Phase O/C or Ground O/C on R2 does not block Instantaneous O/C on CB
C7	Ground O/C on R2 blocks Phase O/C and Ground O/C on CB and tests breaker fail at R2

General design specifications:

9. An SEF fault on any section should not block any protection element on an upstream device.

10. A phase fault on any section should not block an SEF element on an upstream device.

11. The instantaneous phase O/C element at the CB should not be blocked by any downstream device.

12. A downstream device should stop transmitting a blocking signal 200ms after issuing a trip command (to cater for breaker failure).

The test set up deployed is shown in Figure C[3].

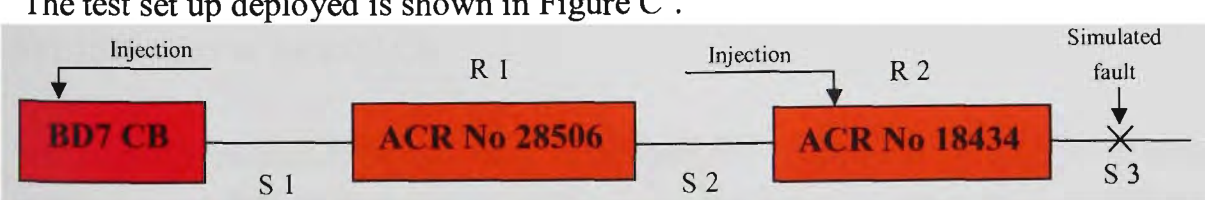


Figure C Test set 'C' set up for R2 blocking BD7 CB

---

[3] CT ratio for the BD7 CB is 700/5. CT ratio for R2 recloser for testing purposes is 200/1. For operational purposes, the effective CT ratio for R2 recloser is 400/1. This is due to the presence of interposing CTs in the recloser tank.

C1 testing regime

Task

To block the BD7 CB, from tripping due to its Phase O/C pick up, with the blocking signal sent by the upstream recloser R1 due to its Phase O/C pick up.

The testing set up is shown in Table C - 2.

Table C - 2 Set up for 'C1' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	1.8 A	12.825s	Trips after 12.825s
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C OFF	Any phase element	4.0 times the O/C setting	17.0 A	1.096s	BD7 Inverse Time O/C element blocked. Trips on the back up O/C element only.

C1 testing

Test C1_1, no blocking

Secondary fault current of 17A was injected into the Phase O/C element of the SEL351S relay at the BD7 CB.

There are two events, No 1 and No 2, in this test. This is because the SEL 351S relay software is capable of displaying only 30 cycles at a time, i.e. approximately 600 ms. As the BD7 CB, without blocking, is expected to trip in 1.096 seconds, a second event is needed to capture the TRIP.

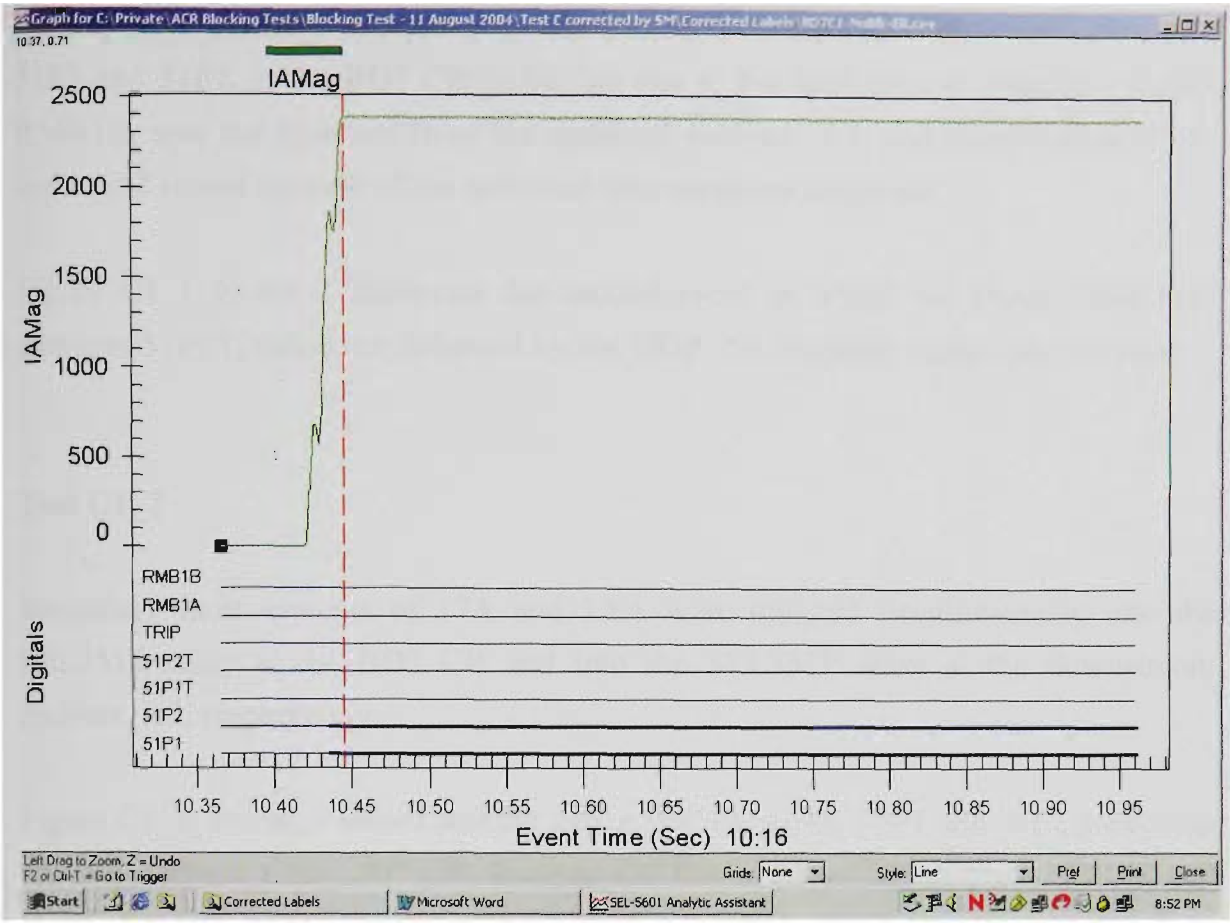


Figure C1_1_Event_1 BD7 CB, Phase O/C pick up, no blocking

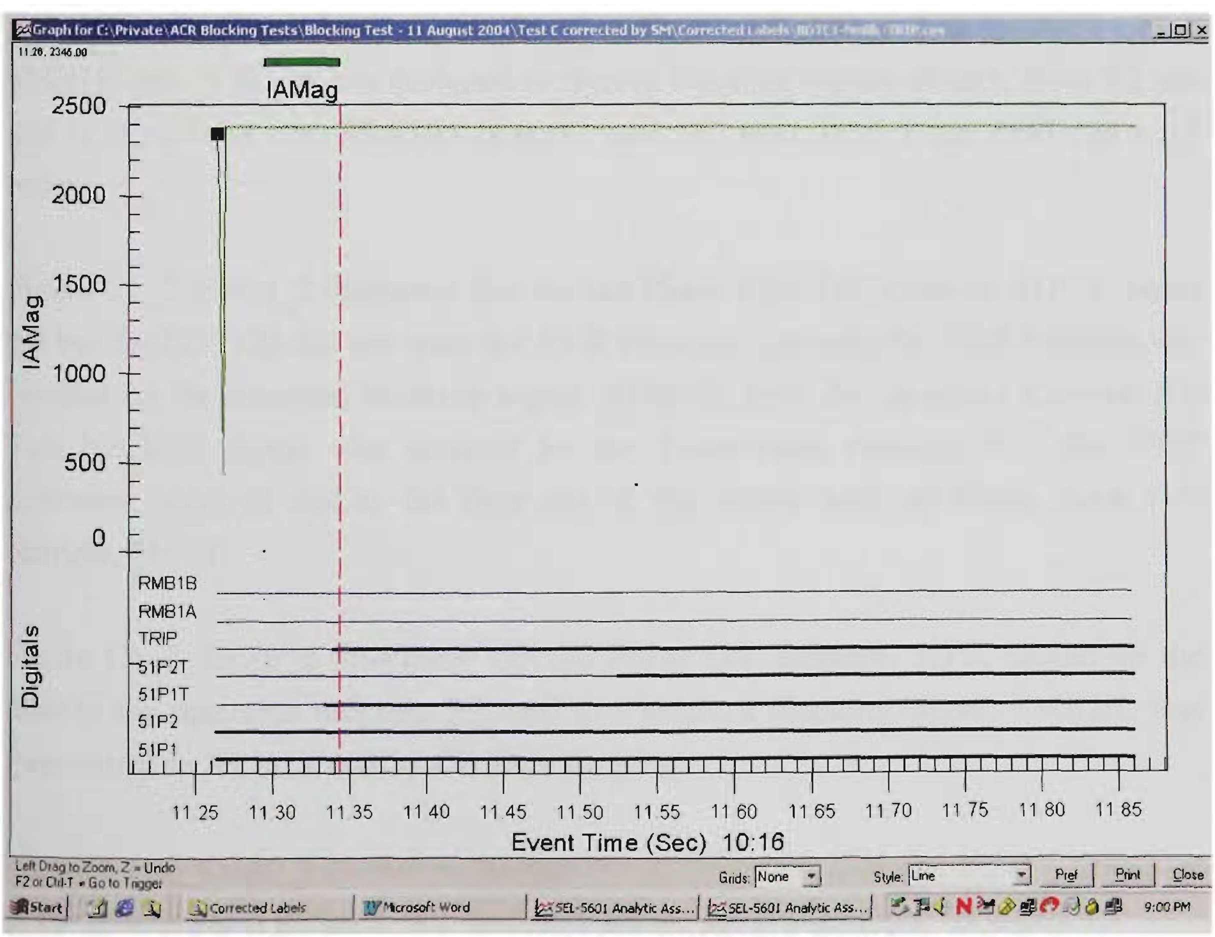


Figure C1_1_Event _2 BD7 CB, trip due to a Phase O/C, no blocking

Figure C1_1_Event_1 illustrates the first event in which the Phase O/C elements, 51P1 and 51P2, at the BD7 CB picked up due to the fault current. Blocking signal, RMB1B, was not received from the upstream recloser, R1, and there was no TRIP command issued as none of the activated time elements timed out.

Figure C1_1_Event_2 illustrates the second event in which the Phase Time O/C element, 51P1T, timed out followed by the TRIP. No blocking signal was received.

Test C1_2

Secondary fault currents of 17A and 1.8A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the downstream recloser, R2, respectively.

Figure C1_2_Event_1 shows that the Phase O/C elements, 51P1 and 51P2 picked up the fault current at the BD7 CB. Because the Phase Time O/C elements, 51P1T and 51P2T, had not timed out yet and the blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not TRIP. Blocking signal, TMB1A, was sent by the downstream recloser, R2, to the upstream recloser, R1. The upstream recloser received this blocking signal as RMB1A and relayed it to the BD7 CB as TMB1B. BD7 CB was not designed to receive blocking signals directly from R2 and that is the reason why RMB1A is never asserted when read at the BD7 CB 351S relay.

Figure C1_2_Event_2 illustrates that the fast Phase Time O/C element, 51P1T, timed out but the BD7 CB did not issue the TRIP command because the TRIP function was blocked by the received blocking signal, RMB1B, from the upstream recloser, R1. This blocking signal was initiated by the downstream recloser, R2. The TRIP operation occurred due to the time out of the slower back up Phase Time O/C element, 51P2T.

Figure C1_2_Event_3 illustrates that the Phase O/C element, 51P2, picked up the fault at the upstream recloser, R1, and as a result, a blocking signal, TMB1A, was transmitted to R1 to stop BD7 CB from tripping.

Figure C1_2_Event_4 illustrates that the Phase Time O/C element, 51P2T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command.

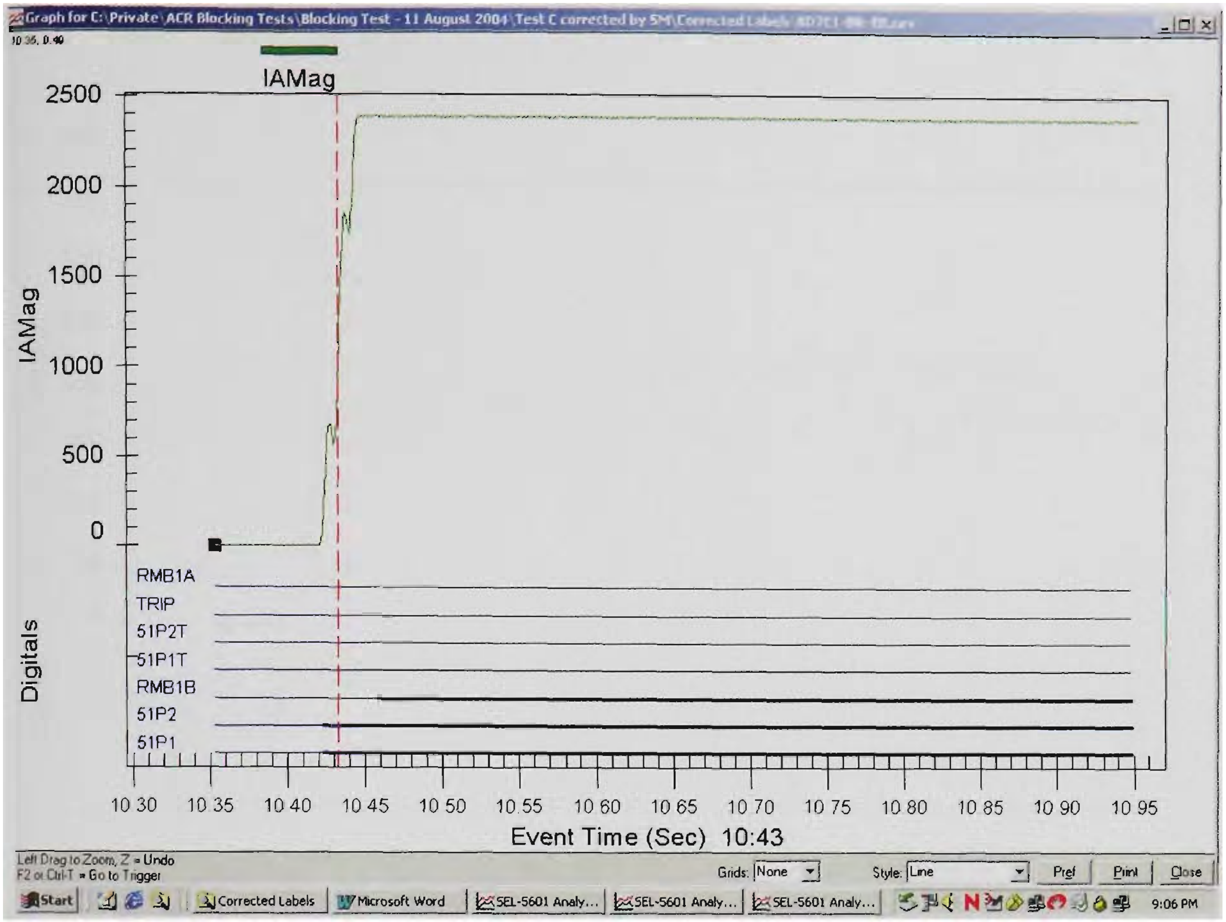


Figure C1_2_Event_1 Blocking of the BD7 CB on Phase O/C by R2

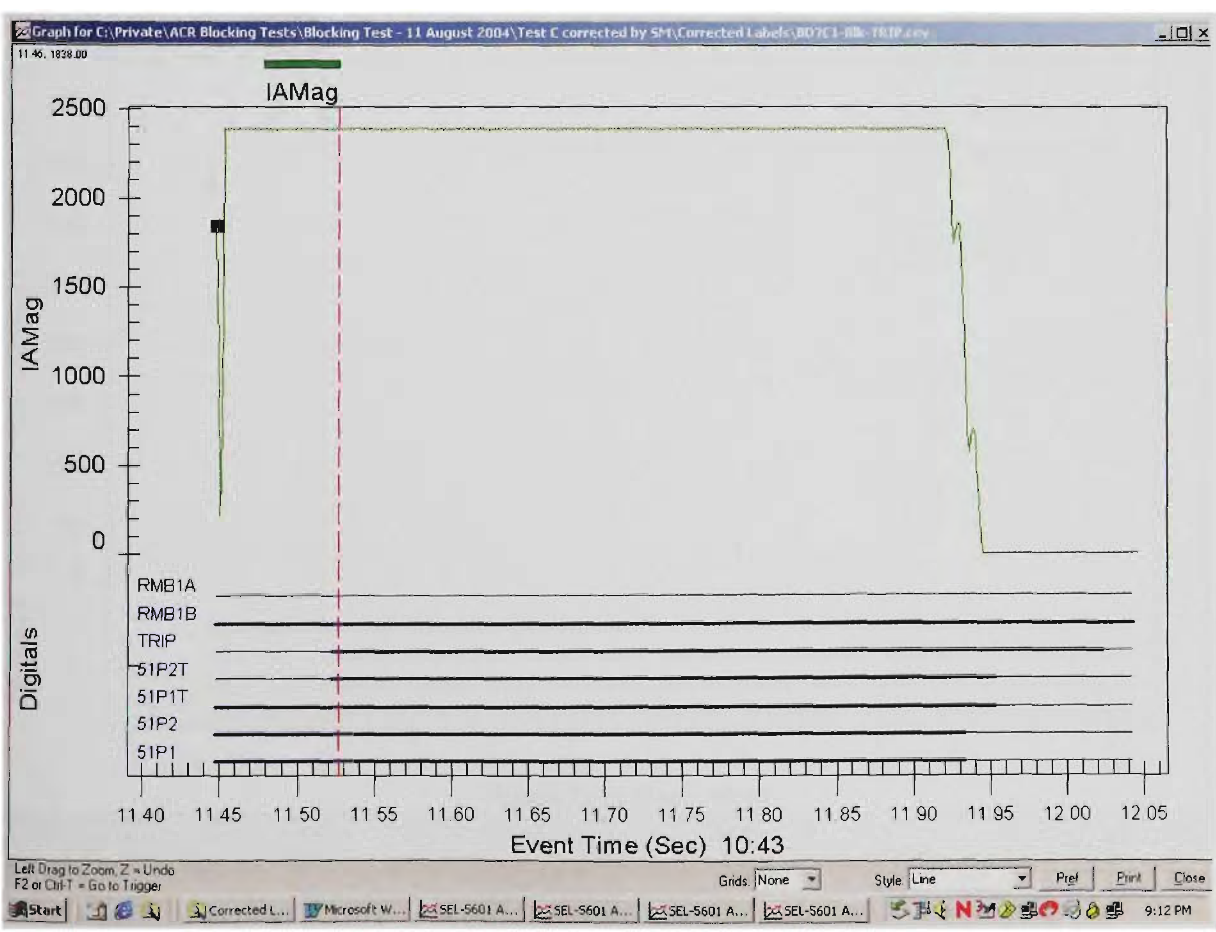


Figure C1_2_Event_2 Blocking of the BD7 CB by R2

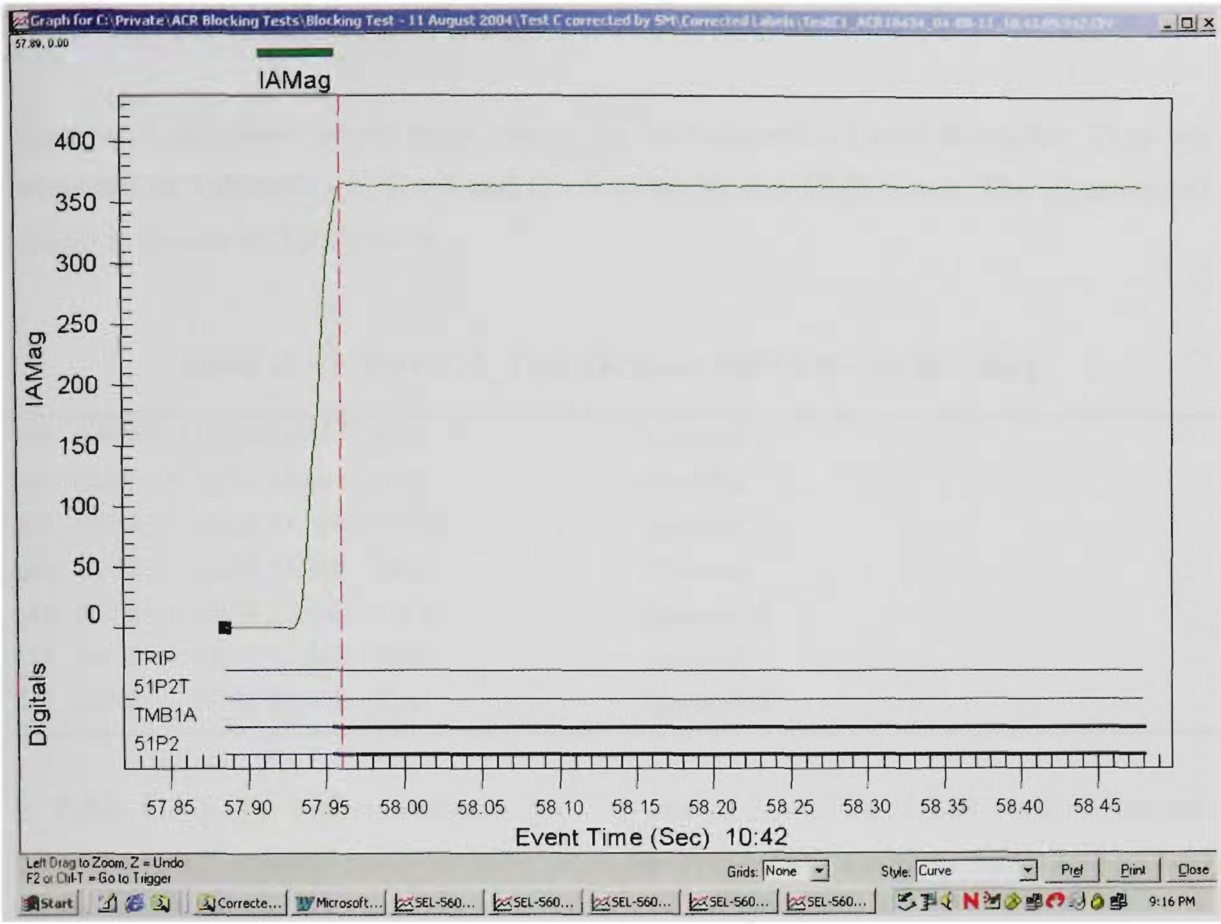


Figure C1_2_Event_3 Phase O/C pick up by R2

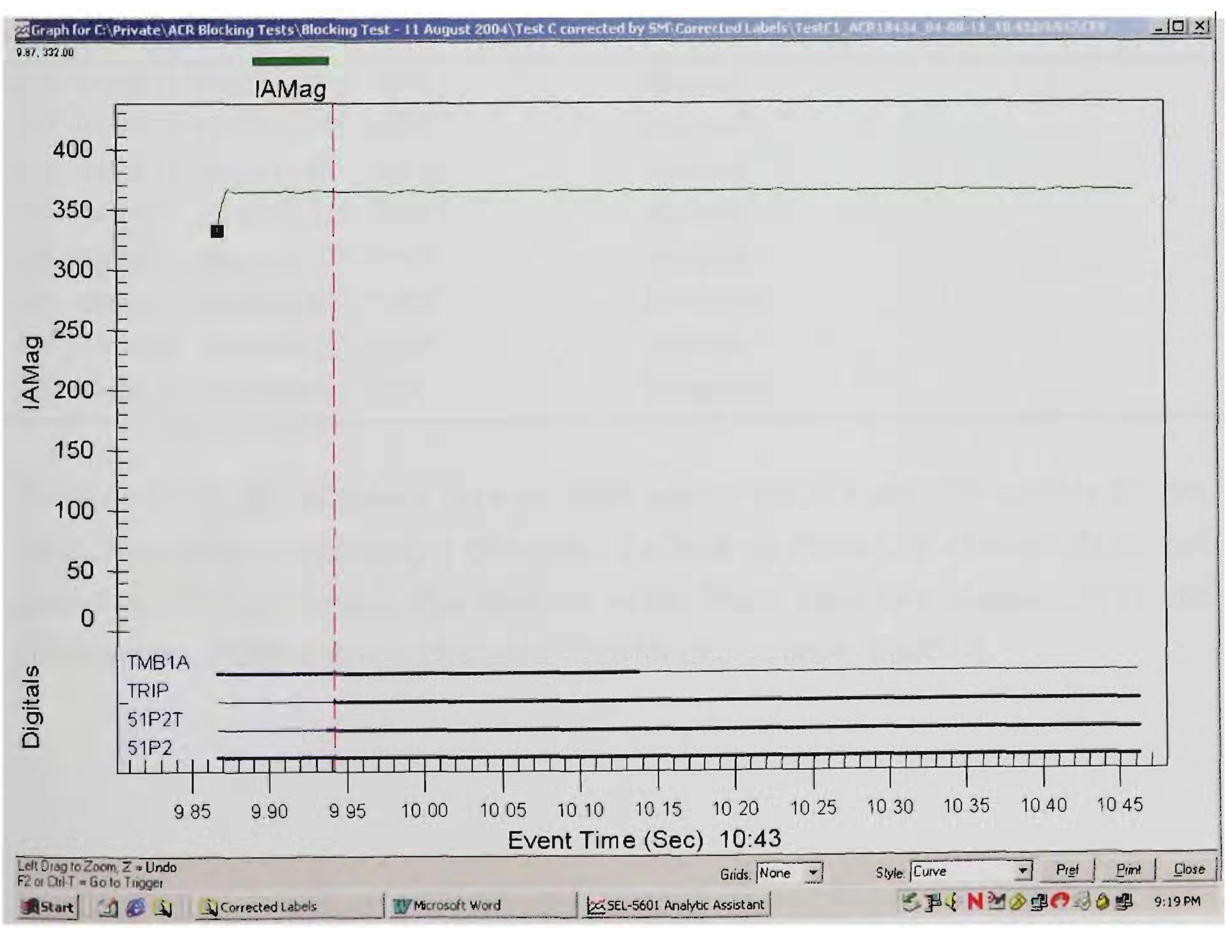


Figure C1_2_Event_4 Tripping of R2 due to the Phase O/C pick up

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 3, C - 4 and C - 5 to verify the TRIP times. The summary of results is shown in Table C - 6.

Table C - 3 Test 'C1_1', SER from BD7 CB - no blocking

249	04/08/11	10:16:10.444	51P1	Asserted
248	04/08/11	10:16:10.444	51P2	Asserted
247	04/08/11	10:16:11.338	51P1T	Asserted
246	04/08/11	10:16:11.343	79CY	Asserted
245	04/08/11	10:16:11.343	79RS	Deasserted
244	04/08/11	10:16:11.343	TRIP	Asserted
243	04/08/11	10:16:11.378	52A	Deasserted

In Table C - 3, the difference between SER entries No 249 and 244 verifies that the TRIP occurred approximately 0.899s after the Phase O/C element, 51P1, had picked up the fault current.

Table C - 4 Test 'C1_2', SER from BD7 CB - with blocking

212	04/08/11	10:43:10.432	51P1	Asserted
211	04/08/11	10:43:10.432	51P2	Asserted
210	04/08/11	10:43:11.337	51P1T	Asserted
209	04/08/11	10:43:11.527	51P2T	Asserted
208	04/08/11	10:43:11.527	79CY	Asserted
207	04/08/11	10:43:11.527	79RS	Deasserted
206	04/08/11	10:43:11.527	TRIP	Asserted
205	04/08/11	10:43:11.561	52A	Deasserted

In Table C - 4, the difference between SER entries No 211 and 206 verifies that the TRIP occurred approximately 1.095s after the back up Phase O/C element, 51P2, had picked up the fault current. The time out of the Phase Time O/C element, 51P1, did not cause the TRIP as it was blocked by the blocking signal, RMB1B.

Table C - 5 Test 'C1_2', SER from R2

164	04/08/11	10:42:57.956	51P2	Asserted
163	04/08/11	10:42:57.956	TMB1A	Asserted
162	04/08/11	10:43:09.937	51P2T	Asserted
161	04/08/11	10:43:09.942	79CY	Asserted
160	04/08/11	10:43:09.942	79RS	Deasserted
159	04/08/11	10:43:09.942	TRIP	Asserted

In Table C - 5, the difference between SER entries No 164 and 159 verifies that the TRIP occurred approximately 11.986s after the Phase O/C element, 51P2, had picked up the fault current.

Table C - 6 Results summary for 'C1' testing

Test C1	**Phase O/C on R2 blocks Phase O/C on BD7 CB**		
BD7 CB results		Without blocking	With blocking
	Expected result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[1]
	Observed result	0.899s	Trip due to the back up element at 1.095s, i.e. in additional 0.196s
R2 results	Expected result	12.825s	
	Observed result	11.986s	

[1] Arbitrarily chosen value to be smaller than 200ms, i.e. for protection coordination this value needs to be smaller than the breaker failure time

C2 testing regime

Task

To block the BD7 CB, from tripping due to the Ground O/C pick up, with the blocking signal sent by upstream recloser, R2, due to its Phase O/C pick up.

The testing set up is shown in Table C - 7.

Table C - 7 Set up for 'C2' testing

ACR	ACR pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	1.2 times the O/C setting	1.8 A	12.825s	Trips after 12.825s
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	1.7 times the E/F setting	4.25 A	3.279s	BD7 CB Inverse Time E/F element blocked. No trip.

C2 testing

Test C2_1, no blocking

Secondary fault current of 4.25 A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

Figure C2_1_Event_1 illustrates that the Ground O/C element, 51N1, at the BD7 CB picked up due to the fault current. The Ground Time O/C element, 51N1T, timed out followed by the TRIP. No blocking signal, RMB1B, was received.

Figure C2_1_Event_1 TRIP by the BD7 CB on Ground O/C, no blocking

Test C2_2

Secondary fault current of 4.25 A and 1.8 A were injected simultaneously into Ground O/C element of the SEL351S relay at the BD7 CB and the Phase O/C element of the SEL351P relay at the downstream recloser, R2, respectively.

Figure C2_2_Event_1 shows that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current. Because the Ground Time O/C element, 51N1T, had not timed out yet and the blocking signal, RMB1B, was received, the BD7 CB did not issue the TRIP command.

Figure C2_2_Event_2 illustrates that the Phase O/C element, 51P2, at the downstream recloser, R2, picked up the fault, and as a result, the blocking signal, TMB1A, was transmitted to the upstream recloser, R1, to stop BD7 CB from tripping.

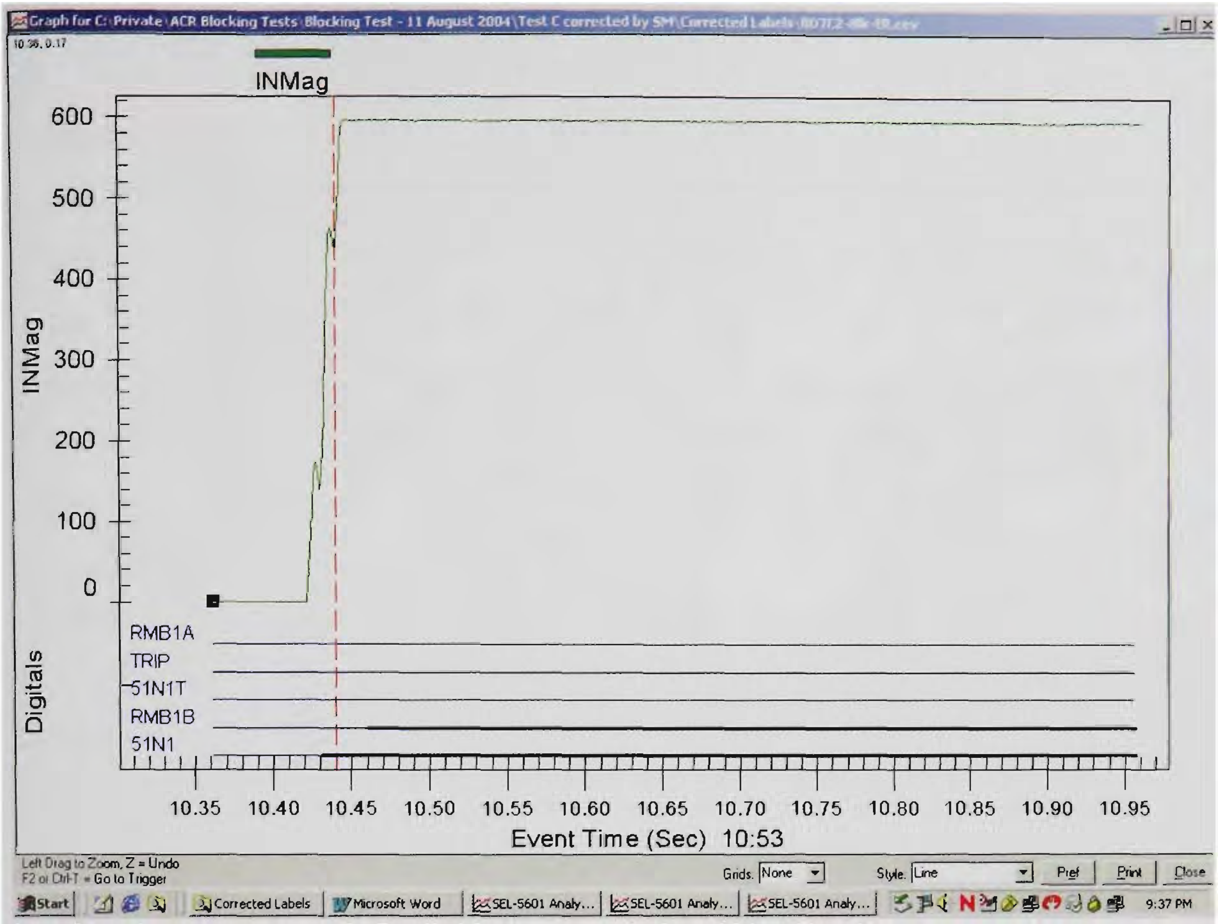


Figure C2_2_Event_1 BD7 CB blocked from tripping on Ground O/C

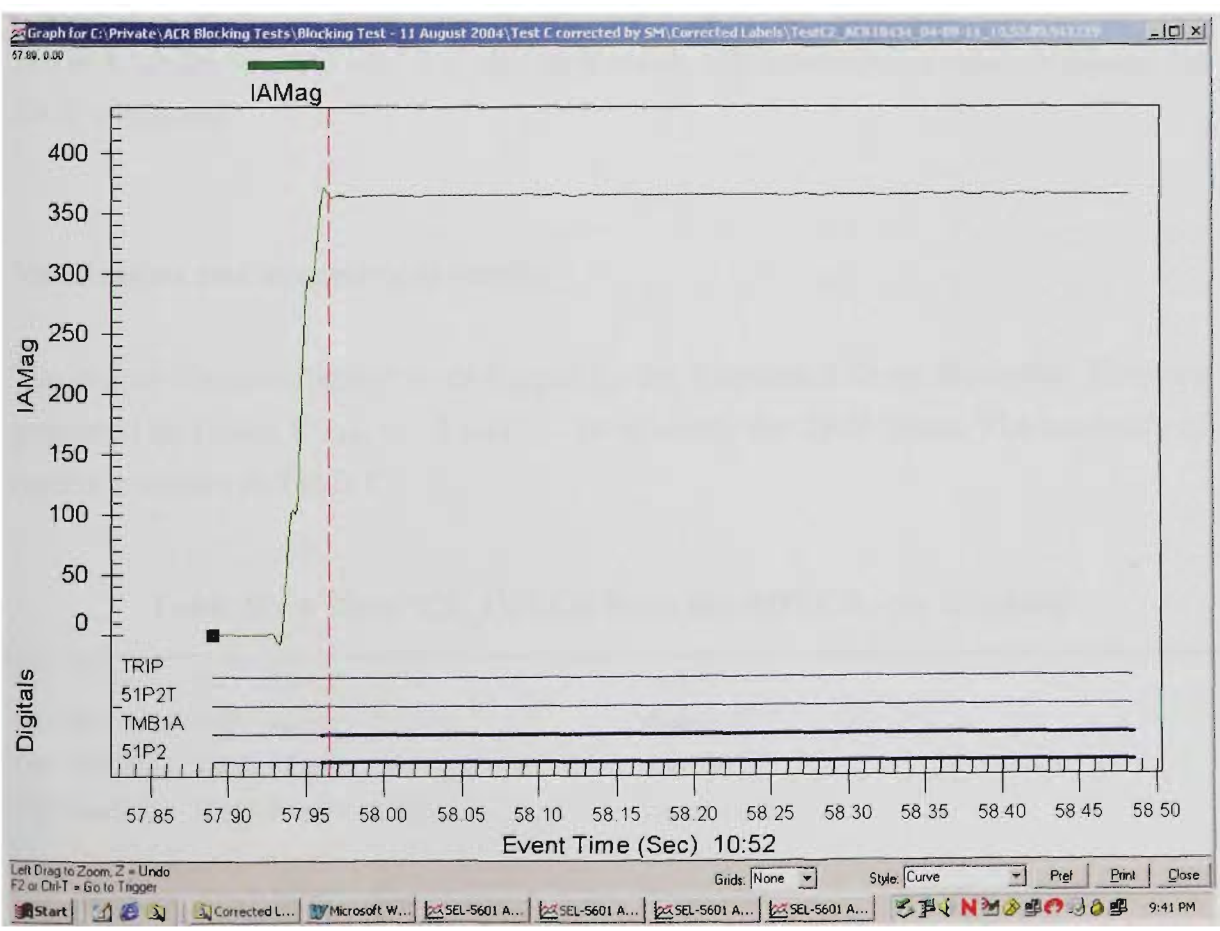


Figure C2_2_Event_2 R2 sending blocking signal designated for BD7 CB

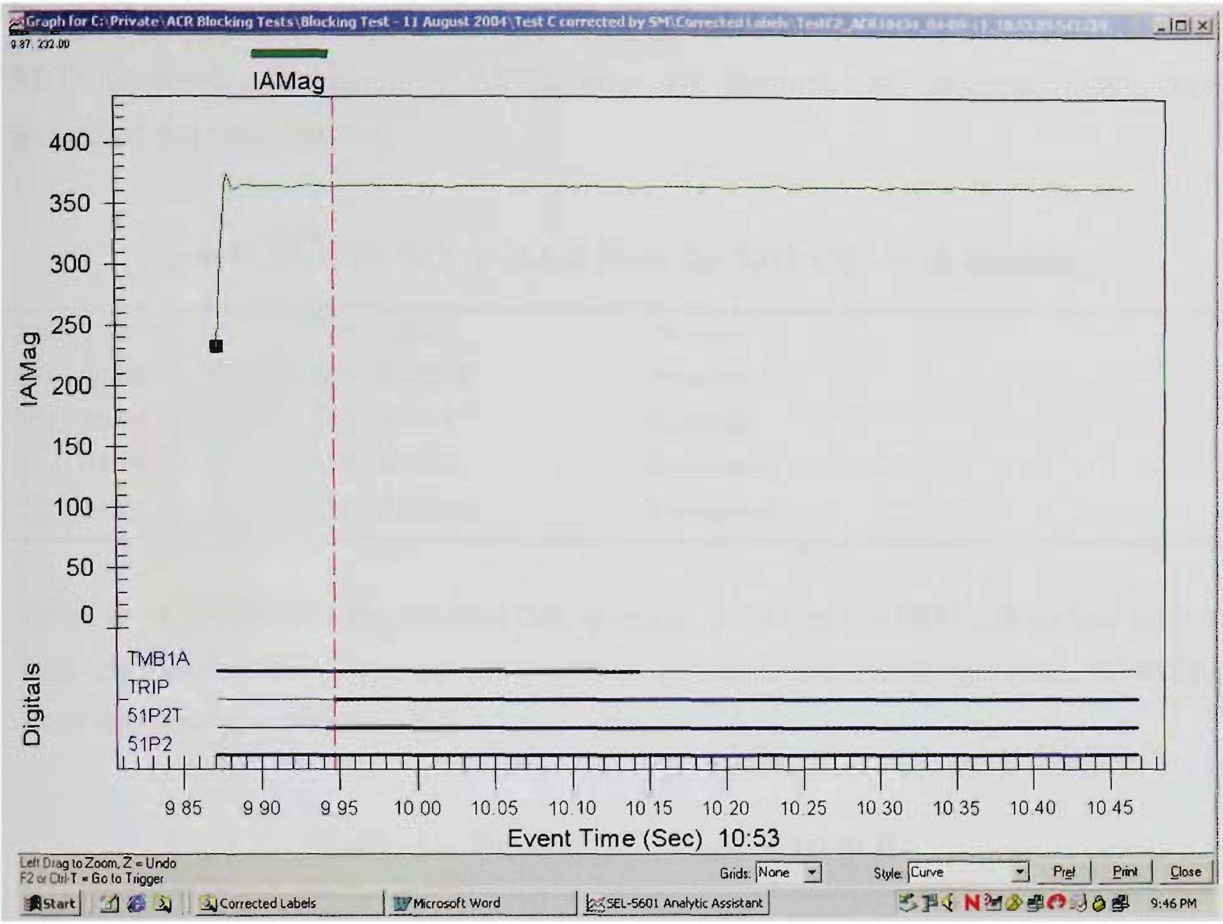


Figure C2_2_Event_3 R2 tripping on Phase O/C

Figure C2_2_Event_3 illustrates that the Phase Time O/C element, 51P2T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 8, C - 9 and C - 10 to verify the TRIP times. The summary of results is shown in Table C - 11.

Table C - 8 Test 'C2_1', SER from the BD7 CB - no blocking

191	04/08/11	10:51:10.425	51N1	Asserted
190	04/08/11	10:51:13.692	51N1T	Asserted
189	04/08/11	10:51:13.697	79CY	Asserted
188	04/08/11	10:51:13.697	79RS	Deasserted
187	04/08/11	10:51:13.697	TRIP	Asserted
186	04/08/11	10:51:13.732	52A	Deasserted

In Table C - 8, the difference between SER entries No 191 and 187 verifies that the TRIP occurred approximately 3.272s after the Ground O/C element, 51N1, had picked up the fault current.

Table C - 9 Test 'C2_2', SER from the BD7 CB - with blocking

174	04/08/11	10:53:10.440	51N1	Asserted
174	04/08/11	10:53:10.465	RMB1B	Asserted
173	04/08/11	10:53:13.714	51N1T	Asserted
172	04/08/11	10:53:13.954	51N1T	Deasserted
171	04/08/11	10:53:22.652	RMB1B	Deasserted

Table C - 9 shows that the Ground O/C element, 51N1, at the BD7 CB picked up the fault current but there was no TRIP due to the received blocking signal, RMB1B, from the upstream recloser, R1.

Table C - 10 Test 'C2_2', SER from R2

142	04/08/11	10:52:57.960	51P2	Asserted
141	04/08/11	10:52:57.960	TMB1A	Asserted
140	04/08/11	10:53:09.942	51P2T	Asserted
139	04/08/11	10:53:09.947	79CY	Asserted
138	04/08/11	10:53:09.947	79RS	Deasserted
137	04/08/11	10:53:09.947	TRIP	Asserted
136	04/08/11	10:53:09.987	52A	Deasserted

In Table C - 10, the difference between SER entries No 142 and 137 verifies that the TRIP occurred approximately 11.987s after the Phase O/C element, 51P2, had picked up the fault current.

Table C - 11 Results summary for test 'C2'

Test B2	**Phase O/C on R2 blocks Ground O/C on BD7 CB**		
		Without blocking	With blocking
BD7 results	Expected result	3.279s	No trip
	Observed result	3.272s	No trip
R2 results	Expected result	12.825s	
	Observed result	11.987s	

C3 testing regime

Task

To block the BD7 CB, from tripping due to the Ground O/C pick up, with the blocking signal sent by the downstream recloser, R2, due to its Ground O/C pick up.

The testing set up is shown in Table C - 12.

Table C - 12 Set up for 'C3' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.2 times the E/F setting	0.912 A	16.200s	Trip after 16.200s
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	1.7 times the E/F setting	4.25 A	3.279s	BD7 CB Inverse Time E/F element blocked. No trip.

C3 testing

Test C3_1, no blocking

Secondary fault current of 4.25 A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB. This test procedure and results obtained are the same as in the test C2_1. Thus, for the test details, the reader is referred to the test C2_1.

Test C3_2

Secondary fault currents of 4.25 A and 0.912 A were injected simultaneously into the Ground O/C elements of the SEL351S and SEL351P relays at the BD7 CB and at the downstream recloser, R2, respectively.

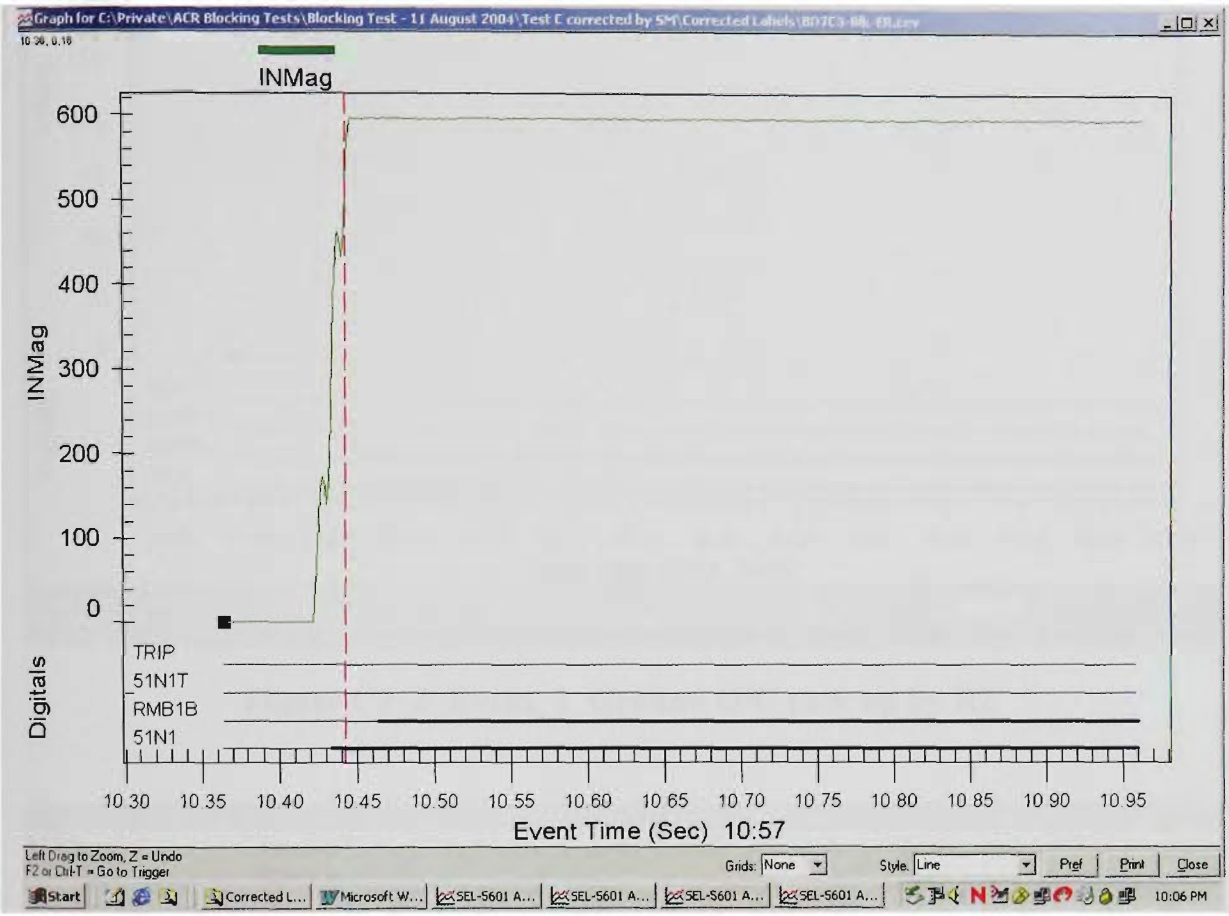


Figure C3_2_Event_1 BD7 CB blocked from tripping on Ground O/C

Figure C3_2_Event_1 shows that the Ground O/C element, 51N1, picked up the fault current at the BD7 CB. Because the Ground Time O/C element, 51N1T, had not timed out yet and the blocking signal, RMB1B, was received, the BD7 CB did not the issue TRIP command.

Figure C3_2_Event_2 illustrates that the Ground O/C element, 51G2, at the downstream recloser, R2, picked up the fault, and as a result, the blocking signal, TMB1A, was transmitted to the upstream recloser, R1, to be relayed to BD7 CB to stop it from tripping.

Figure C3_2_Event_3 illustrates that the Ground Time O/C element, 51G2T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command to its local breaker.

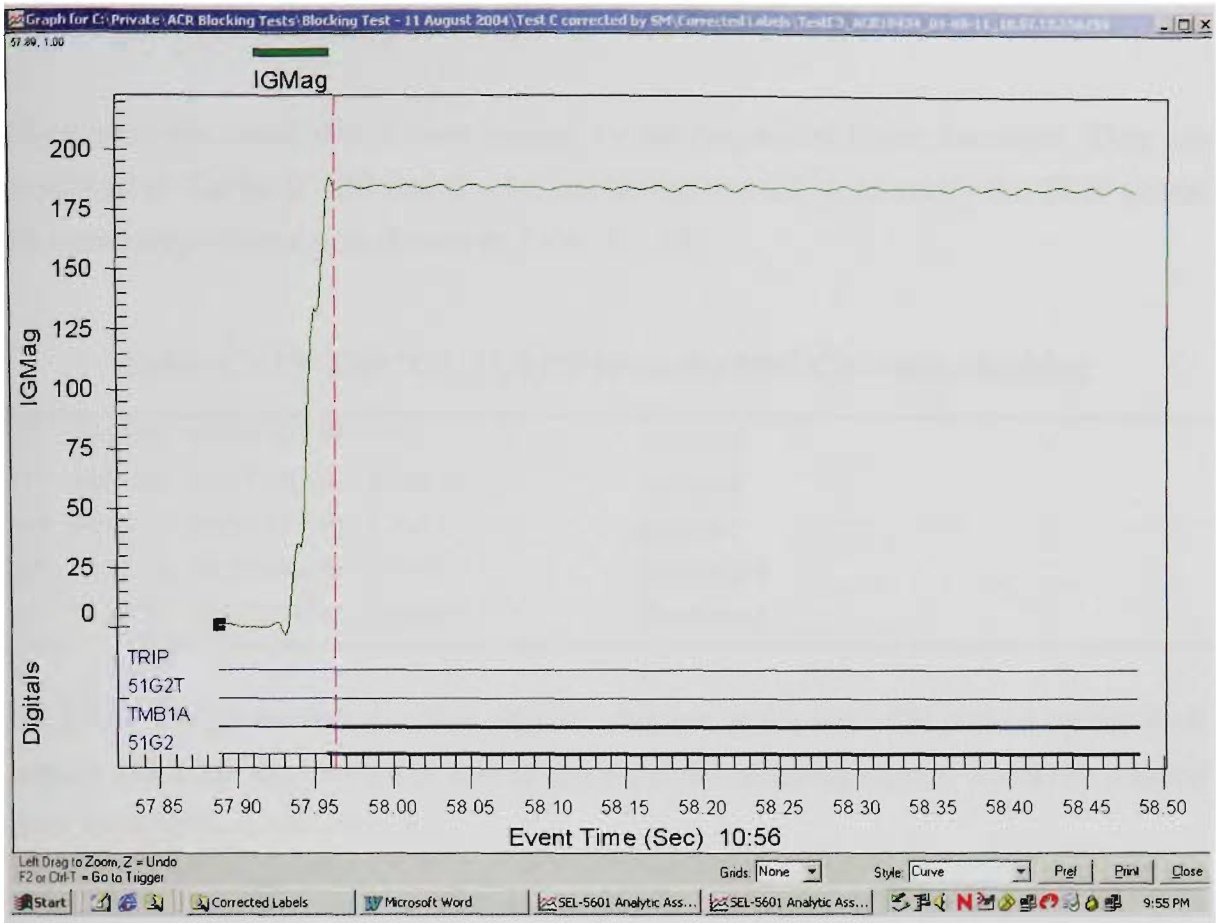


Figure C3_2_Event_2 Ground O/C pick up by R2

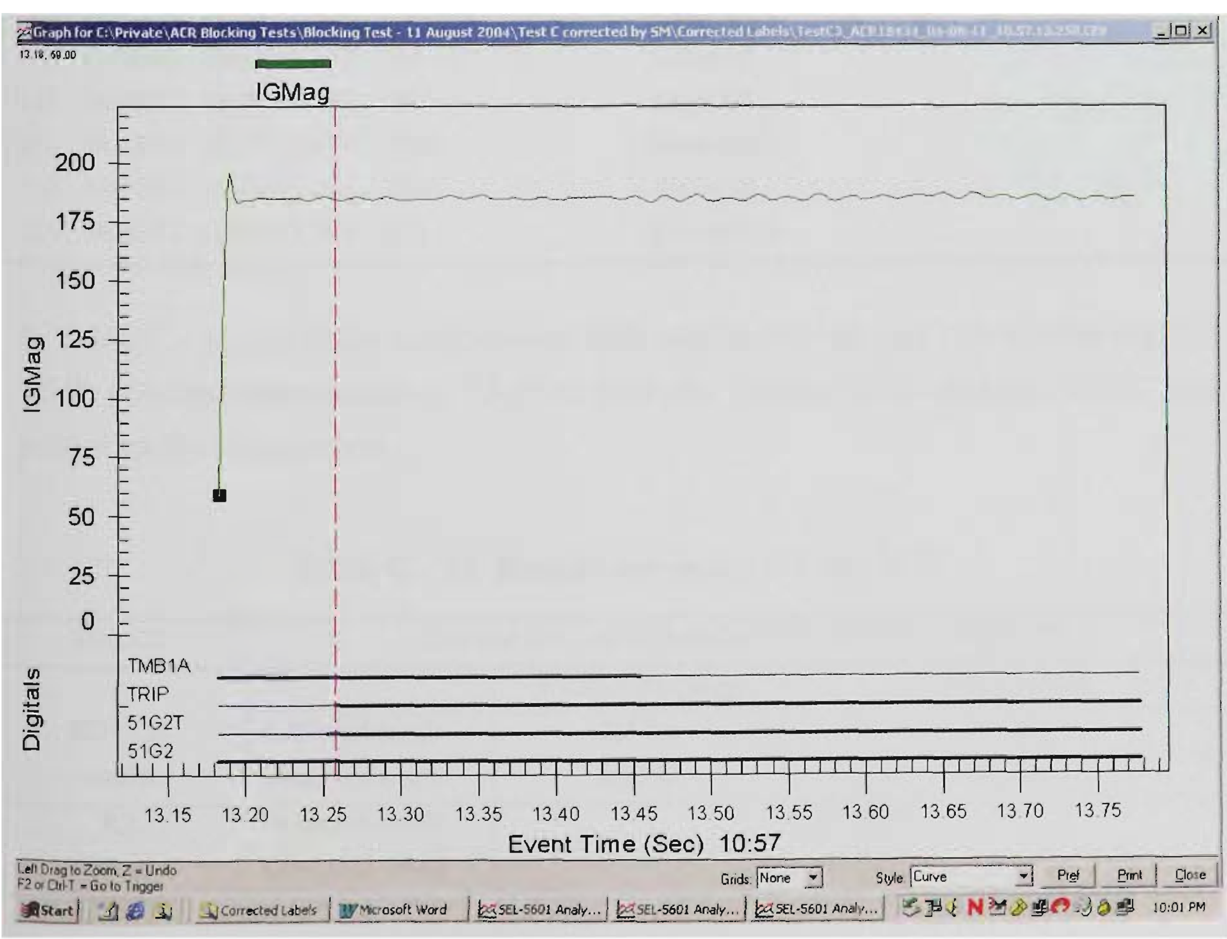


Figure C3_2_Event_3 R2 tripping on Ground O/C

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 13 and C - 14, excluding test C3_1, to verify the TRIP times. The summary of results is shown in Table C - 15.

Table C - 13 Test 'C3_2', SER from the BD7 CB - with blocking

171	04/08/11	10:57:10.443	51N1	Asserted
170	04/08/11	10:57:10.468	RMB1B	Asserted
169	04/08/11	10:57:13.707	51N1T	Asserted
168	04/08/11	10:57:14.456	51N1T	Deasserted
167	04/08/11	10:57:25.963	RMB1B	Deasserted

Table C - 13, shows that the Ground O/C element at the BD7 CB picked up the fault current but there was no TRIP due to the received blocking signal, RMB1B, relayed from the upstream recloser, R1.

Table C - 14 Test 'C3_2', SER from R2 – with blocking

120	04/08/11	10:56:57.958	51G2	Asserted
119	04/08/11	10:56:57.958	TMB1A	Asserted
118	04/08/11	10:57:13.253	51G2T	Asserted
117	04/08/11	10:57:13.258	79CY	Asserted
116	04/08/11	10:57:13.258	79RS	Deasserted
115	04/08/11	10:57:13.258	TRIP	Asserted
114	04/08/11	10:57:13.298	52A	Deasserted

In Table C - 14, the difference between SER entries No 120 and 115 verifies that the TRIP occurred approximately 15.300s after the Ground O/C element, 51G2, had picked up the fault current.

Table C - 15 Results summary for test 'C3'

Test C3	**Ground O/C on R2 blocks Ground O/C on BD7 CB**		
BD7 CB results		Without blocking	With blocking
	Expected result	3.279s	No trip
	Observed result	3.279s	No trip
R2 results	Expected result	16.200s	
	Observed result	15.300s	

C4 testing regime

Task

To block the BD7 CB, from tripping due to the Phase O/C pick up, with the blocking signal sent by the downstream recloser, R2, due to its Ground O/C pick up.

The testing set up is shown in Table C - 16.

Table C - 16 Set up for 'C4' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	1.2 times the E/F O/C setting	0.912 A	16.200s	Trips after 16.200s
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C OFF	Any phase element	4.0 times the Phase O/C setting	17 A	1.096s	BD7 CB Inverse Time Phase O/C element blocked. Trips on the back up Phase O/C only.

C4 testing

Test C4_1, no blocking

Secondary fault current of 17 A was injected into the Phase O/C element of the SEL351S relay at the BD7 CB.

Figure C4_1_Event_1 illustrates the Phase O/C pick up event at the BD7 CB. No blocking signal, RMB1B, was received from the upstream recloser, R1.

For brevity, the TRIP event is not illustrated for this test.

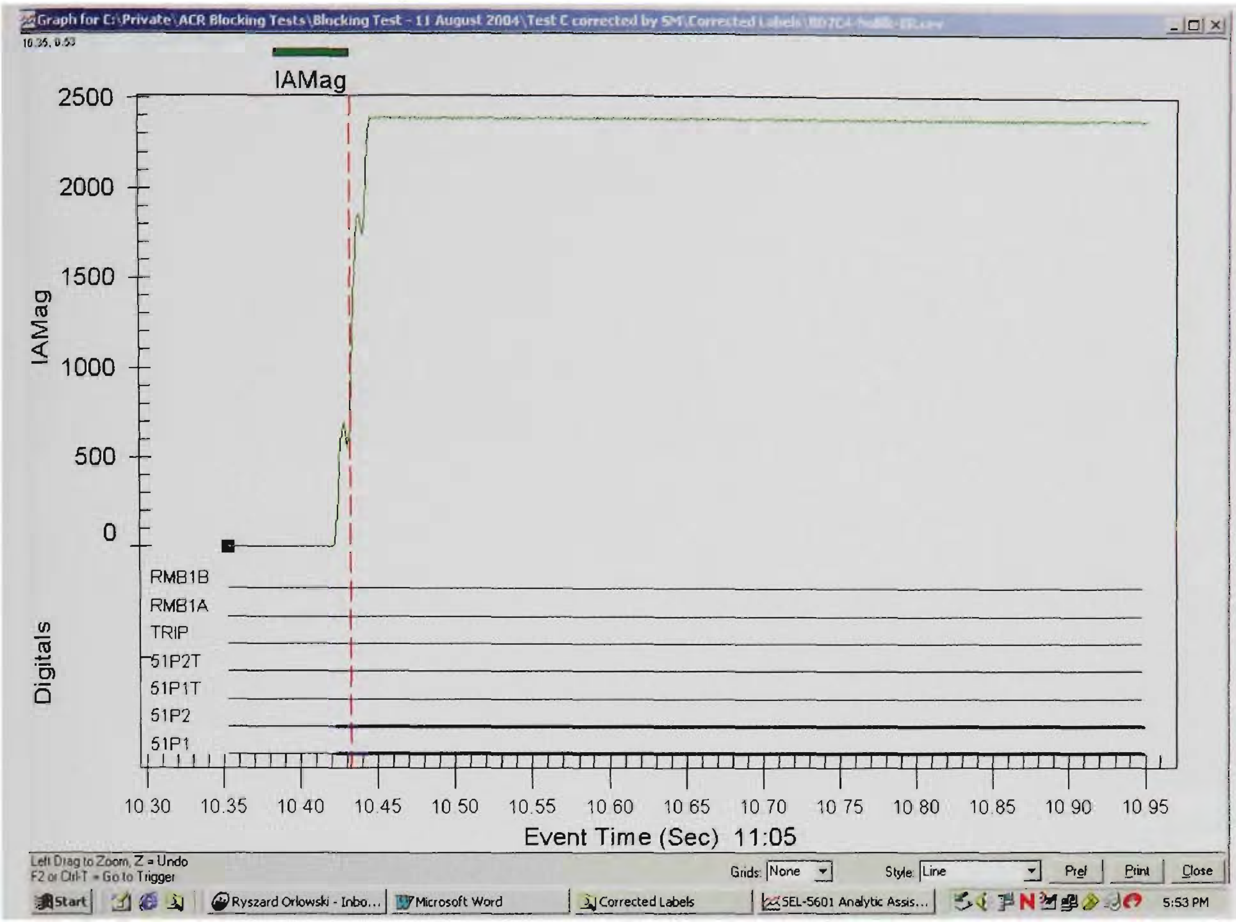


Figure C4_1_Event_1 Phase O/C pick up by the BD7 CB, no blocking

Test C4_2

Secondary fault currents of 17 A and 0.912 A were injected simultaneously into the Phase O/C element of the SEL351S relay at the BD7 CB and the Ground O/C element of the SEL351P relay at the downstream recloser, R2, respectively.

Figure C4_2_Event_1 shows that the Phase O/C elements, 51P1 and 51P2, at the BD7 CB picked up the fault current. As the Phase Time O/C elements, 51P1T and 51P2T, had not timed out yet and the blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not issue the TRIP command.

Figure C4_2_Event_2 illustrates that the Phase Time O/C elements, 51P1T and 51P2T, timed out at the BD7 CB due to the detected fault current. As the blocking signal, RMB1B, was received from the upstream recloser, R1, the BD7 CB did not TRIP on the blocked element, 51P1T. However, it did TRIP on the 'non-blocked' back up element, 51P2T.

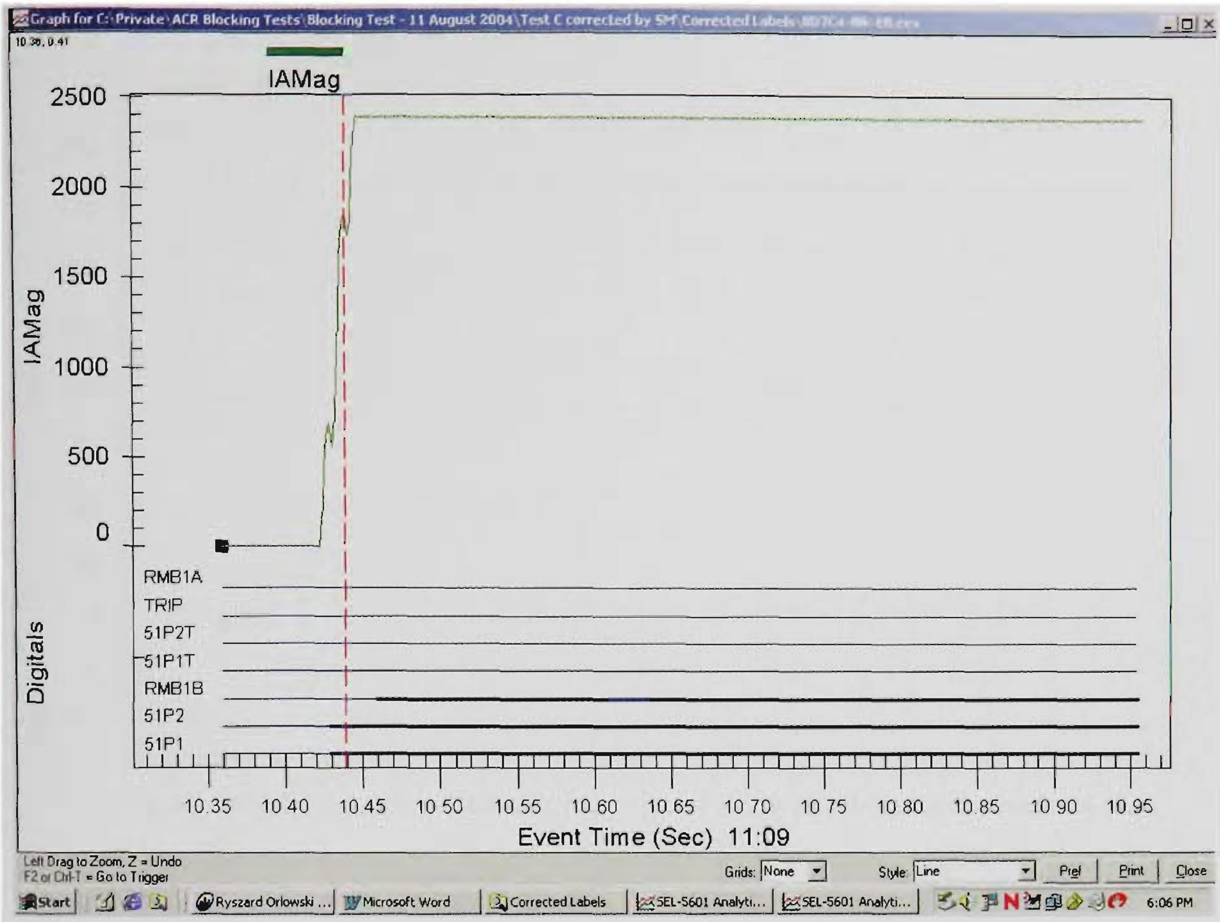


Figure C4_2_Event_1 BD7 CB blocked from tripping on Phase O/C

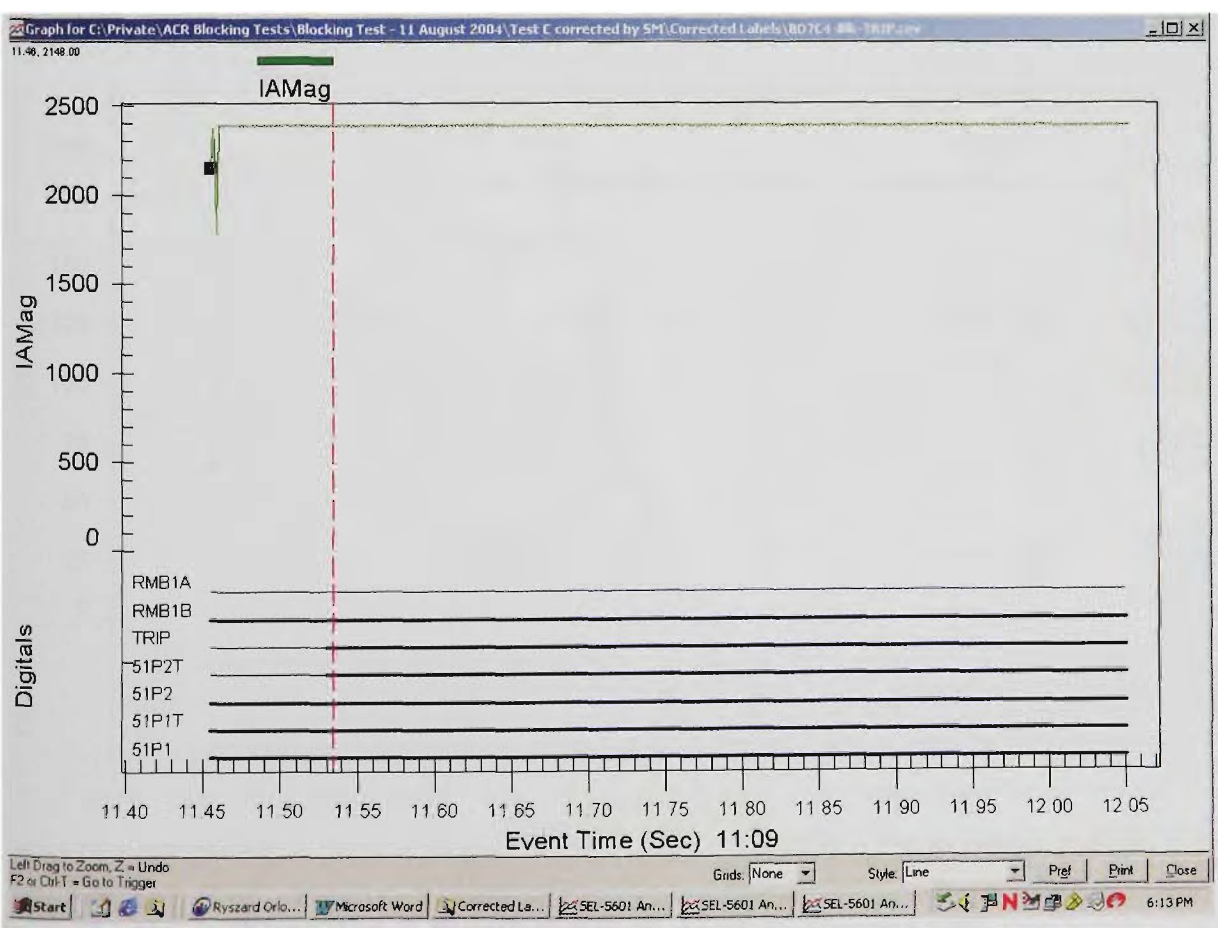


Figure C4_2_Event_2 TRIP of the BD7 CB on the back up Phase O/C element

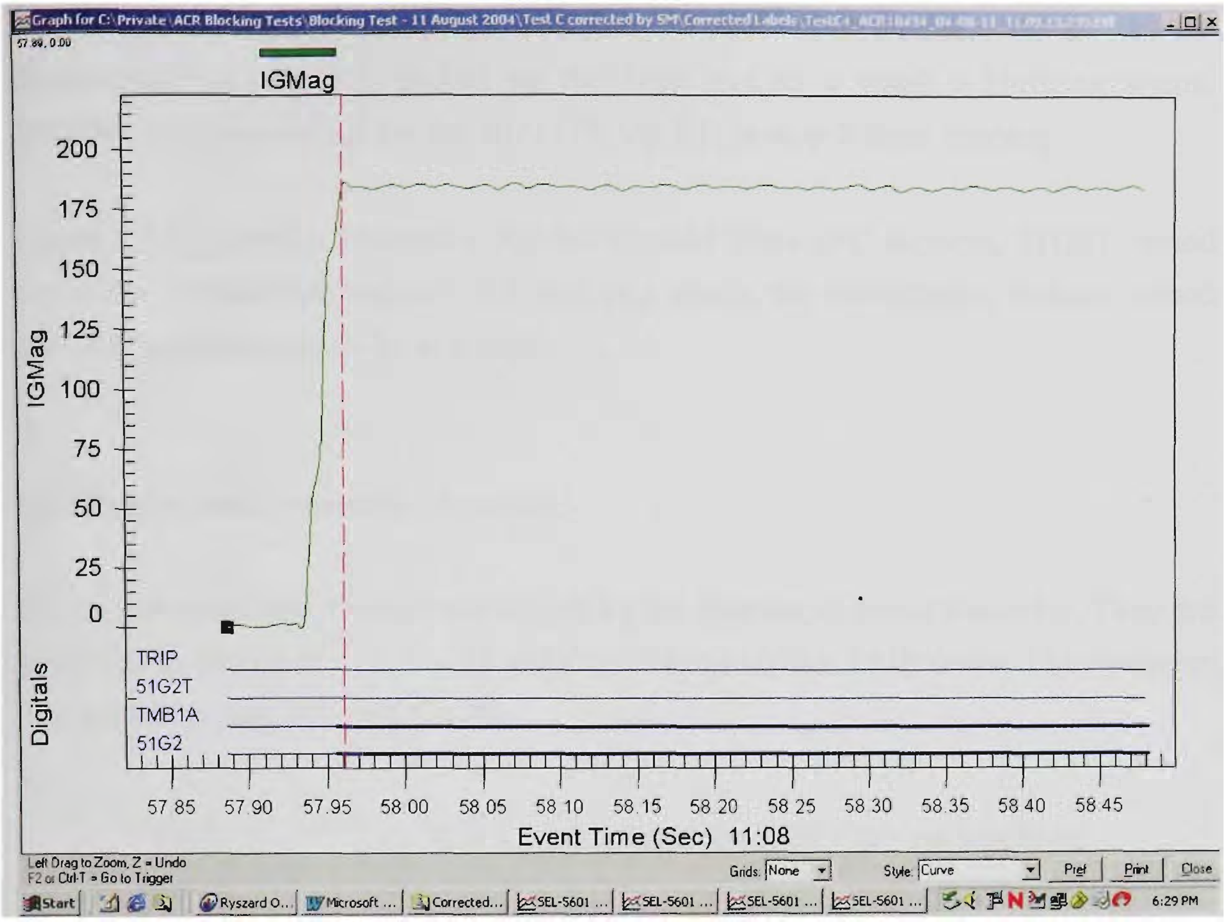


Figure C4_2_Event_3 Ground O/C pick up by R2, blocking signal transmitted

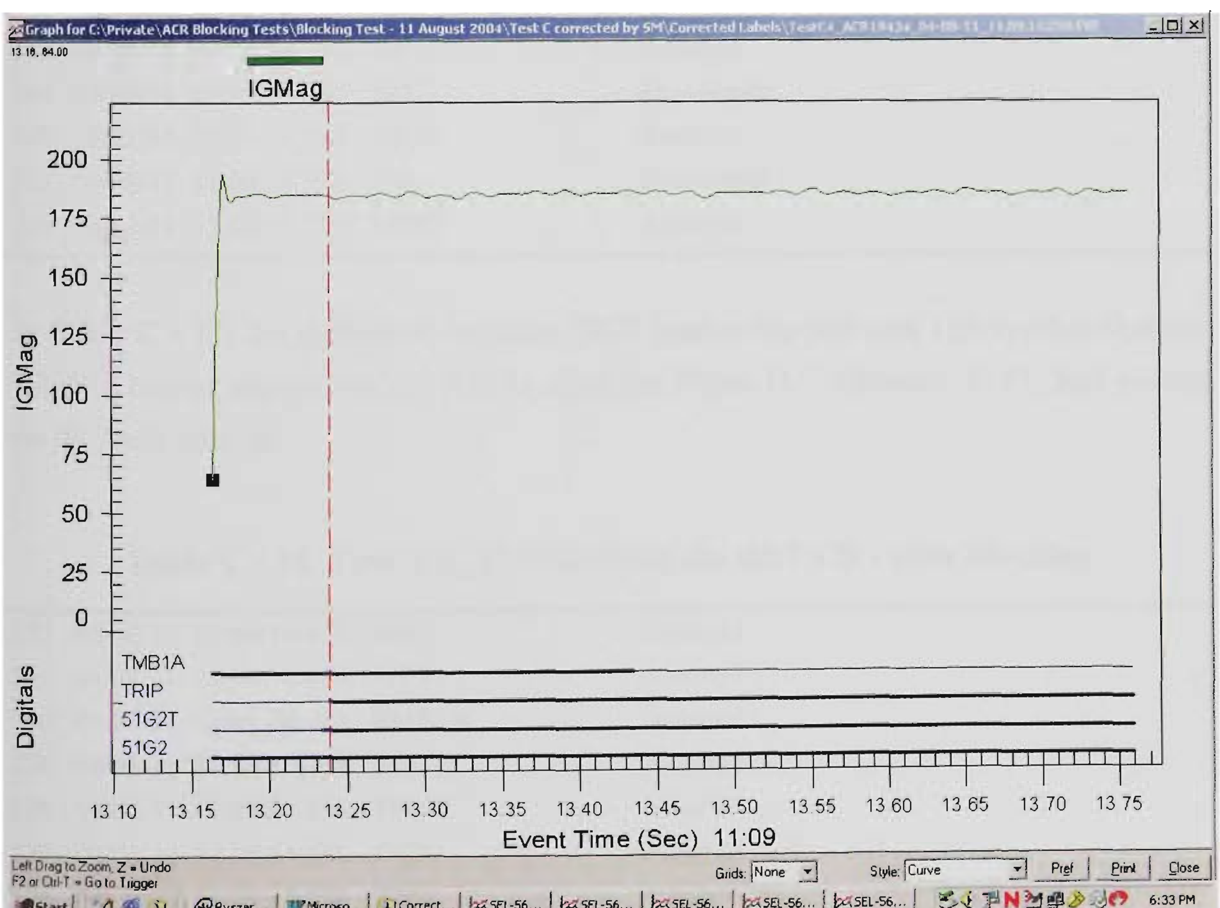


Figure C4_2_Event_4 R2 tripping on Ground O/C

Figure C4_2_Event_3 illustrates that the Ground O/C element, 51G2, at the downstream recloser R2, picked up the fault and as a result a blocking signal, TMB1A, was transmitted for the BD7 CB, via R1, to stop it from tripping.

Figure C4_2_Event_4 illustrates that the Ground Time O/C element, 51G2T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command to its local breaker.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 17, C - 18 and C - 19 to verify the TRIP times. The summary of results is shown in Table C - 20.

Table C - 17 Test 'C4_1', SER from the BD7 CB - no blocking

168	04/08/11	11:05:10.432	51P1	Asserted
167	04/08/11	11:05:10.432	51P2	Asserted
166	04/08/11	11:05:11.338	51P1T	Asserted
165	04/08/11	11:05:11.343	79CY	Asserted
164	04/08/11	11:05:11.343	79RS	Deasserted
163	04/08/11	11:05:11.343	TRIP	Asserted
162	04/08/11	11:05:11.378	52A	Deasserted
161	04/08/11	11:05:11.528	51P2T	Asserted

In Table C - 17, the difference between SER entries No 168 and 163 verifies that the TRIP occurred approximately 0.911s after the Phase O/C element, 51P1, had picked up the fault current.

Table C - 18 Test 'C4_2', SER from the BD7 CB - with blocking

132	04/08/11	11:09:10.438	51P1	Asserted
131	04/08/11	11:09:10.438	51P2	Asserted
130	04/08/11	11:09:10.463	RMB1B	Asserted
129	04/08/11	11:09:11.334	51P1T	Asserted
128	04/08/11	11:09:11.534	51P2T	Asserted
127	04/08/11	11:09:11.534	79CY	Asserted
126	04/08/11	11:09:11.534	79RS	Deasserted
125	04/08/11	11:09:11.534	TRIP	Asserted
124	04/08/11	11:09:11.569	52A	Deasserted

In Table C - 18, the difference between SER entries No 131 and 125 verifies that the TRIP occurred approximately 1.096s after the back up Phase O/C element, 51P2, had picked up the fault current. The time out of the primary Phase Time O/C element, 51P1T, did not cause the TRIP as it was blocked by the blocking signal, RMB1B.

Table C - 19 Test 'C4_2', SER from R2

98	04/08/11	11:08:57.956	51G2	Asserted
97	04/08/11	11:08:57.956	TMB1A	Asserted
96	04/08/11	11:09:13.233	51G2T	Asserted
95	04/08/11	11:09:13.239	79CY	Asserted
94	04/08/11	11:09:13.239	79RS	Deasserted
93	04/08/11	11:09:13.239	TRIP	Asserted
92	04/08/11	11:09:13.279	52A	Deasserted

In Table C - 19, the difference between SER entries No 98 and 93 verifies that the TRIP occurred approximately 15.283s after the Ground O/C element, 51G2, had picked up the fault current.

Table C - 20 Results summary for 'C4' testing

Test C4	Ground O/C on R2 blocks Phase O/C on BD7 CB		
BD7 CB results		Without blocking	With blocking
	Expected result	1.096s	Trip due to the back up element at 1.286s, i.e. in additional 0.190s[3]
	Observed result	0.911 s	Trip due to the back up element at 1.096s, i.e. in additional 0.185s
R2 results	Expected result	16.200s	
	Observed result	15.283s	

[3] Arbitrarily chosen value to be smaller than 200ms, i.e. for protection coordination this value needs to be smaller than the breaker failure time

C5 testing regime

Task

To prove that SEF on the downstream recloser, R2, does not block the Phase O/C or Ground O/C on the BD7 CB.

The testing set up is shown in Table C - 21.

Table C - 21 Set up for 'C5' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F ON SEF ON CB Closed	SEF element	2 times the SEF setting	0.072 A	1.0s DT	Trip on SEF after 1.0s.
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed Inst O/C OFF	E/F element	4.0 times the E/F setting	10.0 A	0.765s	Trip on E/F element after 0.765s. No blocking.

C5 testing

Test C5_1, no blocking

Secondary fault current of 10A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

Figure C5_1_Event_1 illustrates the event in which the Ground O/C element, 51N1, picked up at the BD7 CB due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser.

For brevity, the TRIP event is not illustrated for this test.

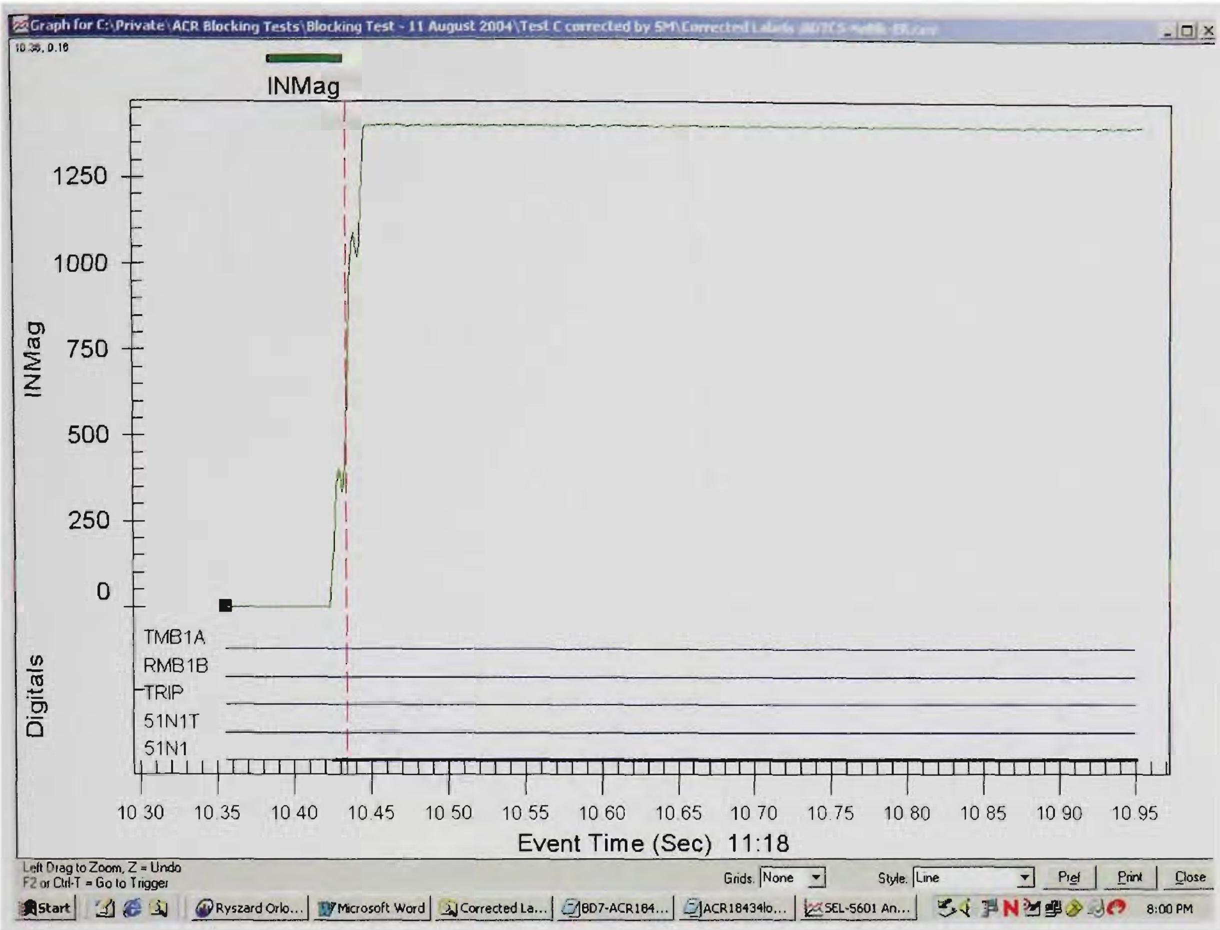


Figure C5_1_Event 1 BD7 CB, Ground O/C pick up, no blocking

Test C5_2

Secondary fault currents of 10A and 0.072A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the downstream recloser, R2, respectively.

Figure C5_2_Event_1 shows that the Ground O/C element, 51N1, picked up the fault current at the BD7 CB. As the Ground Time O/C element, 51N1T, timed out, the TRIP occurred. Blocking signal, RMB1B, was not received from the upstream recloser, R1, as per design specification.

Figure C5_2_Event_2 illustrates that the SEF O/C element, 51N3, picked up the SEF at the downstream recloser, R2. No blocking signal was transmitted as per design specifications.

Figure C5_2_Event_3 illustrates that the SEF Time O/C element, 51N3T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command. No blocking signal was transmitted.

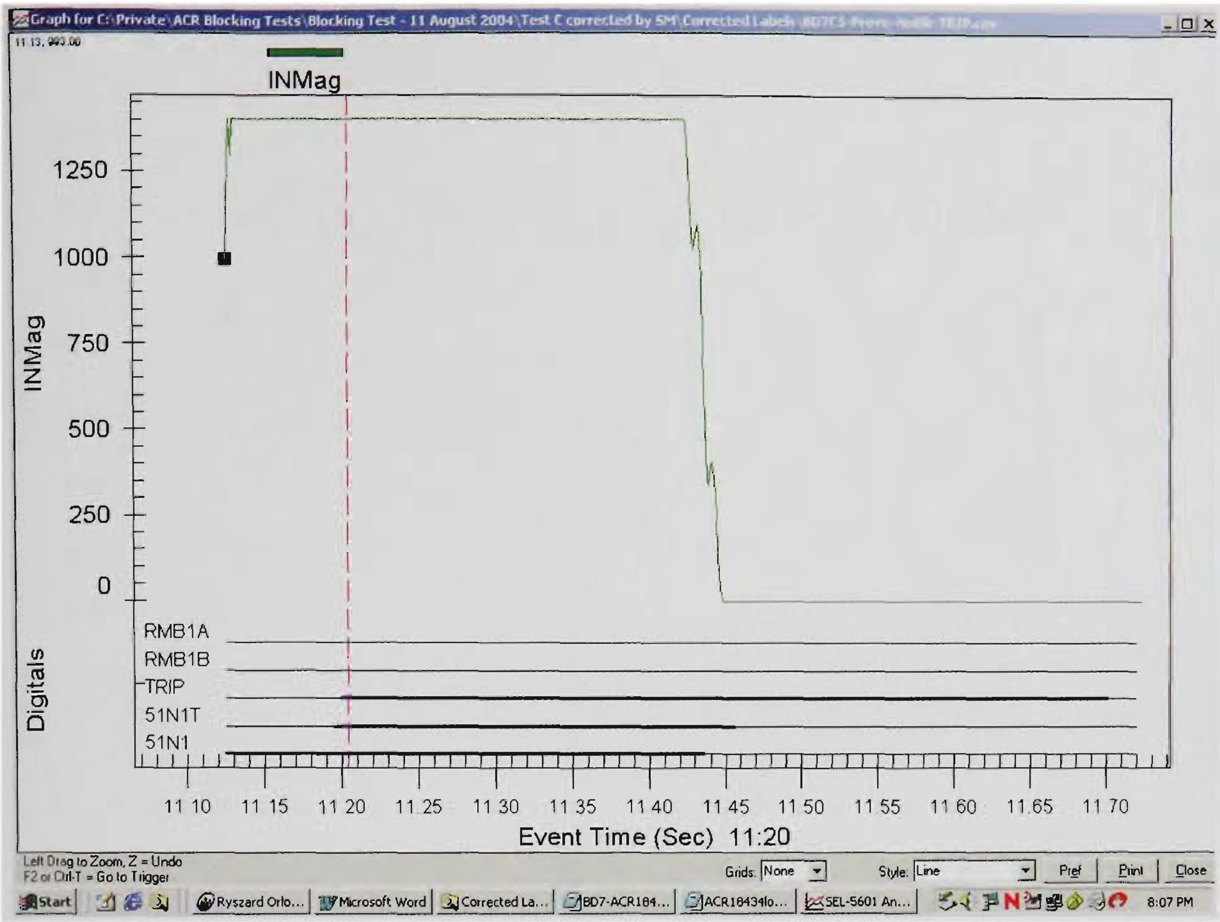


Figure C5_2_Event_1 TRIP on Ground O/C at BD7 CB, no blocking

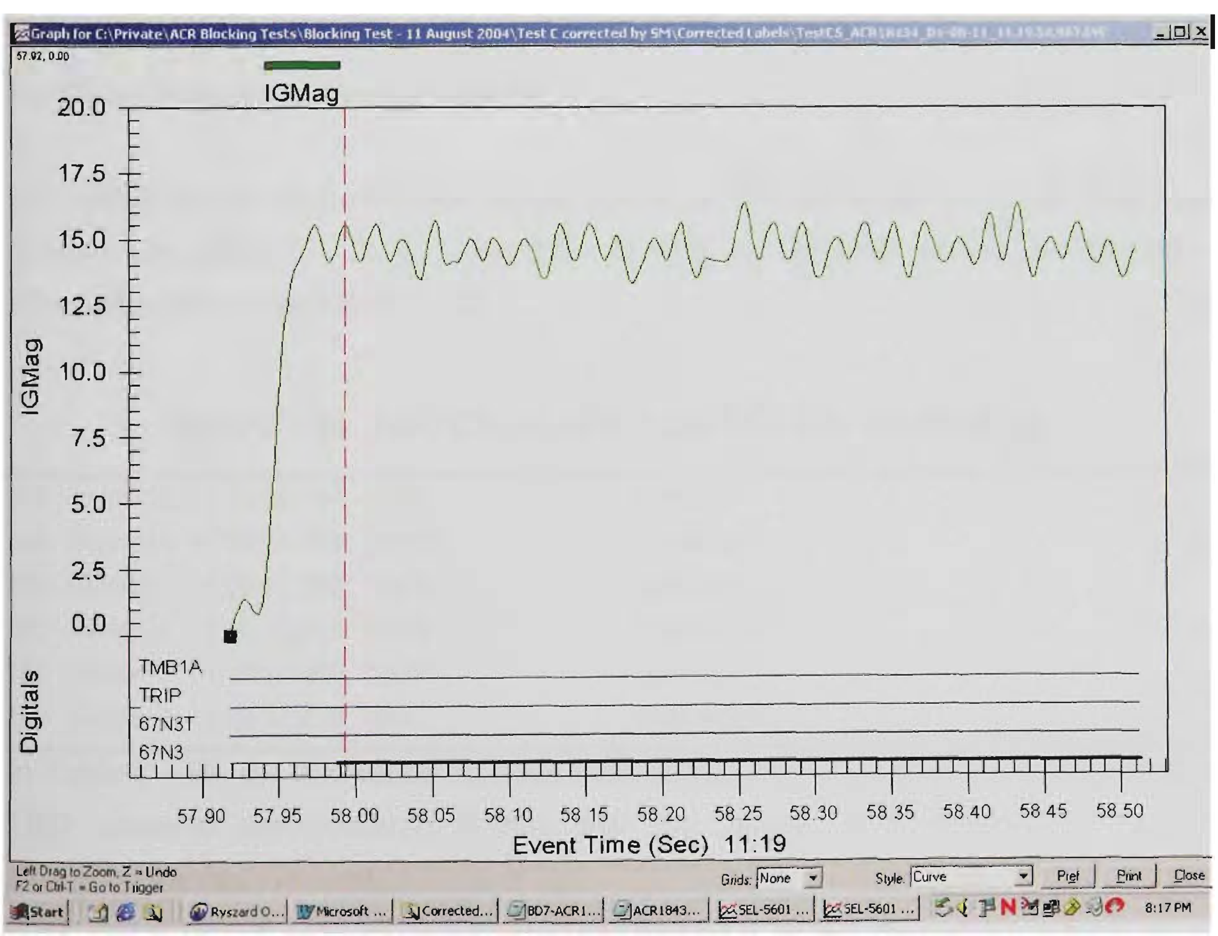


Figure C5_2_Event_2 SEF pick up by R2

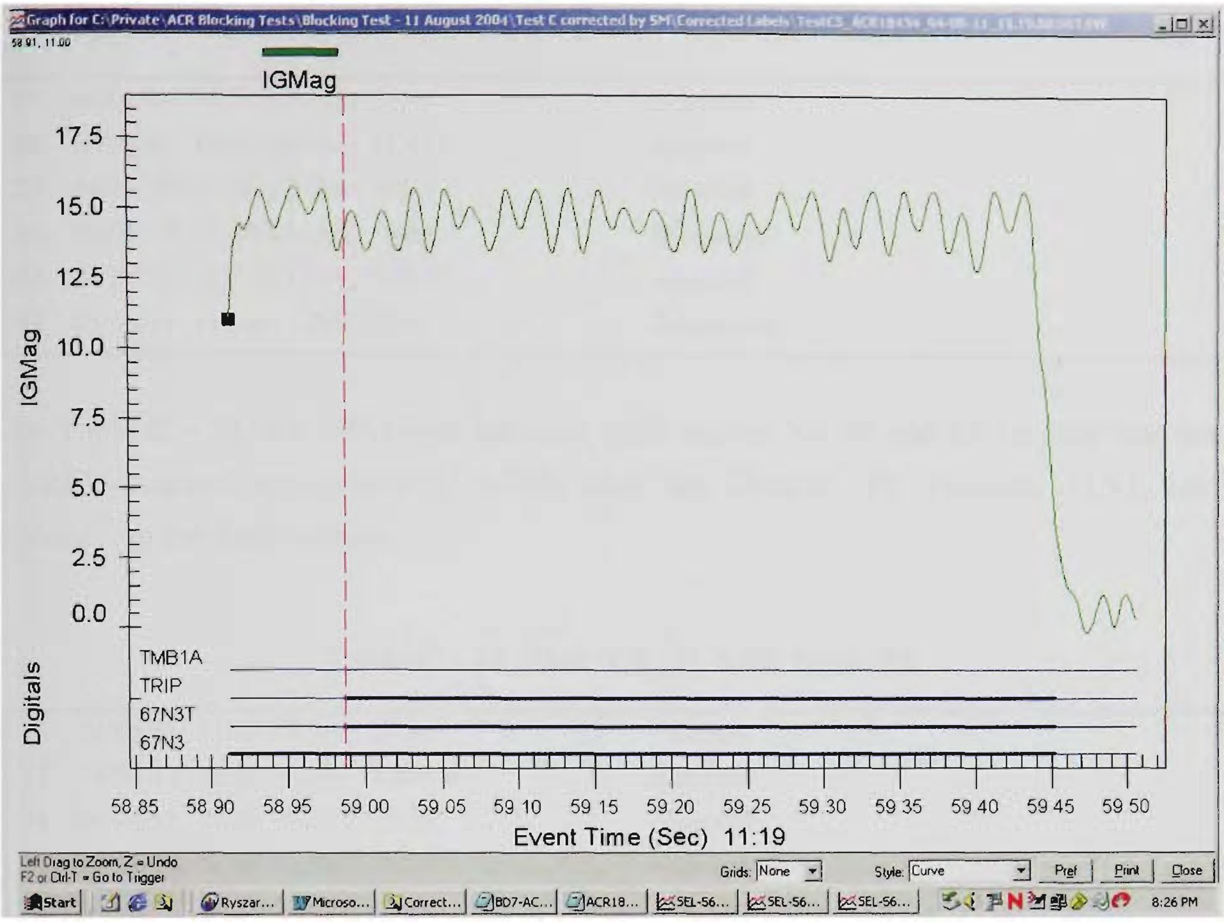


Figure C5_2_Event_3 Tripping of R2 due to the SEF

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 22, C - 23 and C - 24 to verify the TRIP times. The summary of results is shown in Table C - 25.

Table C - 22 Test 'C5_1', SER from BD7 CB - no blocking

105	04/08/11	11:18:10.434	51N1	Asserted
104	04/08/11	11:18:11.198	51N1T	Asserted
103	04/08/11	11:18:11.203	79CY	Asserted
102	04/08/11	11:18:11.203	79RS	Deasserted
101	04/08/11	11:18:11.203	TRIP	Asserted
100	04/08/11	11:18:11.238	52A	Deasserted

In Table C - 22, the difference between SER entries No 105 and 101 verifies that the TRIP occurred approximately 0.769s after the Ground O/C element, 51N1, had picked up the fault current.

Table C - 23 Test 'C5_2', SER from BD7 CB – proving there is no blocking

89	04/08/11	11:20:10.435	51N1	Asserted
88	04/08/11	11:20:11.199	51N1T	Asserted
87	04/08/11	11:20:11.204	79CY	Asserted
86	04/08/11	11:20:11.204	79RS	Deasserted
85	04/08/11	11:20:11.204	TRIP	Asserted
84	04/08/11	11:20:11.239	52A	Deasserted

In Table C - 23, the difference between SER entries No 89 and 85 verifies that the TRIP occurred approximately 0.769s after the Ground O/C element, 51N1, had picked up the fault current.

Table C - 24 Test 'C5_2', SER from R2

76	04/08/11	11:19:57.988	67N3	Asserted
75	04/08/11	11:19:58.987	67N3T	Asserted
74	04/08/11	11:19:58.987	79CY	Asserted
73	04/08/11	11:19:58.987	79RS	Deasserted
72	04/08/11	11:19:58.987	TRIP	Asserted
71	04/08/11	11:19:59.027	52A	Deasserted

In Table C - 24, the difference between SER entries No 76 and 72 verifies that the TRIP occurred approximately 0.999s after SEF element, 67N3, had picked up the fault current.

Table C - 25 Results summary for 'C5' testing

Test C5	**SEF on R2 does not block Ground O/C on BD7 CB**		
BD7 CB results		Without blocking	With blocking
	Expected result	0.765s	No blocking
	Observed result	0.769s	No blocking
R2 results	Expected result	Trip in 1.000s	
	Observed result	Trip in 0.999s	

C6 testing regime

Task

To prove that the Phase O/C or Ground O/C on the downstream recloser, R2, do not block Instantaneous O/C on the BD7 CB.

The testing set up is shown in Table C - 26.

Table C - 26 Set up for 'C6' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F OFF SEF OFF CB Closed	Any phase element	2.5 times the Phase O/C setting	3.75 A	1.710s	Trip after 1.710s.
BD7 CB	Prot ON Reclose ON E/F OFF SEF OFF CB Closed Inst O/C ON	Any phase element	Just above minop	45.0 A	0.100s DT	Trip on Inst O/C after 0.100s.

C6 testing

Test C6_1, no blocking

Secondary fault current of 45A was injected into the Instantaneous Phase O/C element of the SEL351S relay at the BD7 CB.

Figure C6_1_Event_1 illustrates the event in which the Instantaneous Phase O/C element, 67P1, picked up at the BD7 CB due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1. The Instantaneous Phase Time O/C element, 67P1T, timed out followed by the TRIP.

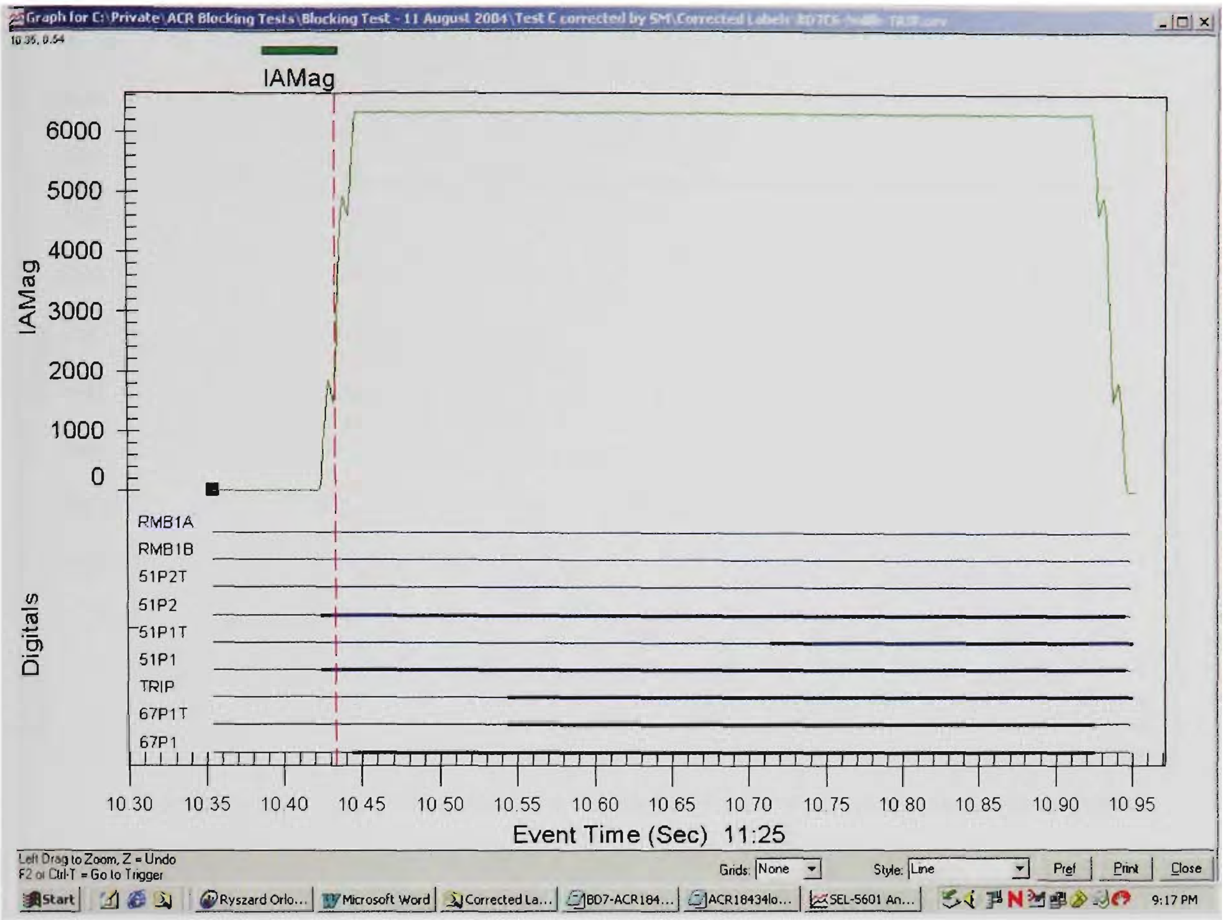


Figure C6_1_Event_1 BD7 CB, Instantaneous Phase O/C pick up and TRIP, no blocking

Test C6_2

Secondary fault currents of 45A and 3.75A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the downstream recloser, R2, respectively.

For brevity, the C6_2 events pertinent to the BD7 CB testing component are not illustrated here. As the testing procedure and results are the same as in the B6_2 testing pertinent to the BD7 CB, for details the reader is referred to the B6_2 testing in Appendix 'B'. The C6_2 events pertinent to the R2 testing component are illustrated below.

Figure C6_2_Event_1 illustrates that the Phase O/C element, 51P2, picked up the fault current at the downstream recloser, R2. Blocking signal, TMB1A, was transmitted. The Phase Time O/C element, 51P2T, had not timed out yet. Thus, the downstream recloser, R2, did not issue the TRIP command.

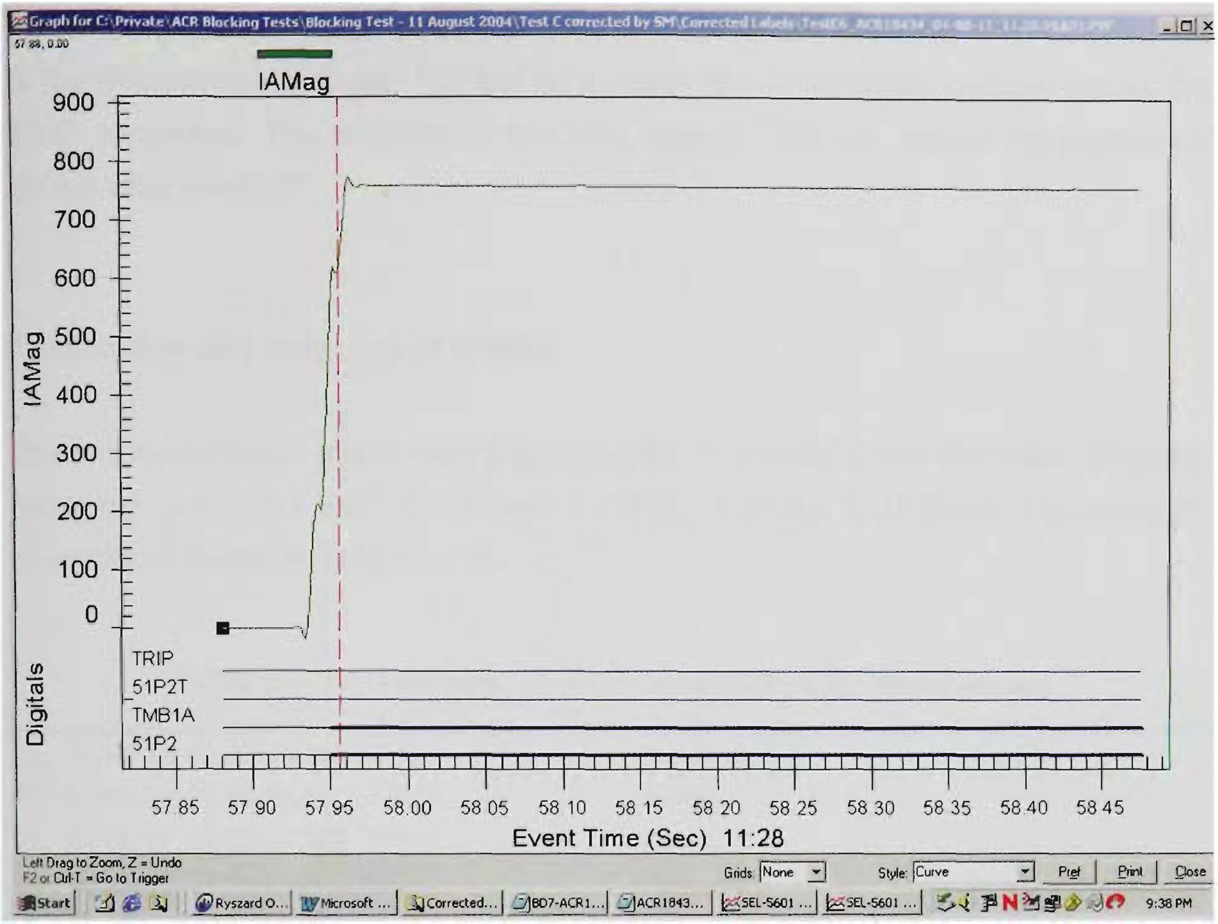


Figure C6_2_Event_1 Phase O/C pick up by R2

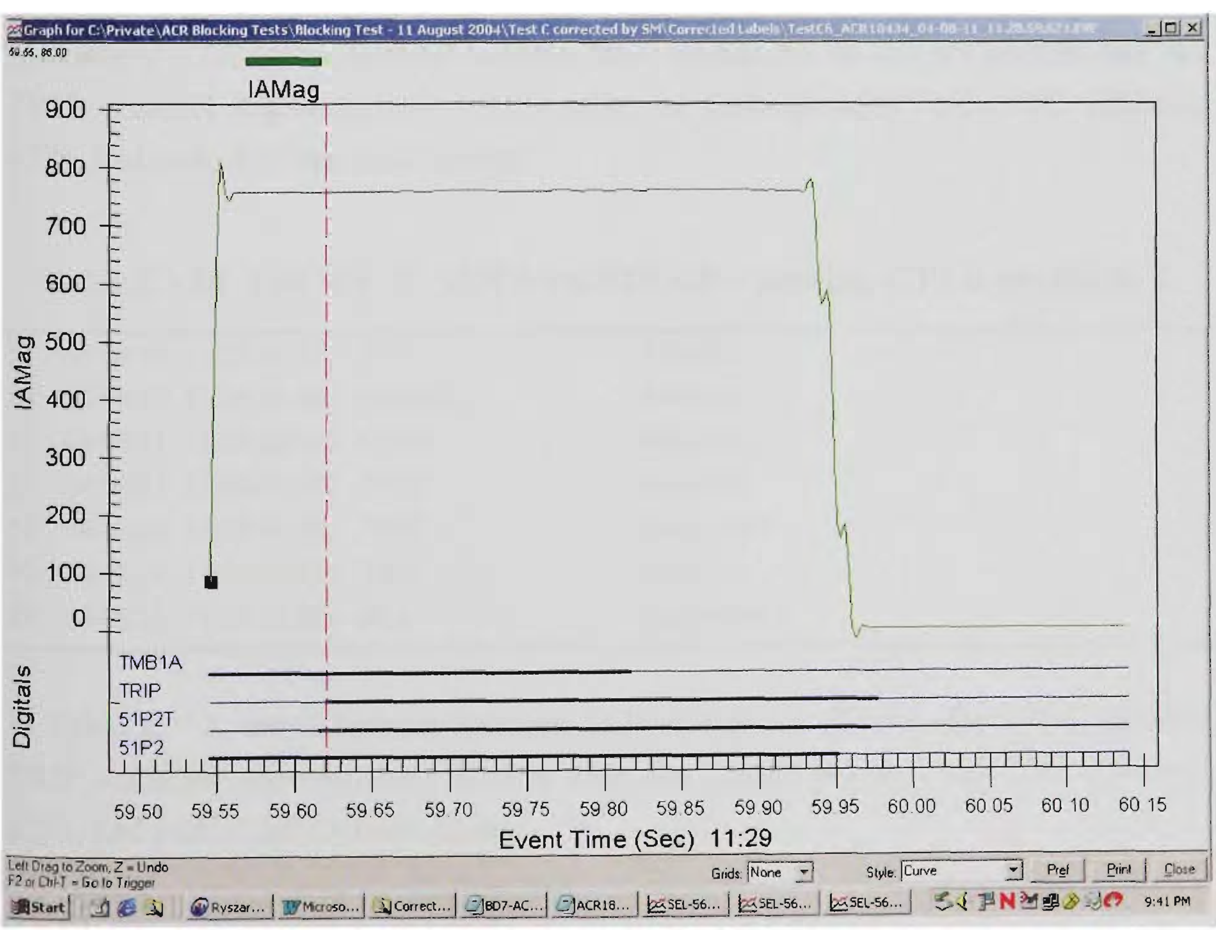


Figure C6_2_Event_2 Tripping of R2 due to the Phase O/C

Figure C6_2_Event_2 illustrates that the Phase Time O/C element, 51P2T, timed out at the downstream recloser, R2, and as a result, the downstream recloser issued the TRIP command. The transmitted blocking signal, TMB1A, ceased approximately 200ms after the TRIP.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 27, C - 28 and C - 29 to verify the TRIP times. The summary of results is shown in Table C - 30.

Table C - 27 Test 'C6_1', SER from BD7 CB - no blocking

73	04/08/11	11:25:10.433	67P1	Asserted
72	04/08/11	11:25:10.548	67P1T	Asserted
71	04/08/11	11:25:10.548	79CY	Asserted
70	04/08/11	11:25:10.548	79RS	Deasserted
69	04/08/11	11:25:10.548	TRIP	Asserted
68	04/08/11	11:25:10.583	52A	Deasserted

In Table C - 27, the difference between SER entries No 73 and 69 verifies that the TRIP occurred approximately 0.115s after the Instantaneous Phase O/C element, 67P1, had picked up the fault current.

Table C - 28 Test 'C6_2', SER from BD7 CB – proving 67P1 is not blocked

55	04/08/11	11:29:10.431	67P1	Asserted
54	04/08/11	11:29:10.462	RMB1B	Asserted
53	04/08/11	11:29:10.546	67P1T	Asserted
52	04/08/11	11:29:10.546	79CY	Asserted
51	04/08/11	11:29:10.546	79RS	Deasserted
50	04/08/11	11:29:10.546	TRIP	Asserted
49	04/08/11	11:29:10.581	52A	Deasserted

In Table C - 1, the difference between SER entries No 55 and 50 verifies that the TRIP occurred approximately 0.115s after the Instantaneous Phase O/C element, 67P1, had picked up the fault current.

Table C - 29 Test 'C6_2', SER from R2

58	04/08/11	11:28:57.951	51P2	Asserted
57	04/08/11	11:28:57.951	TMB1A	Asserted
56	04/08/11	11:28:59.616	51P2T	Asserted
55	04/08/11	11:28:59.621	79CY	Asserted
54	04/08/11	11:28:59.621	79RS	Deasserted
53	04/08/11	11:28:59.621	TRIP	Asserted
52	04/08/11	11:28:59.661	52A	Deasserted

In Table C - 29, the difference between SER entries No 58 and 53 verifies that TRIP occurred approximately 1.670s after Phase O/C element, 51P2, had picked up the fault current.

Table C - 30 Results summary for 'C6' testing

Test C6	**Phase O/C on R2 does not block Instantaneous Phase O/C on BD7 CB**		
BD7 CB results		Without blocking	With blocking
	Expected result	0.100s	No blocking
	Observed result	0.115s	No blocking
R2 results	Expected result	Trip in 1.710s	
	Observed result	Trip in 1.670s	

C7 testing regime

Task

To prove that the Ground O/C on the downstream recloser, R2, blocks Phase O/C and Ground O/C on the BD7 CB. To test breaker fail feature at R2.

The testing set up is shown in Table C - 31.

Table C - 31 Set up for 'C7' testing

Relay at	Relay pushbuttons	Current leads	Fault current	Actual secondary current injected	Expected trip time without blocking	Expected results
R2 18434	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	10 times the E/F setting	7.6 A	0.360s	Trip after 0.360s. However, the fault current is kept on for at least 200ms
BD7 CB	Prot ON Reclose ON E/F ON SEF OFF CB Closed	E/F element	10 times the E/F setting	25 A	0.255s	E/F element blocked by R2. Trip 200ms after R2 trips due to the blocking signal having been removed

C7 testing

Test C7_1, no blocking

Secondary fault current of 25A was injected into the Ground O/C element of the SEL351S relay at the BD7 CB.

Figure C7_1_Event_1 illustrates the event in which the Ground O/C element, 51N1, picked up at the BD7 CB due to the fault current. No blocking signal, RMB1B, was received from the upstream recloser, R1. The Ground Time O/C element, 51N1T, timed out followed by the TRIP.

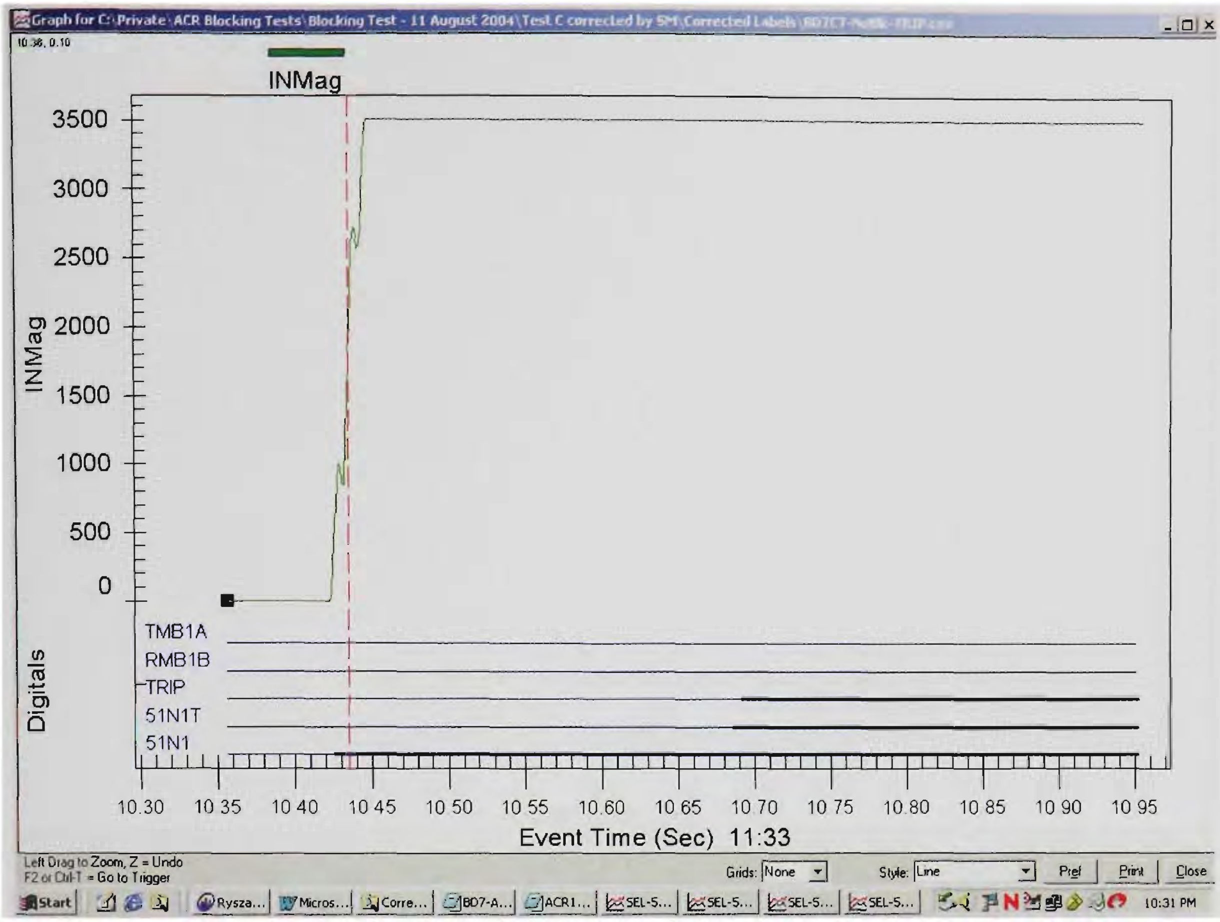


Figure C7_1_Event_1 BD7 CB, Ground O/C pick up and TRIP, no blocking

Test C7_2

Secondary fault currents of 25A and 7.6A were injected simultaneously into the SEL351S relay at the BD7 CB and into the SEL351P relay at the downstream recloser, R2, respectively.

Figure C7_2_Event_1 shows that the Ground O/C element, 51N1, picked up the fault current at the BD7 CB. The Ground Time O/C element, 51N1T, did time out but there was no TRIP due to the blocking signal, RMB1B, received from the upstream recloser, R1.

Figure C7_2_Event_2 illustrates that the Ground Time O/C element, 51N1T, timed out but the TRIP occurred only when the blocking signal, RMB1B, was removed by the upstream recloser, R1, due to its or R2's local breaker failure timer time out, i.e. after 200ms.

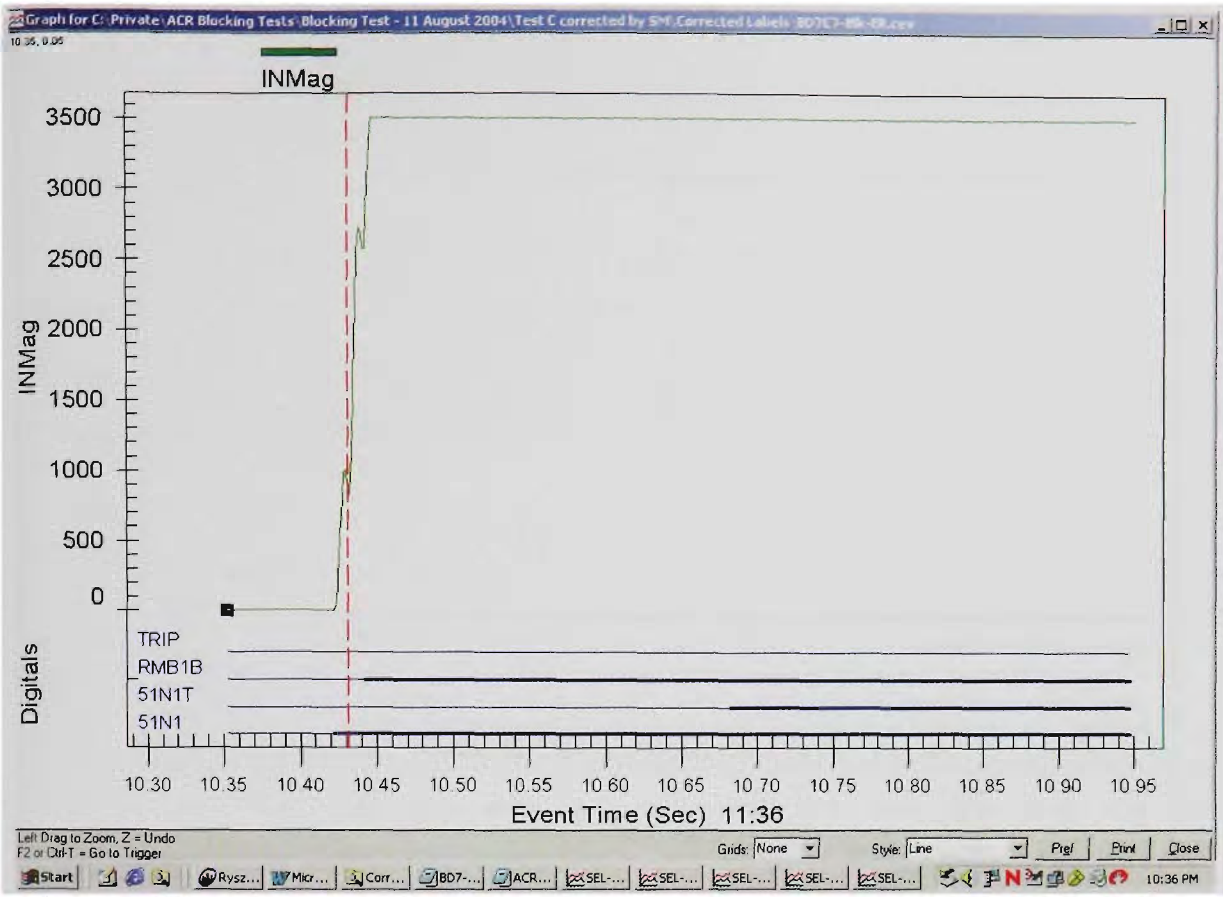


Figure C7_2_Event_1 Ground O/C pick up followed by blocking at BD7 CB

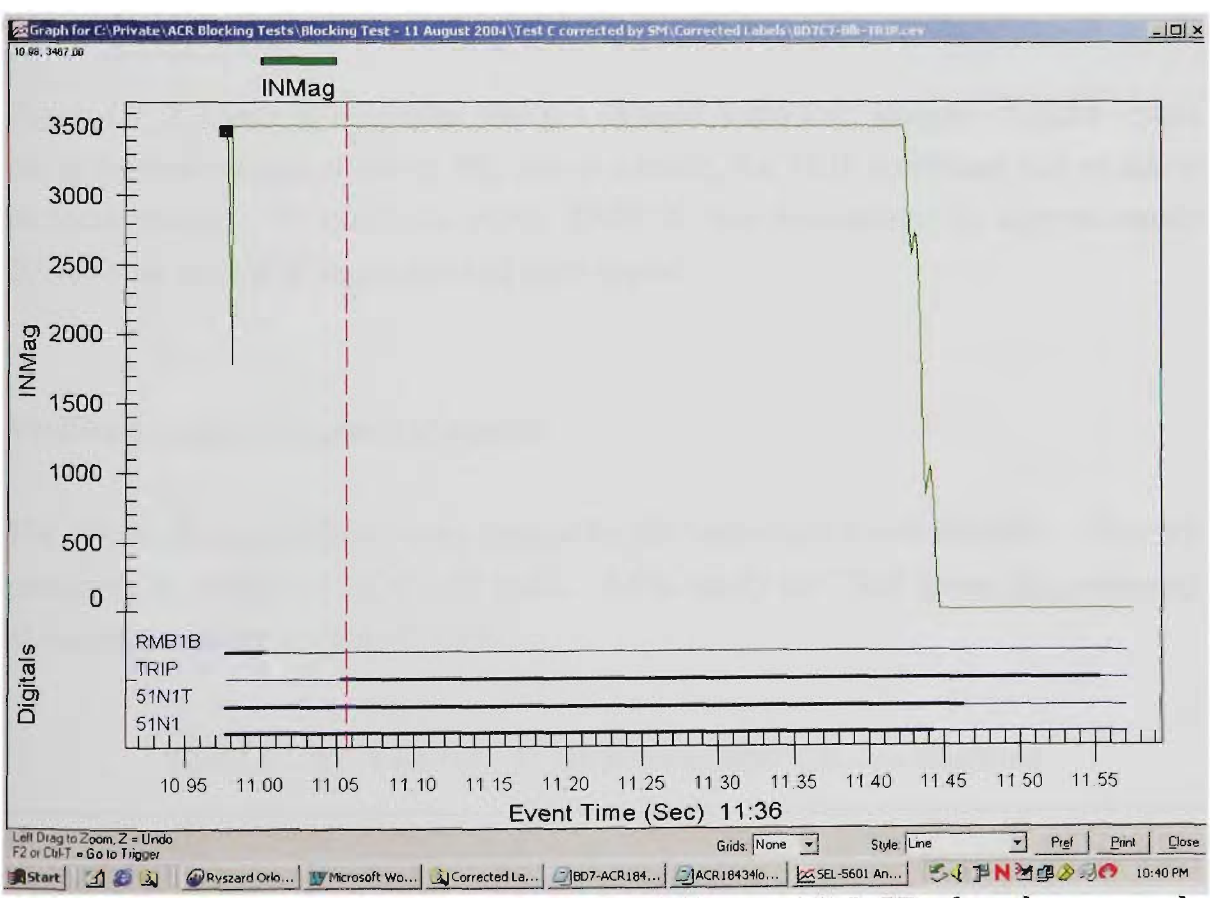


Figure C7_2_Event_2 TRIP on Ground O/C by the BD7 CB after the removal of the blocking signal

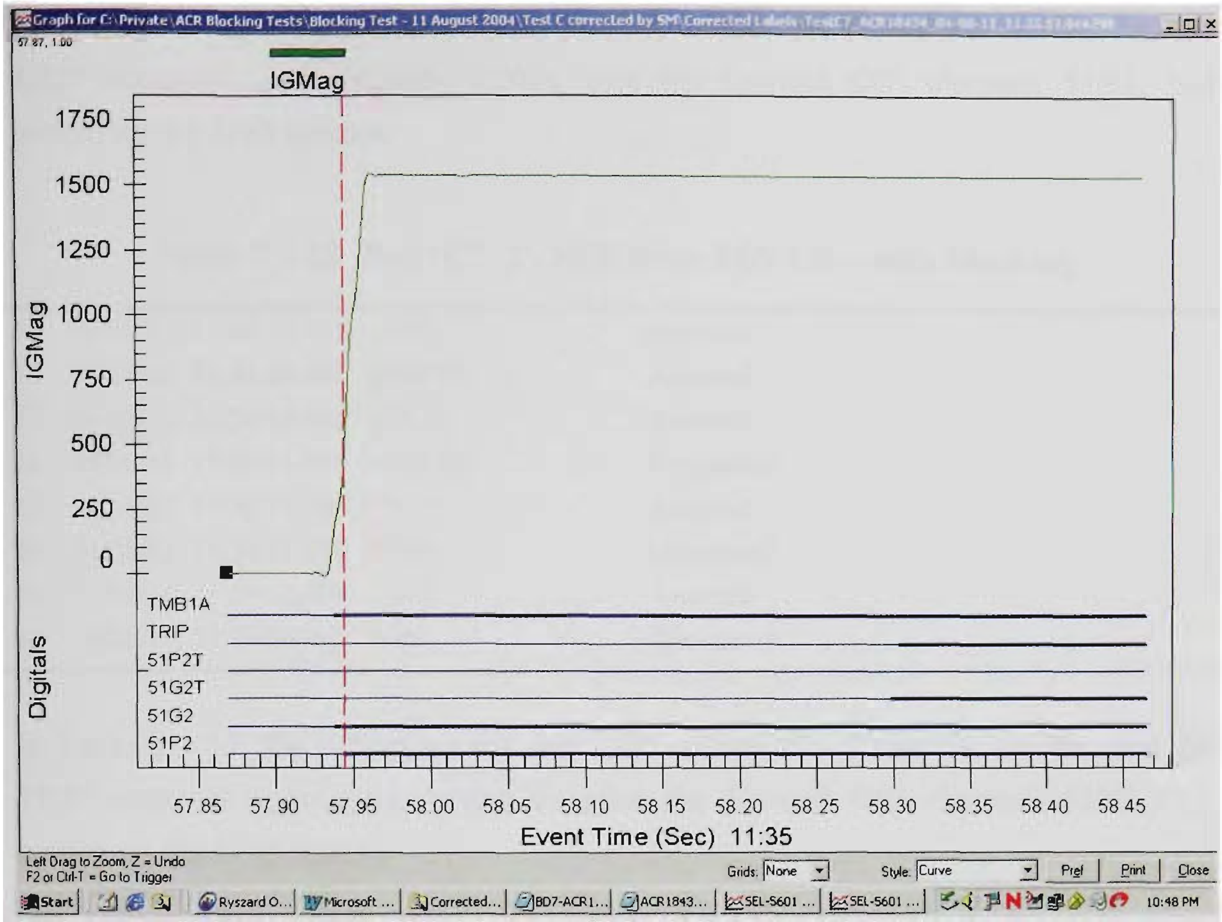


Figure C7_2_Event_3 Tripping of R2 due to the Ground O/C

Figure C7_2_Event_3 illustrates that the Ground Time O/C element, 51G2T, timed out at the downstream recloser, R2, and as a result, the TRIP command was issued to its local breaker. The blocking signal, TMB1A, was transmitted for approximately 200ms after the TRIP command had been issued.

Verification and summary of results

The events discussed above were logged by the Sequential Event Recorder. They are presented in Tables C - 32, C - 33 and C - 34 to verify the TRIP times. The summary of results is shown in Table C - 35.

Table C - 32 Test 'C7_1', SER from BD7 CB - no blocking

35	04/08/11	11:33:10.435	51N1	Asserted
34	04/08/11	11:33:10.690	51N1T	Asserted
33	04/08/11	11:33:10.695	79CY	Asserted
32	04/08/11	11:33:10.695	79RS	Deasserted
31	04/08/11	11:33:10.695	TRIP	Asserted
30	04/08/11	11:33:10.730	52A	Deasserted

In Table C - 32, the difference between SER entries No 35 and 31 verifies that the TRIP occurred approximately 0.260s after the Ground O/C element, 51N1, had picked up the fault current.

Table C - 33 Test 'C7_2', SER from BD7 CB – with blocking

19	04/08/11	11:36:10.431	51N1	Asserted
18	04/08/11	11:36:10.446	RMB1B	Asserted
17	04/08/11	11:36:10.686	51N1T	Asserted
16	04/08/11	11:36:11.006	RMB1B	Deasserted
15	04/08/11	11:36:11.056	79CY	Asserted
14	04/08/11	11:36:11.056	79RS	Deasserted
13	04/08/11	11:36:11.056	TRIP	Asserted
12	04/08/11	11:36:11.091	52A	Deasserted

In Table C - 33, the difference between SER entries No 19 and 13 verifies that the TRIP occurred approximately 0.625s after the Ground O/C element, 51N1, had picked up the fault current.

Table C - 34 Test 'C7_2', SER from R2

36	04/08/11	11:35:57.939	51G2	Asserted
35	04/08/11	11:35:57.939	TMB1A	Asserted
34	04/08/11	11:35:57.944	51P2	Asserted
33	04/08/11	11:35:58.299	51G2T	Asserted
32	04/08/11	11:35:58.304	79CY	Asserted
31	04/08/11	11:35:58.304	79RS	Deasserted
30	04/08/11	11:35:58.304	TRIP	Asserted
29	04/08/11	11:35:58.344	52A	Deasserted
28	04/08/11	11:35:58.499	SV2T	Asserted
27	04/08/11	11:35:58.499	TMB1A	Deasserted
26	04/08/11	11:35:58.564	51P2T	Asserted
25	04/08/11	11:35:58.959	51G2	Deasserted
24	04/08/11	11:35:58.959	51P2	Deasserted
23	04/08/11	11:35:58.979	51G2T	Deasserted
22	04/08/11	11:35:58.979	51P2T	Deasserted
21	04/08/11	11:35:58.979	SV2T	Deasserted
20	04/08/11	11:35:58.984	TRIP	Deasserted

In Table C - 34, the difference between SER entries No 36 and 30 verifies that the TRIP command was issued approximately 0.365s after Ground O/C element, 51G2, had picked up the fault current. The difference between SER entries No 33 and 27 verifies that the breaker failure timer timed out after 200ms.

Table C - 35 Results summary for 'C7' testing

Test C7	Ground O/C on R2 blocks Ground O/C on BD7 CB and tests breaker failure feature at R2		
BD7 CB results		Without blocking	With blocking
	Expected result	0.255s	Trip in 0.560s[4]
	Observed result	0.260s	Trip in 0.625s
R2 results	Expected result	Trip in 0.360s	
	Observed result	Trip in 0.365s	

[4] Trip time

Appendix 'D'

AGLE coverage area and single line diagrams

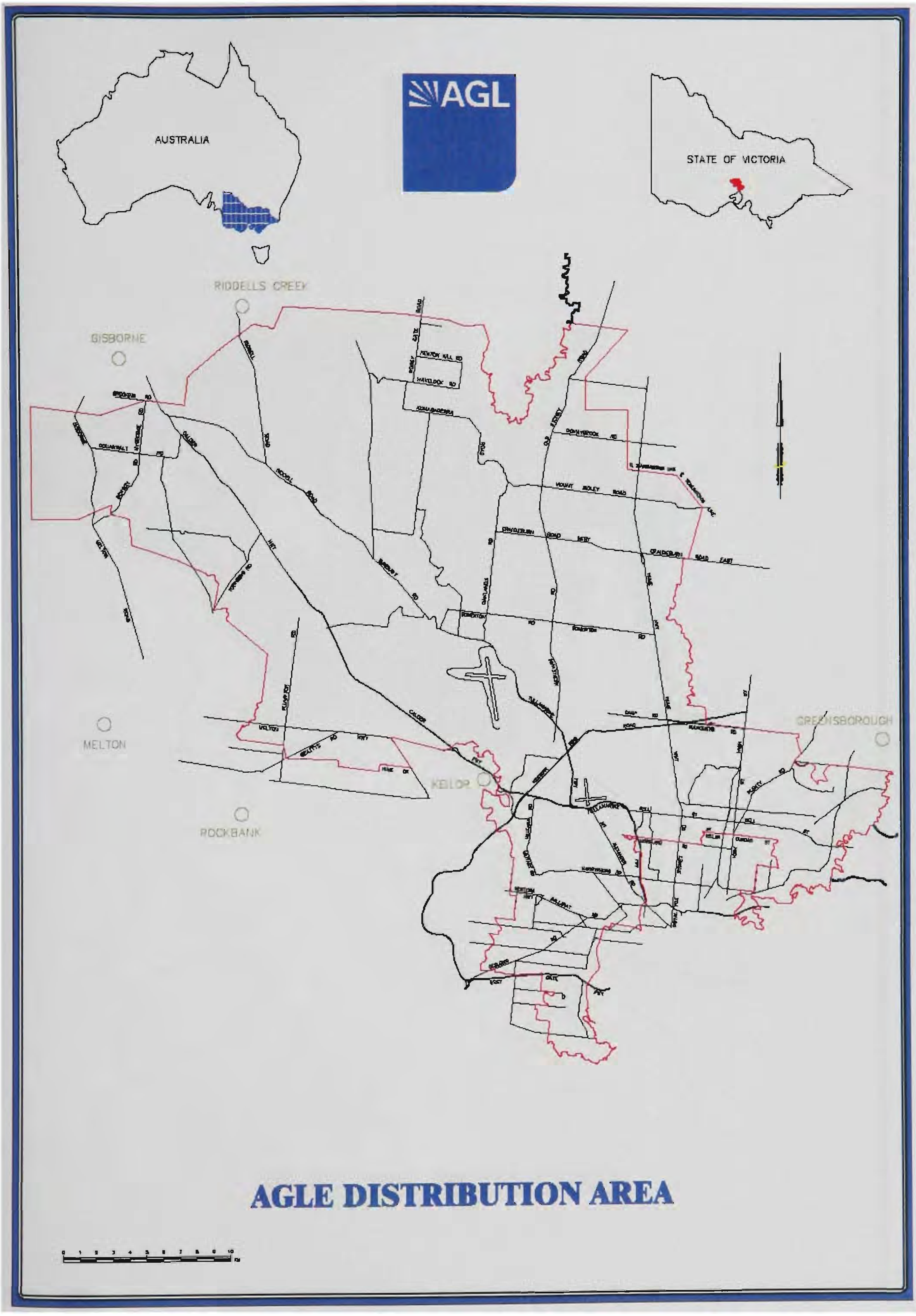


Figure D.1 Boundary of AGLE distribution area

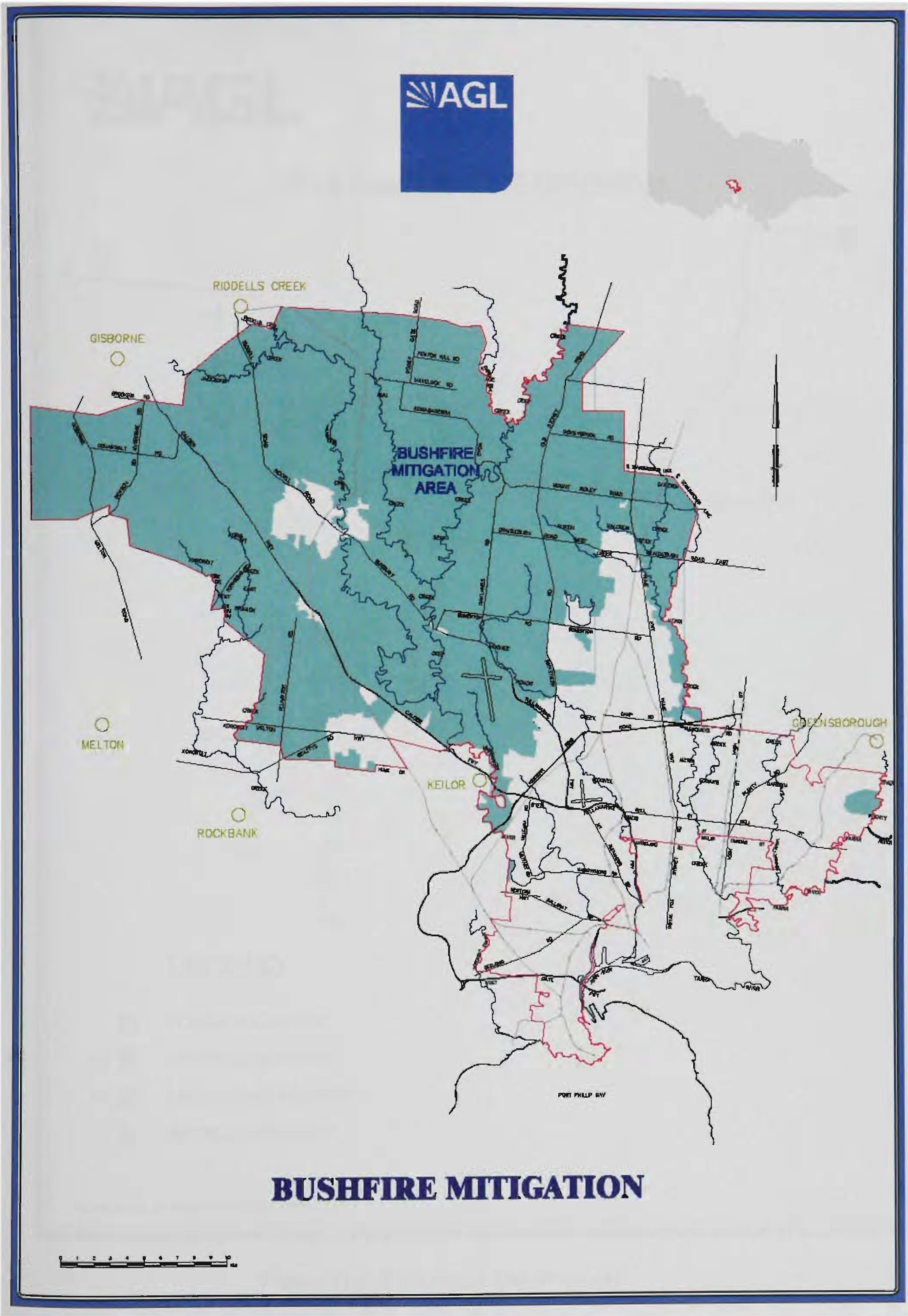


Figure D.2 Bushfire mitigation areas within AGLE coverage area

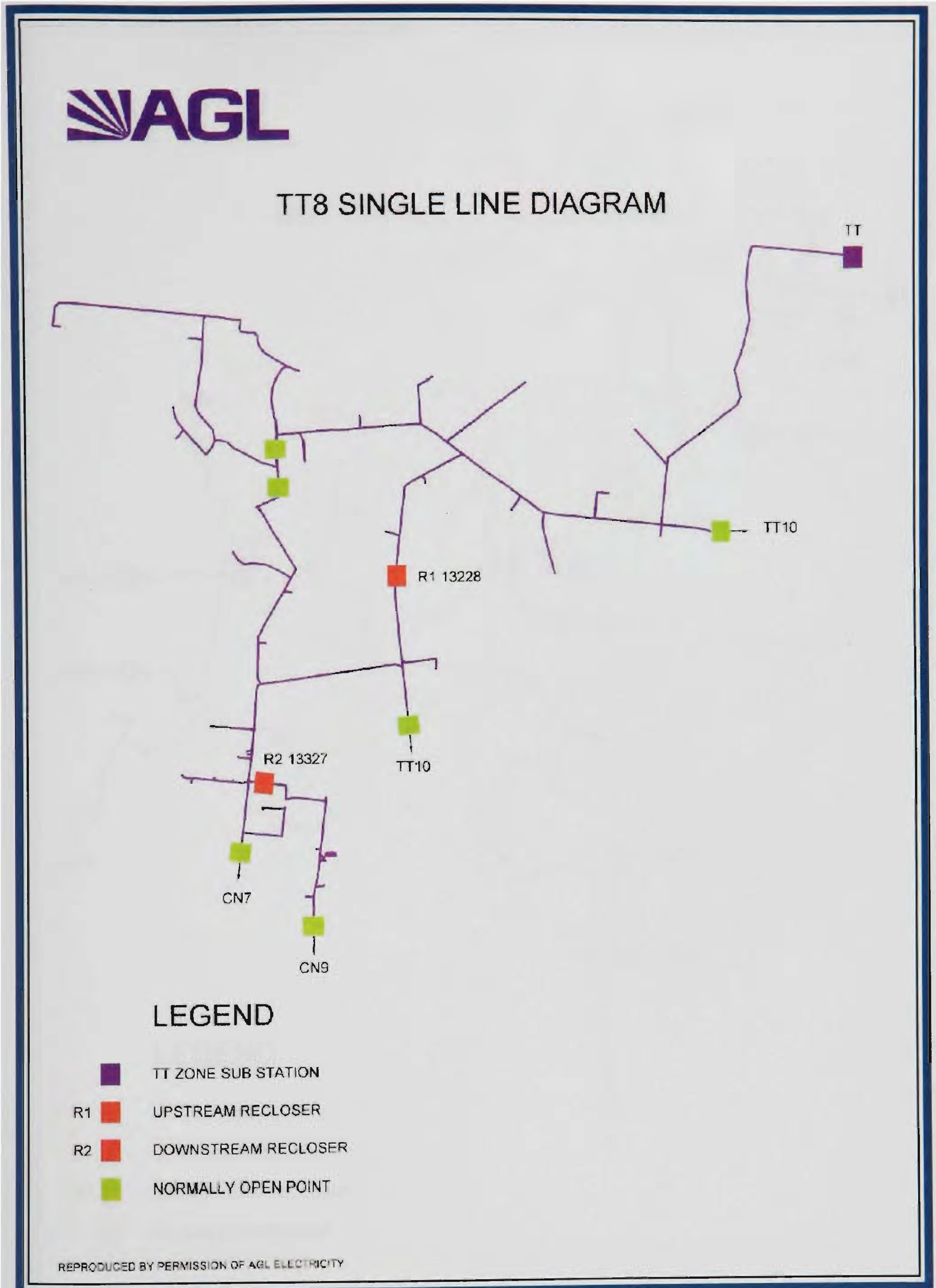


Figure D.3 TT8 single line diagram

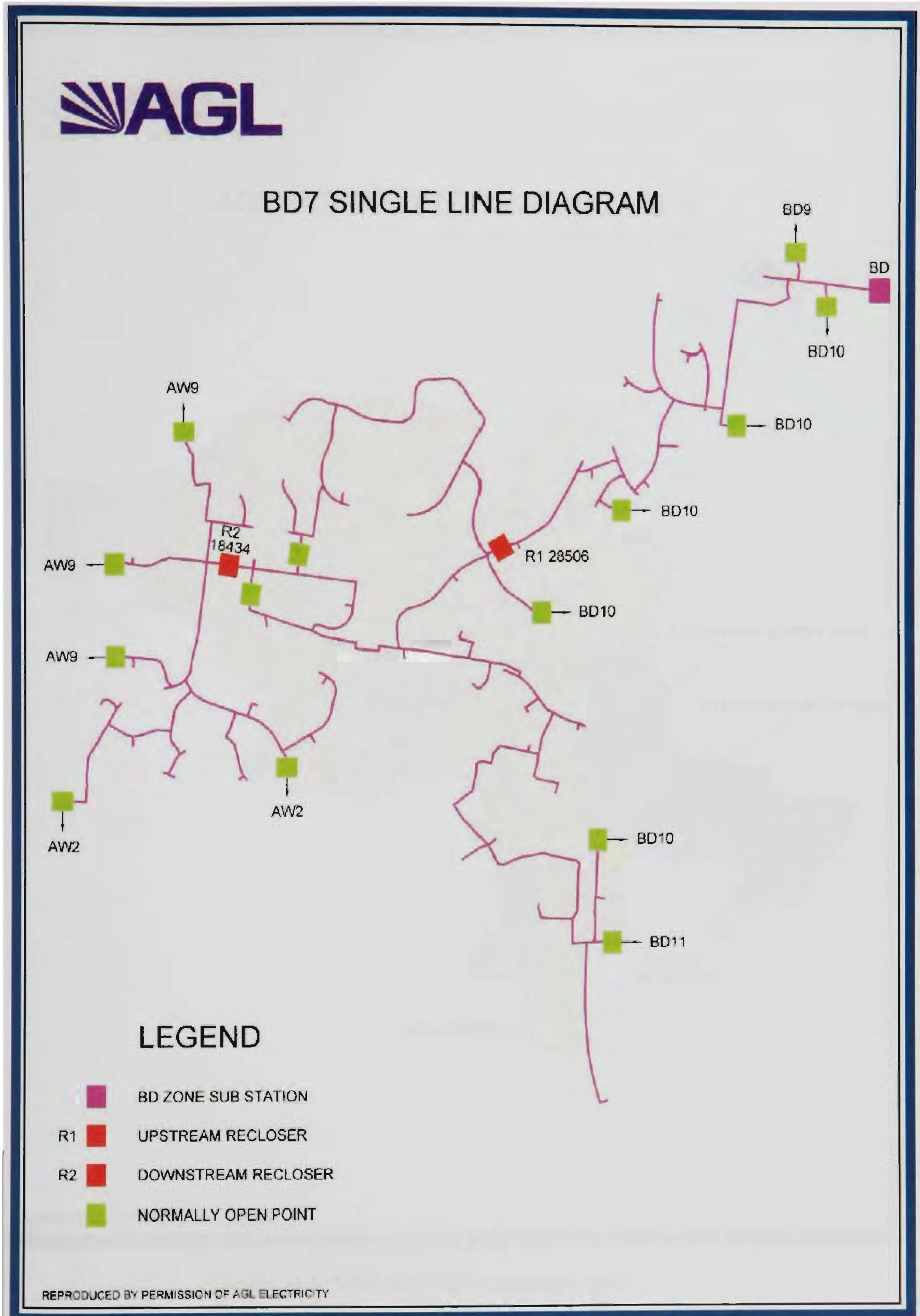


Figure D.4 BD7 single line diagram

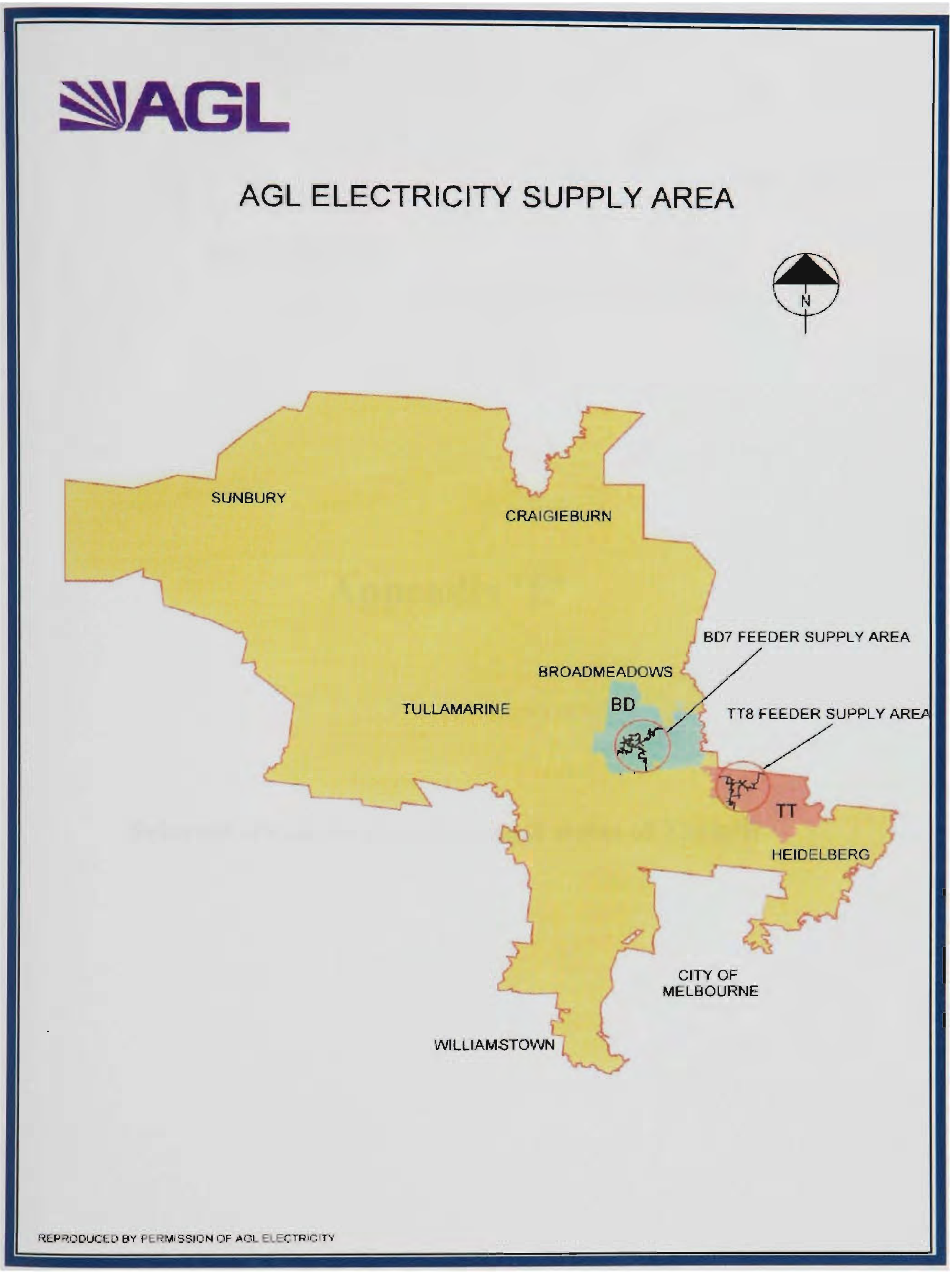


Figure D.5 BD7 and TT8 coverage area

Appendix 'E'

Selected scenarios depicting logic states of TMB1B

Selected scenarios depicting logic states of the upstream recloser Transmitted Mirrored Bit 1 (TMB1B)

The following part of the discussion is based on 11 scenarios listed below. In all of these scenarios three assumptions have been made:

- Glitches in communications are shorter than 40ms, i.e. timer T4 is idle.
- Only sustained P/F and/or E/F are taken into consideration.
- There are no faults occurring simultaneously in different feeder sections.

Scenario 1: no fault, no block, protection suppressed

Scenario 1 presents itself when:

- Protection at the upstream recloser is suppressed, LT1 = 0.
- No faults are detected, G0 = 0 and G5 = 0.
- No blocking signal is received from the downstream recloser, RMB1A = 0.

As there is no blocking signal received then

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable $!SV3T = 1$ is ANDed with $G5 = 0$ at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because $SV2 = 0$ and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables $LT1 = 0$, $!SV2T = 1$ and $G0 = 0$ are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally $G8 = 0$ and $RMB1A = 0$ are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

This is a non event scenario and no action takes place, i.e. TMB1B blocking signal is not sent to the Zone Substation protection relay and no trip occurs. From an operational point of view, having recloser's protection suppressed is a non-standard condition. Enabled recloser protection is the normal operating standard.

Scenario 2: no fault, block received due to communications channel failure, protection suppressed

Scenario 2 presents itself when:

- Protection at the upstream recloser is suppressed, $LT1 = 0$.
- No faults are detected, $G0 = 0$ and $G5 = 0$.
- Blocking signal is received from the downstream recloser, $RMB1A = 1$.

Scenario 2 depicts an abnormal situation whereby a blocking signal is received and no fault has been detected by the upstream recloser, i.e. the communication channel failure occurs and the received blocking signal is held on continuously. No fault has occurred. Under this circumstance, any blocking signal will be cleared, within the predetermined time, by the Mirrored Bits default setting RXDFLT. This setting is a mask of 1s, 0s and/or Xs where X represents the most recently received valid value. The non-blocked, slower because of time grading, back up overcurrent element, located at the Zone Substation's protection relay, will operate to detect and subsequently clear any faults. The logic flow for this scenario is presented below.

As the blocking signal is received from the downstream recloser then

$$SV3 = 1$$

and

$$SV3T = 1$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 0$$

The variable $!SV3T = 0$ is ANDed with $G5 = 0$ at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because $SV2 = 0$ and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables $LT1 = 0$, $!SV2T = 1$ and $G0 = 0$ are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 1 are ORed at gate G11 resulting in

$$G11 = 1 = TMB1B$$

TMB1B is then cleared by the Mirrored Bits communications default setting RXDFLT.

If the communications channel fails for more than 10 seconds, an alarm will be raised at the SCADA host. Subsequently, a decision will need to be made as to what remedial action is the best for the situation. An interim solution is to switch the protection devices on the feeder to Group 2. This action has to be implemented locally, i.e. at the relays control panels. When communications channel between the 'in line' reclosers, MB8A, fails, there will be a local display on the recloser relays' front panels indicating 'COMMS FAIL'. Similarly, when communications channel fails between the upstream recloser and the Zone Substation circuit breaker, MB8B, there will be a local display on the respective relays' front panels indicating 'COMMS FAIL'.

Scenario 3: no fault detected by the upstream recloser, fault in S3, block received from the downstream recloser, protection suppressed

In Scenario 3, a blocking signal is received and no fault has been detected by the upstream recloser, whilst a genuine fault has occurred in the feeder section S3, but is not picked up by the upstream recloser's protection elements, 51P2 or 51G2, due to their failure. Under this scenario, communications is perfect and the downstream recloser's blocking signal is passed onto the Zone Substation circuit breaker's relay to block the fault clearing by the Zone Substation circuit breaker for a maximum time of 200ms and allow the downstream recloser to clear the fault within this time. In case of the downstream recloser's circuit breaker failure, the fault will be detected by the unblocked, slower because of time grading, back up overcurrent element at the Zone Substation's protection relay, and subsequently cleared by the Zone Substation circuit breaker in time longer than 200ms. The blocking signal, originally issued by the downstream recloser, will have been timed out by then. Below, two circumstances, relevant to this scenario, are presented. In Circumstance 3A, the logic flow is presented for the time taken up to the blocking signal clearance. In Circumstance 3B, the logic flow is presented for the time after the blocking signal clearance. It is important to realise that the blocking signal gets cleared by, either the fault clearance or the 200ms time out on the recloser's circuit breaker failure timer T3. Whichever comes first.

<u>Circumstance 3A - logic flow until the clearance of the blocking signal by the downstream recloser.</u>

In this time interval a blocking signal is received from the downstream recloser. Thus

$$SV3 = 1$$

and

$$SV3T = 1$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 0$$

The variable !SV3T = 0 is ANDed with G5 = 0 at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 1 are ORed at gate G11 resulting in

$$G11 = 1 = TMB1B$$

As a result, the blocking signal received from the downstream recloser is passed onto the Zone Substation circuit breaker's relay to block the fault clearing by the Zone Substation circuit breaker.

Circumstance 3B - logic flow after the clearance of the blocking signal from the downstream recloser.

As the blocking signal is cleared due to the time out of the downstream recloser's circuit breaker failure timer T3, then

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. The inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable !SV3T =1 is ANDed with G5 = 0 at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

The upstream recloser stops the transmission of the blocking signal.

Scenario 4: fault in S2, no block received, protection suppressed

Scenario 4 covers two circumstances. In Circumstance 4A, a fault occurs in the feeder section S2, the upstream recloser transmits a blocking signal but does not clear the fault due to the suppressed protection and, as expected, no blocking signal is transmitted by the downstream recloser. In Circumstance 4B, a fault in the feeder section S2 has been cleared by the Zone Substation circuit breaker and no blocking signal is transmitted by the upstream recloser.

<u>Circumstance 4A- time taken up to the blocking signal clearance.</u>
Circumstance 4A presents itself when:

- Protection at the upstream recloser is suppressed, LT1 = 0.
- Fault components are detected, G0 = 1 and G5 = 1.
- No blocking signal is received from the downstream recloser, RMB1A = 0.

As there is no blocking signal received then

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 1 at gate G7 resulting in

$$G7 = 1 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 1, there is a signal pick up followed by timer T3. Thus, while T3 is timing

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 1 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

Although the upstream circuit breaker failure timer, T3, is timing, a blocking signal has not been transmitted to the Zone Substation circuit breaker's relay by the upstream recloser because its protection has been suppressed. This also implies that the upstream recloser will not clear the fault. Instead, the fault will be cleared by the Zone Substation circuit breaker.

<u>Circumstance 4B - time after the blocking signal clearance.</u>
Circumstance 4B presents itself when the fault, in section S2, has been cleared by the Zone Substation circuit breaker, i.e.:

- Protection at the upstream recloser is suppressed, LT1 = 0.

- Fault components are cleared, G0 = 0 and G5 = 0.

- No blocking signal is received from the downstream recloser, RMB1A = 0.

Thus as in Circumstance 4A

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 0, as the fault has just been cleared, at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0, there is no signal pick up followed by timer T3 timing. Thus

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

As the fault, in section S2, has been cleared by the Zone Substation circuit breaker and the protection remained suppressed, no blocking signal is transmitted. The whole feeder has been de-energised.

Scenario 5: fault in S3, no block received due to communications channel failure, protection suppressed

The situation is abnormal due to the communications channel failure. Fault clearing is accomplished by either the downstream recloser or the Zone Substation circuit breaker.

In Scenario 5, a fault occurs in the feeder section S3 and no blocking signal is received by the upstream recloser due to communications channel A, MB8A, failure. The upstream recloser detects the fault though. The inputs for the upstream recloser logic are the same as in Circumstance 4A, i.e. LT1 = 0, G0 and/or G5 = 1 and RMB1A = 0. Thus, the logic flow remains the same as in Circumstance 4A and for that reason it is not repeated here. The outcome for this situation is that when timer T3 is timing, the blocking signal is not being sent to the Zone Substation circuit breaker by the upstream recloser as its protection has been suppressed. Normally, it is the task of the downstream recloser to clear faults occurring in the feeder section S3. However, in case of the downstream recloser's circuit breaker failure occurring simultaneously with the communications Channel A failure, a fault in section S3 will have to be cleared by the Zone Substation circuit breaker. This will have happened in time greater than the 200ms downstream recloser's circuit breaker failure time out due to the time delay curve selected for operation on the Zone Substation circuit breaker's relay.

Scenario 6: fault in S3 cleared by the downstream recloser, block received, protection suppressed

Scenario 6 covers two circumstances. In Circumstance 6A, a fault occurs in the feeder section S3 and a blocking signal is received by the upstream recloser. In Circumstance 6B, the fault is cleared by the downstream recloser.

<u>Circumstance 6A - logic values for the time up to the fault clearance by the downstream recloser.</u>

Until the downstream recloser clears the fault in section S3 the following inputs are present at the upstream recloser:

- Protection is suppressed, LT1 = 0.
- Fault components are detected, G0 = 1 and G5 = 1.

- A blocking signal has been received from the downstream recloser, RMB1A = 1.

As the blocking signal has been received then

$$SV3 = 1$$

and

$$SV3T = 1$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 0$$

The variable !SV3T = 0 is ANDed with G5 = 1 at gate G7 resulting in

$$G7 = 0 = SV2$$

Then the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, thus

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 1 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 1 are ORed at gate G11 resulting in

$$G11 = 1 = TMB1B$$

In this situation a blocking signal, generated by the downstream recloser, is passed onto the Zone Substation circuit breaker by the upstream recloser. This action prevents the Zone Substation circuit breaker from clearing the fault during the time given for the downstream recloser to clear it.

Circumstance 6B - logic values after the fault clearance.

After the fault clearance in section S3 by the downstream recloser the following inputs are present:

- Protection at the upstream recloser is suppressed, LT1 = 0.
- Fault is cleared, G0 = 0 and G5 = 0.
- A blocking signal from the downstream recloser has ceased, RMB1A = 0.

The above inputs are those of the non-event Scenario 1 and for that reason the logic flow reflecting this situation is not discussed here. For details refer to Scenario 1.

Scenario 7: fault in S3, block received, downstream recloser circuit breaker failure, protection suppressed

Because of the downstream recloser's circuit breaker failure to clear the fault and the upstream recloser suppressed protection, the following occurs:

- Protection is suppressed, LT1 = 0.
- Fault components are still detected, G0 = 1 and G5 = 1.
- A blocking signal from the downstream recloser has ceased due to the downstream recloser circuit breaker failure timer time out, RMB1A = 0.

Logic values for the time longer than the 200ms from the fault inception are given below. As a blocking signal has ceased then

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 1 at gate G7 resulting in

$$G7 = 1 = SV2$$

Then the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 1, there is a signal pick up followed by timer T3 timing the second 200ms interval, counting from the fault inception time. Thus

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 0, !SV2T = 1 and G0 = 1 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

In this situation there is no blocking signal, generated by the downstream recloser, to be passed onto the Zone Substation circuit breaker by the upstream recloser. This is because the blocking signal from the downstream recloser has already timed out. As the upstream recloser's protection is suppressed, then no blocking signal is sent by this recloser, and the Zone Substation circuit breaker is allowed to clear the fault in section S3 after the downstream recloser's circuit breaker failure timer has timed out. How quickly the Zone Substation circuit breaker clears this fault depends on the time delay curve selected on the Zone Substation circuit breaker's relay.

Scenario 8: no fault, no block, protection enabled

Scenario 8 presents itself when:

- Protection at the upstream recloser is enabled, LT1 = 1.
- No faults are detected, G0 = 0 and G5 = 0.
- No blocking signal is received from the downstream recloser, RMB1A = 0.

As there is no blocking signal received then

$$SV3 = 0$$

and

$$SV3T = 0$$

because the T4 timer's pick up setting is set to zero. Then, the inverted signal at the inverter I3 output is

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 0 at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 1, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

This is a non event scenario and no action takes place, i.e. TMB1B blocking signal is not generated. From an operational point of view this is a 'stand ready' situation, i.e. the recloser condition facilitating the fault detection and location scheme.

Scenario 9: no fault, block received due to communications channel failure, protection enabled

Scenario 9 presents itself when:

- Protection at the upstream recloser is enabled, LT1 = 1.
- No faults are detected, G0 = 0 and G5 = 0.
- Blocking signal is received from the downstream recloser, RMB1A = 1.

Scenario 9 depicts an abnormal situation whereby a blocking signal is received and yet no fault has been detected by the upstream recloser whilst its protection has been enabled. In this scenario, the communications channel failure occurs and the received blocking signal is held on continuously. No fault has been detected. Under this circumstance, any blocking signal will be cleared by the Mirrored Bits default setting RXDFLT as discussed in Scenario 2. The unblocked, slower because of time grading, back up overcurrent element, located at the Zone Substation's protection relay, will operate to detect and subsequently clear any faults. The abbreviated logic flow is presented below. For full details refer to Scenario 2.

Due to the receipt of a continuous blocking signal from the downstream recloser, variable SV3 = 1. Variable !SV3T = 0 is ANDed with G5 = 0 at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 1, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 1 are ORed at gate G11 resulting in

$$G11 = 1 = TMB1B$$

As a result, the continuous blocking signal, symptomatic of Channel A failure, has to be cleared by the communications default setting. If the communications channel fails for more than 10 seconds, an alarm will be raised at the SCADA host as per Scenario 2.

Scenario 10: fault in S3 but not detected by upstream recloser, block received, protection enabled

In scenario 10, a blocking signal is received and no fault has been detected by the upstream recloser, whilst a genuine fault has occurred in the feeder section S3, but is not picked up by the upstream recloser's protection elements, 51P2 or 51G2, due to their failure. The protection is enabled on the upstream recloser. Under this circumstance, communications is perfect and the downstream recloser's blocking signal is passed onto the Zone Substation circuit breaker's relay to block the fault clearing by the Zone Substation circuit breaker for a maximum time of 200ms and allow the downstream recloser to clear the fault within this time. In case of the downstream recloser circuit breaker failure, the fault will be detected by the unblocked, slower because of time grading, back up overcurrent element, at the Zone Substation's protection relay, and subsequently cleared by the Zone Substation circuit breaker in time longer than 200ms. The blocking signal, originally issued by the downstream recloser, will have timed out by then. Below, the logic flows for Circumstance 10A, covering the time taken to clear the blocking signal by the downstream recloser, and Circumstance 10B, covering the time after the blocking signal clearance, are presented.

Circumstance 10A - logic values for the time up to the blocking signal clearance by the downstream circuit breaker.

Circumstance 10A presents itself when:

- Protection at the upstream recloser is enabled, LT1 = 1.
- No fault components are detected, G0 = 0 and G5 = 0.
- Blocking signal is received from the downstream recloser, RMB1A = 1.

The blocking signal is issued by the downstream recloser until the fault is cleared or the downstream recloser's circuit breaker failure timer times out. Then, for that duration, variable SV3 = 1 and variable !SV3T = 0.

!SV3T = 0 is ANDed with G5 = 0, because of the 51P2 and 51G2 protection elements failure, at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 1, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 1 are ORed at gate G11 resulting in

G11 = 1 = TMB1B

Thus, the blocking signal is being passed on to the Zone Substation circuit breaker's relay until the downstream recloser clears the fault or the downstream recloser's circuit breaker failure timer times out.

Circumstance 10B - logic values for the time after the blocking signal clearance.
Circumstance 10B presents itself when:

- Protection at the upstream recloser is enabled, LT1 = 1.
- No faults are detected, G0 = 0 and G5 = 0.
- Blocking signal from the downstream recloser has ceased, RMB1A = 0.

The blocking signal has been cleared by either the fault clearance or the downstream recloser's circuit breaker failure timer T3. Then variable SV3 = 0 and !SV3T = 1. The variable !SV3T = 1 is ANDed with G5 = 0 at gate G7 resulting in

G7 = 0 = SV2

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0 and, there is no signal pick up followed by timer T3 timing, then

SV2T = 0

and its inverted value, at the inverter I2 output, is

!SV2T = 1

The variables LT1 = 1, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

G8 = 0

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

Thus, no blocking signal is sent to the Zone Substation circuit breaker's relay because there is no trigger for the issue of the blocking signal by the upstream recloser in this situation. This is because no fault is detected by the faulty protection elements of the upstream recloser and no blocking signal is received from the downstream recloser. Logic states covering Scenario 10 are depicted in Figure E.1.

Scenario 11: fault in S2, no block received, protection enabled

Scenario 11 presents itself when:

- Protection at the upstream recloser is enabled, LT1 = 1.
- Fault components are detected, G0 = 1 and G5 = 1.
- No blocking signal is received from the downstream recloser, RMB1A = 0.

Scenario 11 covers two circumstances. In Circumstance 11A, the logic flow during the time up to the fault clearance by the upstream recloser is depicted. In Circumstance 11B, the logic flow during the time after the blocking signal clearance by the upstream recloser is depicted.

<u>Circumstance 11A - time up to the fault clearance by the upstream recloser.</u>
Under this condition a fault occurs in the feeder section S2. As there is no blocking signal received then SV3 = 0 and

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 1 at gate G7 resulting in

$$G7 = 1 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 1, there is a signal pick up followed by timer T3.

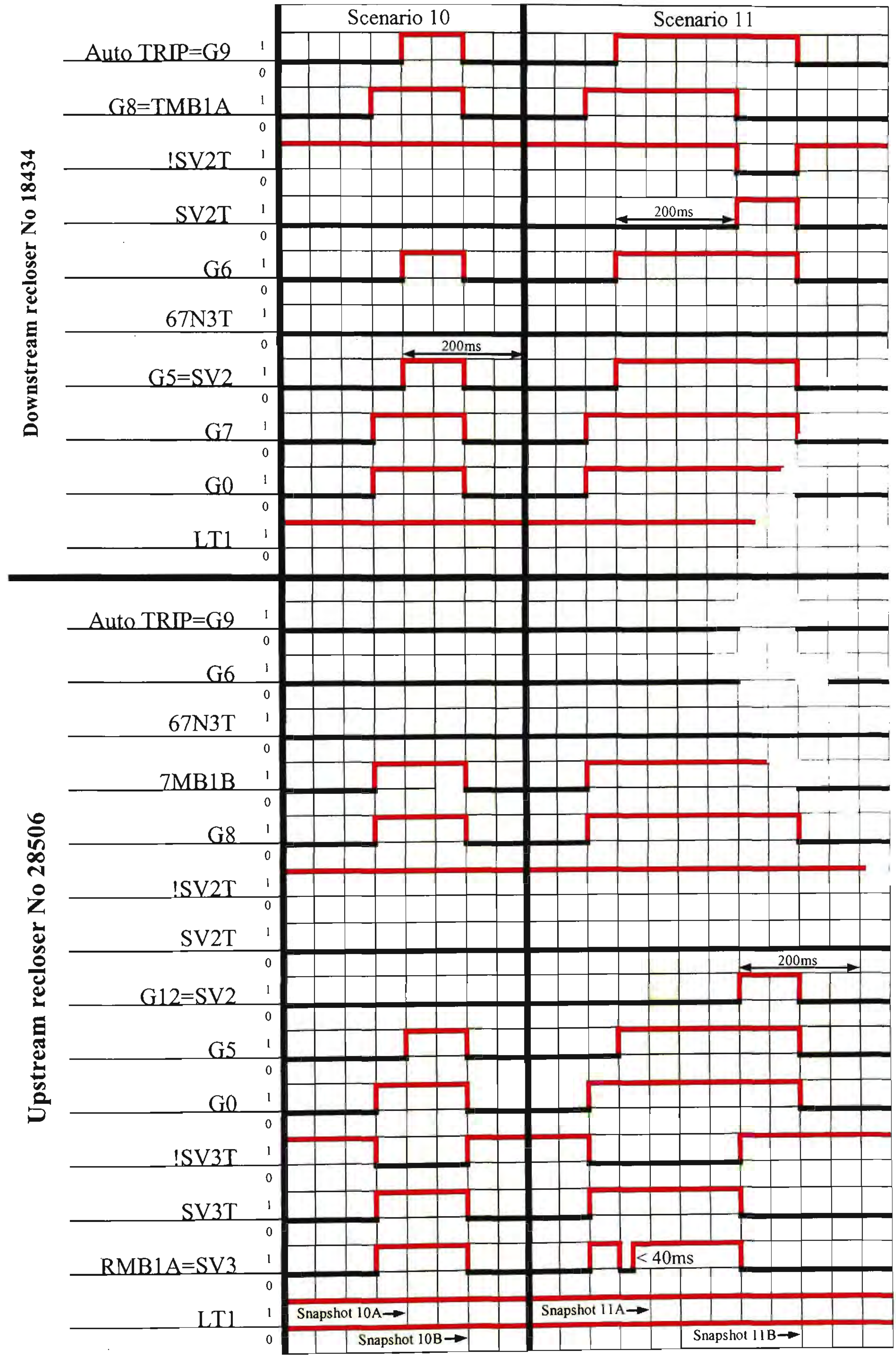


Figure E.1 Logic states for scenarios 10 and 11

Thus

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 1, !SV2T = 1 and G0 = 1 are ANDed at gate G8 resulting in

$$G8 = 1$$

Then finally G8 = 1 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 1 = TMB1B$$

A blocking signal has been issued to the Zone Substation's relay by the upstream recloser to prevent the fault clearance by the Zone Substation's circuit breaker within the initial 200ms time interval since the fault inception. In the meantime, the upstream recloser will clear the fault.

<u>Circumstance 11B - time after the blocking signal clearance by the upstream recloser.</u>

The blocking signal can be cleared by either the upstream recloser fault clearance, considered in the logic flow below, or the upstream recloser circuit breaker failure timer time out. Although, the latter is not considered in the logic flow presented below, its final effect on the transmission of a blocking signal is the same as in the case of the upstream recloser fault clearance. There is a small time difference between the fault clearing time and timing out on the recloser circuit breaker failure timer though.

As there is no blocking signal received then SV3 = 0 and

$$!SV3T = 1$$

The variable !SV3T = 1 is ANDed with G5 = 0. As the fault has been cleared, at gate G7 resulting in

$$G7 = 0 = SV2$$

Then, the SV2 control variable is fed into the upstream recloser circuit breaker failure timer T3. Because SV2 = 0, there is no signal pick up followed by timer T3 timing. Thus

$$SV2T = 0$$

and its inverted value, at the inverter I2 output, is

$$!SV2T = 1$$

The variables LT1 = 1, !SV2T = 1 and G0 = 0 are ANDed at gate G8 resulting in

$$G8 = 0$$

Then finally G8 = 0 and RMB1A = 0 are ORed at gate G11 resulting in

$$G11 = 0 = TMB1B$$

The transmission of the blocking signal is stopped after the fault clearance by the upstream recloser. In case of the upstream recloser circuit breaker failure, the transmission of the blocking signal is stopped after 200ms to enable the Zone Substation circuit breaker to clear the fault. Logic states depicting this scenario are presented in Figure E.1.

Appendix ‘F’

Technical specifications for

GVR27 Whipp & Bourne reclosers

Agility Network Technology
34 King William St, Broadmeadows, Vic, 3047, Australia
Phone: +61 3 9201 2440 Fax: +61 3 9201 2370

TECHNICAL SPECIFICATIONS FOR GVR27 WHIPP & BOURNE RECLOSERS WITH

THE ASSOCIATED PANACEA BASED RECLOSER CONTROLLERS

General

Agility Management Pty Ltd undertakes to install GVR Reclosers with the Panacea relay based recloser controllers on AGL Electricity distribution network in urban areas. The recloser installations are planned to be carried out predominantly under 'live line' conditions. Agility Management Pty Ltd will be responsible for the overall implementation of the Recloser program. However close co-operation with Whipp & Bourne and Hawker Siddeley Switchgear, Australia is necessary to ensure successful implementation of the 'in line recloser' concept including blocking scheme.

Circuit Breaker specifications

Natural finish cast aluminium tank with unpainted, hot-dipped galvanised steel bracket for mounting on a single round wooden pole where pole drilling permitted. Pole fixing bolts excluded.

6 off 630A rated, Silicon insulated HV bushings with Copper conductor stems. Each stem end pre-drilled and tapped size M10 to accept an appropriate cable connector secured by a single bolt, size M10.

Brackets for mounting the recloser onto flat-faced pole where pole drilling permitted.

SF6 gas insulated, 3 phase vacuum circuit breaker, rated 27KV/12KA (150KV BIL) incorporating magnetic actuator control.
3 phase set of primary CTs with interposing current transformers on the bulkhead fitting, giving an effective CT ratio of 400:1 and limiting the open circuit voltage to < 10V.

Multi-pin, weatherproof, socket outlet for connection to the umbilical cable.
Hook-stick operated manual trip/lockout lever (painted yellow), with additional external position indication.

Mechanical I/O (day-glow) indicator visible from ground level.

SF6 gas injection point via Hansen 1/4" BSP male, self sealing valve.

First filling of SF6 gas.

SF6 pressure sensor for low pressure alarm on Panacea relay

Internal arc pressure relief vent.

English language rating plate.

A set of 6 Bird Guards per recloser as supplied on previous contract

GVR STANDARD RATINGS.2.1 STANDARD RATINGS. SPECIFICATION TO ANSI/IEEE C37.60 1981					
Voltage	**15kV**	**15kV**	**27kV**	**27kV**	**38kV**
Impulse Withstand Voltage	110kV	110kV	125kV	150kV	150kV
Frequency	50/60HZ	50/60HZ	50/60HZ	50/60HZ	50/60HZ
Continuous Current	560A 630A	560A 630A	560A 630A	630A	560A 630A
Symmetrical Interrupting Current	6kA	12.5kA	12.5kA	12.5kA	10kA
Symmetrical Making	6kA	12.5kA	12.5kA	12.5kA	10kA

GVR STANDARD RATINGS.2.1 STANDARD RATINGS. SPECIFICATION TO ANSI/IEEE C37.60 1981					
Voltage	**15kV**	**15kV**	**27kV**	**27kV**	**38kV**
Current					
Asymmetrical Making Current	16kAp	32kAp	32kAp	32kAp	21kAp
Weight - Recloser (approx)	145kg	145kg	145kg	155kg	155kg
Weight - Control Cubicle - Lead Acid Batteries (approx)	95kg	95kg	95kg	95kg	95kg
Protection CT Ratio	400/1A	400/1A	400/1A	400/1A	400/1A
SF6 Gas Filling Pressure (guage)	0.3 Bar	0.3 Bar	0.3 Bar	0.5 Bar	0.5 Bar
Rated SF6 Gas Pressure (guage)	0.0 Bar	0.0 Bar	0.0 Bar	0.3 Bar	0.3 Bar
Control Supply Voltage	**24v**	**24v**	**24v**	**24v**	**24v**
Ambient operating temperature range	-40°C to +50°C	-40°C to +50°C	-40°C to +50°C	-40°C to +60°C	-40°C to +50°C

Control Unit specifications

Unpainted, Stainless Steel, weatherproof housing with (I) hinged front cover with padlockable, single point latch and door stop, (ii) unpainted, Stainless Steel bracket for mounting on a single round wooden pole where pole drilling permitted. Pole fixing bolts excluded.

Galvatite coated steel sun shield painted dark grey shade 632 to BS.381C. (Dark admiralty grey to AS2700). The cabinet will also be fitted with a meshed (vermin proof) air entry plug at the bottom.

6 metre, screened, flexible, 24 core, 1.5 sq.mm umbilical control cable with multi-pin plug to connect to circuit breaker tank. The umbilical is also fitted with a detachable plug and socket located in the control box.

Weatherproof umbilical cable gland entry.
Set of Close/Trip control capacitors.
Internally mounted, electro-mechanical operation counter.

Internally mounted, RS232 Serial Port for programming.

Internally mounted, English language rating plate.

PANACEA micro-processor control and protection relay with DNP 3.0 protocol, Level 2.

24V rechargeable sealed lead-acid battery for providing control power to the circuit breaker and PANACEA relay in the event of a loss of auxiliary supply.

Controller operating voltage to be 240V ac as per previous order

240V RCD protected dual power outlet (three pin Australian type)

RS485 serial port as per previous order

Installed load profile and Mirrored Bits (operating off Port 3 with 15cm long ribbon cable with female and male connectors)

Panacea Specifications

Battery Charger Ac Voltage Input	**Input Power: 106 - 140 Vac, 120 Vac nominal.**
12 Vdc Output	**11 - 14 Vdc, 6 W continuous, 13 W for 1 second.**
Ac Voltage Inputs	**Voltage Inputs V_A, V_B, V_C, and V_S. 300 $V_{L\text{-}N}$ continuous (connect any voltage up to 300 Vac). 600 $V_{L\text{-}N}$ for 10 seconds. Burden: 0.03 VA @ 67 V; 0.06 VA @ 120 V; 0.8 VA @ 300 V.**

Ac Current Inputs	1 A nominal: 3 A continuous, 100 A for 1 second, linear to 20 A symmetrical. 250 A for 1 cycle. Burden: 0.13 VA @ 1 A, 1.31 VA @ 3 A. Sensitive Earth Fault: 0.05 A nominal channel IN current input: 1.5 A continuous, 20 A for 1 second, linear to 1.5 A symmetrical. 100 A for 1 cycle. Burden: 0.0004 VA @ 0.05 A, 0.36 VA @ 1.5 A.
Frequency and Rotation	60/50 Hz system frequency and ABC/ACB phase rotation are user-settable. Frequency tracking range: 40.1 - 65 Hz (V_A required for frequency tracking).
Output Contacts Except Trip and Close	Per *IEC 255-0-20 : 1974*, using the simplified method of assessment: 6 A continuous carry 30 A make per *IEEE C37.90 : 1989* 100 A for one second 270 Vac/360 Vdc MOV for differential surge protection Pickup/dropout time: < 5 ms Breaking Capacity (L/R = 40 ms): 24 V 0.5 A 10,000 operations 48 V 0.5 A 10,000 operations 125 V 0.3 A 10,000 operations 250 V 0.2 A 10,000 operations Cyclic Capacity (L/R = 40 ms): 24 V 0.5 A 2.5 cycles per second 48 V 0.5 A 2.5 cycles per second 125 V 0.3 A 2.5 cycles per second 250 V 0.2 A 2.5 cycles per second
Trip and Close Outputs	Trip and close GVR recloser 10000 times without appreciable wear.

Optoisolated Input Ratings	250 Vdc: on for 200 - 300 Vdc; off below 150 Vdc 125 Vdc: on for 105 - 150 Vdc; off below 75 Vdc 48 Vdc: on for 38.4 - 60 Vdc; off below 28.8 Vdc 24 Vdc: on for 16.0 - 30 Vdc. With nominal control voltage applied, each optoisolated input draws approximately 4 mA of current.
Time-Code Input	Relay module accepts demodulated IRIG-B time-code input at Port 1 and Port 2 (Port 1 is an optional EIA-485 port). Do not connect the time-code input into both Port 1 and Port 2 at the same time. Relay time is synchronized to within ±5 ms of time-source input.
Serial Communications	Two side-panel and one front-panel EIA-232 serial communications ports. One optional side panel EIA-485 serial port with 2100 Vdc of isolation. Per-port baud rate selections: 300, 1200, 2400, 4800, 9600, 19200, 38400.
Routine Dielectric Test	Control ac power: 2500 Vac for 10 seconds. Optoisolated inputs, analog inputs, and output contacts except Trip and Close: 3100 Vdc for 10 seconds.
Operating Temp.	Relay module: -40° to +85°C (-40° to +185°F) [LCD contrast impaired for temps. below -20°C (-4°F)]
Environment	IEC 68-2-30 - 1980 Basic environmental testing procedures, Part 2: Test - Tests Ca; Damp heat, cyclic. Severity Level: (12 + 12-hr cycle).
	IEC 529 - 1989 Degrees of protection provided by enclosures - IP32/NEMA 3R (type test).
RFI and Interference Tests	ANSI/IEEE C37.60.6.14 - 1981 Control Elements SWC tests for automatic circuit reclosers and fault interrupters for AC systems, Oscillatory Surge Test method, 6.14.1, applied to control element connections to external devices, 1.0 to 1.5 MHz oscillatory test wave of crest voltage of 2.5 - 3.0 kV occurring in the first half-cycle, decaying to 50% in not less than 6 µs.

	IEEE C37.90.1 - 1989 IEEE SWC Tests for Protective Relays and Relay Systems (3 kV oscillatory, 5 kV fast transient) (type test).
	IEEE C37.90.2 - 1987 IEEE Trial-Use Standard, Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers, 10 V/m (type test with enclosure door open).
	Exceptions: **5.5.2(2) Performed with 200 frequency steps per octave.** **5.5.3 Digital Equipment Modulation Test not performed.** **5.5.4 Test signal turned off between frequency steps to simulate keying.**
	IEC 801-4 - 1988 Electromagnetic compatibility for industrial-process measurement and control equipment, Part 4: Electrical fast transient/burst requirements, Severity Level: 4 (4 kV on optional power supply, 2 kV on inputs and outputs) (type test).
	IEC 255-22-1 - 1988 Electrical disturbance tests for measuring relays and protection equipment, Part 1: 1 MHz burst disturbance tests. **Severity Level 3 (2.5 kV common mode, 1.0 kV differential) (type test).**
	IEC 255-22-3 - 1989 Electrical relays, Section 3: Radiated electromagnetic field disturbance tests**, Severity Level: 3 (10 V/m) (type test).**
	IEC 255-22-4 - 1992 Electrical disturbance tests for measuring relays and protection equipment, Section 4: Fast transient disturbance test **(type test).**
Impulse Tests	***IEC 255-5 - 1977 Electrical relays, Part 5: Insulation tests for electrical relays, Section 6: Dielectric Tests, Series C (2500 Vac on analog inputs including control ac power; 3100 Vdc on optional power supply inputs, contact inputs, and contact outputs excluding Trip and Close). Section 8: Impulse Voltage Tests*****, 0.5 Joule, 5 kV (type test).**

Vibration and Shock Test	IEC 255-21-1 - 1988 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section 1 - Vibration tests (sinusoidal), Class 1 (relay module only).
	IEC 255-21-2 - 1988 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section 2 - Shock and bump tests, Class 1 (relay module only).
	IEC 255-21-3 - 1993 Electrical relays, Part 21: Vibration, shock, bump, and seismic tests on measuring relays and protection equipment, Section 3 - Seismic tests, Class 2 (relay module only).
ESD Test	IEC 255-22-2 - 1996 Electrical disturbance tests for measuring relays and protective equipment, Section 2: Electrostatic discharge tests, Severity Level: 4 (8 kV contact discharge all points except serial ports, 15 kV air discharge to all other points) (type test).
Burn-in	Twenty temperature cycles from ambient to 75°C (167°F) over 48 hours.

Relay Element Pickup Ranges and Accuracies

Instantaneous/Definite-Time Overcurrent Elements

Pickup Range:	0.05 - 20.00 A, 0.01 A steps (1 A nominal) 0.20 - 34.00 A, 0.01 A steps (1 A nominal – for phase-to-phase elements) 0.005 - 1.500 A, 0.001 A steps (0.05 A nominal channel IN current input)
Steady-State Pickup Accuracy:	±0.01 A and ±3% of setting (1 A nominal) ±1 mA and ±5% of setting (0.05 A nominal channel IN current input)
Transient Overreach:	±5% of pickup
Time Delay:	0.00 - 16,000.00 cycles,

	0.25-cycle steps
Timer Accuracy:	±0.25 cycle and ±0.1% of setting

Time-Overcurrent Elements

Pickup Range:	0.10 - 3.20 A, 0.01 A steps (1 A nominal) 0.005 - 0.160 A, 0.001 A steps (0.05 A nominal channel IN current input)
Steady-State Pickup Accuracy:	±0.01 A and ±3% of setting (1 A nominal) ±1 mA and ±5% of setting (0.05 A nominal channel IN current input)
Time Dial Range:	0.50 - 15.00, 0.01 steps (US) 0.05 - 1.00, 0.01 steps (IEC) 0.10 - 2.00, 0.01 steps (recloser curves)
Curve Timing Accuracy:	±1.50 cycles and ±4% of curve time for current between 2 and 30 multiples of pickup

Under and Overvoltage Elements

Pickup Ranges:	0.0 - 150.0 V, 0.1 V steps (various elements) 0.0 - 260.0 V, 0.1 V steps (phase-to-phase elements)
Steady-State Pickup Accuracy:	±1 V and ±5% of setting
Transient Overreach:	±5% of pickup

Synchronism-Check Elements

Slip Frequency Pickup Range:	0.005 - 0.500 Hz, 0.001 Hz steps
Slip Frequency Pickup Accuracy:	±0.003 Hz
Phase Angle Range:	0 - 80°, 1° steps
Phase Angle Accuracy:	±2°

Under- and Overfrequency Elements

Pickup Range:	**40.10 - 65.00 Hz, 0.01 Hz steps**
Steady-State *plus* Transient Overshoot:	**±0.01 Hz**
Time Delay:	**2.00 - 16,000.00 cycles, 0.25-cycle steps**
Timer Accuracy:	**±0.25 cycle and ±0.1% of setting**

Timers

Pickup Ranges:	**0.00 - 999,999.00 cycles, 0.25-cycle steps (reclosing relay and some programmable timers)** **0.00 - 16,000.00 cycles, 0.25-cycle steps (some programmable and other various timers)**
Pickup and dropout accuracy for all timers:	**±0.25 cycle and ±0.1% of setting**

Metering Accuracy

Accuracies are specified at 20°C and at nominal system frequency unless noted otherwise.

Voltages V_A, V_B, V_C, V_S, $3 \bullet V_0$, V_1, V_2	**±0.2% (33.5 - 150 V)**
Currents I_A, I_B, I_C	**±0.3 mA and ±0.1% (0.1 - 2 A) (1 A nominal)** **Temperature coefficient:** $[(0.0002\%)/(°C)^2] * (°C - 20°C)^2$ **(see example below)**
Currents I_N, I_1, $3 \bullet I_0$, $3 \bullet I_2$	**±0.01 A and ±3% (0.1 - 20 A) (1 A nominal)** **±1 mA and ±5% (0.01 - 1.5 A) (0.05 A nominal channel IN current input)**
Phase Angle Accuracy	**±1.0°**

Metering accuracy calculation example for currents I_A, I_B, and I_C due to preceding stated temperature coefficient:

For temperature of 40°C, the <u>additional</u> error for currents I_A, I_B, and I_C is:
$[(0.0002\%)/(°C)^2] * (40°C - 20°C)^2 = 0.08\%$

Appendix ‘G’

Reports on investigations into SEL351P relays recording residual current and voltage traces after tripping the GVR27 reclosers

WHIPP & BOURNE SWITCHGEAR

REPORT No. 8954

Investigation in to the Panacea Recording a Small Current Trace after Tripping the GVR

FKI Energy Technology

BSI REGISTERED FIRM

Registration
Number
Q 6203

Investigation in to the Panacea Recording a Small Current Trace after Tripping the GVR

This report is being written for AGL (Australian Electricity Utility) to explain why small traces of current can be seen on the Panacea event report data after the GVR has been manually opened via the Panacea keypad.

Panacea event data from 17 GVR's was supplied by AGL. This was studied using Schweitzer's SEL 5601 software, which converts the event report data in to an oscillographic display. Of the 17 GVR's, 12 had interposing CT's inside the Panacea and 5 had them inside the GVR tank.

The following information summarises the event report data for each of the 17 GVR's, with regard to a small amount of current flowing after the GVR has opened: -

ACR 12723 (900292-01/004/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 10348 (900292-01/010/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0

amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 16581 (900292-01/006/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 12882 (900292-01/003/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 18256 (900292-01/002/012)

Inspection of the event report data did not show any instances of a small amount of current flowing after the GVR opened. Therefore, there did not seem to be any obvious problem with the GVR.

ACR 14199 (900292-01/008/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 18795 (900292-01/011/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 18898 (900292-01/001/012)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 11614 (900233-01/004/005)

Two Panacea's had been used with this GVR. The original Panacea (351P-1) did not show any signs of current flowing after the GVR was opened. However, the new Panacea (351P-2) showed on several occasion's current flowing on A phase after the GVR appeared to open. In all cases there was no current on B and C phases indicating that the Panacea was probably undergoing commissioning tests. It is therefore likely that the current continued to flow because the Panacea was connected to a 'Dummy' circuit breaker and not the GVR.

ACR 11746 (900292-01/006/010)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 18323 (900233-01/005/005)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 13228 (900292-01/002/010)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 13330 (900300-01/003/005)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 20473 (900463-01/008/010)

Inspection of the event report data showed that in some instances, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 14432 (901318-01/008/010)

Inspection of the event report data showed that in one instance, approximately 50 amps of current flowed in the C phase for approximately 4 cycles after the GVR main contacts had opened. It would appear from this record that the GVR struggled to clear on C phase. However, this GVR has been inspected and no obvious problem has been found. This could have been caused by noise and induced currents, although it is less likely at this higher level of current. It is also worth noting that the current measured was not truly sinusoidal, which may point more to noise than an actual problem with the GVR. Please refer to the individual report for this GVR for further information.

ACR 10003 (900300-01/005/005)

Inspection of the event report data showed that in one instance, a small amount of current flowed after the GVR opened. However, there did not seem to be any obvious problem with the GVR, because this current was <1.0 amp and was not completely sinusoidal. The most likely cause of this is due to noise and induced currents, which is a common phenomenon with iron core CT's.

ACR 28506 (900463-01/010/010)

This GVR had an internal fault that was probably caused by lightning. The internals of this GVR had been severely damaged, so most of the Panacea event data can be disregarded.

Summary

Investigation of the Panacea event data, showed that 13 of the GVR's above had instances where a small amount of current (<1 amp) appeared to be flowing after the GVR main contacts had opened. It is Whipp & Bourne and Schweitzer's opinion that this is a normal measuring phenomenon for protection relays that use Iron Core CT's. When the GVR is open, no current will be flowing in the primary and the CT's are then more susceptible to radio and electromagnetic interference. With the GVR set to a 400/1A CT ratio, it only requires 2.5mA of current in the Panacea CT wiring to report a primary current of 1 amp.

The event data from the 4 other GVR's can be summarised as follows: -

a) The Panacea from ACR 18256 did not show signs of current flowing after the GVR had opened.
b) ACR 11614 had been used with 2 Panacea's. One showed no sign of current flowing after the GVR had opened. However, the other appeared to show that on several occasion's current continued to flow on A phase after the GVR had opened. In these cases there was no current on B and C phases, probably indicating that the Panacea was undergoing single phase secondary current injection tests. Also, it is likely that during these tests, the Panacea was connected to a 'Dummy' circuit breaker and not the GVR. Another point to confirm the above, is that the event report data shows that the event occurred on 03/10/03 and the unit was not actually commissioned until the 10/10/03.
c) The Panacea from ACR 14432 showed one record that appeared to show that the GVR had struggled to clear a 50 amp fault on its C phase. This GVR had been removed from the pole and sent to W&B for investigation. At this time there does not appear to be an obvious problem with this GVR, so it is difficult to form a full explanation for this incident.
d) ACR 28506 had been subjected to an overvoltage, possibly caused by lightning. This caused the GVR to fail internally and resulted in an internal arc, which destroyed most of its internals. Therefore, most of the Panacea data can be disregarded because the CT's were damaged.

END

Prepared [redacted] by: Date: 24/02/04

Approved by: [redacted] Date: 24/02/04

Appendix ‘H’

Publications

Fault detection and location on Distribution Feeders (22kV & 11kV)

Ryszard Orlowski*'** and Akhtar Kalam**

* The Australian Gas Light Company Electricity Limited (AGL Electricity), Melbourne, Australia

** Victoria University of Technology, Melbourne, Australia

Abstract

Following the restructure of the Electricity Supply Industry in Victoria, The Australian Gas Light Company Electricity Limited (AGL Electricity) emerged as one of the five privately owned electricity distribution companies in Victoria. One of the Key Performance Indicators set for the company by the Office of the Regulator-General is the Reliability of Supply. Two major indices that characterise the Reliability of Supply are the duration customers are off-supply and the frequency of customer supply interruptions. AGL's objective is to minimise these two indices so that the Reliability of Supply standards set by the Office of the Regulator-General are met and indeed exceed.

Key words : Fault Detection and Location; Distribution Feeder Automation

1.0 INTRODUCTION

Progressive automation of The Australian Gas Light Company Electricity Limited (AGL Electricity) distribution feeder network, i.e. 22kV and 11kV, was adopted as a means of improving the Reliability of Supply. An absolute prerequisite for safe Distribution Feeder Automation is a reliable fault detection and fault location scheme. Thus the development of the fault detection and location scheme is perceived by AGL Electricity as a preliminary but essential step that will lead to full Distribution Feeder Automation. At present there are a number of Radio Remotely Controlled & Monitored High Voltage devices that were introduced on AGL Electricity distribution network as part of the gradual approach to Feeder Automation. This paper will highlight the introduction, project management as well as the development of the communication strategy necessary for this application.

Fault detection scheme that detects and locates feeder fault under fault condition accurately will facilitate a safe, prompt and yet reliable reconfiguration of the distribution network. Achieving this objective will result in an improvement in the Reliability of Supply which is a key factor in AGL Electricity operation.

Remote monitoring of the distribution network will further facilitate the operational enhancement of the network by providing feeder analogue data that is invaluable for optimising network operation.

2.0 SWITCHING DEVICES BACKGROUND

There are two types of switching devices, available on Australian market, that can be employed as switching apparatus on distribution feeders. They are a load break switch and a fault break recloser. Both can be remotely controlled and monitored. Load break switches were initially used by AGL Electricity as a primary device for remote control and monitoring of distribution feeders. However, recent increase in fault breaking capabilities of reclosers as well as a substantial cost reduction due to new technologies employed by manufacturers made in line reclosers a viable option for the utilities like AGL.
In addition, reclosers address the issue of frequency of customer supply interruptions due to their ability to break fault current thus saving the healthy feeder section, if it happens to be upstream from the recloser. Another taken for granted feature of reclosers is their ability to clear intermittent faults thus saving "minutes off-supply" that would have been lost otherwise.

These recloser features have ensured change in their typical application. Whereas, in the past reclosers were predominantly used in rural areas, these days there are increasing numbers of them installed in urban areas where savings in customer "minutes off-supply" and frequency of customer supply interruptions are much more profound due to a large number of customers affected. This application change has introduced new challenges for electrical and communications engineers as the characteristics of urban distribution feeders are vastly different from rural feeders.

3.0 URBAN FEEDER CHARACTERISTICS

AGL Electricity supply area covers heavily industrialized region of northwest Melbourne. Most of AGL's distribution feeders are radial, relatively short but heavily loaded. Fault currents, depending on the fault location with respect to source, can reach levels of 12kA to 13kA. The load distribution along feeders can be 'lumpy' due to the presence of high voltage customers that require large amounts of energy for their operations. Despite these adverse characteristics, a uniform approach to all distribution feeders is advocated. AGL Electricity distribution feeder switching policy manifests that approach.

4.0 SWITCHING POLICY

Current AGL Electricity distribution feeder switching policy calls for each feeder to be split into three major switching sections by two reclosers as designated in Figure 1. Each section is characterised by a load of around 3MVA. Feeders are inter-connected with adjacent feeders via normally open switches as shown in Figure 1 below.

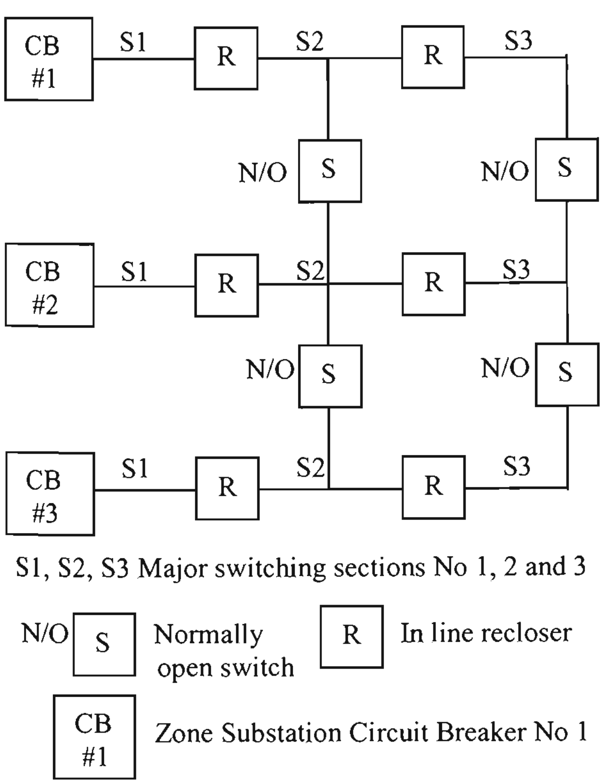


Figure 1 Major switching sections

Remotely controlled and monitored 22kV or 11kV switchgear is being gradually installed at the boundaries of the major switching sections. Thus rapid load transfers can be achieved under normal operating conditions. In the event of a fault, the affected major switching section can be promptly isolated remotely, provided that the fault has been localized within a particular feeder section.

Current AGL Electricity approach to normally open points is to utilize NGK load break switches associated by the switch controllers. However, this approach may be changed once feeder loop configurations are technically matured for automation. In such an event reconfigurable reclosers will be used on open points.

5.0 APPROACH TO FAULT LOCATION

A requirement that guarantees a reduction of the Key Performance Indices is a safe and reliable fault detection and fault location scheme. Fault detection and location schemes can be split into two generic categories :

1. indirect fault detection and location using reclosers that narrow the fault location down to the major switching zone
2. direct fault detection and location that would determine the location of faults within specific range, say 200 meters

A two-prong approach was adopted by AGL Electricity in relation to fault location. To enjoy relatively quick benefits as far as the improvement of supply reliability is concerned, the indirect fault detection and location scheme was chosen for implementation first, irrespective of some communication issues still remaining to be resolved.

Direct fault detection and location is subject to the author's ongoing research and practical investigations within AGL Electricity distribution system due to the complicated nature of the issues involved.

5.1 INDIRECT FAULT DETECTION AND LOCATION

The indirect fault detection and location can be introduced by an implementation of a recloser scheme on a distribution feeder with two, as in AGL Electricity proposal, reclosers in series. The reclosers are located at the boundaries of the major switching sections. The fault current is detected by the recloser's protection circuitry and the fault location is limited to the major switching section. As it is the policy of AGL Electricity to use a single shot reclosers on urban distribution feeders, there is a requirement for a fast blocking scheme that would prevent the upstream recloser from operation whenever a recloser located downstream operates due to a fault occurrence on that feeder section. The importance of such a scheme is illustrated in Figure 2 below.

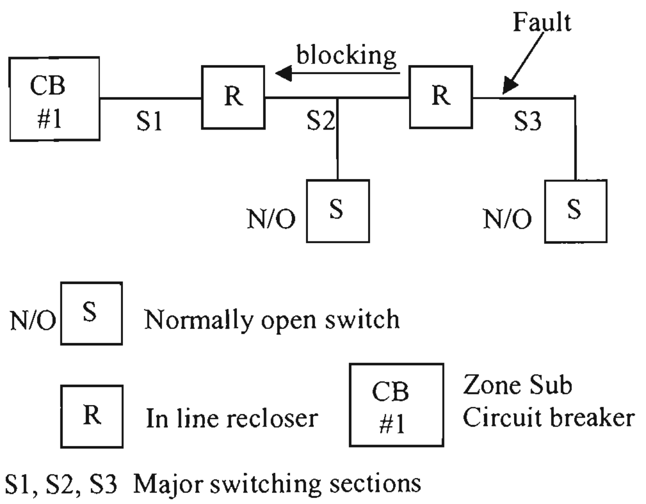


Figure 2 Recloser blocking scheme

Due to the short but heavily loaded feeder with 'lumpy' load distribution the discrimination between the reclosers' inverse characteristic curves cannot be achieved. To prevent the upstream recloser from operation, a blocking scheme needs to be implemented with the overall operational response time shorter than 200ms on the average. The discrimination between the circuit breaker and the two reclosers having the same inverse characteristic curve settings can be achieved on most AGL Electricity distribution feeders.

The reclosers need to operate in two modes of operation. Firstly, in a recloser specific mode when recloser operation is governed by the events on the feeder triggering the protection relays. Secondly, reclosers need to be capable of operating in a standard remote control and monitoring mode when network reconfiguration such as backfeeding needs to be carried out. Remote mode setting is expected to be a standard.

The scenario presented in Figure 2, i.e. when feeder section 3 is faulty, illustrates that two thirds of a feeder will be saved as far as the "minutes off-supply" and the frequency of customer supply interruptions are concerned. Had the load break switches been used in place of reclosers the whole feeder would have been affected by the operation of the circuit breaker at the Zone Substation resulting in very poor key performance indices for this particular feeder.

Other scenarios, i.e. when feeder sections 1 or 2 are faulty, are not considered in this paper as they do not instigate 'racing condition' when both reclosers try to open as it happens with a fault in feeder section 3.

6.0 COMMUNICATIONS ROLE

Communication is of paramount importance in the area of Distribution Feeder Automation in general. In particular, demanding system performance characteristics required by the protection side of automation result in specific communications solutions for specific applications.

Current AGL Electricity communications with high voltage pole top switchgear relies mainly on point to multi-point radio communication operating privately owned sets of frequencies allocated to AGL Electricity within 900MHz band. This solution provides affordable and flexible communications with pole top devices that need to be remotely controlled and/or monitored. As with all multiple access systems the system response time slows down as the number of Remote Terminal Units increases. To combat the response time problem and to increase the system security a number of Communication Nodes are proposed to be established with the maximum number of Remote Terminal Units/pole top devices reaching 50 per Communication Node. Practical tests carried out by AGL Electricity guarantee the overall response time of less than 5 seconds under this arrangement. The overall response time includes the command issue, time needed to perform the operation such as closing or opening of a switch and receiving confirmation about the changed status on a host PC. AGL Electricity is committed to four Communication Nodes planned to provide communications coverage to majority of pole top devices within AGL Electricity supply area.

Whilst 5 second response time is perfectly acceptable for remote control and monitoring it is far too long for the protection requirements.

6.1 COMMUNICATIONS SOLUTIONS FOR INDIRECT FAULT DETECTION

Due to fast response times required by the blocking scheme, planned to be employed by Indirect Fault Detection, only those communication solutions that guarantee response times lesser than 200ms can be considered.

The following communication options are under investigation regarding their implementation in the blocking scheme illustrated in Figure 2.:

- 2.4GHz spread spectrum radio
- fibre optic cable
- pilot wire solution

As the distribution feeders in urban areas are relatively short the communications solutions listed above present viable options for investigations.

6.2 2.4GHz SPREAD SPECTRUM RADIO

The spread spectrum radio presents a reasonably affordable and flexible solution that can be implemented on a recloser installation with the purpose of providing/receiving a blocking signal. This solution is currently under investigations by AGL Electricity. The line of sight requirement dictated by 2.4 GHz operating frequency is a disadvantage. However preliminary tests carried out between locations that did not enjoy line of sight showed a reasonable signal penetration. Considering that the average distance between the two reclosers should not exceed 5km, the prognosis for achieving a reliable and fast blocking signal is encouraging. Further tests are scheduled to gather statistical data on the reliability and speed of this type of communications.

The scheme can also work in a limited point to multi-point configuration. This feature is regarded as advantageous because of possible cost sharing between remote radio units.

6.3 FIBRE OPTIC CABLE APPLICATION

The fibre optic solution can be recommended only under extremely hostile circumstances such as total lack of radio signal penetration. The fibre optic cable run is costly and burdens future network restructures such as relocations of pole top units with additional costs. In addition its installation will most likely meet with the opposition from local councils due to its adverse visual impact. Although it offers the fastest response time and a very good protection against induction, its installation is not justifiable mainly due to extremely low data traffic, i.e. one blocking signal when a fault occurs.

6.4 PILOT WIRE SOLUTION

The pilot wire solution can be justifiable only if an existing pilot wire installation is under consideration or if the distance between reclosers is relatively short. New installation of a standard pilot wire run is not recommended due to its visual impact and isolation issues caused by induction.

7.0 MANAGERIAL/TECHNICAL STRATEGIES

Management of innovative solutions in any field is by its nature associated by a high risk factor. Thus gradual implementation of elaborate pilot schemes ensured successful implementation of remote control and monitoring at a very low cost.

In principle 'off the shelf' components were used to minimize the risk exposure associated with new technologies. A well proven Darcom radio / MOSCAD RTU package was successfully implemented on NGK and S&C load break switches. To maximize security and reliability MDLC 7 layer protocol was employed for the radio wide area network.

Due to shortage of internal resources an external integrator was engaged to build the system according to specifications stipulated by AGL Electricity.

To ensure overall system integrity a rigorous factory acceptance testing is performed every time a new piece of hardware is purchased thus facilitating 'plug and play' approach during field installations.

8.0 CONCLUSION

Current critical mass of 40, 22kV high voltage switches fully operational in remote control and monitoring mode as well as the experience gained during the system establishment phase provides AGL Electricity with a sufficient background for future works on any issue related to the Distribution Feeder Automation. Fault detection and location will always be a vital part of these works as it constitutes the basis for any Distribution Feeder Automation System.

8.0 ACKNOWLEDGEMENTS

The author would like to thank Victoria University, Faculty of Engineering, Melbourne and The Australian Gas Light Company Electricity Limited for their support and provided research environment.

Communications considerations for automation schemes in existing Zone Substations

Ryszard Orlowski* and Akhtar Kalam**

* Agility Pty Ltd, Melbourne, Australia
** Victoria University of Technology, Melbourne, Australia

Abstract

The implementation of communications facilitating automation schemes at new Zone Substations can be factored into the overall project cost as an inherent part of the projects thus making good prospects for their financial justification. However, the implementation of communications/automation in the existing Zone Substations is usually not a financially viable proposition on its own due to the excessive installation and refurbishment costs. One way of implementing automation schemes in the existing Zone Substations is by adopting a piecemeal opportunistic approach. However, this approach is usually burdened with compromises arising from truncated technical scopes such as degraded communications, stand-alone applications and financial constraints. These compromises limit the effectiveness of automation schemes to the extent of making them perceived as not viable.

The successful implementation of automation in the existing Zone Substations followed by the achievement of ultimate benefits can only be assured by a uniform approach guaranteed by a strict adherence to the Business Communications Strategy of the utility. This strategy has to adopt a holistic approach to communications in the business including the Distribution Network communications supporting automation. Special considerations need to be given to the utilisation of hybrid communications media, communications protocols and a secure migration path. Business policies, regulating the sale and lease of excess bandwidth, need to be incorporated within the framework of the Business Communications Strategy. The sale and lease of excess bandwidth present a great potential to offset the high costs associated with the implementation of the inter-Zone Substation WANs.

In a privatised Distribution Business arena, automation strategy will invariably be a staged implementation of automation schemes in Zone Substations so that the changing performance levels set by the Essential Services Commission, stimulated by the heightened performance expectations from the consumers, are progressively met. As a result, the communications solutions supporting automation programs will be also a staged implementation.

Key words: Zone Substation – WAN – LAN – Communications infrastructure – Power system protection - Automation

1.0 Background

1.1 *Existing communications infrastructure*

One of the most critical factors in the successful implementation of automation schemes in the existing Zone Substations is the availability of reliable communications. The communications need to be capable of catering for protection, remote control & monitoring, power quality monitoring as well as automation applications. In a modern Zone Substation environment, a successful automation program can be assured if a Local Area Network (LAN) is implemented in the Zone Substation itself. However, more elaborate automation schemes, such as the schemes catering for the load transfers between Zone Substations, depend heavily on the exchange of information between electrically adjacent Zone Substations. For that reason alone a fast and reliable Wide Area Network (WAN), characterised by deterministic performance, is a prerequisite for the implementation of comprehensive automation schemes. In most cases, the Distribution Networks comprise interconnected subnetworks centred around their Zone Substations. All the Zone Substations participating in the automation schemes need to be interfaced with the inter-Zone Substation WAN. Irrespective of the geographical coverage of the Distribution Network, the implementation of a WAN for the sole use by the Distribution Network communications is usually cost prohibitive. Consequently, concurrent business communications applications need to be incorporated to justify the implementation of a WAN.

Additional difficulty is posed by the need for communications with pole top devices that provide timely information about the network required by an automation scheme to make informed decisions automatically. Provision of this information within the time constraints imposed by automation schemes is the biggest challenge both from a technical and financial point of view.

The profile of the current communications infrastructure for electrical networks, whether it is cabling or the associated electronic equipment, evolved as the result of the gradual development of electrical networks over the last few decades. Generally, the age of the communications infrastructure dates back to the Zone Substations' construction times.

The wide installation time span is reflected by a variety of communications solutions implemented. At present, they can only be described as aged legacy systems. Those communications systems were installed mainly to cater for protection and supervisory control and data acquisition (SCADA) needs. Consequently, from a contemporary point of view, the communications infrastructure servicing most of the existing Zone Substations is characterised by low capacity, slow data transfer rates, the need for regenerators when dealing with longer distances, susceptibility to interference, communications security issues and generally high degree of integration inflexibility.

Communications cabling infrastructure in particular comprises mainly multi-pair copper cables. With the exception of the leased telephone network lines these copper cables are privately owned by the companies involved with the transmission/distribution of electrical energy. The deployed communications cabling network follows predominantly star topology thus making the networks highly vulnerable to communications failures resulting from external factors such as weather or human interference due to the absence of physically diverse paths. Although the design life of these communications cables has been well exceeded, they still give adequate service for the originally designed communications schemes. Thus, overall replacement of the copper cables with modern high speed/high capacity cabling solutions linking the existing Zone Substations is not a financially viable proposition unless other than protection and SCADA applications are incorporated. An example of these additional applications is corporate communications supporting office computer applications such as e-mail or financial/asset management systems.

1.2 *Automation prerequisites*

Automation schemes applied in the Zone Substations are heavily centred around protection relays as primary operation and control devices. Although other intelligent electronic devices (IEDs) are also involved in automation schemes their role is not as paramount as that of protection relays [1].

Traditional electromechanical protection relays have been employed for their basic protection functions on a stand-alone basis. Quite often they are not equipped with communications interfaces, so costly and time consuming 'on site' attendance is required. It is these protection relay types that are targeted for replacement with multifunction digital relays. Multifunction digital relays, equipped with ethernet communications cards, offer a whole gambit of additional functions that were not available before in one package [1]. This in turn makes the implementation of cost-effective automation quite feasible within a Zone Substation as the retrofitting costs can be easily offset by the benefits offered by the availability of additional functions. The multifunction digital relays can also facilitate the implementation of more elaborate automation schemes, such as the schemes catering for the load transfers between Zone Substations, which depend heavily on the 'near real time' exchange of information between electrically adjacent Zone Substations.

Amongst these additional protection relay functions are the availability of pre-fault, fault and post-fault voltages and currents, instantaneous and 'on demand' metering, ability to remotely download protection settings and fault location analysis [1]. The availability of such voluminous data for instantaneous transfers poses a staggering task for the communications systems currently employed in the Zone Substations. In essence, the information made available by multifunction digital relays and other IEDs, located in a typical Zone Substation, cannot be easily utilised by personnel that need it the most under the fault condition, i.e. those located in a remote operational centre / control room. This is due to the lack of fast, reliable and secure communications network linking Zone Substations and operational centre(s).

In addition, protection applications and standards, such as requirements for physically diverse alternative routes in current differential schemes and consideration of propagation delay times, set uniquely high design standards for the forthcoming electrical network communications networks [2]. High bit per second digital transmissions and the ring network topology augmented by automatic route switching are implied. Due to the above mentioned protection data transmission reliability requirements, the need for simultaneous large volume data transmissions, the absolute data security and distances involved, the choice of communications is limited to the guided communications over single-mode fibre optic cables. To ensure most deterministic communications network performance for the time critical protection and control functions, they need to be prioritised or virtually separated from the voluminous diagnostic or event data coming from the relays and other IEDs. These two data streams can then be diverted to the operational centre and the diagnostic centre respectively. The final requirement is the implementation of the data transmission monitoring system providing communications network diagnostics and supervision. The above communications performance prerequisites constitute typical specifications for a protection grade Wide Area Network (WAN).

2.0 Inter-Zone Substation WAN

The need for the implementation of the inter-Zone Substation WAN, based on a ring topology, is predominantly due to the involvement of protection data transmissions. This communications in turn can facilitate various automation schemes. However, other potentially critical applications, such as corporate communications, also stipulate ring topology networks as a preferred solution. The synergies originating from overlapping performance standards, required by different applications or users, offer the basis for a holistic approach to the implementation of a high standard communications backbone such as the inter-Zone Substation WAN. Consequently, concurrent business communications applications need to be incorporated to justify the implementation of an inter-Zone Substation WAN.

The most expensive component of the inter-Zone Substation WAN is its cabling infrastructure and it is this aspect that usually makes a protection grade WAN implementation cost prohibitive. Due to the significant capital outlay necessary to install fibre optic cables, a staged approach needs to be adopted targeting installations to service new Zone Substations first. As the justification process for the existing Zone Substations is much more difficult, naturally those Zone Substations scheduled for significant protection upgrade/retrofitting works should be given priority. An excellent opportunity for communications upgrades presents itself when Zone Substations are scheduled for the Neutral Earthing Resistor (NER) installations. In these cases the outdated protection relays are usually replaced with multifunction digital relays that demand reliable protection grade communications.

The installation of the fibre optic cable backbone is a long-term investment and for that reason it needs to be capable of accommodating the frequent technological changes occurring in the associated terminating equipment. Ultimately the inter-Zone Substation cabling infrastructure may not be altogether privately owned due to the excessive installation cost. Leased or exchanged 'dark fibres' of acceptable quality constitute as sound solution as privately owned ones as long as the maintenance and supervision regimes are adequate for the application needs. Inevitably, there will be cases where the installation of fibre optic cables is unjustifiable due to the continuing reasonable performance of the existing copper cables. A typical example is copper cables that can carry limited capacity multiplexed traffic of approximately 2Mbs. Thus, by necessity rather than choice, the inter-Zone Substation WAN will ultimately end up as a hybrid solution comprising fibre optic and microwave communications as well as communications over selected copper cables.

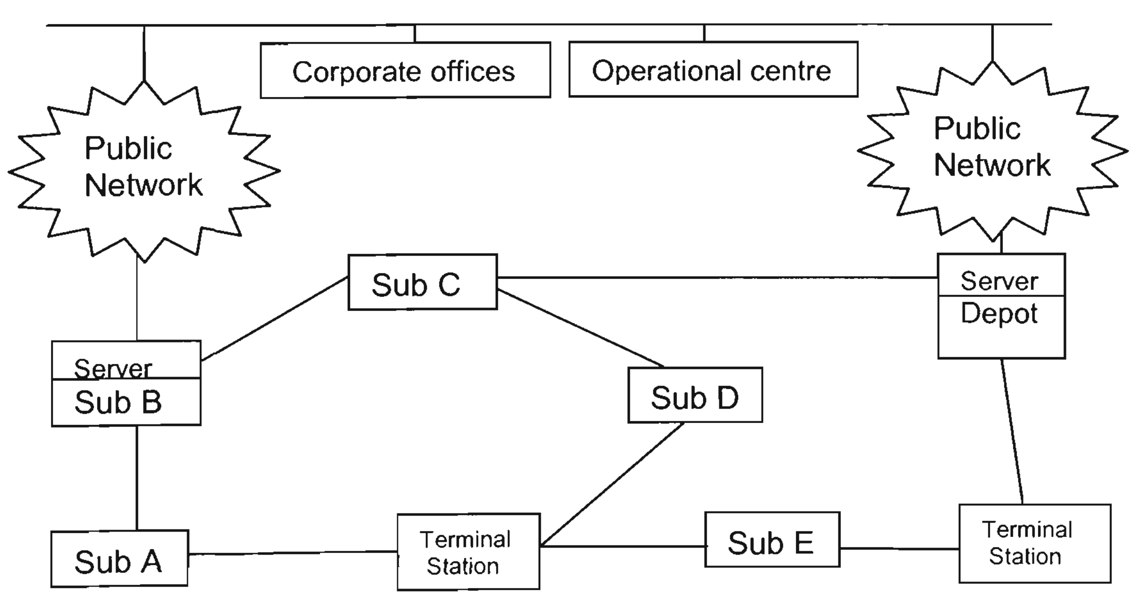


Figure 1: Inter-Zone Substation WAN architecture

The connectivity with the operational centre and the associated 'back up' operational centre, implemented through the telecommunications service providers, needs to be flexible so that changing business needs can be easily accommodated in a timely manner. This ease of interconnectivity needs to be reflected particularly in emergency situations under which business continuity may be threatened. To that extent an example of a resilient inter-Zone Substation WAN is shown in Figure 1. It illustrates that the interconnectivity with the telecommunications service provider(s) can be achieved anywhere within the inter-Zone Substation WAN. The servers constitute an integral part of the WAN. They are located at the boundary of the public network and the private network. Their size and number can be tailored to suit specific needs. In general, the availability of a high capacity WAN solution at Zone Substations is a critical milestone in itself as it allows for the implementation of much more cost-effective work practices by Distribution Businesses.

3.0 Zone Substation LANs

3.1 *General*

The primary role for the Zone Substation LANs is to provide reliable communications and interconnectivity with the IEDs present in the Zone Substations and /or those located out in the field. The LANs are configured, in each Zone Substation case, around a multi-port ethernet switch with a reasonable degree of redundancy built in. These ethernet switches provide interface with the inter-Zone Substation WAN. Due to the single port availability on the individual relays and other IEDs a single layer star topology for the Zone Substation LANs is implied. A typical Zone Substation LAN architecture is shown in Figure 2. It covers the communications confined to a Zone Substation as well as the communications with the field devices located within the Zone Substation coverage area.

3.2 *Zone Substation relays and IEDs*

In the existing Zone Substations the protection relays, which can be communicated with, are the primary target for automation. Those protection relays that lack the ability to communicate are subject to the staged replacement program based on the benefits analysis applied on case by case basis. The relays installed, as a result of the replacement program, usually offer widely accepted and standardised communications solutions such as ethernet cards. However, the remaining relays, usually equipped with a single serial communications port each, can present interconnectivity problems resulting from a range of communications protocols utilised. To be able to address the issue of varying non-ethernet protocols it is advantageous to install Internet Protocol (IP) addressable terminal servers. With their embedded smart protocols they provide transparent communications with IEDs of a varied vintage. Within the Zone Substation environment, point-to-point links over multi-mode fibre is the preferred solution.

Protection relay management communications with the ethernet switch can be implemented either directly or through the terminal server(s) depending on the availability of the ethernet card at the relay end. The same approach applies to the other IEDs present at a Zone Substation. At present, relay protection signalling itself is not recommended to be passed via ethernet switches as a general solution due to the not quite deterministic performance of the IP protocol. However, the forthcoming protocol enhancements, covering the ethernet-based communications for time critical industrial applications, are expected to resolve the issue of unacceptable industry specific time delays. Thus, until these enhancements are proven and recognised by the industry, the protection signalling has to be implemented over the more time definite communications solutions such as time division multiplexing.

3.3 *Power quality (PQ) monitoring*

PQ monitoring of the distribution bus voltage/current and potentially distribution feeder currents at Zone Substations is a formidable and costly task whether carried out routinely or under fault conditions. The forthcoming addition of power quality monitors at the ends of distribution feeders will make this task much more difficult due to the sheer volume of data that will be made available for storage and subsequent analysis. Thus, only the direct access to the corporate network, via the Zone Substation LANs and the inter-Zone Substation WAN will permit the cost-effective automatic data collection/updates. In addition, the achieved flexibility will allow for a prompt multiple access to this information by personnel connected to the network anywhere anytime. Communications solutions involved in data transfers from the remotely located PQ monitors will be limited mainly to the spread spectrum ethernet radio solutions. The limiting factors are the remote locations of the feeder ends and the availability of communications channels with sufficient capacity. This reasoning applies particularly to the rural areas.

3.4 *Automated remote metering*

Automated remote metering can be implemented in a variety of ways. This is due to a wide range of vendor specific telemetry units available on the market. One of the least intrusive ways to implement remote metering is to install a low voltage power line carrier solution between customers' premises and a concentrator that can communicate with a Zone Substation LAN. Generally, the preferred solution for the communications links between the concentrators and Zone Substations is a spread spectrum ethernet radio

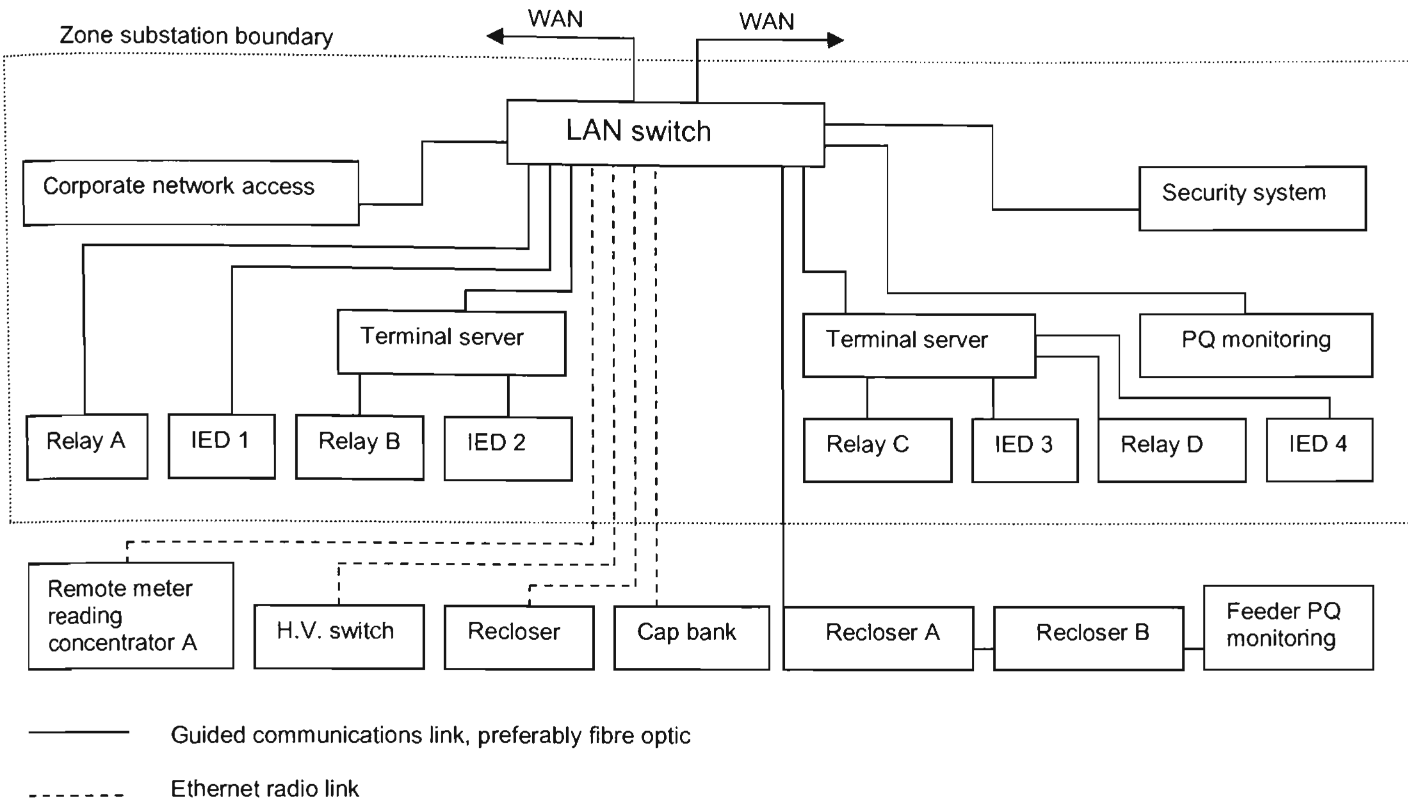


Figure 2: Zone Substation LAN architecture

solution as it is directly compatible with Zone Substation LANs. The Zone Substation LANs pass the metering data, via inter–Zone Substation WAN, onto a server where it is stored. This server makes the data available to the end, most likely corporate, user.

3.5 *Security systems*

Due to the increasing degree of remote control and monitoring as well as automation, the attendance at the Zone Substations is significantly reduced. This poses a security issue. Motion detection devices or surveillance cameras can address this issue. However, the degree of effectiveness of these devices depends on the availability of communications bandwidth. With the presence of the inter-Zone Substation WAN augmented by Zone Substation LANs, an on going Zone Substation surveillance can be implemented effectively. If public network communications is not involved, negligible running cost is expected.

3.6 *Switching devices located in the field*

One of the most challenging aspects of Zone Substation automation is fast and reliable communications with the field devices such as reclosers, remotely controlled switches and pole top capacitor banks. Reclosers and remotely controlled switches play a crucial role in the remotely controlled distribution network switching. Safety considerations are of paramount importance due to their exposure to public, in particular in urban areas. For the 'in line' reclosers installed on short but heavily loaded distribution feeders, protection discrimination is difficult to achieve. Thus, there is a need for protection blocking schemes implemented over guided communications media, preferably fibre optic cables, to ensure protection signalling reliability standards. These blocking schemes may be required between Zone Substation circuit breakers and 'in line' reclosers and/or between the 'in line' reclosers themselves. Figure 2 shows reclosers A and B in an 'in line' configuration. Protection signalling is implemented over a dedicated fibre optic pair connecting the reclosers' relays and the Zone Substation circuit breaker relay. Protection signalling does not involve the LAN switch and for that reason it is not depicted in Figure 2. The associated remote control and monitoring can be implemented over the ethernet-based communications utilising fibre optic cable, as shown in Figure 2, or spread spectrum radio. Both solutions are directly compatible with the Zone Substation LANs.

4.0 Conclusion

The essential prerequisite for the implementation of elaborate automation schemes in the existing Zone Substations is the provision of high bandwidth for communications between the Zone Substations and the Operational Centre(s). This can be achieved by the installation of a privately owned inter-Zone Substation WAN operating in conjunction with the public communications network. Such hybrid network architecture guarantees flexible interconnectivity. Thus, it can promptly accommodate opportunistic business needs.

The high installation cost of the inter-Zone Substation WAN and the continued performance of the existing Zone Substation communications infrastructure make the proposed WAN installations difficult to justify. The existing synergies can be capitalised on provided they are incorporated within the Business Communications Strategy. The holistic approach to the business communications, ensured by the Business Communications Strategy, will stem the opportunistic piecemeal communications infrastructure installations that offer substandard performance in terms of modern communications standards. Resilient communications network, implemented over physically diverse paths, will ensure contingency thus guaranteeing business continuity in emergency situations.

5.0 Acknowledgments

The author would like to thank Victoria University, Faculty of Science, Engineering and Technology, Melbourne and Agility Pty Ltd, Melbourne, Australia for their support.

6.0 Bibliography

1. Kenneth C. Behrendt, Michael J. Dodd: "Substation relay data and communications", Schweitzer Engineering Laboratories and Wisconsin Electric Power Company.

2. A. Kalam: "Communications and Power Systems Protection", Electricity Supply Association of Australia, 2001.

Application of reclosers on urban Distribution Networks

Ryszard Orlowski* and Akhtar Kalam**

* Agility Pty Ltd, 333 Collins St, Melbourne, Australia. Tel: (03) 92012440.
E-mail: ryszard.orlowski@teamagility.com

** Victoria University of Technology, Melbourne, Australia

Abstract

Due to their increasing fault breaking capabilities, suitability for automation and remote control applications as well as feeder parameter monitoring, reclosers constitute a tool guaranteeing significant improvement of the distribution network performance indicators. Combined with innovative hybrid communications solutions, reclosers are capable of catering for special requirements, such as the need for protection blocking schemes, associated with the 'in line' recloser applications on urban distribution feeders. In addition, the reclosers' capability to provide ongoing feeder monitoring over fast and reliable communications links allows for proactive as well as reactive remedial actions to be taken by a Distribution Network owner.

Key words : Essential Services Commission; Distribution network indicators; Fault location; Recloser applications

1.0 BACKGROUND

Following the disaggregation of Victorian Electricity Industry in 1994, a framework was established to regulate service standards of utilities. Superseding the Office of the Regulator-General Victoria, the Essential Services Commission (ESC) has played the role of independent regulator to regulate essential utility services such as electricity. An integral part of the ESC regulatory framework is the reliability improvement incentive schemes. They are designed to reward or penalise the distributor depending on the network performance [1].

As part of the incentive schemes, a financial incentive called the S-factor has been developed. It encompasses Distribution Network performance indicators such as unplanned System Average Interruption Frequency Index (SAIFI), unplanned Customer Average Interruption Duration (CAIDI) and planned System Average Interruption Duration (SAIDI). Within the overall incentive scheme, these performance indicators were weighted to reflect their degree of importance as expressed by customers. As a result, the weightings for SAIFI, CAIDI and SAIDI were defined as 100%, 65% and 25% respectively [1]. It is clear that unplanned events on distribution networks, characterised by SAIFI and CAIDI, present the biggest burden for the customers. Therefore, they are the primary targets for the distribution network owners to focus their reliability improvement strategies on.

2.0 URBAN FEEDER CHARACTERISTICS

Typical urban distribution networks in Victoria operate at 22kV, 11kV or 6.6kV. The feeders are radial but with feeder to feeder paralleling capabilities. Due to the predominantly overhead bare wire construction, the distribution feeders in urban areas are often subject to fauna, vegetation and human interference. Faults caused by urban wild life, such as fruit bats or possums, are of a random nature and difficult to prevent. With feeders of these characteristics the undertaken preventative measures are not always successful. In a privatised Distribution Business arena, re-conductoring of the overhead network with insulated cables and/or undergrounding are not financially viable propositions.

Fault currents, depending on the fault location with respect to source, can reach levels of 12kA to 13kA. Due to the presence of High Voltage customers, characterised by high load consumption, the load distribution along feeders can be 'lumpy' and as a result protection discrimination on short feeders cannot always be achieved. Where protection discrimination can be achieved, the protection may not be as fast as would otherwise be desired.

3.0 FEEDER RELIABILITY IMPROVEMENT STRATEGY

As a consequence of the traditional physical feeder characteristics, unplanned events on the networks, referred to as faults and reflected by worsened SAIFI and CAIDI, will take place. Their effects, however, expressed in terms of the number of customers affected by the feeder faults as well as the resulting duration of outages, could be minimised by implementing a uniform feeder reliability improvement strategy. To improve SAIFI and CAIDI, this strategy focuses on feeder sectionalisation, to minimise the number of customers affected by the interruption(s) to supply, and subsequent fault containment within the affected feeder section(s). To further improve CAIDI, the healthy feeder section(s), located downstream of the faulty section, should be back-fed by the adjacent feeder whenever such an opportunity is presented. It is of paramount importance that the feeder sections on the network are defined on a standardised load capacity basis. Under this scenario the load being transferred is known and the adjacent feeder has adequate capacity to carry the additional load. In effect, this strategy constitutes a fault location scheme heavily reliant on the fault current breaking capabilities of the feeder switching apparatus installed at the boundaries of the feeder sections.

4.0 FEEDER SWITCHING APPARATUS

There are two types of controllable switching apparatus that can be employed on distribution feeders. They are load break switches and fault break reclosers. Both can be remotely controlled and monitored. Load break switches have been widely used as the primary device for remote control and monitoring of distribution feeders. However, their drawback is the lack of a fault current breaking capability. They rely on the Zone Substation circuit breaker fault clearing capabilities thus causing all customers on the feeder to experience an outage whenever a feeder fault occurs. As a result, SAIFI and CAIDI are grossly affected.

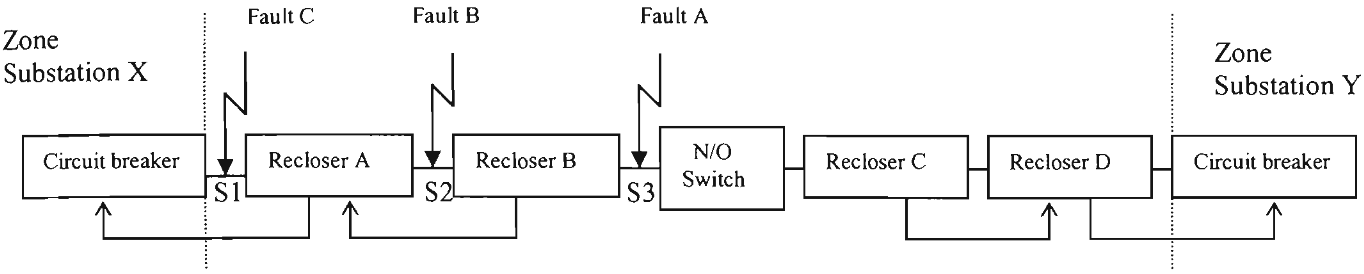
The recent increase in fault breaking capabilities of reclosers as well as a substantial cost reduction due to new technologies employed by manufacturers, have made reclosers a much more attractive feeder switching hardware option. In addition, reclosers installed 'in line' on a feeder address both SAIFI and CAIDI due to their ability to break fault currents. Thus, 'in line' reclosers limit the impact of a fault to a faulty feeder section saving the customers on the healthy feeder section(s) an outage. These recloser features have ensured change in their typical applications. In the past reclosers were predominantly used in rural areas. However, their application in urban areas results in significant improvements in SAIFI and CAIDI due to a large number of customers affected in the event of a feeder fault.

To facilitate the reliability improvement strategy, remotely controlled and monitored distribution feeder switching apparatus needs to be gradually installed at the boundaries of the feeder sections including feeder paralleling points. As a result, rapid load transfers can be carried out under fault conditions as well as during planned network reconfiguration(s). Remotely controlled and monitored load break switches can be successfully utilised on the paralleling points. However, reclosers with re-configurable protection settings, augmented by reliable communications, are envisaged to be commonly used at the primary (feeder backbone) paralleling points.

In the event of a fault, the affected switching section can be promptly isolated via remote control, provided the fault location scheme correctly identified the faulted feeder section.

5.0 APPROACH TO FAULT LOCATION

An approach that guarantees a reduction of key performance indicators, such as SAIFI and CAIDI, is a reliable fault location scheme. A fault location scheme can be introduced by the installation of two 'in line' reclosers in the backbone of each distribution feeder. In such a scheme the two reclosers are located at the boundaries of the switching sections as depicted in Figure 1. The fault current is detected by the protection circuitry of the recloser(s) located upstream, i.e. closer to the point of supply, from the faulted section. Only the recloser that is adjacent to the faulted section is allowed to operate. This can be implemented when protection discrimination can be achieved between the 'in line' reclosers and/or the Zone Substation circuit breaker. However, on feeders that are short, heavily loaded and with 'lumpy' load distribution, the discrimination between the reclosers' inverse time protection characteristics curves cannot always be achieved. In these cases, blocking schemes need to be implemented to prevent the upstream recloser and/or a circuit breaker from operation. Single shot reclose operations, preferred on urban distribution feeders, reinforce the requirement for fast blocking schemes.



N/O - normally open
S1 - feeder section S1

Figure 1: Illustration of a full blocking scheme

Due to the cost involved the simplified schemes, involving blocking between the 'in line' reclosers only, are more likely to be implemented.

6.0 BASIC FAULT SCENARIOS

The operation of a full blocking scheme can be explained in conjunction with Figure 1. Three basic fault scenarios are presented by 'Fault A', 'Fault B' and 'Fault C' and are considered independently. The improvement in SAIFI and CAIDI is understood as savings achieved in comparison with the feeders employing load break switches in place of reclosers. With only load break switches employed, the whole feeder would experience an interruption to supply due to the circuit breaker fault clearing at the Zone Substation end whenever 'Fault A', 'Fault B' or 'Fault C' occurred.

The scenario presented by 'Fault A' illustrates that customers on two thirds of the feeder can be saved from an interruption to supply if a blocking scheme between reclosers A, B and the circuit breaker at Zone Substation X is implemented. This would be reflected in an improvement in SAIFI. Under this scenario, reclosers A, B and the Zone Substation circuit breaker all detect the fault current but only recloser B opens, blocking recloser A and the Zone Substation circuit breaker from operation. As a result the feeder section S3, between recloser B and the normally open high voltage switch, is isolated. The impact of this fault is localised within this feeder section. Overall, two feeder sections are not affected by the fault and one section is permanently affected. An improvement in CAIDI could be expected because the location of the fault has been narrowed to one feeder section.

The scenario presented by 'Fault B' illustrates that customers on one third of a feeder, i.e. section S1, do not experience the interruption to supply at all. This is due to the blocking scheme implemented between recloser A and the circuit breaker at Zone Substation X. The fault is localised to section S2 after recloser B is opened via remote control. Customers on the feeder section S3 do experience an interruption to supply. However, it is as short as the time needed to back-feed section S3 via the normally open switch. The improvement in SAIFI is less significant than in the 'Fault A' scenario as more customers experience the interruption to supply. CAIDI performance however, is further improved by virtue of the fact that although more customers are impacted by the fault, because supply is restored quickly, the CAIDI measure for the overall network is improved. In scenario 'Fault B' one feeder section is not affected by the fault, one section is temporarily affected and one section is permanently affected.

The scenario presented by 'Fault C' illustrates that customers on all three feeder sections are affected by the feeder fault. This is because the fault is cleared by the Zone Substation circuit breaker. Once recloser A is opened via remote control, the fault is localised to section S1. Following the fault containment, feeder sections S2 and S3 are back-fed via the normally open switch. CAIDI performance is better than in the 'Fault B' scenario because more customers have their supply restored quickly following the fault. There is no improvement in SAIFI as all feeder sections experience the interruption to supply. Overall, two feeder sections are temporarily affected and one section is permanently affected.

It is evident that the availability of fast and reliable communications links servicing protection signalling is a basic prerequisite for the implementation of blocking schemes.

7.0 RECLOSER COMMUNICATIONS

7.1 Introduction

To fulfil their role dictated by fault location schemes, reclosers need to operate in two modes. Firstly, in a recloser specific mode when recloser operation is governed by the events on a feeder resulting in actions triggered by recloser protection relays. Secondly, reclosers need to be capable of operating in a remote control and monitoring mode when standard network reconfiguration needs to be carried out. Consequently, there are two aspects of recloser communications, i.e. recloser protection signalling, characterised by response times in the order of milliseconds, and communications facilitating remote control and monitoring. Both of these communications types are of paramount importance in the area of Distribution Feeder Automation involving reclosers as a rule. However, the requirements for the performance standards for these communications types are significantly different. Due to the high speed and reliability, required by protection applications, the choice of a suitable communications medium is quite often limited to fibre optics. In urban areas, the implementation of communications solutions based on fibre optics can be difficult logistically. Also, it is not cost effective when implemented for recloser needs only.

On the other hand, the performance standards for communications, facilitating remote control and monitoring on reclosers, are more relaxed in comparison with those of protection signalling. Response times in the order of 1 second are quite acceptable when specific control functions are considered. Diagnostic functions, such as retrievals of event log files or oscillographic disturbance records can take up to a few minutes.

Overall, specific communications solutions can only address specific communications needs. As a result two distinct communications approaches need to be adopted when considering communications with reclosers, i.e. guided communications for protection signalling and radio communications for remote control and monitoring applications when the implementation of guided communications is not justifiable. In cases where guided communications is available, joint implementation of both protection signalling and communications for remote control and monitoring is the obvious solution.

7.2 Recloser communications considerations

In line with protection relay technology developments, modern recloser protection relays incorporate basic communications functions within the relay. This approach leaves the internal process control with the relay's Central Processing Unit (CPU). Due to the stringent processing time constraints, measured in cycles referenced to the frequency of supply, it is crucial for the CPU to give the first priority to processes catering for protection functions.

Out of the three distinct CPU process categories, i.e. protection parameter calculations, protection signalling and communications covering remote control and monitoring, the latter has the lowest priority so that the relay's CPU does not get overburdened with non-protection tasks at protection critical times. Interfacing with the outside world is usually implemented via a number of serial communications ports. Protection signalling is implemented over dedicated ports. Theoretically, this approach eliminates the need for external Remote Terminal Units (RTUs) implying cost savings.

In practice, however, there is still a need for a communications platform, between field devices and the operational centre, to transport existing/legacy protocols. This communications platform needs to be sufficiently flexible to accommodate the introduction of newer relay types equipped to run with higher communications speeds. Network diagnostics and network re-configuration are the basic features expected from such a platform. Consequently, the installation of additional communications hardware is required in the recloser controller to fulfil the communications needs of modern remote control and monitoring. Only a uniform approach to network communications, such as the extension of ethernet based communications to field devices including reclosers, can address the aforementioned requirements. A prerequisite for that is the implementation of ethernet based communications on recloser protection relays, i.e. ethernet cards, a task the manufacturers of recloser protection relays have not widely embraced.

Ethernet-based communications is not the only solution available for communications with reclosers. However, it is a solution that has the potential to simplify existing network complexities arising from a wide variety of legacy communications protocols used by existing field devices. Due to the high bandwidth requirement of ethernet-based communications only fibre optic and spread spectrum radio solutions can be considered.

7.3 Recloser remote control and monitoring benefits

The primary benefit of remote control and monitoring on reclosers is network switching, whether under fault conditions or during planned network reconfiguration, commanded from the operational centre. Reliable status and alarm monitoring allows for informed decision making under any circumstance. Remotely controlled and monitored reclosers also increase the degree of knowledge about network parameters along the feeders. They allow for proactive as well as reactive remedial actions to be taken by a Distribution Network owner. A feature enabling proactive action is sensitive earth fault (SEF) monitoring. In this application, increasing SEF current levels, compared with the bench-marked SEF current levels, can be met with remedial action before reaching the pre-set trip level. A typical example is when a tree grows into power lines and the resultant intermittent current leakage raises an SEF alarm. The tree branches can be cleared well before the SEF trip level is reached, averting customer outages and reducing the risk of fire. Reclose operations and post fault network switching are examples of reactive remedial actions.

Without remote control and monitoring on reclosers the only option for the distribution network owner is to rely on time consuming reactive remedial actions. A typical example is a feeder recloser that tripped and went to lockout due to a fault that took place at night. Because of light feeder loading at night, the recloser trip may go unnoticed by the operational centre staff until notified by irate customer(s). This notification may come hours after the fault occurrence.

The post fault analyses require reliable remote event log file downloads. Retrieving event reports may use manufacturer specific protocols for each recloser relay type. When the number of reclosers on the network is significant and when they are spread over a large area, efficient downloading, file storage and subsequent access for analysis purposes becomes a complicated and costly exercise. The issue is exacerbated if legacy protocols are involved. For this reason the implementation of an ethernet based communications solution, capable of providing a transportation platform for serial protocols and widely accepted by the communications industry, is of significant importance for the network owner as it brings benefits in terms of reduced maintenance costs.

7.4 Recloser controller with full blocking

The maximum benefits can be achieved when the 'in line' reclosers are equipped with remote control and monitoring as well as protection signalling implemented over fibre optic cables. Depending on specific feeder requirements, protection signalling can be implemented as a limited blocking scheme or as a full blocking scheme. The limited blocking scheme involves blocking of the upstream recloser by the downstream recloser or blocking of the Zone Substation circuit breaker by the upstream recloser. The full blocking scheme involves blocking of the upstream recloser by the downstream recloser as well as blocking of the Zone Substation circuit breaker by the upstream recloser as depicted in Figure 1. In this arrangement the communications hardware and software configuration of the upstream recloser, i.e. recloser A, is the most elaborate as it encompasses two limited blocking schemes. The full blocking scheme communications hardware and the ethernet-based communications hardware for remote control and monitoring are shown in Figure 2. In essence, the ethernet-based communications covering remote control and monitoring is implemented over a self-healing fibre optic loop comprising two fibres. This fibre optic loop begins and ends at the Zone Substation X ethernet switch, which is part of the inter-Zone Substation Wide Area Network (WAN). The WAN facilitates communications with the operational centre. Along this fibre optic loop, recloser A, recloser B, remotely controlled switch, recloser C, recloser D and Zone Substation Y are connected. If need be, other devices may be connected anywhere on the loop. The return path from Zone Substation Y is physically diverse from the forward path to ensure self-healing of the entire loop.

Under normal circumstances, the incoming data arrives at the recloser A controller via the forward fibre connected to the receiving terminal of the optical/electrical media converter M1. Then, the data is passed onto the local ethernet switch where it gets switched according to its encoded address. Data destined for recloser B, remotely controlled switch, recloser C, recloser D and Zone Substation Y is forwarded through the transmitting terminal of M1. Data destined for recloser A is passed to the Internet Protocol (IP) addressable terminal server from where it is communicated serially to the appropriate relay port.

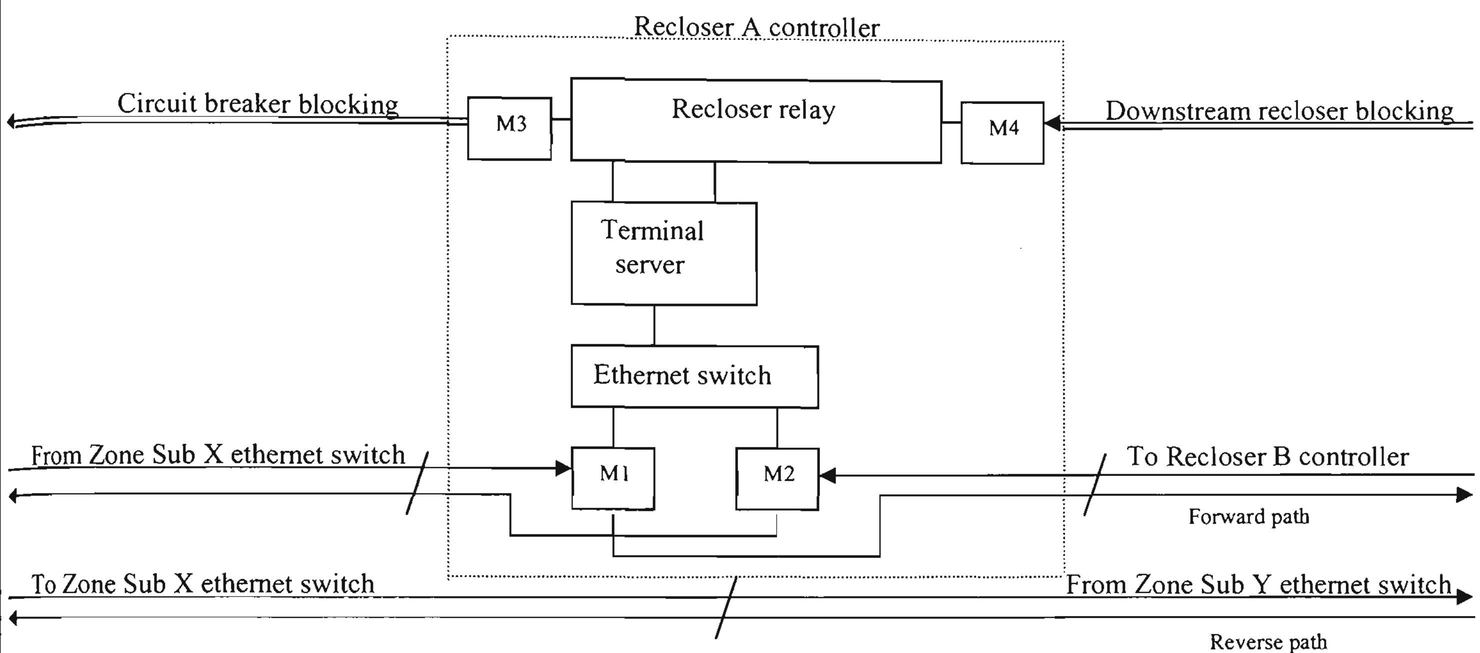


Figure 2: Upstream recloser controller communications hardware

There are two relay ports assigned for non-protection duties. One is for remote control and monitoring using a protocol such as DNP3. The other is for event log downloads using the relay manufacturer's specific protocol.

In the event of a fibre optic cable break down between Zone Substation X and recloser A, the reverse path is used. In this scenario, the incoming data arrives at the recloser A controller via the reverse fibre connected to the receiving terminal of the optical/electrical media converter M2. The data is then passed onto the local ethernet switch where it gets switched according to its encoded address. Data destined for recloser A is passed onto the terminal server from where it is communicated serially to the appropriate relay port.

Two limited blocking schemes are implemented through the dedicated optical/electrical media converters M3 and M4. M3 facilitates circuit breaker blocking and M4 facilitates the downstream recloser blocking. These blocking schemes utilise techniques developed specifically for protection applications [2],[3].

7.5 Ethernet radio considerations

When fibre optic communications is not available at a recloser location, then the only solution available for the ethernet-based communications is the spread spectrum radio. Its practical applications are limited to remote control and monitoring. Protection signalling, over the spread spectrum radio, does not offer the reliability required by protection applications. In urban areas ultra high frequency signal penetration can be inadequate, as the 'line of sight' cannot always be guaranteed. When fibre optic communications is not available the co-ordination of protection systems on reclosers has to rely on current and time discrimination.

The communications hardware of recloser A, depicted in Figure 2, can be easily modified for radio remote control and monitoring needs. A two port spread spectrum radio could be connected directly to the recloser relay offering instant ethernet capabilities.

8.0 CONCLUSION

Reclosers can significantly improve Distribution Network performance, in particular, when applied to combat unplanned outages. To maximise the potential benefits that reclosers offer, fast and reliable communications is essential. Protection signalling for blocking is required on feeders where protection discrimination is not achievable. In urban areas, modern protection signalling is practically limited to the fibre optic communications solution.

Ethernet-based communications is highly desired for the implementation of remote control and monitoring on reclosers. It provides a flexible platform for transportation of legacy protocols and can accommodate newly emerging communications solutions. Its implementation at field devices without access to optical fibres is still a challenge. Spread spectrum radio offers field devices access to ethernet-based communications. As spread spectrum radio provides limited coverage, a network of local master stations may be necessary.

9.0 ACKNOWLEDGEMENTS

The author would like to thank Victoria University, Faculty of Science, Engineering and Technology, Melbourne, Australia and Agility Pty Ltd, Melbourne, Australia for their support.

10.0 BIBLIOGRAPHY

1. Essential Commission Services; 'Electricity Distribution Price Determination 2001 – 2005', Volume 1, 'Statement of Purpose and Reasons (Sept 2000)'; www.esc.vic.gov.au/electricity.

2. K. Behrendt, K. Fodero; 'Implementing mirrored bits technology over various communications media', Schweitzer Engineering Laboratories, Application Guide, Volume 2, AG2001-12.

3. D. Costello, K. Fodero; 'Mirrored Bits Communications With Spread Spectrum Radios', Schweitzer Engineering Laboratories, Application Guide, Volume 2, AG2000-02. Engineering Laboratories, Application Guide, Volume 2, AG2001-12.

POWER SYSTEM COMMUNICATIONS CHALLANGES IN A PRIVATISED ENVIRONMENT

Ryszard Orlowski and Akhtar Kalam***

*Agility Pty Ltd, L2/333 Collins St, Melbourne, Victoria 3000, Australia.
**Victoria University of Technology, Footscray Park Campus, Victoria 3011, Australia.
E-mails: ryszard.orlowski@agility.net.au; Akhtar.Kalam@vu.edu.au

ABSTRACT

The disaggregation of the Power Industry, in the Australian state of Victoria in 1994 [1], led to privately owned power transmission and power distribution companies utilising in essence the same communications infrastructure as in the pre-restructure times. General agreements, outlining the ownership and usage of communications assets, were put in place at the time of the Power Industry restructure. However, the intricate nature of power system communications and the necessary adherence to the inherited Victorian communications network reticulation resulted in shared usage of some of the communications assets. Programs, aimed at building independent communications networks that targeted the specific communications needs of individual companies, were instigated and by now are in progress to a significant extent. The establishment of independent communications networks is inevitably constrained by inherited legacy systems, the replacement of which can be cost prohibitive. As a result, a balanced approach needs to be taken when reconciling the need for enhanced networks, capable of meeting challenges characteristic of contemporary operating environment, and the impact of the incurred communications network augmentation cost on the ever important shareholder value. This paper deals with the dilemma facing a Communications Asset Manager when evaluating the investment prospects in terms of the ageing infrastructure and related maintenance issues, emerging protection and communications technologies, capacity and reliability issues as well as the acceptable degree of interdependence on other transmission and/or distribution companies. In addition, the increased threat of malicious attacks on the power system communications, due to the growing reliance on the widely spread Ethernet solutions, demands the development and implementation of policies aimed at securing business continuity and ensuring safe power system communications network operation at all times.

1. BACKGROUND

Power system communications constitutes an integral, albeit often underestimated, part of a distribution company's operations. In Zone Substations, it services power protection systems, Supervisory Control and Data Acquisition (SCADA), Power Quality communications as well as voice communications implemented on a limited scale. In the field, it caters for communications with remotely controlled pole top devices such as load break switches, reclosers and capacitor banks as well as with field Power Quality and metering devices. As by nature communications solutions are application specific, there is no single solution capable of catering, on a cost-effective basis, for all the specific needs presented by the abovementioned applications. Consequently, power system communications is inevitably a hybrid system comprising a variety of legacy systems, implemented over the years but still performing their initially defined tasks adequately, and more modern systems that comply with modern communications operational standards. However, the overall operating environment has changed. Aged power communications systems, designed to address technical standards typical of the pre-disaggregation days, are still expected to perform well 10 years after privatisation. Admittedly, the heightened customer expectations in regards to the 'Reliability of Supply' issues, awakened by the privatisation justification process [1], can still be adequately addressed by the existing communications systems augmented on as per needs basis and predominantly targeting the most sensitive industrial customers. In general, present power communications systems are capable of supporting the current distribution network performance standards set by the regulator, the Essential Services Commission. The question is for how long they can last and how to determine the replacement time.

1.1 STOCK TAKING

A thorough scrutiny of the existing power system communications infrastructure shows that the vast majority of systems date to pre-disaggregation time, i.e. the year 1994. In fact, the bulk of the communications infrastructure comprises the original installations commissioned in the 1950s, 1960s and 1970s. Privately owned communications infrastructure is augmented by leased infrastructure, leased lines predominantly, usually used for SCADA applications and occasionally for protection applications as well.

1.2 CABLING INFRASTRUCTURE

Most of the privately owned cabling infrastructure consists of copper cables with an average age of 30 and 60 years for the overhead and underground supervisory cables respectively. The remaining cabling infrastructure is fibre optic with multi-mode fibre cable installations prevailing within Zone Substations and single-mode fibre cable installations covering long distances between Zone Substations. Most of the fibre optic cable installations are relatively recent, i.e. they were progressively commissioned commencing in the late 1980s, continuing up to the present day.

Overhead copper cables are generally utilised to their full capacity as they usually comprise only 11 copper pairs. Subject to induction, resulting from co-location with power lines, the overhead copper cables need to be terminated with isolation transformers for safety reasons. This severely restricts the bandwidth offered by the cable. Interference levels experienced by long metallic overhead cables are high, thus causing high error rates on the network and limiting the cable's usefulness for low power but fast signalling. Repeaters on overhead cables are often necessary, although not as often as on underground cables due to the inherently lower attenuation experienced by overhead cables compared to underground cables.

Underground copper cables, predominantly paper insulated, still offer some spare capacity as they are usually of a high copper strand count. However, the outside pairs are now showing signs of significant frequency response degradation due to moisture ingress. As a result of capacitive effect, the performance of underground cables is often constrained by the performance of repeaters that amplify the signalling over longer distances. When faulted, the underground cables are not easily accessible as most of them are directly buried. Quite often they are under sealed roads, due to the road widening works carried out over the years, and as a result the repair work is not always possible without the installation of overhead bypasses. The fault location equipment applied to the underground cables offers poor fault location resolution. In general, the repair work is costly and the restoration time is long. Irrespective of the number of cable cores available in an underground cable, multiplexing can only be implemented on a small number of circuits due to a cross-talk phenomenon occurring in the metallic medium.

Fibre optic cable installations constitute a minority of the cable installations because of the late entry of fibre optic technology into the power industry. All Dielectric Self Supporting (ADSS) fibre optic cables offer high transfer rates, multiple layers of multiplexing, high noise immunity, total immunity from induction and long distance transmissions without the need for repeaters. Long established Zone Substations feature the applications of multi-mode fibre optic technology only as a result of refurbishment or augmentation works. New Zone Substations, in particular, capitalise on the benefits of the multi-mode cables as they offer low-cost solutions perfectly suited for the modern communications terminal equipment that is being installed. Large-scale implementations of single-mode fibre optic cables have commenced and the process is gaining momentum when provision of communications to new Zone Substations is needed.

1.3 TERMINAL EQUIPMENT

Communications terminal equipment technologies, in use with copper cables, reflect the age of the cabling infrastructure. The systems installed over the years to fulfil particular tasks constitute a set of legacy systems that cannot be supported in the long term. These legacy systems are based on analogue technologies offering alarming but not monitoring suitable for the instigation of preventative maintenance. They comprise Voice Frequency (VF) systems, Frequency Division Multiplexers (FDM) and SCADA combining systems when dealing with SCADA communications applications. In addition, these legacy systems comprise schemes utilised for protection applications such as pilot wires, VF modulated pilot applications, remote trips and inter-trips [2].

VF systems were built 'in-house' by the communications departments of the now disaggregated State Electricity Commission of Victoria (SECV). As these departments have not been in existence since 1994, the majority of VF systems are totally unsupported and there are practically no spare parts. The FDM systems and SCADA combining systems, installed in the 1970s, share similar fate. Due to the technological progress in the communications area, the manufacturers of this equipment either ceased to exist or followed the technological change and manufacture modern communications equipment. The communications equipment, deployed for protection applications, is heavily dependent on the type of the protection schemes and relays already installed. In most cases, old electromechanical relays cannot be interfaced with modern communications systems. For that reason a change of a communications solution requires an upgrade of the relays. This process can often be cost prohibitive for the network owner, especially when implemented as an overall relay and communications refurbishment. As a result the old solutions remain in place until more viable justification points can be gathered such as failures in emergency situations. In many cases this equates to purely reactive maintenance.

The more recent Plesiosynchronous Digital Hierarchy (PDH) Nokia multiplexers utilise digital technology, i.e. time division multiplexing (TDM). They can be interfaced with both copper and fibre optic bearers. This technology is monitorable and offers automatic switchover functions to predetermined alternative routes. PDH Nokia multiplexers have been deployed on point to point links, usually between Zone Substations and/or control centre(s), since the late 1980s. This technology is utilised by both SCADA and protection applications. It is still well supported by the manufacturer with local technical support available as well. However, this technology is ageing and a succession path needs to be considered. The need for the next generation multiplexing equipment, such as Synchronous Digital Hierarchy (SDH), ought to be evaluated in terms of its advantages such as large data volumes, ease of extracting multiplexed data streams and long distance transmissions versus the implementation cost of the new system and its life expectancy.

2. THE DILEMMA

To be able to manage power system communications to the standard normally desired in a privatised environment, the power system communications needs to be monitorable to a degree that the 'just in time management' could be implemented through timely preventative maintenance. This approach gives the benefits of maximising shareholder value whilst maintaining the required safety and performance standards. To achieve this goal the contemporary power system communications networks need to be digitised as analogue networks are currently hardly supportable and they do not easily lend themselves for performance monitoring. Ideally, to be able to digitise the power system communications networks there is a need to replace most of the current physical layer of the Open System Interconnect (OSI) model of the communications network [3]. This implies the replacement of aged cabling infrastructure, antiquated communications terminal equipment followed by the replacement of non-communicable protection relays. In practice this approach is not feasible due to the prohibitive replacement costs and the hard fact that the presently employed power system communications, albeit antiquated and without performance monitoring and manufacturers' support, does in principle fulfil its basic tasks as initially designed.

The dilemma is that without ongoing performance monitoring of the communications network, a Communications Asset Manager cannot make an informed decision about its true condition. And for that precise reason the risk exposure present cannot be reliably determined. As a result, the communication network augmentation plan cannot be easily justified despite widespread acknowledgment that the majority of the legacy systems have passed their operational life and their replacement is long overdue. Thus network multiple failures are expected especially in adverse weather conditions. However, timing cannot be determined due to the lack of regular performance monitoring that could reduce the unpredictability factor. Scanty track records of faults are available but they are based primarily on alarms and subsequent reactive maintenance.

Although power systems communications networks were overengineered during SECV days by the implementation of extensive redundant circuits, the expectation of failures is still high as both primary and redundant circuits were subjected to similar detrimental processes. As the majority of legacy systems is no longer supported by the manufacturers, spare parts can only be obtained from decommissioned circuits. The problem is exacerbated by the fact that scheduled maintenance has been reduced to a bare minimum due to the limited human resources having adequate expertise on the legacy systems. It is a well established fact that the maintenance regime followed during the SECV days [4] could not be adhered to in a privatised environment due to the lack of resources and prohibitive costs.

Nevertheless, current plausible operation of the existing power system communications does not alleviate the responsibility from a Communications Asset Manager for what happens when the elements of the communications legacy systems do fail, adversely impacting the electrical network operation. The prudent approach is to commence a gradual refurbishment of the power system communications network within the yearly budgetary constraints, targeting the most vulnerable areas first. An essential part of this approach is the preparation of a Communications Asset Management Plan comprising a risk analysis based on available and projected performance data, prioritisation of the proposed asset augmentation works and development of strategic policies and standards for the future.

3. STRATEGIC DIRECTIONS

Considering the operational status of a typical power system communications network, a temporary compromise needs to be reached between the communications network performance standards achievable at present, with the acceptance of the present risks where permissible, and the expected future performance of a digitised communications network. This inevitably results in a hybrid power system communications wherein the legacy systems coexist with modern communications solutions. The Communications Asset Management Plan must clearly identify the risks present on the network and the implementation of the risk mitigation strategy has to be endorsed by the network owner. For prioritisation purposes, it needs to provide justification for the proposed augmentation works in terms of the identified risk scores. The development and implementation of a succession plan for both human resources and communications technologies are also a vital part of the Communications Asset Management Plan.

The prime target for the augmentation works is the installation of privately owned, protection standard, cabling infrastructure as part of the inter-Zone Substation wide area network (WAN). This approach can address capacity issues and reduce the dependence on other transmission or distribution companies' communications infrastructure. It can also facilitate the introduction of the emerging protection and communications technologies that employ fast digital transmissions. Newly installed single-mode fibre optic cables should be based on ADSS cabling technology and installed in self-healing ring configurations. The terminal equipment needs to be equipped with communications channel performance monitoring so that detected system's unavailability could provide the performance measures required to maintain communications without routine periodic testing [5].

To insure a uniform and cost-effective approach to future communications, it is prudent to adopt ethernet-based solutions as a communications transport layer. However, the easily achievable connectivity makes the ethernet-based solutions vulnerable to malicious attacks. The issue of network security is of tremendous importance due to the safety and business continuity implications. Thus the installation of firewalls augmented by the intrusion detection software is mandatory. Physical separation protecting the corporate network from the SCADA network, and vice versa, is desirable and recommended when the interconnection of the two networks is not necessary for the optimal business operation. The implementation of the network security policies should be a part of the overall business communications strategy.

4. REFERENCES

[1] Sharon Beder, "Power Play the fight for control of the world's electricity", Part four, Scribe Publications Pty Ltd, 2003.

[2] GEC Alsthom Measurements Limited, "Protective Relays Application Guide", Chapter 10, Third edition, September 1990.

[3] William Stallings, "Data and computer communications", Chapter 15, Fifth edition, by Prentice-Hall International, Inc, 1997.

[4] A. Kalam, A. Spicer, R. Coulter, A. Klebanowski, C. Biasizzo, H. McDonald "Power System Protection", Chapter 20, Published by Victoria University of Technology, Melbourne, Third edition 1997.

[5] Edmund O. Schweitzer III, Ken Behrendt, Tony Lee, "Digital communications for power system protection: security, availability and speed", Schweitzer Engineering Laboratories, Inc, Pullman, WA USA.