Operational Implementation of Broken Conductor Detection Method to Mitigate Wires Down Events

A dissertation submitted by

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ABSTRACT

Power system broken conductor events typically occur due to failed aged assets or environmental factors like storms or car accidents involving power poles. Consequently, such events pose significant risk to public safety and reduce network reliability with many inherent factors contributing to the challenges faced by utilities in managing these difficult faults. Regulatory drivers and asset management principles are encouraging utilities to find solutions using innovative processes to mitigate downed conductor risk. Ausgrid have embarked on a trial to implement a detection method based on voltage magnitude which triggers an alarm if certain parameters are met, indicating a broken conductor event.

Literature identifies many proposed detection methods for broken conductors or phase discontinuities that can be broadly categorised into voltage, current or harmonic based alternatives. This project considers several variations available and evaluates the candidate method and algorithm to be integrated into existing network telemetry. An overview of fault analysis theory is provided with focus on voltage and current quantities for open circuit faults. A model was developed using Simulink® to support the candidate method through simulation of various broken conductor scenarios found on Ausgrid overhead 11kV radial feeder systems. Simulation results were validated against previous modelling conducted in Electromagnetic Transients Program (EMPT®) and expected values based on fault analysis theory and delta-star transformer phenomena.

Findings suggest typical broken conductor scenarios can be modelled using the candidate method and obtained results are reproducible across various software applications. As such, analysis indicates the developed algorithm is task appropriate and able to achieve successful detection of broken conductor events using measured changes in voltage magnitude.

Ausgrid's trial is ongoing with teams currently working on system integration, testing and deployment.

ENG4111 and ENG4112 Research Project

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CERTIFICATION

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NOMENCLATURE

The following abbreviations have been used throughout this text: -

ACR	Automatic Circuit Recloser
BC	Broken Conductor
WDE	Wires Down Events
LOP	Loss of Phase
HIF	High Impedance Fault
EF	Earth Fault
SEF	Sensitive Earth Fault
DC	Direct Current
AC	Alternating Current
LV	Low Voltage
MV	Medium Voltage
HV	High Voltage
OH	Overhead
UG	Underground

ELBS	Enclosed Load Break Switch
DM&C	Distribution Monitoring & Control
CCT	Covered Conductor Thick
AEMO	Australian Energy Market Operator
NEM	National Electricity Market
DNSP	Distribution Network Service Provider
TNSP	Transmission Network Service Provider
HAC	Hazard Assessment Checklist
PPE	Personal Protective Equipment
PPS	Positive Phase Sequence
NPS	Negative Phase Sequence
ZPS	Zero Phase Sequence
USQ	University of Southern Queensland

CHAPTER 1

INTRODUCTION

1.1 Outline of Research

Transmission and distribution lines are one of the most basic power system components (Kezunovic, 2005). Failure of this component, causing an open circuit phase condition can be referred to as a broken conductor (BC) event. The consequence of such an event can vary, ranging from customer inconvenience due to poor supply quality or interruption to public safety risk like electric shock or bushfire.

Historically, BC events are difficult to detect due to fault characteristics and environmental factors. Utilities have typically relied upon public reporting to locate and conduct repairs in cases where traditional protection methods have failed to detect or clear the fault. However, through decades of research and technological advancement, sophisticated BC detection methods have evolved, making it increasingly viable for utilities to adopt and implement. Furthermore, regulatory drivers encourage innovation investment strategies like BC detection to address risk, fulfil duty of care obligation and improve network operations for stakeholders.

The following research investigates BC detection technology and evaluates the operational implementation of a chosen BC detection method to mitigate wires down events (WDE) across Ausgrid's entire distribution network. Ultimately, the research seeks to address risks associated with conductors contacting the ground and remaining live through the implementation of new features into existing network equipment and provide greater operational visibility of challenging faults.

1.2 Background

Traditionally, Australia's electricity supply chain includes four key elements. Generation, transmission, distribution, and consumer presented in figure 1 (AEMO, 2023).

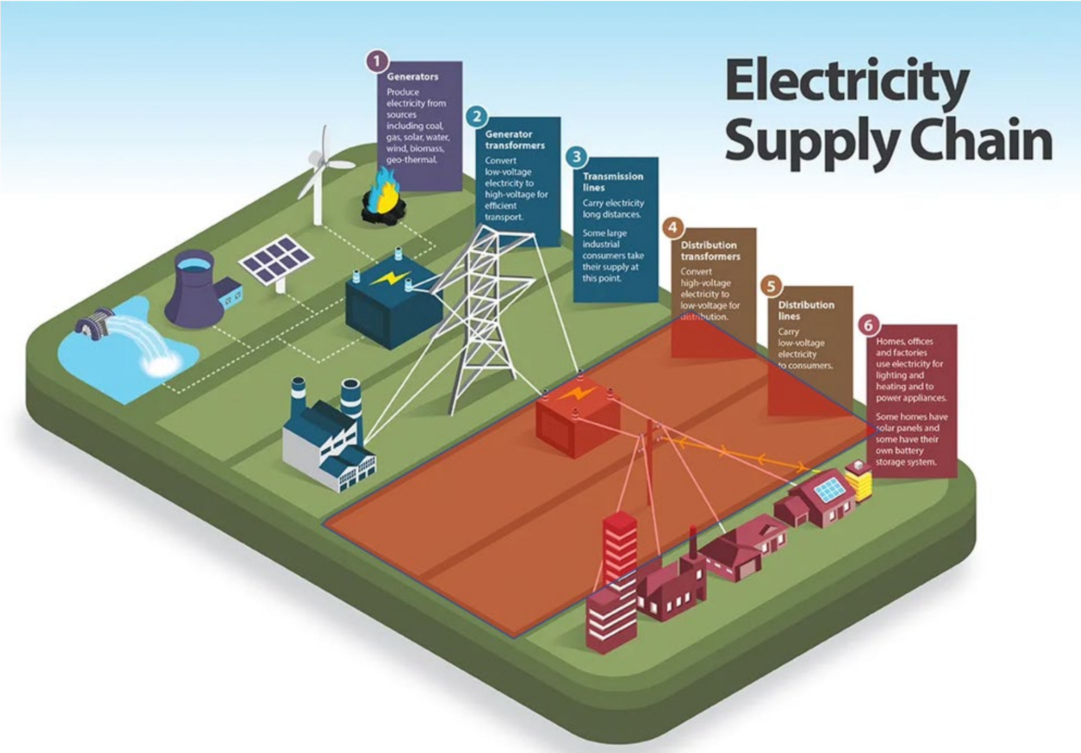


Figure 1 - Electricity Supply Chain. Image adapted from source (AEMO 2017)

The Australian Energy Market Operator (AEMO) coordinate this supply chain within the National Electricity Market (NEM) which is comprised of five physically connected regions on Australia's East coast shown in figure 2 (AEMO, 2023).

Ausgrid operate within the NEM (Figure 2) as a Distribution Network Service Provider (DNSP) and Transmission Network Service Provider (TNSP) (Ausgrid, 2023). The red shaded region of figure 1 shows where Ausgrid are positioned in the electricity supply chain. Ausgrid's network spans the Sydney, Central Coast and Hunter Valley region which covers 22,275 square kilometres as shown in blue shaded region of figure 3.

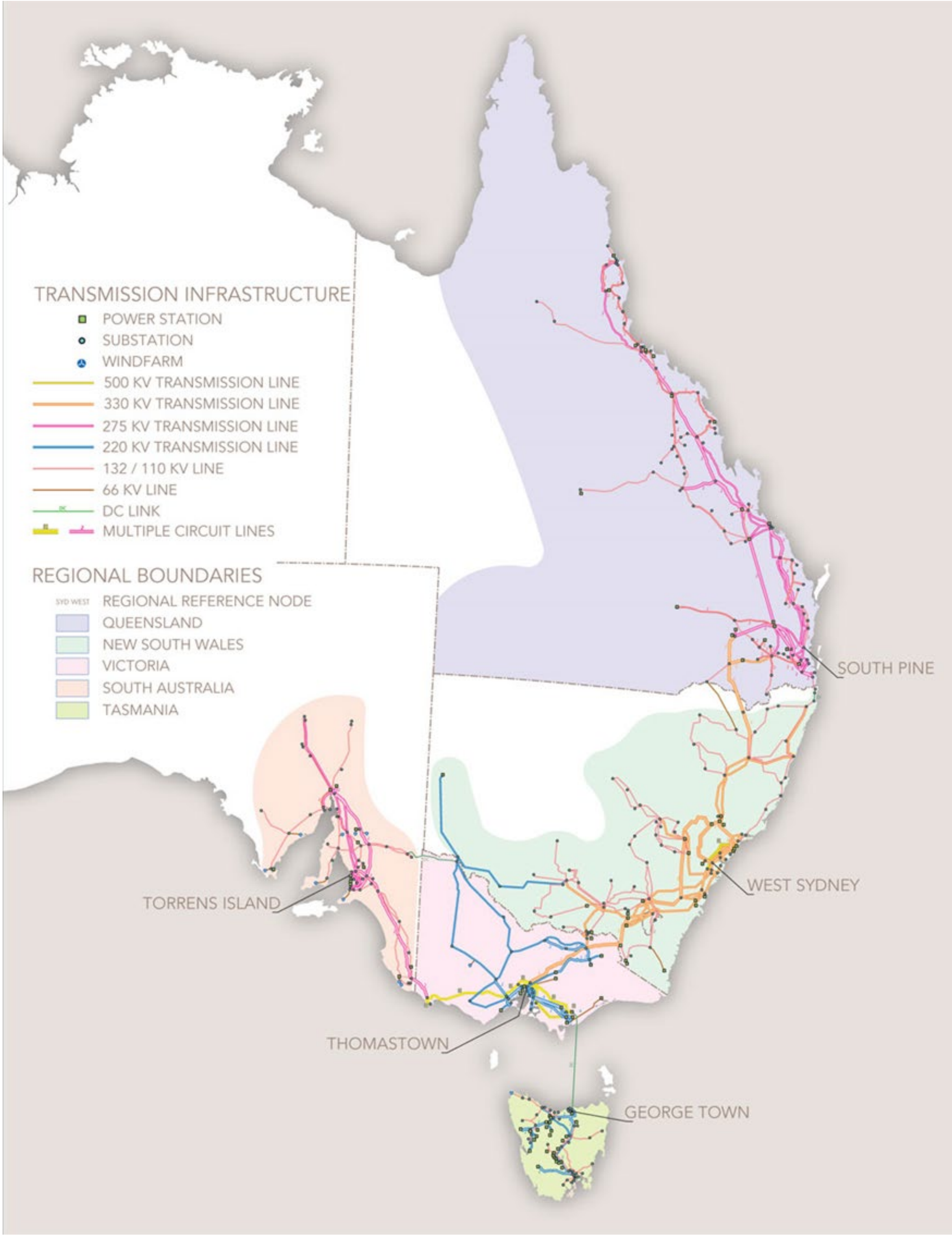


Figure 2 - National Electricity Market (AEMC 2023)

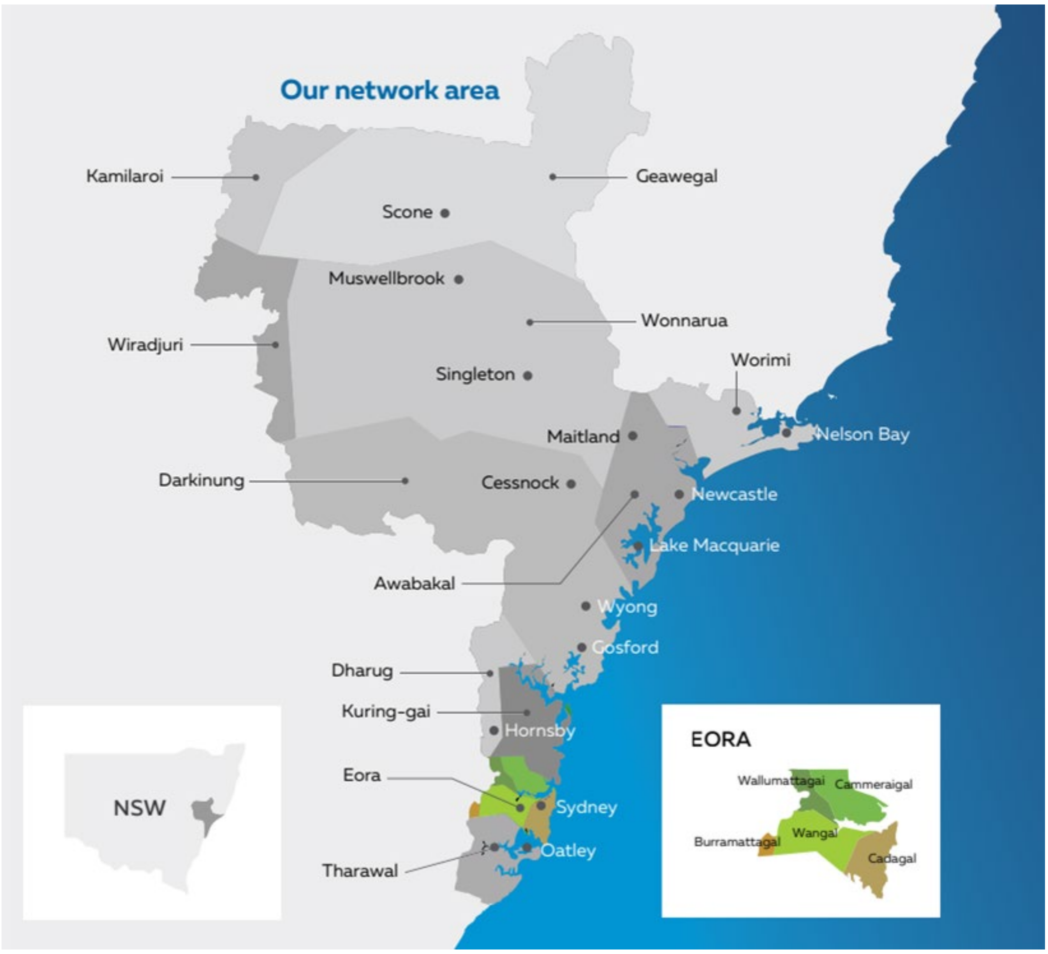


Figure 3 - Ausgrid Network Area (Ausgrid, 2023)

Ausgrid’s network consists of approximately 10,000km of 11kV overhead (OH) mains which are exposed to many threats like weather, vegetation, wildlife, and traffic. Such threats can result in conductors breaking and falling to the ground. Fallen conductors are a significant risk to public safety in the event they remain energised (Stanbury, 2021).

1.2.1 Frequency of Broken Conductor Events on Ausgrid’s Network

Stanbury (Stanbury, 2021) identifies Ausgrid’s MV (11kV) network experiences approximately 9 live WDE annually.

Outage data reviewed by Stanbury (Stanbury, 2021) presents the following findings:

- In a typical year, the MV network records approximately 2410 total events, including trips, interruptions, and breakdowns.

- Of the above events, 134 are WDE, cleared and uncleared by protection.
- 9 or the 134 wires down events were uncleared, representing 6.7% of WDE and 0.37% of all 11kV events.
- 50% of OH faults trigger a reclose attempt. At least 25% of live WDE occur following a successful reclose attempt.
- Covered Conductor Thick (CCT) accounts for 25% of live WDE.
- The following groups all WDE by voltage:
    - 53% of Ausgrid's network comprises of LV OH conductors and represents 71% of WDE.
    - 40% of Ausgrid's network comprises of 11kV OH conductors and represents 22% of WDE.
    - 7% of Ausgrid's network comprises of 33kV OH conductors and represents 7% of WDE.

1.2.2 Asset Management

ISO 55000:2014 refers to asset management as the coordinated activity of an organisation to realise the value from its assets. As an organisation, Ausgrid are committed to applying effective asset management practices to support the delivery of their corporate strategy and objectives.

Ausgrid apply an Asset Management Policy which outlines their commitment and expectations towards asset management including compliance with all applicable legal, regulatory, safety, and environmental requirements.

To achieve the Asset Management Policy, Ausgrid apply four critical asset management principles to exceed customer expectations by excelling at operations to deliver safe and affordable services whilst supporting a net zero future through innovation and organisational growth. The following outlines these principles and justifies Ausgrid's commitment to them through investment in trials like BC detection to mitigate wires down events.

1. ***Safety & Environment First***

   The trial is focussed on improving public safety by reducing risks associated with wires down events so far as reasonably practicable.

2. ***Commercially Minded***

   The trial supports innovation and continuous improvement through engineered solutions utilising existing network equipment.

3. ***Customer Focussed & Collaborative***

   Customer and stakeholder engagement suggest customers value innovation and finding new solutions to for a safer, more agile, and reliable grid. The trial supports such values.

4. ***Honest & Accountable***

   The trial ensures compliance with organisation legal and regulatory obligations by supporting safety of the public, persons near, or working on the network and minimises the risk of property damage including bushfires caused by mal operation of the network.

1.2.3 Problem Statement

Limitations of traditional protection methods, OH conductor type and design, network configuration, the rise of distributed energy resources (DER) and on occasion, timely nature of locating faults make BC events a challenge for utilities.

Sensitive Earth Fault (SEF) protection can detect and clear faults where fault current is too low for standard earth fault (EF) protection schemes and has been provided on 11kV OH feeders for many years. Occasionally, SEF schemes fail to detect BC events in high impedance fault (HIF) scenarios where a live conductor contacts a quasi-insulated object like a vehicle, tree, roadway, or timber fence (Theron, et al, 2018).

Covered Conductor Thick (CCT) is a XLPE covered aerial cable used by Ausgrid. Although not a touch safe screened cable system, its design is to provide protection from initiation of flash-overs due to clashing mains, bird and wildlife incursions and tree branches or debris which may contact the line. Such benefits make CCT a suitable choice for densely vegetated areas, prone to tree branch strikes which can potentially bring them down. In this scenario, the outer XLPE screening can stretch, leaving the BC covered and screened from ground, limiting fault current making it difficult for protection systems to detect (Stanbury, 2021).

Network configuration can further complicate BC events as traditional protection methods (SEF) are unable to detect downed HV mains that are back energised via LV parallels. Additionally, the subsequent overcurrent condition may fail to operate the LV or HV fuses (Stanbury, 2021). Similarly, DER can replicate this scenario if the system is exporting, and anti-islanding protection scheme fails to operate. (Stanbury, 2021).

Ausgrid manage health and safety risks to their personnel and the community in accordance with their “Risk Appetite Statement” (RAS). The organisation adopts a risk averse approach and will not tolerate any activity contrary to their “work safe, live safe” vision or minimisation of all safety risks “So Far As Is Reasonably Practicable” (SFAIRP) (Ausgrid, 2022)

To adhere to the RAS, Ausgrid must face the challenges above and mitigate their risk SFAIRP. Ausgrid seek to do so through the operational implementation of BC detection methods which provide greater operational visibility, enabling more rapid identification and response.

1.3 Project Specification and Objectives

The specific objectives of this project are: -

- Review power system analysis theory and its application in BC detection.
- Review traditional BC detection methods and philosophies.
- Research alternative BC detection methods.
- Investigate BC methods currently used within Ausgrid period contract devices.
- Explore innovation trial candidate BC detection algorithm opportune to Ausgrid risk appetite, existing network architecture and available systems.
- Demonstrate the viability and accuracy of the candidate BC detection algorithm using existing telemetry.
- Present the trial candidate BC detection method using a simulation model.
- Review the development of core systems and integrations to facilitate

analysis and ultimately alarming of detected BC using this system.

- Discuss the business processes and change management requirements for BAU deployment once the concept has been proven.
- Report outcomes of the trial and proposed future developments.

1.4 Thesis Overview

This thesis is structured as follows:

Chapter 1 outlines project background, problem, focus and objectives.

Chapter 2 reviews existing literature relevant to the project including power system theory, BC methods and asset management philosophy.

Chapter 3 discussion on ethical consideration, consequential effects and matters of safety relating to the operational implementation of BC detection methods.

Chapter 4 outlines proposed research, introduces methods to support project specification, objectives, and facilitate project execution.

Chapter 5 presents and evaluates obtained data, including review and interpretation of results, and how the data reflects previous modelling and theory.

Chapter 6 discusses major findings in context of theory and literature, outlines limitations, and draws project conclusions and recommends further work.

CHAPTER 2

LITERATURE REVIEW

2.1 Overview

The following literature review aims to develop understanding of general power system fundamentals, BC detection theory, traditional and alternative detection methodology, asset management principles and regulatory drivers steering utility implementation of technologies like BC detection.

2.2 The Power System

2.2.1 Power Systems Operation

The generation, transmission and distribution of electricity occurs within a large, interconnected network commonly referred to as a power system. Key elements of a power system are generators, transformers, transmission towers and lines, substations, distribution poles and wires, and consumer installations. The electricity supply chain is the combination of these elements. A healthy power system, under normal operating conditions, will see uninterrupted, current flow through all elements of the electricity supply chain as designed and not exceeding equipment rating (Santamaria, 2006). By design, a power system can remain healthy under abnormal operating conditions, single contingency event, or N-1 secure state. AEMO operate the system in line with the NER to ensure power system security (AEMC, 2023).

Although power system operators endeavour to maintain a safe, reliable, and stable network, unforeseen events can occur. Elements of the electricity supply chain exist in varying environments globally, ranging from urban to remote and are exposed to an array of climatic conditions, natural or manufactured. Human interaction, intentional or otherwise is unavoidable, either through network operations or inadvertent contact. Equipment age and condition also differs. Such inherent aspects of a power system contribute to the possibility of undesirable scenarios or events called faults.

Grainger and Stevenson define a fault as any failure which interferes with the normal flow of current. Faults can be classified as either symmetrical or asymmetrical. Alternatively, a symmetrical fault can be referred to as a balanced fault. Moreover, asymmetrical faults can be referred to as unbalanced and may categorised as series, shunt, or simultaneous (Santamaria, 2006). Further detail of fault types is presented in section 2.2.2.2.

2.2.2 Power System Analysis

Typically, modern computer-based modelling software is used to analyse power systems. However, understanding power system fundamentals underpins the design and operation of a safe, reliable, and stable network.

The term three-phase system is a relatively well-known reference when people discuss power or electricity. Furthermore, what people are typically referring to when discussing a three-phase system is in fact a balanced system which is presented in figure 4.

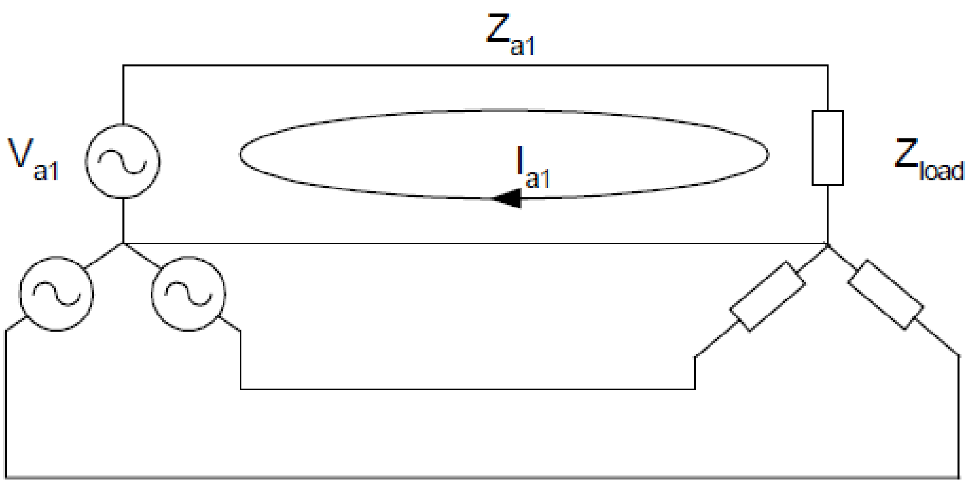


Figure 4 - Diagram of a Balanced Three-Phase Circuit (SEL, 2011)

Characteristics of the above include equal line and load impedance, and the source voltages are equal in magnitude and displaced by 120 degrees (SEL, 2011). This balanced condition enables a single-phase equivalent circuit to represent the three-phase system and perform calculations. From the initial equal values of impedance and source voltage, phase current can be derived. Given the balanced nature of the system we can then assume the other phase currents are of equal magnitude but displaced by 120 degrees (SEL, 2011).

System disturbance or abnormality results in this ideal system becoming unbalanced. Therefore, the simplified single-phase circuit representation cannot be used for power system analysis under these conditions (ELE3804, 2019). This adds significant complexity to analysis making network modelling a challenge for power system engineers. Over time methods have been developed to simplify the complexities associated with unbalanced system. The most notable being the method of Symmetrical Components.

2.2.2.1 Symmetrical Components

Charles L. Fortescue, whilst studying the effects of unbalanced currents on induction motor operation, developed the generalised theory of symmetrical components (Fortescue, 1918). C.F. Wagner and R.D. Evans introduced the concept of sequence networks whilst applying the method to power system faults. Subsequent iterations and developments by E.L. Harder, W.A. Lewis, and Edith Clarke, among others, greatly simplified the method to its current form (Sudan, 2018).

The theory of symmetrical components states that any *N* set of unbalanced phasors can be broken down into *n* sets of symmetric phasors or components (Sudan, 2018). In accordance with the theory, when analysing an unbalanced three-phase network, the unbalanced phasors can be resolved into three balanced systems of phasors (ELE3804, 2019). These phasors are referred to as positive, negative and zero sequence components and should be considered mathematical models representing actual quantities like voltage and current (Taylor, 2016).

A description of Fortescue's symmetrical components is given by Grainger and Stevenson in "Power Systems Analysis", (Grainger & Stevenson, 1994),

Positive sequence components consist of three phasors equal in magnitude, displaced from each other by 120 degrees in phase, and having the same phase sequence as the original phasors (ABC). Two common subscripts denoting positive sequence components are "+" or "1". i.e., Va1, Vb1, Vc1 or Va+, Vb+, Vc+.

Negative sequence components consist of three phasors equal in magnitude, displaced from each other by 120 degrees in phase, and having the phase sequence opposite to the original phasors (ACB). Two common subscripts denoting negative sequence components are "-" or "2". i.e., Va2, Vb2, Vc2 or Va-, Vb-, Vc-.

Zero sequence components consist of three phasors equal in magnitude and with zero phase displacement from each other. Typically, the subscript denoting zero sequence components is "0". i.e., Va0, Vb0, Vc0.

It should be mentioned that the standard convention in Australia for phase sequence rotation is Anti-clockwise (ELE3804, 2019). From an observer's perspective, each phasor should rotate through a common point. The order in which phasors pass this common point is considered the sequence, i.e., ABC (forward) or ACB (reverse).

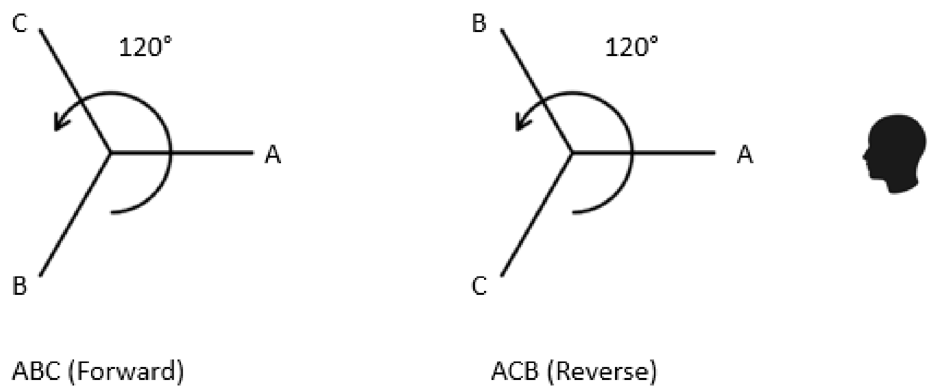


Figure 5 - Phase Sequence & Rotation

Let's consider the following set of unbalanced three-phase currents and their symmetrical components.

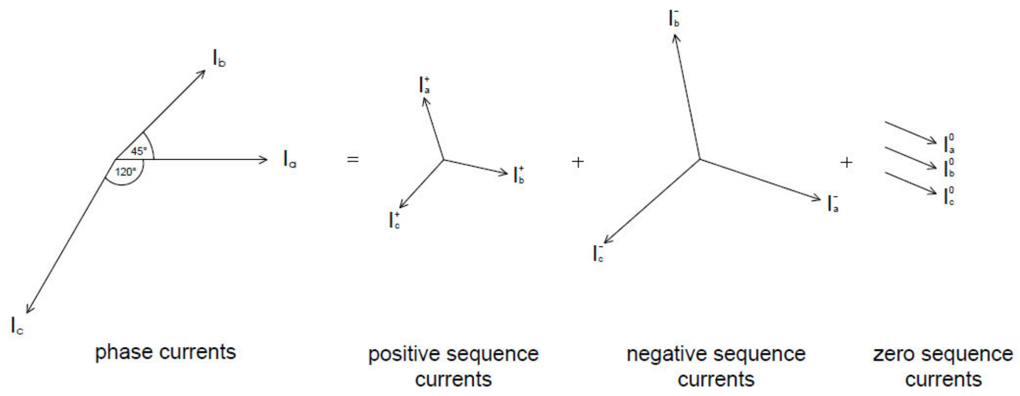


Figure 6 - Symmetrical components of an unbalanced set of three-phase currents (ELE3804, 2019)

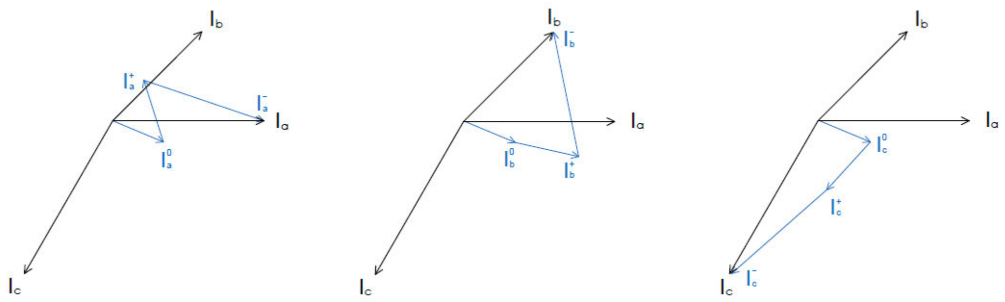


Figure 7 - Symmetrical component phasor addition (ELE3804, 2019)

It can be seen the original unbalanced phasors summate to their respective symmetrical components.

A simplified mathematical decomposition of symmetrical components is presented below:

$$
\begin{aligned}
I_A &= I_{a0} + I_{a1} + I_{a2} \\
I_B &= I_{b0} + I_{b1} + I_{b2} \\
I_C &= I_{c0} + I_{c1} + I_{c2}
\end{aligned}
$$

Equation 1 (Sudan, 2018)

Equation 1 can be simplified and written in matrix form in *Equation 2*. Operator 'α' is in recognition of any phasor within a balanced system can be defined with respect to another phasor phase shifted ±120º. The 'α' operator is a complex number where:

$$\alpha = 1\angle 120 \approx -0.5 + \text{j}0.866$$

$$\begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix} = \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha^2 & \alpha \\ 1 & \alpha & \alpha^2 \end{bmatrix} \begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix}$$

Equation 2 - Matrix form of sequence currents (Sudan, 2018)

Sudan explains *Equation 2's* matrix relationship holds true for when the reference A phase is the reference phase and ABC sequence. An alternative matrix relationship is required if a different base phase is selected. The 3x3 matrix in *Equation 2* is called the A matrix. . If the A matrix is inverted, *Equation 3* can be derived from *Equation 2*, in turn enables sequence current calculation from given three-phase currents.

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3} \begin{bmatrix} 1 & 1 & 1 \\ 1 & \alpha & \alpha^2 \\ 1 & \alpha^2 & \alpha \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$

Equation 3 - Matrix form of phase currents (Sudan, 2018)

Conveniently, the above mathematical decomposition holds true for both voltage and current in a poly phase network (Taylor, 2016).

Lastly, the fundamental empirical relation of Ohm's Law, $V = IZ$, applies to sequence component theory. As sequence voltage and current quantities have been discussed, naturally, sequence impedance should be considered as they are an important factor in determining power system fault levels. Symmetrical component theory considers sequence impedances which Sudan describes for a power system element to be the impedance offered by the element to the flow of sequence currents when applied with respective sequence voltage sources.

Generally positive, and negative sequence impedances are considered equal due to the contributing phase impedances being equal in practice. However, the earthreturn path and larger inductive reactance value associated with zero sequence current magnetic fields contribute to the zero-sequence impedance being different to the positive and negative sequence impedance (Grainger & Stevenson, 1994).

An expression for the above is given below (Grainger & Stevenson, 1994):

$$Z_{a1} = Z_{a2} = Z_{b1} = Z_{b2} = Z_{c1} = Z_{c2}$$

$$Z_{a0} = Z_{b0} = Z_{c0}$$

Moreover, expressions showing the application of Ohm's Law to each set of sequence component relations (Grainger & Stevenson, 1994):

$$V_{a1} = I_{a1} \times Z_{a1}$$

$$V_{a2} = I_{a2} \times Z_{a2}$$

$$V_{a0} = I_{a0} \times Z_{a0}$$

2.2.2.2 Fault Analysis

Fundamentally, a power system should operate in a manner which economically generates and delivers a safe and reliable source of electrical energy to the end user. To facilitate such an outcome, utilities like Ausgrid manage a complex network of assets representing a significant capital and operational investment. Despite rigorous effort to minimise risk and frequency through asset management frameworks and engineering design, power system faults do occur and have the potential for significant consequence. As such, it is prudent for utilities to conduct detailed fault analysis to ensure well informed decisions are made for network planning and operations.

BC events can be defined as an asymmetrical fault causing a system unbalance largely due to an open circuit scenario in one or two phases of an electrical circuit.

BC events can be either shunt faults where the conductor is contacting ground or a series fault where the conductor is not. To elucidate, a brief introduction to typical fault types and characteristics with examples is provided. Additionally, previously discussed sequence component theory is used to present a basic conceptualisation of power system fault analysis.

An equivalent circuit can reduce the complexity of a power system to simplify calculation and serve analysis. Like Ohm's Law, equivalent circuits also apply to sequence components and are commonly referred to as sequence circuits. With respect to sequence components, an unbalanced system is represented as a balanced set of phasors. Similarly, the sequence circuits are arranged into three individual circuits, referred to as positive, negative and zero sequence circuits, shown in figure 8. When a system is faulted, these individually arranged circuits can be connected such they represent the fault condition. Consequently, the sequence circuits become a sequence network.

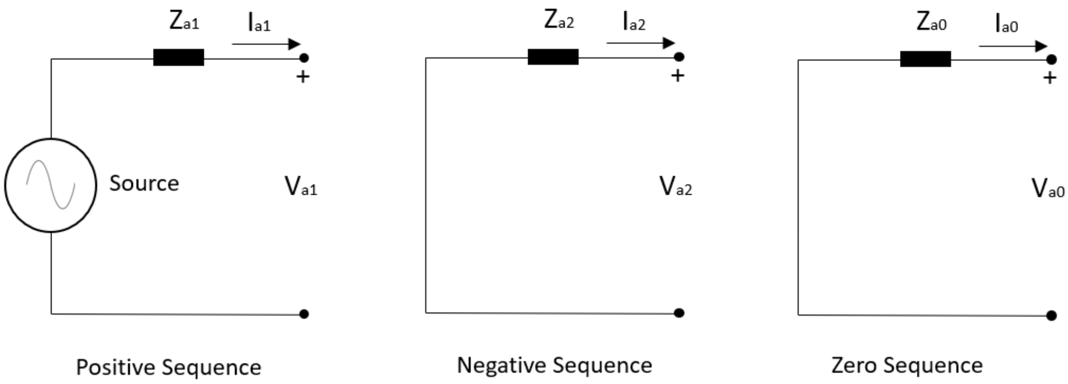


Figure 8 - Sequence Circuits with reference to 'a' phase

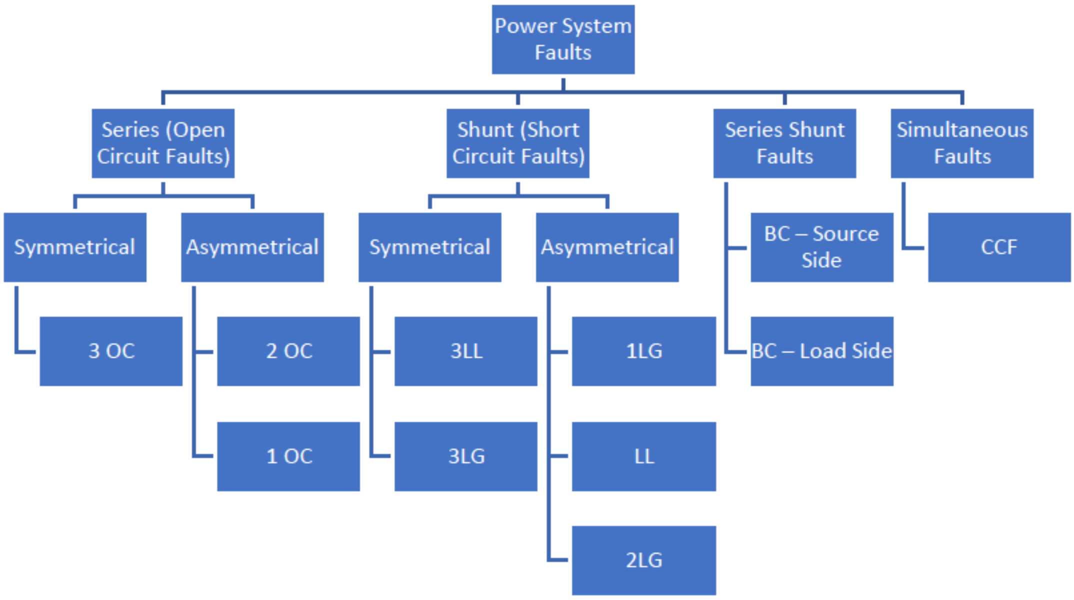


Figure 9 - Power System Fault Types

Figure 8 presents fault types common to power system analysis. The following sections will discuss fault types and their relation to broken conductors, explain characteristics and provide examples.

Shunt or short circuit faults are typically,

- Three phase faults
    - Three-line fault (3LL)
    - Three-line to ground fault (3LG)
- Single line to ground fault (1LG)
- Line to line fault (LL)
- Double line to ground fault (2LG)

Three phase faults are considered balanced in nature and often result from human error or evolve from a previous fault (ELE3804, 2019). Energising plant, mains or apparatus where short-circuiting operator earths remain connected is an example of a three-phase fault. Three-phase faults are not typically associated with broken conductor faults.

Three-phase faults are considered balanced, consequently, only positive sequence currents flow. Thus, only the positive sequence network is relevant. Additionally, a single-phase equivalent circuit is used to simplify calculations as mentioned in 2.2.2. See figure 10 and 11 for relevant diagrams.

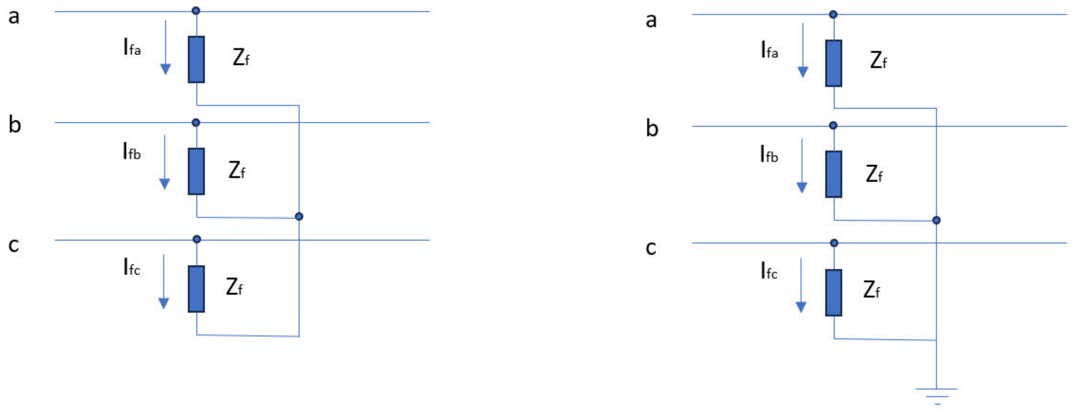


Figure 10 - 3LL & 3LG Fault Connection Diagrams

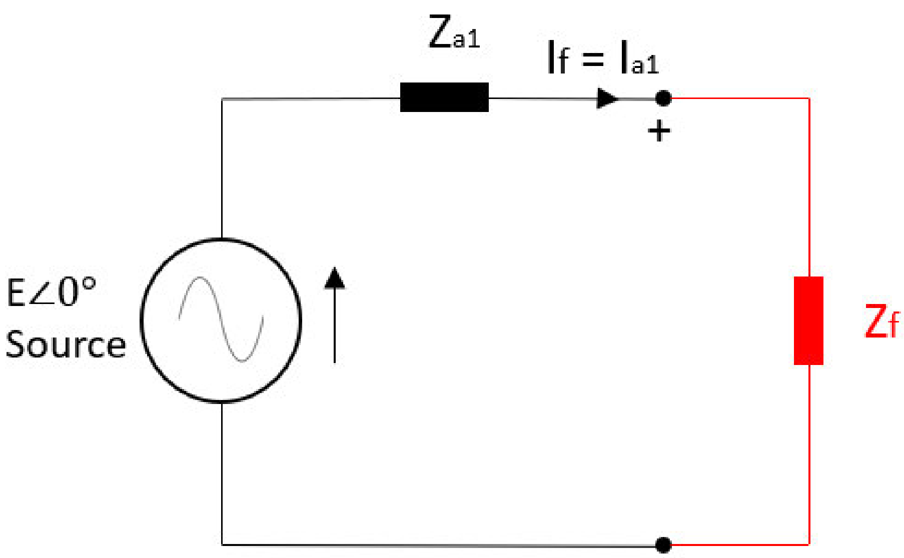


Figure 11 - Three Phase Fault Sequence Network Diagram

The general expression for a three-phase fault current is given by the equation below:

$$I_f = \frac{E\angle 0°}{Z_{a1} + Z_f}$$

If the fault impedance is zero, the term of reference is “bolted” fault.

Single line to ground faults (1LG) are typically caused by lightning or by conductors contacting ground or earthed structures and are considered the most common type of power system fault (Grainger & Stevenson, 1994). As such, a broken conductor event could result in a 1LG fault if the downed wire falls to the ground or rests on structure at earth potential. The connection diagram for a 1LG fault is shown in figure 12 below:

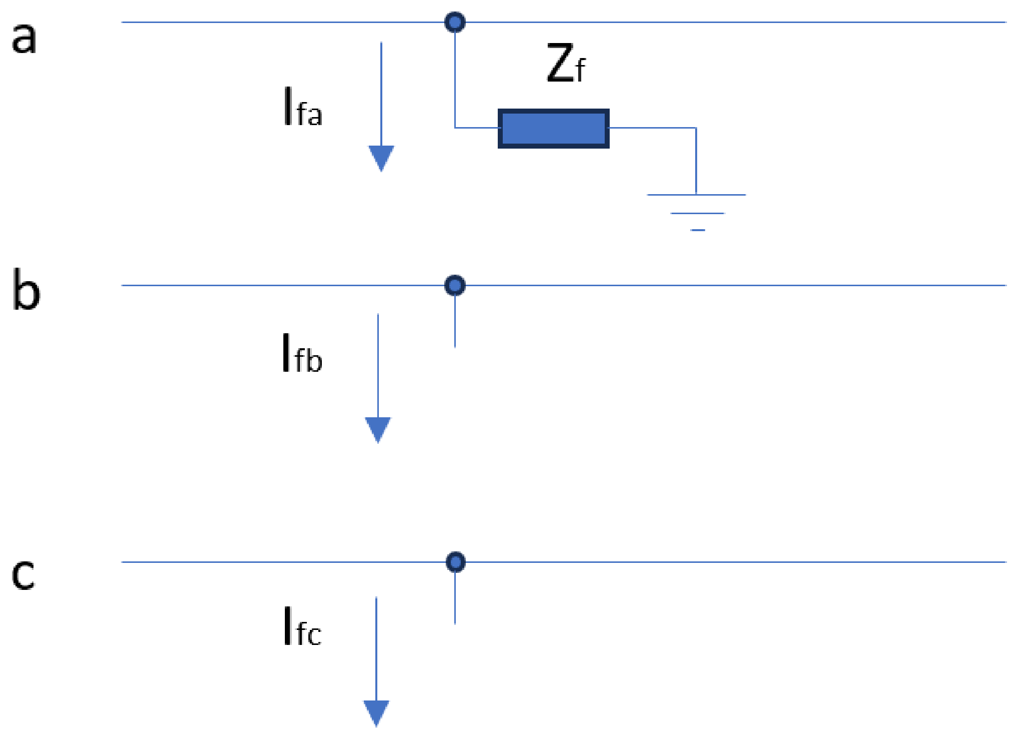


Figure 12 - 1LG Fault Connection Diagram

For a 1LG fault the only fault current that will physically exist will be that in the faulted phase (ELE3804, 2019). As such, for a faulted, arbitrarily designated ‘a’ phase, the boundary conditions are:

$$I_a = I_{fa} = \frac{V_{fa}}{Z_f}$$

$$I_b = I_c = 0$$

Positive, negative and zero sequence components apply to 1LG faults. In terms of symmetrical component theory presented in 2.2.2.1, for a 1LG fault it is required that:

$$I_{a1} = I_{a2} = I_{a0} = \frac{I_{fa}}{3}$$

$$V_{fa1} = V_{fa2} = V_{fa0} = 3Z_f I_{a1}$$

A series connection of the three sequence networks for a 1LG fault satisfies these requirements and is shown in figure 13 (ELE3804, 2019).

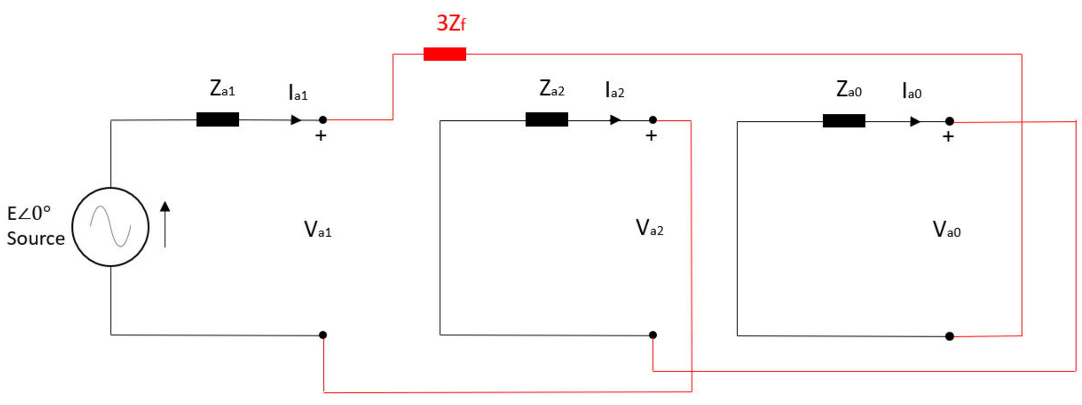


Figure 13 - 1LG Sequence Network Diagram

The general expression for a 1LG fault current is given by the equation below:

$$I_{fa} = \frac{3E\angle 0°}{Z_{a1} + Z_{a2} + Z_{a0} + 3Z_f}$$

Line to line faults (LL) are a short circuit between two phases and are relatively rare in comparison to other shunt faults. Engineering design minimises the risk of clashing mains, however, environmental factors such as high winds, fallen trees or wildlife may cause a LL fault (ELE3804, 2019). A broken conductor event may result in a LL fault if the wire falls into another phase conductor upon failure. The connection diagram for a LL fault is shown in figure 14 below:

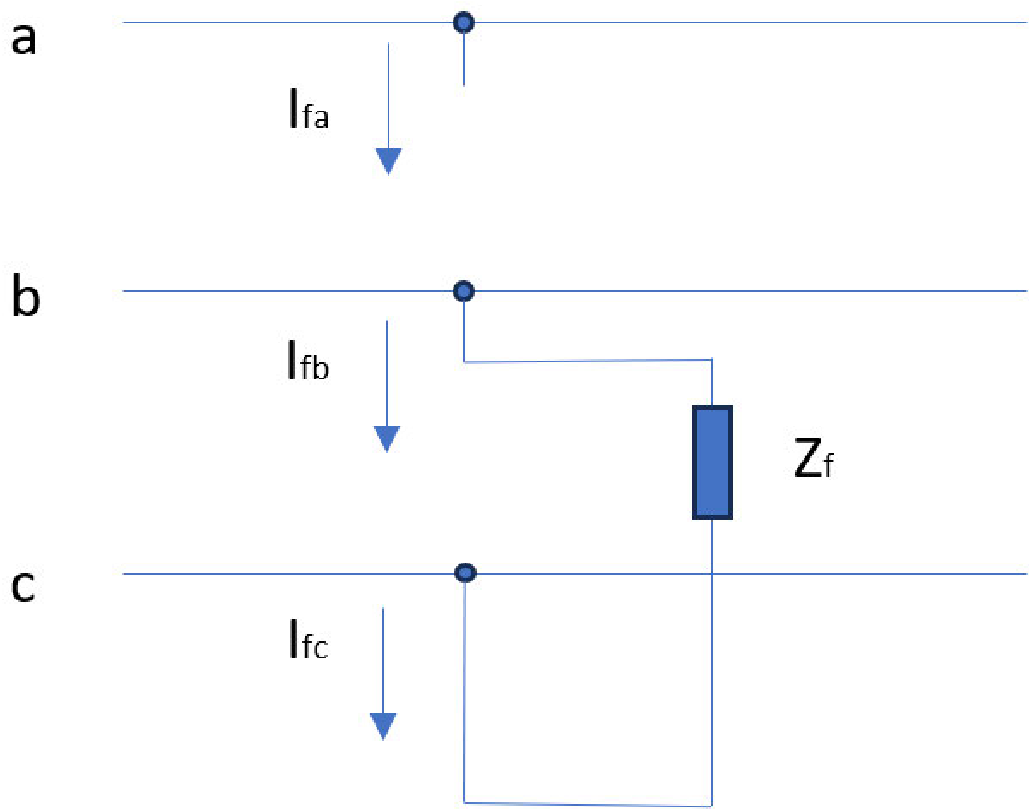


Figure 14 - LL Fault Connection Diagram

Line to line fault boundary conditions are as follows (Grainger & Stevenson, 1994):

$$I_a = I_{fa} = 0$$

$$I_{fb} = -I_{fc}$$

$$V_{fb} - V_{fc} = I_{fb} Z_f$$

Only positive and negative sequence components apply to LL faults, whilst the zero-sequence component is omitted due to no ground contact (Grainger & Stevenson, 1994). Through use of the 'A' matrix and referencing 'a' phase, LL fault are shown below:

$$I_{fa1} = -I_{fa2} = j\frac{I_{fa}}{\sqrt{3}}$$

$$I_{fa0} = 0$$

$$V_{fa1} - V_{fa2} = I_{fa1}Z_f$$

A parallel connection of the positive and negative sequence networks for a LL fault satisfies these requirements and is shown in figure 15 (ELE3804, 2019).

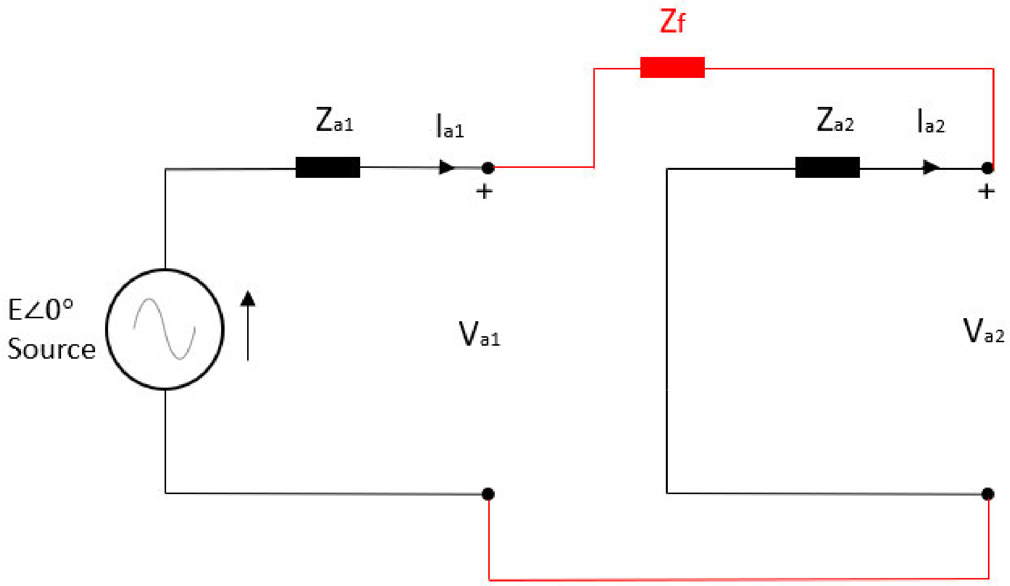


Figure 15 – LL Sequence Network Diagram

The general expression for LL fault current is given by the equation below:

$$I_{fb} = -I_{fc} = -j\sqrt{3}\frac{E\angle 0°}{Z_{a1} + Z_{a2} + Z_f}$$

Double line to ground faults (2LG) are a short circuit between two phases and ground. A broken conductor event may result in a 2LG fault if the wire falls into another phase conductor upon failure and is contacting ground or an earthed structure concurrently.

The connection diagram for a 2LG fault is shown in figure 16 below:

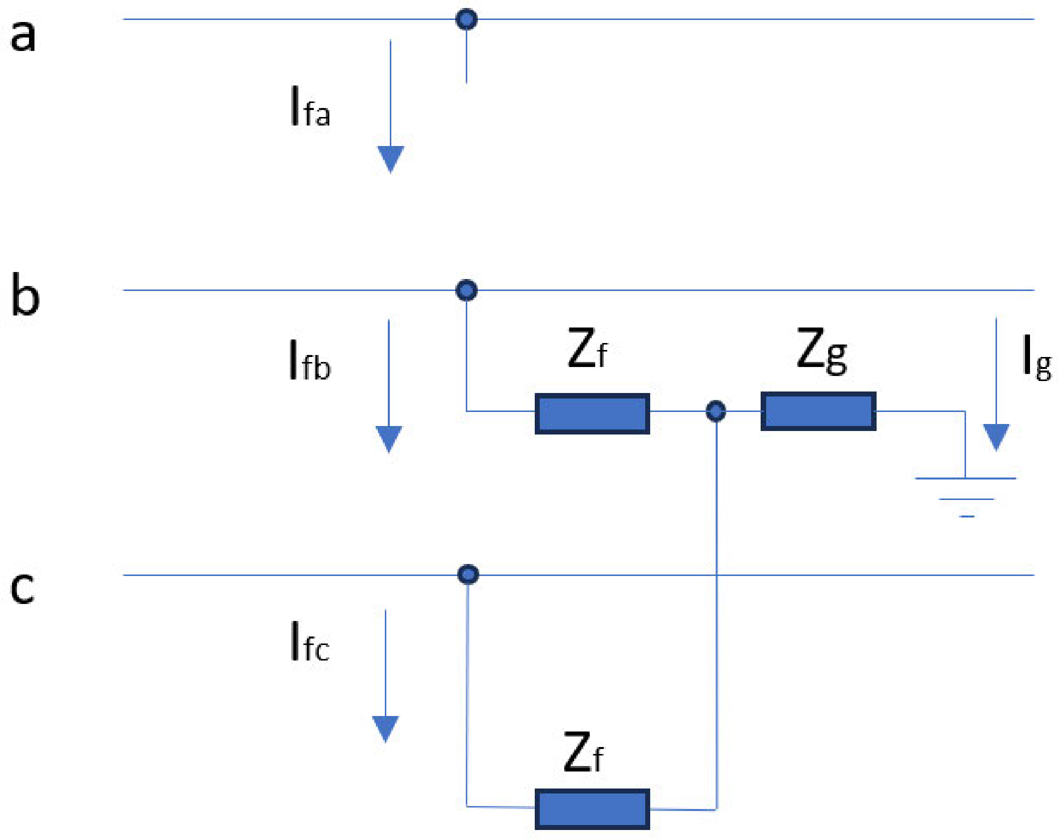


Figure 16 - 2LG Fault Connection Diagram

2LG fault boundary conditions are as follows (Grainger & Stevenson, 1994):

$$I_a = I_{fa} = 0$$

$$V_{fb} = V_{fc} = (I_{fb} + I_{fc})Z_f$$

Positive, negative and zero sequence components apply to 2LG faults (Grainger & Stevenson, 1994). A parallel connection of the positive, negative and zero sequence networks for a 2LG fault is shown in figure 17.

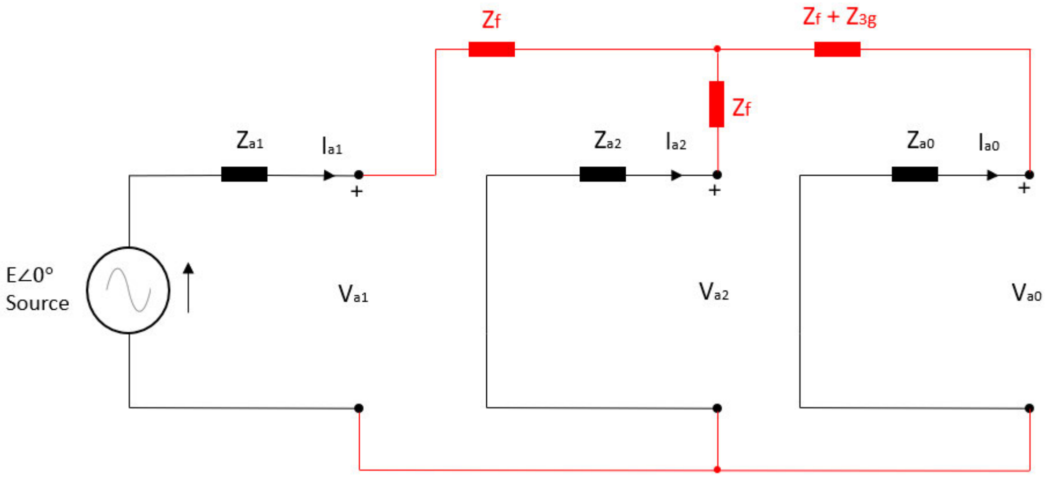


Figure 17 - 2LG Sequence Network Diagram

If ‘a’ phase is taken as reference, we can perform sequence component matrix transformations and equation reduction to arrive at a general expression for ground fault current of:

$$I_g = -3E\angle 0° \times \frac{Z_{a2}}{(Z_{a0} + 3Z_g)(Z_{a1} + Z_{a2}) + Z_{a1}Z_{a2}}$$

Series or open circuit faults are typically,

- Three open conductor (3OC)
- Single open conductor (1OC)
- Double open conductor (2OC)

There was no identified literature during this review that made mention of 3OC faults. It is assumed 3OC scenarios are considered a planned interruption of supply, not a fault. Alternatively, 3OC scenarios may be the result of an unplanned interruption of supply due to a shunt fault.

Single open conductor type faults (1OC) give rise to several possible situations. suggest They include (Al-Baghdadi et al, 2022):

- An open line from two terminals with no ground or earthed structure contact, shown in figure 18.
- An open line from two terminals where the source side is contacting a high impedance surface, shown in figure 19.
- An open line from two terminals where the load side is contacting ground of any impedance, shown in figure 20.

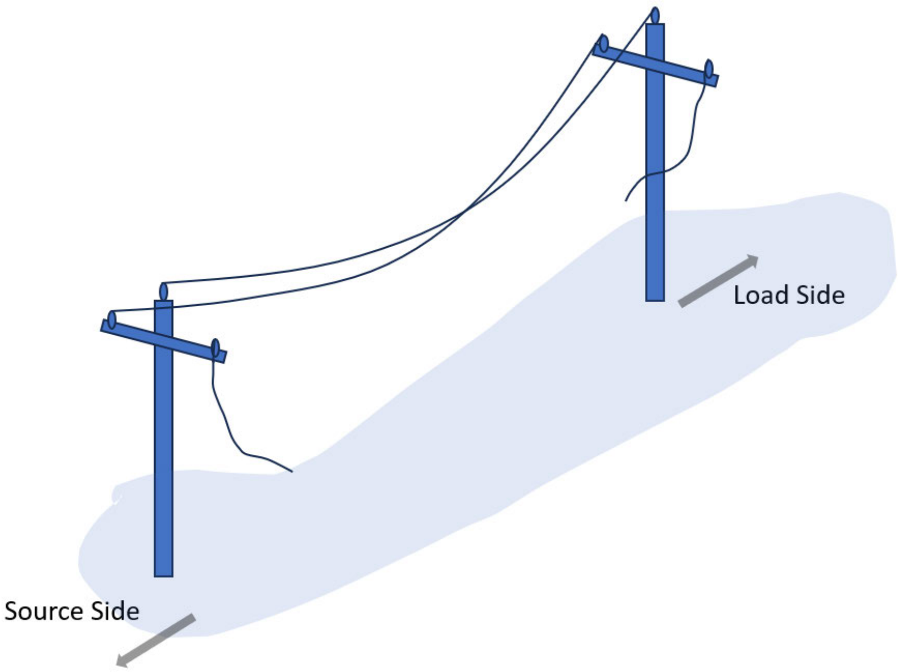


Figure 18 - Floating 1OC

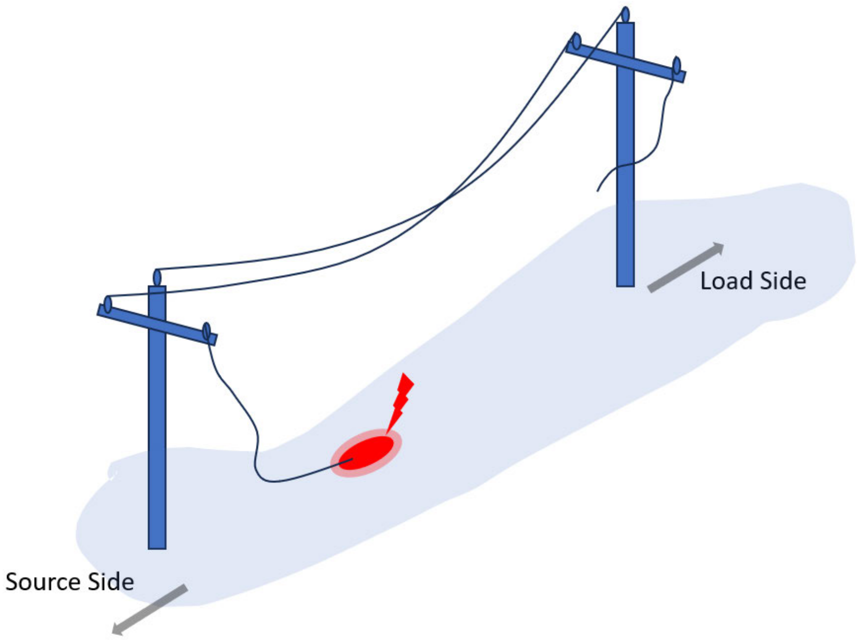


Figure 19 - Source Side 1OC with High Impedance Ground Fault

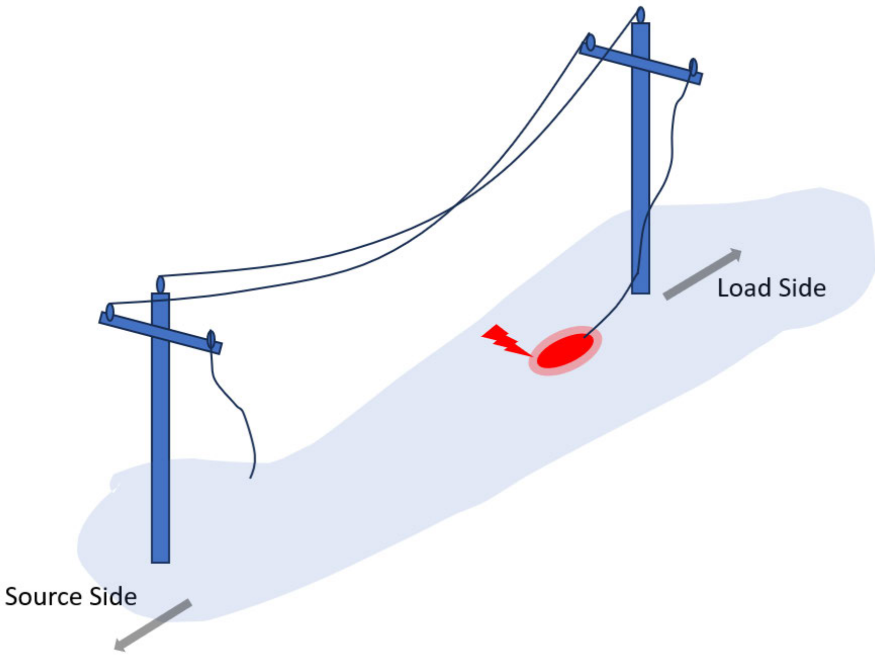


Figure 20 - Load Side 1OC with Any Impedance Ground Fault

Causal factors associated with the above faults have been previously discussed.

Two open conductor faults (2OC) share situational commonalities as 1OC faults with an additional failed conductor. Where a 1OC fault may transition to a 1LG fault, a 2OC fault can transition to a LL or 2LG fault.

Series faults can be analysed like shunt faults by applying sequence component theory. Figure 21 shows the connection diagram for a 1OC fault where the break is between *p* and *p'* on *'a'* phase (Grainger & Stevenson, 1994).

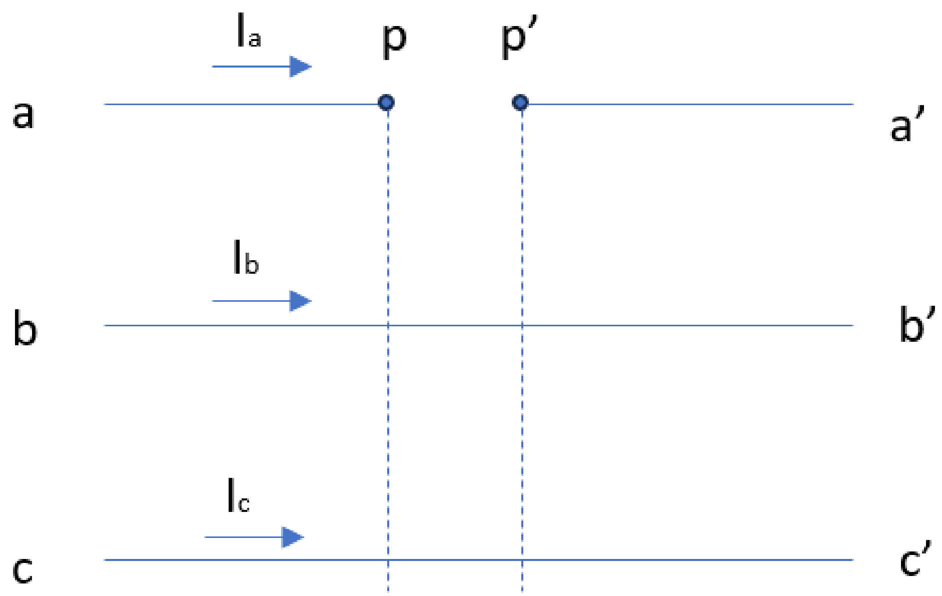


Figure 21 - 1OC Fault Connection Diagram

1OC fault boundary conditions are as follows (Grainger & Stevenson, 1994):

$$I_a = 0$$

$$V_{pp',b} = 0$$

$$V_{pp',c} = 0$$

Positive, negative and zero sequence components apply to 1OC faults. A parallel connection of the positive, negative and zero sequence networks for a 1OC fault is shown in figure 22. Through use of the 'A' matrix and referencing 'a' phase, 1OC sequence components are shown below:

$$V_{a1} = V_{a2} = V_{a0} = \frac{V_{pp',a}}{3}$$

$$I_{a1} = I_{a2} = I_{a0} = 0$$

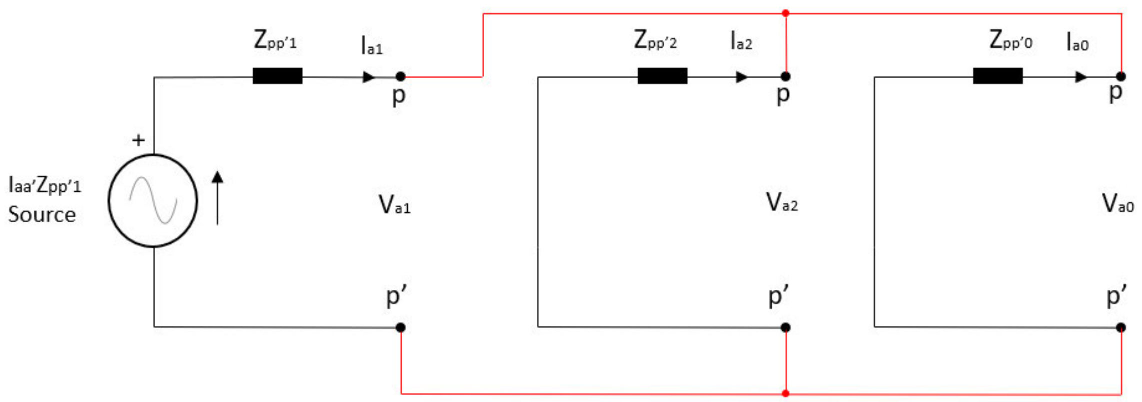


Figure 22 - 1OC Sequence Network Diagram

Figure 23 shows the connection diagram for a 2OC fault where the break is between *p* and *p'* on *'b'* and *'c'* phase.

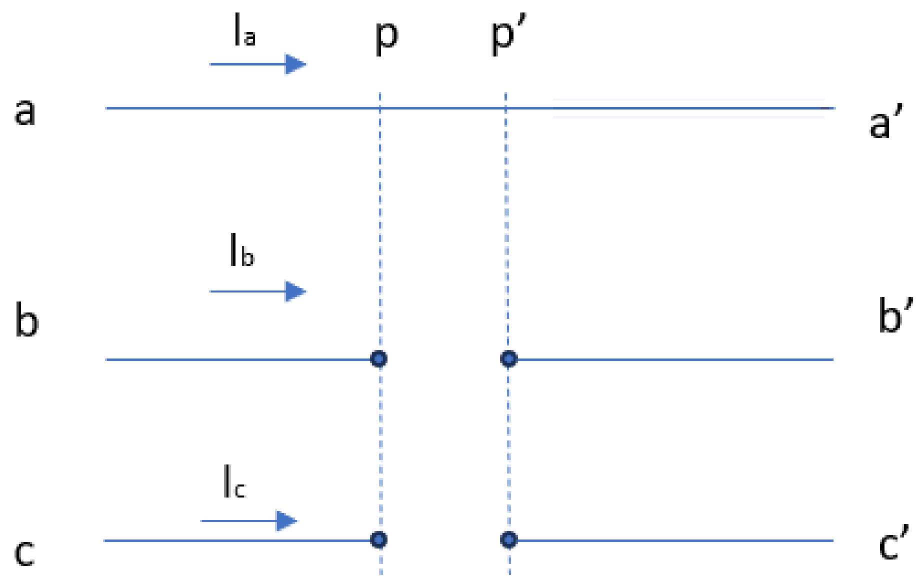


Figure 23 - 2OC Fault Connection Diagram

When two conductors are open, fault conditions exhibit duality with a 1OC fault. Therefore, 2OC fault boundary conditions are as follows (Grainger & Stevenson, 1994):

$$V_{pp',a} = 0$$

$$I_b = 0$$

$$I_c = 0$$

Positive, negative and zero sequence components apply to 2OC faults. A series connection of the positive, negative and zero sequence networks for a 2OC fault is shown in figure 24. Through use of the 'A' matrix and referencing 'a' phase, 2OC sequence components are shown below:

$$I_{a1} = I_{a2} = I_{a0} = \frac{I_a}{3}$$

$$V_{a1} = V_{a2} = V_{a0} = 0$$

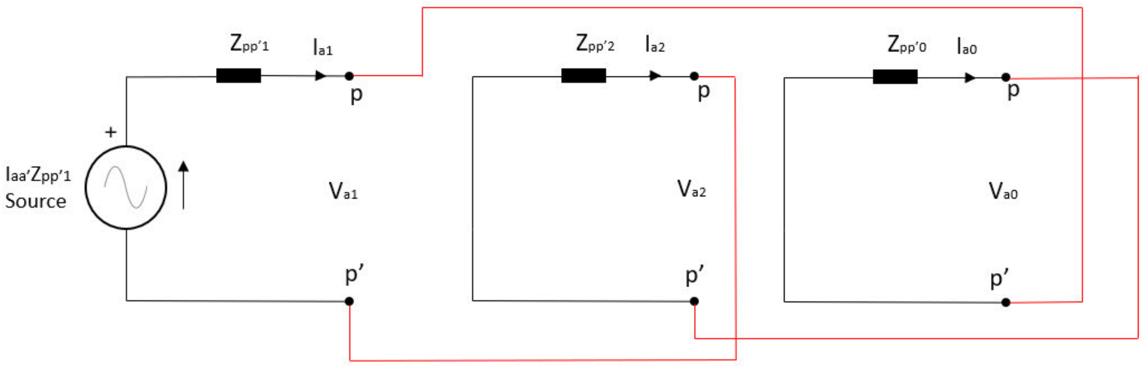


Figure 24 - 2OC Sequence Network Diagram

In summary, the net effect of the open conductors on the positive sequence network is to increase the transfer impedance across the line in which the fault occurs (Grainger & Stevenson, 1994). Therefore, for a 1OC fault this increase is the parallel combination of the negative and zero sequence networks between two designated open points. For 2OC faults the increase in impedance equals the series combination of the negative and zero sequence networks between two designated points (Grainger & Stevenson, 1994). Interestingly, the above analysis does not account for ground contact. Al-Baghdadi et al, consider ground currents and impedances for their analysis.

Simultaneous or more than one fault occurring at the same time can occur in a power system. Cross country faults are one example and are defined as two faults affecting the same circuit, but in different locations and possibly involving different phases. Such faults are considered out of scope for this report.

2.3 Broken Conductor Detection

Historically, series fault protection technology has been relatively sparse as W.A. Elmore suggests very few relaying systems are designed to protect against open circuits on a power system due to their infrequency unless fault induced. João et al (João et al, 2022) mention typical relaying methods only detect 17.5% of cases. BC detection is challenging due to the combinations and permutations of scenario.

Broken conductors can progress from series to shunt faults where contact is made with the ground or earthed structure (1LG), another phase conductor (L-L) or combination of both (2LG). Typically, shunt faults are characterised by high current magnitude. However, in some instances environmental factors contribute to a shunt fault being defined as a high impedance fault (HIF).

HIF are a specific class of disturbance that are challenging for power network protection systems to sense and clear. The two main characteristics giving rise to such challenges is low current magnitude and electric arcing. Ghaderi et al lists additional physical and electrical properties of HIF as, current waveform asymmetry, build-up and shouldering of current magnitude, harmonics, randomness of current magnitude and conduction intervals, non-linearity of current-voltage characteristic due to arc. Vieira et al explains the low current magnitude associated with HIF is due to the poorly conductive surface the downed wire is making unwanted contact. Literature suggests poorly conductive surfaces are inherently dry like sand, concrete, asphalt, gravel, bushland, tree branch, timber fence or vehicle. HIF create major concern for public safety, industrial installations, and bushfire. This is due to the associated high voltages and arcing in fallen conductors (Vieira et al, 2019). Timely detection and fault clearance is critical to utilities like Ausgrid to mitigate risk associated with these scenarios.

Another challenge associated with detecting BC is downed wires contacting ground on the load side of the break as seen in figure 20. Typically, load side broken conductors (LSBC) are seen as an unbalance to the power system not occasioning positive or negative sequence current magnitude significant enough to operate overcurrent protection relays. Additionally, zero sequence currents are said to be "trapped" in the delta winding of Delta-Star distribution transformers that may be connected, therefore, earth fault and sensitive earth fault protective relaying fails to detect LSBC faults.

2.3.1 Traditional Methods

Utilities have traditionally relied on the implementation of zero sequence current actuated protections like "Earth Fault" (EF) and "Sensitive Earth Fault" (SEF) protection to manage BC event risk. Such protection utilise current sensing devices called relays that are time graded and operate inversely proportional to current magnitude. That is, operate fast for high current and relatively slow for lower current magnitudes (Alstom Grid, 2011).

EF and SEF protection relays use parallel connected current transformers to pass residual zero sequence current into the secondary spill circuit of the scheme (Alstom Grid, 2011). For an unfaulted system, the scheme will balance, and no residual current will pass through the EF or SEF relay element for the device to operate. For a faulted system with connection to ground or earth potential, the scheme will become unbalanced resulting in the flow of residual zero sequence current through the EF and SEF element causing an operation. As mentioned, the current magnitude facilitates speed of operation. For downed wire scenarios, particularly LSBC or HIF situations, low magnitude residual zero sequence current may fail to trigger a protection operation and clear the fault. Moreover, fault analysis theory present in 2.2.2.2 indicates traditional methods will not detect series faults not involving ground.

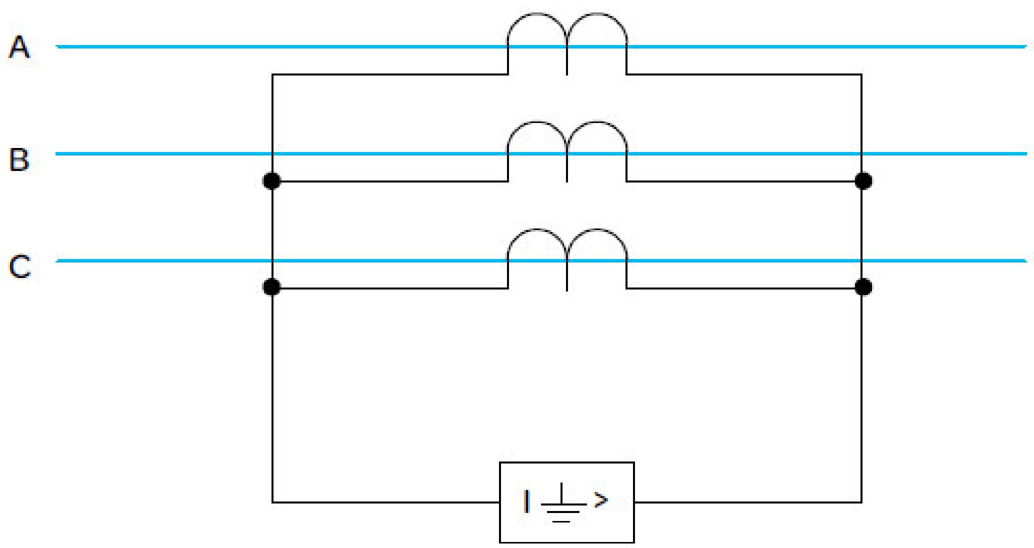


Figure 25 - Residual connection of current transformers to EF relays (Alstom Grid, 2011)

If protection fails to detect and clear a downed conductor fault, utilities have traditionally relied upon internal operational procedures like feeder patrols to manage the risk or the public to report the hazard. As mentioned, in an average year, Ausgrid experiences 9 uncleared wires-down events which equates to 0.37% of all events on the 11kV system. This may be considered low risk; however, the consequence is potentially catastrophic if the fault remains uncleared and human or animal contact is made or triggers a bush fire. Figure 26 displays a potential public risk. Ergo, utilities like Ausgrid are seeking alternatives to traditional methods to manage risk (Stanbury, 2021).

Figure 26 - Live 11kV wire on ground adjacent to vehicle (Stanbury, 2021)

2.3.2 Alternative Methods

The proliferation of information and communication technology (ICT) and microprocessor based intelligent electronic devices (IED) for power system protection and automation has given utilities opportunity to transition aging power system infrastructure into a modern intelligent grid and operate a safer and more reliable network (Anderson et al, 2022). Such advancement in technology enables utilities to manage risk through innovation and seek alternatives to traditional operational methods. A review of available literature has provided insight into several alternative BC detection methods hypothesised by research for grid implementation. The alternative methods presented can be broadly categorised into current-based methods, voltage-based methods, and harmonic-based methods.

Al-Baghdadi et al propose a method for detecting LSBC faults using single-ended measurements of the overhead distribution lines. The detection method is based on the constant ratio of negative to positive sequence current, $| I_2 / I_1 |$, measured at the feeder end. The novel aspect presented by the authors was utilising the ANSI 46BC algorithm for LSBC typically implemented for BC downstream of the measuring point. The author analysed LSBC faults at 15 points along the feeder. Analysis observed source end measurements would go undetected for the last third of the feeder (points 11-15). However, measurements from the feeder end remained constant regardless of fault location or load variation. The proposed study is performed using MATLAB® software and Simulink® toolboxes to implement a real 11kV radial network as a case study and verified by mathematical analysis using symmetrical component transforms. Impact of inherent power system asymmetry like two phase connections is not considered within the paper. Fault location due to the single measurement point at the feeder end can reduce restoration time, consequently, introduces a limitation of the proposed idea.

Diogo et al propose a solution to detect Broken Conductor (BC) fault considering the quantity of neutral current pick-ups during a High Impedance Fault (HIF). The methodology applies the SEF function monitoring in a time box window, where a pick-up counting is processed into that window. Limitations of method could be analysis conducted on unbalanced grid network in Sao Paulo, Brazil. The authors suggest that the di/dt method can be disregarded in a balanced 3ph network. However, can be used to distinguish load variation from faults. Method relies on HIF faults on the source side and ground neutral current initiating a SEF pickup

(ZPS current). It is therefore assumed this method would not apply to LSBC faults. Method requires IEDs with Boolean logic capabilities. Legacy relay types and schemes may restrict a network wide rollout reducing overall system coverage. Moreover, utility capital investment strategies may also impact Boolean logic capable IED's.

Burgess investigates various aspects of arc suppression coil systems to assess their effectiveness in MV distribution networks. The author suggests arc suppression coil systems may benefit BC risk mitigation through analysis of neutral voltage magnitude and phase angle. Burgess suggests limiting factors in detecting a LSBC fault are the earth fault impedance and the impedance between the healthy conductors and the faulted conductor on the load side. Burgess summarises that using a properly tuned arc suppression coil and monitoring neutral voltage, detection of HIF & BC can be achieved in lieu of conventional protection system limitations. Burgess proposes a logic diagram which could be implemented as part of automatic whole of substation or system protection equipment. Worthy of note, arc suppression coil systems do not currently form part of Ausgrid network design philosophy.

Finally, Dase, K. et al propose two novel methods for BC detection using series arching theory. Arching phenomena associated with the opening of load-interrupting disconnector switches has been used. Their research suggests the same principles can be applied to an arc generated upon a conductor breaking and falling. The authors look at current magnitude reduction and phase resistance increase over predetermined times. Series arching theory presented in the paper suggests the proposed method is more suited to meshed networks rather than radial feeds with constant current loads. Testing and analysis of the proposed method was conducted on transmission and sub-transmission networks above 110kV.

The voltage-based method presented by Vieira et al and Udomparichatr utilises smart meter voltage readings to measure system voltage imbalance. The algorithms use a voltage threshold calculation specified in IEC TR 61000-3-13 Electromagnetic compatibility – Assessment of emission limits for the connection of unbalanced installations to MV, HV and EHV power systems, shown in figure 27.

$$u_2 = \sqrt{\frac{1-\sqrt{3-6\beta}}{1+\sqrt{3-6\beta}}} \times 100\%$$

$$\beta = \frac{|U_{ab}|^4+|U_{bc}|^4+|U_{ca}|^4}{(|U_{ab}|^2+|U_{bc}|^2+|U_{ca}|^2)^2}$$

$$u_2 = \frac{|U_a+a^2U_b+aU_c|}{|U_a+aU_b+a^2U_c|} \times 100\%$$

Figure 27 - IEC 61000-3-13 - Unbalanced Voltage Equations

If a meter reports a voltage imbalance above the threshold, all meter data within a defined area will be pulled. Nodes will be designated a colour (red, green, or grey) based on status as per algorithm. Status reporting will prompt network operators to dispatch a line patrol crew. Udomparichatr suggests practical implementation considerations include smart meter failure or loss of device communications, network reconfiguration via load transfer or switching operations. Consequently, graph theory was used to address the considerations for analysis purposes. Smart meters are yet to be rolled out across Ausgrid's entire network. Using smart meter data was a future consideration mentioned in Stanbury's paper. Stanbury identifies advantages of smart meter BC detection over other detection methods as providing visibility of both 11kV and LV broken conductors, better coverage of BC on 11kV spur lines, meter are maintained to a high standard ensuring device reliability, device density provides better network coverage. Conversely, Stanbury suggests possible challenges include a disparity between device hardware requirements for BC detection and retailer requirements for standard consumption metering. Additionally, real time data requirements may require upgrades to back-end metering systems run by third parties (Stanbury, 2021).

Harmonic based methods to mitigate BC risk have been investigated. Several papers explore wavelet transforms to detect distribution network faults. Like

Burgess, Hao et al incorporates an arc suppression coil-based system as above, however, focuses on zero sequence current signal as a reference for analysis. Analysis uses wavelet packet transform to decompose high frequency signal components and calculating the corresponding energy of each sub-band signal. Hao et al also introduces energy entropy to reflect the randomness of fault conditions. The analysis provides a characteristic quantity whereby different fault conditions can be judged according to the spectrum of energy entropy. As such, the zero-sequence transient current can be used for data mining and feature extraction.

Alternatively, Qu et al propose a method of fault detection to mitigate covered conductor (CC) faults based on partial discharge (PD) signals. CC are used to improve reliability and minimise fire risk in densely vegetated areas. However, the insulated conductor fault detection difficulties in certain scenarios. The PD magnitude is typically considered noise by IED filtering or unaccounted for in electromechanical protection relays. Discrete wavelet transform is used to decompose the PD signal and a Long-Short-Term Memory (LSTM) network is used as a sequence prediction model of the decomposed PD signal output and detects the CC fault.

Finally, Lima, et al proposes the use of Short-time Fourier transform (STFT) to detect HIF. Looks at spectral waveform characteristics of HIF due to the arcing generated. This harmonic detection method focused on the 2,3,5 harmonic in the time & frequency domain simultaneously. Review of such harmonic methods for fault detection indicate significant signal processing burden and sampling rate requirements. Further research and understanding of the concepts are required for operational implementation of such methods.

2.4 Asset Management and Regulatory Drivers

Structure and business models within the power sector are adapting to facilitate an increasingly competitive market, consumer needs and evolving network. Aspirations for more reliable, sustainable, and safer energy supply are driving grander investment in power system planning and operations (Vieira et al, 2019).

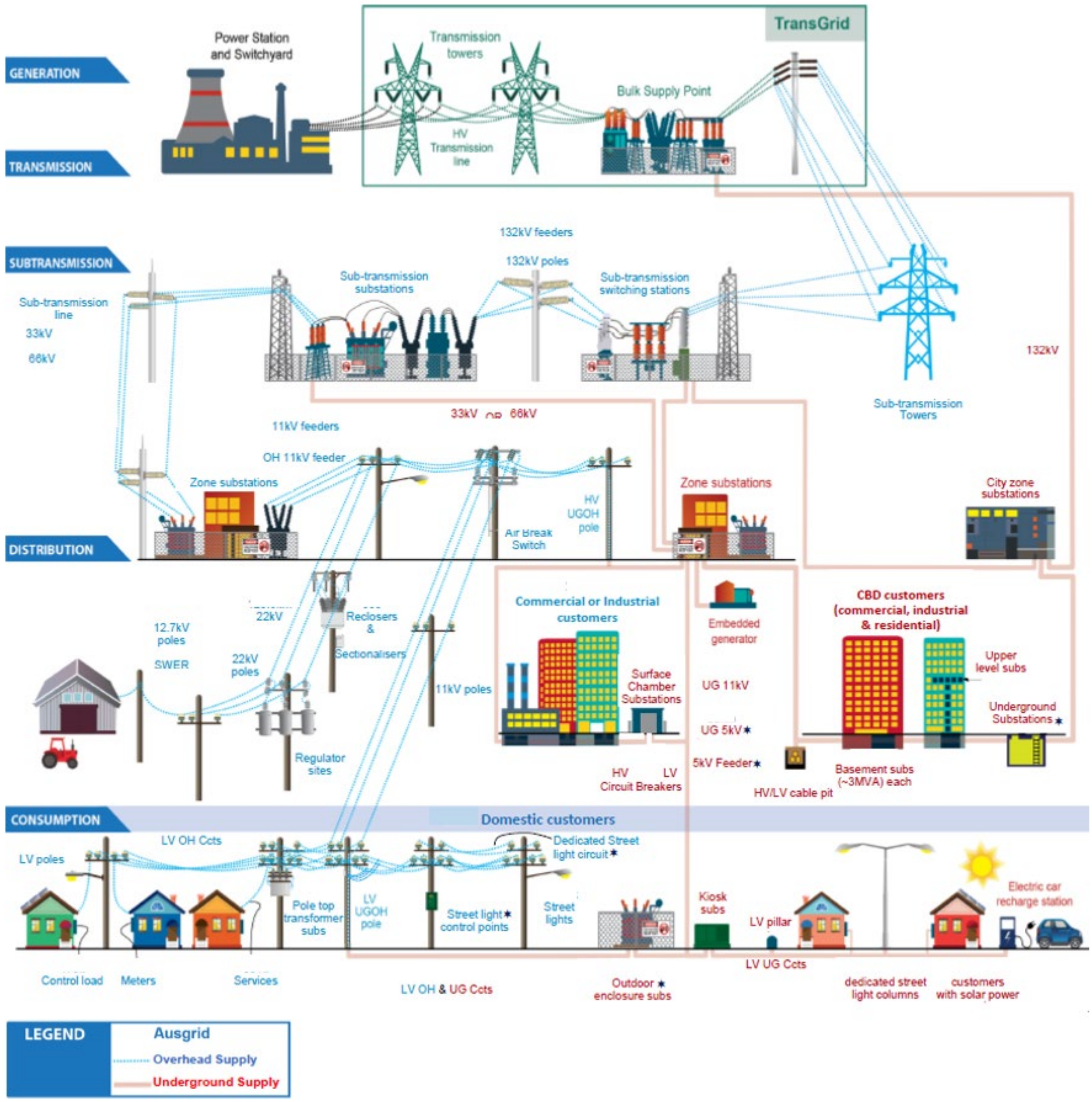


Figure 28 - State of Network Diagram (Ausgrid, 2021)

Figure 2.4.1 presents a recent snapshot of Ausgrid's network topology. The "State of Network" diagram depicts conventional electricity supply chain architecture, generation through to end user consumption. However, a relatively new topology inclusion is embedded generation at the distribution and consumer level. Moreover, electric vehicle charging stations appear with density expected to increase over the coming years with a focus on net zero by 2050 (NSW Govt. 2023). Such additions support the need for power system business model adaptation to facilitate an evolving network and consumer needs.

Ausgrid align their organisational objectives with the National Energy Objective (NEO). NEO, as stated in the National Electricity Law (NEL) is "to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:

- Price, quality, safety and reliability and security of supply of electricity;
- The reliability, safety, and security of the national electricity system." (AEMC, 2023).

Additionally, Ausgrid must deliver upon their regulatory and legal requirements, particularly obligations under the WHS Act 2011, the Electricity Supply (Safety and Network Management) Regulation 2014 (NSW), the National Electricity Law (NEL) and the Electricity Supply Act 1995 (NSW). (Ausgrid ASM, 2021).

Ausgrid's ongoing organisational strategy set out in their business plan is to provide outstanding customer service. The primary tenet of this commitment is to protect the customers and communities in which they live from danger and disruption. The philosophy behind the commitment fundamentally supports the need for the NSW government action to:

- Support the safety of members of the public;
- Support the safety of persons near or working on the electricity network;
- Minimise the risk of property damage including bushfires caused by mal operation of the network;

These actions are outlined in the Regulatory Impact Statement (RIS) covering the 2014 renewal of the Electricity Supply Regulation.

The purpose of the regulation is to prescribe provisions that will apply to network operators, and which will enable the government to direct network operators to provide adequate, reliable, and safe supply of electricity of appropriate quality. The safety of the public and property is the highest priority of the Regulation. (NSW Govt. Resources & Energy, 2014). As such, the Regulation drives network operators like Ausgrid to explore innovations like BC detection to mitigate wires down events to deliver upon their regulatory requirements.

Ausgrid exercise a series of co-ordinated activities that balance the cost, risk, and performance of assets in the pursuit of organisational objectives and regulatory compliance. This function is called asset management. A prudent asset management strategy implements a vigorous asset management system. Ausgrid manage a large quantity and broad range of individual assets spread across a significant geographical area. Asset environments range from public spaces and secure facilities. Such diversity requires the segmentation of assets into classes to manage effectively and appropriately. Asset class strategies are established to achieve asset class objectives. Asset class strategies generally outline key and emerging risks and key opportunities and strategies to address and manage such risk. BC detection applies to the overhead mains and protection, control, and automation asset class.

Finally, Ausgrid employ a strategic approach towards the use of network related technology to support future consumer needs and an evolving operating environment. BC conductor detection is seen as a technology to achieve safety and reliability outcomes represented in figures 2.4.2 and 2.4.3.

Figure 29 - Technology capabilities to reduce safety related incidents (Ausgrid, 2021).

Metrics like SAIDI and SAIFI refer to the duration and frequency of system average interruptions respectively (AER, 2018). Such metrics encourage utilities, like Ausgrid to find solutions to mitigate the duration and frequency of interruptions. Limitations of existing mitigation techniques are well known. Improvements in mitigation techniques should be conceived by integrated systems based on new methods for timely and reliable data acquisition processing (Vieira et al, 2019). Ausgrid's Network Technology Strategy aims to achieve this.

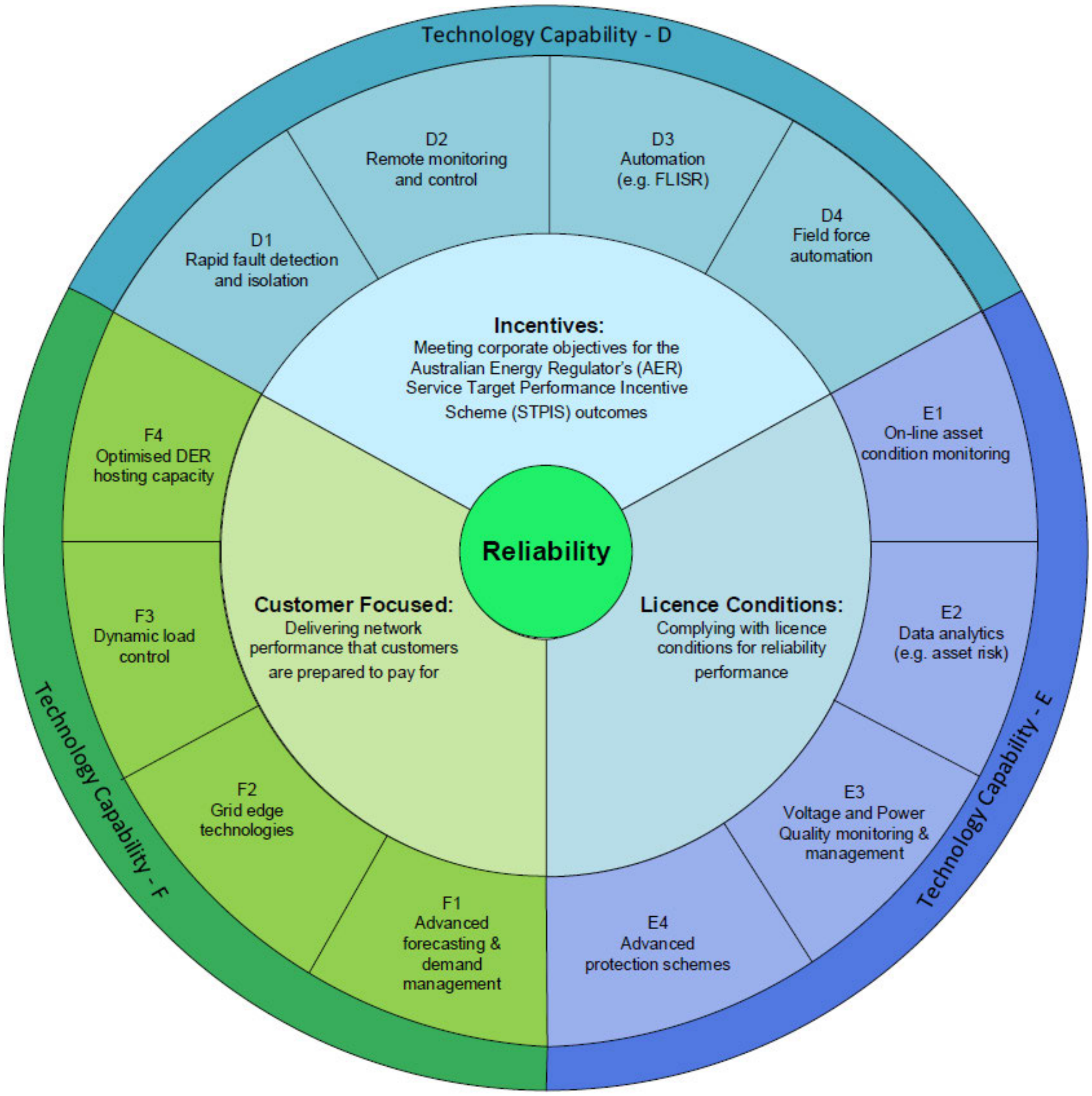


Figure 30 - Technology capabilities to meet or improve reliability target (Ausgrid, 2021).

CHAPTER 3

Discussion

3.1 Consequential Effects

Mains down events are a challenge for utility protection engineers (Stanbury, 2021). Limitations of traditional protection schemes make it inherently difficult to detect BC events and pose a significant risk to people and property. Ausgrid has a duty of care and in accordance with their risk management framework ensure they are risk averse to such events and manage associated risk SFAIRP. Through asset management improvement schemes like the innovation program, investing in research, development, and implementation of technology like BC detection provides a best practice alternative to traditional methods and ensures associated risk is managed SFAIRP.

Consequential effects associated with the operational implementation of BC detection must be considered. A preliminary evaluation presents a range of overarching consequences. They are summarized below.

- Managing risk in accordance with Ausgrid's risk appetite and SFAIRP.
- Adherence to asset management frameworks and best practice engineering through innovation investment.
- Proactively embracing technology for business improvement and sustainability. Conversely, implementation of technology to meet innovation program KPI's before comprehensive assessment of technology is completed. Outcomes may lead to pointless or nuisance initiatives which burden network operations.
- Accepting duty of care, recognizing impacts of inaction, and adopting a zero-tolerance attitude towards complacency.
- Operational and commercial improvements through development of an intelligent network. Conversely, additional operational cost associated with coordinating repairs/failures of sensitive equipment.
- Implementation of change management across business units and associated cost.

As previously mentioned, project objectives are to evaluate Ausgrid's operational implementation of a BC detection algorithm. There is intent for project outcomes to form a reflection piece and assist strategic decision making for other utilities.

3.2 Ethical Responsibility

Engineers Australia's Code of Ethics state: *"As engineering practitioners, we use our knowledge and skills for the benefit of the community to create engineering solutions for a sustainable future. In doing so, we strive to serve the community ahead of other personal or sectional interests."* Through the operational implementation of BC detection, Ausgrid are satisfying their ethical responsibility as a DNSP via engineering and technology.

The following points have been considered during the trial and throughout the research project:

- Research project approval.
- Intellectual property.
- Engineering verification and validation.
- Risk analysis.
- Cost benefit.
- Social value.

Given the research project is based on an Ausgrid Network Innovation Trial, approval to undertake research and report outcomes is required. Consent to use intellectual property has been granted provided such material is referenced and individual work credited. Sensitive network information has been omitted where operational risk exists.

Engineering verification and validation will be conducted throughout the trial and during the research project to support claims and justify outcomes and direction.

Associated trial and project risk have been analysed and addressed throughout the report. Additional risks may be identified during the trial and project. This will be suitably managed and documented as required.

Trial cost benefit identified several key elements driving its rollout proposal. Significant volumes of historical data and existing configurable asset monitors make implementation of the proposed algorithm scalable. Additionally, BC features are to be enabled in all greenfield equipment moving forward. Ultimately, following the initial upfront engineering and development costs, zero incremental cost exists and can be achieved progressively in conjunction with ongoing gradual network improvements. Consequently, trial and implementation costs are minimised to ease consumer impact ensuring ethical responsibility is upheld.

Lastly, trial and research project outcomes have the potential to provide significant social value as the opportunity exists to improve overall safety to the public and property. Although an overall public safety benefit, network construction varies with geographical location. Customer density reduces as the network transitions from urban to rural. The proposed trial utilises existing network equipment and monitors for detection. Such equipment may be less dense or not exist entirely in rural network equipment. The resulting sensitivity to BC events may ensure network operators have greater visibility of these challenging and dangerous occurrences. Although positive, such outcomes may be skewed and raise some ethical concerns.

CHAPTER 4

Methodology

4.1 Broken Conductor Trial Scope

The trial system will implement a real time BC detection algorithm developed by Ausgrid Senior Engineer, Michael Stanbury. The algorithm uses voltage measurement data and will report the BC event using field device recorders.

Specialty teams will work to a timeline, staging delivery from development to deployment. A stakeholder summary for the BC trial is provided below in *Table 1*.

Stakeholder	SoW
Control & Protection Engineering (C&P)	• Evaluate BC functionality in field devices. • Develop/modify device configurations. • Consider live trial and associated requirements. • Mandate BC features in future equipment. • Assess detection sensitivity through investigation of live wires down events reported by System Control. • Assess detection reliability through event triggers. • Report trial outcomes.
Asset Data & Systems (AD&S)	• Use real time voltage data from field devices to detect BC in the Advanced Distribution Monitoring System (ADMS). • Events will be triggered by analogue values. • Future trial development to utilize digital indications from field devices for events.
System Control (SC)	• Document live wires down events.

	• Notify C&P of documented real event to verify trial system events.

Table 1 - Ausgrid BC Trial Stakeholder SoW Summary

A desktop analysis will assess system sensitivity by comparing operator documented events and system detected events. Spurious alarms will be assessed by comparing "real" detections and false alarm rate. Finally, stakeholder engagement will be a critical element of the trial. System feasibility in an operational setting will be evaluated through consultation with relevant stakeholders.

4.2 Voltage-based Magnitude Broken Conductor Detection

The methodology set out in this report focusses on a voltage-based magnitude BC detection method selected for Ausgrid trial implementation. The candidate method is justified based on the multitude of monitoring data currently acquired from existing 11kV and LV field devices. These existing monitors have expansive network coverage with diverse topologies from urban to rural networks.

Mains down events are unlikely for a particular feeder each year, however, more likely across the entire network. Ausgrid's 11kV system has many inherent interconnections, load variations and network configurations due to regular switching operations, planned or unplanned. System volatility may add complexity when trying to implement other methods, whereas the candidate method is expected to be relatively robust. Moreover, Ausgrid's 11kV system has standard transformer vector groupings for 11/0.433 kV distribution transformers. The DY (delta/star) vector grouping provides a common value of voltage and current unbalance across the primary and secondary as described in *"Open Phase Conditions in Transformers - Analysis and Protection Algorithm*" (Norouzi, 2013). This provides a consistent expected value of healthy and unhealthy voltage for the proposed BC detection algorithm to reference.

Observations can be made for systems with ungrounded primary windings (delta or star), when one phase is open. In a delta primary the coil with no lost phase will have the same voltage as before the open circuit fault occurred. The other two coils will maintain half their original voltage. These voltages will have the same magnitude and phase angle, however, the new angle is totally different from prior to the loss of phase (Norouzi, 2013).

Figure 31 illustrates an *A* phase open circuit condition in a system representative of a distribution network with an ungrounded delta primary transformer connection. The phase sequence is *ABC* and configuration is *DY1* where the delta lags the secondary star side by 30°. Individual phase coils are labelled W_A, W_B, and W_C (Norouzi, 2013).

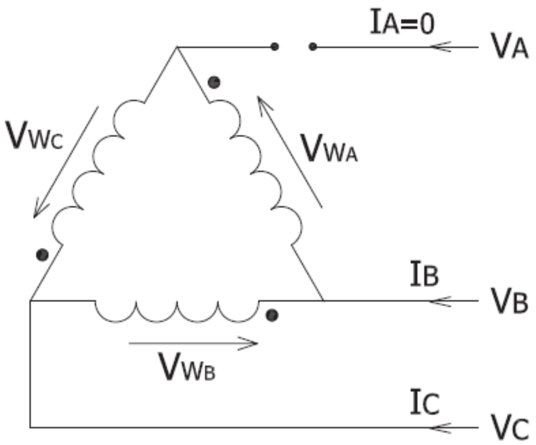


Figure 31 - Delta Primary Winding with Open Circuit A Phase

With *A* phase open, the voltage across W_B is still V_{BC}, remaining unchanged. However, V_{BC} is evenly divided between coils W_A and W_C. After the loss of *A* phase and considering the dot convention, the follow is true for the coil voltages and line currents (Norouzi, 2013):

$$Vw_B = V_{BC}$$

$$Vw_A = Vw_C = -\frac{1}{2}V_{BC} = \frac{1}{2}V_{BC}\angle 180°$$

$$I_A = 0;\ I_C = -I_B$$

For a *DY11* configuration:

$$Vw_C = V_{BC}$$

$$Vw_A = Vw_B = \frac{1}{2}V_{BC} = \frac{1}{2}V_{BC}\angle 0°$$

The above equations can be transposed for an open circuit condition on the other two phases.

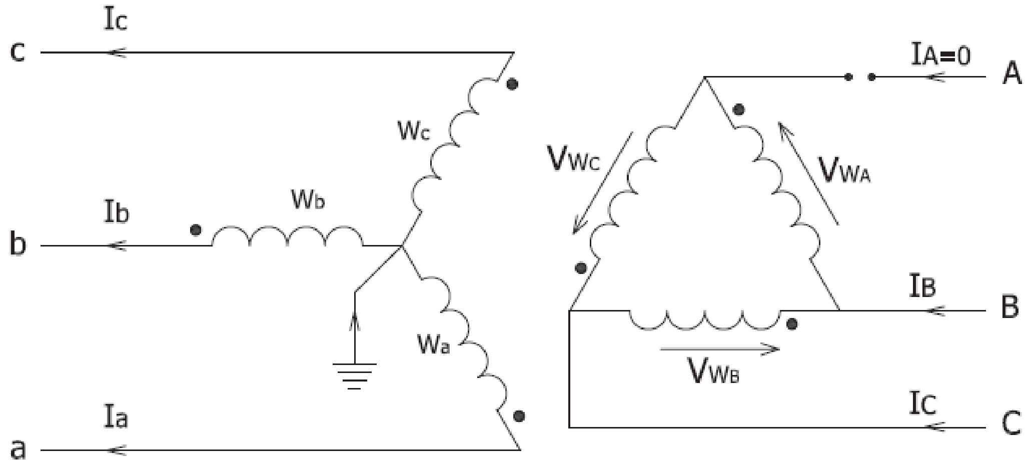


Figure 32 - DYg Transformer with A-phase Open Primary

Figure 32 illustrates a *DYg* transformer with open circuit *A* phase. As discussed, with ungrounded delta primary winding, only half the line voltage will be established across the two coils associated with the lost phase on the high side, i.e., coils W_A and W_C, shown in the equations above. Therefore, in the corresponding secondary coils of W_a and W_c, a voltage equal to half the pre-fault voltage will be induced (Norouzi, 2013). Norouzi simulated the above using a sample power system shown in figure 33 and corresponding results shown in figure 34.

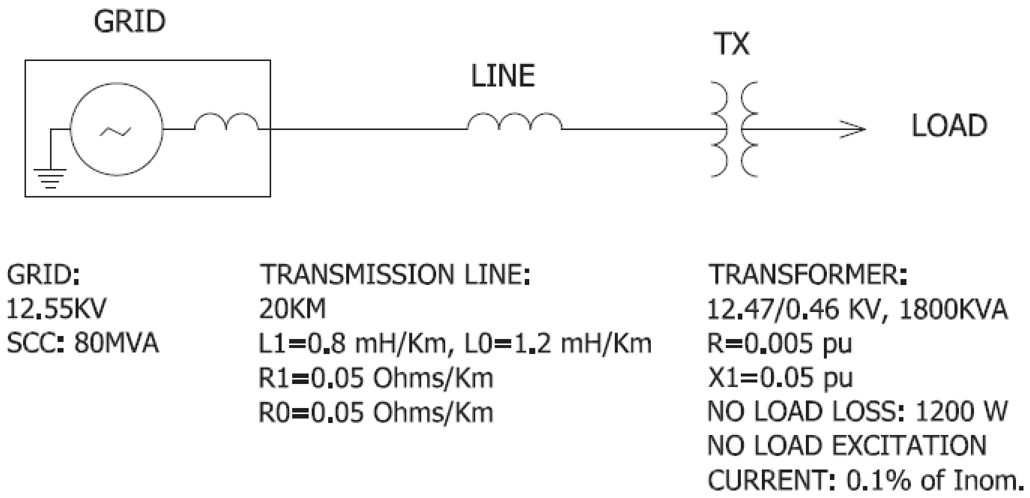


Figure 33 - Single Line Diagram of Sample Power System

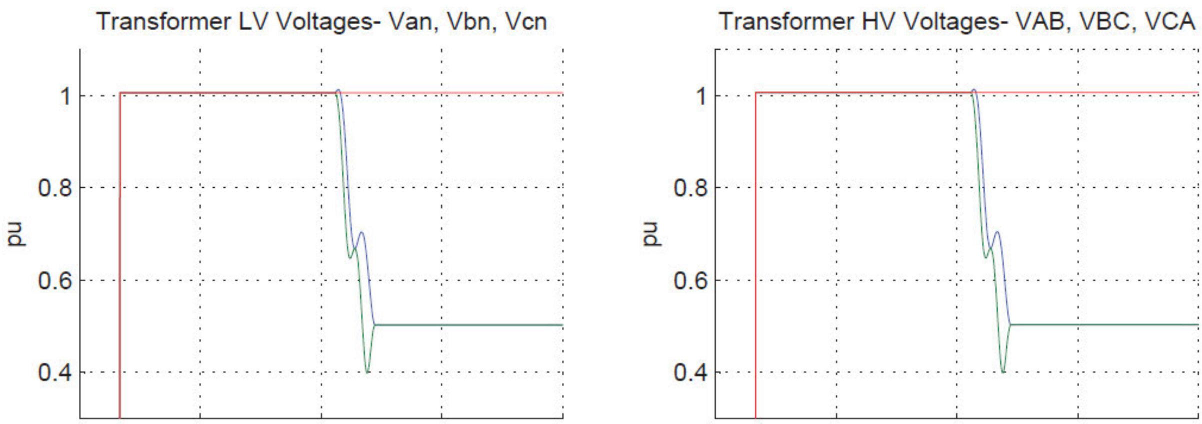


Figure 34 - Simulation Results for DYg Transformer with Phase Discontinuity

Variants of the voltage-based method include “Loss of Phase” (LOP) protection which detects if one or two (but not three) phases fall below nominal voltage on the 11kV network. Alternatively, partial voltages (neither fully live nor fully dead) can be analysed. LV measurements can be used to detect a single broken conductor on the source 11kV feeder (Stanbury, 2021). Parameters for each variant are summarised below:

LOP Method

- 3 phase 11kV L-G voltages – At least one phase is below 75% nominal voltage while at least one other phase is above 75% nominal voltage for >10 seconds.
- 3 phase LV L-N (230V) voltages – At least one phase is below 75% nominal voltage while at least one other phase is above 75% nominal voltage for >10 seconds.

Partial Voltage Method

- 3 phase 11kV L-G voltages – At least one phase is between 10% and 75% nominal voltage for >10 seconds.
- 3 phase 11kV L-L voltages – At least one phase is between 10% and 75% nominal voltage for >10 seconds.
- 2 phase 11kV L-L voltages – At least one phase is between 10% and 75% nominal voltage for >10 seconds.
- 3 phase LV L-N (230V) voltages – At least one phase is between 10% and 75% nominal voltage for >10 seconds.

Setting of the lower band threshold of 10% aims to eliminate spurious alarms triggered by failed voltage sensors for 11kV measurements or secondary fuse operation for LV measurements.

In addition to detecting BC, the methods described above will trigger an event for other series faults like broken bonds or bridges, 11kV fuse operation, faulty load break switches, single phase switching and distribution transformer failures. Although less hazardous than live wires down events, rapid notification will assist timely restoration to customers, improving reliability.

4.3 Algorithm Overview

An overview of Michael Stanbury's (Stanbury, 2021) algorithm is provided below.

1. Algorithm steps forward through time.

   a. Note: real-time implementation should be triggered by new DNP packets. When a trigger occurs, it could possibly wait a second to see if the other phase voltages report shortly after.
2. Each device's code can run in parallel (no interdependence between field devices)
3. At each time step, the algorithm:
   a. Performs a basic check for loss of phase: One voltage is nominal and the other 2 are between 10% and 95% of nominal. (Actual percentages vary.)
   b. If this is true, it calculates a "brokenConductorIndicator" which is 0 for an ideal broken conductor, and typically < 0.05 for most real events.
      i. This checks whether 2 phase voltages add up to the 3rd one. (An effect of downstream delta windings)
   c. The brokenConductorIndicator is accumulated into the cumulativeIndicator over time. If the subsequent data samples continue to look like a broken conductor, cumulativeIndicator will increase, otherwise it will decrease.
   d. We also accumulate the number of timesteps that look like a broken conductor (brokenConductorTimeStepCounter). If subsequent time steps are unlike broken conductors, this brokenConductorTimeStepCounter will decrease.
   e. There are 2 ways to declare the event as a valid broken conductor (eventValid == true).
   f. In summary:
      i. **Method 1**: good for latent data which only comes in every 10 minutes, but measurements are synchronised. The aim is to minimise the time to detection because data comes in rarely.
      ii. **Method 2**: focussed on dead-banded voltage measurements. More frequent measurements allow more stringent detections but still flag them in 10 – 90 seconds, most of the time.
   g. If eventValid == true, send a real-time notification and log the event

4.4 Preliminary Modelling & Trial Desktop Analysis

Preliminary modelling of a simple 11kV radial feeder was conducted by Ausgrid Senior Engineer, Michael Stanbury using Electromagnetic Transients Program (EMTP®) shown in figure 32. The model consists of an 11kV source, source end bus, 11kV line, load bus, *DY11* 11/0.433 kV distribution transformer and connected load. The BC scenario presented in figure 32 is an open C phase with a low impedance load side earth fault. With consideration of the previously presented theory, results for LV measurements in per unit were obtained from a series of scenarios modelled in the program and are shown in table 2. Table 3 indicates effectiveness of SEF protection for each scenario based on a cursory check of the zero-sequence current (I_0) measurement at the source and provides an approximation value based on the per unit LV measurements.

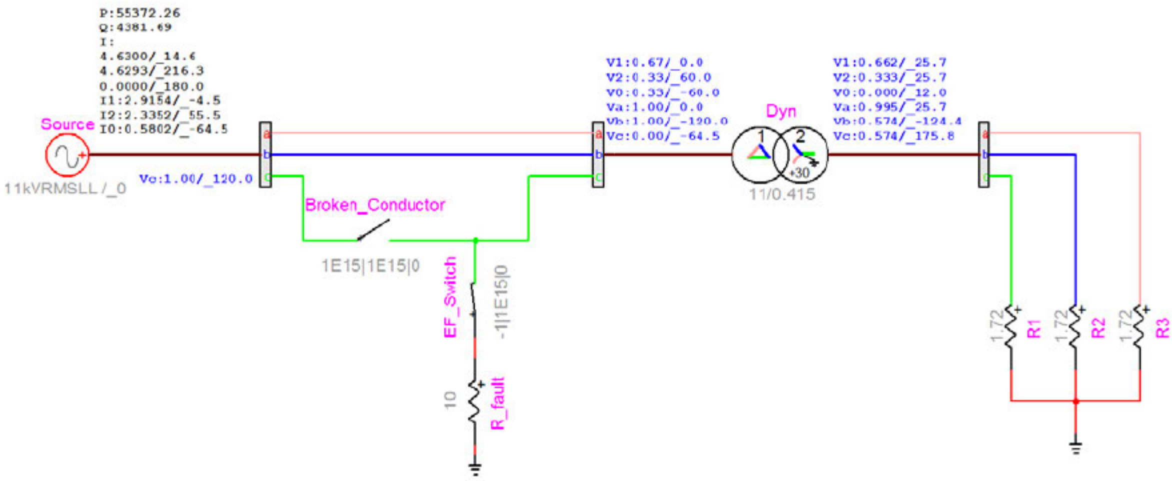


Figure 35 - EMTP Model of 11kV Radial Feeder - LSBC with Low Impedance EF (Stanbury, 2021)

Scenario	Description	LV Voltages [per unit]		
		V_{an}	V_{bn}	V_{cn}
1	C-phase broken with earth fault	0.995	0.574	0.574
2a	C-phase broken without earth fault, balanced load	0.995	0.497	0.498
2b	C-phase broken without earth fault, unbalanced load	0.995	0.417	0.577
3a	B and C phases broken with earth fault on C, balanced load	0.286	0.286	0.572

3b	B and C phases broken with earth fault on C, unbalanced load	0.426	0.148	0.573
4	B and C phases broken with earth faults on B and C	0.573	0	0.573
5	B-phase broken with B to C fault, without earth fault	0.995	0	0.995
6a	C-phase broken with C-phase HV fallen into LV without earth fault	0.995	0.569	0.586
6b	C-phase broken with C-phase HV fallen into LV with HV earth fault	0.995	0.574	0
6c	B and C-phases broken with C-phase HV fallen into LV with HV earth fault	0.287	0.287	0
6d	B and C-phases broken with C-phase HV fallen into LV	0.294	0.294	0.587

Table 2 - EMTP Model Scenarios (Stanbury, 2021)

Scenario	SEF Sensitivity	LV Voltage Approximations
1	Poor: significant load and solid fault required	1, 1/sqrt(3), 1/sqrt(3)
2a	None	1, 1/2, 1/2
2b	None	1, X, 1-X (not 1/sqrt(3))
3a	Poor: significant load and solid fault required	1/(2*sqrt(3)), 1/(2*sqrt(3)), 1/sqrt(3)
3b	Poor: significant load and solid fault required	?, ?, 1/sqrt(3)
4	Poor: significant load and solid faults required	1/sqrt(3), 0, 1/sqrt(3)
5	None	1, 0, 1
6a	Poor: significant load required	1, 1/sqrt(3), 1/sqrt(3)
6b	Poor: significant load and solid faults required	1, 1/sqrt(3), 0
6c	Poor: significant load and solid faults required	1/(2*sqrt(3)), 1/(2*sqrt(3)), 0
6d	Poor: significant load required	1/(2*sqrt(3)), 1/(2*sqrt(3)), 1/sqrt(3)

Table 3 - EMTP Model - SEF Sensitivity Assessment & LV Approximations (Stanbury, 2021)

As discussed in section 4.3, figure 31 illustrates a *DY1* transformer with open *A* phase on the high side. With an ungrounded delta primary winding only half the line voltage will be established across the two coils associated with the lost phase. Therefore, in the corresponding secondary coils, a voltage equal to half the pre-fault voltage will be induced (Norouzi, 2013). This is evident in scenario 2a shown in tables 2 and 3 above.

Ausgrid uses a proprietary historian database to collect and store time-series data from various monitors and measurement devices across the network. A single point of measurement, for example, voltage or current, is given a unique storage point identifier called a tag which can be searched for and located within a defined time range. Using available spreadsheeting application plugins, a link can be established to the database and specific tags can be imported for analysis. Therefore, a desktop analysis was conducted using the historian database as a tool to test and build confidence in the BC detection algorithm.

A script was developed to source relevant historian tags, place them in a spreadsheeting application, run the algorithm and print the results. The script was programmed to run 6 months of data at a time. For each time interval, the script stores the voltages and times in an array. If a BC event is detected (voltage <75% & >10% nominal) for greater than 10 seconds, the event will flag and be added to the results. As a sanity check, the result would also print the final value before the end of event occurs. If at least one of the final voltages remains above the threshold it is noted as "Loss of Phase", otherwise noted as "Loss of all phases".

Table 4 presents a list of flagged BC events that the algorithm identified during the desktop analysis. With consideration of the algorithm overview in section 4.4 the following should be noted. The "*Broken Conductor Indicator*" (column 4) uses a threshold of <0.1 for detection. When this value is close to zero it looks like a BC event. "*Num Time Steps that look like a broken cond*." (column 5) looks at the total event data collected. A large number is representative of a long duration event or a field device with high sample rate or frequent data reporting. "*Time to detect broken cond. [s]"* (column 6) reports the delay between event start and when the algorithm decides the event is a legitimate BC, in seconds. From an operational perspective, this is when the system would flag an event to system control. Ideally, these times should be of short duration.

Device Name	Va	Vb	Vc	Broken Conductor Indicator (at end of event)	Num Time Steps that look like a broken cond.	Time to detect broken cond. [s]
1	174	76	250	0	18	599.999
2	173	247	74	0	8	1199.999
3	120	151	251	0.079681275	15	599.999
4	248	128	99	-0.084677419	15	2399.999
5	154	255	111	0.039215686	13	1200
6	122	124	248	-0.008064516	11	1800
7	125	123	248	0	3	1200.001
8	156	113	242	0.111570248	14	1200
9	243	193	55	0.020576132	42	1799.999
10	247	167	79	-0.004048583	5	1200.001
11	136	94	245	-0.06122449	30	1200
12	72	180	249	0.012048193	230	117
13	243	194	93	0.181069959	116	194.999
14	244	214	39	0.036885246	104	127.999
15	59	202	245	0.065306122	1458	136
16	217	245	51	0.093877551	522	138.999
17	245	172	76	0.012244898	77	56.999
18	244	94	168	0.073770492	36	234
19	82	139	236	-0.063559322	55	140
20	243	76	170	0.012345679	456	168.999
21	180	69	252	-0.011904762	57	139
22	119	242	142	0.078512397	61	592.999
23	119	242	142	0.078512397	61	592.999
24	94	72	235	-0.293617021	314	109.999
25	154	244	94	0.016393443	434	120
26	245	36	233	0.097959184	628	19
27	155	81	242	-0.024793388	264	19.999
28	116	238	139	0.071428571	90	194
29	245	113	138	0.024489796	93	590.999

Table 4 - BC Events Flagged by Algorithm (Stanbury, 2021)

Internal Ausgrid systems were reviewed to verify recorded historical measurement data and incident reporting repositories. The 11kV and LV voltage measurement profiles for device 3 in table 4 are shown in Figure 33 and 34 respectively. Historian data pulled by the script for this event indicates an event start time of 16:09:59 and finish time of 16:50:00, December 28, 2018. Figures 33 and 34 are representative of these times. Both figures show the transition from healthy pre fault voltage to unhealthy voltage to restored healthy voltage. During the event, $V_{a(red)} + V_{b(yellow)} = V_{c(blue)}$. This is consistent with a scenario like 2b in table 2 and 3. System Control incident reporting indicated an underground to overhead (UGOH) connection fault which resulted in an open circuit tapping and pole fire.

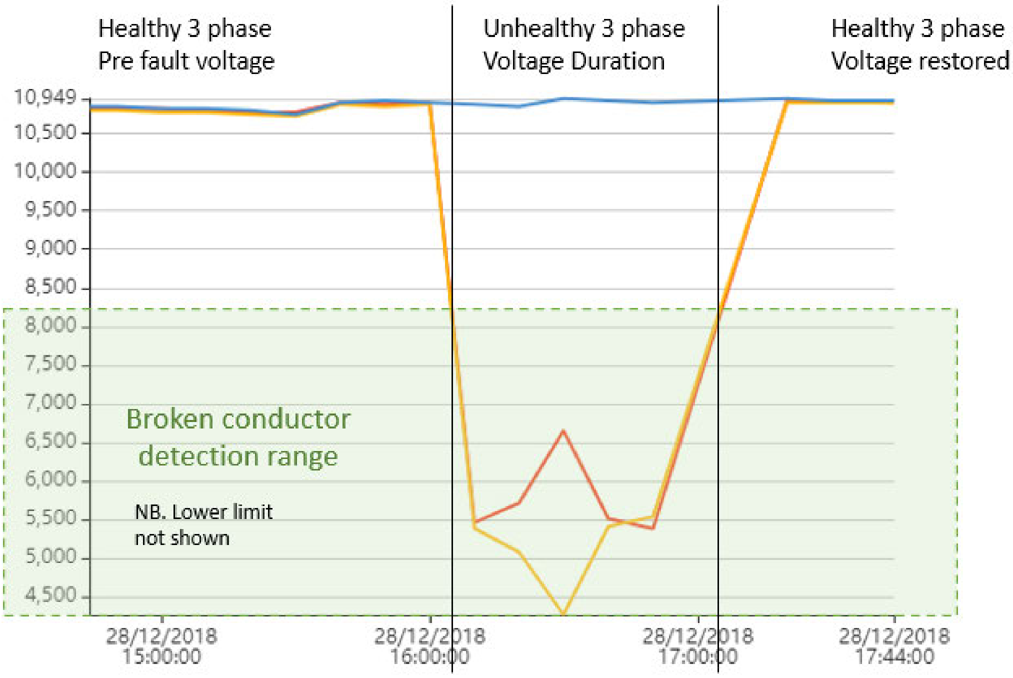


Figure 36 - 11kV Voltage Measurement Profile for Identified BC Event

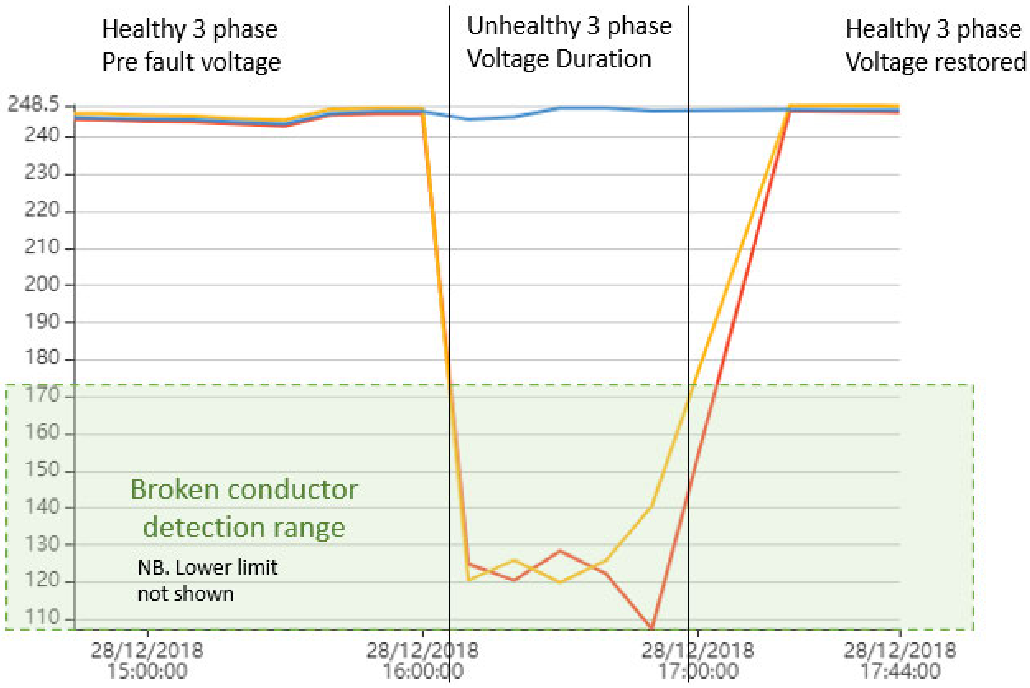


Figure 37 - LV Voltage Measurement Profile for Identified BC Event

4.5 Proposed Model

To demonstrate the viability and accuracy of the candidate BC detection method, a steady state model will be developed using suitable power system modelling software. The intent is to construct a simplified 11kV radial feeder typically found on Ausgrid's network and simulate various BC scenarios. The topology will align with previous modelling conducted in EMTP® by Ausgrid's Michael Stanbury. Measurement devices strategically positioned at key feeder nodes will log voltage and current quantities. Specialised analysis blocks within the modelling software will compute and output the magnitude and phase of the fundamental, positive, negative and zero sequence component of a three-phase input signal.

Following its development, the model will be validated to build confidence and ensure correct system implementation. The validation process will be performed by inspection and initially involve running simulations on a network normal arrangement to confirm output quantities are congruent with expected theoretical results. Furthermore, shunt fault scenarios will be introduced to create an unbalanced system to verify the sequence component outputs. These results will be compared to expected theoretical values outlined in chapter 2 and results obtained from a sequence component transform calculator sourced from Schweitzer Engineering Laboratories (SEL). Moreover, the validation process will extend to BC scenario simulations that align with previous EMTP® modelling and confirm equivalent results. These results will also be cross referenced with the expected theoretical results in presented in literature.

Lastly, the logged data will be exported from the modelling software to a spreadsheeting application for qualitative analysis. The analysis will interpret the logged data and evaluate the viability of the candidate BC detection method for operational implementation.

4.6 Algorithm Integration

Ausgrid recently integrated a new tool providing an intelligent platform for optimal network operations and management called the Advance Distribution Monitoring System (ADMS). In its relative infancy, AMDS bundles SCADA, outage management and distribution management into a single digital package. Adopting ADMS enables Ausgrid to meet the challenges of a future grid (Stefani, 2021)

ADMS will be the tool used to conduct real time coordination of voltage data for the BC detection trial. Control Systems Engineers will integrate field-based monitor data into ADMS using Stanbury's algorithm, specialised coding and proprietary development and simulator environments to build the detection system. The process involves complex computer-based networking between servers, remote terminals, and virtual machines.

The integration of the BC detection algorithm within ADMS will be discussed. The discussion will provide key inputs driving its integration and operational implementation outcomes. The extent of the discussion will rely on the progress of the teams managing this trial responsibility. A detailed evaluation of this trial component is outside the scope of this report.

CHAPTER 5
Modelling & Analysis

5.1 Model

A simple 11kV radial feeder was developed using MATLAB® and Simulink® toolboxes to validate the candidate BC detection method. The architecture of the model was chosen to represent a simplified 11kV radial feeder commonly found on Ausgrid's network. Ausgrid's general arrangement for the 11kV distribution network sees a 132, 66 or 33/11kV Zone Substation consisting of two to three source transformers feeding an 11kV switchboard where several 11kV feeders supply surrounding suburbs. Figure 35 depicts the zone substation general arrangement.

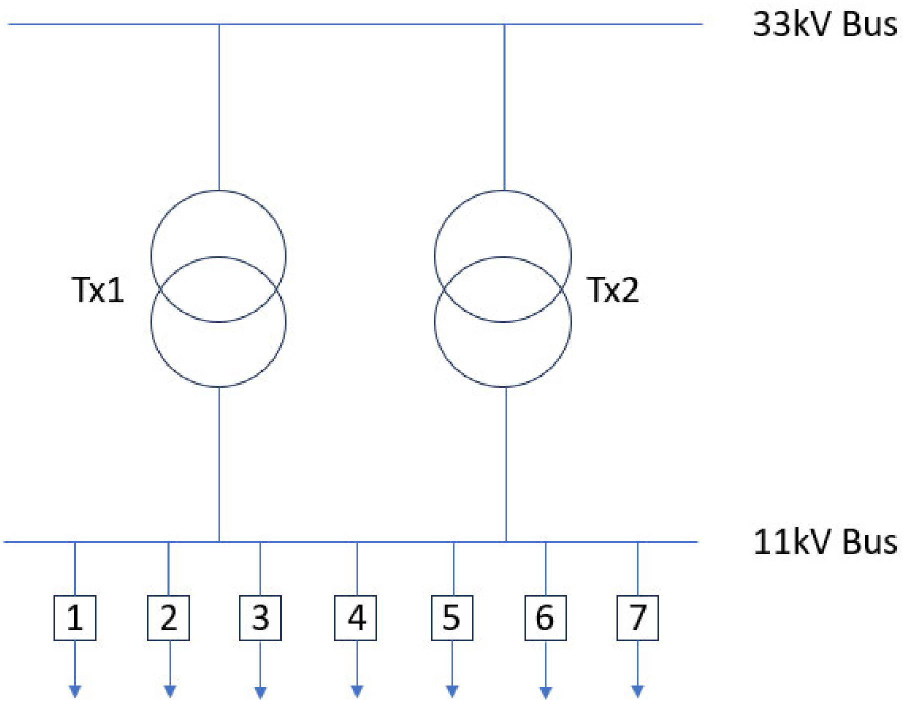


Figure 38 - Typical Zone Substation Schematic Layout

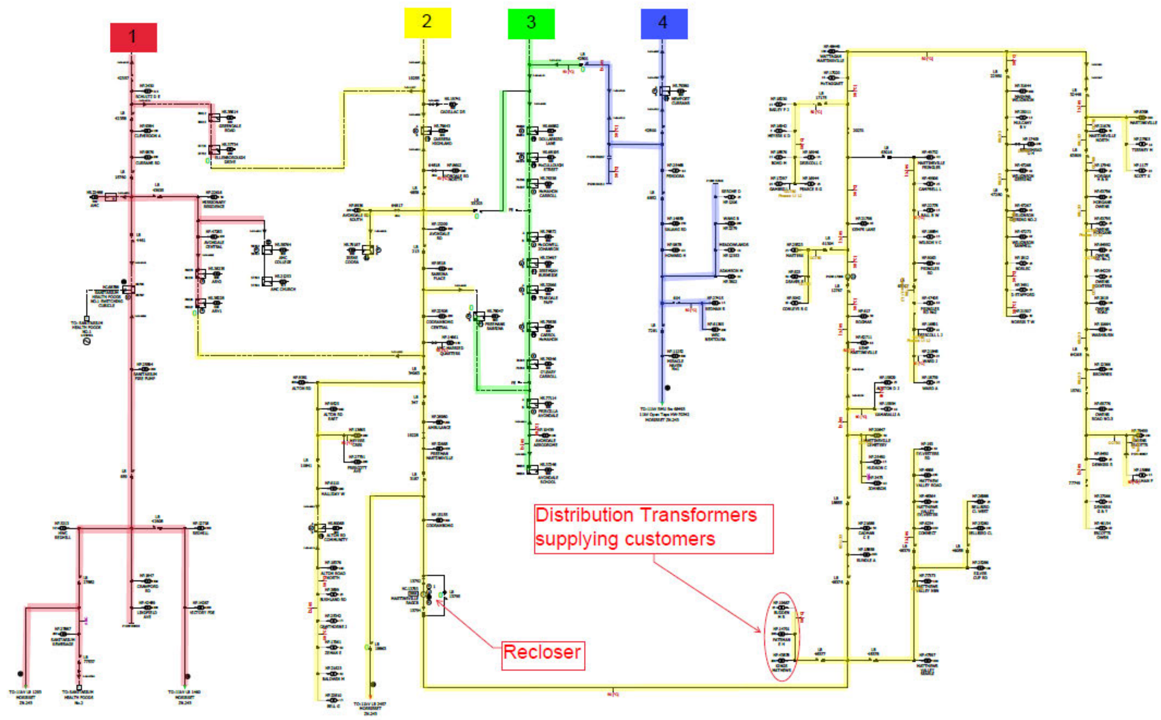


Figure 39 - 11kV Distribution System Diagram (Feeders 1-4)

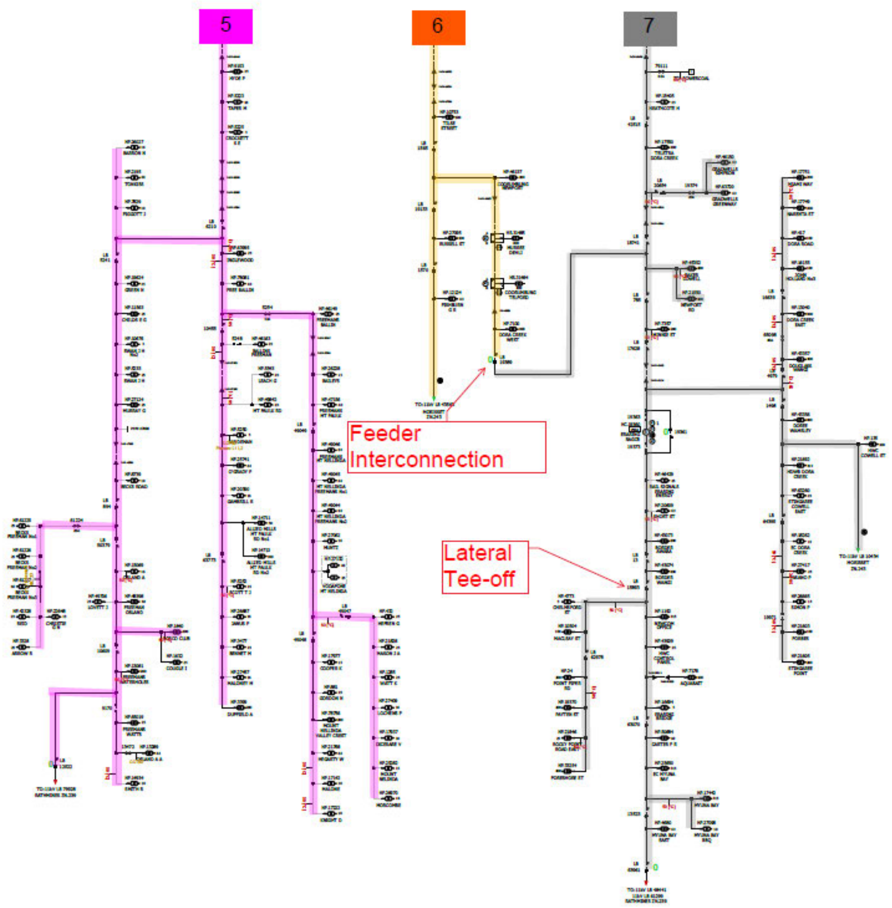


Figure 40 – 11kV Distribution System Diagram (Feeders 5-7)

Figures 36 and 37 are 11kV distribution system diagrams, colour coded to identify and delineate the seven radial feeders shown in figure 35. These diagrams represent the 11kV network only and do not include low voltage connections. A geographical trace of an arbitrarily selected feeder from the seven previously shown is presented in figure 38 and is a typical semi-rural radial feeder commonly found throughout Ausgrid's network boundary.

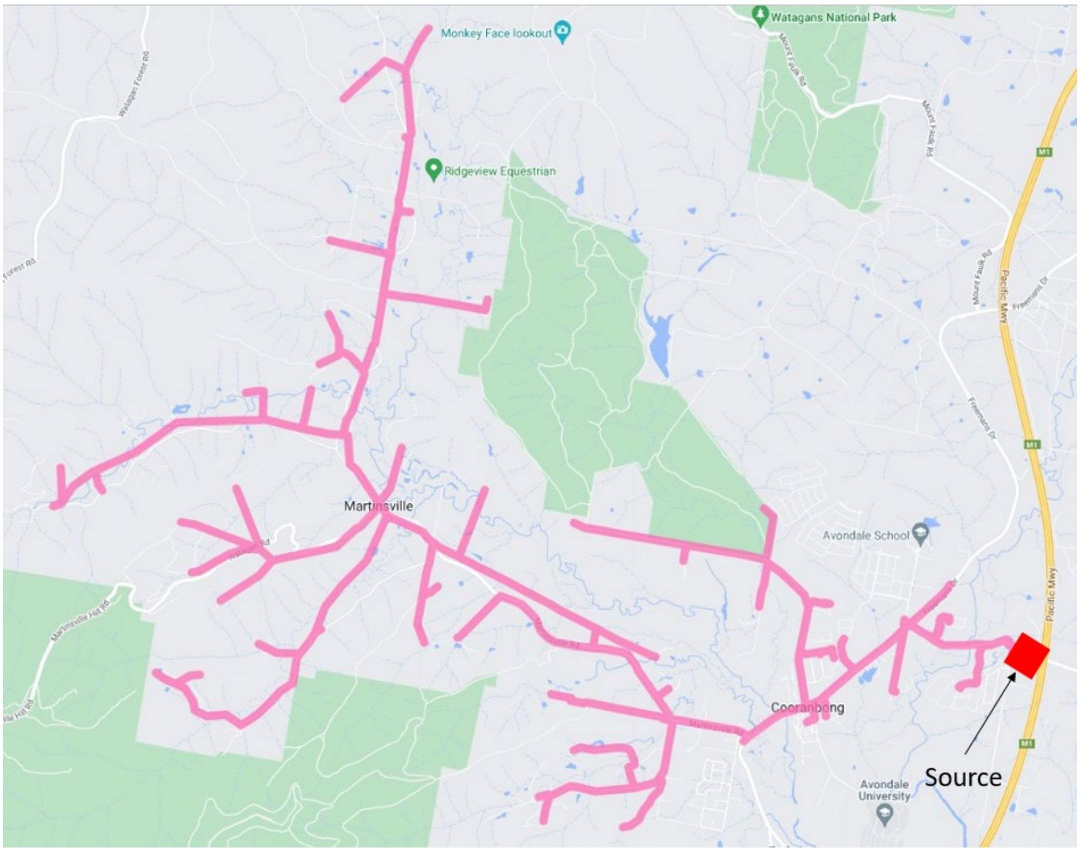


Figure 41 - Geographical Trace of Typical 11kV Radial Feeder

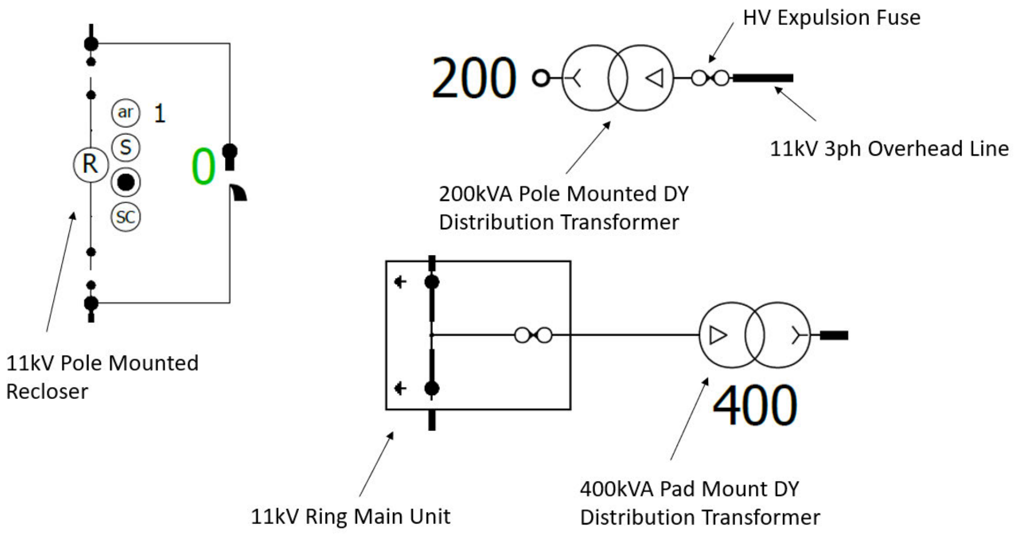


Figure 42 - Common 11kV System Diagram Elements

The previous figures show Ausgrid's 11kV radial feeders typically have many interconnections, lateral tee-offs, and customer loads. Figure 39 are system diagram symbols representing common elements found on an 11kV radial feeder and are key elements of the simple model developed in Simulink®.

The model consists of three systems. They are:

- ***System 1*** - 3 phase balanced network with ideal components (figure 40).
    - Source - Swing bus
    - Line - Ideal
    - Transformer
        - Ideal – zero series impedance, infinite magnetising impedance,
        - Vector Grouping - DY11,
        - Rating - 400kVA, 11/0.433 kV, 50Hz.
    - Load
        - Resistive - 1.76 ohm/phase (~30kW)
    - Measurements
        - Source bus (V & I)
            - Scope.
            - Display,
                - 3ph RMS Block,
                - Fourier Block (Mag/deg),
                - Sequence Analyser Block (012 Mag/deg).
        - 11kV load bus (V & I)
            - Scope.
            - Display,
                - 3ph RMS Block,

            - Fourier Block (Mag/deg),
            - Sequence Analyser Block (012 Mag/deg).
    - 0.433kV load bus (V & I)
        - Scope.
        - Display,
            - 3ph RMS Block,
            - Fourier Block (Mag/deg).

- ***System 2*** – System 1 + Parallel 11kV Source (figure 41).
- ***System 3*** – System 1 + 2 phase 11kV Spur (figure 42).

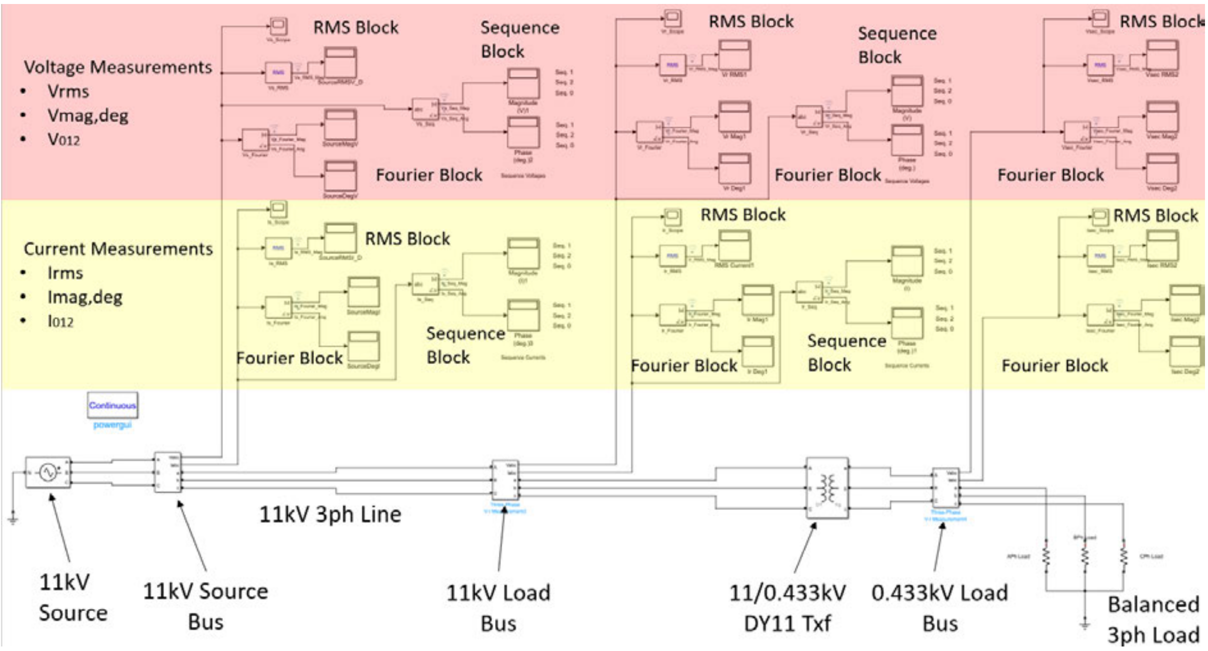


Figure 43 - System 1 Model

System 1 represents an ideal, balanced, unfaulted 3-phase 11kV radial feeder with system normal conditions. System 2 is an extension of System 1 with a parallel 11kV source connected between the source and load bus of System 1. System 3 is also an extension of System 1 with 2-phase spur and 1-phase load connections off the main 3-phase feeder trunk.

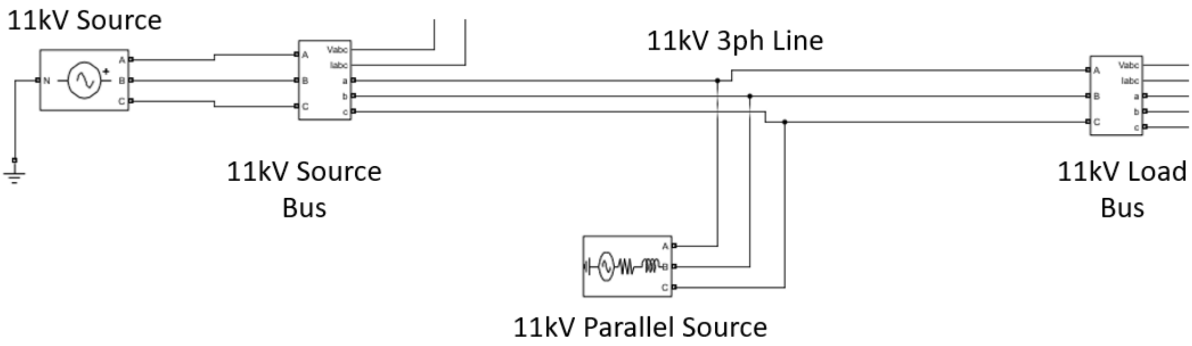


Figure 44 - System 2 Model (System 1 omitted from image)

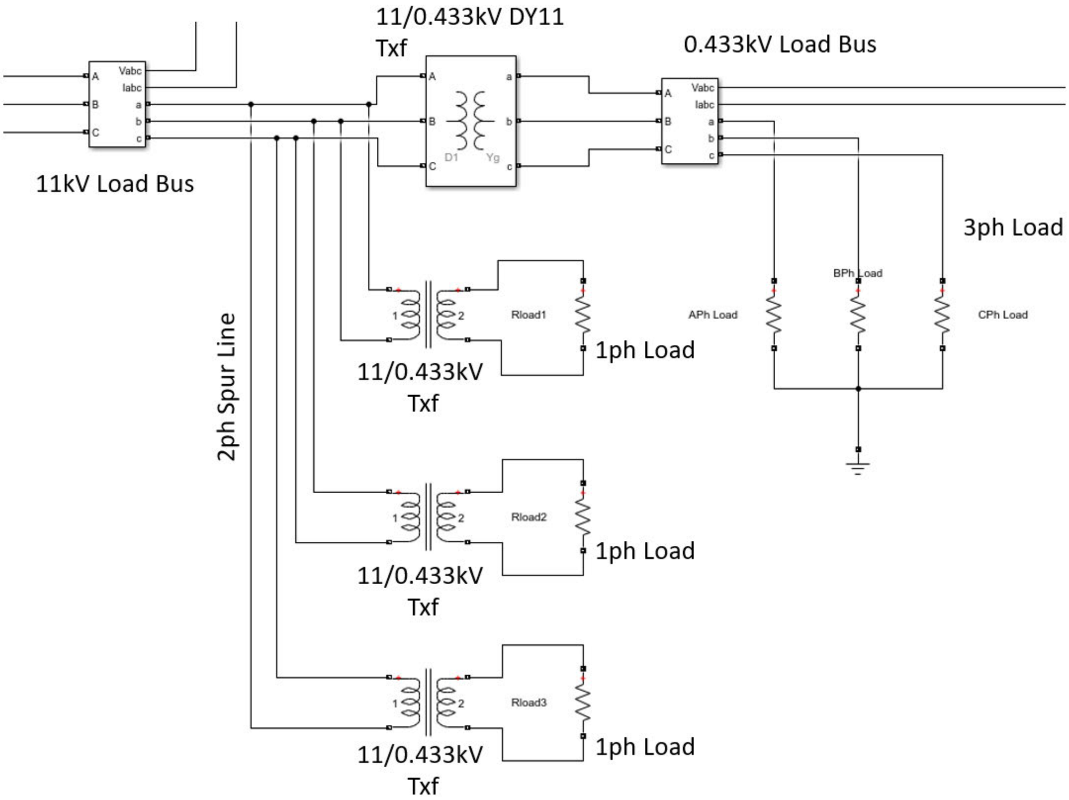


Figure 45 - System 3 Model (System 1 omitted from image)

The three systems align with modelling conducted during the desktop analysis, however, MATLAB® and Simulink® were used as an alternative modelling package for this research project. The model was constructed using ideal power system elements from the Simscape Electrical library (`sps_lib`) of Simulink® to ensure simulation data is consistent with results obtained from EMTP® modelling and theoretical expected values presented in literature.

Several BC scenarios outlined in table 2 were simulated, and measurements logged for data analysis. Scenario selection was based on historical event data which illustrated the most common load side BC events with some lower probability events included for completeness. Scenarios 0-11 assesses the validity of voltage magnitude-based BC detection. Data obtained from these scenarios is sourced from "System 1" simulations. Scenarios 12-14 were included to assess the impact a parallel source of supply has on voltage magnitude-based BC detection. Typically, detection sensitivity is reduced (Stanbury, 2012). The data obtained from these scenarios is sourced from "System 2" simulations. Scenarios 15-19 were included to assess the viability of current-based methods utilising the ratio of negative sequence to positive sequence current. The data obtained from these scenarios is sourced from "System 3" simulations.

Scenario	Description
0	System Normal
1	C-phase broken with earth fault
2	C-phase broken without earth fault, balanced load
3	C-phase broken without earth fault, unbalanced load
4	B and C phases broken with earth fault on C, balanced load
5	B and C phases broken with earth fault on C, unbalanced load
6	B and C phases broken with earth faults on B and C
7	B-phase broken with B to C fault, without earth fault
8	C-phase broken with C-phase HV fallen into LV without earth fault
9	C-phase broken with C-phase HV fallen into LV with HV earth fault
10	B and C-phases broken with C-phase HV fallen into LV with HV earth fault
11	B and C-phases broken with C-phase HV fallen into LV
12	System Normal with parallel source
13	C-phase broken with earth fault with parallel source
14	C-phase broken with earth fault with weak parallel source (electrically far from fault)
15	I2/I1 Check - C-phase broken without earth fault, balanced 3ph load
16	I2/I1 Check - C-phase broken & earth fault, balanced 3ph load

17	I2/I1 Check - Unbalanced 3ph load without BC
18	I2/I1 Check - Balanced 3ph system without BC, 2ph connections balanced across 3 phases, equal loading
19	I2/I1 Check - Balanced 3ph system without BC, 2ph spur with A-C connections only, equal loading

Table 5 - Model Simulation Scenarios

5.2 Validation

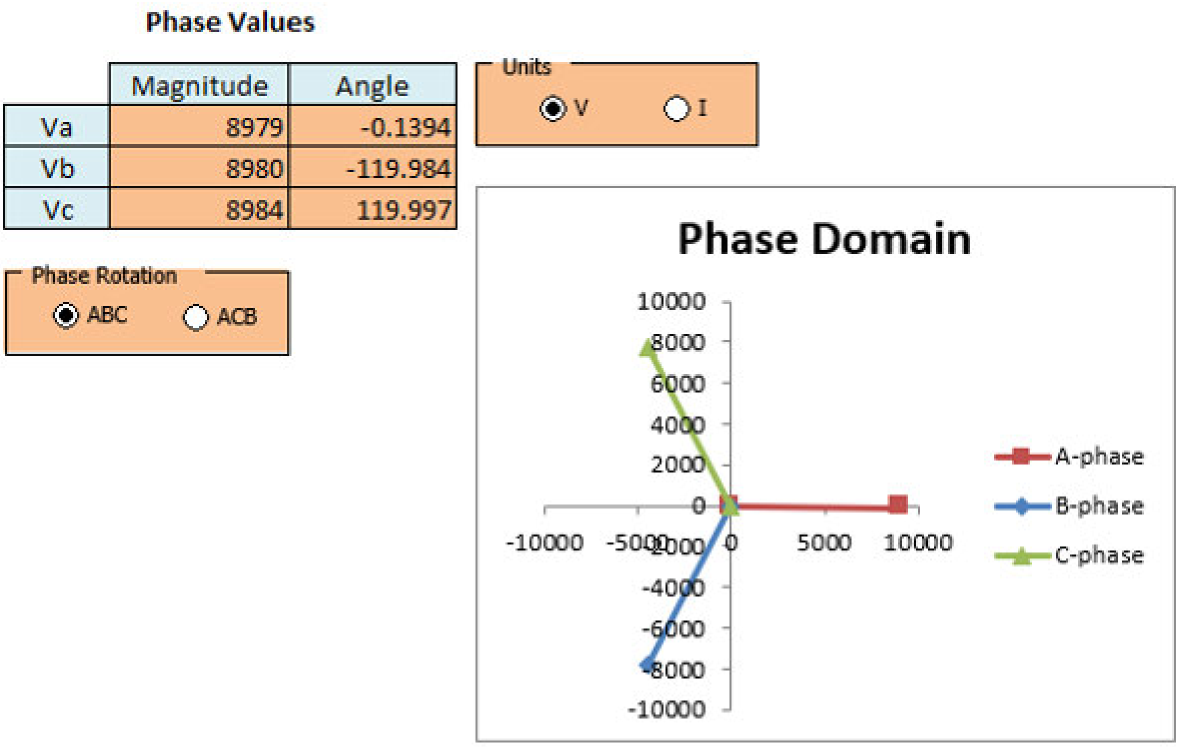
Scenario 0 in table 5 is referred to as "System Normal". The function of this scenario was to establish a reference model that upon simulation, exhibited typical voltage and current quantities attributed to a healthy network state. This formed part of the initial model validation process. The premise of Scenario 0 was to ensure all model components are working as intended and each designated logging point outputs expected values. The initial process of validation was done by inspection whereby a simulation of Scenario 0 was run, and the output values were viewed on each display. The values were assessed against basic electrical theory. For example, a balanced three phase system with ideal voltage source supplying a 11/0.433 kV *DY11* transformer with balanced three phase constant resistance load should see 11kV phase to phase volts on the primary terminals and 0.433 kV phase to phase volts on the secondary terminals. Taking phase to ground quantities, the phase voltages should be equal in magnitude and reduced by a $\sqrt{3}$ factor and phase angles displaced by 120°. Considering the vector grouping of the transformer, a 30° phase shift exists from primary to secondary which was also confirmed. The RMS values should indicate a value with $1/\sqrt{2}$ or ~0.7071 factor applied to the peak value, which was confirmed. Current quantities were also checked based on the connected load. Finally, for "System Normal" the source and load bus measurements should not differ whilst the expected per unit values of the voltage and current quantities is 1p.u. on either side of the connected transformer.

Table 6 outlines Scenario 0 validation results from the three measurement nodes along the feeder. It should be noted that per unit measurements have only been taken for voltage on the secondary side of the transformer, also shown in table 6. The phasor diagrams in figures 43-46 visually represent the results outlined in table

6. The balanced nature of the unfaulted system normal conditions for both voltage and current quantities is shown. As such, results obtained and presented via Scenario 0 simulations have suitably validated the model for ideal conditions.

Logged Value	A	B	C	Comment
Vs_pk_Mag	8979.739	8980.432	8984.217	$Vpp\_pk \div \sqrt{3}$. Balanced P-G values.
Vs_Ang	-0.01394	-119.984	119.9975	Phasors displaced by 120°
Vs_RMS_Mag	6350.244	6350.488	6351.827	$Vpg\_pk \times (\frac{1}{\sqrt{2}})$. Balanced.
Is_pk_Mag	7.93266	7.933272	7.936615	Balanced values.
Is_Ang	-0.01394	-119.984	119.9975	Phasors displaced by 120°
Is_RMS_Mag	5.609776	5.609992	5.611174	$Ipg\_pk \times (\frac{1}{\sqrt{2}})$. Balanced.
Vr_pk_Mag	8979.739	8980.432	8984.217	$Vpp\_pk \div \sqrt{3}$. Balanced P-G values.
Vr_Ang	-0.01394	-119.984	119.9975	Phasors displaced by 120°
Vr_RMS_Mag	6350.244	6350.488	6351.827	$Vpg\_pk \times (\frac{1}{\sqrt{2}})$. Balanced.
Ir_pk_Mag	7.93266	7.933272	7.936615	Balanced values.
Ir_Ang	-0.01394	-119.984	119.9975	Phasors displaced by 120°
Ir_RMS_Mag	5.609776	5.609992	5.611174	$Ipg\_pk \times (\frac{1}{\sqrt{2}})$. Balanced.
Vsec_pu_Mag	0.999693	1.000192	1.000115	Per Unit Value of secondary voltage. Balanced system.
Vsec_Ang	30.00255	-89.9861	149.9835	30° phase shift due to DY11. Phasors displaced by 120°
Vsec_RMS_Mag	0.706998	0.707175	0.707147	$Vpg\_pu \times (\frac{1}{\sqrt{2}})$. Balanced.
Isec_pk_Mag	200.8151	200.9153	200.8998	$Vpg\_pk \times (\frac{1}{\sqrt{2}}) \div R_{L\_ph}$. Balanced values.
Isec_Ang	30.00255	-89.9861	149.9835	30° phase shift due to DY11. Phasors displaced by 120°
Isec_RMS_Mag	142.0195	142.0549	142.0494	$Ipg\_pk \times (\frac{1}{\sqrt{2}})$. Balanced.

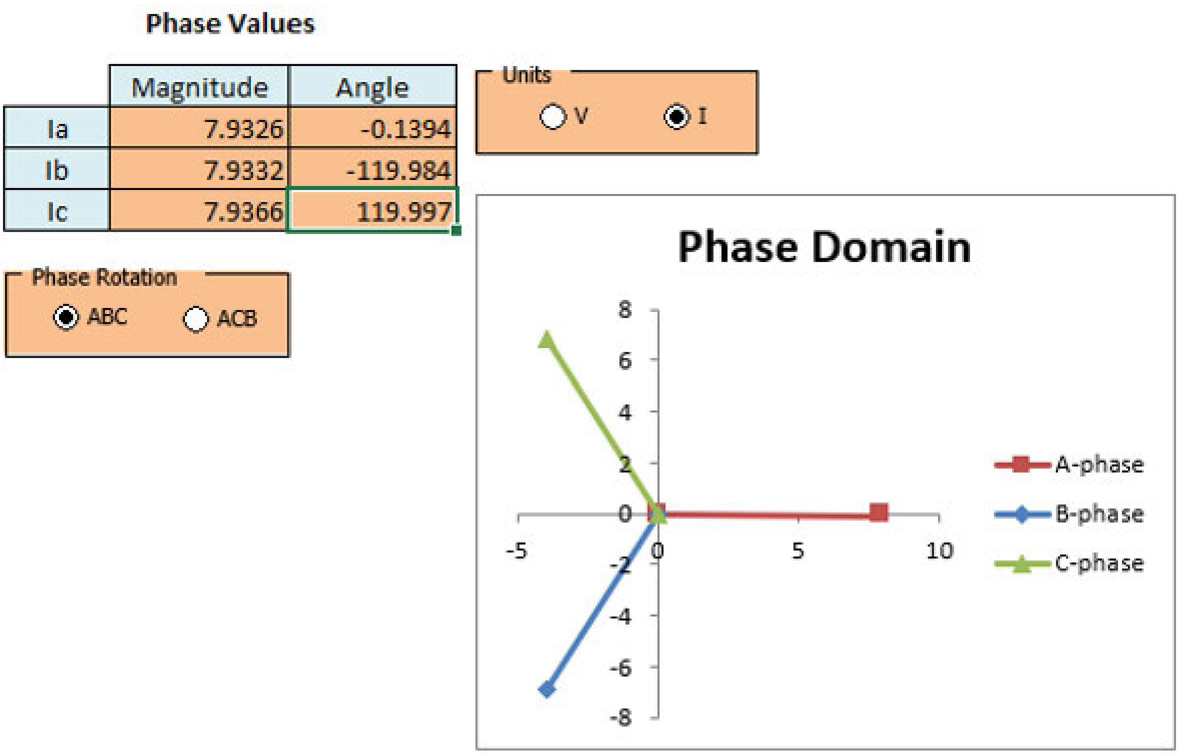
Table 6 - "System Normal" Validation Results



Phase Values

	Magnitude	Angle
Va	8979	-0.1394
Vb	8980	-119.984
Vc	8984	119.997

Figure 46 - Source & Load Bus - Peak Voltage Phasor Diagrams (Scenario 0)



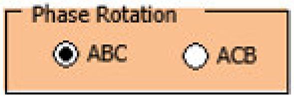
Phase Values

	Magnitude	Angle
Ia	7.9326	-0.1394
Ib	7.9332	-119.984
Ic	7.9366	119.997

Figure 47 - Source & Load Bus - Peak Current Phasor Diagrams (Scenario 0)

Phase Values

	Magnitude	Angle
Va	0.999693	30.002
Vb	1.000192	-89.986
Vc	1.000115	149.983



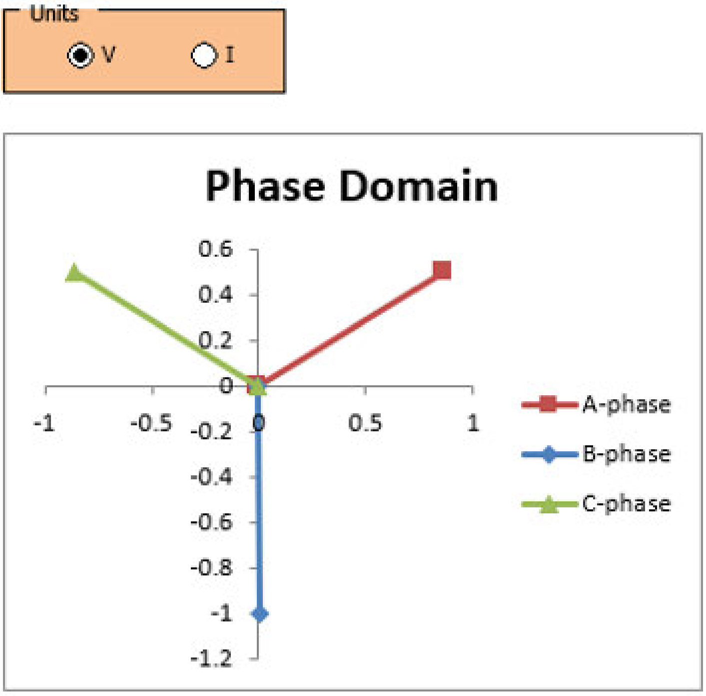


Figure 48 - Transformer Secondary Bus - Per Unit Voltage Phasor Diagrams (Scenario 0)

Phase Values

	Magnitude	Angle
Ia	200.815	30.002
Ib	200.915	-89.986
Ic	200.899	149.983

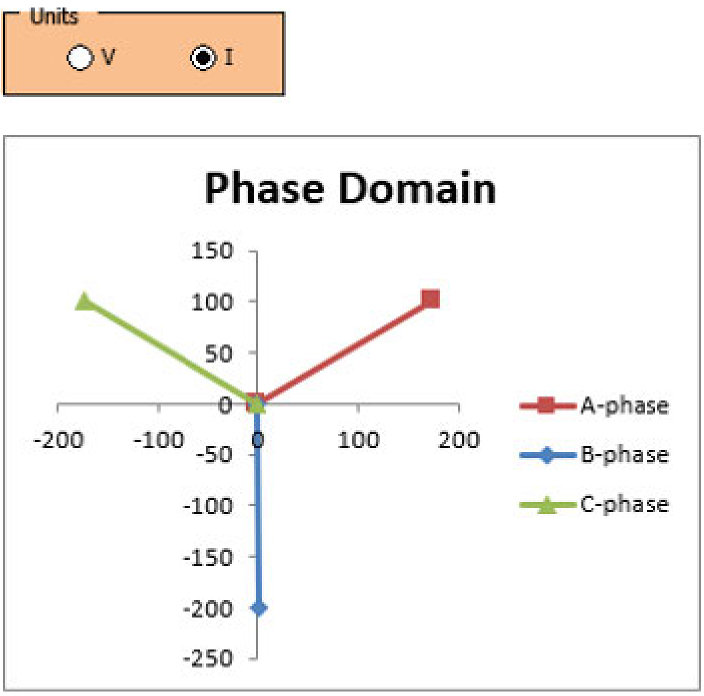


Figure 49 - Transformer Secondary Bus - Peak Current Phasor Diagrams (Scenario 0)

5.3 Data

An early design concept for this project involved a single automated model transitioning between various states simulating each scenario for a specified duration. A MATLAB® script would be developed to call the single Simulink® file and run the simulation. Prior to the next state transition, the script would index the measurement data. At the conclusion of all state simulations, the script would package and format the indexed measurement data and export to a spreadsheeting application for analysis. A pilot model was constructed to evaluate the feasibility of this concept. The outcome determined attempts to fully automate the model would introduce spurious signal data due to the transient states impacting the exported dataset. To resolve the spurious data, it was decided to construct an individual model for each scenario and consider steady state data only. Recognising simulation quantity may yield inefficiencies, development of a script like that described for the pilot design was pursued. The distinguishing feature being the call routine of multiple files rather than a single file with multiple states.

Each model consisted of three measurement nodes along the 11kV radial feeder, source bus, load bus and transformer secondary bus. Several measurement instruments at each bus providing a specific output signal were configured for data logging. The proposed script would call each Simulink® (.slx) file from local disk and run the simulation. Logged data would be output to the MATLAB® Workspace where the individually indexed measurements could be accessed, formatted, and exported to a spreadsheeting application for analysis. Attempts to develop a suitable script failed, hence the pursuit of this method was abandoned in the interest of meeting project deadlines.

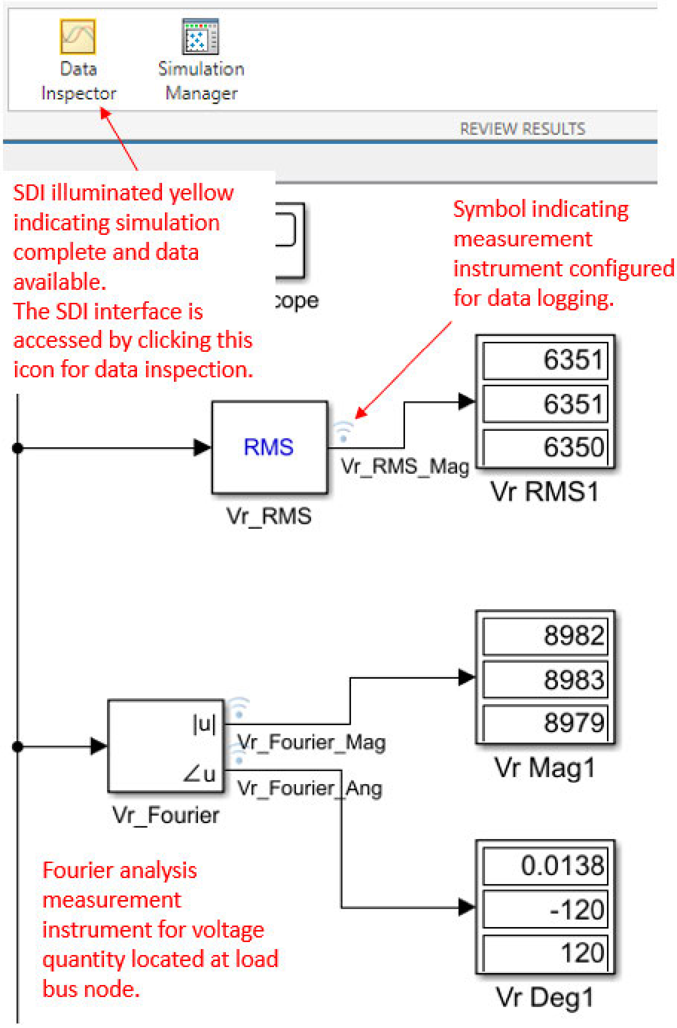


Figure 50 - Completed simulation with data accessible via SDI.

Previously unsuccessful data management efforts led to the utilization of a Simulink® tool called Simulation Data Inspector (SDI). At the completion of each simulation, configured measurement instruments would output logged signal data for convenient inspection via the SDI interface as shown in figure 47 and 48. The SDI interface provides an export option which enables data to be transferred to a spreadsheeting application as shown in figure 49. Although a substandard method in terms of efficiency, this manual process achieved the desired outcome of data acquisition necessary for the project.

The Fourier and Sequence Analyzer measurement instruments require one cycle of simulation to be complete before the outputs give the correct magnitude and angle.

Given this constraint and to minimise processing burden, simulation runtime was set for two cycles or 40 milliseconds.

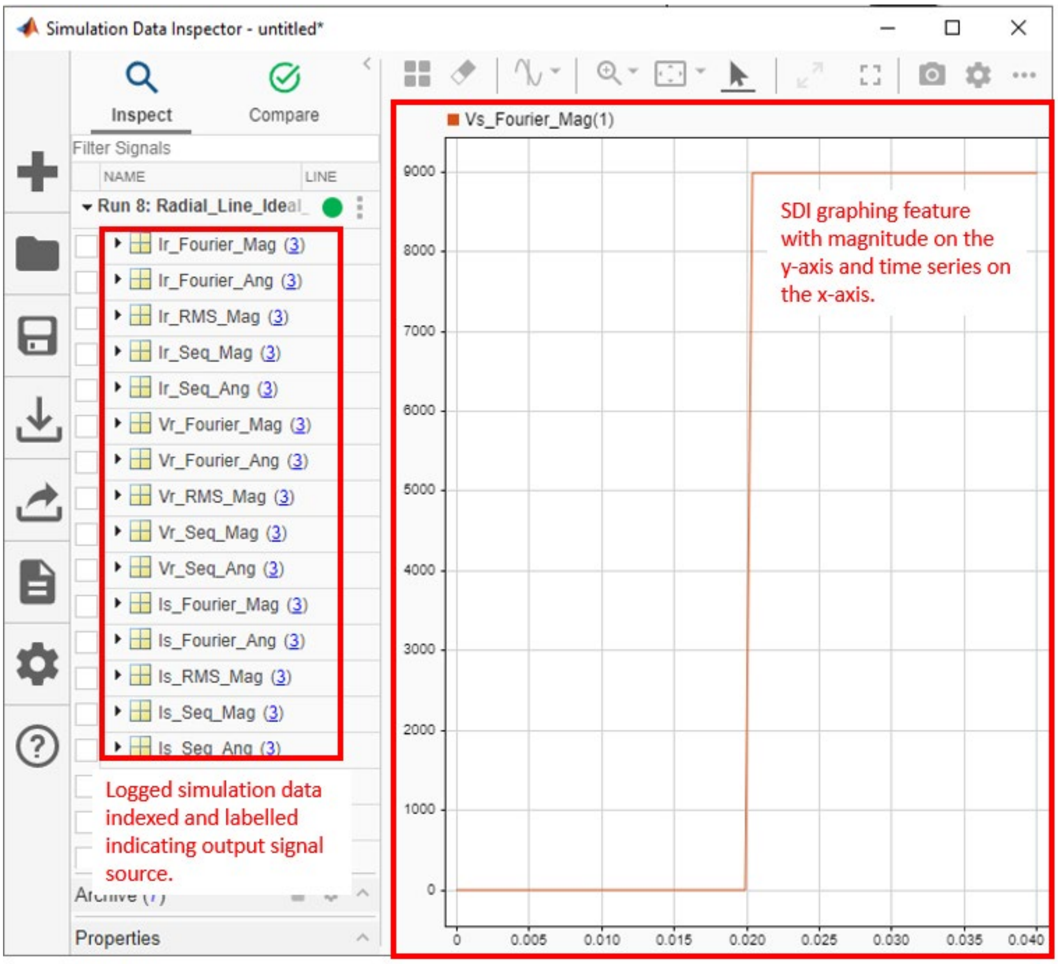


Figure 51 - SDI Interface

Following the export of all scenarios, a "master data" spreadsheet was developed consolidating desired data for analysis. The "master data" spreadsheet consisted of the following worksheets:

- *"Scenario Dump"* – a dump of all signal data from measurement instruments configured for logging at t = 40 ms (2 cycles) or final data point of simulation.
- *"Voltage Magnitude"* – the per unit voltage measurements for all three phases of each node along the 11kV radial feeder. This tabulated data will be analysed in section 5.4.

- *"I2_I1 Check"* – source bus positive and negative current component to assess the viability of the current based detection methods like ANSI 46BC. Discussed as future work.

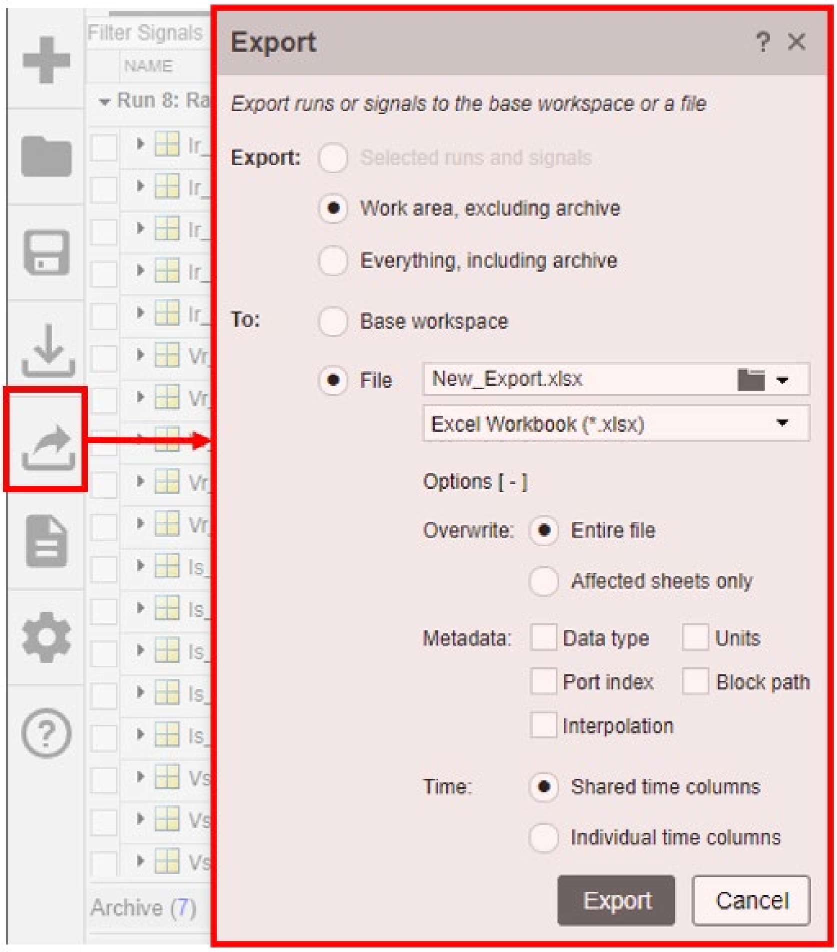


Figure 52 - SDI Export

5.4 Voltage Magnitude Analysis

Voltage magnitude simulation results for the three model measurement nodes are presented in tables 7-9 below. Table 7 represents the per unit voltage magnitudes of each BC scenario at the "source" bus. Similarly, table 8 represents the "load" bus results and table 9 represents the "transformer secondary" bus results. Table layout consists of a column per unit voltage magnitude result per phase for respective scenario. The voltage column headers are shaded red, yellow, blue (RYB) to visually represent the respective phase. Conditional formatting was applied to the data cells with shading to indicate the result status relating to the BC detection algorithm thresholds. That is, green indicates "healthy" volts above the fault threshold, > 75% nominal. Yellow indicates "detection range" volts below the fault threshold and above the minimum threshold, 75% < nominal > 10%. Red indicates "discontinuity" volts below the minimum threshold, < 10% nominal.

"Source" bus voltage was expected to remain at constant nominal voltage for all scenarios due to the BC fault being downstream of the measurement point and the three-phase voltage source load flow generator type being set to "swing bus". As such, model voltage magnitude and phase angle were effectively fixed to 1 per unit as shown in table 7.

Scenario	Vs_pu(1)	Vs_pu(2)	Vs_pu(3)
0	0.99980816	0.99988526	1.00030665
1	0.99956784	1.00054022	0.99989219
2	0.99956784	1.00054022	0.99989219
3	0.9995398	1.00034975	1.00011063
4	0.99956784	1.00054022	0.99989219
5	0.99956784	1.00054022	0.99989219
6	0.99956784	1.00054022	0.99989219
7	0.99956992	1.00053783	0.99989249
8	0.99975303	1.00030824	0.99993881
9	0.99956889	1.0005392	0.99989216
10	0.99957037	1.00053846	0.99989141
11	0.99956784	1.00054022	0.99989219

12	0.99980816	0.99988526	1.00030665
13	1.00007098	1.00001659	0.99991244
14	0.99980453	1.00033161	0.99986395

Table 7 - Source Bus Per Unit Phase Voltage Results

Initially, it was thought the application of the "swing" bus may create result error due to the firming of source voltage magnitude and phase angle. However, by introducing the phase discontinuity applicable to each scenario, the expected fluctuations of voltage magnitude at the "load" bus eventuated. The results shown in table 8 are relative to each scenario with fluctuation magnitude linked to fault characteristics like single or double break, conductor floating, contacting ground or earthed structure, or another phase, load variation and connection of parallel source. The resulting magnitudes in table 8 are the voltages seen across the delta primary winding. Theory discussed in chapter 4 suggests the expected magnitudes are equivalent to the phase to neutral voltages measured on the star secondary side of the *DY11* transformer shown in table 9.

Scenario	Vr_pu(1)	Vr_pu(2)	Vr_pu(3)
0	0.99980816	0.99988526	1.00030665
1	1.00010813	0.57595182	0.57539544
2	1.00010813	0.50005485	0.50005375
3	1.00010813	0.4136215	0.58648663
4	0.28728146	0.28728146	0.57456293
5	0.2878264	0.2878264	0.57565281
6	0.57540639	5.9816E-17	0.57540639
7	0.99916809	0.00029413	0.99946222
8	1.00006127	0.57093292	0.59062975
9	1.00010816	0.57441054	0.58365741
10	0.29182914	0.29182914	0.58365828
11	0.29526065	0.29526065	0.59052131
12	0.99980816	0.99988526	1.00030665
13	1.00007098	1.00001659	0.99884093

14	1.00009916	0.78725138	0.72864597

Table 8 - Load Bus Per Unit Phase Voltage Results

Scenario	Vsec_pu(1)	Vsec_pu(2)	Vsec_pu(3)
0	0.999693353	1.0001919	1.000114818
1	1.000108129	0.576817946	0.576259011
2	1.000108129	0.500054853	0.500053754
3	0.999889591	0.413531118	0.586358473
4	0.287281465	0.287281465	0.574562929
5	0.287826404	0.287826404	0.575652808
6	0.575406389	2.34312E-18	0.575406389
7	0.99916807	0.000294134	0.999462203
8	1.00006129	0.57093294	0.590629741
9	0.9989527	0.5768689	5.894E-05
10	0.2882981	0.2882981	5.894E-05
11	0.295260653	0.295260653	0.590521305
12	0.999693353	1.0001919	1.000114818
13	1.000087564	0.999385448	0.999455627
14	1.000136145	0.787458017	0.728386643

Table 9 - Transformer Secondary Bus Per Unit Phase-Neutral Voltage Results

Table 9 displays the "transformer secondary" bus results for the simulated scenarios. Table 9 results match that yielded by previous EMTP® modelling shown in table 2.

Table 9 indicates each scenario has a significant impact on the secondary voltage magnitude and in many cases lies within the detection range of the candidate detection method. It should be noted these conditions need to be satisfied for multiple time steps for the algorithm to trigger an event alarm.

Scenarios 12-14 attempted to support constraints mentioned in Michael Stanbury's paper suggesting voltage magnitude detection sensitivity may be affected by a parallel source of supply, either parallel feeder or high-powered embedded generation. Simulation results supported this constraint as shown in tables 8 and 9.

Figures 55-65 graphically represent simulation results for scenarios 1-11. Each figure displays the simulation duration of two cycles on the x-axis and the resulting per unit secondary voltage magnitude on the y-axis. The algorithm detection range is bound by limits represented on each graph with "Algorithm Upper Limit" (AUL) indicating 75% of *Vsec_pu* and "Algorithm Lower Limit" (ALL) indicating 10% of *Vsec_pu*. Each graph exhibits a pre-fault duration of one cycle at 1 per unit voltage magnitude before a step change at t=0.02 seconds defines the impact of each scenario condition has on the affected phases.

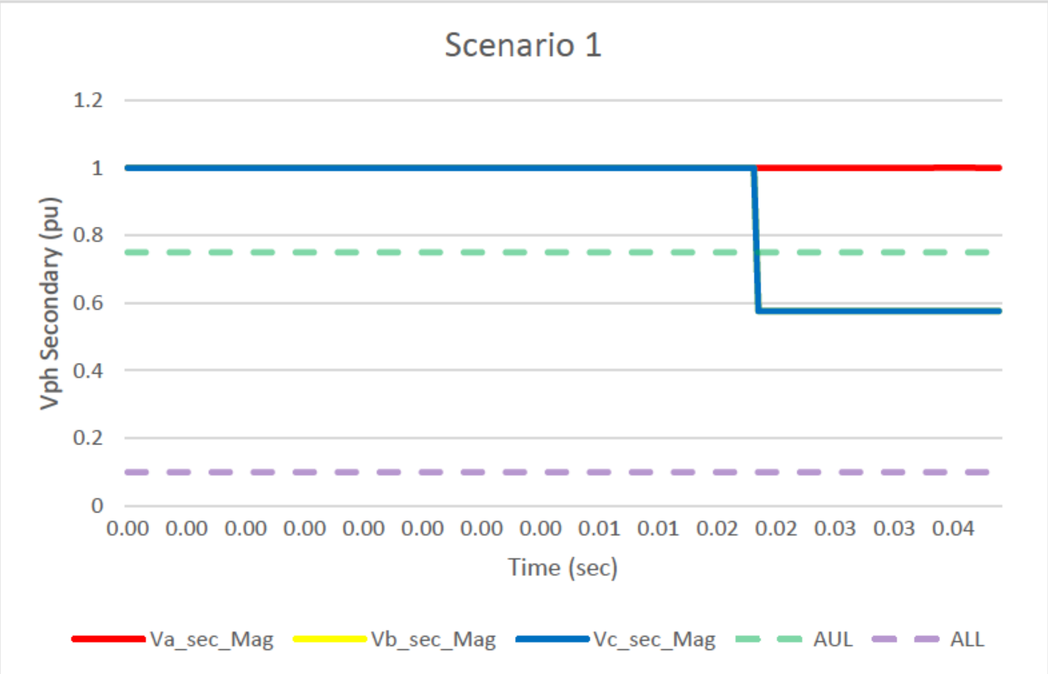


Figure 53 - Secondary Per Unit Magnitude Result - Scenario 1

Figure 55 displays the resulting secondary voltage magnitudes for scenario 1, C-phase broken with earth fault. Red phase remains healthy as yellow and blue phase reduce to $\frac{1}{\sqrt{3}} \times Vpu$ and are positioned within the detection region. The algebraic sum of the two unhealthy phases equate to the healthy phase. Thus, scenario 1 satisfies the algorithm parameters for this data sample and would be expected to trigger an alarm if subsequent data samples and time steps accumulated enough for the algorithm to declare the event valid.

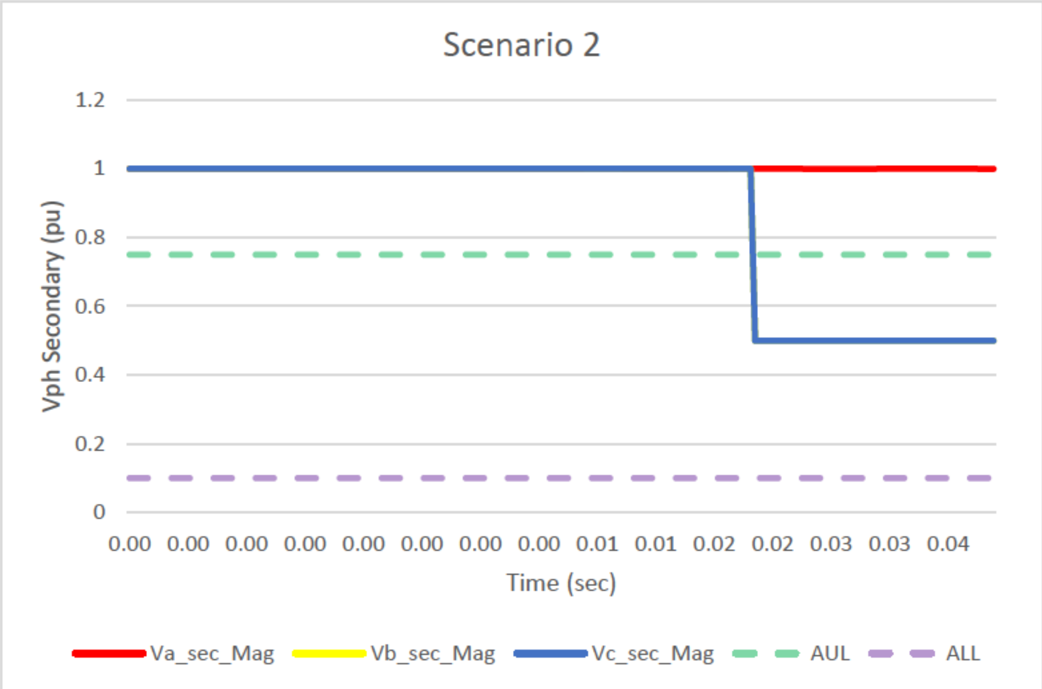


Figure 54 - Secondary Per Unit Magnitude Result - Scenario 2

Figure 56 displays the resulting secondary voltage magnitudes for scenario 2, C-phase broken without earth fault, balanced load. Red phase remains healthy as yellow and blue phase reduce to $\frac{1}{2} \times Vpu$ and are positioned within the detection region. The algebraic sum of the two unhealthy phases equate to the healthy phase. Thus, scenario 2 satisfies the algorithm parameters for this data sample and would be expected to trigger an alarm if subsequent data samples and time steps accumulated enough for the algorithm to declare the event valid.

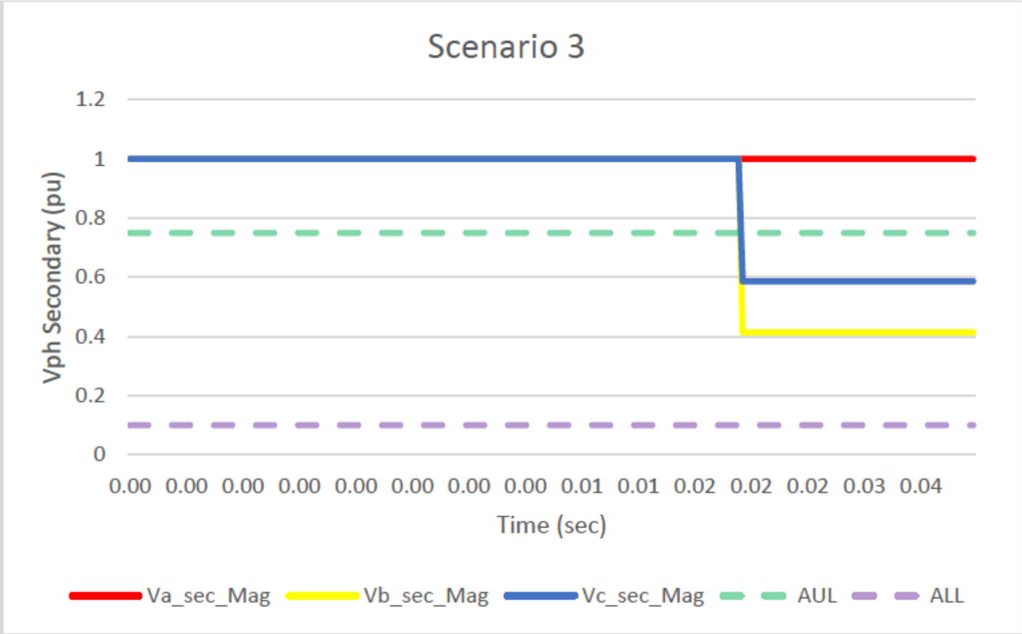


Figure 55 - Secondary Per Unit Magnitude Result - Scenario 3

Figure 57 displays the resulting secondary voltage magnitudes for scenario 3, C-phase broken without earth fault, unbalanced load. Red phase remains healthy as yellow and blue phase reduce to $x \times Vpu$ and $1 - xVpu$ respectively where x represents the load imbalance and is therefore an unknown variable. The unhealthy phases are positioned within the detection region. The algebraic sum of the two unhealthy phases equate to the healthy phase. Thus, scenario 3 satisfies the algorithm parameters for this data sample and would be expected to trigger an alarm if subsequent data samples and time steps accumulated enough for the algorithm to declare the event valid.

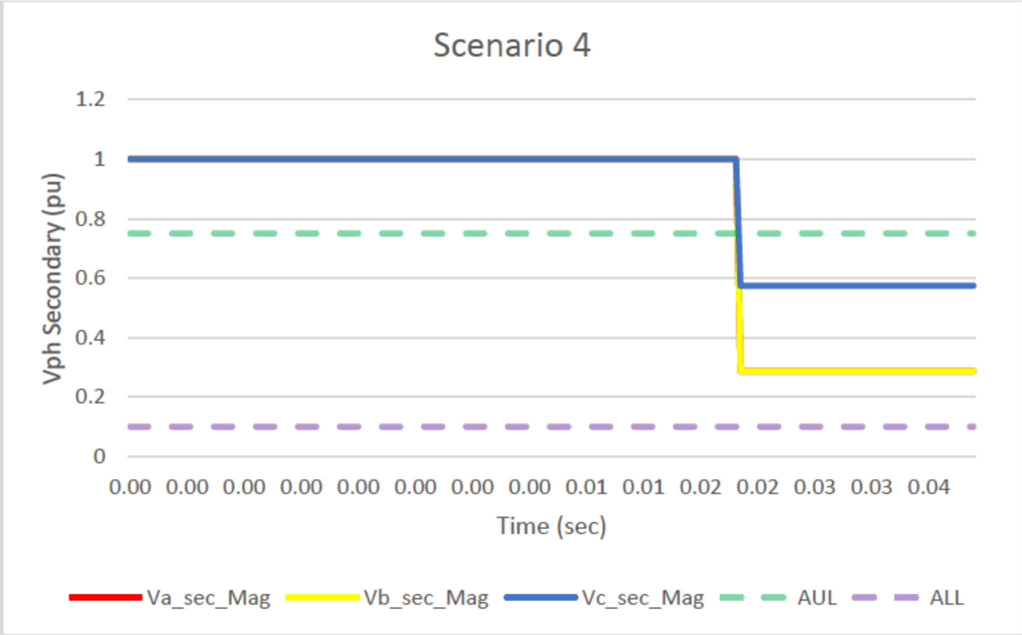


Figure 56 - Secondary Per Unit Magnitude Result - Scenario 4

Figure 58 displays the resulting secondary voltage magnitudes for scenario **4,** B and C phases broken with earth fault on C, balanced load. Red and yellow phase reduce to $\frac{1}{2\sqrt{3}} \times Vpu$ and blue phase reduces to $\frac{1}{\sqrt{3}} \times Vpu$ and are both positioned within the detection region. The algebraic sum of the red and yellow phase equates to the blue phase which satisfies the algorithm parameter for the delta winding characteristic. However, it does not meet the LOP parameter where at least one phase is above 75% nominal. Hence, this data sample would not be expected to calculate a brokenConductorIndicator for this event. If the partial voltage variant was used as the parameter this scenario may trigger an event due to at least one phase being between 10% and 75% nominal.

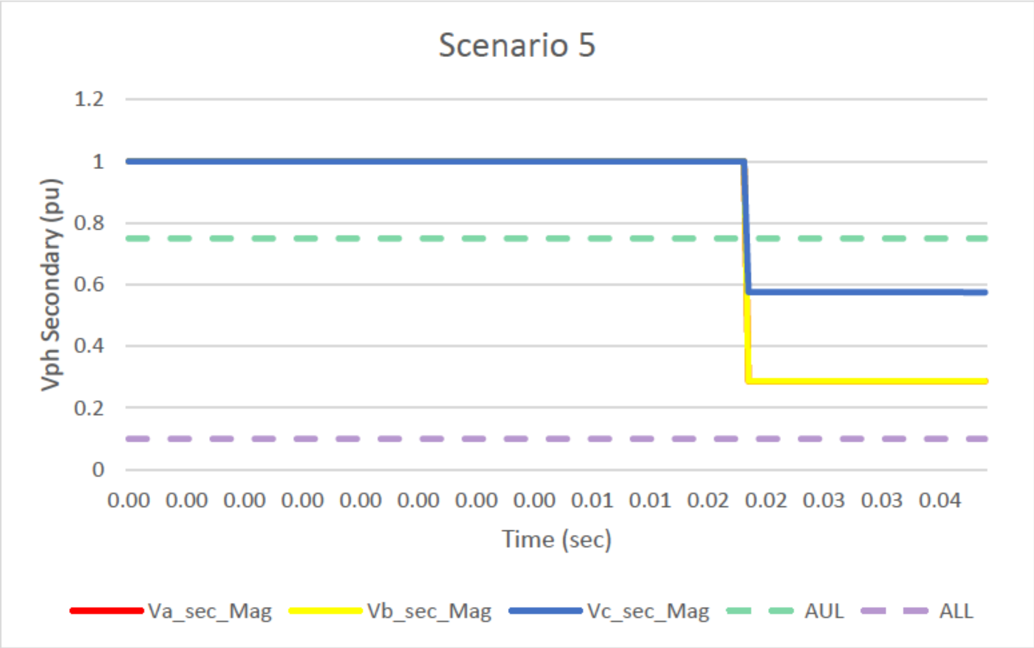


Figure 57 - Secondary Per Unit Magnitude Result - Scenario 5

Figure 59 displays the resulting secondary voltage magnitudes for scenario 5, B and C phases broken with earth fault on C, unbalanced load. Red and yellow phase reduce to $x \times Vpu$ where x represents the load imbalance and is therefore an unknown variable. Blue phase reduces to $\frac{1}{\sqrt{3}} \times Vpu$. All phases are positioned within the detection region. The algebraic sum of the red and yellow phase equates to the blue phase which satisfies the algorithm parameter for the delta winding characteristic. However, it does not meet the LOP parameter where at least one phase is above 75% nominal. Hence, this data sample would not be expected to calculate a brokenConductorIndicator for this event. If the partial voltage variant was used as the parameter this scenario may trigger an event due to at least one phase being between 10% and 75% nominal.

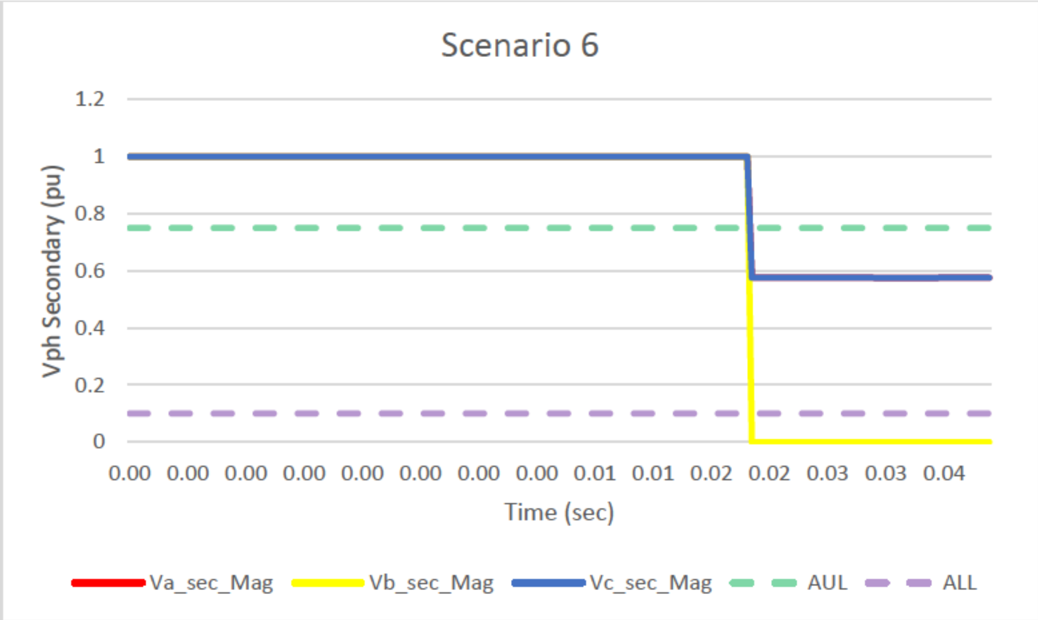


Figure 58 - Secondary Per Unit Magnitude Result - Scenario 6

Figure 60 displays the resulting secondary voltage magnitudes for scenario 6, B and C phases broken with earth faults on B and C. Red and blue phase reduce to $\frac{1}{\sqrt{3}} \times Vpu$ and are positioned within the detection region while yellow phase reduces to 0. This scenario does not meet the LOP parameter where at least one phase is above 75% nominal. Hence, this data sample would not be expected to calculate a brokenConductorIndicator for this event. If the partial voltage variant was used as the parameter this scenario may trigger an event due to at least one phase being between 10% and 75% nominal.

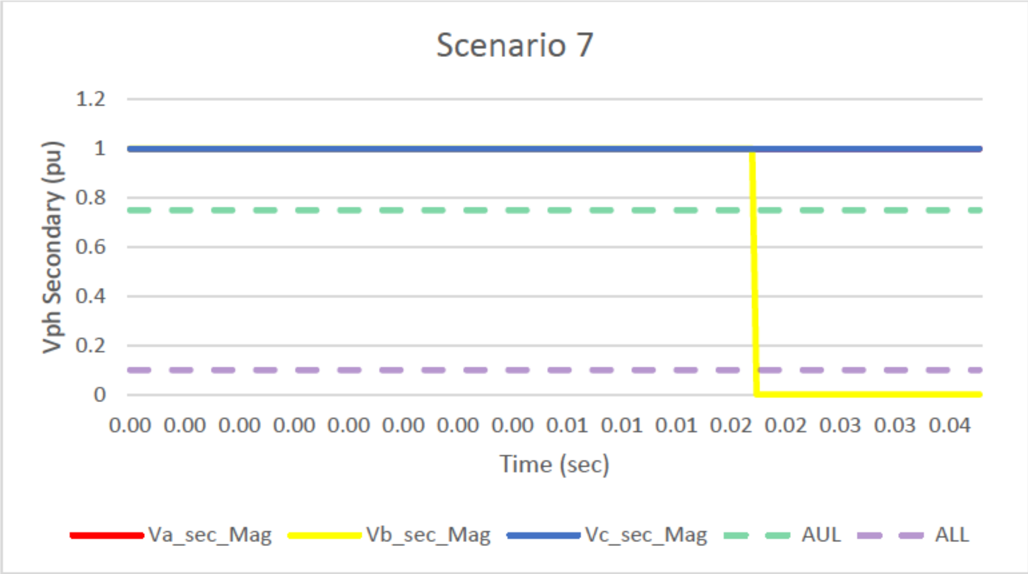


Figure 59 - Secondary Per Unit Magnitude Result - Scenario 7

Figure 61 displays the resulting secondary voltage magnitudes for scenario 7, B-phase broken with B to C fault, without earth fault. Red and blue phase remain at $1 \times Vpu$ and are positioned above the fault threshold while yellow phase reduces to 0. Therefore, this data sample would fail to trigger any BC event for either variant.

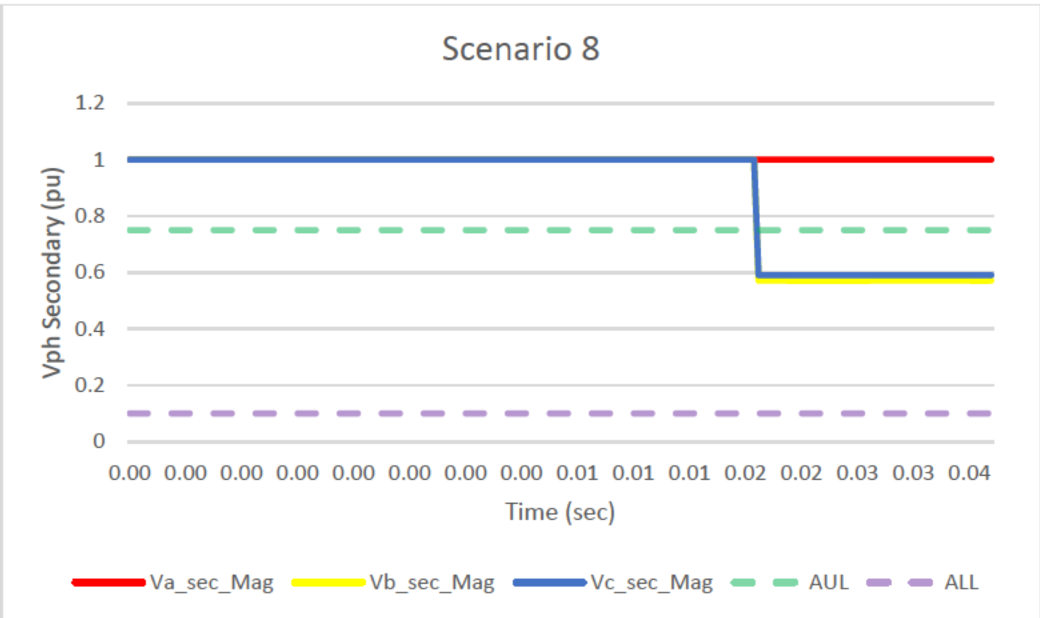


Figure 60 - Secondary Per Unit Magnitude Result - Scenario 8

Figure 62 displays the resulting secondary voltage magnitudes for scenario 8, C-phase broken with C-phase HV fallen into LV without earth fault. Red phase remains healthy as yellow and blue phase reduce to $\frac{1}{\sqrt{3}} \times Vpu$ and are positioned within the detection region. The algebraic sum of the two unhealthy phases equate to the healthy phase. Thus, scenario 8 satisfies the algorithm parameters for this data sample and would be expected to trigger an alarm if subsequent data samples and time steps accumulated enough for the algorithm to declare the event valid.

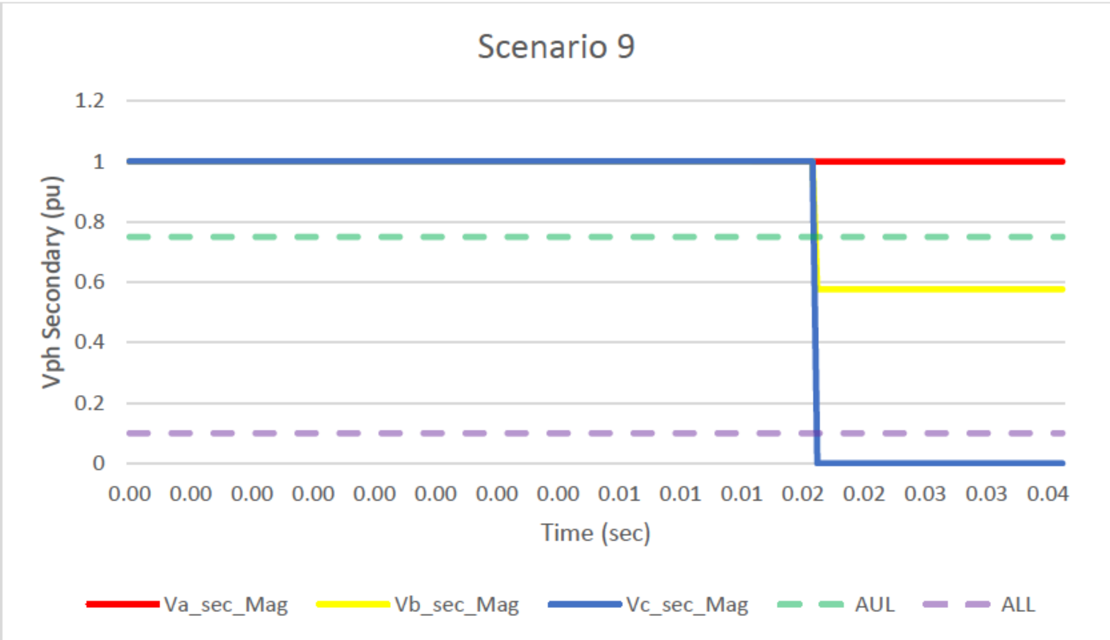


Figure 61 - Secondary Per Unit Magnitude Result - Scenario 9

Figure 63 displays the resulting secondary voltage magnitudes for scenario 9, C-phase broken with C-phase HV fallen into LV with HV earth fault. Red phase remains healthy, yellow phase reduces to $\frac{1}{\sqrt{3}} \times Vpu$ and is positioned within the detection region while blue phase reduces to 0. This scenario satisfies the LOP parameter where at least one phase is above 75% nominal and phase is below 75% nominal. Hence, this data sample would be expected to calculate a brokenConductorIndicator for this event. However, the algebraic sum of any two phases does not equate to the third which fails to satisfy the algorithm parameter for the delta winding characteristic. As such, this scenario is unlikely to trigger a BC event.

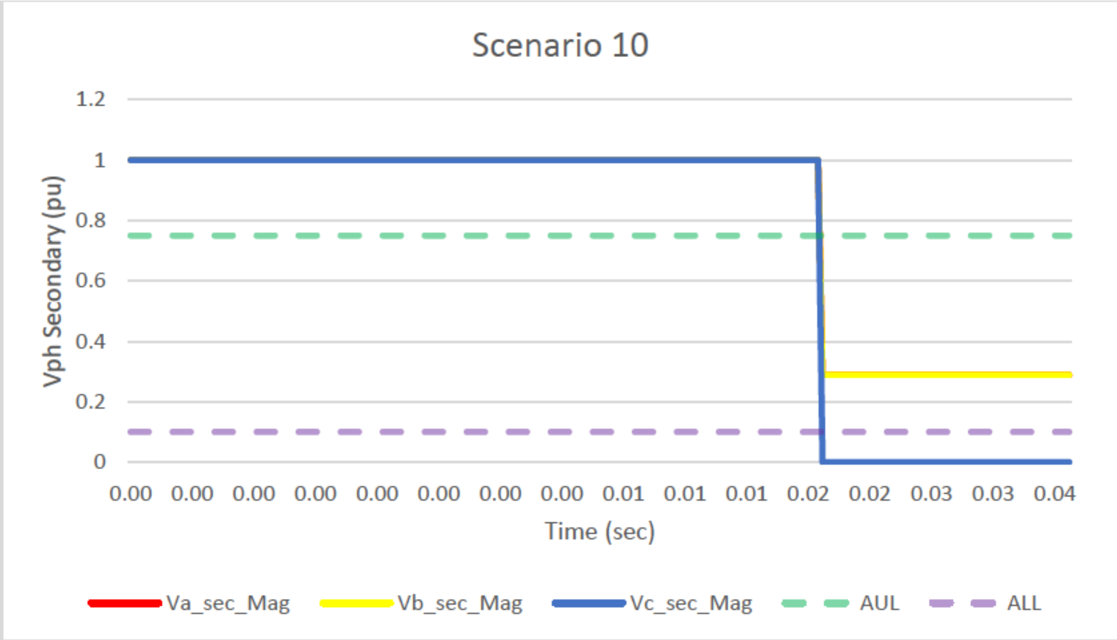


Figure 62 - Secondary Per Unit Magnitude Result - Scenario 10

Figure 64 displays the resulting secondary voltage magnitudes for scenario 10, B and C-phases broken with C-phase HV fallen into LV with HV earth fault. Red and yellow phase reduce to $\frac{1}{2\sqrt{3}} \times Vpu$ and are positioned within the detection region while blue phase reduces to 0. The algebraic sum of any two phases equates to the third which satisfies the algorithm parameter for the delta winding characteristic. However, it does not meet the LOP parameter where at least one phase is above 75% nominal. Hence, this data sample would not be expected to calculate a **brokenConductorIndicator** for this event. If the partial voltage variant was used as the parameter this scenario may trigger an event due to at least one phase being between 10% and 75% nominal.

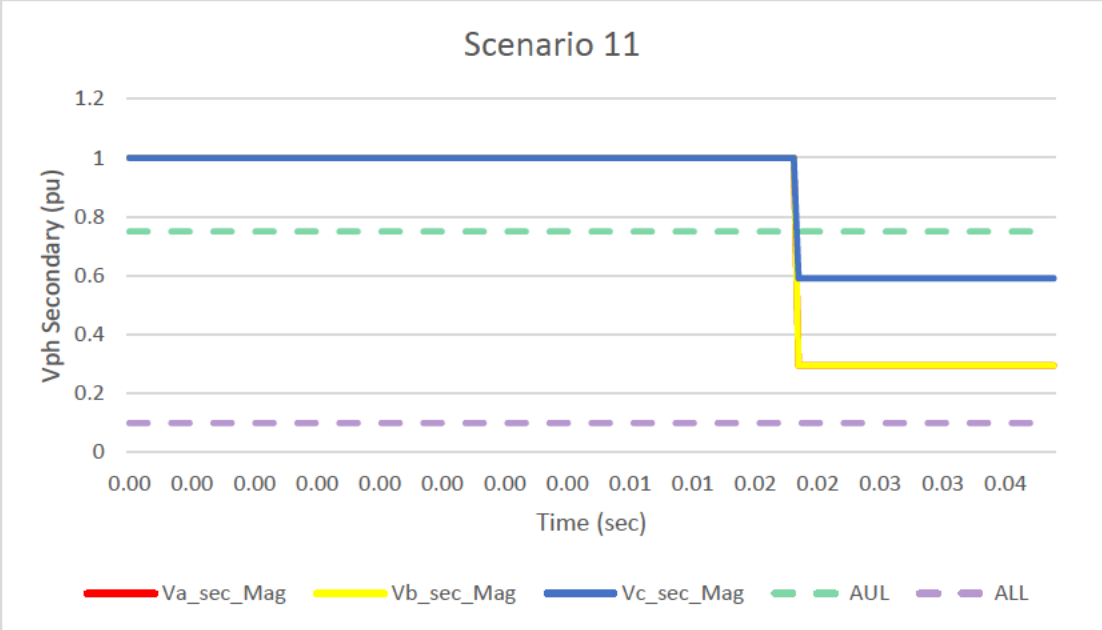


Figure 63 - Secondary Per Unit Magnitude Result - Scenario 11

Figure 65 displays the resulting secondary voltage magnitudes for scenario 11, B and C-phases broken with C-phase HV into LV. Red and yellow phase reduce to $\frac{1}{2\sqrt{3}} \times Vpu$ and blue phase reduces to $\frac{1}{\sqrt{3}} \times Vpu$ and are both positioned within the detection region. The algebraic sum of the red and yellow phase equates to the blue phase which satisfies the algorithm parameter for the delta winding characteristic. However, it does not meet the LOP parameter where at least one phase is above 75% nominal. Hence, this data sample would not be expected to calculate a brokenConductorIndicator for this event. If the partial voltage variant was used as the parameter this scenario may trigger an event due to at least one phase being between 10% and 75% nominal.

Figure 66 shows this case is like scenario 10 (figure 54), however, the ground reference is removed on the HV side due to the BC floating. As such, the results align with previous EMTP® modelling.

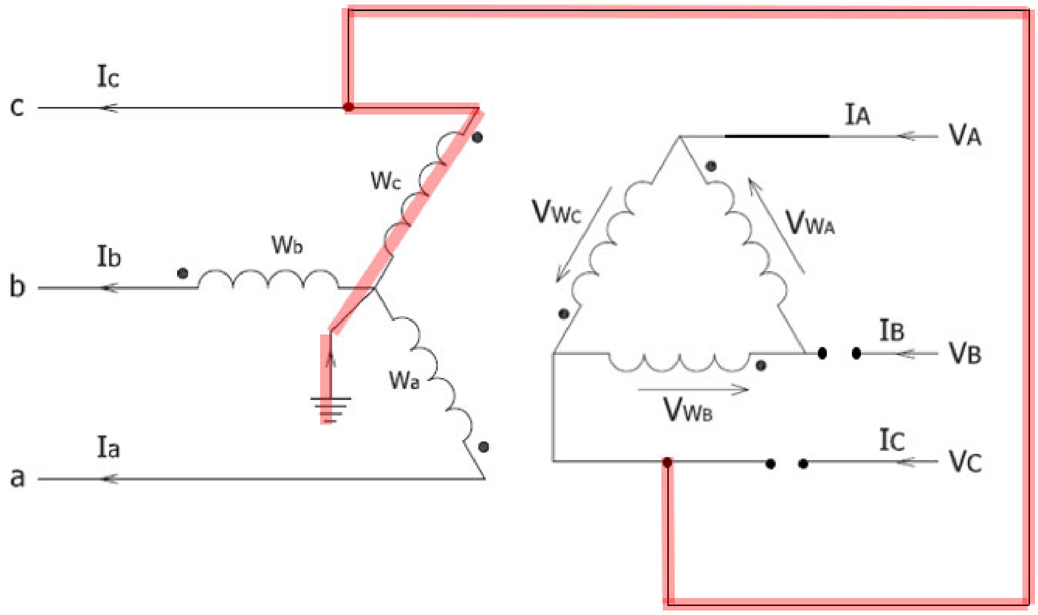


Figure 64 - Scenario 11 Connection Diagram

5.5 ANSI 46BC Broken Conductor Detection Modelling

ANSI 46BC protection elements use the ratio of negative to positive sequence current or | I2 / I1 |. This function is available in several of Ausgrid's current period contract 11kV feeder protection devices like the NOJA OSM ACR shown in figure 67. During new installs the element is being enabled to "alarm only" for real time assessment.

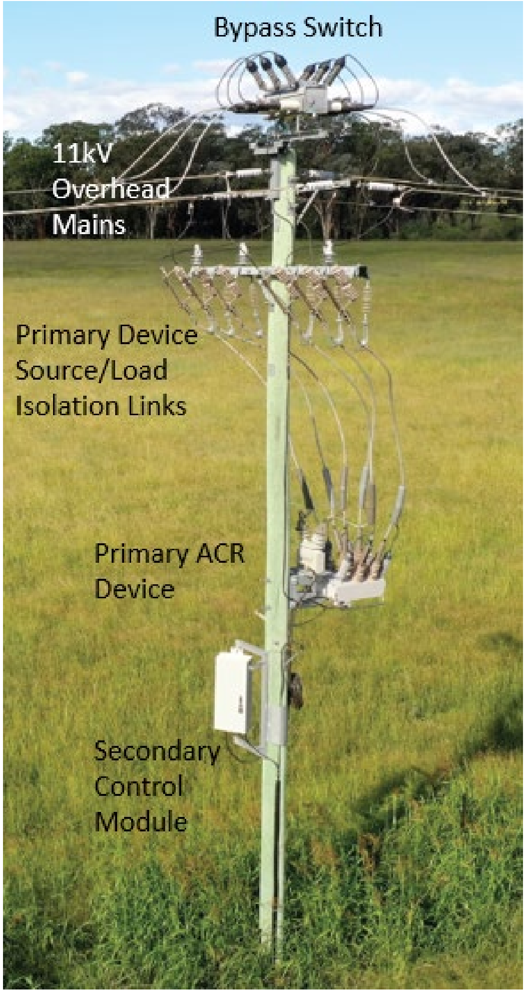


Figure 65 - NOJA OSM ACR

Several devices implementing ANSI 46BC have recently been commissioned on various 11kV feeders on Ausgrid's network. Typically, these devices are situated in rural areas where the system loading can be low, and system configuration includes numerous 2 phase spur lines and single-phase loads. Early feedback suggests many of the commissioned devices with 46BC elements enabled are picking up and asserting "Phase Loss Downstream" alarms, particularly at times of low load. The typical setting for the BC element is $| I2 / I1 | = 0.2$. Figures 68 and 69 are real time plots of recently commissioned devices with 46BC element enabled and "Phase Loss Downstream" alarm assertion during a period of low load. NPS (I2) current signal is shown in blue, and PPS (I1) is shown in green. The $| I2 / I1 |$ ratio in figure 68 is 4A/6A = 0.6.

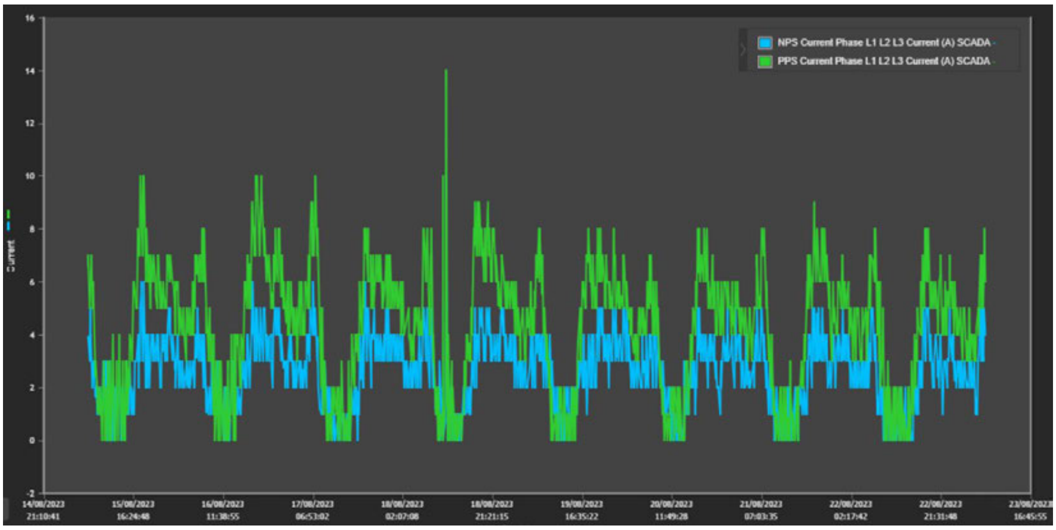


Figure 66 - Ratio of NPS/PPS Current Plot at Low Load from Ausgrid Device

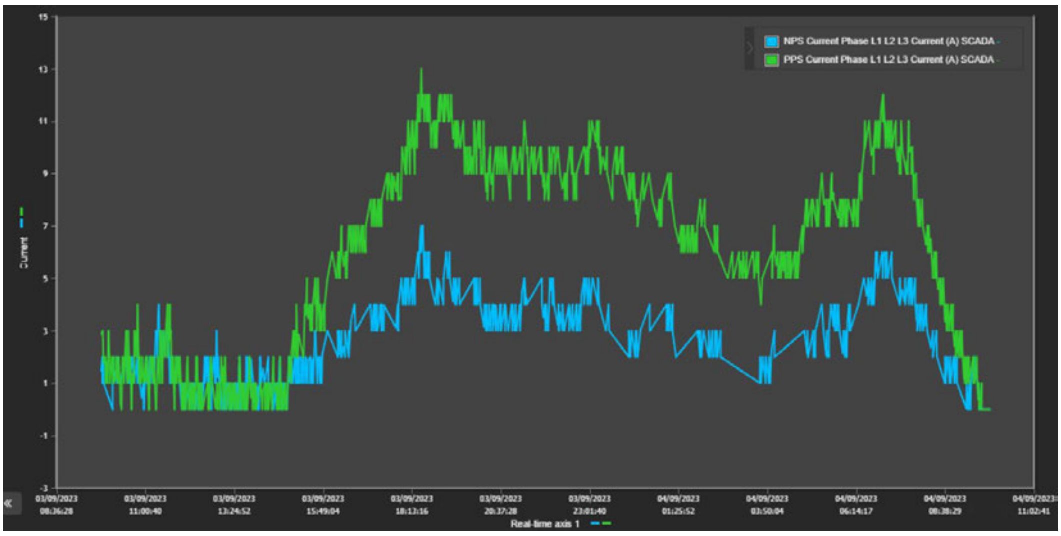


Figure 67 - Ratio of NPS/PPS Current Plot at Low Load from Ausgrid Device

Cursory assessments suggest system configuration and practical limits in achieving balanced networks hinder the success of 46BC implementation. Figure 70 is a real time plot displaying the network loading on an 11kV feeder where a 46BC enabled device is installed. The plot suggests network connections on this portion of the feeder are predominately red and blue phase. Thus, an inherent system imbalance exists.

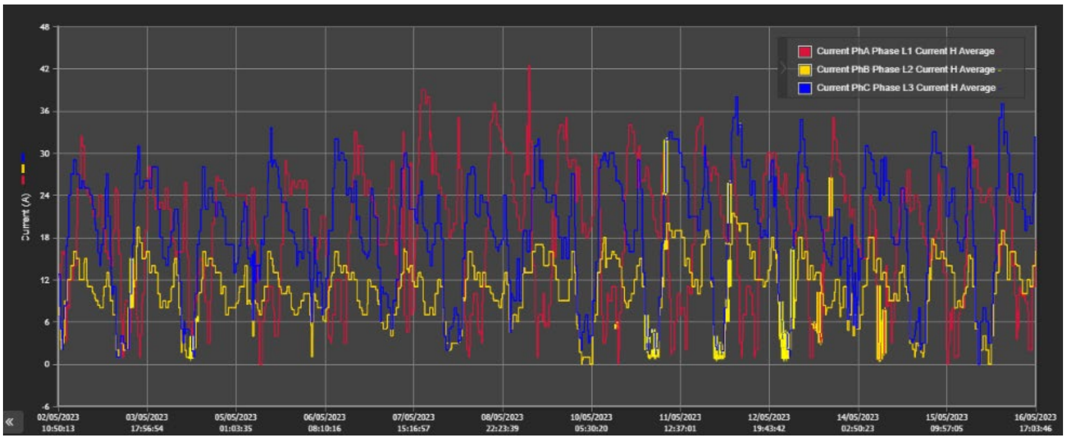


Figure 68 - Sample Ausgrid 11kV Feeder Loading Plot

NOJA Power's ANSI 46BC Application Note (NOJA-7476-01) provides a thorough analysis of open conductor faults using power system analysis techniques by Stevenson and Grainger, also outlined in chapter 2 of this report. The application note suggests a system study can be performed using system load and impedance data to identify possible adjustments to the standard 46BC setting of 0.2 Alternatively, the device can calculate sequence quantities during commissioning where an onsite calculation and subsequent ratio setting adjustment can be performed if required. System studies or in service sequence measurements are yet to be considered by Ausgrid due to lack of field monitor capability resulting in unobtainable sequence historian data and commissioning constraints like time and resource respectively.

ANSI 46BC does not form part of Michael Stanbury's algorithm, the Ausgrid trial or this report's focused method. However, preliminary modelling was commenced during this research project with an intent to progress analysis as further work. Scenarios 15-19 were developed to test the impact 2 phase spurs and single-phase loads had on sequence components, namely the ratio of NPS to PPS current. Simulink® Sequence Analyzer blocks were used to perform a sequence domain transform of the voltage and current quantities to extract the positive, negative and zero sequence magnitude and angle. Prior to these scenarios being simulated, the sequence analyzer block outputs were validated by conducting simulations of several shunt faults on the "system normal" model, obtaining results, applying these results to a sequence component calculator, and confirming values align with fault analysis boundary conditions outlined in Chapter 2.

Shunt fault simulation results are shown in table 17 below. The various faults were simulated between the source and load bus measurement nodes. Only the source bus measurements are shown with load bus measurements not considered as the fault location is upstream and would be outside the zone of protection on a radial feeder. Due to the model construction omitting line impedance and the three-phase voltage source load flow generator type being set to "swing bus", model voltage magnitude and phase angle were effectively fixed to 1 per unit as shown in table 10 and fault resistances were set to 10 ohms per phase. Unfortunately, due to project time constraints and uncertainty in model development and credibility, results obtained for scenarios 15-19 remain incomplete and do not provide any valuable contribution to the project at this time.

Quantity	Fault				
	3ph	3LG	1LG	LL	2LG
Vs_A_Mag	8981.65	8981.65	8981.65	8981.65	8981.65
Vs_B_Mag	8981.12	8981.12	8981.12	8981.12	8981.12
Vs_C_Mag	8981.62	8981.62	8981.62	8981.62	8981.62
Vs_A_Ang	0.00	0.00	0.00	0.00	0.00
Vs_B_Ang	-120.00	-120.00	-120.00	-120.00	-120.00
Vs_C_Ang	120.00	120.00	120.00	120.00	120.00
Is_A_Mag	906.10	905.91	905.91	7.93	7.93
Is_B_Mag	906.05	905.98	7.93	1562.85	905.98
Is_C_Mag	906.10	906.36	7.94	1562.86	906.36
Is_A_Ang	0.00	-0.01	-0.01	-0.02	-0.01
Is_B_Ang	-120.00	-119.98	-119.98	-90.13	-119.98
Is_C_Ang	120.00	120.00	120.00	90.17	120.00
Is_1_Mag	906.08	906.08	307.26	906.28	606.76
Is_2_Mag	0.03	0.28	299.32	898.35	299.50
Is_0_Mag	0.00	0.00	299.32	0.00	299.32
Is_1_Ang	0.00	0.00	-0.01	0.02	0.01
Is_2_Ang	-56.73	-128.26	-0.01	-179.98	-179.97
Is_0_Ang	-123.69	28.61	-0.01	-98.13	179.99

Table 10 - Shunt Fault Simulation Results

5.6 System Integration, Testing and Deployment

To fully address the project objective of reviewing the development of core systems and integrations to facilitate analysis and ultimately alarming of detected BC's, additional detail of the processes is required. System integration and associated complexities are being managed by a specialist team of SCADA and Control Systems Engineers. As mentioned in chapter 4, this team will integrate field-based monitor data into ADMS using Stanbury's algorithm, specialised coding and proprietary development and simulator environments to build the detection system. The process involves complex computer-based networking between servers, remote terminals, and virtual machines. This stage of the trial is ongoing, so a comprehensive review is unachievable for this report.

Limited feedback indicates a key input driving system integration is the data calculation method used which impacts scalability of the algorithm within network telemetry. Rolling out the calculation is achieved by either a single calculation which is centralised and reaches out to multiple network monitors located at distribution substations or multiple calculations which are the same calculations, however, distributed and contained within every network monitor location. Both methods have advantages and disadvantages that require a detailed assessment to determine the optimal solution. Considerations include code management and optimisation, stakeholder preferences like initial flagging of events in the ADMS testing phase. For example, report or email.

Prior to deployment stakeholder engagement and change management processes will be required. It is expected stakeholder engagement will follow rigorous testing within the ADMS environment to evaluate operational feasibility. Stakeholder engagement will most likely be in the form of meetings to provide relevant teams with opportunities to ask questions and provide feedback. Following the engagement process, a consultation process will commence where the wider business will be notified of deployment. Finally, operational staff will be trained in how to manage a BC alarm and steps taken to address the possible risk.

CHAPTER 6
Discussion & Conclusion

6.1 Discussion

Limitations of traditional protection methods, network evolution like the increase of network connected DER, and inherent characteristics of existing network topologies make BC detection a challenge for utilities. Regulatory drivers and asset management frameworks are encouraging utilities to develop and implement suitable strategies to combat the risk associated with downed conductor events. Consequently, this research project reports on aspects of an Ausgrid led trial to operationally implement a candidate method of BC detection.

The major findings of this research are:

- Literature identifies many proposed detection methods for broken conductors or phase discontinuities that can be broadly categorised into voltage, current or harmonic based alternatives.
- Many alternatives rely on the installation of new equipment or impose a significant processing burden on existing equipment, most of which is yet to be trialed in a real-world setting.
- Typical broken conductor scenarios identified by utilities can be modelled using the candidate method and obtained results are reproducible across various software applications.
- The operational implementation of a concept introduces significant complexities in addition to the fundamental idea.

The following shares research interpretations and implications, acknowledges limitations and states recommendations and future work.

6.1.1 Interpretations and Implications

A voltage magnitude-based option is the protagonist detection method focused upon within this paper. However, alternative methods were identified in literature and outlined in chapter 2. Moreover, a current based method that uses the ratio of negative to positive sequence current has recently been implemented on Ausgrid's 11kV network using capable devices and is discussed in chapter 5. The key points of this discussion were that a standard setting is accepted across industry and would typically cover most broken conductor scenarios. However, this standard setting has been causing nuisance alarm assertion. It was alluded that system studies or in service setting adjustments following sequence measurements during commissioning may improve setting performance. Cursory assessments from operational teams suggested system design and configuration of the network where the devices were installed and 46BC element enabled have inherent system imbalances due to significant 2 phase spur lines and single-phase loads such that the standing negative sequence current may already be high and as load drops the I2/I1 increases causing broken conductor alarm assertion. Preliminary feedback suggests this method is somewhat unreliable and indicative that current based methods may be difficult to operationally implement due to load variability and network complexity.

Alternatively, literature, modelling and analysis conducted throughout this research project indicates voltage-based methods of detection are comparatively robust. Obtained results present relationships based on certain scenario parameters and electrical theory. As discussed, the ungrounded delta primary of the connected *DY11* transformer creates an inherent response where the winding voltage connected to the discontinued phase is half the magnitude of the winding voltage connected across the healthy phases. If an earth reference is introduced to the discontinued phase on the transformer side, a $\frac{1}{\sqrt{3}} \times Vpu$ magnitude exists on the open phase connected windings whilst the winding connected to the healthy phases remains at 1 per unit. If a second phase discontinuity occurs during the earthed reference condition the results alter to two phases being $\frac{1}{2\sqrt{3}} \times Vpu$ with the third being $\frac{1}{\sqrt{3}} \times Vpu$. Such relationships exist when the connected load is balanced, however, when phase imbalance occurs caused by load variation, these factors tend to fluctuate. Moreover, an interesting phenomenon exists where the two affected phases algebraically sum to the value of the unaffected phase.

Additionally, the obtained HV results are induced on to the star secondary so when measuring phase to neutral quantities, the results correlate. Therefore, the candidate method is dynamic and can be applied to either HV or LV systems. Furthermore, grid voltage stability due to network connected on-load tap changers and line drop compensation schemes regulate and maintain voltage magnitudes within the bandwidth specified by Australian standards being +10/ -6 % nominal. Finally, Michael Stanbury's algorithm calculations and thresholds are based on percentage of nominal volts, ultimately minimizing the impact of load variation and voltage fluctuations. Therefore, such justification categorically suggests that at the time of writing this report the candidate method for broken conductor detection being trialed at Ausgrid is more robust than the alternative current based method discussed.

6.1.2 Limitations

Several limitations exist with the model and simulations run for this project. The voltage source generator is set to "swing bus" which effectively fixes the voltage magnitude and phase angle. Although the obtained results seem to align with previous EMTP® modelling and examined theory, applying this setting may introduce unidentified data inaccuracies. Connected load types did not vary, remaining a constant resistance mode throughout the modelling process. Finally, elements like line impedance, ground impedance and fault resistance, are neglected. Justification for the model's omission of line impedance relates to the assumption that the accumulation of fault resistance and ground impedance in a HIF scenario would be significantly higher than the total upstream line impedance value. Secondly, the assumption is made that on-load tap changing mechanisms and line drop compensation schemes would be regulating the voltage to ensure magnitudes are as close to nominal volts as possible. As such, line impedance can effectively be neglected.

The LOP variant provides good coverage of most scenarios. However, a small sample required the partial voltage variant to be implemented for adequate detection.

Despite limitations of the Simulink® model, previous EMTP® modelling and validation through the desktop analysis process indicated algorithm suitability and rigour.

6.1.3 Recommendations and Future Work

Preliminary estimates provide costings for trial basis engineering development and testing. However, deployment costs like technician time for testing and commissioning, including materials, incidentals and overheads is yet to be determined. Therefore, a detailed cost analysis is recommended.

Opportunistic benefits may be achievable during deployment including the utilisation of resources to deliver other programs of work whilst onsite. Communication and coordination between engineering, portfolio planning, and delivery teams is also recommended.

Continued development of the Simulink® model for this project is recommended as future work given the limitations described above. Considerable improvements can be made to ensure greater accuracy of results.

Variants of detection method would provide better coverage of potential BC events. Assessment and modelling of alternative BC detection methods available via current period contract devices could be advantageous. Preliminary analysis of ANSI 46BC commenced during this research project. As such, continued model development to support detailed system studies, improve deployment strategy and enhance feature benefit is recommended as future work.

Finally, continued reporting on trial outcomes is recommended to reflect on the process and provide learning opportunities for other utilities beyond this report.

6.2 Conclusion

The primary objectives of this project were:

- Review power system analysis theory and its application in BC detection.
- Review traditional BC detection methods and philosophies.
- Research alternative BC detection methods.
- Investigate BC methods currently used within Ausgrid period contract devices.
- Explore innovation trial candidate BC detection algorithm opportune to Ausgrid risk appetite, existing network architecture and available systems.
- Demonstrate the viability and accuracy of the candidate BC detection algorithm using existing telemetry.
- Present the trial candidate BC detection method using a simulation model.
- Review the development of core systems and integrations to facilitate analysis and ultimately alarming of detected BC using this system.
- Discuss the business processes and change management requirements for BAU deployment once the concept has been proven.
- Report outcomes of the trial and proposed future developments.

Through adequate review of literature, structured research methodology, model development, acquisition and analysis of obtained data, and collation of this structured report, the above objectives have been suitably addressed.

Ausgrid's trial is ongoing with teams currently working on system integration, testing and deployment. It is expected a final evaluation of the trial will be completed and the identified future work pursued following the submission of this thesis. The intent is for internal stakeholders and external industry to reflect and make further improvements or recommendations on the operational implementation of broken conductor detection methods to mitigate associated risk.

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APPENDICES

Appendix A – Project Specification

University of Southern Queensland

ENG4111/4112 Research Project

Project Specification

For:	Matthew Bargwanna
Title:	*Operational Implementation of Broken Conductor Detection Method to Mitigate Wires Down Events*
Major:	Power Engineering
Supervisors:	Tony Ahfock
Enrollment:	ENG4111 – EXT S1, 2021
	ENG4112 – EXT S2, 2021

Project Aim:

Ausgrid are running a Network Innovation trial where a Broken Conductor (BC) detection algorithm is operationally implemented to mitigate risk of wires down events.

The main objectives of this trial are:

- Demonstrate the viability and accuracy of a voltage-magnitude based broken conductor detection algorithm using existing telemetry.
- Develop the core system and integrations to facilitate analysis and ultimately alarming of detected broken conductors using this system.
- Establish the business processes and change management requirements for BAU deployment once the concept has been proven.

Programme: Version 1, 15th March 2023

I plan to develop a research project using the following methodology:

- Investigate BC detection methods through literature review.
- Exploration and analysis of candidate BC detection methods using a simulation model.
  - Model construction to be a typical network arrangement where the method would be implemented.
- Evaluate the chosen BC detection method and its operational implementation across Ausgrid.
- Report outcomes of the trial and proposed future developments.

ENG 4111 Project Specification S1, 2023

Appendix B – Risk Management Plan

Appendix B.1 – Risk Management Overview

Project risks were identified, and controls developed to reduce their likelihood and consequence. The UniSQ Online Risk Management System was accessed to document the preliminary RMP (Ref #: 2350) as preliminary risk assessments indicated possible lab/field testing. However, as the trial/project progressed, such testing was no longer applicable. Consequently, the risk was eliminated. Therefore, the final RMP was developed for this project based on content outlined in Appendix B.2.

Appendix B.2 – Project Risk Assessment

The following outlines a plan to manage risk associated with project research and development to satisfy the requirements of ENG4111 & ENG4112. The subsequent risk statement is sourced internally from Ausgrid, and its key message will be adopted when assessing project related risk.

"To treat risk Ausgrid implements an integrated risk management framework that is embedded into all critical processes and systems for making decisions. The organisation uses risk management techniques to take appropriate action to reduce the uncertainty around the achievement of its objectives. Ausgrid's management of network risk is in accordance with the Board Policy - Risk Management (GV000-Y0014) and the Risk Management Framework (GV000-Y0237) aligned with AS ISO 31000:2018 Risk Management – Guidelines".

Additionally, Ausgrid use a safety and risk management tool called the "Hazard Assessment Conversation" (HAC). The following are examples of the tools used to support the HAC process. The same tools can be adapted to support a risk management and strategy for the project. The project risk assessment highlights relevant tasks/risks, mitigation controls and matrix identifiers. This risk assessment will be supported by relevant policies, company publications, SWMS and environmental processes. Electrical and other hazards associated with any possible live trial event will be assessed using the same method.

LIKELIHOOD		CONSEQUENCE				
		Insignificant	Minor	Moderate	Major	Severe
	Almost Certain	11	16	20	23	25
	Likely	7	12	17	21	24
	Possible	4	8	13	18	22
	Unlikely	2	5	9	14	19
	Rare	1	3	6	10	15

Table 11 - Project/Hazard Risk Matrix

Consequence Definitions	
Consequence	**Definition**
Severe	Probability of event occurring – > 5x per year
Major	Probability of event occurring – < 5x per year, > 1x per year
Moderate	Probability of event occurring - > 1x per 10 years, not > 1x per year
Minor	Probability of event occurring - > 1x per 25 years, not > 1x per 10 years
Insignificant	Probability of event occurring - < 1x per 25 years

Table 12 - Consequence Definitions - Hazard Assessment Conversation

Likelihood Definitions	
Likelihood	**Definition**
Almost Certain	One or more fatalities. Significant permanent injuries/work related illnesses to one or more persons
Likely	Permanent injuries/work related illnesses to one or more persons
Moderate	Significant non-permanent injuries/work related illnesses requiring emergency surgery or hospitalisation for more than several days
Minor	Non-permanent injuries/work related illnesses requiring medical treatment
Insignificant	Low level injury/symptom requiring first aid only

Table 13 - Likelihood Definitions - Hazard Assessment Conversation

Risk Ranking	Priority
EXTREME	**Immediate Priority** – Do not start work under these conditions, requires urgent and immediate attention
HIGH	**High Priority** – Unless ALRP can be demonstrated, controls must be put in place to reduce the risk level, proactive management or risk required.
MEDIUM	**Medium Priority** – Unless ALRP can be demonstrated, controls must be put in place to reduce the risk level, actively monitor this hazard.
LOW	**Low Priority** – Unless there is something simple and easy you can do to further eliminate or reduce the risk, deal with other hazards first. Monitor the situation for change.
ALARP	**As Low as Reasonably Practicable** (ALARP) means that everything practical to reduce the risk and make the situation safe has been implemented.

Table 14 - Risk Ranking

Hierarchy of Controls	
Control	**Description**
Elimination	The hazard and associated risk is eliminated from the work environment
Substitution	Reducing risk by substituting a hazard with another that is less hazardous
Isolation	Reducing risk by restricting access to or preventing contact with hazards including the use of barriers, access controls
Engineering	Reducing risk through engineering means preventing access to or contact with hazards. Engineering controls include machine guarding and interlocking.
Administrative	Reducing risk through the implementation of work procedures, training, job rotation.
PPE	Reducing risk through reducing exposure to the hazard, e.g., wearing hearing protection to reduce exposure to noise, wearing gloves to prevent chemicals coming into contact with skin

Table 15 - Hierarchy of Controls

Task	Description	Risk Mitigation/Controls	Initial Matrix Score	Final Matrix Score
1	Project Approval and Commencement	Seek approval as soon as practical.	25	5
2	Resource Procurement and Acquisition	Ensure resource availability. Seek approvals from IT. Ensure relevant licences acquired.	25	5

3	Understanding Technology	Adequate research. Seek advice from project supervisor, Ausgrid senior engineering staff or 3rd party consultants.	18	10
4	Lab/Offline simulator Testing	Ensure adequate risk assessment and controls are in place for lab work.	22	9
5	Network Access Request	Seek network security and safety services approval. (Possible future works).	25	6
6	Pilot Install	Ensure all necessary onsite controls are in place. (Possible future works).	25	6
7	Data/Analysis	Ensure all data is captured and recorded. Confirm accuracy.	13	6
8	Real Time Testing Completion	Quality documentation and test sheets. (Possible future works).	22	10
9	Preparing Draft Dissertation	Ensure adequate time to complete the draft dissertation and results are checked and verified.	18	10
10	Proof Reading and Checking Dissertation	Conduct final check, ensure no grammatical errors.	13	6
11	Present Results PP2	Ensure project readiness.	13	6
12	Complete Dissertation and Submit	Conduct final checks and submitted on time.	13	6

Table 16 - Project Risk Assessment

Appendix C – Project Timeline

Appendix C.1 – Timeline

Activity ID	Project Identifier (Activity level)	Project Officer	Activity Types	Works Order	Street Address	Suburb	Activity Description	Start Date and Time	End Date and Time	Duration (hrs)
Research Specificati Project Timeline								03/01/2023 08:00	17/11/2023 17:00	223.0
Research Specificati.1 Stage 1								03/01/2023 08:00	28/04/2023 17:00	80.0
A1000							Early Research/Reading	03/01/2023 08:00*	28/04/2023 17:00	80.0
A1010							Submit Research Proposal/Specification	03/01/2023 08:00*	15/03/2023 17:00	51.0
A1020							Explore Legal/Regulatory Drivers for BC Trial	03/01/2023 08:00*	28/04/2023 17:00	80.0
Research Specificati.2 Stage 2								03/01/2023 08:00	30/06/2023 17:00	124.0
A1030							Obtain Historian Data	03/01/2023 08:00*	28/04/2023 17:00	80.0
A1040							Analyse Time-Series data	03/01/2023 08:00*	28/04/2023 17:00	80.0
A1050							Develop Model using BC theory/Simscape	03/01/2023 08:00*	30/06/2023 17:00	124.0
A1060							Evaluate Algorthim	03/01/2023 08:00*	30/06/2023 17:00	124.0
A1070							Explre production of streamlined reports	03/01/2023 08:00*	30/06/2023 17:00	124.0
A1080							Validate Algorthm to confirm actual events	03/01/2023 08:00*	30/06/2023 17:00	124.0
A1090							Summarise Learnings	03/01/2023 08:00*	30/06/2023 17:00	124.0
Research Specificati.3 Stage 3								28/02/2023 08:00	31/07/2023 17:00	106.0
A1100							Commence Literature Review	28/02/2023 08:00*	31/07/2023 17:00	106.0
A1110							Discuss Scope and Develop Methodology	28/02/2023 08:00*	31/07/2023 17:00	106.0
A1120							Participate in Offline detection simulator	28/02/2023 08:00*	31/07/2023 17:00	106.0
A1130							Summarise and record learnings	28/02/2023 08:00*	31/07/2023 17:00	106.0
Research Specificati.4 Stage 4								01/06/2023 08:00	29/09/2023 17:00	86.0
A1140							Commence report writing	01/06/2023 08:00*	29/09/2023 17:00	86.0
A1150							Evaluate monitoring/dectection in offline environment	01/06/2023 08:00*	29/09/2023 17:00	86.0
A1160							Summarise and record learnings	01/06/2023 08:00*	29/09/2023 17:00	86.0
Research Specificati.5 Stage 5								01/09/2023 08:00	17/11/2023 17:00	55.0
A1170							Implement BC detection into production environment	01/09/2023 08:00*	17/11/2023 17:00	55.0
A1180							Summarise and record learnings	01/09/2023 08:00*	17/11/2023 17:00	55.0
A1190							Identify future works/research	01/09/2023 08:00*	17/11/2023 17:00	55.0
A1200							Finalise and Submit draft report	01/09/2023 08:00*	17/11/2023 17:00	55.0
A1210							Present research at PP2	01/09/2023 08:00*	17/11/2023 17:00	55.0
A1220							Submit final report for assessment	01/09/2023 08:00*	17/11/2023 17:00	55.0

Figure 69 - Research Project Timeline

Appendix C.2 – Project Gantt

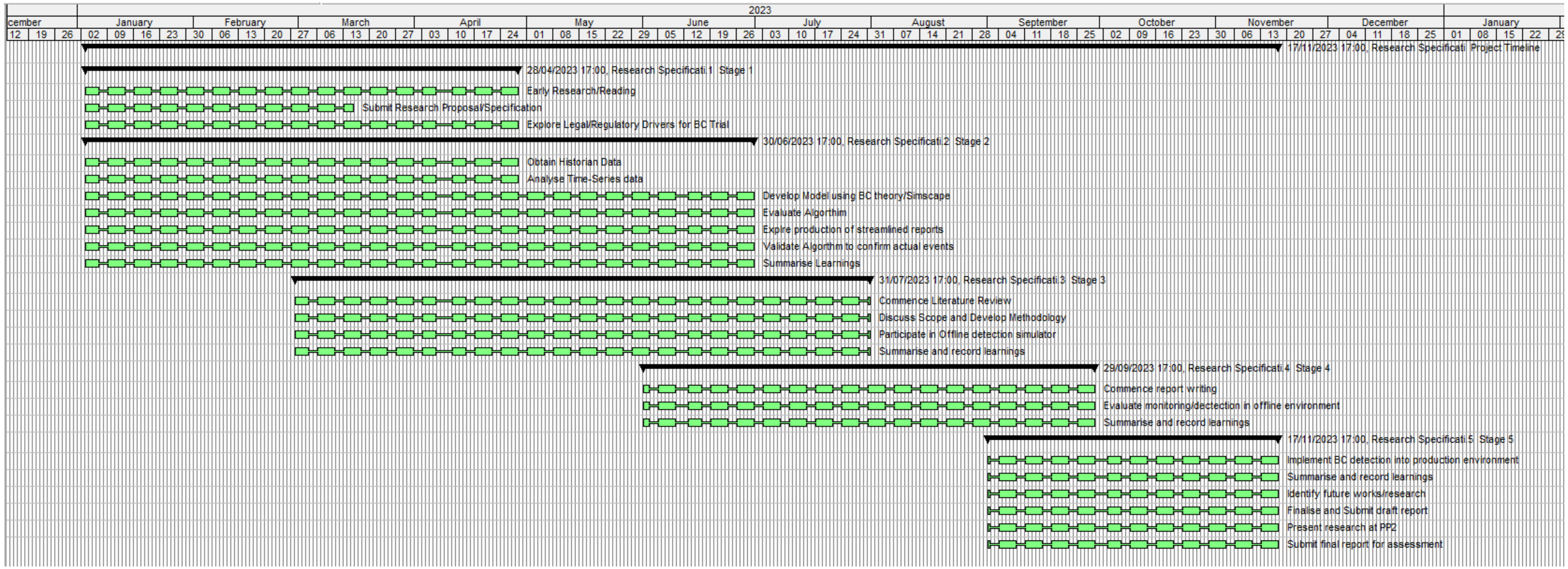

Figure 70 - Research Project Gantt Chart

Appendix D – Project Resources

Appendix D.1 – Resources Requirements

Various resources are required for successful project completion. They are outlined in the table below:

Item/Equipment	Qty	Source	Cost ($)	Comments
PC	1	Student/Ausgrid	Nil	Combination of student acquired and Ausgrid supplied application licences
Literature Databases	1	UniSQ	Nil	Accessible through Student Library
MS Word	1	Student/Ausgrid	Nil	Installed
MS Excel	1	Student/Ausgrid	Nil	Installed
MATLAB®/ Simulink®	1	UniSQ	Nil	Installed
Access to offline simulator	1	Ausgrid	Nil	Funded by Network Innovation Trial
Network Access for potential live trial	1	Ausgrid	Nil	Funded by Network Innovation Trial

Table 17 - Project Resource Requirements

Appendix E – Modelling Results

Scenario	Description	Vs_Mag_A	Vs_Mag_B	Vs_Mag_C	Vs_Ang_A	Vs_Ang_B	Vs_Ang_C
0	System Normal	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
1	C-phase broken with earth fault	8977.581	8986.314	8980.494	0.021	-119.989	119.968
2	C-phase broken without earth fault, balanced load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
3	C-phase broken without earth fault, unbalanced load	8977.329	8984.604	8982.456	0.008	-119.981	119.973
4	B and C phases broken with earth fault on C, balanced load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
5	B and C phases broken with earth fault on C, unbalanced load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
6	B and C phases broken with earth faults on B and C	8977.581	8986.314	8980.494	0.021	-119.989	119.968
7	B-phase broken with B to C fault,	8977.600	8986.293	8980.497	0.021	-119.989	119.968

	without earth fault						
8	C-phase broken with C-phase HV fallen into LV without earth fault	8979.244	8984.231	8980.913	0.012	-119.994	119.982
9	C-phase broken with C-phase HV fallen into LV with HV earth fault	8977.590	8986.305	8980.494	0.021	-119.989	119.968
10	B and C-phases broken with C-phase HV fallen into LV with HV earth fault	8977.604	8986.299	8980.487	0.021	-119.989	119.968
11	B and C-phases broken with C-phase HV fallen into LV	8977.581	8986.314	8980.494	0.021	-119.989	119.968
12	System Normal with parallel source	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
13	C-phase broken with earth fault with parallel source	8982.100	8981.611	8980.676	0.003	-120.005	120.002
14	C-phase broken with earth fault with weak parallel	8979.707	8984.441	8980.240	0.015	-119.998	119.983

	source (electrically far from fault)						
15	I2 Check - C-phase broken without earth fault, balanced 3ph load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
16	I2 Check - C-phase broken & earth fault, balanced 3ph load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
17	I2 Check - Unbalanced 3ph load without BC	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
18	I2 Check - Balanced 3ph system without BC, 2ph spur with connections across 3 phases, equal loading	8979.740	8980.426	8984.222	-0.014	-119.983	119.997
19	I2 Check - Balanced 3ph system without BC, 2ph spur A-C connections	8980.736	8979.082	8984.570	-0.020	-119.986	120.006

Table 18 - Source Bus Voltage Data for Simulated Scenarios

Scenario	Description	Vr_Mag_A	Vr_Mag_B	Vr_Mag_C	Vr_Ang_A	Vr_Ang_B	Vr_Ang_C
0	System Normal	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
1	C-phase broken with earth fault	8977.581	8986.314	26.290	0.021	-119.989	-60.032
2	C-phase broken without earth fault, balanced load	8977.581	8986.314	4482.636	0.021	-119.989	-60.032
3	C-phase broken without earth fault, unbalanced load	8977.329	8984.604	4689.298	0.008	-119.981	-76.685
4	B and C phases broken with earth fault on C, balanced load	8977.581	4508.530	39.479	0.021	0.021	0.021
5	B and C phases broken with earth fault on C, unbalanced load	8977.581	4500.053	22.525	0.021	0.021	0.021
6	B and C phases broken with earth faults on B and C	8977.581	26.358	26.358	0.021	0.021	0.021
7	B-phase broken with B to C fault, without earth fault	8977.600	8976.535	8980.497	0.021	119.953	119.968

8	C-phase broken with C-phase HV fallen into LV without earth fault	8979.244	8984.231	208.798	0.012	-119.994	-179.981
9	C-phase broken with C-phase HV fallen into LV with HV earth fault	8977.590	8986.305	101.988	0.021	-119.989	-179.979
10	B and C-phases broken with C-phase HV fallen into LV with HV earth fault	8977.604	4437.808	101.988	0.021	0.021	-179.979
11	B and C-phases broken with C-phase HV fallen into LV	8977.581	4384.403	208.775	0.021	0.021	-179.979
12	System Normal with parallel source	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
13	C-phase broken with earth fault with parallel source	8982.100	8981.611	8971.052	0.003	-120.005	120.003
14	C-phase broken with earth fault with weak parallel source (electrically	8979.707	8984.441	4409.312	0.015	-119.998	110.966

	far from fault)						
15	I2 Check - C-phase broken without earth fault, balanced 3ph load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
16	I2 Check - C-phase broken & earth fault, balanced 3ph load	8977.581	8986.314	8980.494	0.021	-119.989	119.968
17	I2 Check - Unbalanced 3ph load without BC	8979.739	8980.432	8984.217	-0.014	-119.984	119.997
18	I2 Check - Balanced 3ph system without BC, 2ph spur with connection across 3 phases, equal loading	8979.740	8980.426	8984.222	-0.014	-119.983	119.997
19	I2 Check - Balanced 3ph system without BC, 2ph spur A-C connections	8980.736	8979.082	8984.570	-0.020	-119.986	120.006

Table 19 - Load Bus Voltage Data for Simulated Scenarios

Scenario	Description	Vsec_pu_Mag_A	Vsec_pu_Mag_B	Vsec_pu_Mag_C	Vsec_pu_Ang_A	Vsec_pu_Ang_B	Vsec_pu_Ang_C
0	System Normal	1.000	1.000	1.000	30.003	-89.986	149.984
1	C-phase broken with earth fault	1.000	0.577	0.576	30.032	-120.135	-179.833
2	C-phase broken without earth fault, balanced load	1.000	0.500	0.500	30.032	-149.912	-150.024
3	C-phase broken without earth fault, unbalanced load	1.000	0.414	0.586	30.027	-149.973	-149.973
4	B and C phases broken with earth fault on C, balanced load	0.287	0.287	0.575	0.021	0.021	-179.979
5	B and C phases broken with earth fault on C, unbalanced load	0.288	0.288	0.576	0.021	0.021	-179.979

6	B and C phases broken with earth faults on B and C	0.575	0.000	0.575	0.021	-179.979	-179.979
7	B-phase broken with B to C fault, without earth fault	0.999	0.000	0.999	-30.011	-30.011	149.989
8	C-phase broken with C-phase HV fallen into LV without earth fault	1.000	0.571	0.591	30.018	-118.827	-179.988
9	C-phase broken with C-phase HV fallen into LV with HV earth fault	1.000	0.574	0.000	30.032	-119.423	101.290
10	B and C-phases broken with C-phase HV fallen into LV with HV earth fault	0.288	0.288	0.000	-0.295	-0.295	-101.282

11	B and C-phases broken with C-phase HV fallen into LV	0.295	0.295	0.591	0.021	0.021	-179.979
12	System Normal with parallel source	1.000	1.000	1.000	30.003	-89.986	149.984
13	C-phase broken with earth fault with parallel source	1.000	0.999	0.999	29.998	-90.020	150.024
14	C-phase broken with earth fault with weak parallel source (electrically far from fault)	1.000	0.787	0.728	30.017	-103.762	158.706
15	I2 Check - C-phase broken without earth fault, balanced 3ph load	1.000	0.500	0.500	30.032	-149.968	-149.968

16	I2 Check - C-phase broken & earth fault, balanced 3ph load	1.000	0.575	0.575	30.032	-120.421	-179.546
17	I2 Check - Unbalanced 3ph load without BC	1.000	1.000	1.000	30.003	-89.986	149.984
18	I2 Check - Balanced 3ph system without BC, 2ph spur with connection across 3 phases, equal loading	1.000	1.000	1.000	30.003	-89.986	149.983
19	I2 Check - Balanced 3ph system without BC, 2ph spur A-C connections	1.000	1.000	1.000	29.994	-89.980	149.986

Table 20 - Transformer Secondary Bus Voltage Data for Simulated Scenarios