Protection Studies of Geographically Dispersed Type 3 Wind Energy Systems

A Thesis
Presented in Partial Fulfillment of the Requirements for the
Degree of Master of Science
with a
Major in Electrical Engineering
in the
College of Graduate Studies
University of Idaho
by
Alaap Anujan

Major Professor: Brian K. Johnson, Ph.D.
Committee Members: Herbert Hess, Ph.D.; Joseph Law, Ph.D.
Department Administrator: Mohsen Guizani, Ph.D.

December 2015

Authorization to Submit Thesis

This thesis of Alaap Anujan, submitted for the degree of Master of Science with a major in Electrical Engineering and titled "Protection studies of geographically dispersed type 3 wind energy systems," has been reviewed in final form. Permission, as indicated by the signatures and dates given below, is now granted to submit final copies to the College of Graduate Studies for approval.

Major Professor: ______________________________ Date: ____________
Brian K. Johnson, Ph.D.

Committee Members: ______________________________ Date: ____________
Herbert Hess, Ph.D.

______________________________ Date: ____________
Joseph Law, Ph.D.

Department Administrator: ______________________________ Date: ____________
Mohsen Guizani, Ph.D.

Abstract

Global energy demands have been increasing every year. There is a push towards switching to renewable sources of energy, primarily through wind energy, to meet these demands. The influence of wind turbine generators on power system dynamic performance is becoming increasingly important as global wind generation grows.

In this thesis, the design and performance of a comprehensive protection scheme for a grid integrated Type 3 (Doubly Fed Induction Generator based) wind energy system is studied. The protection system is tested in real time by hardware-in-the-loop simulation using a Real Time Digital Simulator (RTDS). A multiple machine aggregated model is designed and tested for its response to various fault contingencies by connecting modern protective relays to the RTDS. The operating conditions of the wind energy system are varied to simulate a condition of geographically displaced wind turbine units, and the response of protection elements to numerous fault contingencies are recorded. The faults are analyzed from the relay's perspective and comparisons made, based on the challenges encountered during relay operation, to suggest improved protection settings and to ensure proper coordination between relays. The results showed that different fault contingencies, such as wind turbine operating states and faults with resistance, had an effect on the effectiveness of the protection scheme.

Acknowledgements

I thank my major professor, Dr. Brian Johnson for being my mentor and guide all through my Master's program. He has taken keen interest in supporting me at every stage of my research with prompt inspirations and timely suggestions, kindness and enthusiasm which helped me, to a great extent, in completing my thesis.

Also, I'm thankful to Dr. Herbert Hess and Dr. Joseph Law for their valuable time, insightful suggestions and questions, which motivated me to evaluate my work and thesis.

I am thankful to Mr. Rishabh Jain, who performed the initial work on this topic and laid the framework for further studies into this research. His support during the initial stages of my thesis has been invaluable. A special thanks to my supervisor and mentor, Mr. Jordan Bell for his guidance in strengthening my knowledge in power protection concepts.

I am also thankful to my fellow students, faculty and staff of the ECE department who have been part of my Master's Degree completion.

Last but not the least, I would like to thank my family and friends, for their unwavering belief in me throughout my personal and academic life. I would not be able to attain this position in my studies if not for their motivation and support.

Table of Contents

List of Figures

List of Tables

Acronyms

230kV G - 230kV Grid Side Generator

230kV W – 230kV Wind Turbine Side Generator

AB – Phase A to Phase B Fault

ABCG – Three Phase Fault

ABG – AB to Ground Fault

AG – Phase A to Ground Fault

BC - Phase B to Phase C Fault

BCG - BC to Ground Fault

BG - Phase B to Ground Fault

CA - Phase C to Phase A Fault

CAG - CA to Ground Fault

CG - Phase C to Ground Fault

CT – Current Transformer

CTR – Current Transformer Ratio

DFIG – Doubly Fed Induction Generator

DLG – Double Line Ground

DT – Definite Time

EI – Extremely Inverse

FACTS – Flexible AC Transmission Systems

FID – Faulted Phase Identification

GWEC – Global Wind Energy Council

IEEE – Institute of Electrical and Electronics Engineers

LAN – Local Area Network

LL – Line to Line Fault

PFCC – Power Factor Correction Capacitor

PMSG – Permanent Magnet Synchronous Generator

POTT – Permissive Overreaching Transfer Trip

POW – Point on Wave

PTR – Potential Transformer Ratio

RTDS – Real Time Digital Simulator

RSCAD – RTDS Simulator Computer Aided Design

SCIG – Squirrel Cage Induction Generator

SI – Standard Inverse

SLG – Single Line to Ground

TD – Time Dial

TMS – Time Multiplier Setting

VI – Very Inverse

VSC – Voltage Sourced Converter

VT – Voltage Transformer

WRIG – Wound Rotor Induction Generator

WTG – Wind Turbine Generator

Chapter 1: Introduction

Global demand for energy is increasing each year at a rapid pace. With the looming threat of conventional fossil fuel reserves soon to be depleted, the push to switch to renewable sources to meet the energy demands is higher than ever. Fossil fuels such as coal, oil and natural gas are dense forms of energy which have taken millions of years to form. But within the past few decades, the world has consumed an incredible amount of them, leaving the vast reserves all but gone and the climate seriously impacted.

The current reserves of fossil fuels are finite and are soon to run out. On a global scale, we are consuming an equivalent of over 11 billion tonnes of oil in fossil fuel [1]. At the current rate of consumption, global crude oil reserves are expected to be depleted by the year 2052 and all forms of fossil fuels by 2088. Figure 1.1 shows the expected timeline for the depletion of fossil fuel reserves.

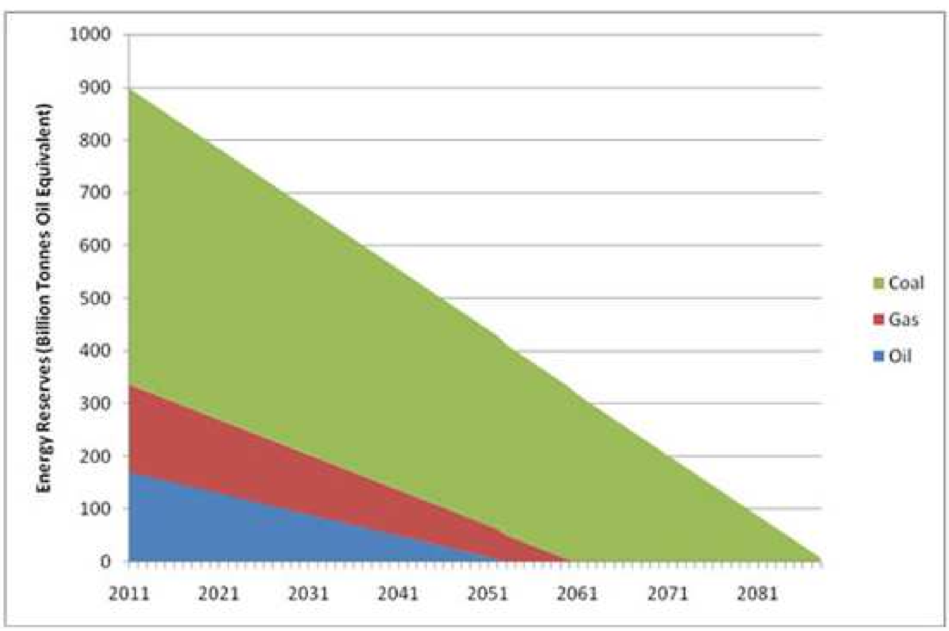


Figure 1.1. – Depletion rate of conventional energy resources [2]

The renewable sources of energy such as wind, solar, geothermal and bioenergy are abundant and easily available forms of energy. With the right means of harnessing them, they can meet global energy demands for years to come. It is true that the current costs of setting up and generating energy from renewables are comparatively higher than those of fossil fuels. However, with improvements in technology and greater acceptance of these energy reserves, it's only a matter of time when renewable resources becomes more feasible that the conventional energy sources.

A major concern regarding the use of fossil fuels for energy is the impact to the environment, specifically its contribution towards global warming. Considering the U.S. alone, the electricity production accounts for more than one-third of the global warming emissions, the majority of which are due to coal-fired power plants. Statistically, natural gas emits between 0.6 to 2 pounds of carbon dioxide equivalent per kilowatt-hour (CO2E/kWh), coal and oil between 1.4 to 3.6 CO2E/kWh, whereas, renewable energy sources such wind, emits only 0.02 to 0.04 pounds CO2E/kWh, solar 0.07 to 0.2, geothermal 0.1 to 0.2 and hydroelectric between 0.1 to 0.5 [2]. With such low carbon footprints, these renewable forms of energy need to be given impetus to grow towards being the primary source of electricity generation.

Renewable energy has started to be more affordable with improved technological developments each year. For instance, the average price of a solar panel has dropped by almost 60 percent since 2011 and the cost of generating wind energy has decreased by 20 percent [2]. Realizing the importance and potential of these energy reserves, many countries have come out with investment policies and subsidies on setting up these renewable energy plants. The cost will decline even further as markets mature and companies increasingly take advantage of the economies of scale.

Recent advancements in power electronics and control systems have helped better integrate distributed generators to the existing power grid. Protection systems are developing at a rapid rate, with the move from conventional electromechanical systems to microcontroller based systems and the integration of communication aided protection schemes. Protection schemes are now more versatile, with a wide range of sensitivity and selectivity settings for various system contingencies. There is also the fact that they are simply better and faster now. All these help in ensuring that the power grid remains resilient even with continuous addition of distributed generating sources, primarily, the renewables.

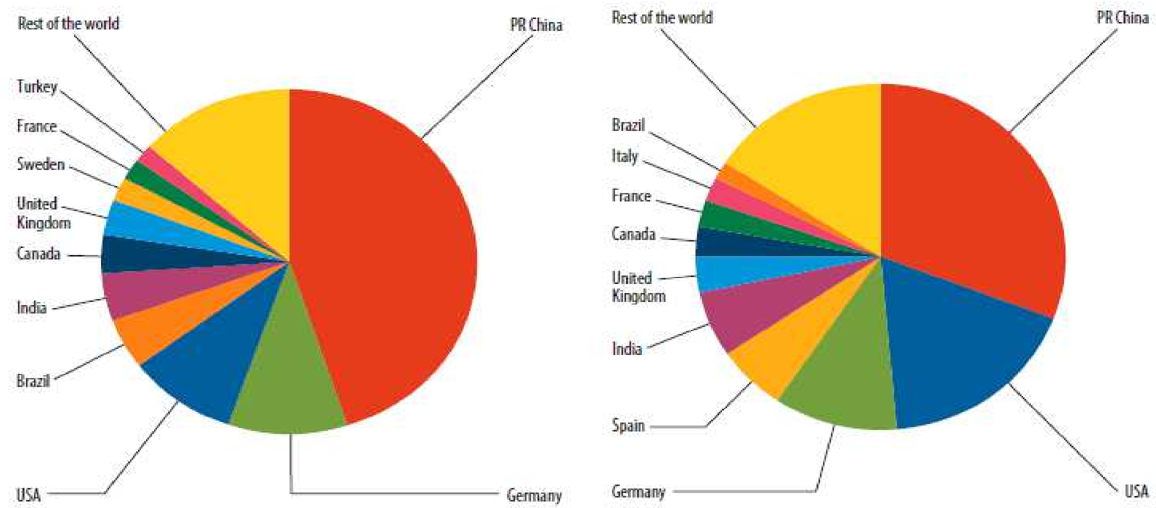
1.1. Wind as a Reliable Energy Source

Wind energy has always been one of the most available forms of renewable energy which if harnessed effectively, has the potential to meet future global energy demands. Currently the availability of wind energy is high and it is just a matter of time before it becomes one of the primary renewable resources.

1.1.1. Current Scenario and Future of Wind Energy

The current prospects of wind energy are bright, and as per the Global Wind Energy Council (GWEC), installed wind energy capacity currently stands at 369.6 Gigawatts (GW) worldwide [3]. The push towards wind energy has been phenomenal, with the year 2014 having 51GW of newly installed wind power capacity, which was the highest ever in annual installations. Figure 1.2 illustrates the installed capacity in the year 2014 and the cumulative capacity up to December 2014.

Looking ahead, the GWEC predicts the net installed capacity to go up by almost 30% over the next 5 years, which is as described in Figure 1.3.



Country	MW	% SHARE
PR China	23,196	45.1
Germany	5,279	10.2
USA	4,854	9.4
Brazil*	2,472	4.8
India	2,315	4.5
Canada	1,871	3.6
United Kingdom	1,736	3.4
Sweden	1,050	2.0
France	1,042	2.0
Turkey	804	1.6
Rest of the world	6,852	13.3
Total TOP 10	**44,620**	**87**
World Total	**51,473**	**100**

** Projects fully commissioned, grid connection pending in some cases* — *Source: GWEC*

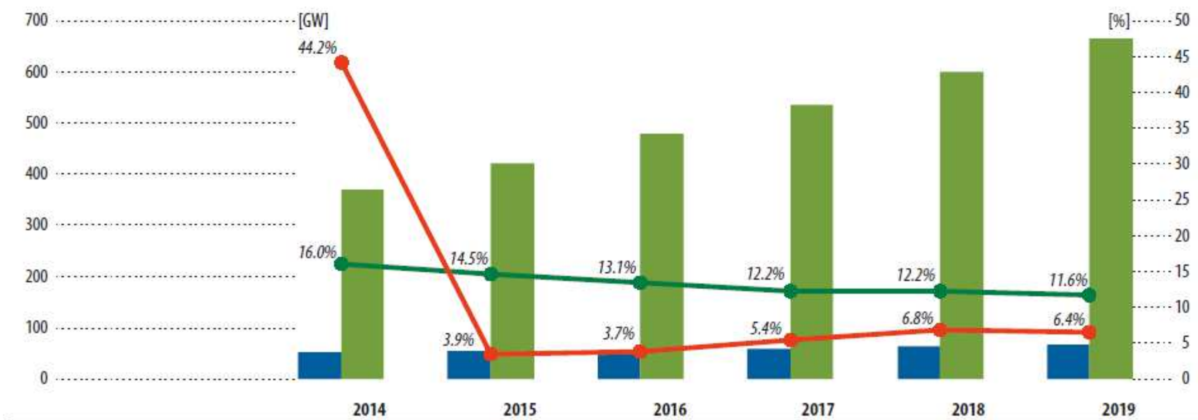
Country	MW	% SHARE
PR China	114,609	31.0
USA	65,879	17.8
Germany	39,165	10.6
Spain	22,987	6.2
India	22,465	6.1
United Kingdom	12,440	3.4
Canada	9,694	2.6
France	9,285	2.5
Italy	8,663	2.3
Brazil*	5,939	1.6
Rest of the world	58,473	15.8
Total TOP 10	**311,124**	**84.2**
World Total	**369,597**	**100**

** Projects fully commissioned, grid connection pending in some cases* — *Source: GWEC*

Figure 1.2. – Global Wind Energy Generation Capacities [3]

1.2. Principles of Wind Energy Generation

Wind energy works on the principle of conversion of kinetic energy of wind to mechanical energy and further its conversion into electric power. The process involves wind flowing over the wind turbine blades, causing the rotation of the blades and the shaft on which they are mounted on. The mechanical shaft is coupled to the rotor of the generator which induces currents on the stator when it rotates in the magnetic field.



	2014	2015	2016	2017	2018	2019
Cumulative [GW]	369.6	423.1	478.6	537.1	599.6	666.1
Cumulative capacity growth rate [%]	16.0%	14.5%	13.1%	12.2%	12.2%	11.6%
Annual installed capacity [GW]	51.5	53.5	55.5	58.5	62.5	66.5
Annual installed capacity growth rate [%]	44.2%	3.9%	3.7%	5.4%	6.8%	6.4%

Source: GWEC

Figure 1.3. – Global Wind Energy Market Forecast [3]

The power of the wind that flows through the blades of the wind turbine is expressed in (1.1) [5]

$$P_{wind} = \frac{1}{2}\rho A V^3 \ (Watts) \quad (1.1)$$

Where, ρ is the air density in $kg\ m^{-3}$

A is the blade sweep area in m^2

V is the wind speed in ms^{-1}

The total power in wind as (1.1) cannot be completely extracted. The optimum amount of power that can be extracted from wind is given by the Betz equation described in (1.2) [5]

$$P_{Betz} = (0.59).\frac{1}{2}\rho A V^3 \tag{1.2}$$

The above equation implies that even with no losses during power extraction, only 59% of the wind power can be utilized.

1.3. Wind Turbines – Operating Principle

The principle of operation of the wind turbine is mainly dependent on the aerodynamic properties of the turbine blades and the generator that converts the mechanical energy to equivalent electrical energy. The aerodynamic principle of the turbine blade is similar to that of airplane wings. The blades are so shaped that the curves create a difference in speed between the wind speed above to that below the blade. This creates an inverse pressure difference in both regions. By Bernoulli's principle, the pressure difference between the top and the bottom of the blade results in a net lift force F_w on the blade. A torque is subsequently created on the turbine shaft, resulting in rotational motion of the wind turbine [4]. Figure 1.4 shows a turbine blade and flow of air around it.

The rotor of large three blade wind turbines usually operate at a speed between 6 to 20 rpm which is much slower than the rated speed of a 1200 or 1800 rpm standard 6 or 4 pole induction wind generator. The gearbox is thus essential to convert the low turbine rotor speeds to the high speeds of the generator. The gearbox conversion ratio (r_{gb}) is as expressed in (1.3).

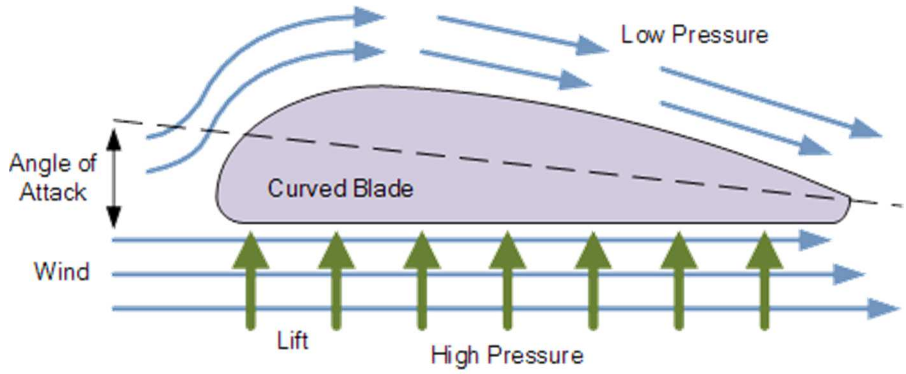


Figure 1.4. – Wind Turbine Blade Air Flow [4]

$$r_{gb} = \frac{n_m}{n_M} = \frac{(1-s).60.f_s}{P.n_M} \quad (1.3)$$

Where, n_m and n_M are generator and turbine speeds in rpm

s is the rated slip

f_s is the rated stator frequency in Hz

The wind generator performs the conversion of rotational mechanical energy to electrical energy. There are different types of generators used in wind energy systems, such as squirrel cage induction generators, doubly fed induction generators and synchronous generators, which are discussed in Section 1.4 of this chapter.

A more detailed description of wind energy components and the process of energy conversion is given in [4].

1.4. Types of Wind Turbine Systems

Wind turbines systems are broadly classified into the following four types described below.

1.4.1. Type 1 Wind Turbine System

The type 1 wind turbine system (Figure 1.5) consists of a squirrel-cage induction generator (SCIG) connected directly to the step up transformer. The turbine speed is fixed to the electrical grid frequency. This type generates real power when the turbine shaft rotates faster than the electrical grid frequency, producing a negative slip. For a given wind speed, the operating speed of the turbine under steady conditions has a nearly linear relationship to torque. Under sudden wind speed variations, the mechanical inertia of the drive train will limit the rate of change in electrical output. It is essential to have capacitor banks connected for reactive power compensation since this type machine requires reactive power.

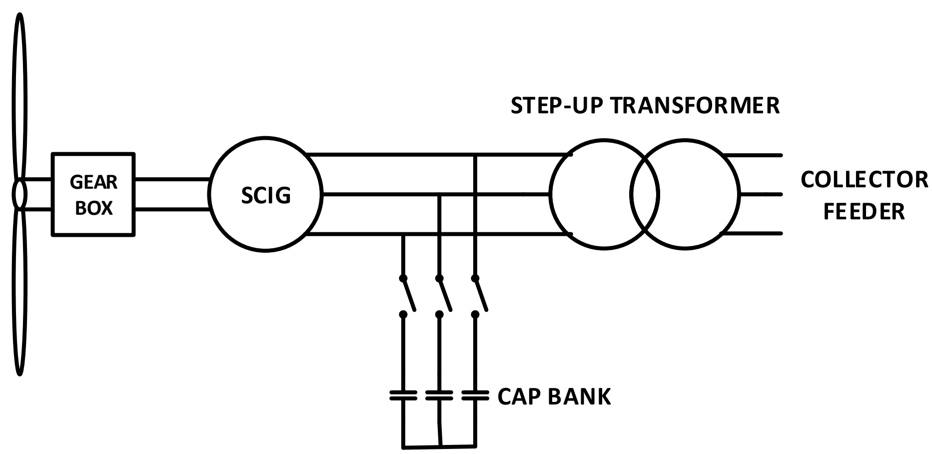


Figure 1.5. – Type 1 Wind Turbine System

1.4.2. Type 2 Wind Turbine System

The type 2 wind turbine system (Figure 1.6) uses wound rotor induction generators (WRIG) connected directly to the WTG step up transformer, but also have variable resistor in the three phase rotor circuit. These are implemented with a set of resistors and power electronics external to the rotor, with currents flowing between the resistors and the rotor via the slip rings. The resistors can also be mounted on the rotor, eliminating the need for slip rings. The variable resistors can control the rotor currents quite rapidly to keep constant power even during high wind gusts and can influence the machine dynamic response during grid disturbances. Capacitor banks need to be installed here too for reasons similar to the Type 1 WTGs.

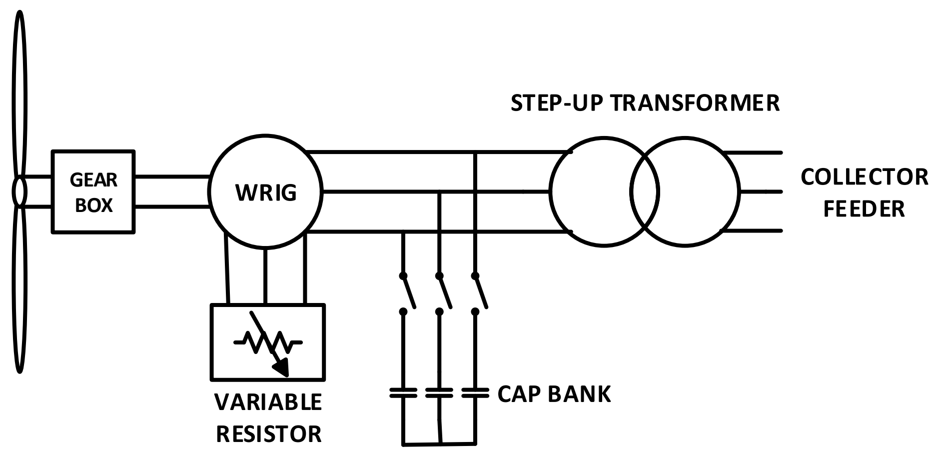


Figure 1.6. – Type 2 Wind Turbine System

1.4.3. Type 3 Wind Turbine System

The type 3 wind turbine is an upgrade to the type 2 design through addition of a variable frequency AC excitation source to the rotor circuit. This is referred to as a Doubly Fed Induction Generator (DFIG). The additional rotor excitation is often provided via slip rings by a current regulated, voltage source converter, which can adjust the rotor currents' magnitude and phase almost instantaneously. The rotor side converter is connected back-to-back with the grid side converter, which exchanges power directly with the grid. The type 3 wind turbine has been studied in this thesis work. The schematic for the Type 3 wind turbine system is as shown in Figure 1.7.

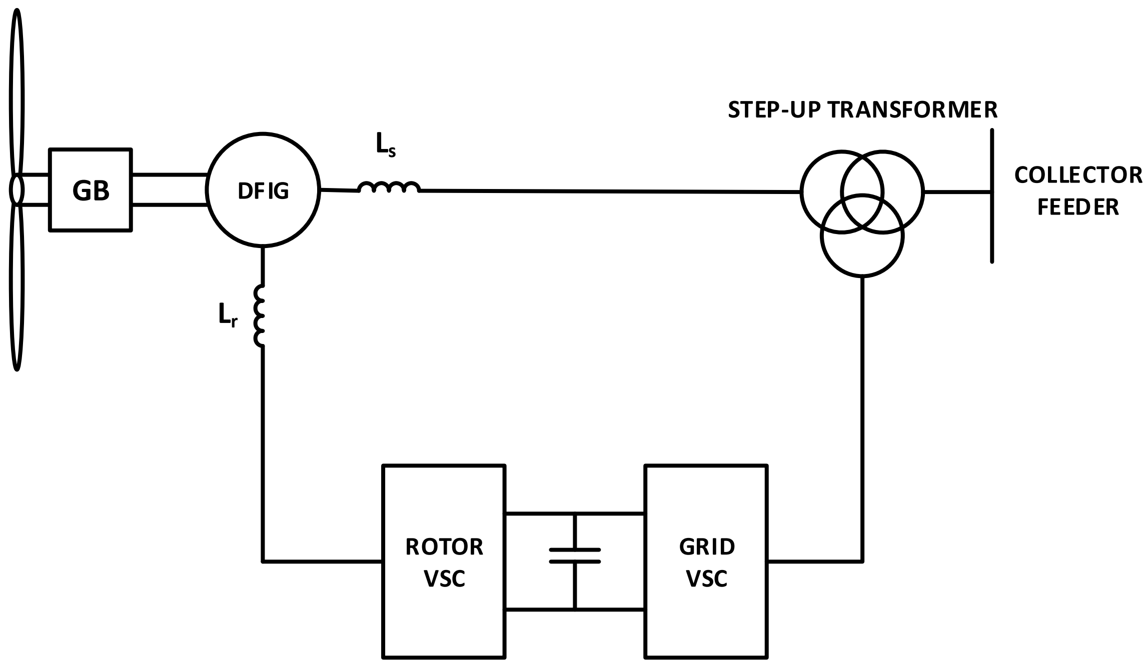


Figure 1.7. – Type 3 Wind Turbine System

1.4.4. Type 4 Wind Turbine System

The type 4 wind turbine system (Figure 1.8) offers a great deal of flexibility in design and operation since the output of the generator is sent through a full output power rated back-to-back frequency converter. The gearbox could be eliminated, so that the machine spins at slow turbine speed and generates electrical frequency below that of the grid. The rotating machine in this type are often constructed as permanent magnet synchronous machines with no control of the field current and high pole numbers.

Reference [6] gives a good account of the characteristics of each type of wind turbine and can be referred to for more information.

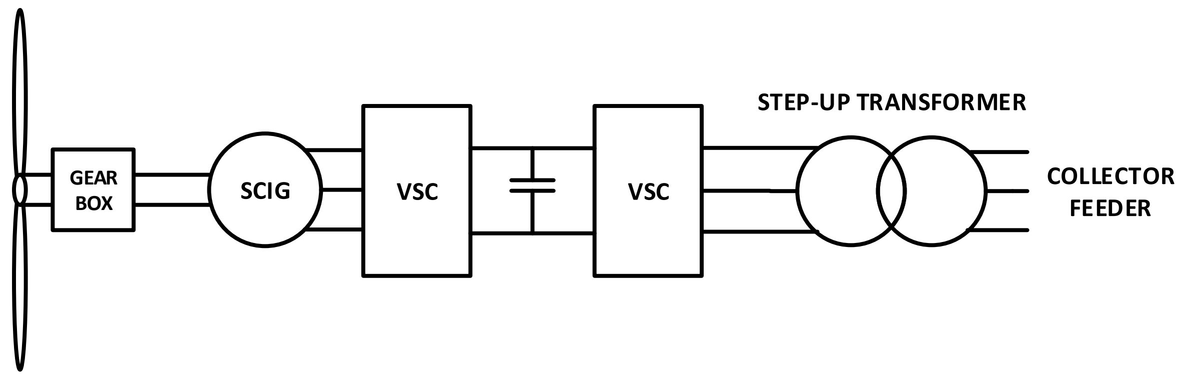


Figure 1.8. – Type 4 Wind Turbine System

1.5. Voltage Control Capabilities

The voltage control capabilities depend on the wind turbine type. Type 1 and 2 WTGs are typically incapable of voltage control. However, they use power factor correction capacitors to maintain either the power factor or the reactive power output on the low voltage terminals of the machine to a set point. Type 3 and 4 WTGs can control voltage. They are capable of varying the reactive power at a given active power and terminal voltage within limits, which allows for voltage control. The voltage control capabilities of each WTG type are basically used to control the voltage at the collector bus or on the high side of the main step up transformer [6].

1.6. Reactive Power Capabilities

Reactive power capabilities of WTGs are an important factor since most grid codes require wind energy plants to have a specific power factor range at the point of interconnect. These generally are 0.95 leading (inductive) to 0.95 lagging (capacitive) [7]. Type 1 and 2 WTGs use power factor correction capacitors (PFCC) to maintain the power factor of the machine to within the specified thresholds. The PFCCs may be sized to maintain a slightly leading power factor or slightly lagging power factor. Type 3 WTGs have reactive power capability equivalent to a power factor of 0.95 lagging to 0.9 leading at the terminals of the machine. The type 4 WTGs can vary the grid side converter current allowing power factor control over a wide range.

1.7. Fault Response of Wind Turbines

The study of the response of wind turbines to fault conditions is essential in understanding the fault withstand capabilities of the machines and in protection element coordination [6]. The responses to short circuit faults on the grid depends largely on the type of WTG involved. The response of type 1 and type 2 are similar to those of large induction machines used in industrial applications, whereas, type 3 and type 4 depend mostly on the WTG controls [6].

For short circuit calculations, the type 1 WTG can be represented as a voltage source behind a direct axis sub-transient inductance.

The type 2 WTG are fundamentally induction generators employing limited speed control via external rotor resistance. If during the fault, the external resistance control were to result in the short circuiting of the generator rotor, the fault behavior would be similar to a type 1 WTG.

For type 3 WTGs, if the rotor power controller remains active during the fault, the machine stator currents would be limited to within 1.1 to 2.5 per unit of the machine rated current. The type 3 fault response characteristics will be discussed in detail later in this thesis. In type 4 WTGs where the turbine employs full rated power converters as an interface to the grid, currents during network faults will be limited to slightly above rated current. The limitation is affected by the power converter control and is generally necessary to protect the power semiconductor switches.

1.8. Need for Protection of Wind Energy Systems

Initial advent of power generation through wind turbines mostly involved the use of conventional type 1 and type 2 wind energy systems. As discussed in Sections 1.5 and 1.6, these WTGs lack voltage control capabilities and tend to absorb reactive power during system unbalance conditions. PFCCs are used to control the power factor. However, these are not dynamic and during faults in the power system, the effective voltage sags increase, resulting in longer fault recovery times. For this reason, earlier grid interconnection requirements needed the WTGs to be disconnected from the grid during system faults.

Type 3 and type 4 wind energy systems brought better fault control with technologies such as the use of DFIGs and PMSGs with frequency based voltage converters which provide improved low voltage ride through capabilities. With an increasing amount of wind farms switching to type 3 and 4 WTGs, grid code amendments have resulted in wind farms required to stay connected to the grid during faults. It is necessary that these WTGs have low voltage ride through capabilities if allowed to stay connected to the grid, to help maintain voltage during faults. Hence it has become even more important to understand the dynamics of WTGs during fault occurrence.

The wind turbine generators and the complex power electronics can tolerate fault currents to a certain extent, but will essentially have to be disconnected for faults of longer duration or high levels [21]. Hence, it becomes important to model the protection scheme for such grid interconnected wind energy systems based on the above factors. It is also necessary to consider the operating conditions, such as, the instantaneous generating capacity of the WTGs, since it has an effect on the protection scheme fault thresholds. This thesis will explore these factors while setting an effective protection scheme for the type 3 wind energy system.

1.9. Scope of the Thesis

The scope of the thesis is as follows,

1. Modify the existing Type 3 wind turbine system and it controllers to a multiple DFIG system to better simulate real-world conditions.
2. Validate the performance of the final Type 3 model complete with grid interconnection components.
3. Design protection scheme for the main transmission line, main transformer, collector feeder and the collector bus.

4. Study the performance of protection elements involved and suggest methods to ensure proper response as well as proper coordination between the relays.
5. Propose recommendations based on challenges encountered by the above protection elements.

1.10. Summary

This chapter has provided a brief insight into the current energy scenario and how wind energy would be able to meet the energy deficit in the near future. The principles of wind energy generation and the various types of wind energy systems were described. The scope of this thesis was set based on the significance of having an effective protection scheme for type 3 wind energy systems.

Chapter 2: Modeling and Protection for Type 3 Wind Energy System

This chapter will describe the modelling of a grid interconnected type 3 wind energy system. The protection schemes used to protect various zones in the power system will also be discussed in detail.

2.1. Type 3 Wind Energy Systems

Type 3 wind turbines are Doubly Fed Induction Machines (DFIGs) which operate on the same principles as conventional wound rotor induction generator, but with additional external power electronic circuits on the rotor and stator to optimize the generator operation. These additions to the conventional induction generator help extract and regulate the maximum mechanical power from the available wind energy resource, better than what is possible using squirrel cage induction generators or wound rotor machines with switched resistors. A simple schematic of a type 3 wind turbine system is as shown in Figure 2.1.

The DFIG type 3 WTGs have a wound rotor induction machine. The rotor circuit is connected through slip-rings and brushes. The three phase stator winding is connected directly to a three phase supply voltage at desired power system frequency (50/60 Hz). Back to back AC – DC – AC voltage sourced converters are used to rectify the supply voltage and convert it to three phase AC, for the rotor excitation. Thus in the DFIG the stator and the rotor windings are independently excited. Only part of the real power flows through the rotor circuit and so, the power rating of the converter need only be 20-30% of the rated generator stator output. A control system is setup to regulate the real and reactive power, to extract the maximum possible power from the wind and to regulate the reactive power output of the generator. The controllers used in this study

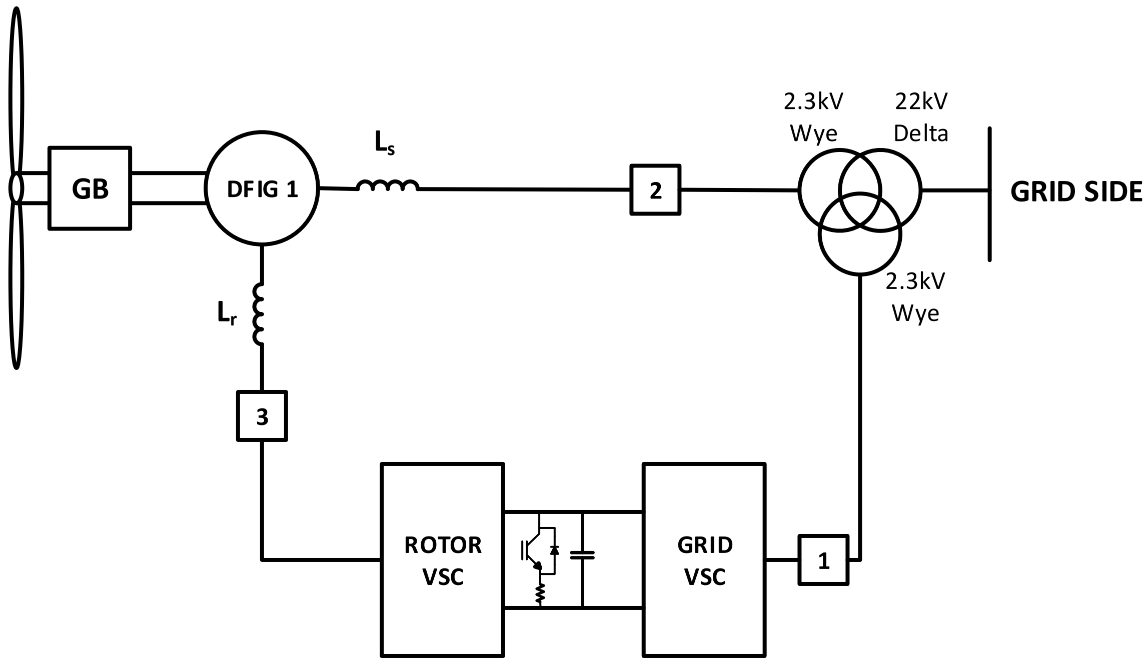


Figure 2.1 – One Line Schematic of Type 3 Wind Turbine System

are current regulated. There are two sides to the controller system, the grid side controller and the rotor side controller. The grid side controller regulates the power that flows in or out of the rotor circuit. The rotor side controller tracks the maximum power point relative to the wind speed and regulates the rotor excitation to get the desired power output from the DFIG.

2.2. Significance of Type 3 Wind Energy Systems

DFIG's are generally more complex and expensive compared to type 1 and 2 WTGs, however, they are, along with type 4 WTGs, the most preferred types of wind turbine today. The advantages of type 3 over type 1 and 2 are as follows [4].

- Dedicated active and reactive power control

- The generator can operate up to 30% above and below the rated wind speed with minimal slip losses involved
- Improved low voltage ride-through performance
- Maximum wind power extraction compared to Type 1 and Type 2 WTGs
- Reduced mechanical stress due to improved rotor control

DFIGs have certain advantages over type 4 systems as well. The type 4 WTGs have their power converters on the stator winding, which implies that the converter has to be rated at the full generator capacity, thus increasing its cost when compared to DFIGs. The electrical dynamic performance of the DFIG at fundamental frequency is dominated by the converter on the rotor circuit. The conventional aspects of the generator performance related to internal angle, excitation voltage and synchronism are not as relevant in the case of DFIG, due to it being an induction machine. The electrical behaviour of the generator and converter in the DFIG is more like that of a current regulated voltage source inverter, which makes modelling comparable to the type 4 WTG.

2.3. Modeling of Type 3 Wind Energy System

The type 3 WTG used in this thesis consists of a DFIG with back to back voltage sourced converters (VSCs). The DFIG consists of a three phase stator winding which is connected to the grid power supply and the rotor excited using the VSC. The rotor which is coupled to the turbine shaft rotates within a magnetic field, inducing currents in the stator coils. The stator is connected to the primary windings of the three winding transformer, which steps up the voltage and delivers it to the collector feeders of the wind farm. This system is modeled using a Real Time Digital Simulator (RTDS) which uses hardware-in-the-loop technique to simulate the system equivalent to real world conditions. Figure 2.1 is a simplified one line diagram of the single DFIG based type 3 WTG implemented using RTDS.

This thesis builds on a previous work performed in modeling a single DFIG type 3 wind energy system using the RTDS, which is described in [19] and [20]

2.3.1. Type 3 Controller

The power electronic circuits of the VSC are modeled as averaged converter model in this work. An averaged converter model is different from a switching model; it replaces the switches and associated components such as IGBTs and diodes with equivalent current and voltage sources, which makes for a more constant voltage output.

The type 3 WTG converter consists of a rotor side VSC and a grid side VSC separated by a common DC voltage link. The grid side controller regulates the magnitude and direction of power flow between the VSC and the grid. This depends on the wind speed. At times of low wind speeds, there will be more power flowing from the grid to the rotor. The rotor side controller is used to regulate the amount of flux to the rotor field windings. During subsynchronous speeds, the rotor controller imports power from the grid to provide more excitation to the rotor, and during super synchronous speeds, it exports power from the rotor to the grid, through the DC link. The DC link is essential to the VSC scheme, ensuring power flow between the grid and the rotor controllers.

References [19] and [20] give a detailed explanation of the principles involved in the modeling of type 3 WTGs and the actual implementation on the RTDS. This thesis work builds on the single DFIG WTG modeled in [19], to formulate a grid interconnected multiple DFIG wind farm model, on which protection studies can be carried out.

2.4. Modeling of Multiple DFIG Type 3 Wind Energy System

The multiple DFIG WTG system used in this thesis was derived from the single DFIG model in [19]. The single DFIG model parameters were multiplied by a factor of 10, to generate a 10 machine equivalent DFIG. A similar 10 machine model was designed and the equivalent multiple machine models were connected to the collector bus through local step up transformers. The equivalent model with its parameters is explained in detail in Chapter 3. Figure 2.2 is a simplified one line diagram of the multiple DFIG model used in this study.

The significance of having a multiple DFIG model is to simulate a real world condition involving wind turbines which are geographically displaced from each other. Depending on the wind flow at various regions of the wind farm, there could be certain WTGs operating at subsynchronous speeds and others operating at super synchronous speeds. In this research, a multiple DFIG model helps simulate such a condition, by varying the output capacities of the DFIGs as desired to see the impact it has on the protection scheme.

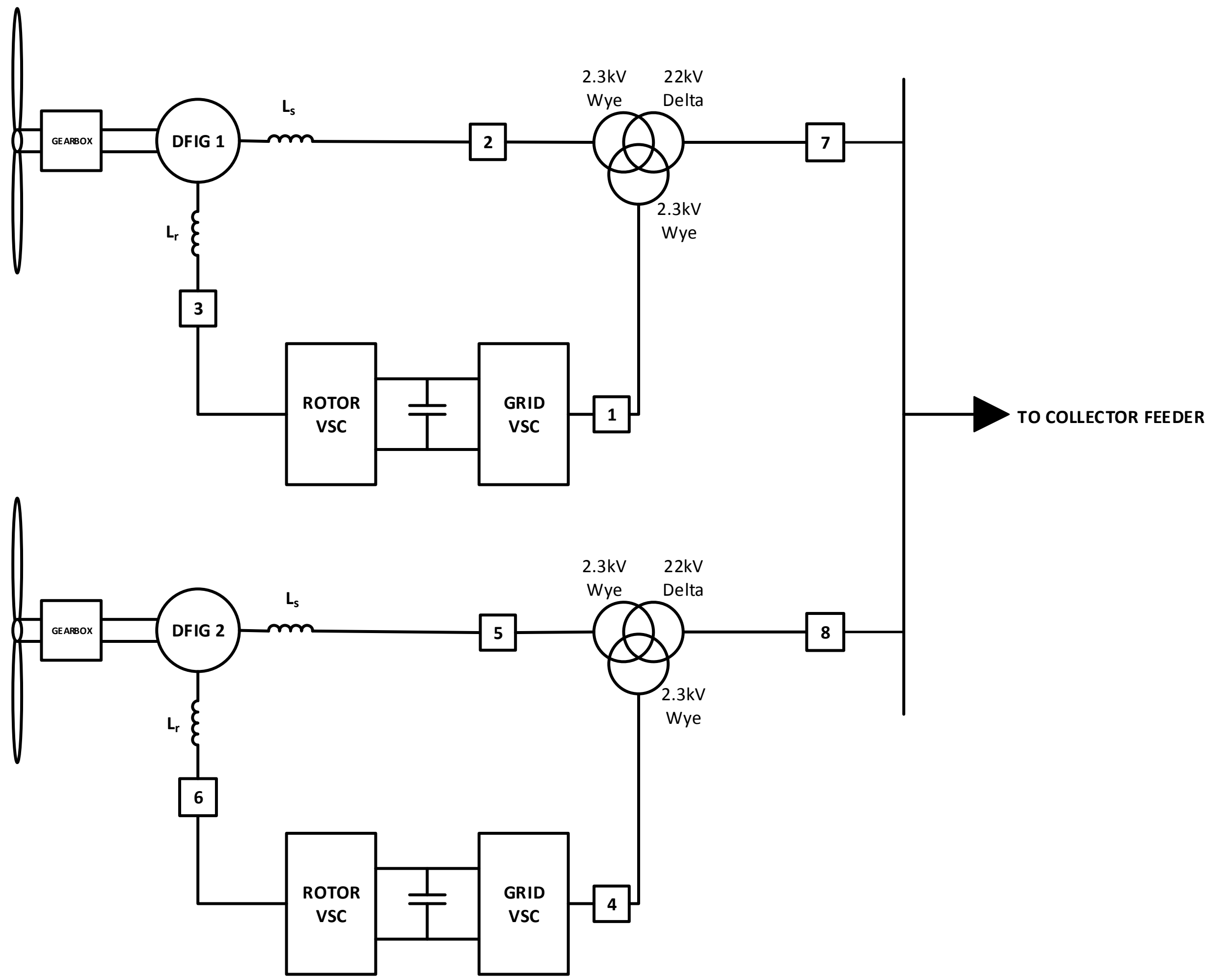


Figure 2.2 – One Line Schematic of Multiple DFIG Type 3 Wind Turbine System

2.5. Protection Scheme – Basics

Protective relays operate in response to system unbalances or fault conditions and are applied to all parts of a power system. Each power system is divided into protection zones defined by the equipment and the available circuit breakers. There are 6 common zones of protection [8]

1) Generator Units

2) Transformers

3) Buses

4) Transmission and distribution lines

5) Equipment loads (motors, static loads or dynamic load)

6) Capacitor or Reactor banks

The common protection zones are as shown in the Figure 2.3.

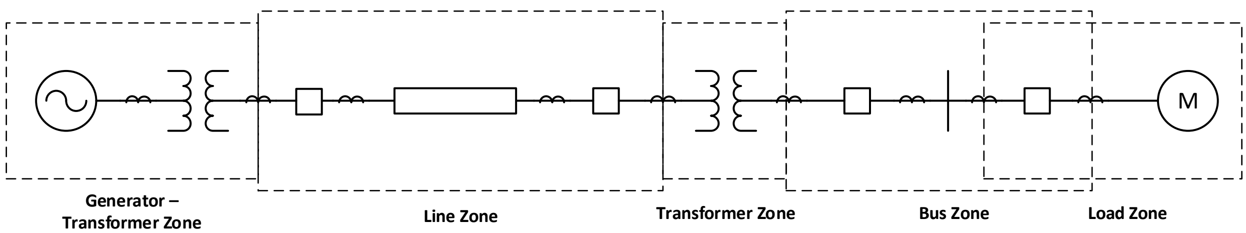


Figure 2.3. – Protection zones illustrated in a simple radial system

Different types of protection elements are used to protect these zones as will be described below.

2.6. Overcurrent Protection (50 and 51)

2.6.1. Instantaneous Overcurrent Protection (50)

Instantaneous or definite time overcurrent protection, as the name implies, is used to protect the system instantaneously when a fault occurs. These elements detect a fault when the measured current exceeds a predefined set threshold, called the pickup value. The pickup values are set for the elements, 50P, 50Q and 50G which will be explained below. Each element has Levels 1, 2 and so on, corresponding to the primary and backup time delayed zones of protection [9].

The 50P element is the phase instantaneous overcurrent element which asserts the trip logic if the phase current exceeds a set pickup. The 50P is set to a pickup based on the fault current measured for a three phase fault, preferably at weak source conditions. A definite time delay can be added to the 50P element which makes it a 67P element.

The ground instantaneous overcurrent element, 50G, asserts when the ground current exceeds the pickup value. The pickup value is set based on the minimum ground fault current on the power system being protected. A 50G element with a definite time delay becomes a 67G element. The 50Q element or the negative sequence instantaneous overcurrent element is similar to the above elements and is set based on phase-to-phase fault current levels, with a 67Q to indicate a definite time delay added to it.

2.6.2. Time Overcurrent Protection (51)

A time overcurrent relay bases its trip decision on an inverse time characteristic for coordination with downstream devices and fuses for its protective function zones [8]. The scheme results in fast operation at high currents and slow operation at light currents. Modern microcontroller based relays essentially replicate these characteristics of electromechanical relays with lower burden and at wider application ranges with adjustable time characteristics.

The tripping characteristics of 51 elements are varied to coordinate with the characteristics of other protection devices connected to the network. Subsequently, there are a number of standard characteristic curves defined which are as follows,

1) Standard Inverse (SI)

2) Very Inverse (VI)

3) Extremely Inverse (EI)

4) Definite Time (DT) (as described earlier)

The standard time overcurrent relay characteristics are described in Tables 2.1 and 2.2. [10].

Relay Characteristics	Equation
Standard Inverse (SI)	$t = TMS\left(\frac{0.14}{Ir^{0.02} - 1}\right)$
Very Inverse (VI)	$t = TMS\left(\frac{13.5}{Ir - 1}\right)$
Extremely Inverse (EI)	$t = TMS\left(\frac{80}{Ir^{2} - 1}\right)$
Long time standby earth fault	$t = TMS\left(\frac{120}{Ir - 1}\right)$

Table 2.1 – Definitions of Standard Relay Characteristics

Where,

I = Measured Current

Is = Relay setting current

TMS = Time Multiplier Setting

TD = Time Dial setting

Ir = I / Is

Relay Characteristics	Equation
IEEE Moderately Inverse	$t = \frac{TD}{7}\left[\left(\frac{0.0515}{Ir^{0.02} - 1}\right) + 0.114\right]$
IEEE Very Inverse	$t = \frac{TD}{7}\left[\left(\frac{19.61}{Ir^{2} - 1}\right) + 0.491\right]$
IEEE Extremely Inverse	$t = \frac{TD}{7}\left[\left(\frac{28.2}{Ir^{2} - 1}\right) + 0.1217\right]$
US CO8 Inverse	$t = \frac{TD}{7}\left[\left(\frac{5.95}{Ir^{2} - 1}\right) + 0.18\right]$
US CO2 Short Time Inverse	$t = \frac{TD}{7}\left[\left(\frac{0.02394}{Ir^{0.02} - 1}\right) + 0.01694\right]$

Table 2.2– North American inverse definite minimum time (IDMT) definitions of standard relay characteristics

2.6.3. Implementation of an Overcurrent Protection Scheme

Each relay has its own zone of protection settings, starting with its primary zone and one or more backup zones. An example of a basic one line diagram of radial system protection is shown in Figure 2.4. Referring to this system, the primary zone or Zone 1 of a relay trips the fastest for a close-in fault and the other zones act as a backup to the primary zone of other relays connected down the line. These zones have a defined reach which is the percentage of the line which it protects.

Relay 1 has its primary zone defined between bus 1 and bus 2, with a reach of 50% - 80% of the line. Irrespective of the type of protection scheme used, the primary zone should protect this region. The backup zone or zone 2 should generally have a current pickup lower that Zone 1 and have a reach of 120% or higher. However the zone 2 element has a time delay associated with it which is greater than the zone 1 time of relay 2. This implies that if relay 2 trips for a fault in front of it, the fault current seen by zone 2 of relay 1 drops drastically, preventing it from asserting the trip command to the local breaker. If the relay 2 does not operate, then the relay 1 zone 2 trips the local breaker after the set time delay.

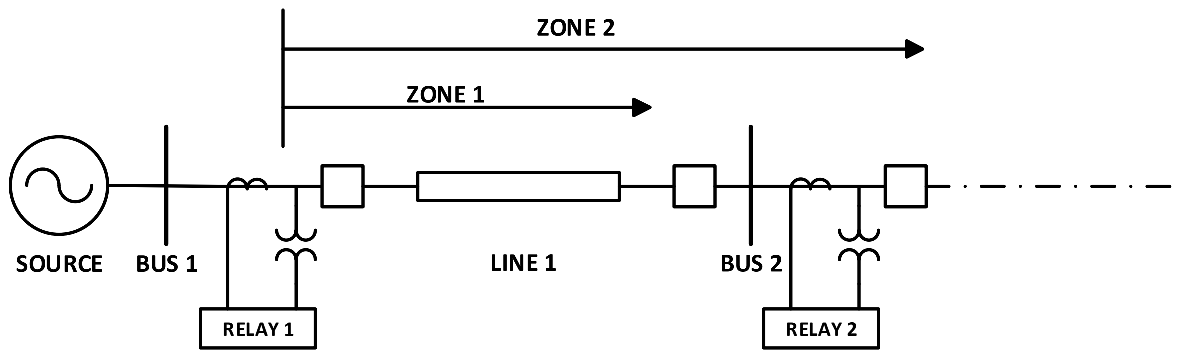


Figure 2.4. – Basic radial system protection

2.7. Differential Protection (87)

Differential Protection is considered the best and most efficient protection technique [8]. The fundamental principle behind differential protection is Kirchhoff's Current Law. The sum of currents flowing into the protected zone is equal to the sum of currents flowing out, during normal operation. The basic differential scheme is illustrated in the Figures 2.5 and 2.6 below.

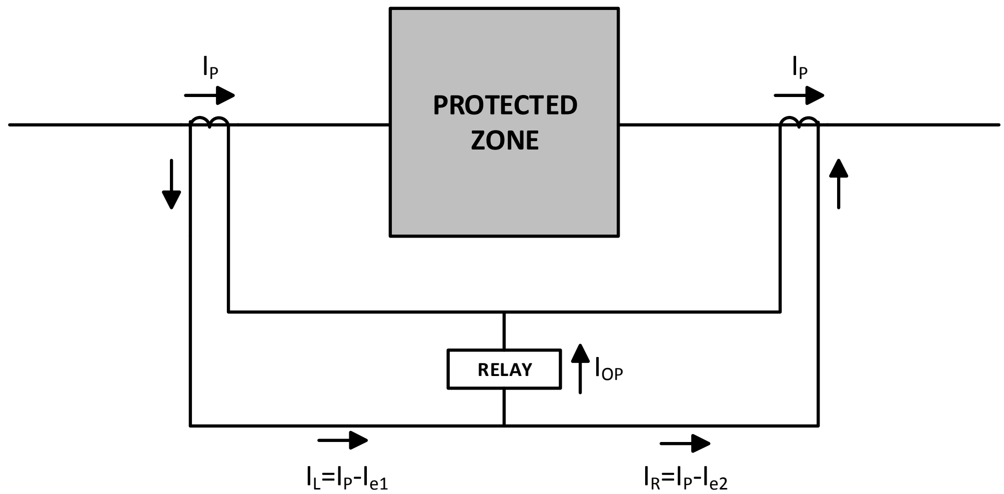


Figure 2.5 – Normal condition

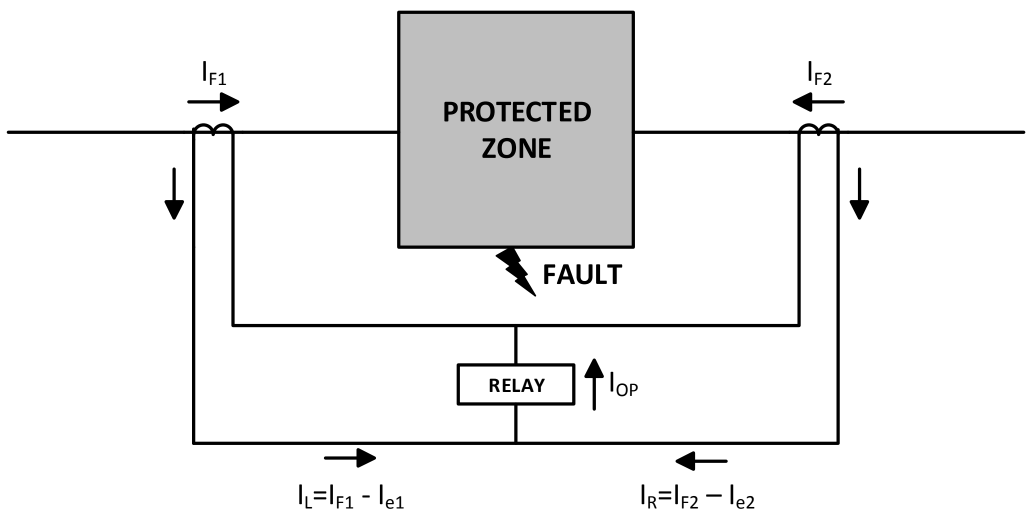


Figure 2.6 – Internal fault condition

From the figures,

I_P – Primary current

I_{OP} – Operating current

I_{e1} – Secondary exciting current of CT 1

I_{e2} – Secondary exciting current of CT 2

Under normal operating conditions (Figure 2.3),

$$I_{OP} = I_{e1} + I_{e2} \tag{2.1}$$

When internal faults occurs in the protected zone,

$$I_{OP} = I_{F1} + I_{F2} - (I_{e1} + I_{e2}) \tag{2.2}$$

To use this information more effectively for protection with microprocessor relays, it is common to define restraining current and relate it to operating current as in (2.3) and (2.4) [11].

$$I_{OP} = |I_L + I_R| \tag{2.3}$$

$$I_{RT} = |I_L| + |I_R| \tag{2.4}$$

Where (referring to Figure 2.6),

I_L – Current flowing on the left side of the protected zone

I_R - Current flowing on the right side of the protected zone

A differential element would operate if

$$I_{OP} \geq k.I_{RT} + k_0 \tag{2.5}$$

Where,

k – Coefficient of the slope of relay characteristic

K_0 – Minimum pickup current

A differential relay operating characteristic based on (2.5) is shown in Figure 2.7.

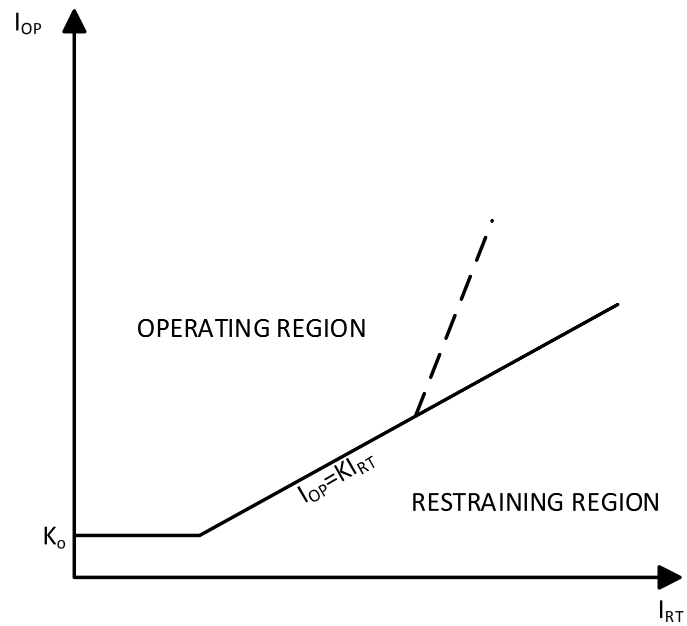


Figure 2.7. – Differential element characteristics

Care should be taken to consider the CT errors while defining the slope of the differential element.

Reference [12] gives a more in-depth description of differential protection and its applications.

2.8. Distance Protection (21)

The main principle of distance protection is based on the division of the voltage at the relaying point by the measured current. The impedance thus calculated is compared with the impedance reach setting of the relay. If the measured impedance is found to be smaller than the reach, it can be assumed that a fault has occurred somewhere in the protected zone. [10]

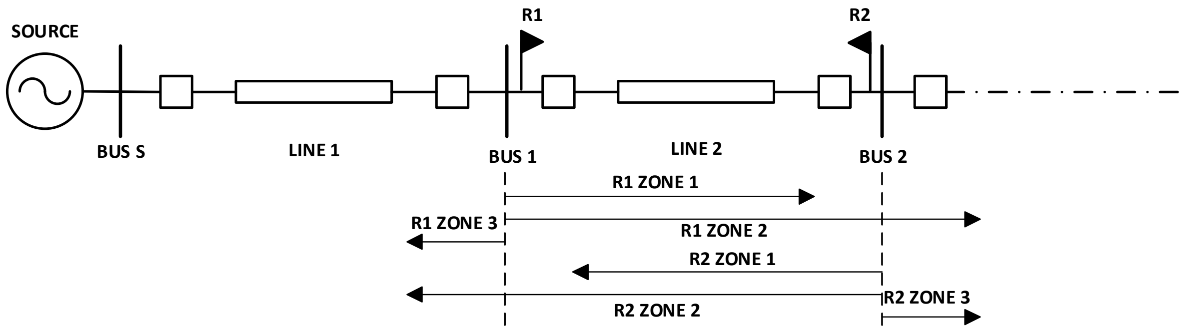


Figure 2.8. – Distance protection with commonly used zones

From Figure 2.8, the impedance as measured at the relay 1 at bus 1 for a 3 phase current is given in (2.6).

$$Z_{R1} = V_{R1} / I_{R1} \tag{2.6}$$

Where,

V_{R1} – Voltage measured by relay 1 at bus 1

I_{R1} – Current measured by relay 1 at bus 1

Under normal operating conditions, Z_{R1} is the effective impedance due to load flow occurring in the line between bus 1 and 2. If a fault occurs somewhere along the line, the voltage reduces and the current increases, thus reducing Z_{R1}. The moment Z_{R1} goes below a set threshold value, the relay asserts a trip signal.

Most modern distance relays operate using either mho distance based elements or quadrilateral distance based elements.

2.8.1. Quadrilateral Distance Relay

The quadrilateral distance elements express their characteristics in an impedance R-X diagram, where resistance R is the abscissa and the reactance X is the ordinate. An example of the R-X diagram is shown in Figure 2.9. When the ratio of system voltage and current falls within the polygon shaped region, the relay operates.

2.8.2. Mho Distance Relay

The basic characteristic diagram of a modified impedance or mho distance relay is shown in Figure 2.10.

The mho circle is functionally similar to the quadrilateral polygon diagram, but is more directional and more sensitive to low impedance fault currents in the presence of load. If the ratio of voltage to current lies within the mho circle, the relay asserts a trip signal. The mho distance relays from SEL use 'm' calculations as shown in (2.7), which calculates the per unit distance of the fault point from the relay as used in this work [12],

$$m = \frac{V_{ph}.V_{pol}^{*}}{Z_L(I_{ph}+k_0.3.I_0).V_{pol}^{*}} \tag{2.7}$$

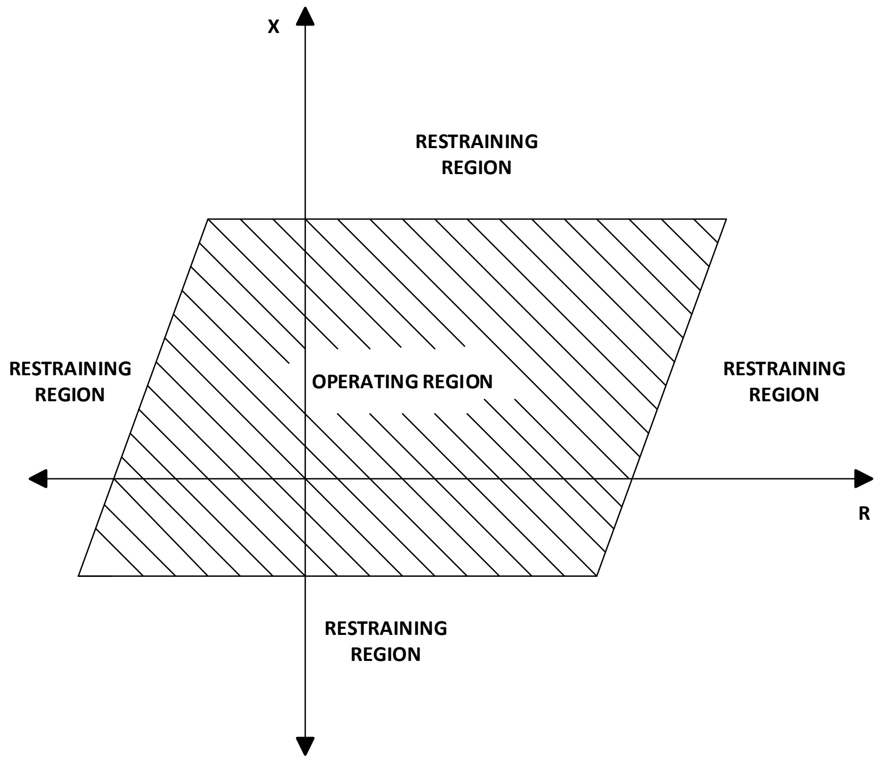


Figure 2.9. – Quadrilateral Distance Elements

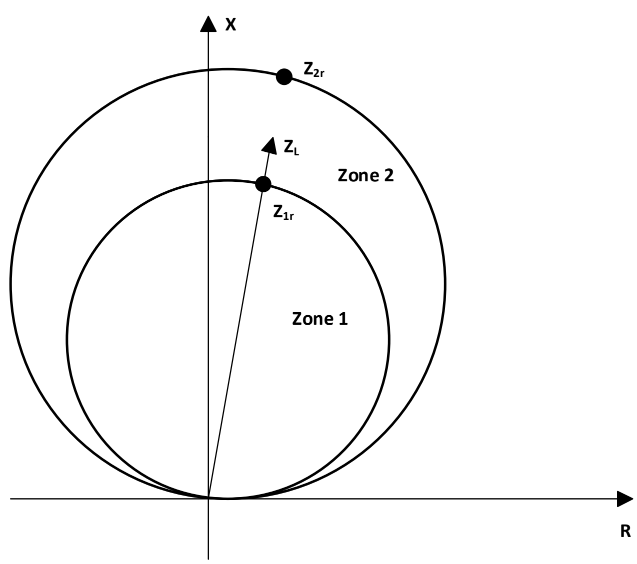


Figure 2.10. – Static Mho Distance Elements

Where,

V_{ph} - Phase voltage

V_{pol}^{*} - Polarizing voltage signal

Z_L – Line impedance

I_{ph} - Phase current

k_0 – Zero sequence compensation

I_0 – Zero sequence current

A detailed description on performing distance relay calculations and applying them to power systems networks is available in [12]

2.9. Directional Supervision (32)

Supervisory elements ensure more secure and reliable efficient protection by evaluating the fault direction, fault type, breaker condition, loss of potential and other conditions in the region being protected. A directional element is one such important supervision element. In power networks where a fault can occur in any location and the fault current can flow in either direction relative to the relay location, it is necessary to supervise the relay response based on whether the fault is in front of the relay or behind the relay to minimize unnecessary loss of load due to tripping. In most cases, it is necessary that the relay sense a forward fault accurately and not respond to a reverse fault. A direction element can supervise this aspect and ensure the required selectivity of protection.

Directional supervision usually works on the concept of tracking the angle between the voltage and current measured by the relay [12]. For a forward fault, the relay should be able to see an effective angle close to the angle of the source impedance. Current usually lags the voltage by close to 90 degrees for such faults. But for a reverse fault, in the angle of the current relative to voltage is opposite that of a forward fault which makes it the primary differentiator to a forward fault. Directional elements are usually based on sequence currents for unbalanced faults for added security.

For three phase positive-sequence fault, a voltage-polarized directional element (32P) can be applied. The 32P element compares the angle of the effective measured positive sequence impedance, Z_1, with two thresholds as shown in (2.8). The relay declares a forward fault when Z1ANG is within the threshold parameters, and declares a reverse fault if it is outside the threshold.

$$(-90^{o} + Z1ANG) < \theta_{Z1} < (90^{o} + Z1ANG) \quad (2.8)$$

Where,

θ_{Z1} – Angle of measured Z_1

Z1ANG – Relay setting, normally equal to the positive sequence impedance line angle

The negative sequence, voltage-polarized directional element (32Q) is an effective directional element for unbalanced faults and can supervise ground elements. The 32Q element calculates Z_2 based on (2.9).

$$Z_2 = \frac{Re[(\overline{V_2}(\overline{I_2}.1\angle Z1ANG)^{*}]}{I_2^2} \quad (2.9)$$

Where,

$\overline{V_2}$ - Negative sequence voltage

$\overline{I_2}$ – Negative sequence current

I_2 – Magnitude of $\overline{I_2}$

$Z1ANG$ - Relay setting, equal to the positive sequence impedance angle of the line

The zero sequence, voltage-polarized directional element (32V) is similar to the 32Q element and calculates Z_0 as per (2.10).

$$Z_0 = \frac{Re[(3\overline{V_0}(3\overline{I_0}.1\angle Z0MTA)^*]}{(3I_0)^2} \tag{2.10}$$

Where,

$\overline{V_0}$ – Zero sequence voltage

$\overline{I_0}$ – Zero sequence current

I_0 – Magnitude of $\overline{I_0}$

$Z0MTA$ - Relay setting, equal to the zero sequence impedance angle of the line

Both 32V and 32Q elements make directional decisions based on two thresholds. If the effective Z_2 or Z_0 is below the forward fault threshold, a forward fault is declared. The same applies to a reverse fault as well, but above the pickup value.

A more detailed description of directional supervision is provided in [12].

2.10. Faulted Phase Identification (FID)

Faulted phase identification logic is essential in identifying the faulted phase or phases for faults involving ground. Different relay manufacturers have different methods of FID, but the main intention is to quickly identify the faulted phase and desensitizing all the other unfaulted elements. FIDS is appropriate for single pole tripping and also helps to avoid false trips under DLG fault with resistance.

The relays used in this study compare the angle difference between negative and zero sequence currents to identify the faulted phases. The FID logic also distinguishes the fault type to certain extent, such as single line to ground from the double line to ground fault. The ratio of the angle of zero sequence current to the negative sequence current angle is used to determine the type of ground fault and the fault phase type.

Reference [12] gives a brief account of Faulted phase identification techniques used in modern relays.

2.11. Wind Farm Protection System

A wind farm protection system implemented is divided into different protection zones including the wind farm generator area, wind farm collector system, and the transmission line system as shown in Figure 2.11. Each protection zone usually has its own set of protective relays which may or may not communicate with each other depending on the degree of protection required. A detailed description of each protection zone is as provided in the following Sections 2.11.1 through 2.11.3.

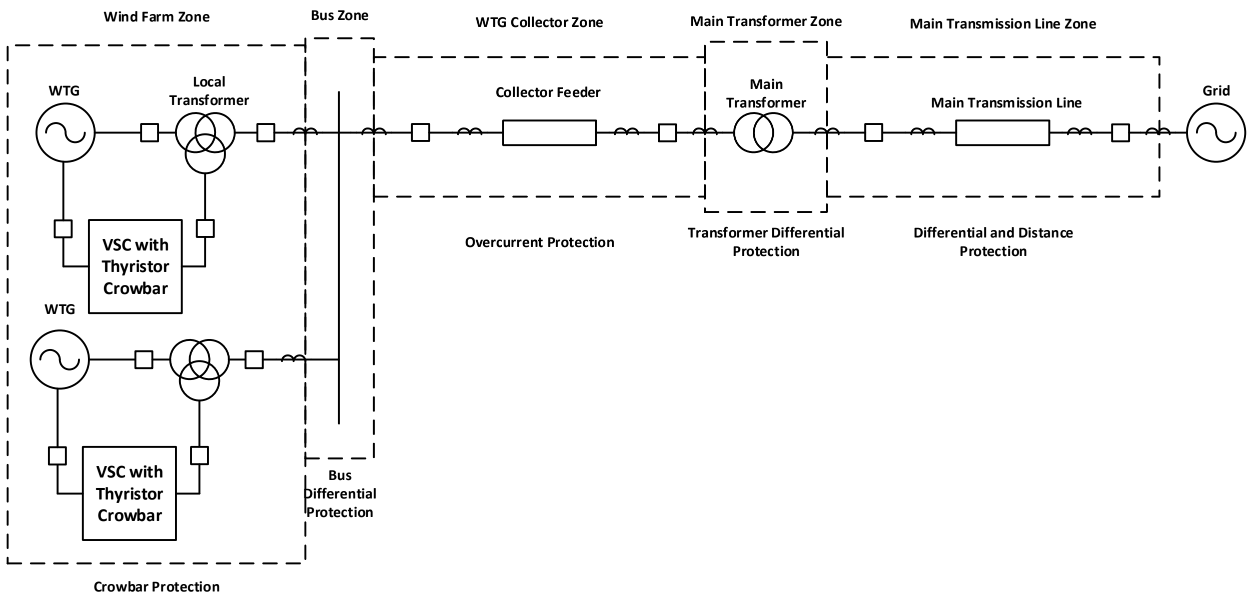


Figure 2.11. – Protection Zones of Wind Turbine Generation System

2.11.1. Wind Farm Generator Protection Zone

2.11.1.1 Rotor Protection System

The rotor protective system mainly is comprised of the crowbar protection circuit which absorbs dissipates energy from the rotor through resistors to limit the rotor voltage from exceeding damaging levels during faults on the ac power systems [5]. When a fault occurs on the ac system, very high currents are induced in the rotor system due to the stator currents. In additional mechanical energy continues to come into the rotor from the turbine blades, but neither the stator winding nor the grid side converter are able to transfer all of that energy out of the machine due to the fault condition. These result in overvoltages on rotor circuit, which in turn affects the dc-link voltage of the VSC circuit. Some crowbar circuits provide an additional path for the fault current away from the rotor system in case of an internal rotor fault.

There are two types of crowbar circuits, ac crowbars between the VSC and the rotor windings and dc chopper crowbars on the dc link of the convert. The ac crowbar consists of a diode bridge that rectifies the rotor phase currents and a single thyrsitor in series with a resistor to activate the circuit. The crowbar can either be triggered based on the measured rotor voltages of the dc link voltage.

The dc chopped based crowbar utilizes an IGBT in series with a resistor connected in parallel with the dc link capactor.. When the dc link voltage exceeds a set threshold the IGBT is gated on. When the voltages are low enough after the overvoltage condition has been cleared, the crowbar system is switched off. The basic schematic of the crowbar system implemented in this study is as shown in Figure 2.12.

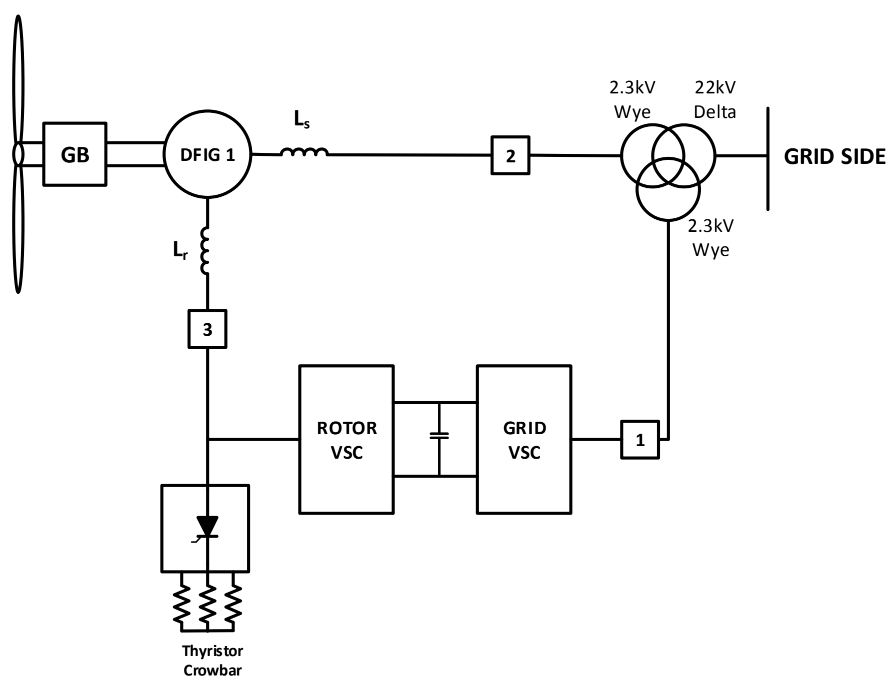


Figure 2.12. – Crowbar Protection for DFIG's

2.11.1.2 Local Step-up Transformer Protection

The local step-up transformers connected to DFIGs are usually Delta-Grounded Wye or Grounded Wye-Grounded Wye, based on the manufacturer/utility specifications. Protection for the transformer is provided using Current Limiting Fuses for low-cost and simplicity. The fuse is connected at the high voltage side of the transformer and acts as the first and most important protection element for various short circuit faults that occur in the system. There are two considerations that need to be made when rating the fuse, one is that the fuse should melt rapidly and reliably when faults occur inside the transformer. Secondly, the fuse should not melt at maximum load currents for the WTG, maximum inrush current of the transformer, or when the WTG feeds faults in the collector line. The transformer damage curve and fuse characteristics are taken into consideration while designing relays upstream.

2.11.2. Wind Farm Collector System Protection Zone

A wind farm collector system is a mostly radial system protected using overcurrent protection elements, either instantaneous overcurrent (50) or inverse time overcurrent (51). These elements are set to detect faults at the region between the collector breaker and the wind turbine local step up transformer. Another factor to be considered is the selectivity and sensitivity of the protection scheme. Taking these into consideration, there are three commonly used methods available for the wind farm collector system protection [13].

The first method involves setting the minimum pick-up at 120% of the maximum three phase fault current at the end of the line. This method ensures selectivity of the protection scheme in the collector line area. But it does not reach to the end of the line, and so the protective range would be short. It is preferable to have a definite time delayed instantaneous overcurrent relay as the primary protection element.

The second method uses the minimum end of the line double line fault current level as the threshold for the pick-up setting. With this method the relay can reach up to the end of the main step up transformer at the end of the collector line. Care should be taken to ensure coordination with the upstream relays so that only the necessary section of the power system may be isolated during fault occurrence [38].

The third method involves setting the minimum pick up value to 120% of the maximum three phase fault current on the low-voltage side of the wind turbine transformer. This has a similar reach to the second method with coordination to be considered if enabled.

For this study, the required protection can be ensured by implementing both the second and third methods. However, the second method has a comparatively limited reach, and so, for faults on the step up transformer, this method is less likely to operate. Thus, taking into account, the sensitivity and selectivity of the instantaneous overcurrent protection, the third method is implemented in this study.

An inverse-time overcurrent protection (51) element acts as a backup to the 50 element, protecting the collector line and the step-up transformer. The 51 element should ensure selectivity between the fuse and the element itself, by having an operating time above the fuse's rated melting time when a three phase fault occurs on the high voltage side of the local step up transformer. The 51 element should also ensure considerable sensitivity by protecting for close-in faults at the low voltage side of the main step up transformer. The inverse time curve should be selected based on the required sensitivity and selectivity of the protection scheme and fuse characteristic.

The setting of the overcurrent protection scheme is explained in Chapter 3.

2.11.2.1 Main Transformer Protection

The transformer is the single most expensive piece of equipment in the wind farm. The primary protection for the main transformer is through current differential protection elements. The main criterion is to set the pick-up value greater than the worst case unbalance current due to CT error for maximum external fault current flowing through the transformer.

Additionally, as a backup to the differential protection, a definite time overcurrent protection could be set up on the high voltages side with pick-up values greater than the rated current of the transformer inrush [13].

2.11.3. Main Grid Transmission Line Protection Zone

2.11.3.1 Main Transmission Line Protection

The main transmission line is one of the most important components of the wind farm ensuring efficient power flow outwards into the grid. The protection scheme implemented for this study involves a combination of primary protection using line current differential elements and a backup provided using distance and overcurrent elements. The line current differential protection involves two relays at both ends of the transmission lines with communication via optic fiber cables. A differential relay at one end of the transmission line measures the current flowing into the line from its end and also receives measured values from the remote end. Under normal operation, the difference between the two currents is the capacitive charging current of the line. However, when a fault occurs somewhere between the line, there is a considerable difference in the currents between the ends of the line, which, causes the relay to assert a trip signal when it exceeds the settings threshold.

The mho distance elements are set based on the total line impedance, with a reach for each zone as follows.

Zone 1 – 80% of the line impedance

Zone 2 – 120% of the line impedance

Zone 3 – Reverse, 20% looking towards behind the relay

When a fault occurs, the relays calculate the effective impedance trajectory from measured voltage and current. If the trajectory falls within the reach setting, a trip signal or time delay is asserted based on the zone at which the fault is present at.

The overcurrent elements are set based on the principle explained previously in Section 2.2. These elements form an additional backup to the differential and distance elements.

A detailed explanation calculations of the settings for the main transmission line protective elements is given in Chapter 4.

2.12. Summary

This chapter has explored the various protection schemes pertinent to this thesis. Implementation of these protection schemes depends on the zone of protection within the wind energy system. The principles used in this chapter was used to define the protection of the type 3 wind energy system as explained in Chapters 3 and 4.

Chapter 3: The Test System

Studies were performed on a Real Time Digital Simulator (RTDS) with SEL protective relays. The test system was set up on the RTDS and protection performance under various system and fault contingencies was carried out and observed. The components of the test setup are as follows.

3.1. The Real Time Digital Simulator (RTDS)

The RTDS is a power system simulator that generates power transient simulation results in real time for hardware-in-the-loop analysis of real-world conditions. It has a set of processor cards, analog and digital I/O cards, network and synchronization cards for this purpose. RSCAD is the user interface used to build models and to communicate with the RTDS. The power system is modelled and compiled as a “Draft” file. The “Runtime” module runs the system based on the conditions specified by the user.

The processor cards are used to solve algorithms based on the power and control system components modelled in the RSCAD. The network cards are used to interface the RTDS to the external network through a LAN connection with appropriate network protocols. The analog I/O cards interface analog signals to and from external devices (protective relay in this case) and the RTDS. The same applies to the digital I/O card. The synchronization card ensures synchronization between the RTDS time-step and the external precision time source. All of these components constitute one rack of an RTDS system. There can be multiple racks within the system to run multiple instances at the same time. Reference [14] gives a detailed account of all the RTDS functions.

3.2. The Test System

The test power system for an aggregated Type 3 Wind Turbine System is as shown in Figure 3.1.

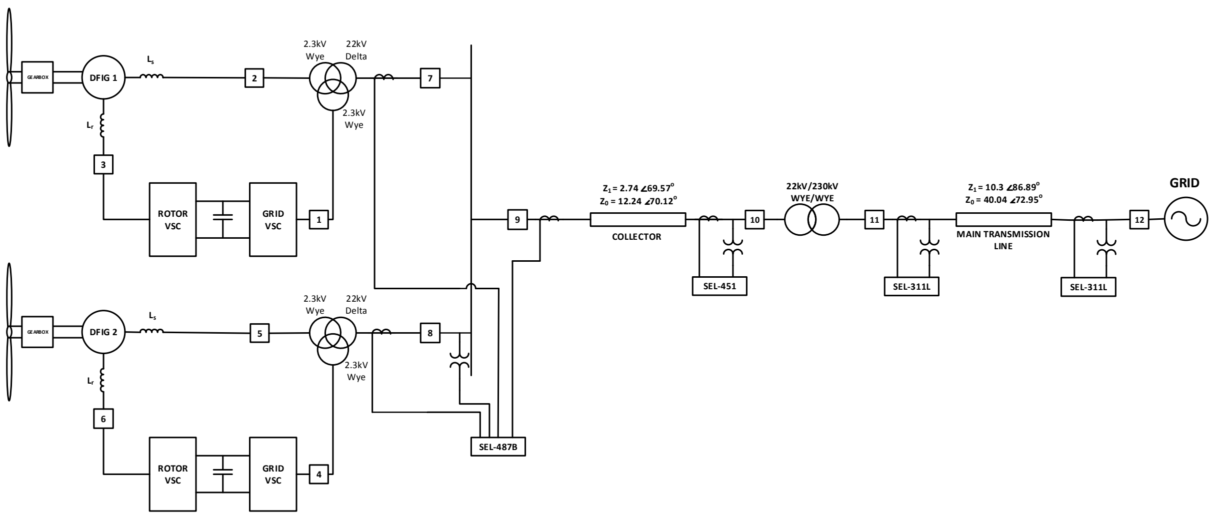


Figure 3.1. – Type 3 Aggregated Wind Turbine Power System

This system was modelled on the RSCAD and tested for various faults on the transmission line, the collector line and the collector bus. For this purpose, there are protection relays at the above locations indicated in the figure.

3.2.1. Aggregated Type 3 Multiple DFIG Model

The basic single DFIG Type 3 WTG model using an averaged VSC. An averaged model was implemented since it has an inherent quality of eliminating the switching transients and harmonics generated during operation while at the same time not eliminating the dynamics which do not affect the relay performance [15]. It also reduces RTDS resource usage, allowing for a more extensive power system to be modelled.

The single DFIG model was aggregated into a 10 machine model rated at 16.78MW and in turn combined in parallel with another similar aggregated model to reflect actual windfarms with multiple wind turbines which are geographically displaced from each other.

The parameters of the aggregated DFIG model is as described in the Table 3.1 below.

Quantity	Value
Rated Voltage (L-L RMS)	2.3kV
MVA Rating	16.78MVA
Rated Frequency	60Hz
Rated Current	5960A
Stator Resistance	29mΩ (0.00920pu)
Stator Inductance	34.12mH (0.072pu)
Rotor Resistance	26mΩ (0.00825pu)
Rotor Inductance	34.12mH (0.072pu)

Table 3.1. – Type 3 Aggregated Wind DFIG Parameters

3.2.2. Transformers

There are two types of transformers used in the test system,

- The three winding transformer that forms part of the wind turbine generator. It steps up the 2.3kV L-L voltage output from the aggregated DFIGs to the 22kV collector bus rated voltage. The parameters are as given in Table 3.2.

Quantity	Value
MVA Rating	100MVA
Base Operation Frequency	60Hz
Winding 1 Configuration	Delta
Winding 2 Configuration	Wye
Winding 3 Configuration	Wye
Winding 1 Voltage Rating	22kV
Winding 2 Voltage Rating	2.3kV
Winding 3 Voltage Rating	2.3kV
Leakage Current	1%
No Load Losses	0.0001pu

Table 3.2. – Three Winding Transformer Parameters

- The two winding transformer that steps up the 22kV Collector voltage to 230kV which is the voltage in the main transmission line to the grid. The parameters are listed in Table 3.3.

3.2.3. Transmission Lines

There are two main classes of lines in this model.

3.2.3.1. The Collector Line – 22kV

The collector line transmits the power generated from the wind turbine units to the main collector substation; where the voltage is stepped up to the grid rated voltage for transmission.

Quantity	Value
MVA Rating	100MVA
Base Operation Frequency	60Hz
Winding 1 Configuration	Delta
Winding 2 Configuration	Wye
Winding 1 Voltage Rating	22kV
Winding 2 Voltage Rating	230kV
Leakage Current	1%
No Load Losses	0.001pu

Table 3.3. – Two Winding Transformer Parameters

In this case, the collector line is rated at 22kV and 10 kilometers long. A detailed line description with the tower configuration is given in Table 3.4.

3.2.3.2. The Main Transmission Line – 230kV

As the name suggests, the main transmission line does the bulk power transmission from the substation at the wind farm to the main grid. In this model, the transmission line is rated at 230kV and is 30 km long. A detailed line description and tower configuration is as described in Table 3.5.

Quantity		Value	
Line Data			
Model Type		Bergeron	
Line Length		10km	
Ground Resistivity		100Ω-m	
Rated Frequency		60Hz	
Tower Data			
Number of Conductors		3	
Number of Circuits on Tower		1	
Number of Ground wires on Tower		1	
Conductor Data			
Transposition		Transposed	
Conductor Type		ACSR	
Sub-Conductor Bundle		0.864cm	
DC Resistance per Sub-Conductor		0.19Ω/km	
Shunt Conductance		1.0e-11mho/km	
Number of Sub-Conductors per Bundle		2	
Bundle Configuration		Symmetrical	
Sub-Conductor Spacing		15.72cm	
Conductor Bundle	Bundle 1	Bundle 2	Bundle 3
Horizontal Distance	0m	0.762m	1.372m
Conductor Height at Tower	8.839m	8.839m	8.839m
Sag at Mid-Span		0.8m	
Ground Wire Data			
Ground Wire Radius		0.715cm	
DC Resistance per Wire		0.368Ω/km	
Horizontal Distance		1.219m	
Height at Tower		10.058m	
Sag at Mid-Span		0.8m	

Table 3.4. – 22kV Collector Line Parameters

Quantity	Value		
Line Data			
Model Type	Bergeron		
Line Length	30km		
Ground Resistivity	100Ω-m		
Rated Frequency	60Hz		
Tower Data			
Number of Conductors	3		
Number of Circuits on Tower	1		
Number of Ground wires on Tower	2		
Conductor Data			
Transposition	Transposed		
Sub-Conductor Bundle	2.034cm		
DC Resistance per Sub-Conductor	0.0321Ω/km		
Shunt Conductance	1.0e-11mho/km		
Number of Sub-Conductors per Bundle	2		
Bundle Configuration	Symmetrical		
Sub-Conductor Spacing	45.72cm		
Conductor Bundle	Bundle 1	Bundle 2	Bundle 3
Horizontal Distance	`-6.401m	0m	6.401m
Conductor Height at Tower	17.069m	17.069m	17.069m
Sag at Mid-Span	5.486m		
Ground Wire Data			
Ground Wire Radius	0.715cm		
DC Resistance per Wire	0.368Ω/km		
Ground Wire	Ground Wire 1	Ground Wire 2	
Horizontal Distance	`-4.267m	4.267m	
Height at Tower	21.336m	21.336m	
Sag at Mid-Span	6.096m		

Table 3.5. – 230kV Collector Line Parameters

3.3. Fault Modeling and Simulation Technique

Fault modelling is essential to understand how a power system and the protection system would respond to various fault events. Based on the data obtained from the system response, an effective protective system can thus be designed.

The fault model designed for this test system is as shown in Figure 3.2.

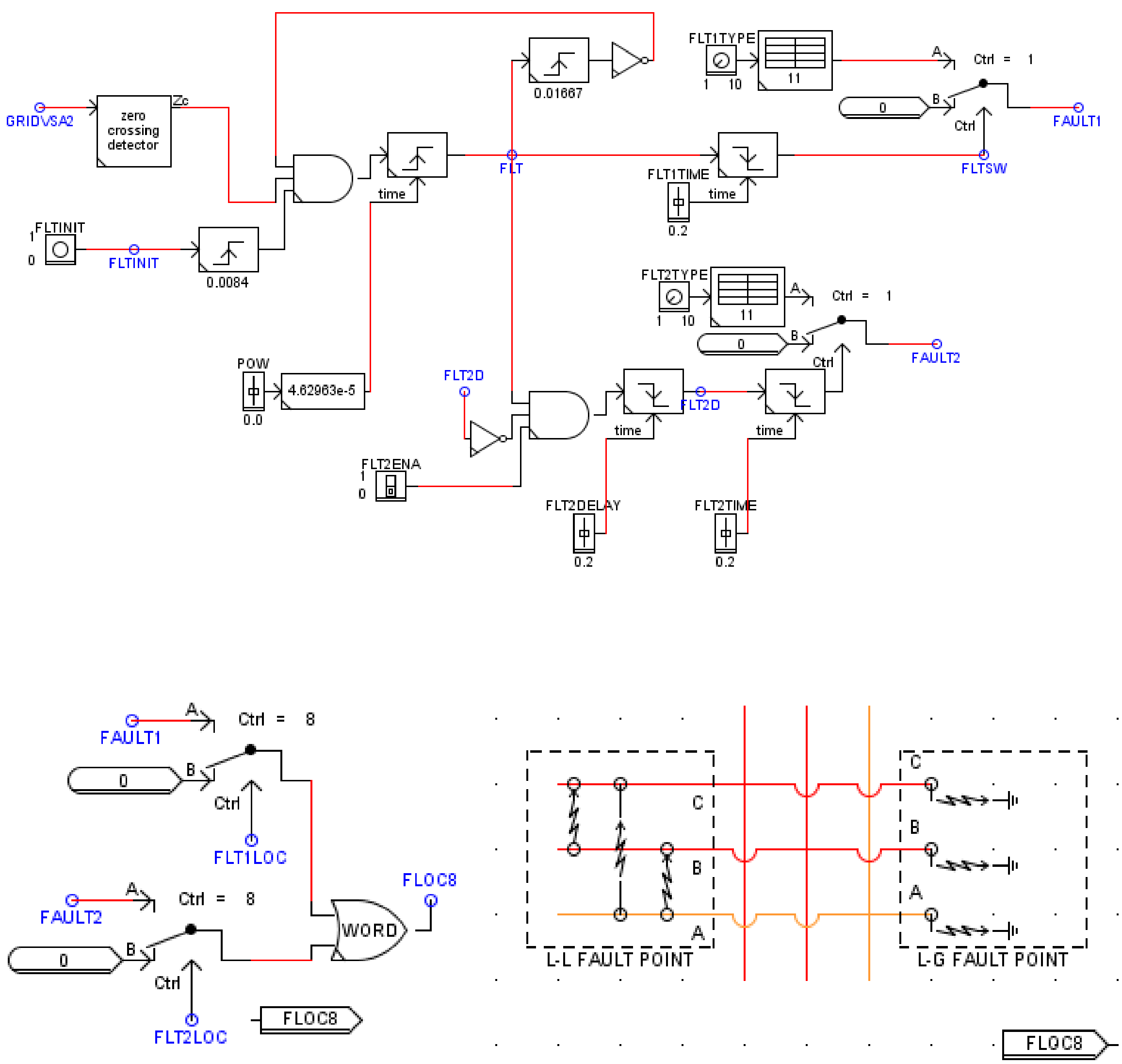


Figure 3.2. – The Test System Fault Model

The fault model designed has certain features added to it such as Point on Wave (POW) selection, duration of fault, fault type, fault location and the fault resistance. The POW of the fault injection is based on a reference voltage input and addition of a certain delay to ensure the fault occurs at the exact point on the voltage waveform. The fault model also has the ability to add a second fault at a certain delay from the initial fault injection, creating an evolving fault. The fault type is selected from a lookup table which has bits assigned to particular fault types such as AG, BG, CG, ABG and so on. Each fault location has its respective fault number assigned to it. Based on the fault number selected, the corresponding fault selector switch asserts, as shown in Figure 3.2, resulting in the fault at that location.

3.4. Instrument Transformers

Instrument transformers form a fundamental part of every power protection circuit. They convert the high voltage or high currents circuits to a lower rated voltage or current on which the metering and protection devices operate. In a way, instrument transformers also act as a protective device, isolating the devices connected to its secondary circuit from the high rated primary circuit.

3.4.1. Current Transformers

A current transformer (CT) an instrument transformer that supplies a stepped down secondary current proportional to the primary current. The secondary can either be 1A or 5A at maximum rated load, based on the device it is connected to. For this work, a 5A CT secondary is used.

Current transformers are generally defined by their ratio, power and accuracy class. The current transformer ratio (CTR) is the ratio of the primary current to the secondary current. The power rating of the CT is usually expressed in Volt Amperes (VA). The accuracy class of the CT is a function of CT load and the over current and is chosen based on the application. Protection CTs need to have a high accuracy factor for large current ranges to precisely represent the fault currents as they get generated. They also need to be able to withstand high current transients in the network. An instrument or metering CT requires a good accuracy only around its nominal rating. They don’t need to be accurate over a wide range with good transient response.

3.4.1.1. Modeling the Current Transformer

A current transformer is modelled to represent impacts of factors such as a the maximum fault current at that location, the system X/R ratio and the CT burden. Also to be considered are the CTR and the accuracy class of the desired CT. CT saturation occurs when the CT is no longer able to reproduce the output current proportional to the primary current. This happens due to the core of the CT going into magnetic saturation, and can be due to high symmetrical fault current due to overvoltage on core or DC offset driving a unidirectional saturation. Before a CT can be used in a power system, it is important that it be sized as per the system load conditions. (3.1) describes the method used to size CTs to never saturate [8].

$$\left(1+\frac{X}{R}\right)\frac{I_{mag}}{I_{rated}N}\frac{|R_B+j\omega L_b|100}{V_{RAT}} \tag{3.1}$$

Where,

X = Inductive reactance of the power system

R = Resistance of the power system

I_{mag} = RMS magnitude of the CT primary current

I_{rated} = Rated secondary current

N = CT turns ratio

R_B = Resistive burden

ω = Angular frequency

L_b = Burden inductance

V_{RAT} = Rated voltage

If the output of (3.1) is less than 20, the CT satisfies the criterion to avoid saturation completely.

For the purposes of this power system, the CTs were modelled as ideal CTs with a low secondary resistance and inductance because CT saturation effects were not central to the objective of this work. The turns ratio were selected so as to provide an effective secondary current required for the protective relays to operate. The CTR selection is based on [16].

<u>230kV Main Transmission Line CTs:</u>

Secondary Side Resistance – 0.5Ω

Secondary Side Reactance – 0.0008H

(The values of secondary side resistance and reactance are derived from the RTDS standard component library for ideal CTs)

Maximum load current - 114A.

Select 250:5 CT

The same CT was chosen for CTs at both end of the main transmission line.

<u>22kV Collector CT</u>

Secondary Side Resistance – 0.5Ω

Secondary Side Reactance – 0.0008H

Maximum load current – 1199A

Select 1500:5 CT

3.4.2. Voltage Transformers

Voltage transformers or potential transformers are used for measuring voltage on transmission and distribution systems. There are two types of voltage transformers used in protective relaying, wound voltage transformer and the capacitive voltage transformers [8]. The wound voltage transformer is a conventional transformer having primary and secondary windings. The primary winding is connected directly to the power circuit between one phase and ground, based on the transformer rating and its application. The capacitive voltage transformer uses a capacitive voltage divider between phase and ground of a power circuit to reduce its voltage transformation ratio. In general, voltage transformers step-down the power system rated voltage to a level that the protective relays can operate on effectively, which is commonly 115V or $\frac{115}{\sqrt{3}}$ V in the US.

3.4.2.1. Modelling the Voltage Transformer

The accuracy of voltage transformers have more to do with the secondary burden and the current it draws, than any other factor. A voltage transformer can be considered good as long as the burden is within the thermal VA rating of the transformer. At an acceptable accuracy, a voltage transformer is suitable over the range from zero to 110% of the rated voltage. Operating above 10% saturation may cause increased errors and excessive heating and damage.

For the purpose of this work, the voltage transformers used in the RTDS model were modelled as ideal VTs since CVT response was not part of the objective of this work. The turns ratio was selected based on the rated measuring voltage of the protective relay. The VT specifications are as follows:

230kV Main Transmission Line VTs:

Primary Side Resistance - 300Ω

Primary Side Inductance – 6H

Primary Side Turns – 132790 Turns

Secondary Side Resistance – 0.034Ω

Secondary Side Inductance – 0.0H

Secondary Side Turns – 66 Turns

Burden Series Resistance – 0.150Ω

Burden Series Inductance – 0.001H

Burden Parallel Resistance - 40Ω

(These VT parameters are derived from the standard RTDS component library for ideal VTs)

22kV Collector PT:

Primary Side Resistance - 300Ω

Primary Side Inductance – 6H

Primary Side Turns – 12702 Turns

Secondary Side Resistance – 0.034Ω

Secondary Side Inductance – 0.0H

Secondary Side Turns – 66 Turns

Burden Series Resistance – 0.150Ω

Burden Series Inductance – 0.001H

Burden Parallel Resistance - 40Ω

3.5. Interface between RTDS and the Protective Relays

In order to analyze a power system to using the full potential of RTDS, it is essential to have it connected to external devices, in this case, protective relays. The RTDS uses a Gigabit Transceiver Analogue Output Card (GTAO) to interface the analog signals generated to the external relays. The GTAO card has twelve, 16 bit analog output channels with an output range of +/-10 volts. These 16 bit channels allow for a dynamic range of measuring quantity which the relay can use to analyze steady-state or fault conditions. The GTAO card outputs are oversampled at 1 microsecond and the channels are updated synchronously. The RTDS GTAO cards are physically connected to the protective relays using specially configured low voltage DB-25 cables.

Fault testing was carried out using the low-level test interface of the SEL protective relay. The output from the GTAO card is in the low level mV range and is directly fed into the low-level test interface of the relay. For this process, the outputs from RTDS need to be first multiplied by a suitable scaling factor entered in RTDS settings for GTAO to bring the signal to acceptable limits for the relay. Each relay has its own scaling factor and so, care was taken that the right value be provided into the GTAO card. The scaling factors for the relays are listed in Table 3.6 and 3.7 [9] [17]. Both SEL relays have 12 input channels, with W and X as the current channel subset, and Y and Z as the voltage channel subset. These are indicated as a prefix to each input channel quantity.

Channel	Quantity	Scale Factor	Unit
1	IAW	250	A
2	IBW	250	A
3	ICW	250	A
4	IAX	250	A
5	IBX	250	A
6	ICX	250	A
7	VAY	255	V
8	VBY	255	V
9	VCY	255	V
10	VAZ	255	V
11	VBZ	255	V
12	VCZ	255	V

Table 3.6. - Scaling factor for SEL-311L Relay used in the Main Transmission Line

Channel	Quantity	Scale Factor	Unit
1	IAW	75	A
2	IBW	75	A
3	ICW	75	A
4	IAX	75	A
5	IBX	75	A
6	ICX	75	A
7	VAY	150	V
8	VBY	150	V
9	VCY	150	V
10	VAZ	150	V
11	VBZ	150	V
12	VCZ	150	V

Table 3.7. - Scaling factor for SEL-451 Relay used in the Main Collector Feeder

3.6. Summary

This chapter has described in sufficient detail, the various components of the test system and their specifications. The comprehensive RTDS model has also been illustrated with a suitable one line diagram. The implementation of the protection scheme and the analysis of results will now be explained in the next chapter.

Chapter 4: Protection Performance, Analysis and Results

This chapter discusses the RTDS simulation of the Type 3 wind turbine and its interaction with the protection system and the analysis of the observed results. The protection scheme was tested using SEL relays and the event files from these relays were used for the analysis.

4.1. Main Transmission Line Protection

The main transmission line protection was implemented based on the protection scheme discussed in Section 2.12.3.2 of Chapter 2.

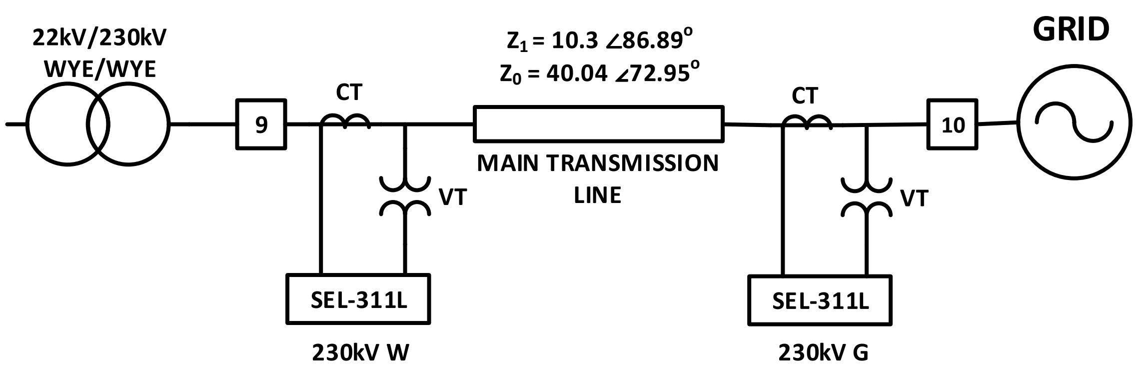


Figure 4.1. - Main Transmission Line Protection One Line Diagram

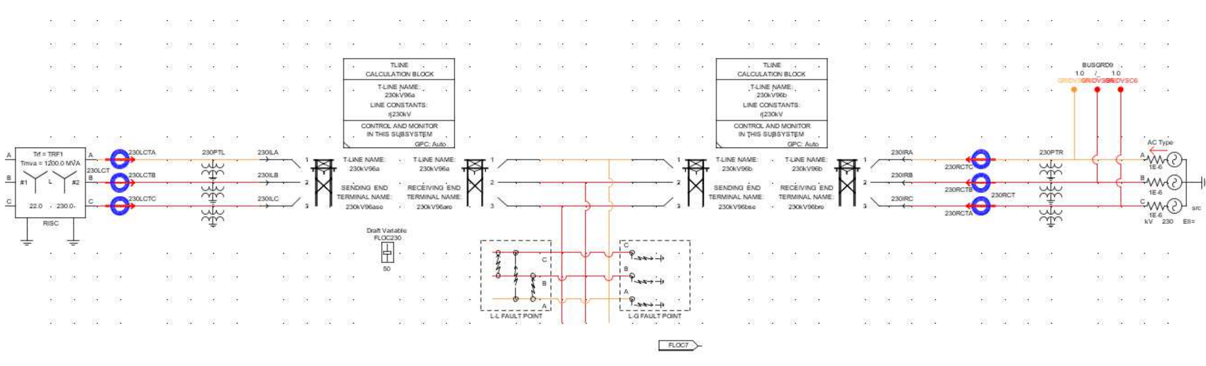


Figure 4.2: 230kV Transmission Line RSCAD Model

Figures 4.1 and 4.2 shows the 230kV Transmission line modelled in the RSCAD with its respective step-up transformer, line sections, fault sections, CTs and VTs. The primary protection implemented is a differential protection scheme. The backup protection is initiated by a combination of distance and overcurrent protection. For this purpose, the CTs and VTs were modelled and placed at both ends of the line. The setting of the relays connected to the instrument transformers will be discussed later in this chapter.

4.1.1. Modeling CTs and VTs

For the purposes of this study, the CTs and VTs were modelled in close to an ideal condition to set up an efficient protection scheme. The CT and VT ratios were calculated as follows.

$$CTR = \frac{250A}{5A} \tag{4.1}$$

$$PTR = \frac{230kV}{115V} \tag{4.2}$$

The secondary currents and voltages as measured from the output of the CT and VT on one side of the transmission line are as shown in Figure 4.3 and Figure 4.4 respectively.

To verify the secondary CT outputs,

Current through the 230kV line = 113.3A

Secondary currents on the CT = 3.74A

$\text{Equivalent current as seen by the relay} = 3.75 * \text{CTR} = 112.5\text{A}$

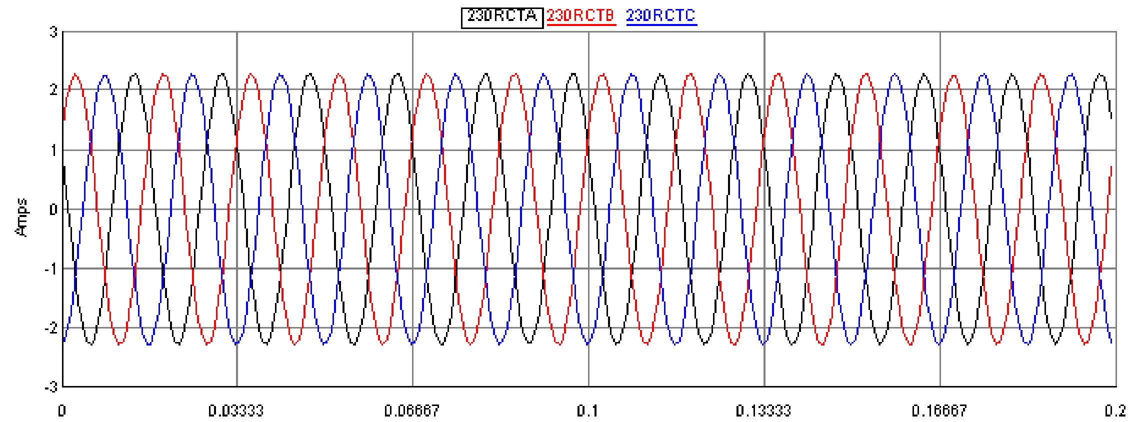


Figure 4.3 - CT Secondary Currents on 230kV Transmission Side

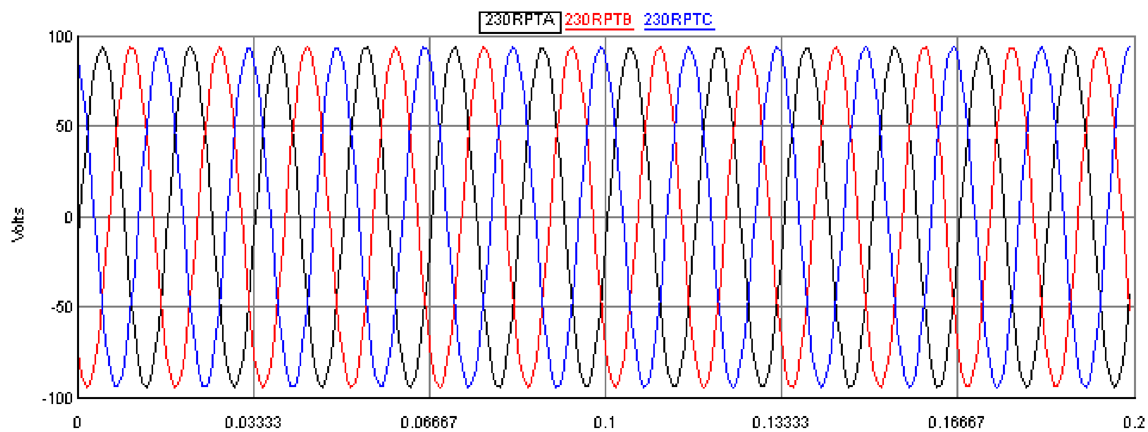


Figure 4.4: VT Secondary Voltage on 230kV Transmission Side

Now, verifying the secondary PT outputs:

Actual voltage on the 230kV line = 186.6kV

Secondary voltage on the VT = 92.85

$$\text{Equivalent voltage seen by the relay} = 92.85 * \text{PTR} = 185.7\text{kV}$$

4.1.2. Differential Protection (87)

The primary protection on the 230kV transmission line is offered by the 87 elements. The differential protection scheme is set up in this study using two SEL-311L relays taking the inputs from the secondary outputs of the CTs and VTs connected to both ends of the line. The settings involved in the SEL-311L relays for differential protection are described in Appendix A. Following are the brief set of differential parameters that were considered while setting the relays. [17]

4.1.2.1. 87LPP

The 87LPP qualifies trip generated by the phase differential elements 87LA, 87LB and 87LC. These phase differential elements restrain when the phase difference current is less than 87LPP. Following are the factors kept in mind when setting the 87LPP element.

- Set 87LPP above maximum expected load current on the line during steady state
- The 87LPP must be above the line charging current

The 87LPP in this study is set to 6A (secondary current) in both relays, which is a good setting for almost all internal 3 phase faults, which means that the 87L elements will assert for all internal faults that produce a current greater than 6*30 = 180A of phase difference current. This is the primary current seen by the relay in the line during a fault internal to the protection zone.

4.1.2.2 87LANG

The 87LANG defines the angular extension of the differential restrain region. Since, the line under consideration is a simple two terminal radial transmission line, the 87LANG is set to 195 degrees, which is the relay factory default.

4.1.2.3 87L2P

The 87L2P element is similar to the 87LPP, but for a negative sequence 87L2 differential element. The 87L2 element restrains when $3*I_2$ is less than 87L2P. The following factors were taken into consideration when setting this element.

- Set 87L2P above internal unbalanced currents, but also above expected maximum line charging current imbalance.
- Consider setting 87L2P at 10% of the nominal secondary current.

For the system operating at 1pu,

Line charging current of the 230kV line (unbalance) = 6A

Line charging current in secondary CT value = 0.22A

Hence, the 87L2P was set above the secondary equivalent of the line charging current. It was set at 0.5A secondary, since it is the minimum setting for 87L2P in the SEL-311L relay

4.1.2.4 87LGP

The zero sequence differential element 87LG restrains when $3*I_0$ is less than 87LGP. Care was taken to set 87LGP above the line charging current imbalance. In this study, the 87LGP element was disabled.

4.1.2.5 CTALRM

The CTAA relay word bit asserts when the A-phase differential current exceeds the CTALRM setting. The same implies for CTAB and CTAC word bits. These word bits are basically used to detect and send an alarm for an excessive steady state phase difference current. An example of such a condition is when the one or more of CTs are shorted. For this study, the CTALRM was set to 3.0A secondary.

4.1.2.6 87LR

This element controls the outside radius and the inner radius of the restraint region as shown in Figure 4.5. The 87LR element excludes all internal three phase faults, including those with zero infeed, from the restraint region. Since, the line under consideration is a simple two terminal radial transmission line, the 87LR = 6.0. This gives an outside radius of 6 and an inside radius of 1/6. This comfortably excludes zero infeed conditions from the restraint region.

Figure 4.5 describes operate and restraint region of SEL-311L relay and 87 elements mapped within it.

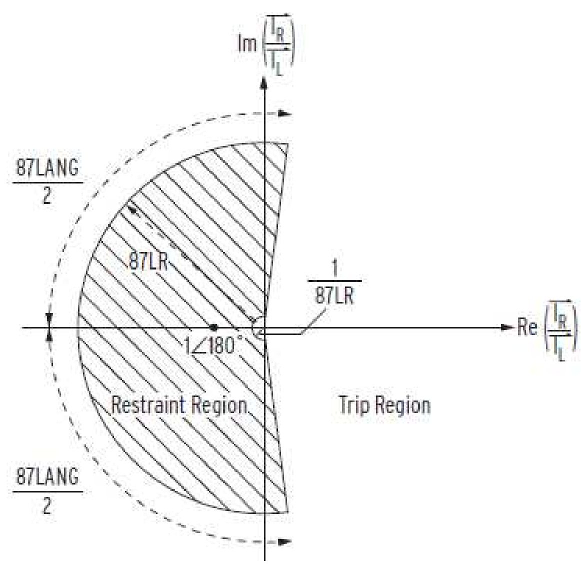


Figure 4.5. – Operate and Restraint Region of SEL-311L Relay [17]

4.1.3. Distance Protection (21)

The distance protection elements act as backup to the primary differential protection scheme. The 21 elements can be set up in the SEL-311L relays with inputs taken from the CTs and VTs at both ends of the line. The settings are described in Appendix A. Following are the brief set of distance parameters considered while setting the relays [17].

4.1.3.1. Line Parameters

To set the line parameters, we need to first convert all impedances to secondary Ohms. This is done as follows,

CTR = 50, PTR = 2000 (from Section 4.2.1)

$$k = \frac{CTR}{PTR} = \frac{50}{2000} = 0.025$$

$$Z_{Lsecondary} = k * Z_{Lprimary}$$

$$Z1MAG = k * |10.3\angle 86.89\text{deg}| = 0.1545\Omega$$

$$Z1ANG = 86.89 \text{ deg}$$

$$Z0MAG = k * |40.04\angle 72.95\text{deg}| = 0.6\Omega$$

Z0ANG = 72.95 deg

Line Length = 30 km

4.1.3.2. Distance Elements Settings

$$Z1P = 80\% \ of \ Z1MAG$$

$Z1P = 0.8 * 0.1545 = 0.1236\Omega$

$Z2P = 125\%\ of\ Z1MAG$

$Z2P = 1.25 * 0.1545 = 0.193\Omega$

To set the reverse zone 3 element, we need to define the line parameters of the collector feeder line.

For the collector feeder,

CTR = 300, PTR = 2000

$$k_{collector} = \frac{CTR}{PTR} = \frac{300}{2000} = 0.15$$

$$Z1MAG_{collector} = k_{collector} * 2.74 = 0.411\Omega$$

$Z3P = 0.411 * 0.25 = 0.1027$ (Looking in the reverse direction)

Similarly the ground distance elements are also set up and their values are as follows.

Z1MG = 0.48Ω

Z2MG = 0.75Ω

Z3MG = 0.46Ω

The zero sequence current compensation (k01) as in (4.3) adjusts the apparent reach of the ground distance element so that it is equal to the phase element reach [17].

$$k0M1\angle k0A1 = \frac{(Z0MAG\angle Z0ANG) - (Z1MAG\angle Z1ANG)}{3*(Z1MAG\angle Z1ANG)} \tag{4.3}$$

Here,

$$k0M1\angle k0A1 = 1.052\angle -36.36$$

4.1.4. Trip Logic Equations

The unconditional trip equation, TR is set with the phase and negative 87L elements and Zone 1, time delayed Zone 2 and Zone 3 phase and ground distance elements. The trip equation is implemented as follows.

TR = 87L + M1P + Z1G + M2PT + Z2GT + M3PT + Z3GT (4.4)

The 87L element provides instantaneous tripping over the whole length of the line. The Zone 1 distance elements provide instantaneous trip for up to 80% of the line. The Zone 2 and Zone 3 are time delayed and provide and overreaching tripping beyond the main transmission line, into the collector feeder. M2PT and M3PT are the time delayed zone 2 and zone 3 phase distance elements respectively. Figure 4.6 shows the protection elements and their reach.

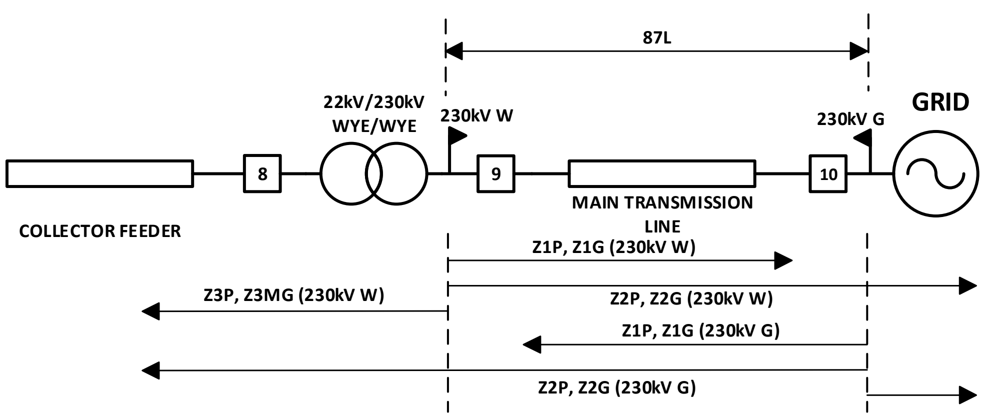


Figure 4.6. – Main Transmission Line Protection

4.1.5. Plan for Fault Simulation and Analysis

Faults were simulated on the 230kV transmission line shown in Figure 4.1. For ease of explanation, we will refer to the relay close to the grid side as “230kV G” and the relay on the other end, close to the step up transformer as “230kV W”. Before simulating faults on the relay, the steady state voltages and currents on the 230kV line with the WTGs running at 100% capacity are as shown in Figures 4.7 and 4.8 respectively.

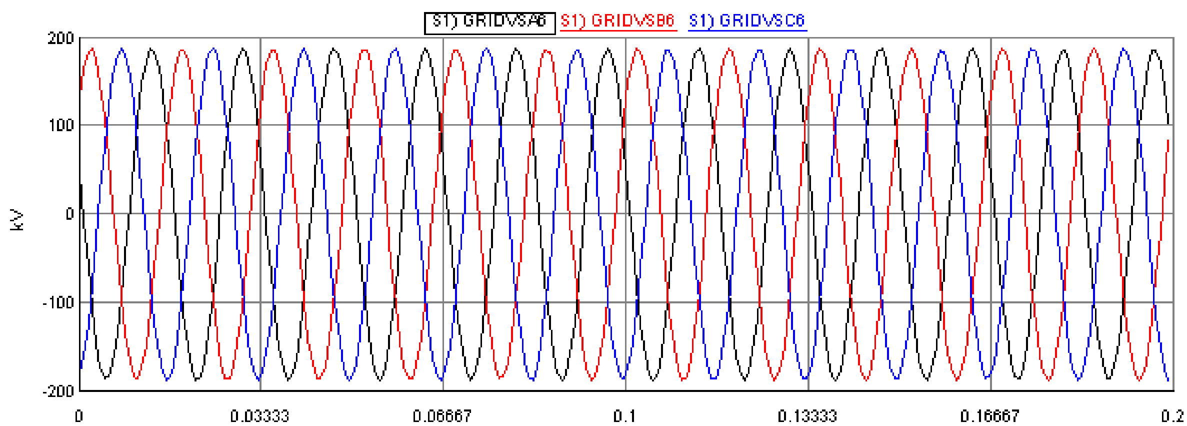


Figure 4.7. – Primary Voltage across the 230kV Transmission Line

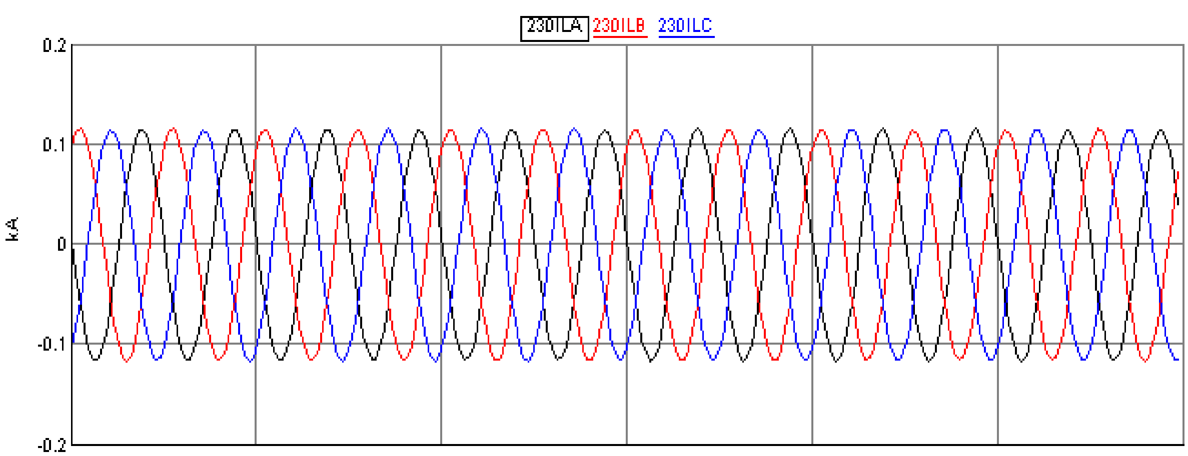


Figure 4.8. – Primary Current through the 230kV Transmission line

The secondary currents and voltages from the CTs and VTs at both ends of the line are shown in Figure 4.3 and Figure 4.4.

The following fault cases were simulated on the system and the integrity of the protection scheme was tested. The fault resistance was varied from 0Ω to 80Ω (primary ohms).

a. AG Fault
b. BG Fault
c. CG Fault
d. ABG Fault
e. BCG Fault
f. CAG Fault
g. AB Fault
h. BC Fault
i. CA Fault
j. ABCG Fault

The above faults cases were carried out at fault locations of 20%, 50% and 80% of the line, and with the WTG system output ranging from 1pu to 0.7pu (low wind speeds). For all the scenarios above, the following behavior is expected from the relays.

1. The relays should trip instantaneously.
2. The differential elements should pick up for all fault along the whole length of the line.

3. The directional supervision should ensure that the relay trip signal asserts only for faults in front of them.
4. The faulted phases should be identified properly and selected.
5. Zone 1 and Zone 2 mho distance elements should pick up for all fault types. They could not be asserted for increasing fault resistances.
6. Both relays should send permissive trip to the other relay.

All fault scenarios as mentioned above were tested and analyzed. For simplicity and ease of explanation, we will consider the following four cases, in more detail.

1. AG fault (Single line to ground fault)
2. ABG fault (Double line to ground fault)
3. AB fault (Line to line fault)
4. ABCG fault (3 phase to ground fault)

4.1.6. Results for Faults on the 230kV transmission line

Faults were simulated at the fault locations on the 230kV transmission line described above. The response of the relays were recorded in the form of event reports. It is to be noted that the relay close to the WTG side is named “230kV W” and the relay close to the 230kv grid side is named “230kV G”. The faults are simulated at locations starting from 230kV W side to the 230kV G side, indicated by increasing percentage of the fault location.

One important aspect of the tests was that the communication between the relays used in the test were at minimum delay and with almost no packet loss. This was due to the fact that the relays were placed close to each other with short length of optical fiber communication channel between them. As a result the 87L elements picked up faster than the distance elements and issued a faster trip signal. In a real world application, the relays would have miles of distance between them, creating communication delay and certain amount of packet loss. The fact that the relay asserted the correct trip with the 87L elements more often than distance elements, proves that the differential protection scheme is quite reliable for protection of transmission lines.

4.1.6.1. Case A – Bolted faults at set fault locations

In this case, the faults were simulated on the line with zero fault resistance. The WTGs are operating at rated speeds, providing power output at 1pu.

4.1.6.1.1 Event A.1 - AG fault at 20% of the line

Figures 4.9 through 4.12 illustrate the relay response to the AG fault at 20% of the line. Following are the key observations for this event.

- The grid side relay sees prominently high and unbalanced currents due to being close to a strong source. The 230kV W relay on the other hand senses a comparatively lower current imbalance. This is due to the fact that the type 3 WTG controller adjusts its modulation to remove the unbalance to a great extent. Also, since the local step up transformer is a Wye-Delta, there are low zero sequence currents from the WTG side. With the Delta secondary winding on the local step up transformer, it becomes a zero sequence trap, preventing zero sequence currents from flowing to the collector feeder.

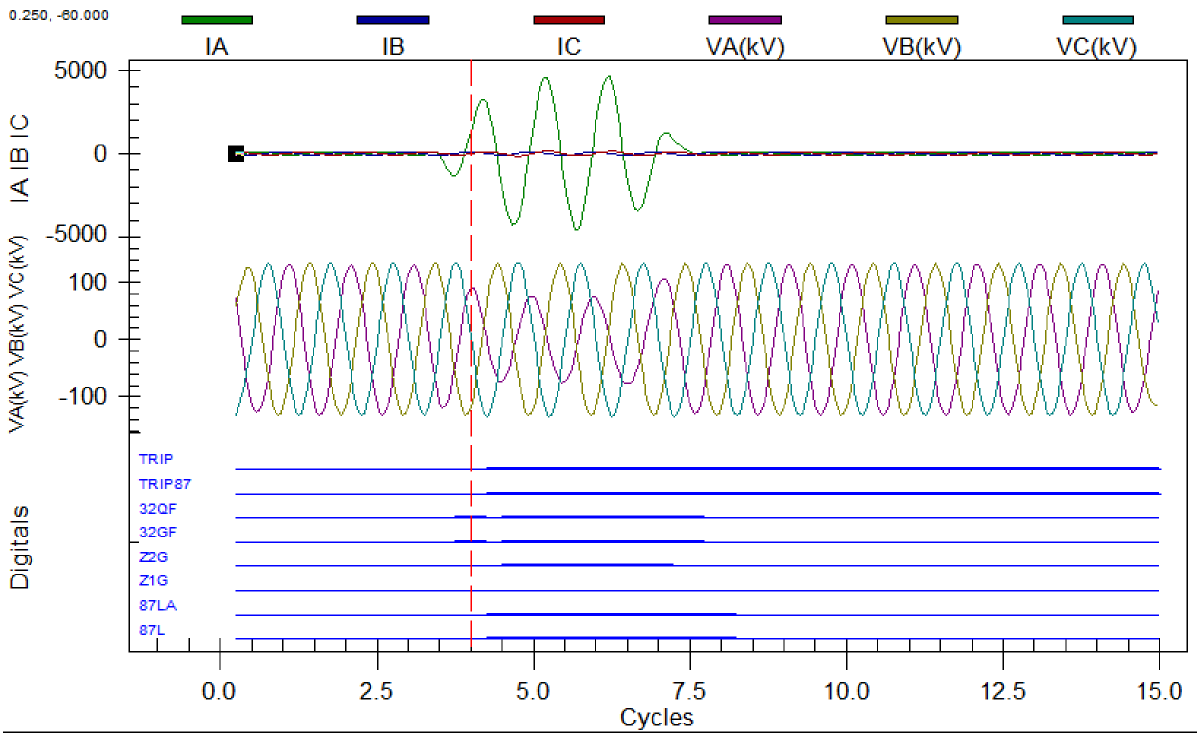


Figure 4.9. – Event A.1. 230kV G Relay Event Report

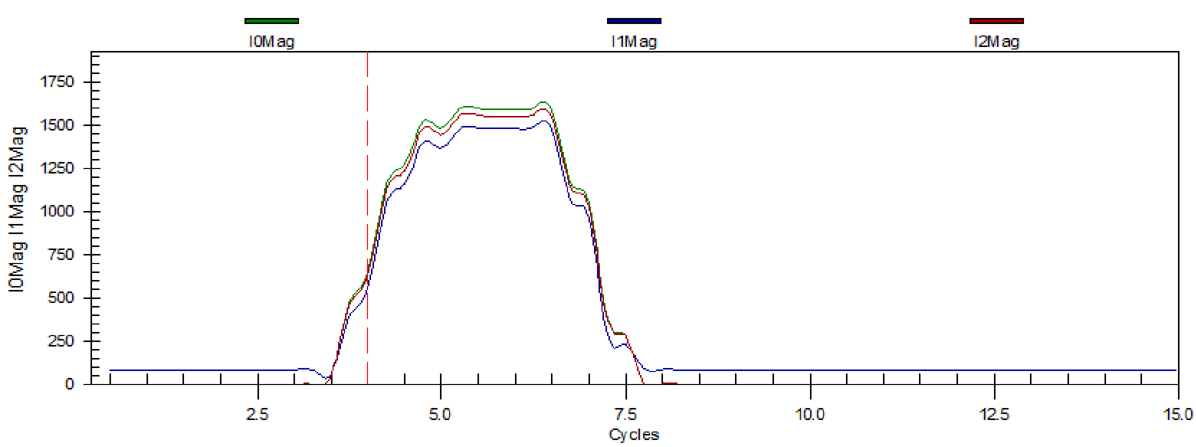


Figure 4.10. – Event A.1. 230kV G Relay Sequence Current Magnitudes

- The voltage imbalance is prominent in both grid side and WTG side relay.
- The 87L elements, the A phase and ground differential elements on both relays see the fault as expected within their zone of protection and assert the trip signal.

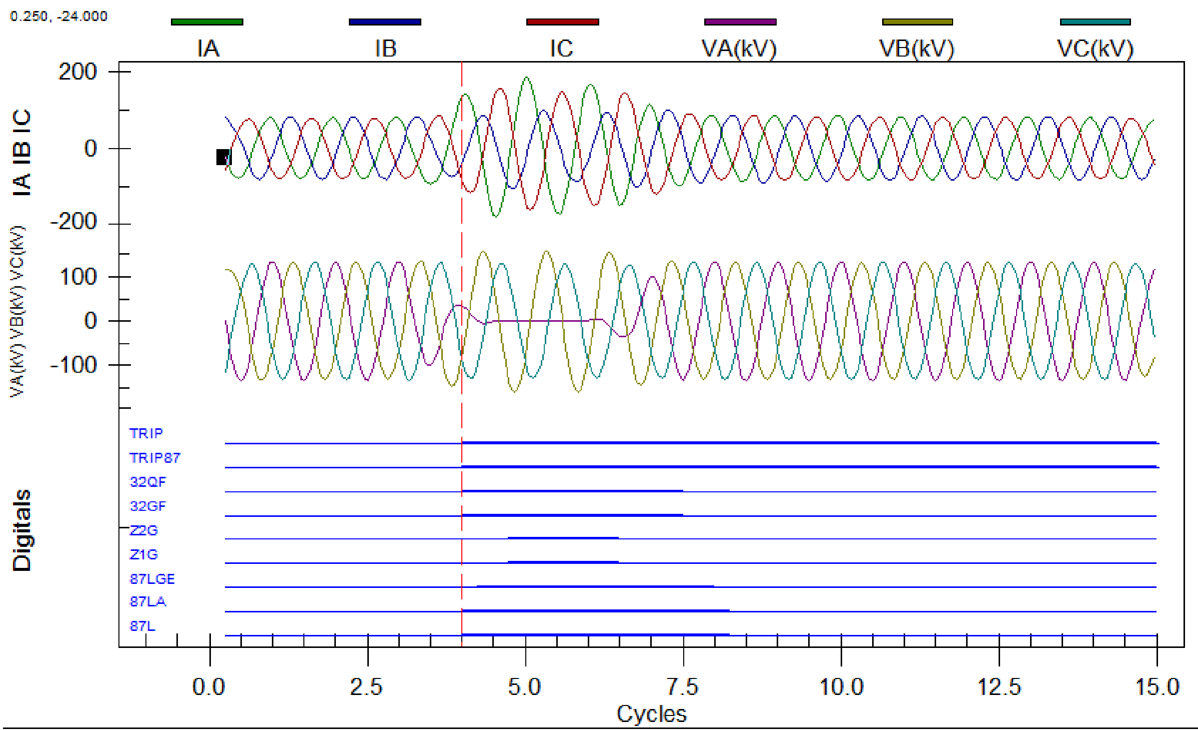


Figure 4.11. – Event A.1. 230kV W Relay Event Report

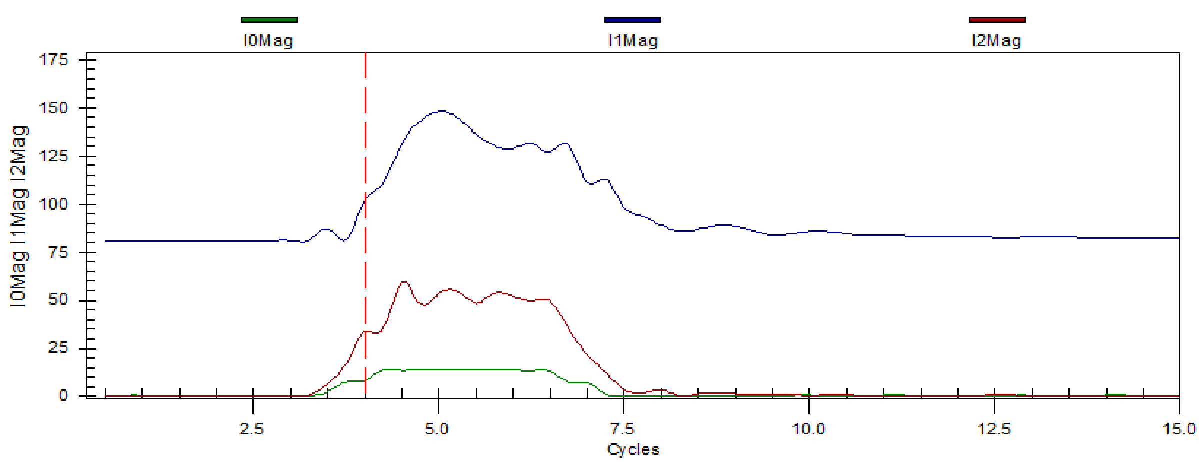


Figure 4.12. – Event A.1. 230kV W Relay Sequence Current Magnitudes

- The distance elements Z1G and Z2G of the WTG side relay picks up instantaneously since the fault is close in to the relay. The zone 2 distance element at the grid side, Z2G, asserts, whereas, Z1G does not assert. The operation of the distance elements is as expected since the fault lies beyond the reach of the zone 1 ground distance element of the 230kV G relay.

- The directional elements 32QF and 32GF assert for both grid and WTG side relays, as expected.

4.1.6.1.2 Event A.2 ABG fault at 20% of the line

Figures 4.13 through 4.18 illustrate the relay response to the ABG fault at 20% of the line. Following are the observations for this event.

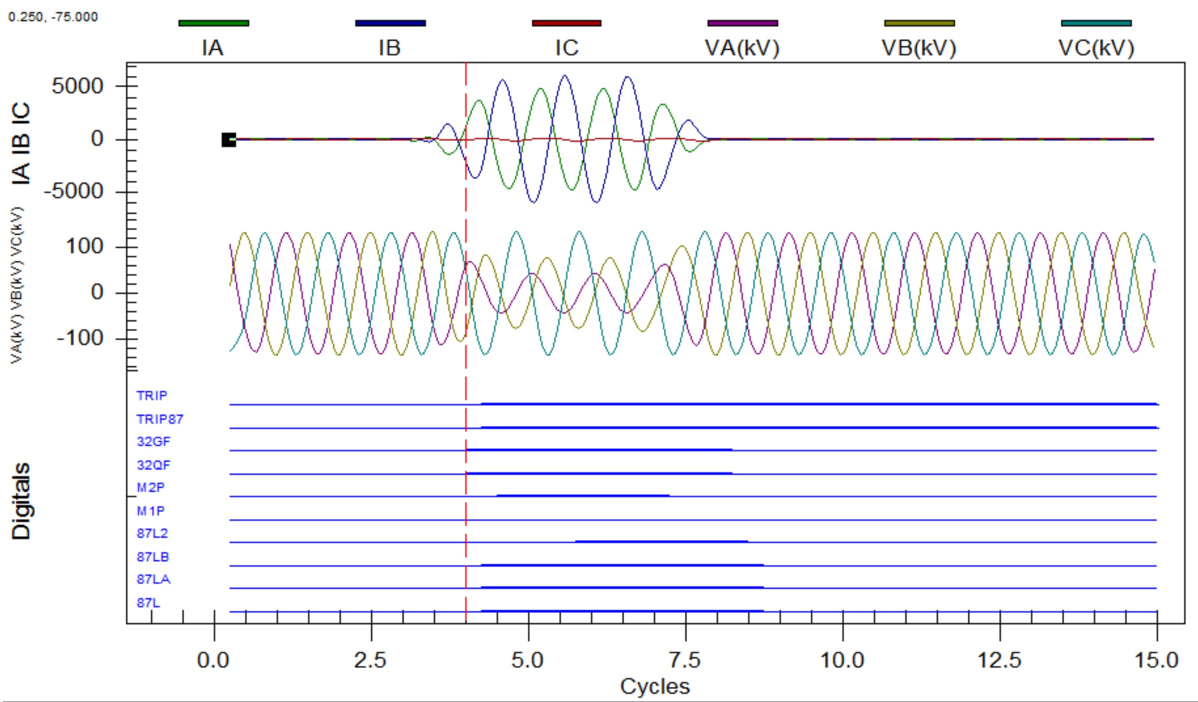


Figure 4.13. – Event A.2. 230kV G Relay Event Report

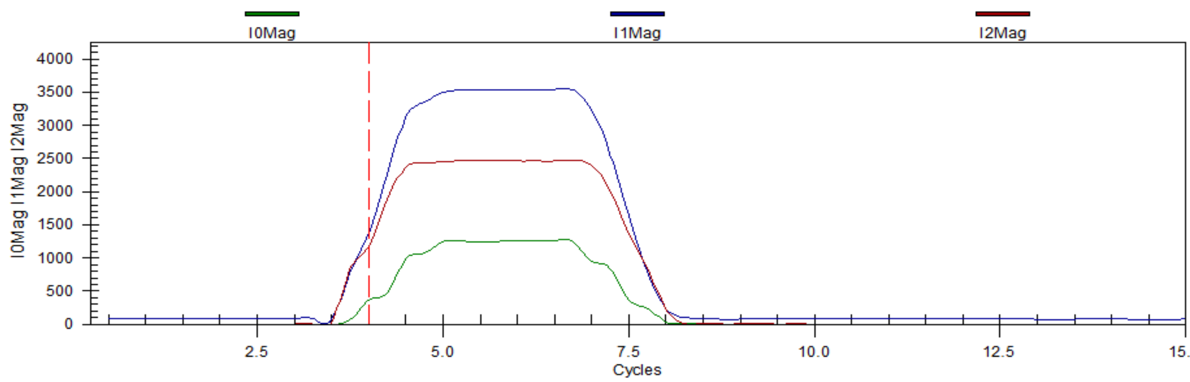


Figure 4.14. – Event A.2. 230kV G Relay Sequence Current Magnitudes

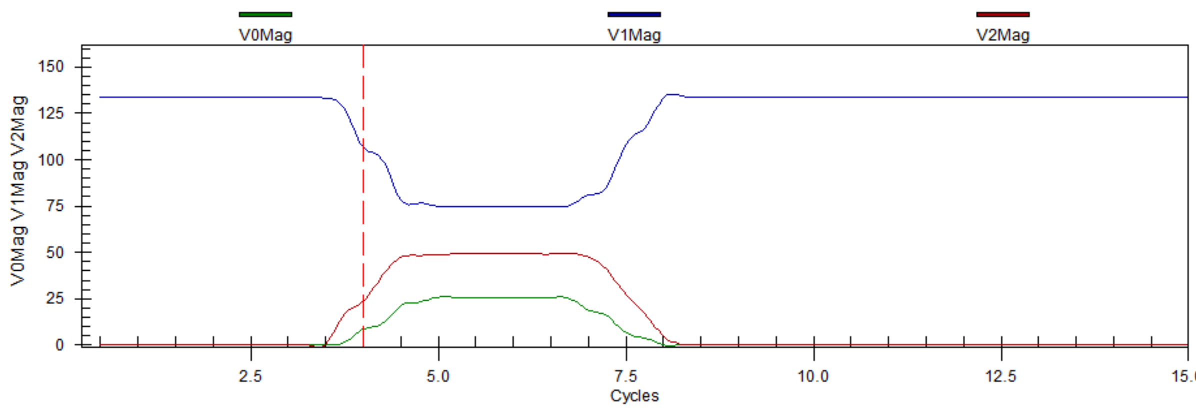


Figure 4.15. – Event A.2. 230kV G Relay Sequence Voltage Magnitudes

- The voltage and current imbalances are clearly higher than that seen in the A-G fault. This can be attributed to the type of fault involved here.
- The differential elements, 87LG, 87LA and 87LB correctly assert for the relays at both ends of the line.
- The zone 1 and zone 2 distance elements, M1P and M2P, on the WTG side pickup instantaneously. The M2P element asserts, however, M1P does not assert of the 230kV G relay. These are as expected for a close-in double line to ground fault due the fact that the fault lies beyond the zone 1 phase distance element reach of the 230kV G relay.

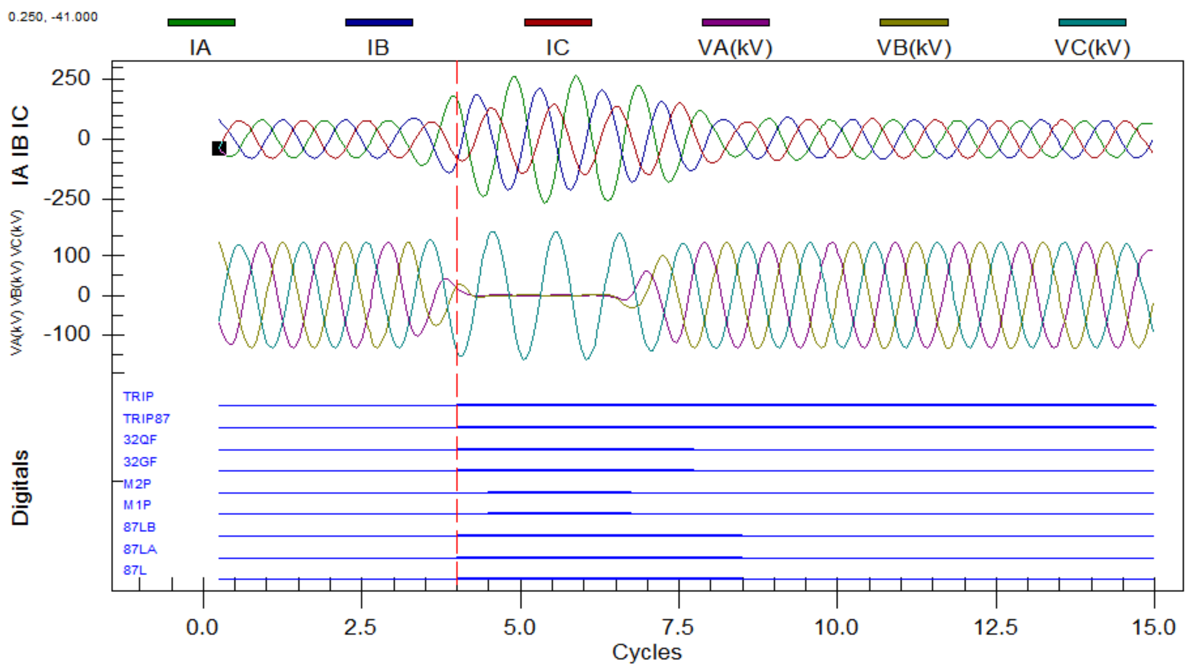


Figure 4.16. – Event A.2. 230kV W Relay Event Report

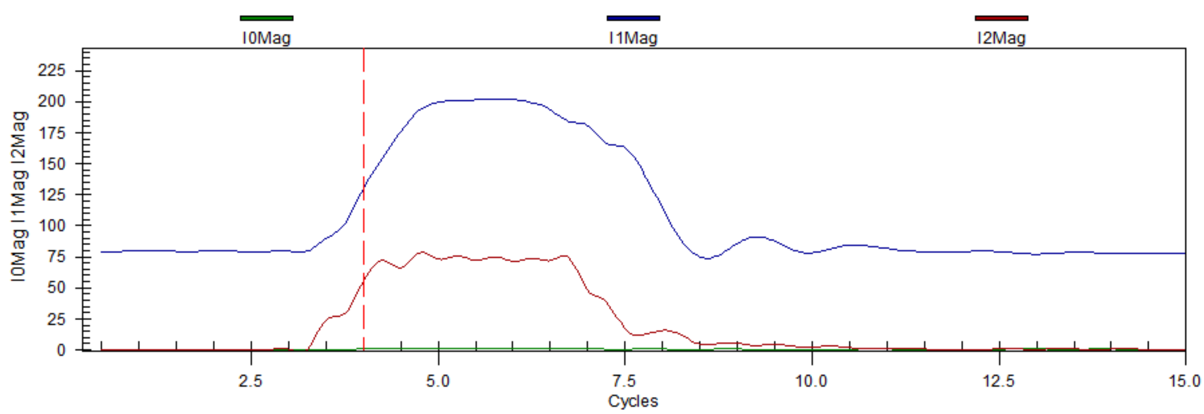


Figure 4.17. – Event A.2. 230kV W Relay Sequence Current Magnitudes

- The directional elements, 32GF and 32QF assert for relays at both ends.

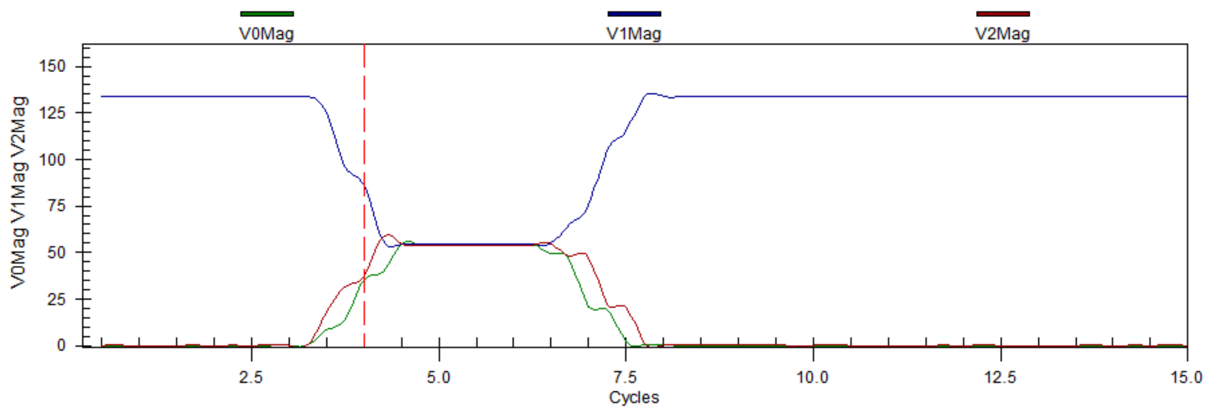


Figure 4.18. – Event A.2. 230kV W Relay Sequence Voltage Magnitudes

4.1.6.1.3 Event A.3 - AB fault at 20% of the line

Figures 4.19 through 4.24 illustrates the relay response to the AB fault at 20% of the line. Following are the observations for this event.

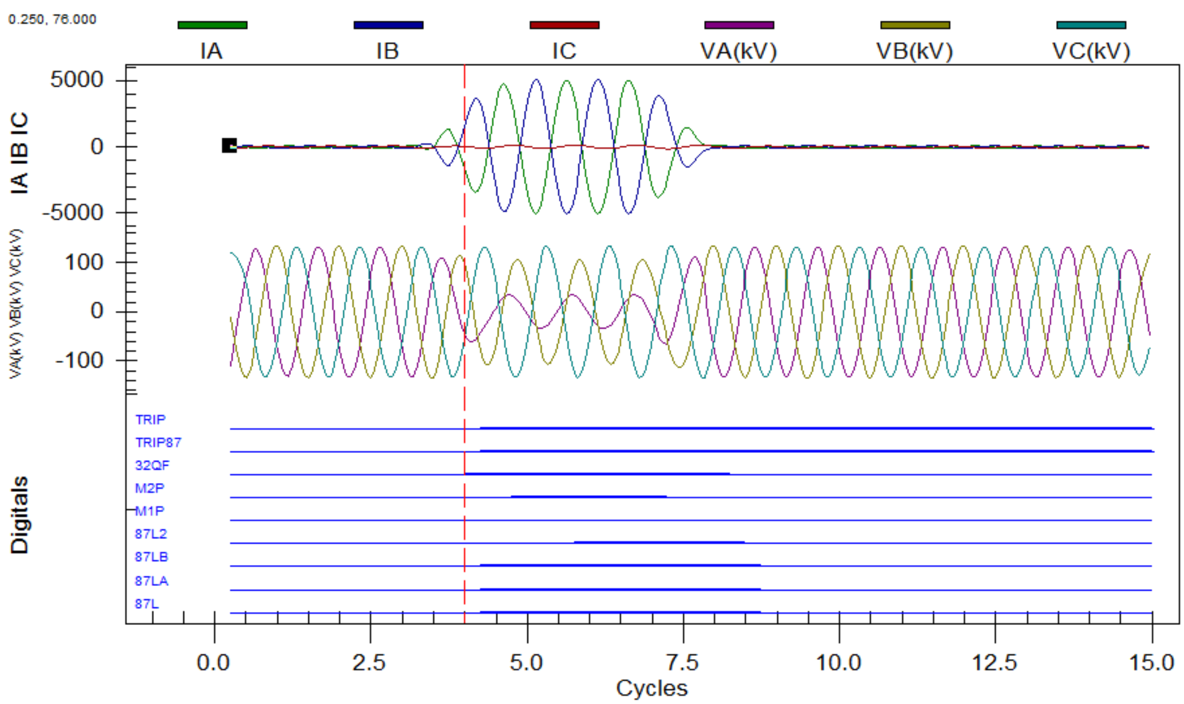


Figure 4.19. – Event A.3. 230kV G Relay Event Report

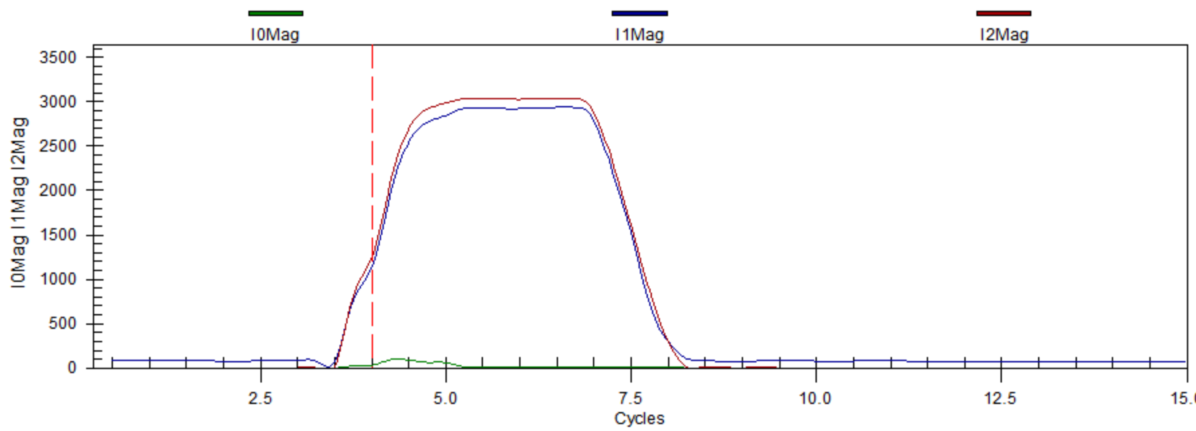


Figure 4.20. – Event A.3. 230kV G Relay Sequence Current Magnitudes

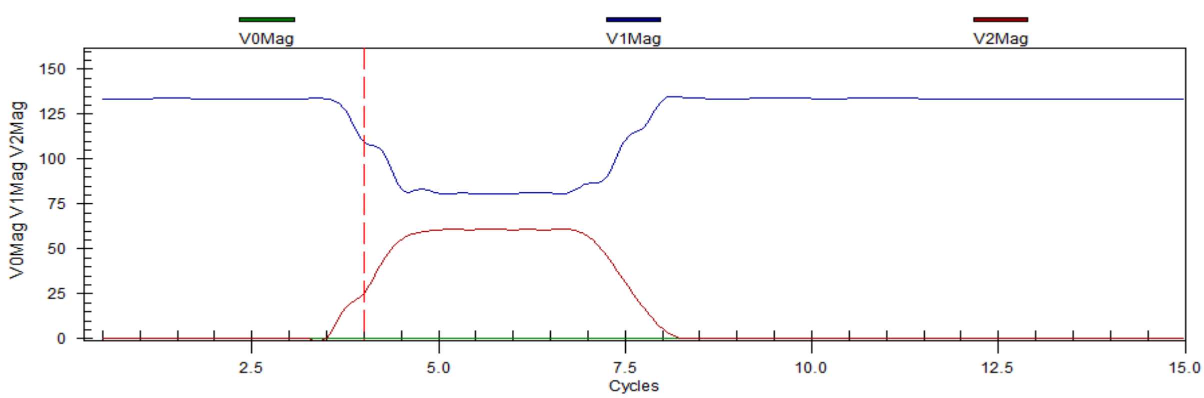


Figure 4.21. – Event A.3. 230kV G Relay Sequence Voltage Magnitudes

- The voltage and current profiles are fairly similar to that seen in the ABG fault.
- The directional elements, 32GF and 32QF correctly assert for relays at both ends.
- The negative sequence differential element, 87L2 picks up, indicating an increase in negative sequence attributed to a line to line fault. The 87LA and 87LB assert correctly.
- The distance elements correctly pick up similar to that seen in the ABG fault.
- The 32GF and 32QF forward elements see the fault in front of them and correctly pick up instantaneously.

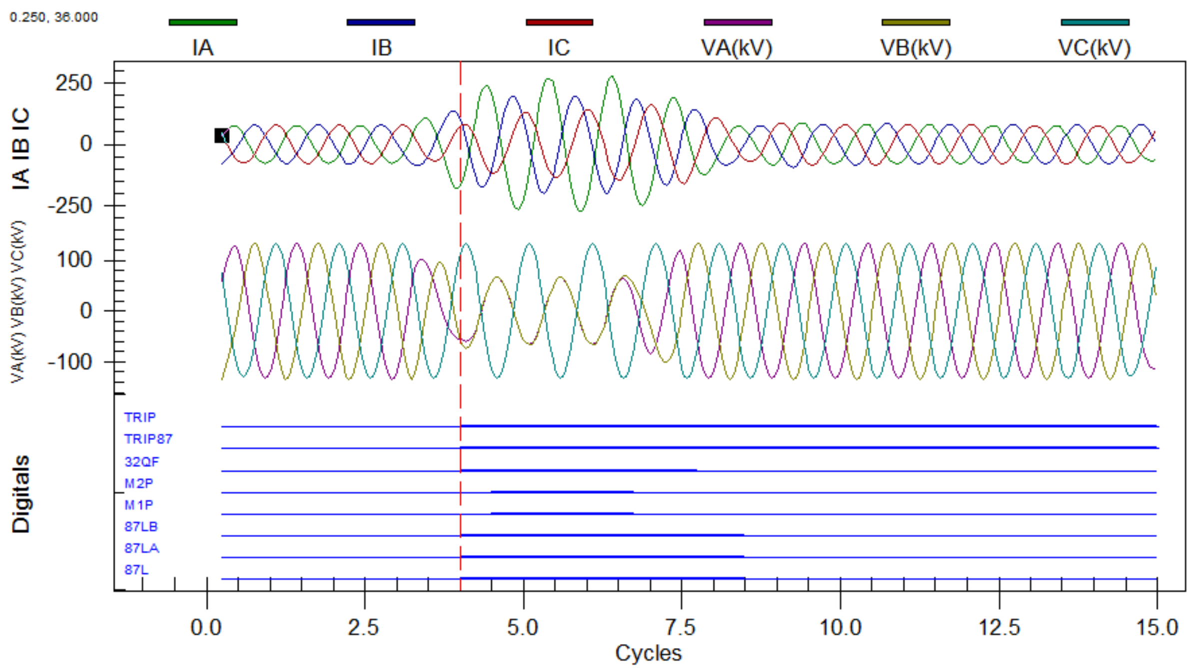


Figure 4.22. – Event A.3. 230kV W Relay Event Report

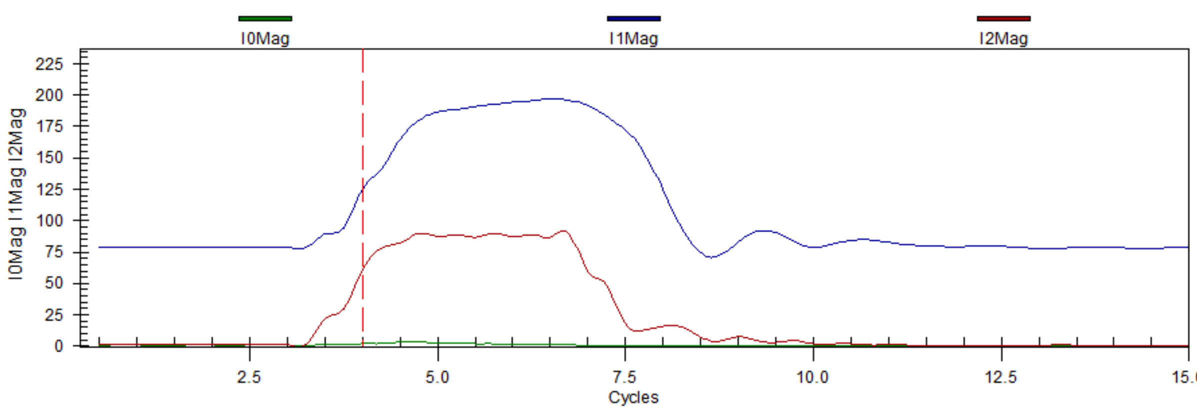


Figure 4.23. – Event A.3. 230kV W Relay Sequence Current Magnitudes

4.1.6.1.4 Event A.4 - ABCG fault at 20% of the line

Figures 4.25 through 4.30 illustrates the relay response to the ABCG fault at 20% of the line. Following are the observations for this event.

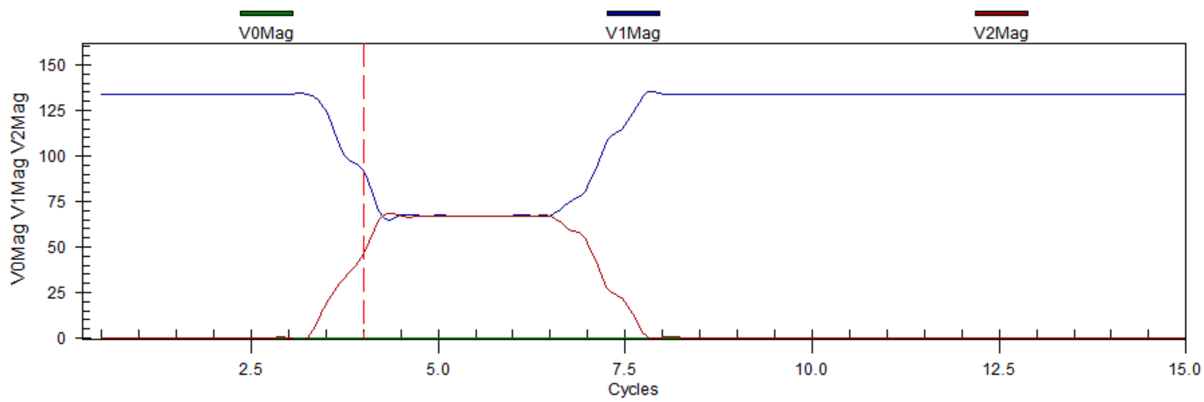


Figure 4.24. – Event A.3. 230kV W Relay Sequence Voltage Magnitudes

- The current unbalance profiles are almost the same in the grid side relay. However there is a slight difference in the current unbalances profiles in the 230kV W side relay which could be attributed to the WTG current regulation.
- The directional elements correctly see the fault in front of them for both of the relays.
- The differential elements 87LA, 87LB & 87LC correctly assert for increase in differential currents in all three phases.
- The zone 2 distance element, M2P picks up at the grid side relay. Additionally, the zone 2 mho phase to phase mho elements, MAB2, MBC2 and MCB2 assert, reinforcing the relay decision to trip on a three phase fault.
- The distance elements at the WTG side relay do not pick up at all during the course of the fault. A closer inspection of the sequence currents reveal that the negative

sequence currents do not rise to as high as the positive sequence currents, which can be attributed to the controllers on the WTG continuously adjusting itself to the phase unbalance.

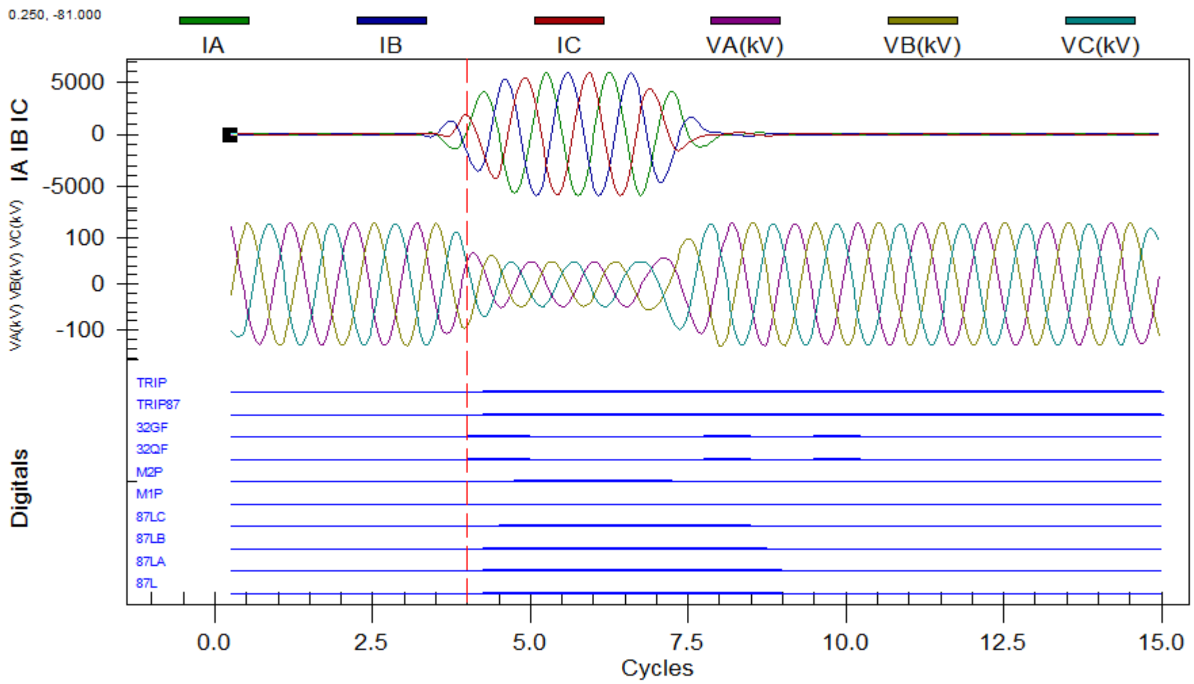


Figure 4.25– Event A.4. 230kV G Relay Event Report

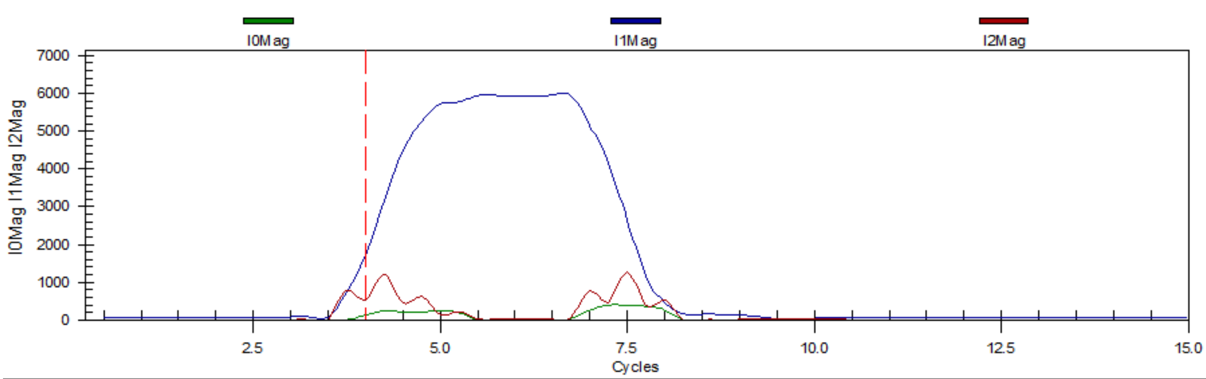


Figure 4.26. – Event A.4. 230kV G Relay Sequence Current Magnitudes

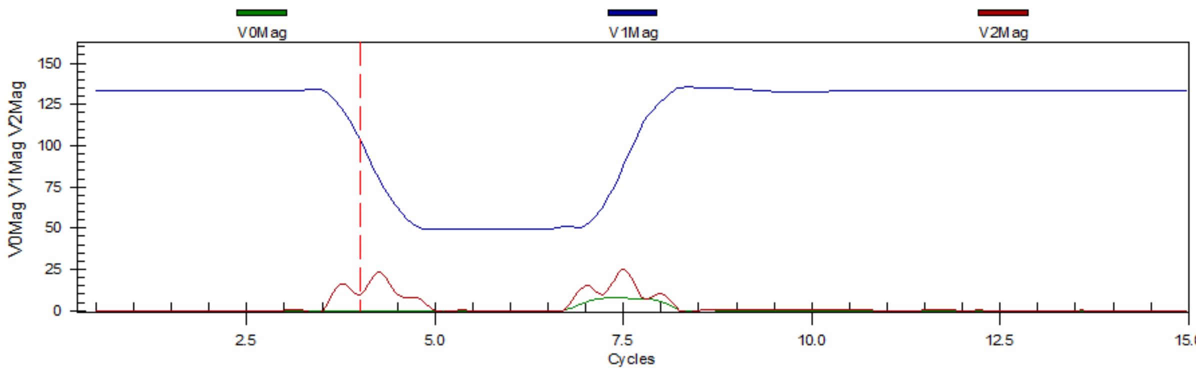


Figure 4.27. – Event A.4. 230kV G Relay Sequence Voltage Magnitudes

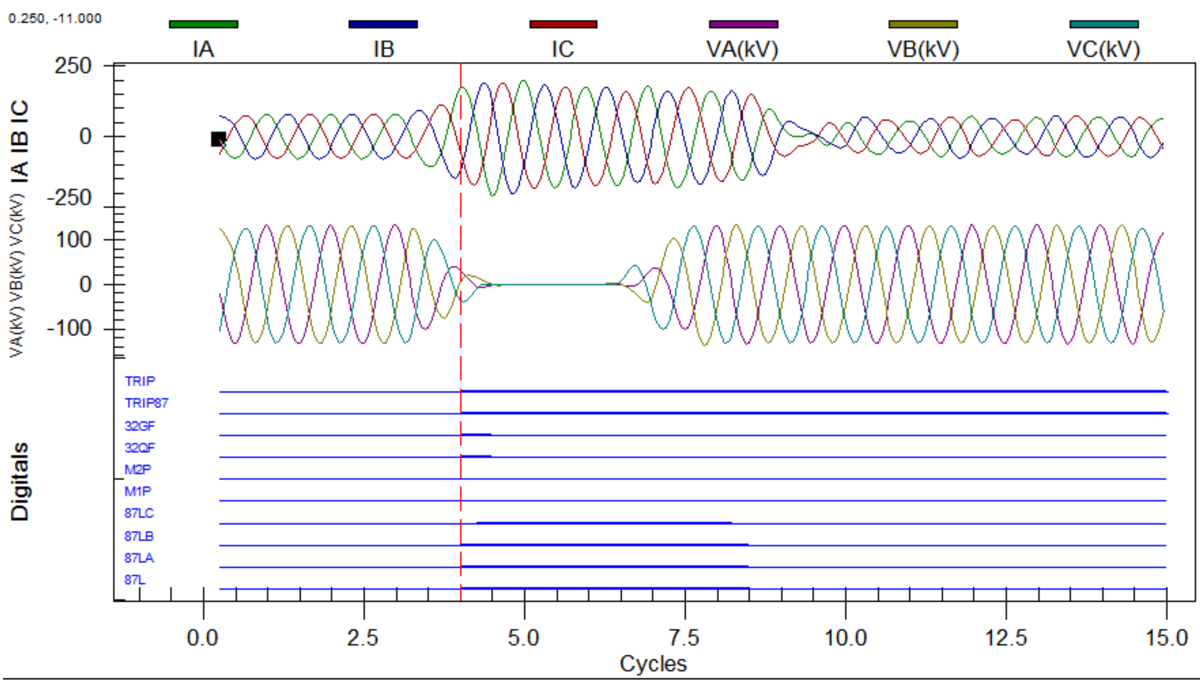


Figure 4.28. – Event A.4. 230kV W Relay Event Report

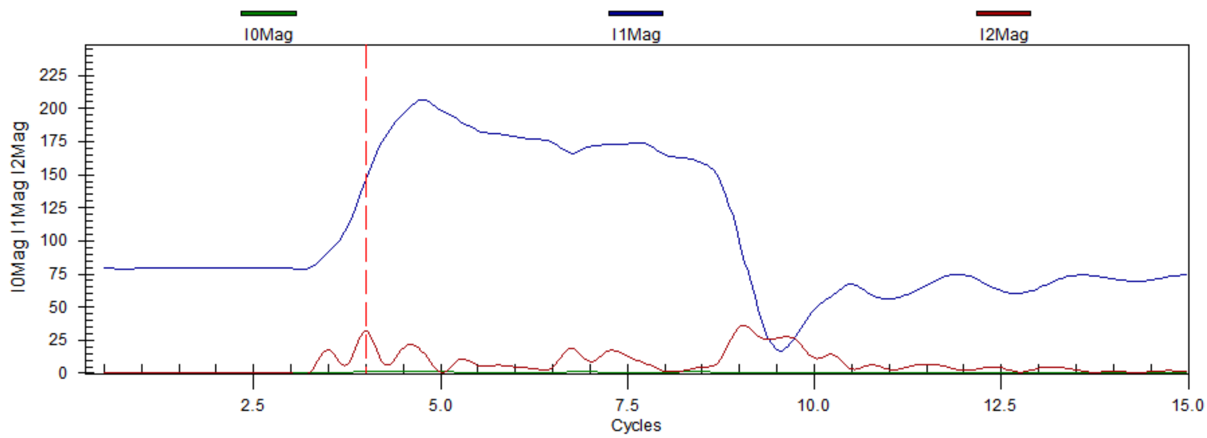


Figure 4.29. – Event A.4. 230kV W Relay Sequence Current Magnitudes

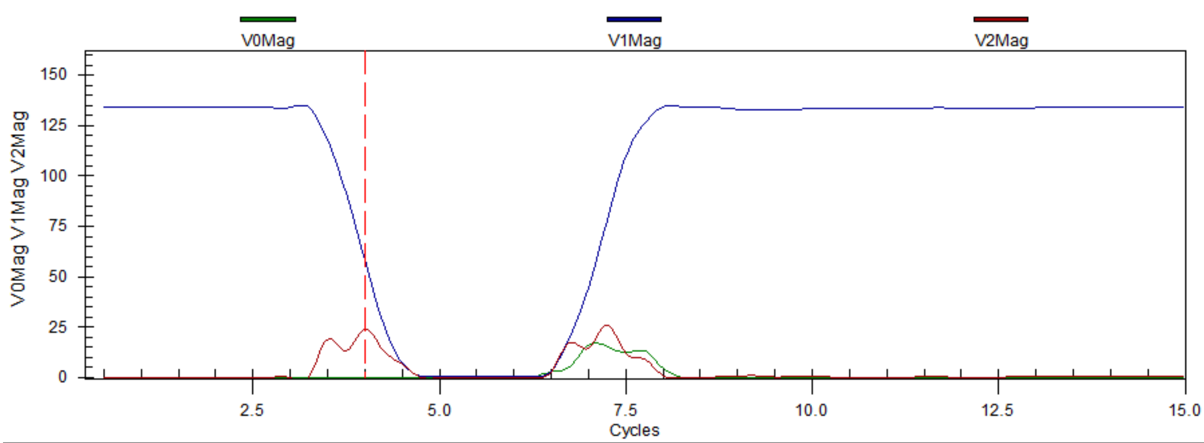


Figure 4.30. – Event A.3. 230kV W Relay Sequence Voltage Magnitudes

The summary of faults on the 230kV line for case A is shown in Table 4.1.

Fault Issued	Fault Location	Relay	Fault Detected	Protection Element Operation					Element Tripped on
				87L	M1P	M2P	Z1G	Z2G	
AG	20%	230kV W	AG	Y	N	N	Y	Y	87LG
		230kV G	AG	Y	N	N	N	Y	87LG
ABG		230kV W	ABG	Y	Y	Y	N	N	87LG, 87LA
		230kV G	ABG	Y	N	Y	N	N	87LG, M2P
AB		230kV W	AB	Y	Y	Y	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	N	Y	N	N	87L2, 87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LA
		230kV G	ABCG	Y	N	Y	N	N	87LA
AG	50%	230kV W	AG	Y	N	N	Y	Y	87L
		230kV G	AG	Y	N	N	Y	Y	87LG
ABG		230kV W	ABG	Y	Y	Y	N	N	87LG, 87LA
		230kV G	ABG	Y	Y	Y	N	N	87LG,
AB		230kV W	AB	Y	Y	Y	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	N	Y	N	N	87L2, 87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LB, 87LC
		230kV G	ABCG	Y	Y	Y	N	N	87LA, 87LB, 87LC
AG	80%	230kV W	AG	Y	N	N	N	N	87LG
		230kV G	AG	Y	N	N	Y	Y	87LG, Z1G
ABG		230kV W	ABG	Y	N	Y	N	N	87LA, 87LB
		230kV G	ABG	Y	Y	Y	N	N	87LA, 87LB
AB		230kV W	AB	Y	N	Y	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	Y	Y	N	N	87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LA, 87LB
		230kV G	ABCG	Y	N	Y	N	N	87LA

Table 4.1 – Bolted Faults on the 230kV Transmission Line

Following are the observations of the faults simulated as shown in Table 4.1 summarizing the relay responses.

- The differential elements operate as desired for all faults.

- The distance elements operate as desired for all the faults except for the following situations:
  - The M1P and M2P elements on the WTG side relay do not pick up for ABCG fault at any fault location. This can be explained in the discussion of event 4. The over currents due to the fault are continuously adjusted for by the current regulating elements of the type 3 WTG.
  - The zone 2 distance element, Z2P does not pick up for AG fault at 80% of the line, in the WTG side relay. This is because the Wye-Delta local step up transformer makes the WTG system a weak zero sequence source. There is minimal zero sequence flowing to the fault from the WTG.
  - The directional elements pick up for all the fault conditions.

4.1.6.2. Case B – Effect of fault resistance

In this case, the faults were simulated with a fault resistance of 80 Ohms for all fault cases. The WTG's are operating at synchronous speeds and the faults are simulated at various points of the line similar to case A.

A summary of events generated in both relays for fault on the 230kV line for case B is as provided in Table 4.2.

Following are the observations of the faults summarized in Table 4.2 and the observed relay responses.

- The directional elements 32QF and 32GF operate as desired for all faults in front of the relays.

- The current imbalance and voltage imbalance profiles are significantly smaller. This can be attributed to the fact that an increased fault resistance reduces the fault currents. This was seen in the reduced sequence currents in every fault event generated.

Fault Issued	Fault Location	Relay	Fault Detected	Protection Element Operation					Element Tripped on
				87L	M1P	M2P	Z1G	Z2G	
AG	20%	230kV W	AG	Y	N	N	N	N	87LA
		230kV G	AG	Y	N	N	N	N	87LG
ABG		230kV W	ABG	Y	N	N	N	N	87LA, 87LB
		230kV G	ABG	Y	N	N	N	N	87LG
AB		230kV W	AB	Y	N	N	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	N	N	N	N	87L2, 87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LA
		230kV G	ABCG	Y	N	N	N	N	87LA
AG	50%	230kV W	AG	Y	N	N	N	N	87L
		230kV G	AG	Y	N	N	N	N	87LG
ABG		230kV W	ABG	Y	N	N	N	N	87LG, 87LA
		230kV G	ABG	Y	N	Y	N	N	87LG,
AB		230kV W	AB	Y	N	N	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	N	N	N	N	87L2, 87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LB, 87LC
		230kV G	ABCG	Y	Y	Y	N	N	87LA, 87LB, 87LC
AG	80%	230kV W	AG	Y	N	N	N	N	87LG
		230kV G	AG	Y	N	N	Y	Y	87LG, Z1G
ABG		230kV W	ABG	Y	N	N	N	N	87LA, 87LB
		230kV G	ABG	Y	Y	Y	N	N	87LA, 87LB
AB		230kV W	AB	Y	N	N	N	N	87L2, 87LA, 87LB
		230kV G	AB	Y	Y	Y	N	N	87LA, 87LB
ABCG		230kV W	ABCG	Y	N	N	N	N	87LA, 87LB
		230kV G	ABCG	Y	Y	Y	N	N	87LA

Table 4.2 – Faults on the 230kV Transmission Line with Fault Resistance

- The zone 1 and zone 2 distance elements of the 230kV W relay do not pickup for any fault along the line. This is due to the fact that the WTG which is already a weak source, when coupled with a fault of high resistance, does not generate enough fault current to bring the impedance profile within the zone 1 and zone 2 mho circles in the impedance plane. The phase and ground distance element settings would have to be altered to make the system more sensitive to a fault with resistance.

- The 87 differential elements operate as desired for all fault cases and was found to be more reliable in this case.

To help reinforce the observations and analysis of case B, two events of the same nature, but with different fault resistances are discussed in more detail.

4.1.6.2.1 Event B.1. AG fault at 50% of the line with fault resistance (230kV W relay)

Figures 4.31 through 4.36 illustrate the 230kV W relay response to A-G fault at 50% of the line with and without the fault resistance.

Following are the observations, describing a comparison of relay response, with and without a fault resistance:

- There is a marginal decrease in current imbalance when a resistance is added to the fault, accompanied by a slightly increased voltage imbalance. This is due to the fact that the reduced fault currents flowing to the ground from the WTG source.
- Looking at Figures 4.33. and 4.34., there is a noticeable decrease in zero sequence currents, which causes the difference between the ground elements picking up or not. The sequence voltages mostly remain the same.

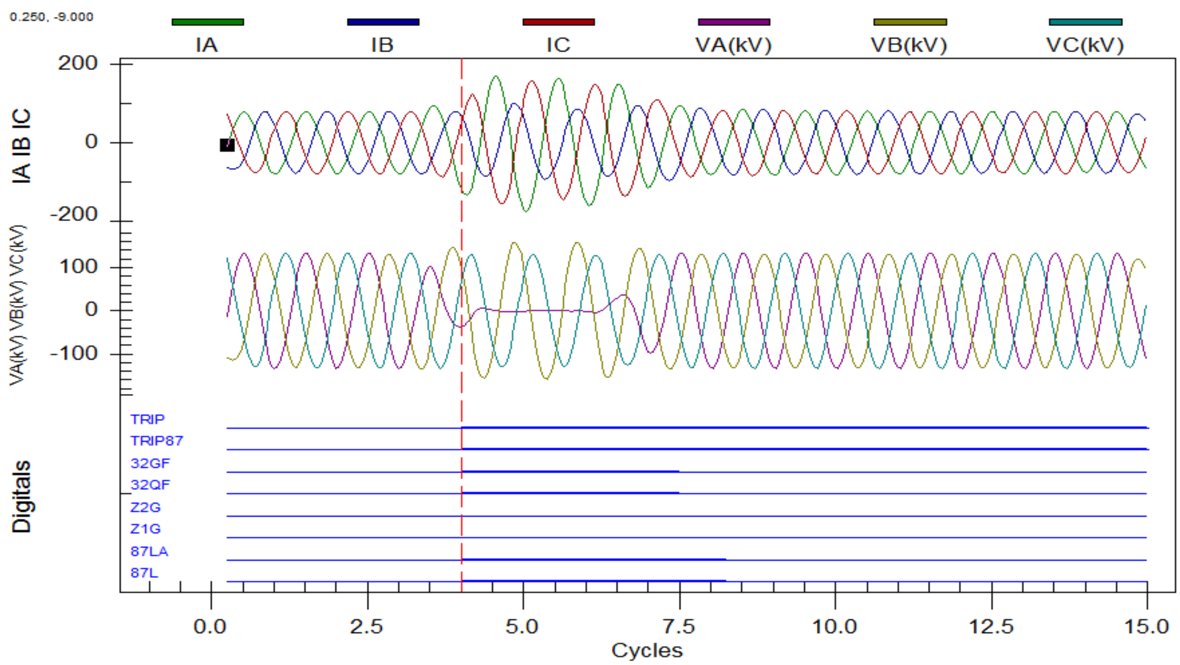


Figure 4.31. – Event B.1. (a) 230kV R Relay Event with Fault Resistance

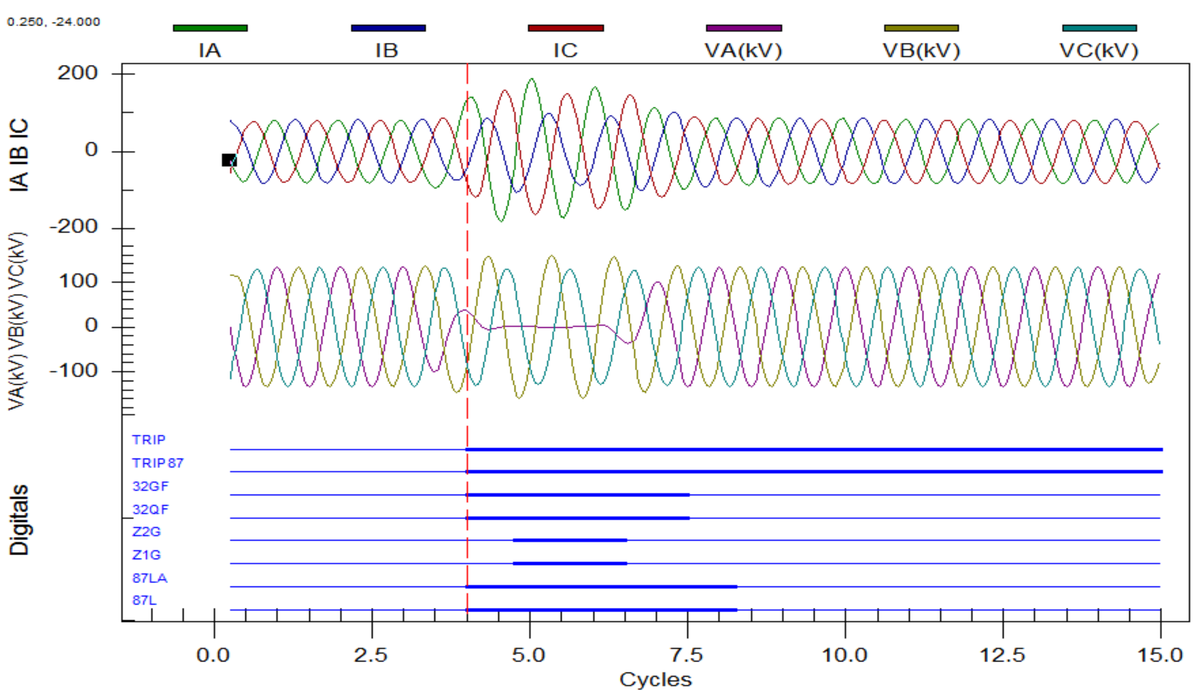


Figure 4.32. – Event B.1. (b) 230kV W Relay Event without Fault Resistance

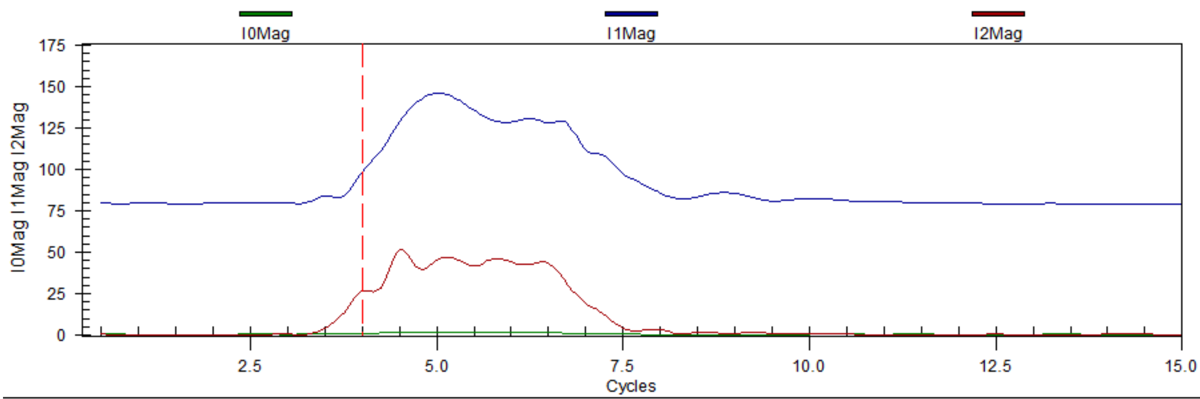


Figure 4.33. – Event B.1. (a) Sequence Current Magnitudes

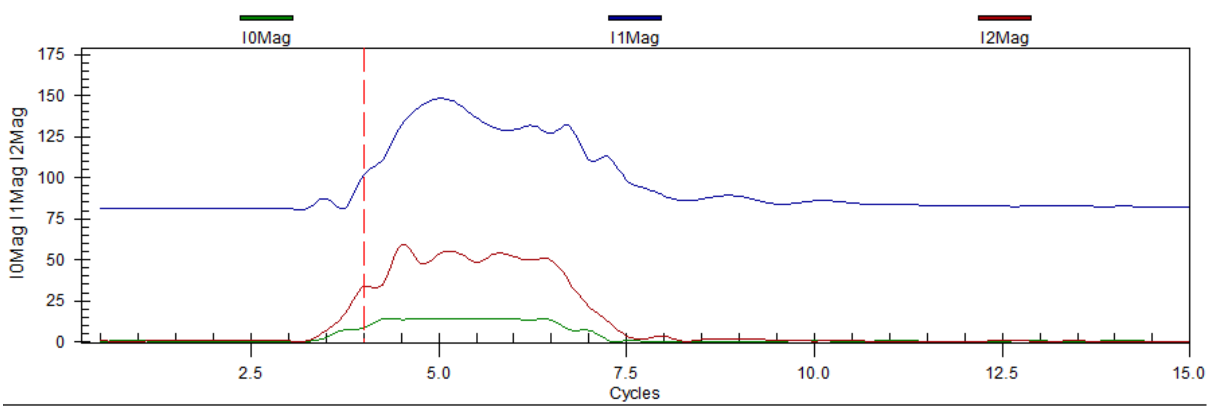


Figure 4.34. – Event B.1. (b) Sequence Current Magnitudes

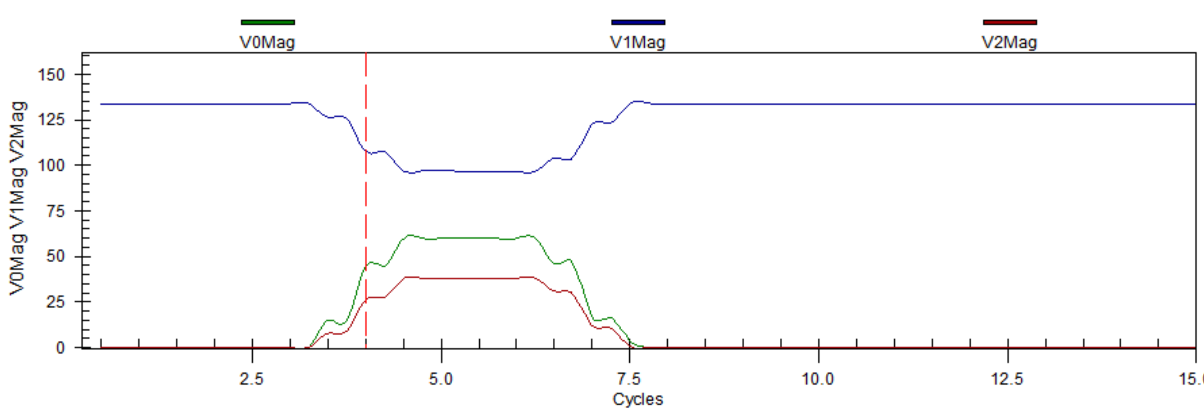


Figure 4.35. – Event B.1. (a) Sequence Voltage Magnitudes

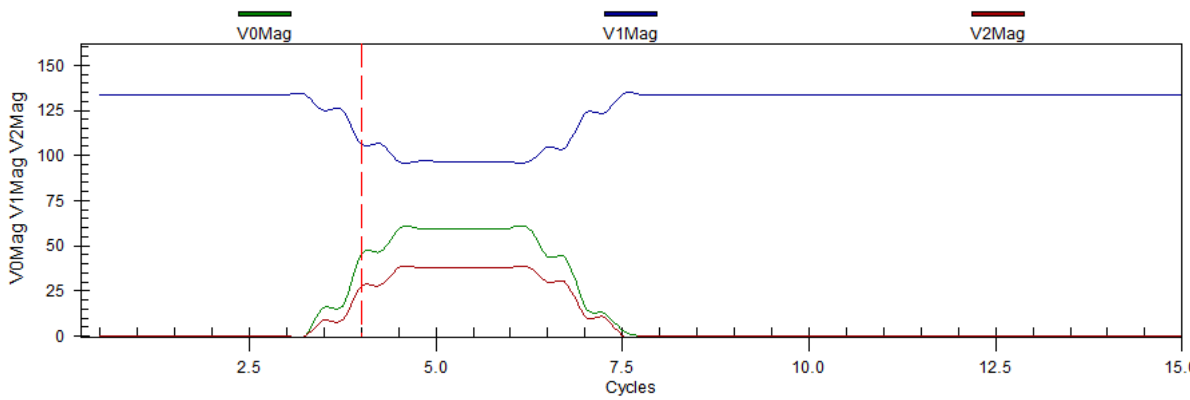


Figure 4.36. – Event B.1. (b) Sequence Voltage Magnitudes

- The differential elements operate correctly for both cases. It shows that the differential protection set was sensitive enough to pick up for the minimal nature of faults.
- The ground distance elements, Z1G and Z2G do not assert for faults with resistance. This can be attributed to the negligible zero sequence currents in the line. The small zero sequence contribution circulating in the line due to the conventional source and transformer ground was negated with the addition of the fault resistance.
- Both 32GF and 32QR are sensitive enough to operate even with a fault resistance.

4.1.6.3 Case C – Effect of operating conditions

A key aspect of this study was to explore the protection capabilities when a certain amount of wind turbines are not operating. In a real world, all the wind turbines in a particular wind energy plant would not operate at the same time with the same efficiency. In certain conditions, we could have one section of the plant switched off, and another section operating normally, depending on the geographical position of the wind turbine units and the wind flow contour in the region. For this case, 10 of the 20 available WTGs were switched off, and the rest were operated at 80% output capacity. Such a configuration was set up to explore the effectiveness of the protection scheme for a close-to-worst case minimal operation of the WTGs. Faults were generated at 50% of the line with and without a resistance. Table 4.3 shows the summary of events generated for this case.

A summary of events generated in both relays for fault on the 230kV line for case C is as provided in Table 4.3.

- There is a substantial decrease in the fault contribution from the WTG side due to the reduced power output of the wind turbines. Subsequently, there are reduced sequence currents generated for faults.

Fault Issued	Fault Location	Relay	Fault Resistance	Protection Element Operation					Element Tripped on
				87L	M1P	M2P	Z1G	Z2G	
AG	50%	230kV W	0 ohms	Y	N	N	N	N	87LA
		230kV G		Y	N	N	Y	Y	87LG, 87LA
ABG		230kV W		Y	N	N	N	N	87LG, 87LA
		230kV G		Y	Y	Y	N	N	87LG,
AB		230kV W		Y	N	Y	N	N	87L2, 87LA, 87LB
		230kV G		Y	Y	Y	N	N	87L2, 87LA, 87LB
ABCG		230kV W		Y	N	N	N	N	87LB, 87LC
		230kV G		Y	Y	Y	N	N	87LA, 87LB, 87LC
AG	50%	230kV W	80 ohms	Y	N	N	N	N	87L
		230kV G		Y	N	N	N	N	87LG
ABG		230kV W		Y	N	N	N	N	87LG, 87LA
		230kV G		Y	N	N	N	N	87LG,
AB		230kV W		Y	N	N	N	N	87L2, 87LA, 87LB
		230kV G		Y	N	N	N	N	87L2, 87LA, 87LB
ABCG		230kV W		Y	N	N	N	N	87LB, 87LC
		230kV G		Y	N	N	N	N	87LA, 87LB, 87LC

Table 4.3 – Effect of operating conditions on 230kV Transmission Line Faults

- The magnitude of voltage and current imbalance attributed from the WTG is also reduced. It was observed that for faults with a considerable fault resistance, the current imbalance is minimal.
- It was observed that the phase and ground distance elements do not operate for faults cases with and without fault resistance. This can be expected due to reduced fault current contributions and current imbalances in this case. If the system primarily used distance protection, the degree of sensitivity needed for faults would be a crucial factor to be considered.
- The differential protection elements operate as desired for all faults. The degree of sensitivity has been achieved with this scheme of protection.
- The directional supervision elements operate as desired for all faults.

To help reinforce the observations mentioned for Case C, an event from the Table 4.3 is discussed and compared to previous cases.

4.1.6.3.1 Event C.1. – AG Fault at 50% of the line (WTG side relay response)

Figures 4.37 through 4.39 illustrate the 230kV W relay response to a fault at 50% of the line, with 10 of the 20 available WTGs switched off, and the rest operated at 0.8pu.

The event C.1 as shown in Figures 4.37, 4.38 and 4.39 is compared to the event B.1 (a) described in Figures 4.31, 4.33 and 4.35, which is a fault of the same nature but with optimal wind output operating conditions. Following are the observations based on the comparison of the two events.

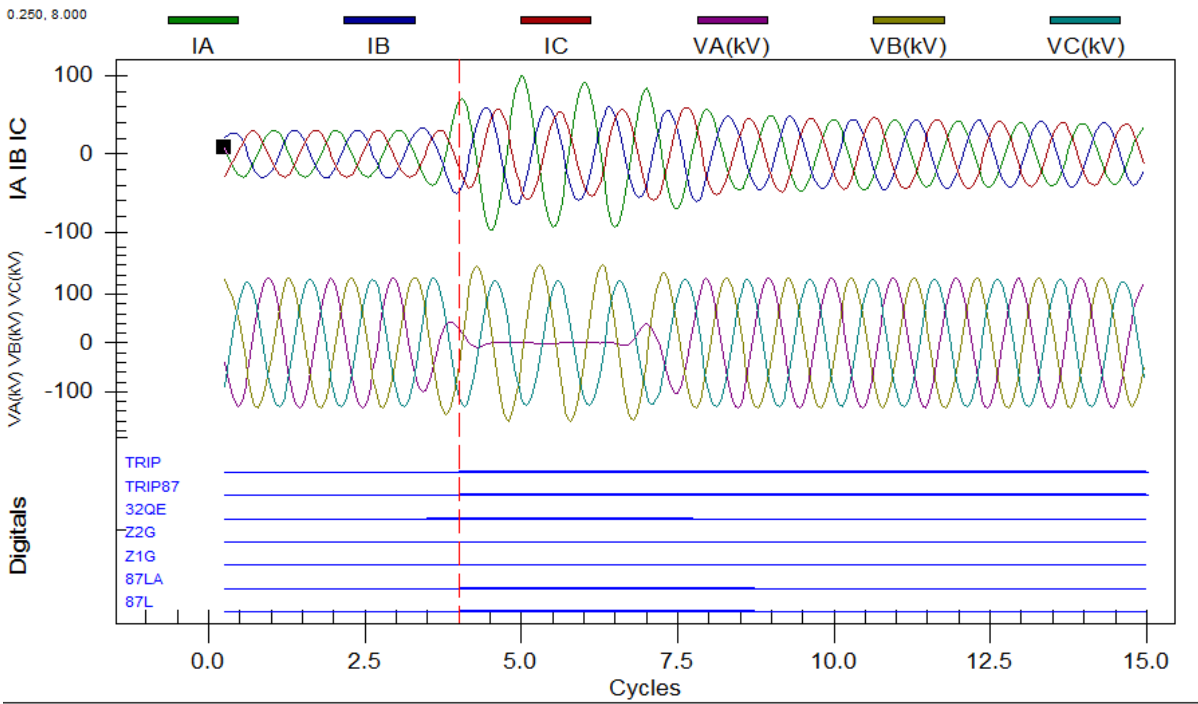


Figure 4.37. – Event C.1. 230kV W Relay Response

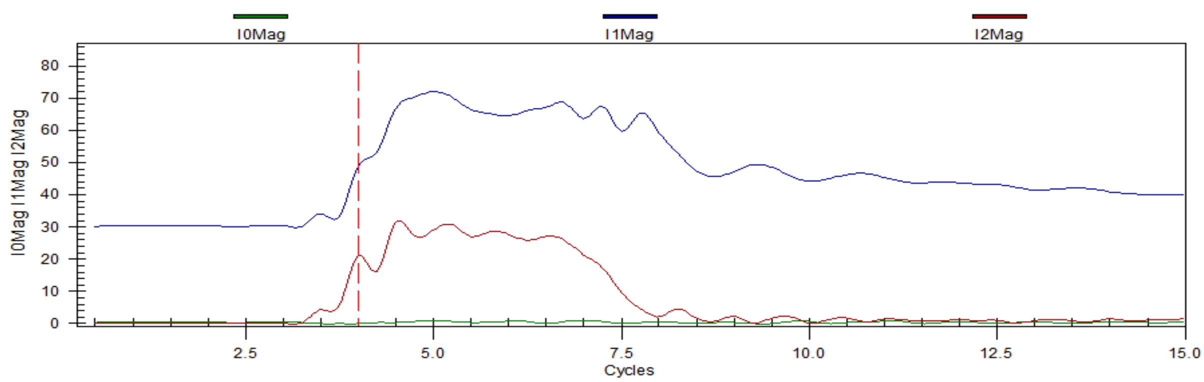


Figure 4.38. – Event C.1. Sequence Current Magnitudes

- With a decrease in the number of wind turbine units operating, there is a visible decrease in the load current through the line. Subsequently, the magnitude of current imbalance is also reduced. However, the profile of the current and voltage remain the same.

- There is a noticeable decrease in the sequence current, primarily with the zero sequence almost reducing to zero. The sequence voltages remain the same in comparison.

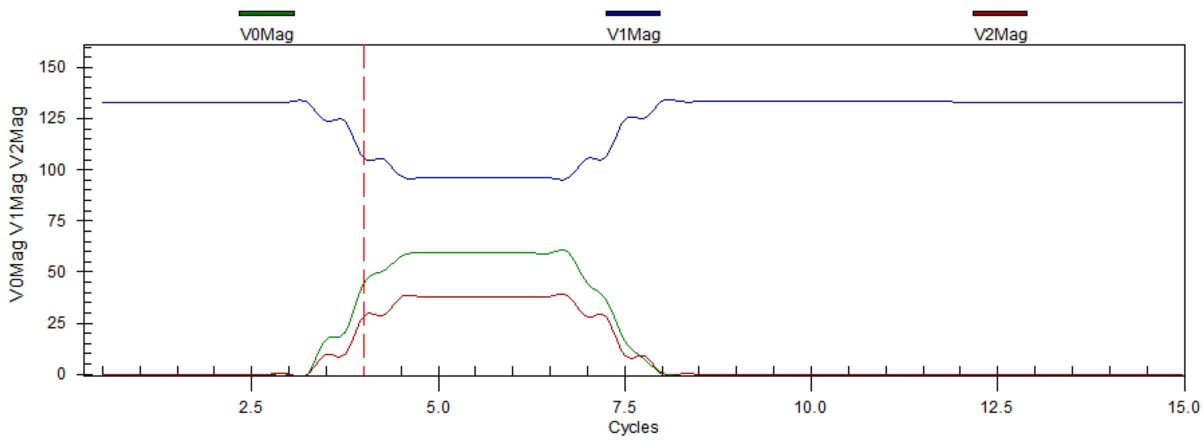


Figure 4.39. – Event C.1. Sequence Voltage Magnitudes

- A decrease in zero sequence currents has a profound influence in the operation of the ground distance elements, with the Z1G and Z2G not picking up at all. The sensitivity of the distance elements now becomes a deciding factor for the protection scheme involved.
- The differential elements proved to be sensitive enough to operate even in low generation as in this case.
- The directional supervision elements operate as desired.

4.1.7. Analysis of Events on the 230kV Main Transmission Line

4.1.7.1. Differential Protection

The differential protection scheme for this study proved to be very reliable in identifying the fault correctly and asserting the trip signal instantaneously. The differential elements related to each fault picked up accurately and assisted in the fault selection process. An increase in resistance had minimal effect on the protection since the differential elements were set for sufficiently low pickup values. Also, a high fault contribution from the grid side aided in making the right trip decision.

It is to be noted that the study was carried out in a lab with the minimal distance between the relays, making the communication channel delay very small. But, in the real world, we would have a communication channel measuring tens of miles. This would bring in a certain travel time delay, based on the propagation velocity of the data through the optical fiber cables, coupled with random noise, which could delay the trip assertion by a fraction of a cycle. However, this delay is minimal and would not seriously affect the overall protection scheme.

4.1.7.2. Distance Protection

The distance protection scheme proved to be relatively reliable at optimal power generation except for certain conditions where the distance elements would not pick up, such as three phase faults on the WTG side. This can be attributed to the voltage sourced converter on the wind turbine side continuously adjusting itself to minimize the effect of voltage imbalances due to the fault.

With the addition of fault resistance, the reach of all distance elements is greatly reduced, resulting in the WTG side relays not picking up at all. The same can be said about the grid side relays as well. However, since the grid side is a strong source and still contributing high fault currents, the distance elements pick up for faults up to 50% of the line as seen in Table 4.3. The sensitivity of the distance element may have to be increased to operate on such high resistance faults or quadrilateral distance elements can be used. This is an important consideration since in reality, faults are actually not bolted and may have a certain amount of resistance associated with them.

4.1.7.3 Effect of operating conditions

A wind energy plant operating in a region with multiple wind turbines spread out over a large area, at times would not have all its wind turbine operating at full capacity. Depending on the geographical location, which affects the wind flow contour, there would be certain wind turbines operating at synchronous speeds and others at sub synchronous speeds. The first observation, before generating any faults on the system is that the CTs secondary currents are reduced considerably, and could fall below minimum pickup.

With the application of faults on the system, the differential elements on both relays operate successfully to identify the fault with the right phase. It was observed that the pickups set for both differential and distance elements were set close to equally sensitive values, but it was the differential element that asserted for all fault conditions.

The distance protection elements on the other hand were affected by the loading of the WTGs. This was especially true on the 230kV W relay since the fault contribution were reduced to a large extent. The distance elements failed to pick up for faults involving ground, which is due to the fact that the zero sequence contribution became further negligible with reduces power flow through the line. The grid side distance elements operated satisfactorily, but with increased fault resistance, the elements failed to operate. This points to the fact that distance element reach would have to be reduced and more zones added if it is important to protect the line with this form of a protection scheme. Communication aided protection schemes with special logic for weak infeed systems would help improve reliability of the distance elements.

4.2. Collector Feeder Protection

The collector feeder protection was implemented based on the protection scheme discussed in Section 2.11.2 of Chapter 2.

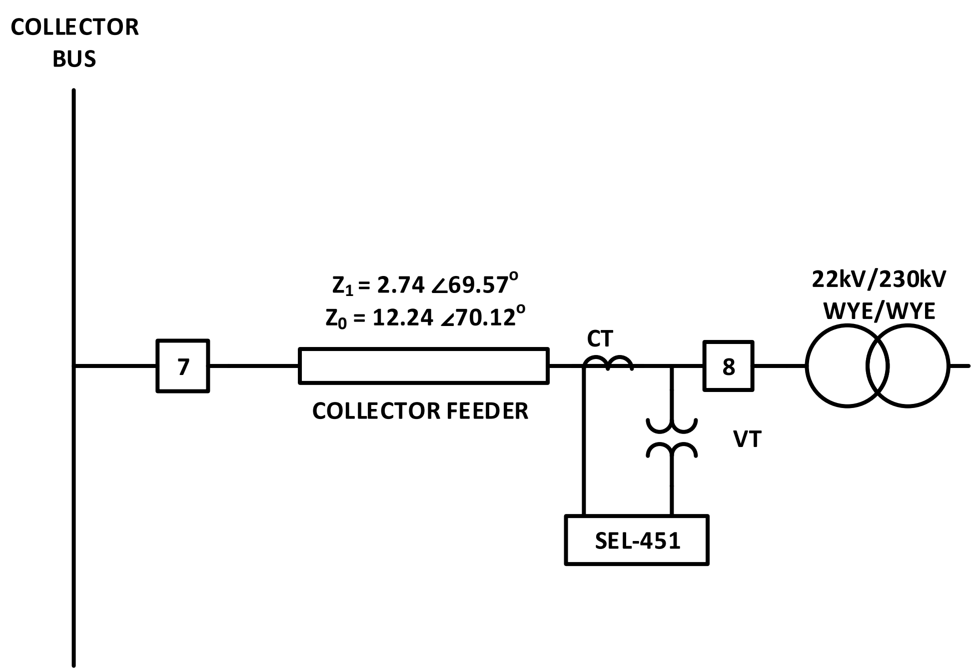


Figure 4.40 - Collector Feeder Protection One Line Diagram

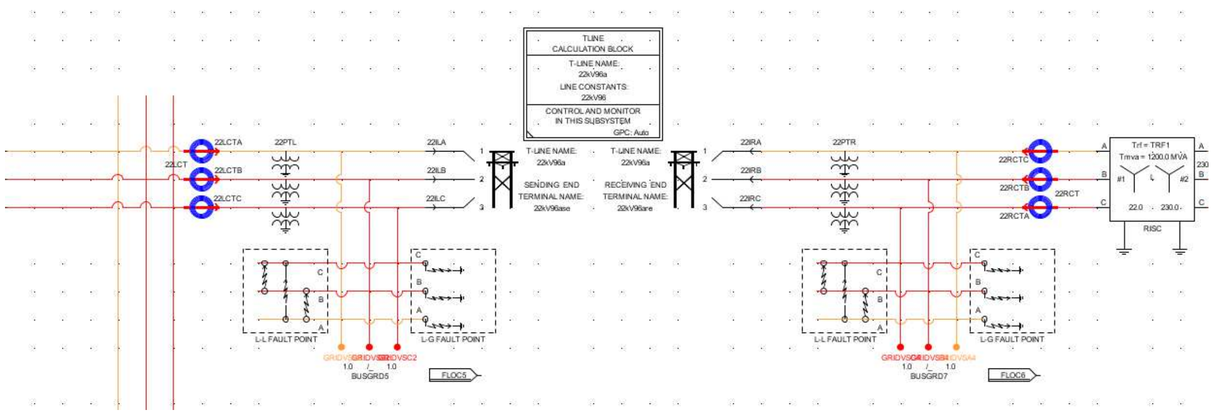


Figure 4.41 – Collector Feeder RSCAD Model

Figure 4.40 and 4.41 shows the 2.2kV collector feeder line modelled in RSCAD with its step-up transformer, line sections, fault sections, CTs and VTs. The primary protection is implemented using instantaneous overcurrent (50) protection elements and the backup is provided by inverse time overcurrent (51) protection elements. The CTs and VTs positioned at the end of the line provide the measured quantities required for the relays to operate.

4.2.1. CT and VT Modelling

The CT and VT for this protective scheme were modelled as nearly ideal transformers. The CT and PT ratios were calculated as follows,

$$CTR = \frac{1500A}{5A}$$

$$PTR = \frac{22kV}{115V}$$

The secondary voltages and currents measured from the output of the CTs and VTs are shown in Figure 4.42 and Figure 4.43.

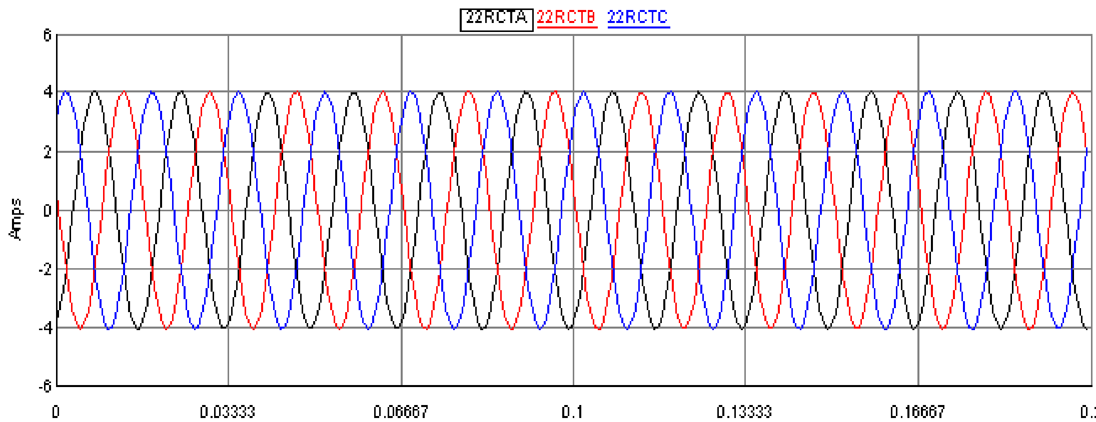


Figure 4.42 – Secondary currents at the 22kV Collector line CT

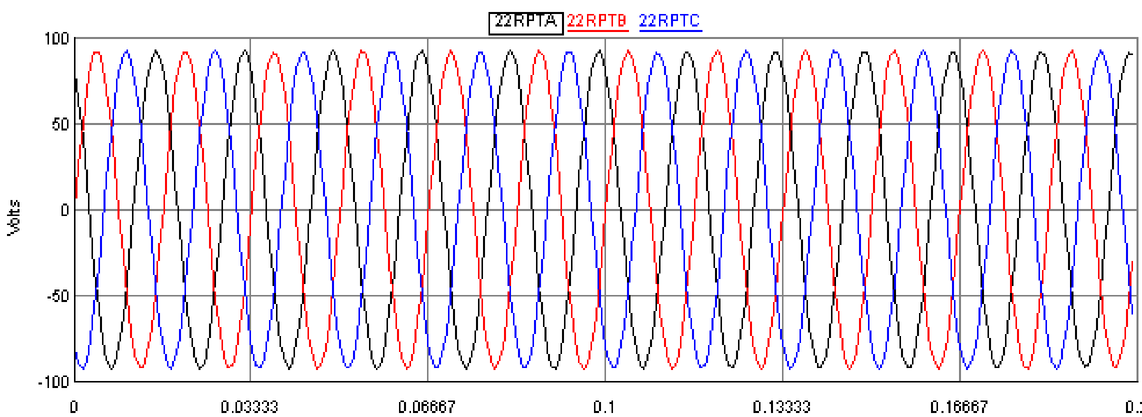


Figure 4.43 – Secondary voltages at the 22kV Collector line PT

The secondary currents and voltages as seen in the CT and PT connected to the protective relay were compared to the actual quantities in the line and were seen to be an accurate representation of the real voltages and currents. The protective scheme employed for the 22kV collector line will be discussed in the next section.

4.2.2. Instantaneous Overcurrent Protection (50)

The primary protection for the collector feeder line is provided by the 50 elements. The overcurrent protection is set up using an SEL-451 relay. The relay is positioned at the end of the collector line next to the main step up transformer and looking toward the wind turbine generator units. The settings involved in this protection scheme are described in Appendix A. Following are the brief set of important parameters that need to be considered while setting up this protection scheme.

4.2.2.1. 50P1P

The level one phase instantaneous overcurrent element asserts a trip when any one of the phase currents goes beyond the set threshold. In this study, to rapidly clear faults, the 50P1P element is set approximately equal to 50 percent of the fault current measured at the local terminal when a close-in three phase fault occurs. With directional supervision, the 50P1P acts as a forward element. There is no definite time delay added to this element.

The 50P1P is set to 6.0A (secondary current), which is a good threshold for three phase faults along the whole length of the collector feeder. This implies that the element would assert if the fault current exceeds 6*300A = 1800A in the collector line.

4.3.2.2. 50G1P

The 50G1P element is used to detect ground faults along the line. In this study, the 50G1P is set to pick up for a minimum ground fault close in to the local step up transformer at the wind turbine generator zone. The 50G1P element was set to 3.0A (secondary current) which meant that the relay element would assert for ground faults exceeding 3*300A = 900A in the collector line.

4.3.2.3. 50Q1P

The 50Q1P is the level one negative sequence instantaneous overcurrent element that picks up for phase to phase and double line to ground faults along the line. This element was set to 9.0A (secondary current) based on the minimum phase to phase fault current close-in to the local step up transformer. The 50Q1P element would assert for phase to phase faults exceeding 9*300A = 2700A in the collector line.

4.2.3. Time Overcurrent Protection (51)

The time overcurrent protection scheme acts as the backup protection to the instantaneous overcurrent elements. The 51 elements are basically set up in this study to pick up for faults that are of lower current magnitude and allow for a slower trip time. The 51 elements are aided by directional supervision to prevent tripping the breaker for faults behind the relay and outside its zone of protection. Following are the 51 elements that have been set to protect the collector line in this study.

4.2.3.1. 51S1

The 51S1 element is used to detect three phase fault on the line. The pickup is set greater than the maximum load current. A time dial is selected to coordinate with SEL-311L relays upstream at the main transmission line. The electromechanical reset and torque control quantities are not being used.

51S1O = IMAXL (51S1 Operate quantity)

51S1P = 6.0A (Secondary Amps)

51S1C = U3 (51S1 Inverse time overcurrent curve)

51S1TD = 1.0 (51S1 Time Dial)

4.2.3.2. 51S2

The 51S2 element is used to detect ground fault along the line. The pickup is set similar to its corresponding instantaneous element, and used for minimum ground faults at the farthest point along the line. A time dial is suitably selected to coordinate with SEL-311L relays upstream.

51S2O = 3I0L (51S1 Operate quantity)

51S2P = 3.0A (Secondary Amps)

51S2C = U3 (51S1 Inverse time overcurrent curve)

51S2TD = 1.50 (51S1 Time Dial)

4.2.3.3. 51S3

The third 51 element in this study is set low enough to see phase to phase faults and phase to ground faults along the entire length of the line. A time dial is selected to coordinate with relays upstream.

51S3O = 3I0L (51S1 Operate quantity)

51S3P = 9.0A (Secondary Amps)

51S3C = U3 (51S1 Inverse time overcurrent curve)

51S3TD = 1.00 (51S1 Time Dial)

4.2.4. Faults on the 22kV transmission line

Faults were simulated on the 22kV transmission line and the relay responses were recorded in the form of relay field event reports. The 22kV relay was located on the WTG local step up transformer, looking into the 22kV transmission line, as shown in Figure 4.40. Faults were simulated similar to the method described in Section 4.1.5, and the responses of the relay to various faults were recorded and summarized in Table 4.4.

Faults were simulated at 20% (close-in) and 80% of the line with fault resistances ranging from 0Ω to 15Ω. Condition of low wind speed, with certain WTGs not generating were also considered for fault studies. For all scenarios, following are the responses expected from the protection elements.

1. The relays should trip instantaneously
2. The 50 and 51 elements should pick up for faults along the whole length of the line.

3. The 50 elements should assert the trip signal for all faults of low resistance.
4. The faulted phases should be properly identified
5. The relay should not trip for faults outside its zone of protection

Following are the different cases for faults on the 22kV collector line, and the observations made based on the relay responses.

4.2.4.1. Case D – Bolted faults on the 22kV collector line

In this case, the faults were simulated at 20% and at 80% of the line. Table 4.4 summarizes the relay responses to all the fault scenarios.

Fault Issued	Fault Location	Fault Resistance	Protection Element Operation		Element Tripped on
			50 Elements	51 Elements	
AG	20%	0 ohms	Y	Y	50G1
ABG			Y	Y	50Q1
AB			Y	Y	50Q1
ABCG			Y	Y	50P1
AG	80%	0 Ohms	Y	Nil	50G1
ABG			Y	Y	50Q1
AB			Y	Y	50Q1
ABCG			Y	Y	50P1

Table 4.4 – Bolted faults on 22kV Collector Line

Following are the observations based on relay response described in Table 4.4.

- The current imbalance on the line was relatively high compared to the 230kV line. This can be attributed to the fact that the line is short and closer to the WTG system. There is also a considerable fault current contribution from the grid side.
- The voltage imbalance is more pronounced due to the fact that the VTs are on the weak source end. The voltage profiles are as expected for each fault type.

- The 50 element asserts instantaneously for all fault types. The 51 element also follows closely and picks up after a short time delay based on its time dial.
- The relay sees the fault and trips on the right overcurrent element, indicating the actual fault type.
- The directional elements pick up for all forward faults.
- Additionally it was observed that the overcurrent element stayed de-asserted for faults behind the relay and outside its zone of protection.

4.2.4.2. Case E – Faults on the 22kV collector line with fault resistance

Faults were simulated on the collector line with increasing resistance. It was observed that at a resistance of 15Ω, the overcurrent protection failed to operate since the fault currents were not high enough to cross the threshold values set for the 50 and 51 elements. The 50/51 elements would have to be set to a lower pickup value, but not low enough to be able to assert on load current flow. The generator start up and the transformer inrush currents would also have to be taken into consideration while setting a sensitive 50/51 protection on the collector line. The current contribution from WTGs caused an infeed effect, increasing the impact of fault resistance.

4.2.4.3. Case F - Effect of operating conditions on the 22kV protection

For this case, 10 of the 20 available WTG's were switched off, and the rest were operated at 80% output capacity. It was observed that the 50 and 51 elements operated as desired, being sensitive enough to pick up all faults in the line. This can be attributed to the fact that there is essentially the same fault contribution from the grid even though the current has decreased considerably from the WTGs. This can be verified by comparing events of an AG fault at normal operation and at minimal WTG operation

4.2.4.3.1. Event F.1 – AG fault at 20% of the line at varying operating conditions

Figures 4.44 through 4.47 illustrate a comparison of faults on the collector line with the WTGs running at maximum capacity and at minimum capacity.

Following are the observations based on comparison of the events E.1 (a) and E1 (b).

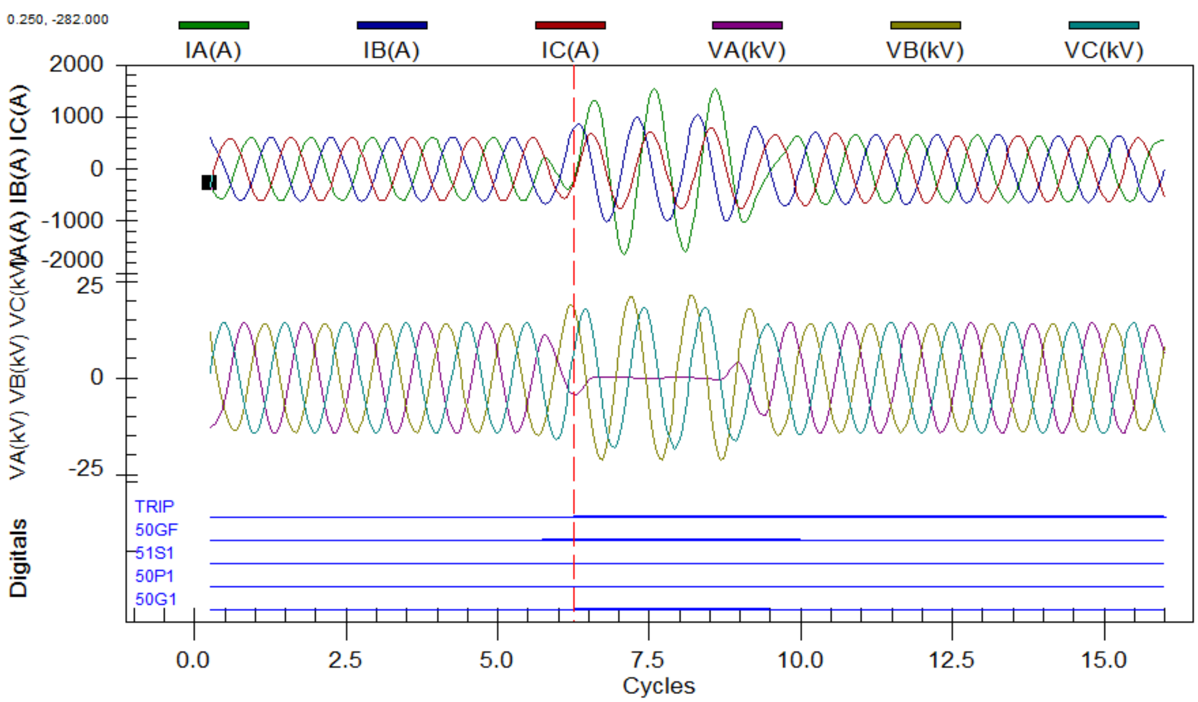


Figure 4.44 – Event 1(a) relay response with WTGs running at maximum capacity

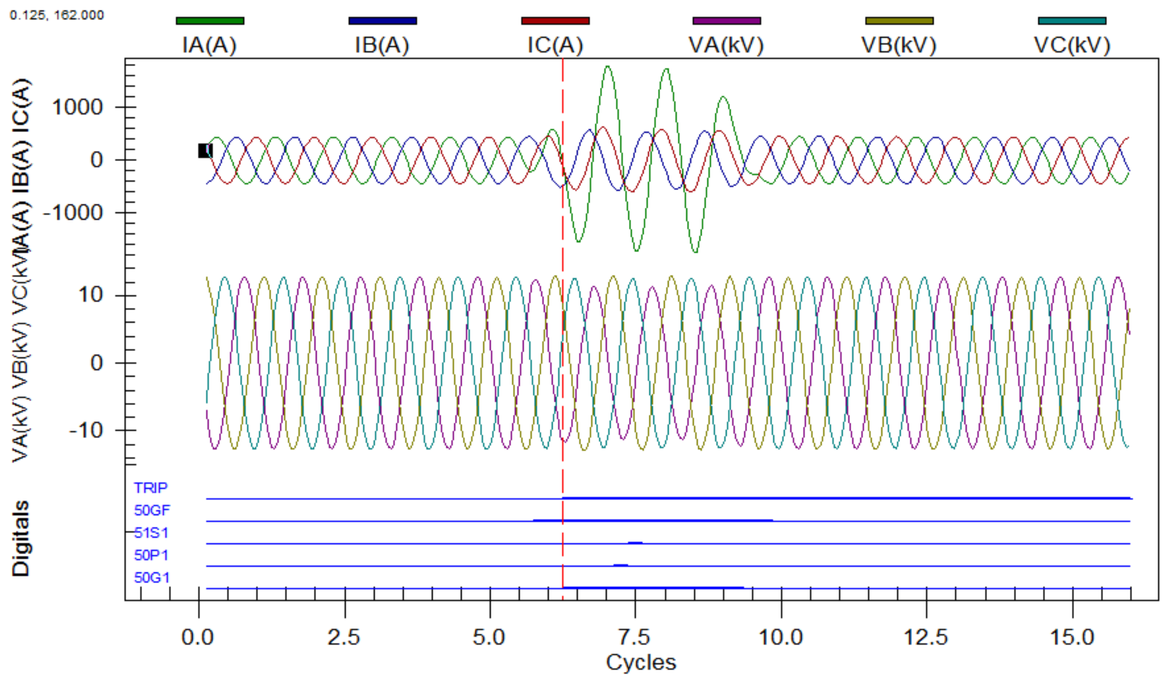


Figure 4.45. – Event 1(b) relay response with WTGs running at minimum capacity

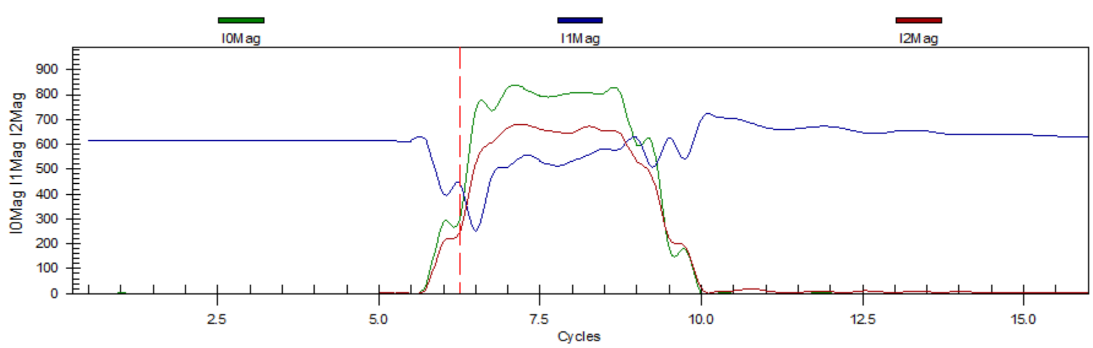


Figure 4.46. – Event 1(a) relay sequence current magnitudes

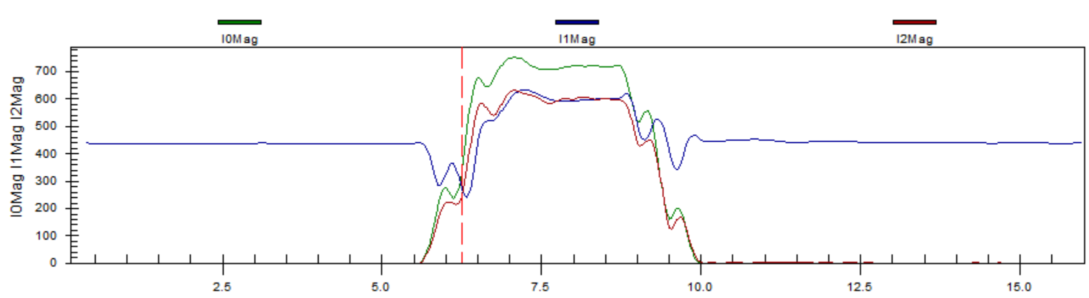


Figure 4.47. – Event 1(b) relay sequence current magnitudes

- The fault current levels are almost the same but slightly lesser for Event 1(b). However, fault contribution from the grid side remains about the same.
- The current imbalance has a noticeable difference between cases. With a reduced capacity of WTG operation, the current imbalance is primarily contributed from the grid side indicating a strong A-phase fault current. For operation at full capacity, the current regulators on all the WTGs try to compensate for the current imbalance by adjusting currents on all phases, which can be seen in the fault current profiles.
- The zero sequence currents appear to be slightly smaller in event 1(b), as compared to that in 1(a). The zero sequence currents appear to be from the grid side.
- The 50 elements operate as desired for the AG fault on the line.
- The 50 forward directional element, 50GF, picks up indicating a forward fault in event 1(b), which is expected.
- The 50 elements operate in both cases and assert an instantaneous trip.

4.2.5. Analysis of faults on the 22kV collector line

Based on the relays responses observed for the faults on the 22kV collector line, the instantaneous and the inverse time overcurrent elements operated properly for all bolted fault types. With increasing fault resistance, the 50 and 51 elements eventually failed to operate. This is expected since the fault currents were not significant enough for the elements to assert. The transformer damage curves and machine fault limits must be considered while setting the overcurrent pickups.

The overcurrent elements generally did not operate for faults on the 230kV main transmission line, however, in one case, the relay did trip for a three phase fault close-in to the WTG side of the 230kV line. Adding a time delay to the 51 overcurrent element would ensure that the relay on 230kV line trips first to a close in fault. Also a delayed trip will make sure that the 22kV line is protected if the 230kV relay fault to operate for a fault on its line.

As discussed in the observations of the Section 4.2.4.1.1 there is a minimal effect of the operating state of the WTG's on the protection scheme. This can be attributed to the fault contribution from the grid side. There is more current coming in from the grid side due to the rotor circuit VSC's extracting currents from the grid. During the fault, the collector line offers a low resistance to the ground. To summarize, the WTG operating conditions had little impact on the protection performance.

4.3. Collector Bus Protection

The 22kV collector bus consists of incoming feeders from the WTGs through the local step up transformers and an outgoing collector feeder. This section has been protected using the bus differential protection scheme. The bus protection was implemented using a SEL-487B relay.

Figure 4.48 shows the 22kV bus with the connected incoming and outgoing feeders, with their respective CTs and VTs. On an actual implementation, the collector bus is usually located at the collector substation, with the respective protection devices close-by. The same system has been implemented on the RTDS and tested. The protection scheme consists of CTs and VTs for both incoming and outgoing feeders. The setup of the protection scheme will now be discussed in Sections 4.3.1 through 4.3.4.

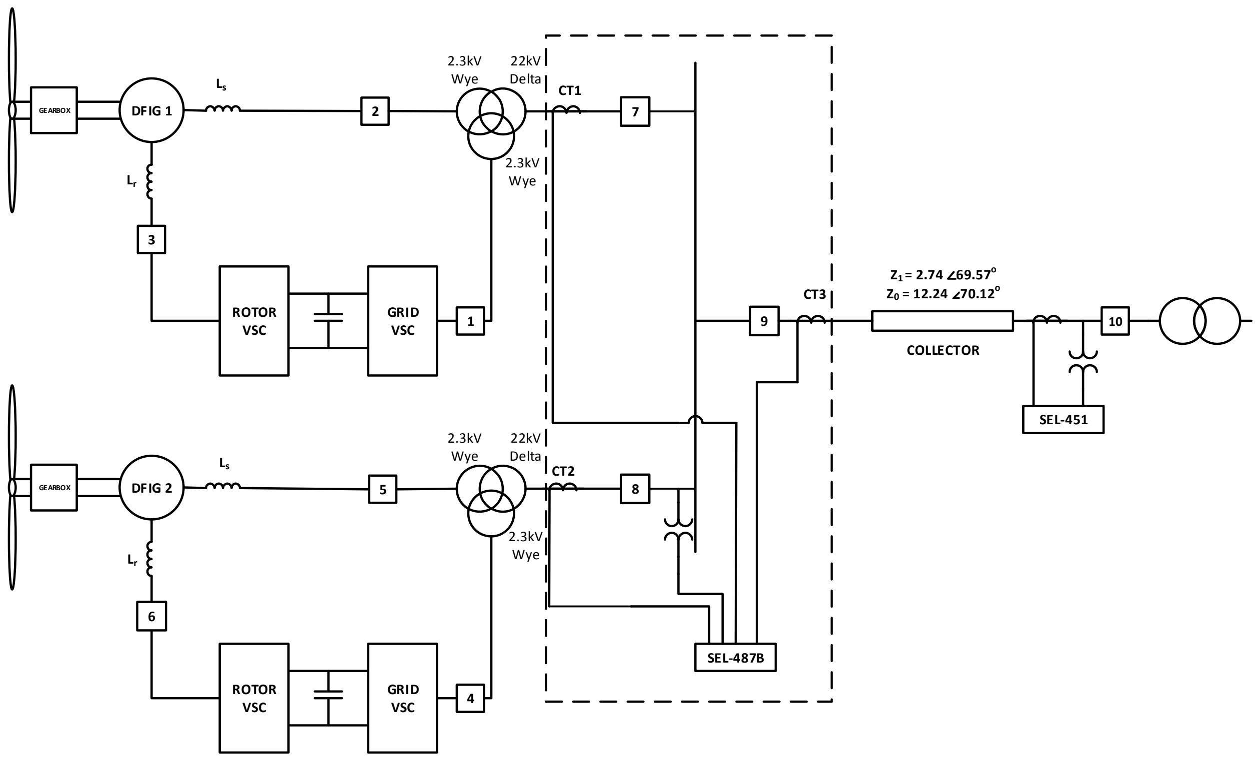


Figure 4.48. – Collector bus Protection

4.3.1. Modeling of CTs and VTs

The CTs and the VTs involved in this protection scheme have been modelled the same as discussed in Section 4.2.1, since they are on the same rated system. As a result, following are the CT and the VT ratios.

$CTR = \frac{1000A}{5A}$ (For CT1 and CT2)

$CTR = \frac{1500A}{5A}$ (For CT3)

$$PTR = \frac{22kV}{115V}$$

4.3.2. Bus Differential Protection (87B)

The protection scheme for the 22kV collector bus has been implemented using an SEL-487B relay with its input received from the CTs and VTs on both sides of the bus. The primary element set in this relay is differential protection. The relay looks at currents entering into the bus from various incoming feeders and the currents that leave the outgoing feeder(s). The relay picks up when there is a fault in the bus protection region and sends a trip command to the breaker. Following are a brief set of parameters that need to be considered while setting up the bus protection using the SEL-487B.

4.3.3. Terminal Bus-Zone Connections

The terminal bus-zone setting is used to assign the CT currents to the respective bus zones. This study involves a simple single zone configuration with two incoming feeders and one outgoing feeder connected to the collector bus as shown in the Figure 4.48.

The secondary current inputs are assigned to the relay terminal input as follows.

I01-BZ1: CT1 A phase

I02-BZ1: CT1 B phase

I03-BZ1: CT1 C phase

I04-BZ1: CT2 A phase

I05-BZ1: CT2 B phase

I06-BZ1: CT2 C phase

I07-BZ2: CT3 A phase

I08-BZ2: CT3 B phase

I09-BZ2: CT3 C phase

Care was taken to assign the correct polarities to the CT currents while setting the terminal bus-zone connections

4.3.4. Differential and Directional Elements

4.3.4.1. Sensitive Differential Elements

The sensitive differential elements in each zone detect the increase in differential current which could result from a CT open or short circuit condition and need to differentiate from faults of high fault resistance.

4.3.4.2. E87SSUP

The E87SSUP element is used to enable or disable the sensitive differential element supervision. In this study, E87SSUP = Y.

4.3.4.3. S87P

The threshold for the sensitive differential element is defined by the value of the S87P element. It is set as the per unit differential current in the bus zone. In this study, S87P is set to 0.1pu.

4.3.4.4. 87STPU

The 87STPU adds a delay timer to the 87S1 that picks up during a fault or CT malfunction condition. In this study, this element is set to the relay default of 300 cycles.

The Figure 4.49 gives a better understanding of the sensitive differential element block.

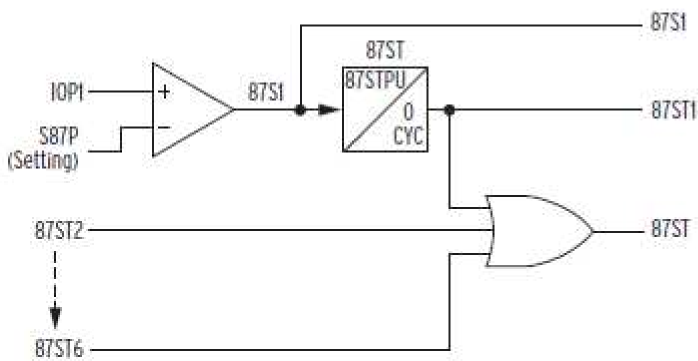


Figure 4.49 – Sensitive Differential Element [18]

Where,

IOP1 – Differential operating quantity

87ST1-6 – Time delayed differential word bits

4.3.4.5. Restrained Differential Elements

The restrained differential elements are used to differentiate between an internal and an external fault based on the relay differential characteristics. Figure 4.50 shows the differential element characteristic of a bus differential protection scheme.

O87P defines the minimum restrained differential element pickup of the relay. When the operating quantity (IOP1) exceeds the O87P for low current conditions, the differential element issues an output. For larger currents, the slope comes into use. There are two slope settings available. Slope 1 (SLP1) comes into effect for internal faults. The slope 2 (SLP2) is activated during external fault. Following are the restrained differential element settings used in this study:

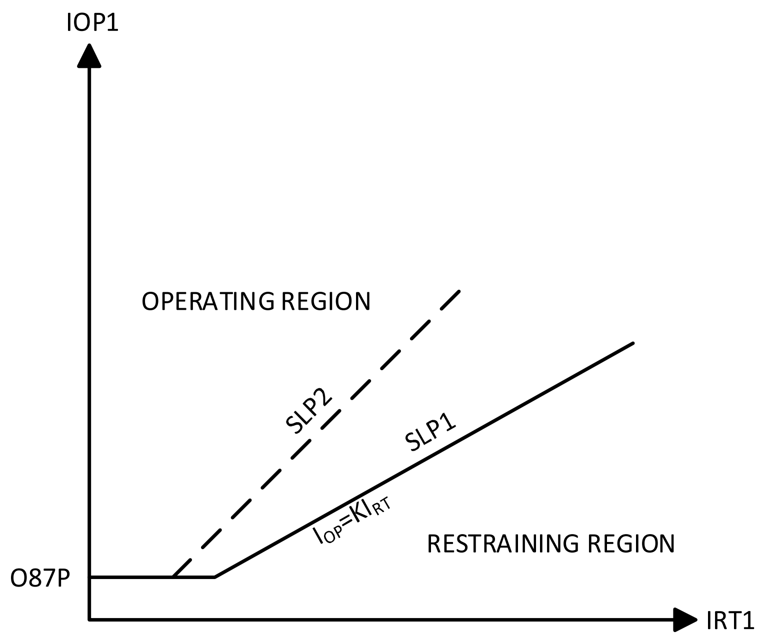


Figure 4.50. – Filtered Differential Element Characteristic

O87P = 0.1pu (Minimum restrained differential element pickup)

EADVS = Y (Advances settings enable)

SLP1 = 60 (Restrained slope 1 percentage)

SLP2 = 80 (Restrained slope 2 percentage)

RTDI = 1.6pu (Incremental restrained current threshold)

OPDI = 1.2pu (Incremental operating current threshold)

4.3.5. Faults on the 22kV Collector bus

Faults were simulated on the 22kV collector bus with relay responses recorded from the relay connected to the CTs of the incomer and the outgoing feeders. The fault resistances were increased from 0Ω to 15Ω and faults involving A-phase were simulated. Table 4.5 shows the relay responses to faults on the collector bus.

Fault Issued	Fault Resistance	87Z1 Operation
AG	0 ohms	Y
ABG		Y
AB		Y
ABCG		Y
AG	15 Ohms	N
ABG		N
AB		N
ABCG		N

Table 4.5. – Faults on the 22kV Collector bus

Following are the observations based on the relay responses as shown in Table 4.5.

- The CT’s on the two incoming feeders and the outgoing feeders reflect the current imbalances as expected.
- The relay picks up for a fault in its differential zone and asserts the trip signal instantaneously for low fault resistance.
- The relay does not pick up for faults with fault resistance over 12Ω.
- Additional faults were simulated external to the zone of protection. The relays operated correctly and did not trip.

Figures 4.51 through 4.54 describes an AG fault at the collector bus and the corresponding relay response.

4.3.5.1. Event G.1. AG Fault on the 22kV Collector Bus

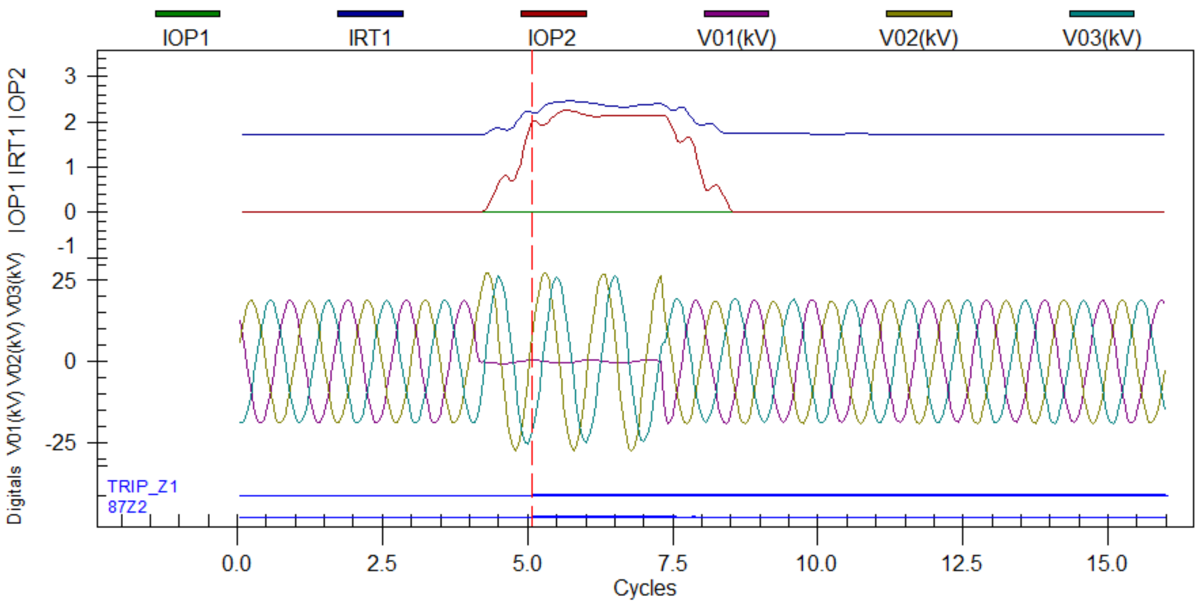


Figure 4.51 – Event G.1. 22kV Collector Bus Event Report

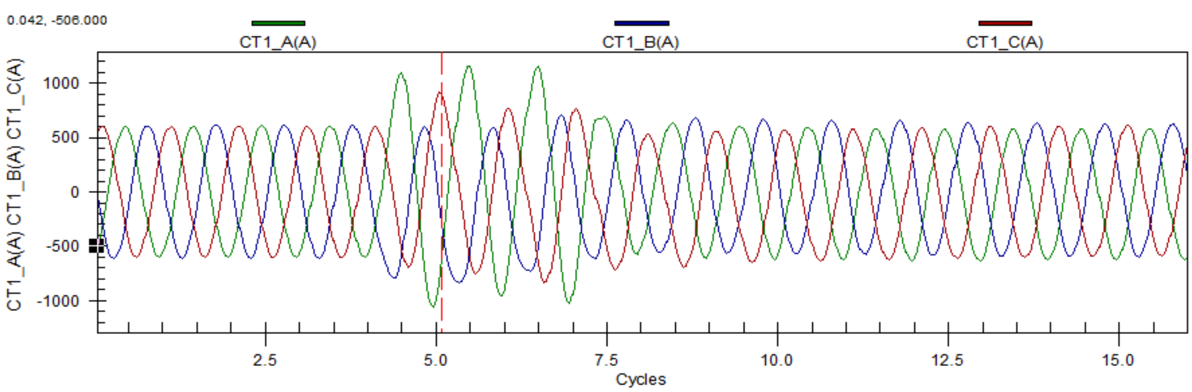


Figure 4.52 – Event G.1. CT 1 Currents

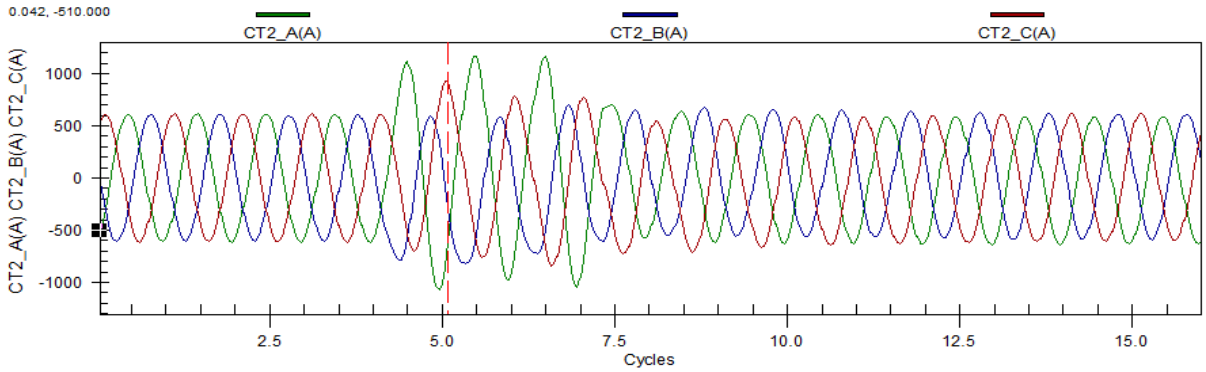


Figure 4.53 – Event G.1. CT 2 Currents

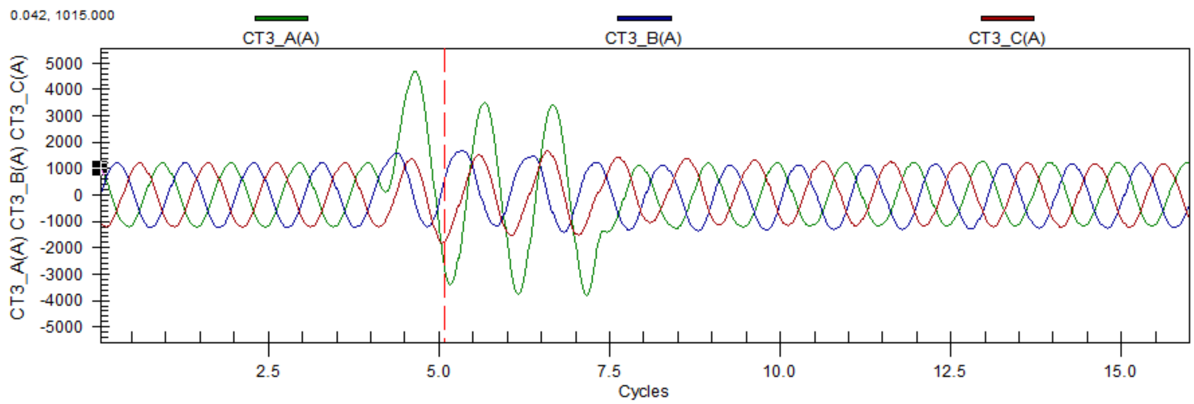


Figure 4.54 – Event G.1. CT 3 Currents

4.3.6. Analysis of Faults on 22kV Collector Bus

The bus differential elements were sensitive enough to pick up for all bolted faults on the collector bus. However, as the fault resistance increased, the fault current contribution decreased to a point where the currents are insignificant enough to the differential elements to sense and assert.

The operation of the bus differential protection was not impacted by the operation of the WTGs. The behavior seen in this study would be true for any bus scheme. The CTs were sized well enough to reflect the primary currents accurately, without going into saturation. The CTs were also able to ride through external faults.

4.5. Summary

The faults simulated at the collector bus, feeder and the main transmission lines, gave a good insight into the effect of WTG operating conditions on various protection schemes. The differential elements operated under all fault and operating conditions. The distance elements were found to be affected by reduced operating states of the WTGs. The collector overcurrent and the collector bus differential elements were unaffected by WTG operating conditions.

Chapter 5: Conclusion and Future Scope

5.1. Conclusion

The type 3 WTG protection scheme designed in this research study gives good insight into the influence of distributed generation on the dynamic performance of a grid integrated power system. The voltage sourced converters provide a steady output during times of low wind speed. In this study, a comprehensive protection scheme was devised based on optimum operation of the WTG system. Based on the faults simulated on the system and the relay response analysis, several conclusions can be drawn.

With operation of the WTG at varying speeds, based on wind flow at the particular location, this system cannot be considered equivalent to a conventional energy source. It was observed that at times when many of the generators were operating at minimum sub synchronous speeds, the fault current contribution of the aggregated system was considerably lower than under ideal conditions. This affected the operation of the distance elements on the WTG side of the 230kV line primarily. The distance elements failed to pick up for faults involving ground, due to a negligible zero sequence current in the line. It was observed that an even weaker source does have an impact on the zero sequence currents, even with the local step up transformer having a Wye-Delta configuration. The grid side relay was not affected in any way, due to a strong fault current contribution from the grid side, except for faults involving a considerably high fault resistance. Reducing the distance relay reach and increasing the number of zones of protection could help mitigate this problem to an extent. This study did not look into the implementation of communication aided distance protection. Having such a scheme where the relays would communicate with each other, and with a weak infeed logic active, would make the distance protection more reliable. Such communication aided scheme has been studied and implemented in [19].

The differential protection scheme was observed to operate for cases with minimal WTG loading which can be attributed to the fact that there is a considerable fault contribution from the grid side for a fault on the 230kV line. The differential protection scheme was set up to operate for the smallest operate current settings available in the relay. With a considerable distance between the two relays and a communication delay to the scheme, the performance times between the distance and differential schemes would be comparable. However still, it is expected that the delay would not be high enough to seriously affect the components in the system. The main disadvantage of using differential protection for transmission lines is the costs of running communication wires over a long distance. This has been the main reason why differential protection hasn’t seen widespread use among power systems all around the world. However, until recently, comparing the costs of wind farm installation, the installation of a differential scheme might not be as high. In the long run, a differential protection scheme could also save on the maintenance costs of power system components due to its reliability.

The overcurrent protection scheme on the collector feeder line operated accurately for all fault cases. The 50 and 51 elements were set for fault threshold levels at 80% of the line under maximum operating conditions. At minimum operating state, it was observed that the overcurrent elements still were able to pick up for fault currents on the line. This was due to the high fault contribution from the grid side. The collector bus differential protection operated seamlessly for all fault types due to its relatively small zone of protection.

A key aspect to consider in this study was that all protection elements were set to operate on maximum source operating conditions. In the real world, there would be a fine balance between sensitivity and selectivity requirements. This would depend on many factors such as the criticality of the loads connected to the network, grid – source interconnection agreements, generator/transformer damage curves etc. This study proves to be a good starting point on setting a protection scheme for an equivalent network of this kind, over which the degree of sensitivity and selectivity can be incorporated.

Thus to summarize the work performed in this thesis,

- The protection scheme for the main transmission line, collector feeder and collector bus was successfully designed and implemented
- Various fault cases were implemented successfully
- The performance of protection elements was studied from the recorded relay event reports
- Comparisons were made between distance and differential protection on the basis of faults of varying resistances and at varying operating conditions
- Recommendations based on observations and analysis were made to improve the accuracy of each protective scheme.

5.2. Future Work

This research study has laid the framework for setting up a comprehensive protection scheme for a type 3 grid interconnected wind energy system, and provided insight into the effectiveness of protection schemes to varied WTG operating capacities. Based on the observations and analysis, future work on modifying this model to address the following is suggested.

- As discussed before, the differential protection was operating at minimal communication delay. Hence, adding suitable delay matching real-world conditions, to the system by means of a channel delay simulator would simulate the actual effectiveness of the overall protection scheme.
- To help mitigate the effects of reduced operating conditions of the WTGs, a communication scheme can be set up between the bus, collector line and the main transmission line relays. Multiple settings groups could be formulated for different levels of operating conditions. The relays at the bus or the collector line would be able to sense the operating conditions based on the WTG source contribution and appropriately send communication bits to the main transmission line relays, to initialize settings changes.
- Improved protection for the collector line than the overcurrent protection can be explored for more reliable protection.
- Protection for more complex system fault conditions such as switch-onto-fault, evolving faults, breaker failure etc. can be studied and the existing settings be varied to accommodate these fault contingencies.
- Wind farms having a mixture of different types of wind energy systems, such as an aggregated combination of type 2 and 3, or types 3 and 4, would have considerable effect on the protection scheme. Similar studies can be carried out on the RTDS with protective relays connected to understand the effectiveness of similar protection schemes.

References

[1] "The World Factbook", www.cia.gov [Online], Available: https://www.cia.gov/library/publications/the-world-factbook/, December 2015

[2] "Benefits of Renewable Energy Use", www.ucsusa.org [Online], Available: http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/public-benefits-of-renewable.html, December 2015

[3] Global Wind Energy Council, "Global Wind Report – Annual Market Update 2014", Global Wind Energy Council, 2014

[4] Bin Wu, Yongqiang Lang, Nave Zargari, and Samir Kouro, *Power Conversion and Control of Wind Energy Systems*. John Wiley & Sons, September 2011

[5] Thomas Ackermann, *Wind in Power Systems*. John Wiley & Sons, April 2012

[6] IEEE PES Wind Plant and Solar Plant Collector Design Working Group, "Characteristics of Wind Turbine Generators for Wind Power Plants". IEEE/PES Transmission and Distribution Committee, Published at PES general meeting, 2009

[7] IEEE PES Wind Plant and Solar Plant Collector Design Working Group, "Reactive Power Compensation for Wind Power Plants". IEEE/PES Transmission and Distribution Committee, Published at PES general meeting, 2009

[8] J. Lewis Blackburn and Thomas J. Domin, *Protective Relaying: Principles and Applications*, Fourth Edition, CRC Press, June 2014

[9] SEL-451-5 Relay Instruction Manual, Schweitzer Engineering Laboratories, June 2015

[10] *Network Protection & Automation Guide*, ALSTOM, May 2011 Edition

[11] Demetrios A. Tziouvaras, Hector Altuve, Gabriel Benmouyal, Jeff Roberts, "Line Differential Protection with an Enhanced Characteristic", Eighth IEE International Conference on Developments in Power System Protection, April 2004

[12] Hector J. Altuve Ferrer and Edmund O. Schweitzer, *Modern Solutions for Protection, Control, and Monitoring of Electric Power Systems*, Schweitzer Engineering Laboratories, Incorporated, 2010

[13] Y. B. Li, T. S. Bi, T. Y. Zheng, J. X. Wang, L. H. Ma, D. P. Liu and S. M. Liu, "Configuration and Setting of Protection for Large-scale Wind Farm", International Conference on Power System Technology, October 2014

[14] RTDS technologies. "Real time digital simulator controls library manual", July 2013

[15] Amirnaser Yazdani and Reza Iravani, *Voltage-Sourced Converters in Power Systems*, IEEE-Wiley, March 2010

[16] IEEE Power Engineering Society, "IEEE Standard Requirements for Instrument Transformers", IEEE Standard C57.13 – 2008

[17] SEL-311L-1-7 Relay Instruction Manual, Schweitzer Engineering Laboratories, January 2015

[18] SEL-487B-1 Relay Instruction Manual, Schweitzer Engineering Laboratories, June 2015

[19] Rishabh Jain, *Grid Integrated Type 3 Wind Systems - Modeling, and Line Protection Performance Analysis using the RTDS Master's Thesis*, July 2014

[20] Rishabh Jain, Brian K. Johnson and Herbert Hess, "DFIG based wind turbine system modelling in the real time digital simulator", North American Symposium, 2014 IEEE, 2014

[21] IEEE Standards Coordinating Committee 21 on Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage, "IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems", IEEE Std. 1547.2 - 2008

Appendix A

This appendix lists the settings of all SEL relays used in this thesis. The settings were based on the protection philosophy explained in Chapter 4.

SEL-311L Relay Settings

General Settings

CTR - 50

APP – 311L

EADVS - Y

Line Current Differential Settings

E87L – 2

EHST – 2

PCHAN – X

EHSC – N

CTR_X – 50

87L Settings

87LPP – 6.0

87L2P – 0.5

87LGP – OFF

CTALRM – 0.5

87LR – 6.0

87LANG – 195

Backup Protection and Line Parameters

CTRP – 200

PTR – 2000.0

Z1MAG – 0.25

Z1ANG – 86.89

Z0MAG – 72.95

LL – 30.0

Phase Distance

E21P – 3

Z1P – 0.2

Z2P – 0.31

Z3P – 0.1

50PP1 – 0.5

Ground Distance

E21MG – 3

Z1MG – 0.8

Z2MG – 1.25

Z3MG – 0.46

E21XG – N

50L1 – 0.5

50GZ1 – 0.5

k0M1 – 1.014

k0A1 - -18.48

Z1PD – OFF

Z2PD – 10

Z3PD – OFF

Z1GD – OFF

Z2GD – 10

Z3GD – OFF

Directional Elements

E32 – AUTO

ELOP – Y

DIR3 – R

ORDER – QVI

Trip Logic

TR – 87L+M1PT+Z1GT+M2PT+Z2GT+M3PT+Z3GT

SEL-451 Relay Settings

General Global Settings

NFEQ – 60

PHROT – ABC

FAULT - 51S1 OR 51S2 OR 50P1

Line Configuration

CTRW – 300

CTRX – 300

PTRY – 193.0

VNOMY – 115

Z1MAG – 2.74

Z1ANG – 69.57

Z0MAG – 12.24

Z0ANG – 70.12

Relay Configuration Enables

E50P – 1

E50G – 1

E50Q – 1

E51S – 3

E59 – N

E27 – N

E81 – N

ECOMM – N

Phase Instantaneous/Definite-Time Overcurrent

50P1P – 6.0

67P1D – 0.0

67P1TC – 1

Residual Ground Instantaneous/Definite-Time Overcurrent

50G1P – 3.0

67P1D – 0.0

67P1TC - 1

Negative-Sequence Instantaneous/Definite-Time Overcurrent

50G1P – 9.0

67P1D – 0.0

67P1TC - 1

Time Overcurrent

51S1O – IMAXL

51S1P – 6.0

51S1C – U3

51S1TD – 1.0

51S1RS – N

51S1TC – 1

51S2O – 3I0L

51S2P – 3.0

51S2C – U3

51S2TD – 1.0

51S2RS – N

51S2TC – 1

51S3O – 3I2L

51S3P – 9.0

51S3C – U3

51S3TD – 1.0

51S3RS – N

51S3TC – 1

Trip Logic

TR - 50P1 OR 51S1T OR 50Q1 OR 51S2T OR 50G1 OR 51S3T

SEL-487B Relay Settings

CT and PT Ratios

PTR1 – 193

CTR01 – 200

CTR02 – 200

CTR03 – 300

Terminal to Bus-Zone Connections

I01-BZ1: CT1 A phase

I02-BZ1: CT1 B phase

I03-BZ1: CT1 C phase

I04-BZ1: CT2 A phase

I05-BZ1: CT2 B phase

I06-BZ1: CT2 C phase

I07-BZ2: CT3 A phase

I08-BZ2: CT3 B phase

I09-BZ2: CT3 C phase

Differential and Directional Elements

E87SSUP – Y

S87P – 0.5

87STPU – 300

O87P = 0.1

EADVS = Y

SLP1 = 60

SLP2 = 80

RTDI = 1.6

OPDI = 1.2

Trip Logic

TR01 – 87Z1 OR 87Z2