CHALMERS
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Power System - Fault Clearance with Limited Fault Current

A study of fault detection and clearance in presence of converter interfaced generators

Master of Science Thesis

ANUP ARYAL

Department of Electrical Engineering
Division of Electrical Power Engineering

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Abstract

The integration of renewable energy sources like wind and solar power into the grid, typically through converter interfaces, has introduced significant technical challenges, particularly in fault current management. This thesis explores the evolving challenges and solutions in power system protection as the share of converter interfaced generators continues to grow in response to global ambitions for reducing greenhouse gas emissions. Traditional synchronous generators provide predictable and substantial fault currents that are essential for the reliable operation of existing protection schemes. However, converter interfaced generators, governed by converter controllers, produce fault currents that are not only lower in magnitude but also less predictable, creating a need to reassess and adapt current protection systems.

This research investigates the impact of high converter interfaced generators penetration on short-circuit capacity and the preparedness of transmission system operators to manage these changes. The study highlights the limitations of conventional protection schemes, such as overcurrent and distance protections, where they exhibit under-reaching of distance relays and delayed tripping of overcurrent relays. These issues arise when fault currents are significantly reduced and exhibit varying characteristics, including diminished negative sequence currents and a wider range of phase angles. The research also examines the potential of new protection technologies and contingency strategies, such as grid forming converters, synchronous condensers, adaptive protections, and advanced methods like traveling wave-based protection, in addressing these challenges.

Despite promising developments, the thesis identifies several obstacles to the widespread implementation of these new technologies, including high costs, complex performance evaluations, communication and cybersecurity concerns, and a lack of standardization, which hinders interoperability among different equipment vendors. Furthermore, evolving grid codes and new requirements for fault ride through and reactive power control demonstrate the ongoing efforts to mandate better fault management characteristics for converter interfaced generators.

The reliability of overcurrent protection in distribution system and distance protection in transmission system can be significantly compromised in the evolving grid. There has been significant progress in adapting protection systems to accommodate more renewable resources, but further research and development are crucial to overcoming the remaining challenges and ensuring reliable fault detection and clearing in the modern power systems.

Keywords: Protection, Relay, Converter, Wind turbine, Fault, Short circuit, Grid code

Kraftsystem - Felbortkoppling med begränsad felström
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Chalmers Tekniska Högskola

Sammanfattning

Integrationen av förnybara energikällor som vind- och solkraft i elnätet, ofta genom omriktargränssnitt, har skapat betydande tekniska utmaningar, särskilt när det gäller hantering av felström. Denna avhandling undersöker de föränderliga utmaningarna och lösningarna inom kraftsystemskydd i takt med att andelen generatorer med omriktargränssnitt fortsätter att öka som svar på globala ambitioner att minska växthusgasutsläpp. Traditionella synkrona generatorer ger förutsägbara och betydande felströmmar som är avgörande för tillförlitlig drift av befintliga skyddssystem. Omriktarstyrda generatorer producerar dock felströmmar som inte bara är lägre i storlek utan också mindre förutsägbara, vilket skapar ett behov av att ompröva och anpassa nuvarande skyddssystem.

Denna forskning undersöker påverkan av hög penetrering av generatorer med omriktargränssnitt på kortslutningseffekt och beredskapen hos transmissionssystemoperatörer att hantera dessa förändringar. Studien lyfter fram begränsningarna i konventionella skyddssystem, såsom överströmsskydd och distansskydd, när felströmmarna är betydligt reducerade och uppvisar varierande egenskaper, inklusive minskade minusföljdsströmmar och ett bredare spektrum av fasvinklar. Forskningen undersöker också potentialen hos nya skyddsteknologier och beredskapsstrategier, såsom nätstyrande omriktare, synkronkompensatorer, adaptiva skydd och avancerade metoder som skydd baserat på vandringsvågor, för att hantera dessa utmaningar.

Trots lovande utveckling identifierar avhandlingen flera hinder för den utbredda implementeringen av dessa nya teknologier, inklusive höga kostnader, komplexa prestandautvärderingar, kommunikations- och cybersäkerhetsproblem samt brist på standardisering, vilket hindrar interoperabilitet mellan olika utrustningsleverantörer. Dessutom visar nätkoder och nya krav för felridning och reaktiv effektreglering på de pågående ansträngningarna att ställa högre krav på felhanteringsegenskaper för generatorer med omriktargränssnitt.

Sammanfattningsvis, även om det har gjorts betydande framsteg i att anpassa skyddssystem för att rymma mer förnybara resurser, är ytterligare forskning och utveckling avgörande för att övervinna de återstående utmaningarna och säkerställa tillförlitlig feldetektering och felbortkoppling i moderna kraftsystem.

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And to my friends, who have inspired, guided, and uplifted me: those who encouraged me to pursue a master’s degree, those who convinced me to take the leap and move to a new country, and those who supported me every day over the past two years. I am truly fortunate to have friends who make each day a little brighter. Thank you all for being a part of this journey.

Anup Aryal

Gothenburg, October 2024

List of Acronyms

Below is the list of acronyms that have been used throughout this thesis listed in alphabetical order:

CIG	Converter Connected Generator
CT	Current Transformer
DFIG	Double Fed Induction Generator
DG	Distributed Generation
ENTSO-E	European Network of Transmission Service Operators for Electricity
FCL	Fault Current Limiters
FRT	Fault Ride Through
GFC	Grid Forming Converters
IDE	Intelligent Electronic Device
IEC	International Electrotechnical Commission
POTT	Permissive Overreach Transfer Trip
PPM	Power Park Module
P.U.	Per Unit
PUTT	Permissive underreach Transfer Trip
RES	Renewable Energy Source
SC	Synchronous Condenser
SCC	Short Circuit Capacity
SG	Synchronous Generator
TSO	Transmission System Operator
TW	Travelling Wave
WTG	Wind Turbine Generator

Contents

1 Introduction

This section aims to serve as an introduction providing a brief overview of the thesis project, its relevance, and interesting aspects. In addition, it also provides a problem description, objectives, scope, and limitation of the project work. This section ends with a description of the structure of the report.

1.1 Background

The ambition of cutting greenhouse gas emissions and increasing energy efficiency to tackle climate change has created a shift in how electricity is produced and consumed. The share of renewable energy sources (RES) in the power system is increasing every year. This energy transition has brought many challenges to the power system.

Wind and solar power are connected to the grid through a converter interface. Converters are electric circuits that have semiconductor switches used to alter amplitude, frequency, and phase angles of the electrical parameters. These devices are used in AC/DC conversion in rectifiers or inverters. Flexible AC transmission system (FACTS) and high voltage direct current (HVDC) links also use power electronic converters. HVDC is particularly popular in integration of offshore wind farms whereas FACTS devices are used in transmission systems to maintain voltage and angle stability. These devices are capable of absorbing and injecting reactive power in the transmission system at different points.

While the converters offer significant advantages like flexibility and control, it has also introduced several challenges like harmonic distortion, voltage and frequency instability, fault current limitation, etc. Among these, limited fault current from converter connected generators has emerged as a major challenge in power system protection. The fault response from converter interfaced generators (CIG) are governed by the converter controller and can provide the fault current in the same range as rated current (1-1.5 p.u.). Whereas the traditional synchronous generators (SGs) can provide fault current of around five times its rated operational current. Fault response from the traditional generators is predictable and can be used during design of protection system for power system. Fault current from CIGs on the other hand depends on the type of controller and is not well defined.

Protection schemes are designed and implemented to detect abnormal conditions, locate the abnormal area, and isolate faulty parts from the rest of the system. It helps in keeping equipment and people safe from electrical hazard and maintains the safe operation of the rest of the system. Fault current is important for relays to detect faults and execute protection schemes. Overcurrent and impedance-based protection schemes like distance protection schemes use fault current amplitude to detect fault in the system. The power system protection schemes in use today are based on the fault current contribution from conventional generators. With the increasing penetration of CIGs, the protection system needs to be investigated for adequacy and preparedness. In Swedish power system where wind and solar power are increasing, new hydropower are not being built and nuclear plants might get shut down, a situation where CIGs contribute most of the fault current doesn’t seem so distant. This thesis aims to study short circuit capacity in CIG dominated grid, investigate how prepared the Transmission system operators (TSO) are, and study the changing role of existing protection schemes and promising new technologies.

1.2 Objective

The main objective of this thesis is to study, describe and sort different principles used in fault clearing when converter-based generation is dominant in power system. A power system model is used to study how the short circuit capacity of the Swedish grid will change if the nuclear plants are discontinued and are replaced by wind power. The technology and principles available today are studied and analysed on whether they will be helpful in new network topology. Suitability and implementation of some promising technologies and principles are also analysed. With the help of literatures, computer simulation, equipment manuals, grid codes, and standards, sufficiency of existing and new technologies, technical challenges and required support are presented in this report.

1.3 Scope

The focus of this report is on fault detection and clearance with limited fault current. Detection of low fault current and contribution from generators for fault current support are part of the study. The primary focus will be on the transmission network. However, a few effects of CIG domination on distribution system are also studied. Wind turbine CIG is the main focus of the study and solar will not be studied in detail. Effects of compensation devices, HVDC links, DC-DC converter, DC power system are not included.

1.4 Structure of the report

This report has 11 chapters which serve to fulfill the objectives. Chapter 2 introduces the power system faults and some protection schemes that are in practice. Chapter 3 provides insights into the grid strength and characteristics of fault current response from CIGs. Chapter 4 evaluates fault current calculation standard. Chapter 5 studies the impact on fault current level on the grid when CIGs replace SGs, with the help of a power system model. Chapter 6 describes the impact of integration of CIGs in transmission and distribution level on protection coordination as well as the common protection scheme. Chapter 7 examines some of the functionalities present in the available protection devices and their appropriability for the CIG dominated grid. Chapter 8 investigates some old and new grid code provisions for the integration of CIG and. Some available and implemented technology and some promising technologies and principles are analyzed in chapter 9. Chapter 10 aims to tie together the findings of the thesis work and provide discussion on the previous chapters. Lastly, conclusions and recommendations for future work are presented in chapter 11.

2 Power system faults and protections schemes

Events like lightning strikes on overhead lines, insulation breakdown, trees falling on a transmission line, open circuit due to broken conductors, mechanical damage of components or mis-operation of breakers create faults in power system. Only the faults that connect live phases to ground or other phases, also known as shunt faults, are within the scope of this thesis. Such power system faults are classified as balanced/symmetrical and unbalanced/unsymmetrical faults depending on number of phases involved in the fault. Three phase to ground is a balanced fault that is least frequent yet the most severe type. The most common type of fault is single line to ground (SLG), an unbalanced fault. Line to line (LL), and line to line to ground (LLG) are less common unbalanced faults. Fault studies are essential for selecting the appropriate ratings of protective switchgears and coordination of relays.

The balanced faults can be solved using the per phase approach. But during the unbalanced faults, per phase impedances are not identical and it results in unbalanced current and voltages. Then it's not possible to use the per phase approach as in balanced system. Solution using three phase approach is much more numerically complicated. So, the unbalanced faults are analyzed using the symmetrical components method as it is simpler to solve three different single phase circuits than solving a one single phase circuit in one set of equation. The unsymmetrical phase components are linearly transformed into a set of symmetrical components i.e., the positive, negative and zero sequence components. The unbalanced components can be decomposed into three sets of balanced components. Positive sequence components consists of a set of balanced three phase components with phase sequence ABC, where A, B and C are three phases with a phase angel of 120°, and negative sequence components are in ACB phase sequence. Zero sequence components consist of three single phase components that are equal in magnitude and have the same phase angles. The balanced sequence networks, formed by the sequence components, are connected to the point of unbalance where a fault has occurred. Then, the three symmetrical circuits are solved individually to obtain fault current [1]. Power system faults are usually accompanied by a resistance known as fault resistance. Such resistance can be an arc resistance, resistance of object connecting live wire to the ground. Fault resistance affects the magnitude of fault current and could hinder fault detection.

The protection system is implemented to detect faults and isolate the faulty part from the rest of the system. Effective protection systems will not let the abnormality propagate and disturb the stability and safety of the rest of the system. The protection system consists of a measurement section consisting of current and voltage transformers. Which means that the input to the protection system are voltage and current. Input data is fed to a relay, electromechanical or digital, where the data is interpreted and compared to a predefined value. Any abnormal situation is detected in this process and a trip signal is created. This signal is used to operate a breaker and disconnect all three phases, regardless of how many phases are affected by the fault. Relays are equipped with functions that can be set to serve desired protection scheme. Protection system design criteria include speed of operation, selectivity of fault, sensitivity to weak signals and reliability when required. The most used protection systems are explained in the following section.

2.1 Overcurrent protection

Overcurrent protection scheme discriminates between fault current and load current by the magnitude of current. During a short circuit, current magnitude can rise to a much higher value than load current and easily to detectable. It is commonly used in the medium voltage (MV) radial networks and distribution networks. A time delayed overcurrent protection is often used in the case of a radial system with multiple sections. Overcurrent relays are coordinated in such a way that the device closest to the fault trips in the shortest time. A directional relay feature is added to the protection scheme when there is presence of distributed generators and fault can be fed from multiple sides. Hence, it is a reliable measure for detecting a fault in a radial distribution system.

However, overcurrent protection has several challenges. Fault resistance and neutral ground impedance can limit the fault current magnitude. A weak source, a long line or presence of high impedance components like transformer line will reduce the fault current magnitude. Since overcurrent relays are based on inverse time characteristics, fault clearing time also increases if the fault current is low. Coordinating a directional overcurrent relay is a difficult challenge in meshed system. Hence, its use is limited and in a meshed network, distance relay is preferred.

Overcurrent protection can be used to protect the system against ground faults by measuring residual currents. A residual overcurrent protection scheme measures the vector sum of the currents in all three phases and neutral, if present, and detects the residual current during ground fault. Residual current is the imbalance current in the three-phase system where the sum of three phase currents should ideally be zero. The residual current has a permitted limit, and the relay operates when the threshold is exceeded. This protection system is designed to detect ground faults and earth leakage currents. It is used in protection of devices like generators and transformers where detection of ground fault is critical.

2.2 Distance protection

Distance protection uses impedance measurements to detect faults. It takes advantage of the fact that fault not only increases the current level in the network but also decreases voltage level. Current and voltage, whose ratio gives the impedance, are measured in the line end and apparent impedance is computed. This computed value is compared to the known impedance of the transmission line. In normal operating conditions, the calculated impedance is much higher than the set amount. Whereas, during fault current increases rapidly and voltage decreases resulting in low impedance calculation. A comparison between the two is made and a fault is declared. The measured apparent impedance value gives the fault location as well. Distance protection is assigned to a portion of the line, known as reach, that the relay is supposed to protect. With fixed reach and measurement of current and voltage, distance relays are more sensitive and precise than overcurrent relays. A directional unit can be added to define the reach in forward direction only.

Distance protection scheme is usually divided into instantaneous zone and one or more time delayed zones. The instantaneous zone usually covers 80-90% of the immediate protected line. Zone two usually covers 120% of the line impedance. More zones can be added which serve as a backup protection with a time delay. Other zones can be set depending on the section of network with further time delay. Figure 1 shows a section of a transmission line where R1 and R2 are distance relays on two ends, and I represent direction of current flow. Zone 1 and Zone 2 are also marked in the figure.

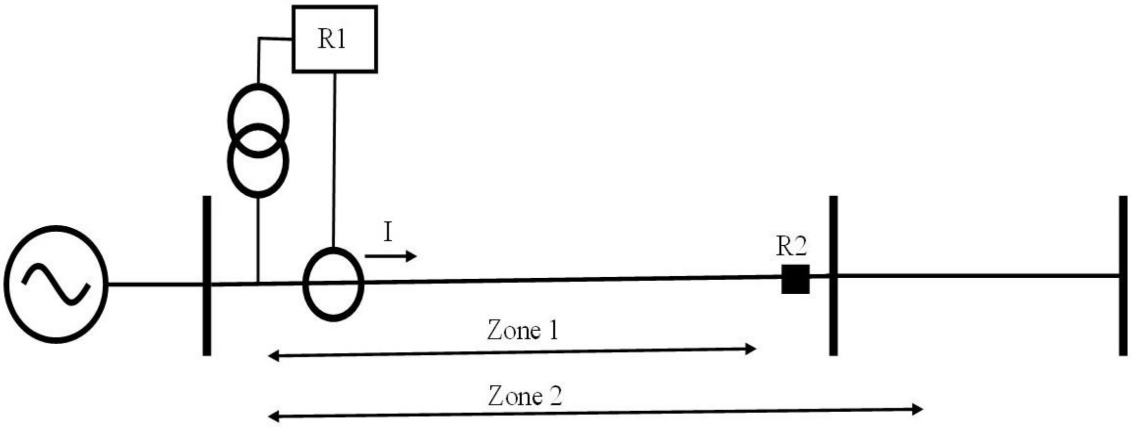

Figure 1. Distance protection scheme

An impedance plane, known as R-X diagram, is used to represent distance relay characteristics and impedance of the line seen by the relay. An R-X diagram, a tool used to visualize the operation of distance relay, is presented in figure 2. A relay either has a circular or quadrilateral characteristics, selected based on fault characteristics they are supposed to clear. The region inside the circle or quadrilateral is called trip region and the outside is called block region. The line “Z” in the figure represents line impedance locus between the relay and points along the line. A solid fault will lie on this line but if there is a change in impedance due to the fault resistance, the fault will lie outside of the line. If the impedance seen by the relay is within the block region, normal operation condition is assumed. If the fault is in the trip zone, trip signal can be issued. Distance relay with quadrilateral characteristics is more popular because the resistive reach can be extended independently of reactive reach. This is one advantage it possesses over circular distance relays or mho relays by having enough reach for high resistive faults.

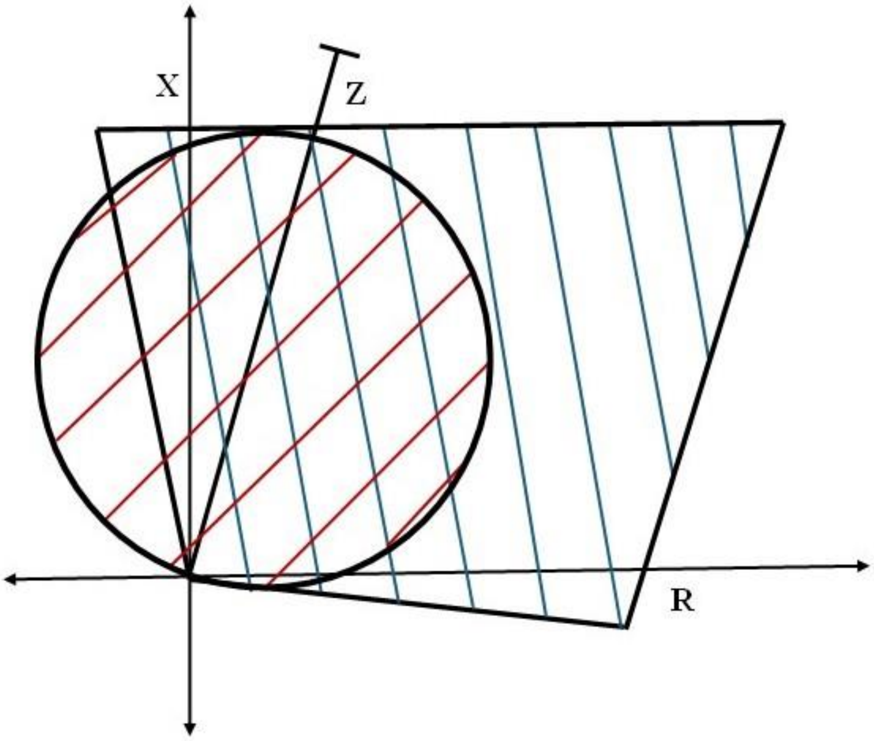

Figure 2. XR diagram with quadrilateral and circular characteristics

Distance protection is equipped with communication schemes where relays at ends of protected parts communicate with each other to reduce fault clearing time. The relays in two ends, R1 and R2 in figure 1, are referred to explain the schemes. Direct transfer trip (DDT) is one basic type of communication scheme that is often used in radial lines. In this scheme, when a fault is detected by relay R1, it sends a trip signal to the relay R2 at the other end of the line and both relays trip immediately. This scheme, however, is not widely used due to being prone to malfunctioning. Some more advanced types of communication scheme are more popular and discussed in the following section.

Permissive underreach transfer trip (PUTT) scheme uses two-way communication for fast fault clearance. When relay R1 detects a fault in its zone 1, it sends permissive signal to remote end relay R2 to trip. R2 receives the signal and detects the fault in its zone 2 and issues a trip command. R2 can trip without time delay even for the fault in its zone two. In case there is a failure in protection scheme, the relays can revert to the original scheme where each relay trips for faults in a zone it sees. In permissive overreach transfer trip (POTT) scheme, relays are set to detect faults beyond the protected line, extending into the next line section allowing faults to be detected near the zone boundaries. When a fault occurs somewhere within the overreaching zone, relays at both ends detect the fault and sends permissive signals to each other. Breakers near both relays trip simultaneously.

2.3 Line differential protection

Differential protection is very common in generators, transformers, and busbars protection. It’s also used for protection of short transmission lines and cables. Differential protection is based on Kirchoff’s current law. Current is measured at each end of the line and compared. If there is any difference in the measured value, it violates Kirchoff’s law and fault is declared. Communication between two measurement location to the relay is very important in differential protection. Current transformers will also not always read same current values in two ends. External faults in the networks can cause errors in phase angle, magnitude measurements and saturations of equipment. This creates a need to set overcurrent relay above a maximum error current during external faults. A percentage differential relay is used to fix this problem. The differential current must exceed a fixed percentage of the average of the primary and the secondary current of the protected element for the percentage differential relay to operate. Primary and secondary current here meaning the current measurements in the two ends of the protected element and is input to the relay. This average is known as through current or restraining current or bias current. The bias current helps distinguish between actual faults within the protected zone and external conditions that might otherwise cause unintended operation of the relay. The maximum differential current that is allowed without declaring fault depends on the current level where permitted differential current is larger for higher fault currents. Figure 3 shows operating characteristics of percentage differential relay through a differential current vs restraining current or biased current graph. The slope of the relay determines the trip zone. The restraining zone encompasses margin for safety and error like CT errors and current ratio mismatches [2].

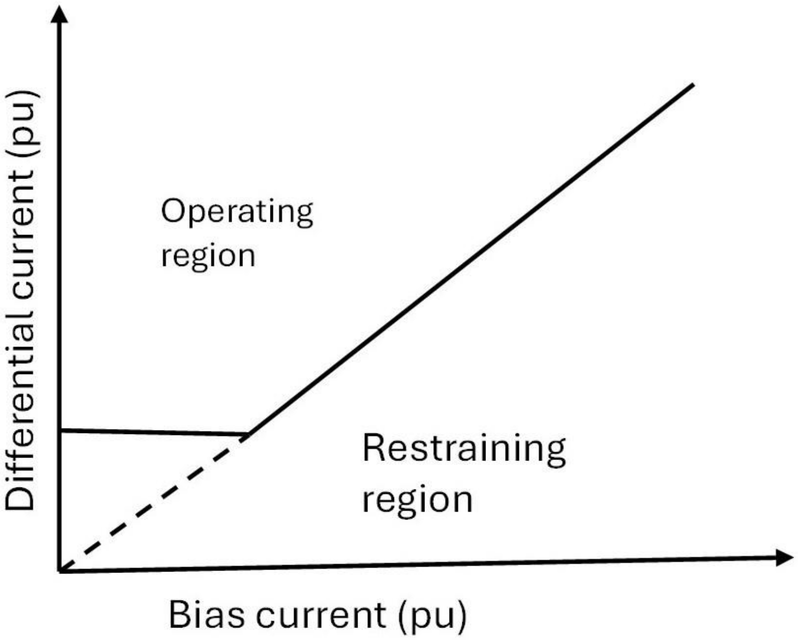

Figure 3. Percentage differential relay operation characteristics.

3 Grid strength and fault response from converter interfaced generators

Grid strength is the measure of capacity and robustness of power grid to reliably supply electricity without interruptions. A strong grid can maintain voltage and frequency stability of the network during disturbances and maintain uninterrupted power supply. The short circuit capacity (SCC) of a grid is a critical parameter and is a measurement of maximum short circuit current that can flow in the grid during a bolted three phase fault and is a strong indicator of the grid strength.

Knowledge of SSC is important in the selection of equipment with the correct ratings and specifications. Components like transformers, switchgear, generators, cables, etc., must be selected to withstand the maximum fault current. SSC is essential for selection and coordination of protection devices such as circuit breakers and relays. Proper protection coordination ensures that the devices nearest to the fault operate quickly and stops the fault from spreading into the system. Traditionally, protective devices are operated based on detection of rapid rise of current in a short interval as discussed in previous section. Hence, coordination among protection devices is naturally easy in grid with high SCC.

Conventional power generators or SGs have rotational mass that is coupled with the generators. It allows SGs to help during abnormal situations with inertial and frequency support. This feature helps restore stability in the system during frequency and power angle instabilities [1], [3]. But one of the most important characteristics of SG in maintaining grid strength is its response during a fault. SGs can inject fault current between 3-6 per unit (p.u.). Fault current injection from SGs during fault is predictable and usually easy to distinguish between normal load current and fault current. The short circuit current form SGs is proportional to the back EMF and the terminal voltages in a SG can be maintained by control of generator excitation current [3]. Although the traditional power system has faced issues like voltage instability and collapse, above mentioned inherent nature of SGs and ample SCC, has helped to mitigate the issues.

CIGs, however, inject just 1-1.5 p.u. fault during a fault. Fault response from CIGs is determined by control scheme of power electronic devices and are not universal like SGs. The fault current injection of such power electronic interfaced generators is limited because of possible damage to the converters due to overcurrent and overheating of switches [4]. Other factors like fault ride through, reactive current support, etc., guided by the grid codes, also determine how a fault current is contributed [5].

Global push for net carbon zero by 2050 and the subsequent energy transition has created a steep rise in investment in RES. Figure 4 shows the recent trend in increase in wind and solar generation capacity according to International Renewable Energy Agency [6]. Wind and solar are trusted as the leaders in the energy transition due to low climate impact and recent technological advancements. According to [7], if all the countries abide by their pledges to the carbon neutralization target, RES will rise from about 30% of the total share of electricity in 2020 to nearly 70% in 2050. Solar and wind together is expected to supply half of the total electricity demand. Since both sources have converter interface with the grid, a significant reduction in SCC can be expected in the future.

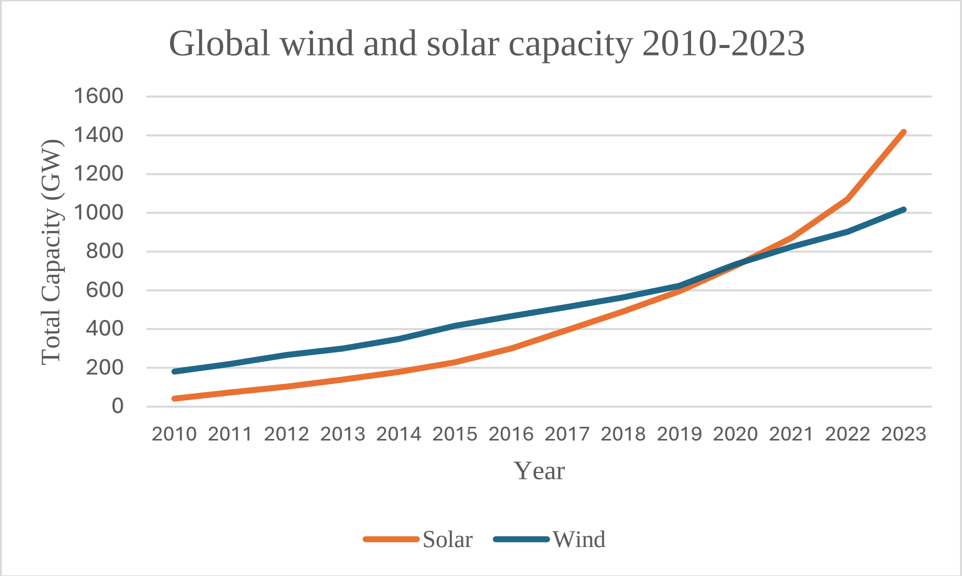

Figure 4. Global wind and solar capacity 2010-2023 [6]

Two commonly used types of wind turbine generators (WTGs) are Double-Fed Induction Generators (DFIG or Type III) and Full-Scale Converters (Type IV). In DFIG, the stator is directly connected to the grid, but the rotor is connected through rectifier- inverter pair. Full-scale converters are fully connected via rectifier-inverter pair. Type IV WTG is fully decoupled from the grid and shows a different fault response than Type III WTG. Grid connected solar plants also have a DC-AC interface and are decoupled from the grid [8]. So, Type III WTG operates differently during a fault compared to other CIGs. A crowbar is used in Type III WTG to disconnect rotor from converter during fault to protect the converter from thermal damage. Crowbar is kept in connection during mild faults and disconnected during sever faults. Mild faults are disturbances like minor voltage dips that do not cause extreme changes in the system. Severe faults are more extreme such as large voltage drops and prolonged faults. The rotor of the WTG faces induction of large voltage during severe fault, and this can cause high currents and stress on the power converter. The use of crowbar makes fault response from Type III WTG more complicated [8]. Since solar PVs are not in the scope of this thesis, it will not be explained in detail, but they are also completely decoupled from the grid with the converter interface and their fault response is similar to type IV WTG.

Magnitude of the continuous fault current from CIG has a nonlinear relationship with the terminal voltage, and the current remains low due to converter constraints. Hence, phase angle of the fault current changes dynamically depending on the control and the terminal voltage [5]. The fault current from CIGs can be resistive, inductive, or capacitive unlike a SG which normally produces inductive fault current. The control scheme of a CIG impacts the VI characteristics during a fault near CIG. The change in angular relationship may lead to mis operation of protection function, like directional elements, that depend on phase angle [5], [8].

CIGs generally contribute to positive sequence fault current only. A CIG fault contribution does not generate a zero-sequence component unless a transformer with a high-side wye-grounded winding is used to establish a ground connection [5]. The amplitude of negative sequence component is also suppressed depending on type of controller. The lack of sequence components may lead to mis-operation of protection equipment [5]. All these characteristics create the necessity to give each type of CIG individual consideration while studying SCC of the system and protection coordination.

Wind and Solar are prominent sources of renewable energy among the alternative energy sources and their integration to grid is taking place at rapid pace. But its limited fault current capacity is not the only thing that’s making the grid weaker. The internal impedance of SGs affects the network impedance from its terminal to the point of fault. Since they are connected in parallel to the network, fewer number of SGs mean the equivalent impedance seen from the location of fault increases. A higher equivalent impedance results in reduced the fault current level [3]. The increasing number of CIGs in the grid means that SCC of the grid is going down and more weak areas in the grid are being created.

Generally, RESs are integrated to the grid at distribution level as a concept of distributed generation. Wind and solar are a common source in microgrids as well. However, When the generation is in bulk like a solar plant or an offshore wind farm, they may be integrated at transmission or sub transmission level [9]. Increasing penetration of CIGs can cause fault current limitation which can lead to undetected fault in distribution network [10]. Dominance of limited fault feeding source will make transmission network weak. Such CIGs pose questions on reliability of protection system and there is a need to rethink the whole protection system.

4 Standard for fault current calculation

International Electrotechnical Commission (IEC) has prepared and published a standard, IEC 60909: Short-circuit currents in three phase AC system [11], to harmonize international standards for short circuit calculations. This standard is important in the design, calculations of parameters, operation, and protection of electrical components, ensuring the equipment can successfully handle short circuit current. It provides guidelines to represent the network and its components to calculate short circuit currents accurately. The standard provides manual correction methods, but it is commonly used in power system analysis software for fault analysis on complex and large networks. It addresses the contribution from different sources but the short circuit current calculation from wind power station with doubly fed asynchronous generator and full-size converter is focused on this section.

- Short circuit impedances:

  Short circuit impedances (Z_k) are defined as the impedance of the system viewed from the location of short circuit. In this standard, generators of wind power stations and their unit transformers are combined into one unit for calculations of short circuit currents. The short circuit current at the terminal of DFIG or full-size converter connected WTGs are not dealt with in this standard. Many grid codes dictate that WTGs should feed mostly the reactive current during short circuit and during the interval, in which duration, station acts as current source [11]. These are the basis for impedance calculations.

  The total positive sequence short circuit impedance (Z_{WD}) of DFIG WTG is given by (5).

$$Z_{WD}=\frac{\sqrt{2}*K_{WD}*U_{rTHV}}{\sqrt{3}*i_{WDmax}} \tag{5}$$

  Where, K_{WD} is factor for calculation of peak short circuit current referred to HV side of transformer. This value is given by the manufacturer and depends on converter protection equipment like crowbar resistance. U_{rTHV} is the rated voltage of the unit transformer at the HV side. i_{Wdmax} is the highest instantaneous value for three phase short circuit. In the case of unbalanced short circuits, the design and control strategy influences negative sequence impedance, while the type of transformer and earthing scheme determines zero sequence impedance. These values can be varied among different manufacturers.

  Similarly, full-scale converter WTGs are modelled as current sources in the positive-sequence system. The source current varies across different WTGs and is influenced by the type of short circuit. The positive sequence impedance is assumed to be infinite. The zero sequence impedance is also infinite. For unbalanced short circuits, the controller determines the negative sequence impedance, which is provided by WTG manufacturer.

- Calculation of short circuit current:

  Knowledge of maximum short circuit current is necessary for mechanical and thermal stress withstanding capacity of an equipment while minimum short-circuit current is important for selection of protection system. IEC 60909 uses voltage factor “c” to calculate maximum and minimum short circuit currents when the national standard for grid is not available. The voltage factor represents voltage variation at the bus. The maximum and minimum values of factor varies from 0.9 to 1.1 depending on the voltage level. The “c” factor, maximum and minimum, is multiplied with the voltage available at the fault location in the network during normal operation to get maximum and minimum voltage. The voltage values are used with most likely impedance for each component. In this method, an equivalent source voltage is taken which provides short circuit current towards the fault impedance and all other voltages are set to zero.

  IEC 60909 places particular emphasis on the initial symmetrical short circuit current ($\mathbf{I_K}$”), peak short circuit current (i_p), symmetrical short circuit breaking current, and steady state short circuit current (I_K). These values are illustrated in the figure 5. The initial short circuit current is the RMS value of the AC symmetrical component the moment the short circuit occurs. Symmetrical short circuit breaking current is the RMS value taken over a full cycle of the symmetrical AC component of the short-circuit current at the instant when the breaker operates. The peak short circuit current represents the highest instantaneous value of the available short circuit current. The key difference between the initial symmetrical short circuit current and the symmetrical short circuit breaking current is that the former decreases over time, particularly near generators. The steady state short circuit current is the RMS value of the short circuit current once transient currents have decayed. IEC60909 provides the formula for calculation of initial, peak, and symmetrical breaking short circuit current from full size converter interfaced power generation units. There is no formula for calculation of steady state short circuit current provided by DFIG and full-size converter. This data is based on design and test and is provided by the manufacturer.

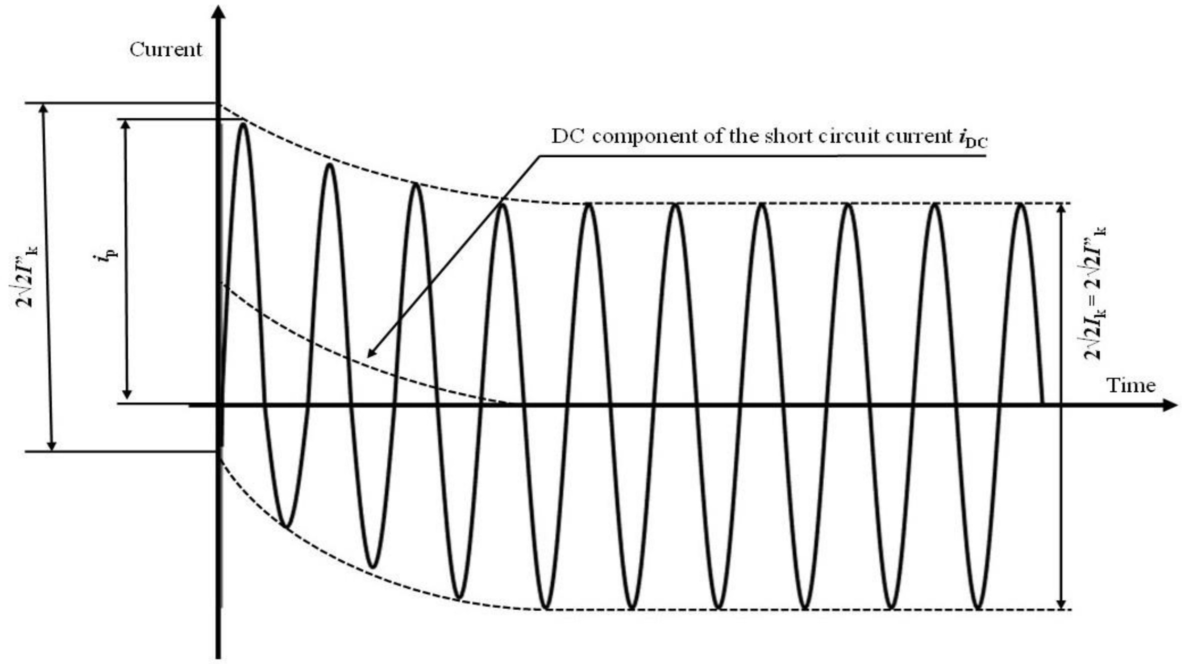

Figure 5. Fault current according to IEC 60909 [11]

The IEC 60909 steady state fault current calculation provides a good estimation in the SG dominated power system [12]. However, when fault current from a CIG, which is of different characteristics than that from SG, is injected, the standard might not be as efficient. In the past the fault currents from CIGs were usually ignored in steady-state fault current calculations as fault currents from such generators were limited and it didn’t affect the accuracy of estimation. But with increasing penetration of CIGs and grid codes adopting FRT requirements, the steady state fault calculation from such devices can’t be ignored anymore [13]. In recent version of IEC 60909, CIGs are recommended to be considered as a current source model according to its maximum overrating capability if its fault current is more than 5% of the total fault current [13]. In a current source model, a decoupled CIG is modeled as a current source, and it injects fault current according to a predefined value. But reference [12] shows that efficiency of this method might be dependent on location of the fault. This model was found more efficient when the fault location was near to the source.

Reference [13] proposes a method to improve the accuracy of steady state fault current calculations of IEC 60909 utilizing full converters. The method proposes reactive current injection from CIG in accordance with FRT requirements. The study is based on modeling CIG as a current source model with infinite impedance. The model ignores the impedance of the fault path and assumes a balanced fault. The fault current calculation procedure is two steps where fault current is calculated separately without considering CIGs and considering only CIGs. In the first step, equivalent impedance is calculated at the faulty point using Thevenin equivalent method. Then, faulty point voltage, nominal pre-fault phase voltage is divided by the calculated impedance to get initial symmetrical current. For the second step where only CIGs are considered, the value of current source is obtained from the manufacturer of the generator. The transfer impedance is calculated between faulty buses where CIGs are connected. Then the fault current contribution from CIG is calculated by multiplying the maximum current from the current source with the transfer impedance and dividing the result by equivalent impedance calculated without considering CIGs. Two fault currents from two steps are added to get total fault current. The proposed method for improving fault current calculations involves adjusting the value of the current source. Rather than using the fixed value supplied by the manufacturer, a variable value is assigned to CIGs based on the voltage dip and FRT and reactive current injection grid code requirements. The proposed steps are listed below:

- The fault current calculated without considering RES and the impedance matrix is used to calculate the voltage distribution at buses during the fault.
- The characteristic proportional gain or k factor and threshold voltage is obtained from grid code. It is also a voltage at which FRT control becomes active. The maximum combined current, which is the value of active and reactive current injection during a fault, is obtained from the converter manufacturer.
- Then the current from each CIG is calculated using the calculated post fault voltage for the respective bus in the first step. Here, the maximum combined current must be higher than the injected reactive current that was calculated.
- Then the total fault contribution from CIG can be calculated using calculated current value from the previous step rather than the one provided by the manufacturer. The rest of this step is as per the IEC 60909 standard.

These steps give different fault current fed from the CIG depending on the voltage and reactive current injection and is used to calculate total fault current. The paper then implements the proposed method in power system models and compares the obtained result with the ones obtained from IEC 60909 standard. The IEEE 14 bus power system model is used for the study with the proportional gain value of 2 and 10. The study finds that the IEC standard calculates erroneous fault current calculations regardless of the fault location. However, the calculation results are acceptable if the fault is near the CIGs. The study concludes that this method can reduce the error in fault current calculation in high CIG penetration scenarios by 50%.

The proper estimation of fault current calculation is pivotal for a proper design and coordination of protection system. Overestimation of fault current can lead to selection of oversized and more expensive equipment. The risk of fault going unnoticed cannot be ignored either. Underestimation can also compromise the reliability and safety of the power system. With the increasing share of renewables and CIGs in the grid, the fault current contribution from them must be integrated in compliance with the grid code requirements. Accurate fault current calculations are even more crucial for protection system design of CIG dominated grid.

5 Fault current study on a power system model

This section is a study of how short circuit current level is affected by a CIGs using a power system model. The fault current available in transmission and distribution systems is studied and compared between the system rich in SGs and a system where some of the SGs have been replaced by CIGs. It gives a better perspective of whether the lack of short circuit current in the system could become a concern in the future.

5.1 Simulation tool

A power system model with transmission, sub-transmission and distribution network has been used for the study of fault current with different levels of penetration of renewable energy. A model based on the Nordic44 power system model has been designed for the study. The Nordic44 power system model is a sophisticated framework used for analysis and management of power systems in the Nordic region. The Nordic44 model has been used by market operators to acquire key data on cost generation and transmission capabilities for energy trading and by the power system developers to study accommodation of new components including renewable energy. A simplified Nordic44 model overlapped on the map of Nordic region is presented in figure 6.

The model used in this project has been developed by The Norwegian University of Science and Technology and is available in Power System Simulation for Engineers (PSS/E) [14]. PSS/E is a high-performance transmission simulation, planning and analysis software. It is a comprehensive set of programs for analysis of power transmission networks for steady state and dynamic simulations. Steady state short circuit current calculations are used for design of power system, selection of equipment and insulation, and protection coordination. Hence, in this thesis project, steady state simulation has been done in PSS/E to study fault current on different parts of the power system model.

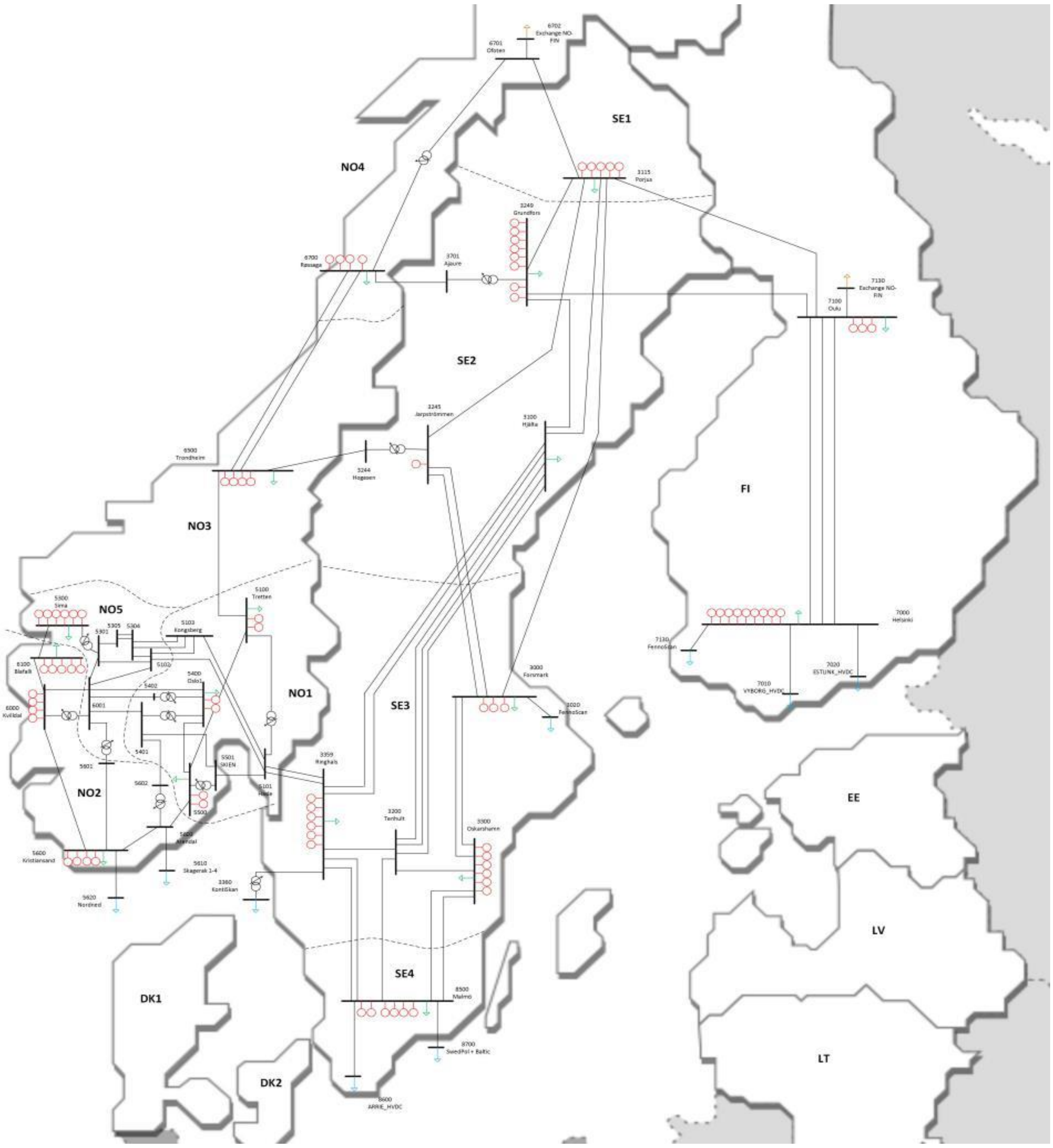

Figure 6. The simplified Nordic44 model overlapped on the map of Nordic region [15].

5.2 Model description

The Nordic44 model covers the grid in Norway, Sweden, and Finland. Each country is divided into different regions and the model has 44 buses. But for sake of this project, the Norwegian and Finnish part has been removed and the study has been conducted in the Swedish transmission system only. The Nordic44 model is vast comprehensive representation of Nordic power system and the fault current contribution from Swedish generators should be enough in to understand short circuit capacity. The network reduction keeps the calculations straight forward.

The model has 420 kV transmission and eleven 420 kV buses on the HV transmission level. The model has been divided into four regions, i.e., SE1, SE2, SE3 and SE4. The short circuit current study in this project will be focused on SE3. The nuclear reactors which are connected to the 420 kV bus bar are in this region. Oskarshamn bus bar, marked bus number 3300 in the figure 7, has been expanded to include a transmission and distribution network. The distribution network consists of seven buses of 135 kV, 50 kV and 11 kV voltage level. Bus 13501 and 13502 are 135 kV, 5001 and 5002 are 50 kV busses, 1101, 1102 and 1103 are 11 kV busses. The expanded network has step-down transformers and medium voltage transmission lines. The distribution network is radial and does not have any distributed generators. The loads have been left as they were in the existing transmission and Five loads of 20MW and 5 MVAR each have been added to the distribution network.

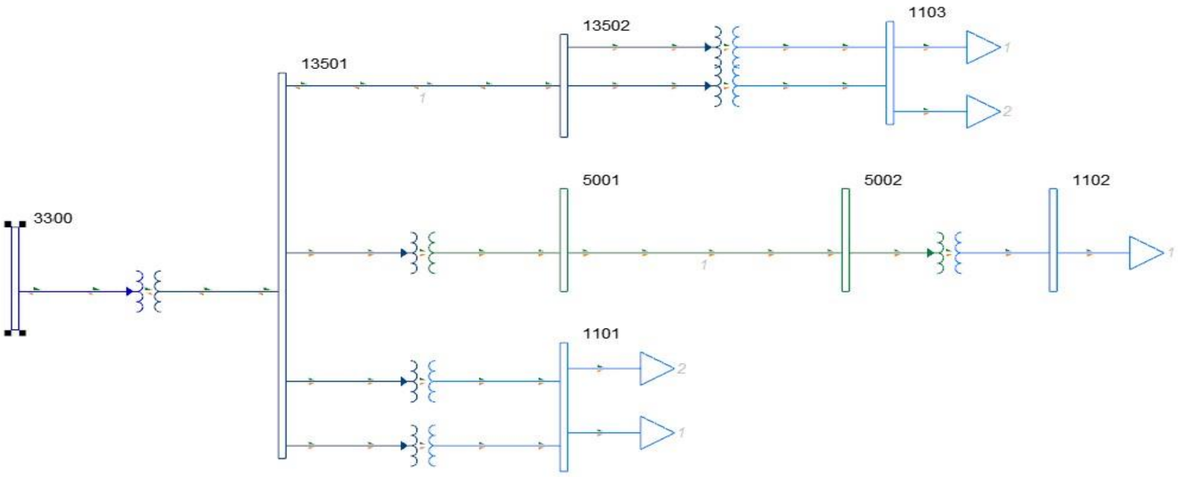

Figure 7. Added distribution network.

The power lines are modelled as pi-sections with series resistance, reactance, and shunt capacitive line charging. The inter-country connection lines have been removed from the Nordic44 model. The impedance values of the added distribution line are presented in table 1.

Table 1. Power line impedances

Line voltage level	Resistance (pu)	Reactance (pu)	Charging (pu)
135	0.001	0.0040	0.4
50	0.005	0.0015	0.02

The transmission network has one 420/135 kV transformer. Seven stepdown transformers have been added to the distribution network. Regular two winding transformers without tap changers used. Since our concern is only short circuit current available at the location of fault, tap changing is not a concern. Ratings and parameters of the transformer are listed in table 2.

Table 2. Transformer ratings

Voltage	Capacity (MVA)	Resistance (pu)	Reactance (pu)
420/135	1000	0.0005	0.120
135/50	63	0.0010	0.120
135/11	30	0.0010	0.100
50/11	30	0.0010	0.100

The model has several conventional generators. All the sources in Sweden including hydropower, nuclear, wind, CHP, etc. have been modeled as conventional source and connected to the transmission network. Since the goal of this simulation is to study fault current level in presence of CIGs, this model is perfect. The generators have been provided with sub transient reactance. Since the simulation is for balanced faults, the sequence data was not necessary for any components. The SGs that would be replaced by a converter connected generators are listed below in table 3.

Table 3. Synchronous generators in the busses under study

Connected bus	Number of units	Base MVA	Sub-transient reactance
Oskarshamn	3	1100	0.1600
Forsmark	3	1300	0.2250
Ringhals	6	1350	0.1937

5.3 Methodology

Apart from removing the Norwegian and Finnish networks and adding a distribution network, the Nordic44 model was used as made available. In other words, the generators that were switched off were left as they were in the base case as well as the whole short circuit study. The only change made was in the 12 generators on Ringhals (3359), Oskarshamn (3300), and Forsmark (3000) buses. The generators that were feeding 4-6 p.u. fault current was modified to mimic replacement of nuclear and thermal plants connected to these busses with a wind farm. The sub transient reactance of the generators were set to a value that would only contribute fault current of 1.3 p.u.

All the fault current calculations were done using the IEC 60909 standard methodology in PSS/E. Three phase faults were applied to different buses in the model to study the short circuit current level on them. Multiple assumptions were made to simplify the calculations which are discussed here:

- Only three phase faults have been calculated in the bus bar. In symmetrical faults, calculations are simplified due to absence of sequence components and transformer grounding has less impact. Three phase faults are rare in the system but usually results in high fault current.

- The fault current calculated with IEC 60909 are initial symmetrical short circuit current (I’’k) which is the initial current that occurs immediately after the inception of fault.
- The tap ratios and phase shift angles have been left unchanged. Adjusting the tap setting changes the impedance of the transformer as seen by the fault and can change the fault current calculation. When the tap ratios and phase shift are unchanged, the transformer ratios are kept to nominal settings and retain the phase shift angles. It is essential to represent transformers phase relationships accurately.
- Line charging, shunt and load have been left unchanged. These elements are parts of the fault current paths and influence reactive power and voltage profile during fault conditions. Including them rather than setting them to zero provides more accurate modeling of power system and can result in more precise calculation of fault currents magnitude and phase angle.
- Voltage factor ‘C’ has been set to maximum (1 p.u.). This will simulate the worst-case scenario where the voltage is at upper limit at the inception of the fault resulting in highest possible fault current.

In the first step, faults were applied individually to buses 3000, 3300, and 3359. The total fault current and the fault current contribution from each generator and the transmission lines connected to each bus were calculated. The same procedure was repeated after modifying the conventional generators to contribute a maximum of 1.3 p.u., simulating the fault current contribution from CIGs. For the distribution network, faults were applied to all buses when all generators were synchronous. In the next step, faults were applied again, but this time the generators on buses 3000, 3300, and 3359 were set to contribute only 1.3 p.u. fault current.

5.4 Results of simulation

In the 420kV network, a significant drop was observed in all three buses under consideration when the fault currents were limited. In Oskarshamn bus, fault current reduced from initial value of 59.57 kA to 37.25 kA when the SGs in the bus were replaced and 31.97 kA when SGs on the three buses were replaced. The numbers represent about 62% and 53% of the fault current originally available respectively. Similarly, in Forsmark bus, fault current reduced from 61.10 kA to 44.39 kA when the SGs on the bus were replaced and 37.37 kA when SGs were replaced on all three buses under consideration. This represents about 72% and 61% of the fault current available with SGs respectively. But the largest drop in fault current level was observed on Ringhals bus where loss of up to 59% fault current was observed. The fault current dropped down from 72.71 kA to 30.05 kA and 29.26 kA. The results are presented in figure 8 and table 4 below. All the current values are in kilo amperes.

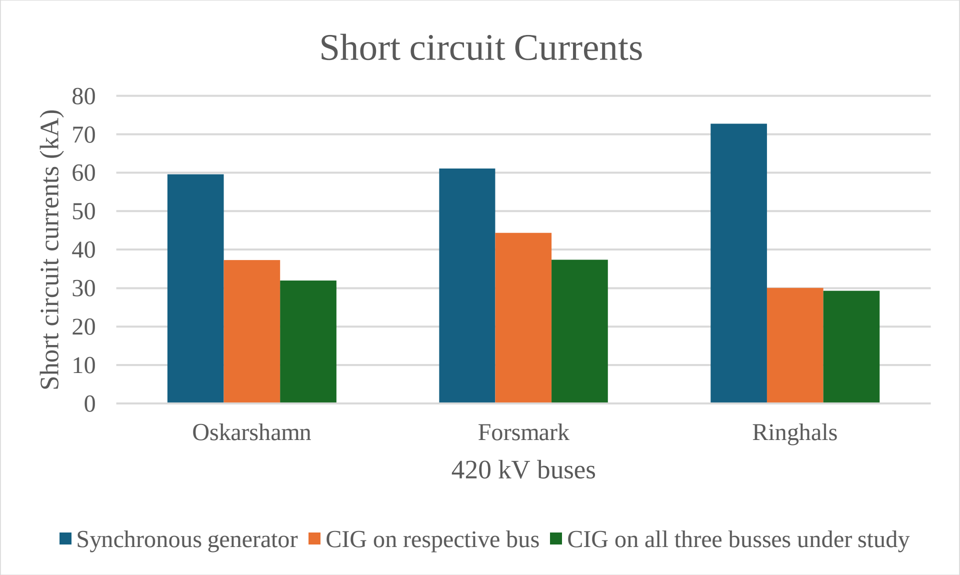

Figure 8. Short circuit currents on different 420 kV busses under different level of CIG penetration

Table 4. Summary of short circuit currents(kA) on 420kV buses

	Oskarshamn	Forsmark	Ringhals
Synchronous generator	59.57	61.10	72.71
CIG on respective bus	37.25	44.39	30.05
CIG on all busses	31.97	37.37	29.26
Percentage drop with CIG on respective bus	37.5%	27.4%	58.7%
Percentage drop with CIG on all buses	46.3%	38.8%	59.8%

In the radial medium voltage network, a similar trend was observed. In the 135 kV buses, bus 13501 and bus 13502, a drop of about 3% of fault current was observed. The fault current drop on the lower voltages were even less significant. The results are presented the figure 9 and listed on table 5. All the current values are in kilo amperes.

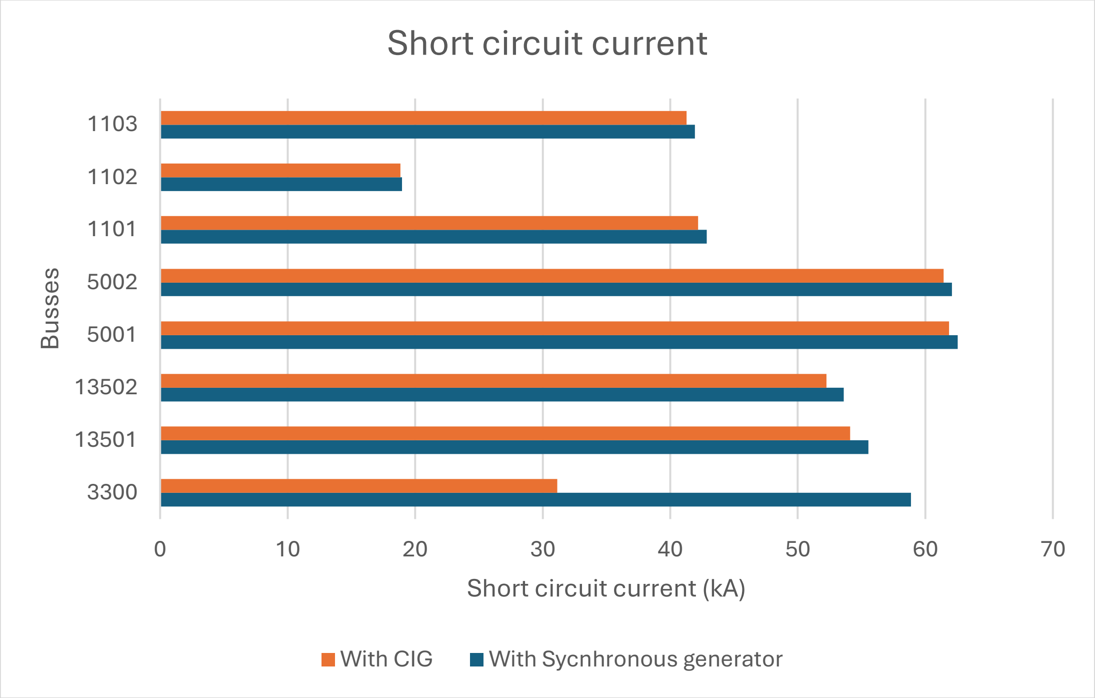

Figure 9. Short circuit currents with SG and when all SG are replaced by CIGs in all three transmission level busses under study

Table 5. Short circuit currents (kA) on distribution network

Bus	With SG	With CIG	Percentage decrease
3300	58.88	31.15	47.10%
13501	55.54	54.1	2.59%
13502	53.6	52.26	2.50%
5001	62.54	61.87	1.07%
5002	62.09	61.43	1.06%
1101	42.87	42.18	1.61%
1102	18.97	18.84	0.69%
1103	41.94	41.28	1.57%

5.5 Interpretation of simulation results

On the transmission level, the drop in short circuit current level on buses close to the generators was as expected. But the significant amount of drop could affect the protection scheme that is based on the detection of high current magnitude. The reduction in fault current level reflects on fundamental change in how power system responds to faults. Miscoordination can be expected where circuit breakers and relays may not operate correctly or in proper sequence. On transmission level, where stability is of utmost priority, reduced short circuit capacity can affect voltage stability. At the same time, reduced inertia means lower critical clearing time pointing to the need to clear faults in an even shorter time. Transient stability of individual generators will experience larger voltage dips during faults and have to ride through more severe disturbances. Low short circuit capacity can also lead to lower system kinetic inertia leading to faster frequency deviations and lower resilience to disturbances. This change necessitates a re-evaluation of protection schemes, potential modifications to the grid infrastructure, and an understanding of the broader implications for grid stability and resilience.

In the 135kV, 50kV and 11kV bus bars, the difference in fault current when switching from SG to CIG was less significant. This can be attributed to the fact that at 400kV, the impedance seen from the fault point to the source is lower and contribution of the source is directly reflected in the fault current response. In the lower voltage levels, the impedance between the fault point and the generator increases due to the presence of high impedance elements like transformers. This increased impedance tends to dominate the fault current calculation, reducing the impact of the source's contribution on the total fault current. As a result, the difference in fault current when switching from a SG to a WTG becomes less pronounced at lower voltage levels. In essence, the lower impedance at higher voltage levels means the generator's fault current characteristics has a greater impact, while at lower voltage levels, the network and step-down transformer impedance these differences less significant. On the other hand, a radial network-like figure 7 is not very common and some generators that add impedance and contribute fault current can be expected to be present at 135kV level and the lower voltage level as well. In any case, the replacement of SGs with CIGs at transmission, sub transmission or distribution can be expected to cause issues in fault detection and protection coordination.

6 Impact of converter interfaced generators on existing protection scheme

The contrasting short circuit capacity in SG and CIG dominated grids have been established in the previous chapter. The existing protection schemes are designed based on the fault current characteristics of SGs. This section explores the impact of fault current contribution from CIGs in the protection scheme and their coordination.

6.1 Impact on protection of distribution network

Existing protection systems in distribution networks are designed on the assumption that the power flows unidirectionally in the radial network. Hence, they are protected using current sensing devices like overcurrent relays, fuses and reclosures. These devices continuously monitor the current and generate a trip signal when the current level exceeds a predefined value. In the case of distributed generators or loop distribution networks, directional overcurrent relays (DOR) are used to avoid sympathetic tripping where a relay operates incorrectly due to fault in adjacent circuit. But with higher penetration of converter interfaced intermittent sources, changes in short circuit capacity and DORs with fixed settings cannot be relied upon [9]. A few issues introduced by the variable nature and weak infeed of fault current from the CIGs in protection coordination of distribution network with distributed generation are discussed below.

- Blinding of protection:

  The CIGs can supply up to 1.5 p.u. fault current. As shown in figure 10, fault current sensed by relay R1, I_{fG}, will be less than the total fault current due to the fault current, I_{fDG}, from the distribution generator. Relays have a certain pickup value for breaker operation. Fault downstream of R2 will be supplied from grid and the DG. Fault current form DG will vary depending on its rating and impedance. Due to this varying fault current and change in impedance, R1 will face under reach issue. This phenomenon where sensitivity of R1 is compromised is known as blinding of protection [9], [16].

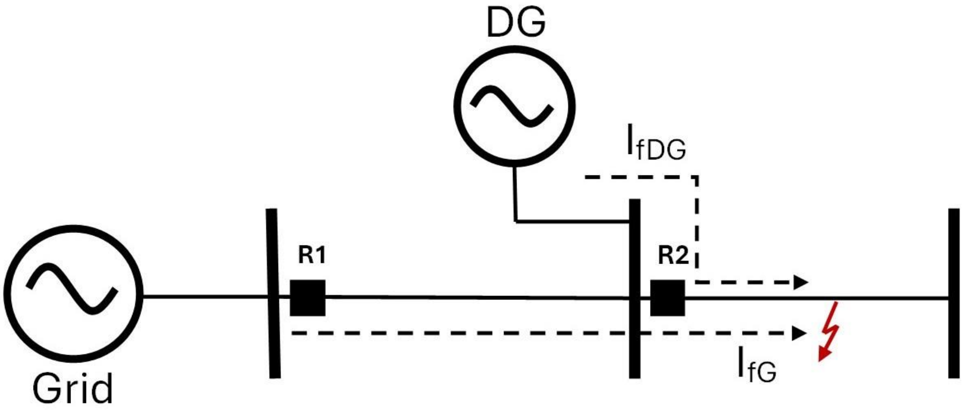

Figure 10. Blinding of a protection in a distribution network

- False tripping or sympathetic tripping:

  False, sympathetic, or spurious tripping occurs when a DG is connected close to a substation, supplies fault current to an adjacent feeder with common bus and the magnitude of the fault current exceeds the pickup value of the relay [16]. Relay R1 in figure 11 could trip and isolate the feeder from the grid due to fault in another feeder. The consequence of bidirectional power flow is visible in this example. In a meshed distribution system, some relays experience higher fault current than pickup values and trip before the primary relay and isolate unwanted feeder [9]. Coordination of overcurrent relays can be more complicated with penetration of more DGs.

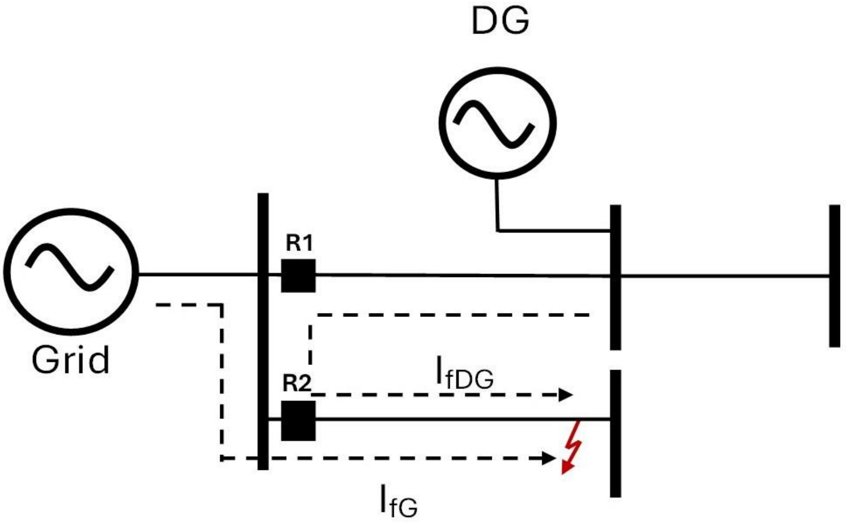

Figure 11. False tripping in distribution network in presence of DG.

- Islanding:

  In the network in figure 11, if R1 senses enough fault current to trip, then it will isolate the DG from the grid. The DG will continue to supply the local load in an islanding operation. The islanding may face unbalanced operation with power imbalance, voltage and frequency fluctuations [17].

6.2 Impact on protection of transmission network

At the transmission level, overcurrent relays, distance relays, and differential protections are commonly used. Distance protection, with multiple zones, is the primary protection scheme for transmission lines. Several other backup protections are also provided in case the distance relay fails or does not detect high resistance faults. Directional overcurrent relays are a good back up option. It can be coordinated with adjacent line relays and can be set to detect fault in particular direction. The availability of communication channels makes it easier to use other backup protection like differential protection and overreaching and underreaching pilot protection schemes. Line differential protection is commonly used in short and medium length transmission lines. In longer transmission lines, pilot protection schemes provide faster backup protection with communication signals between line ends. Differential protection schemes are primary protection for generators and transformers. They are fast, sensitive and provide good selectivity. Restricted earth fault protection also provides high sensitivity for ground faults near neutral points of transformers. Over current relays can also be employed near line terminations for transformer protection. Generators have overcurrent protection for backup for overloads and external faults, and stator ground fault protection for ground faults in stator windings. Most of these protection schemes rely directly on measuring current amplitude, and with reduced fault current, their reliability can be compromised [9]. The reduced fault current magnitude, along with changes in phase angle and the nature (capacitive, reactive) of the fault current from CIGs, can significantly impact above mentioned protection schemes. The following section discusses the impact on some major protection schemes.

6.2.1 Distance protection

Impedance-based protection systems with quadrilateral relay characteristics are more common. However, due to the low infeed and variable nature of CIGs, these impedance-based protections can cause underreach and overreach of relays, potentially resulting in faults going unnoticed within the relay's designated zone. Distance relays are also used in coordination with other types of relays, but low fault current can disrupt the cooperation and coordination among different relays [9], [18].

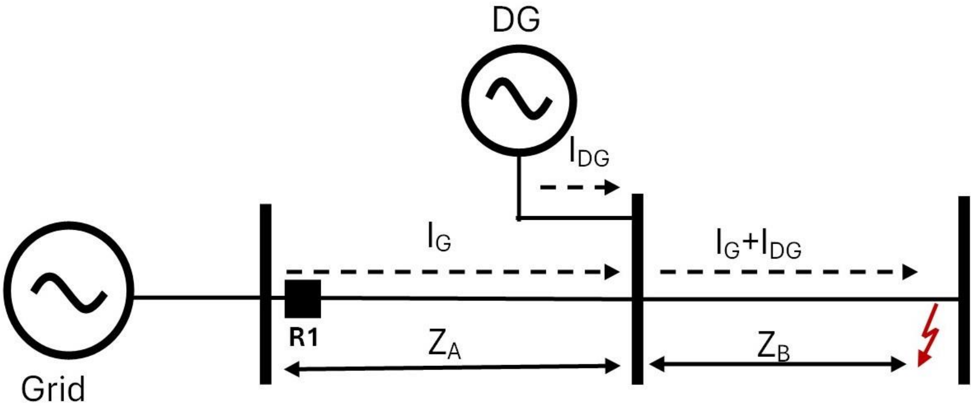

Figure 12. Distance protection scheme in presence of DG

In figure 12, the impedance Z_{AP} for the fault location seen by the distance relay R1 is given by (1).

$$Z_{AP} = ZA + ZB + (\frac{I_{DG}}{I_G})\ ZB \qquad (1)$$

As infeed current I_{DG} depends on the input availability of the DG, the factor $I_{DG}/\ I_G$ is different for different instances. If the variable current infeed from the CIG is not considered while coordinating distance relay, the impedance seen by relay during fault will be reduced due to CIG current creating under reach. And if the infeed from the CIG is considered during coordination and fault occurs when the infeed is low, the distance relay may over reach [9].

Increasing penetration of CIGs may impact the operation of distance protection mostly due to reduced reach accuracy. Misoperation caused by low supervising current, misfunction of directional elements, incorrect selection of faulty phase are other issues that reduce the reliability of distance protection in presence of CIGs. The issues in operation of distance relay and its cooperation with other protection scheme are explained below.

6.2.1.1 Impedance and reach

In a CIG dominated system, the impedance can change dynamically. This will cause complications in distinguishing faults in certain zones of protection. The intermittent nature of the source plays an important role in determining the reach of distance relay. SGs offer predictability, control, inertia, and voltage regulation, which stabilize the grid and reduce variations in impedance seen by distance protection relays. But fluctuating wind speed causes variations in voltage level which in turn changes the apparent impedance seen by the distance protection relay. Varying measurement of impedances causes changes in the reach of the distance relay settings [19], [20].

Type III WTGs are widely used with wind power due to its ability to work on unity power factor with power electronic converters, adaptability to variable wind speeds and reduced converter size. [21], [22]. In addition to the limited current capability of converters, other characteristics of CIGs, such as DFIGs, reduce fault current level in the grid. With the increasing number of RESs in the power system, new grid codes related to fault ride through (FRT) have been established, requiring DFIGs to remain connected to the grid during faults. This requirement leads to high current flow in the generator, risking damage to its rotor. To prevent such damage, a crowbar circuit is typically connected to the rotor. The crowbar circuit provides a path for the high short-circuit current, resulting in different fault current than normal operating conditions. During a three-phase fault, the crowbar resistance and rotor winding resistance combine to make the fault impedance very high. This change in impedance affects the reach of transmission line protection schemes, making it challenging for relays to detect faults accurately [21].

Impact of change of source impedance on reach of a distance relay has been discussed in [23]. Memory-polarized mho distance relays are common in transmission line protection.

These relays measure impedance based on pre-fault conditions. They use pre-fault voltage as a reference to accurately measure the impedance and detect faults along the line. The expansion of the mho distance circle is influenced by memory polarization, which depends on the amplitude and phase angle of the impedance of the source that lies behind the relay. When the source is a CIG with a varying internal impedance, this causes inconsistent initial expansion of mho circle [5], [23]. A larger ratio of source impedance to the line impedance causes greater expansion of the mho circle relay [23].

When a CIG is connected radially to a grid, it creates a weak end. A weak end is the remote end of a transmission line where source or generation is limited or nonexistent. Such an end has low voltage stability and fault current strength. When a CIG is supplying a fault current in line with weak end and there is variation in phase angle, the fault impedance has significant influence on the apparent impedance measured by the distance relay [24]. In the figure 13, Relay R1 measures voltage $V_{A,}$ and current I_A and calculates the apparent impedance $Z_{AP.}$ Z_A is the line impedance from the relay to the point of fault. If I_{DG} is the fault current from the DG and R_F is the fault impedance, the apparent impedance seen by the relay is given by (2).

$$Z_{AP} = \frac{V_A}{I_A} = Z_A + \left(\frac{I_{DG}}{I_A}\right) R_F \tag{2}$$

The factor I_{DG}/I_A is dependent on the fault current source. The apparent impedance seen by the relay is significantly different from the actual impedance in case of a CIG. If there is a significant difference in phase angle between load current and fault current, a reactive part is added to the apparent impedance and it deviates towards X in the R-X plane [24]. In a SG dominated system, the pre fault and post fault current are almost identical. However, in CIG, some converter controllers can cause voltage phase jumps. All these characteristics complicates relay coordination regarding zone settings.

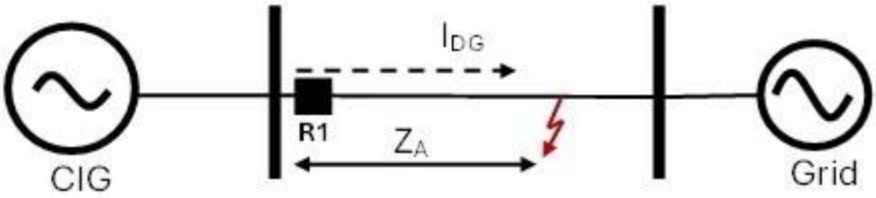

Figure 13. A CIG connected radially to a grid.

6.2.1.2 Fault identification logic

Different identification algorithms are used by distance protection relays to identify the type of fault and the faulted phase. In general fault identification logic, the faulted phase loop is identified using the mathematical relationship between zero and negative sequence current. According to [5], this mathematical relationship holds true in a SG dominated system because of the inductive nature of negative sequence network and SG impedances [5], [25].

Traditionally, this was an effective and logical algorithm as negative sequence current was sufficiently supplied by the SGs. However, CIGs may not inject any negative-sequence current. Hence, in CIG dominated system, the mathematical relation might behave differently. This phenomenon has been studied in [5] where current based fault identification logic has been simulated in networks supplied by only SGs, Type IV CIG with no negative sequence current control and Type IV CIG with negative sequence current control according to German grid code. It was found that for a single line to ground fault in a SG system, negative sequence current lagged positive sequence current by -4° and the fault identification logic could declare the fault on the right phase. A similar relationship was observed for Type IV CIG with negative sequence current control. However, in Type IV CIG with no negative sequence current control, negative sequence current lead zero sequence current by -140°. This caused fault declaration on the wrong phase i.e., fault was applied in phase A but declared on phase C due to the angel difference. In situations where negative and zero sequence current are not in sufficient amount, fault is identified using voltage components [25].

6.2.1.3 Direction identification

Directional elements use negative sequence current and negative sequence voltage to identify direction of the fault. This approach is effective in traditional power systems dominated by SG, where the negative sequence components are significant and consistent due to the inductive nature of the generators and the network. However, in systems with domination of CIGs, the fault current often lacks or has very limited negative-sequence components. Consequently, the reliability of directional elements is compromised in CIG-dominated systems, as they cannot accurately determine fault direction without the expected negative sequence components. This leads to potential mis operation and reduced effectiveness of directional elements.

Operation of directional negative sequence overcurrent element used in distance relay to determine direction of fault is discussed in references [5], [25]. It operates by comparing the phase angle of negative sequence current and negative sequence voltage. This element operates on the assumption that the grid impedance, source impedance and, consequently, the negative sequence network is inductive in nature. The logic is that, ideally in forward faults, the negative sequence current leads to the negative sequence voltage by 90°. In case of a reverse fault, the negative sequence current lags the negative sequence voltage by 90°. This phenomenon is observed in a SG dominated network but, in a CIG, dominated network, where fault current can be resistive or capacitive as well, this assumption is invalid.

6.2.1.4 Communication schemes

In the POTT scheme, relays at each terminal trip when they receive local and remote trip commands. Directional elements detect sensitive unbalanced faults, potentially supplementing or replacing ground distance elements in communication-based protection schemes [5]. However, if the directional negative sequence element misoperates, it can cause a cascading failure in communication-assisted protection schemes. When this element malfunctions, the distance relay will not send a permissive trip signal to the remote relay. This will cause the POTT scheme to mis-operate for faults within the protected zone [25].

To illustrate this misoperation, a SLG fault was applied to a transmission line with POTT protection scheme in reference [5], [25]. The relays on the line end had ground distance relay and directional negative sequence overcurrent relay. In a scenario where the fault is supplied by a SG dominated system, The POTT operated successfully where ground distance relay and directional negative sequence overcurrent relay picked up in both end and successfully sent the permissive trip command to the remote relays. However, when the SGs were replaced by a Type IV CIG with no negative sequence current control, the directional negative sequence overcurrent relay of one end generated transient trip signals and could not send assertive trip command to remote end relay. The POTT scheme could not trip remote end relay for an in-zone fault due to change in phase angle of negative sequence current injected from Type IV CIG. When the sources were replaced with a Type IV CIG with negative sequence current control the POTT operated as expected. The negative sequence current control allows reactive negative sequence current injection and the relays can successfully send permissive trip signal to the remote relays [25].

6.2.2 Overcurrent protection

Overcurrent protection scheme is based on detection of current magnitude and is best to understand the impact of CIG on fault detection. Several factors like fault resistance and neutral ground impedance, a long line or presence of high impedance components like transformer can limit the fault current magnitude even in a conventional SG dominated network. Limited fault current from the CIG makes this scheme even less reliable. As overcurrent relays are based on inverse time characteristics, fault clearing time increases with low fault current. It creates an increased risk of equipment and personal damage.

6.2.3 Line differential protection

Line differential protection is a communication assisted protection scheme popular in short length transmission lines where security is critical and use of other protection scheme is not enough [5]. Traditionally, line differential protection is activated when sum of amplitude of current entering and leaving the protected region of a transmission line are different than user defined value. However, other algorithms, like current-ratio plane, are also used by some vendors.

Different types of CIGs inject fault current of different characteristics. If this difference is significant, fault current may fall in the wrong region of defined differential characteristics. In [5], a simulation study has been carried out to see how traditional and alpha plane line differential operate differently in presence of SG and CIG. In traditional differential protection scheme, the fault current from SG and CIGs don’t affect line differential protection if the communication channels are intact. In current ratio plane (alpha plane) differential protection however, protection was found to act differently for SG and CIG fault current. The This differential technology uses a complex ratio of terminal currents to determine differential value. The location of this complex ratio in the alpha plane determines the action of the relay. When the Type IV WTG with no negative sequence current control was supplying the fault current, the alpha plane line differential scheme failed to detect the internal fault. This mis operation was due to low magnitude of fault current together with change in phase angle of negative sequence current from type IV CIG. Further simulation with negative sequence control suggests that this issue could be fixed when the negative sequence current is almost in phase.

6.2.4 Other protection schemes

Asynchronously connected CIGs reduce the system inertia, and it impacts the reliability of system designed to operate in inertia rich system. Some protection schemes affected by loss of inertia in CIG dominated system are explained below.

- **Rate of change of frequency (ROCOF)**

ROCOF protection, a protection scheme used to avoid unintentional island formation in the grid, is one of the affected schemes with reduced inertia. A rapid rate of change of frequency suggests that an island is forming on the grid and the protection system should operate to isolate the island and protect the rest of the grid. The ROCOF settings has a wide range varying from 0.1 Hz/s to 2Hz/s depending on the standard defined on grid codes [5]. ROCOF is inversely proportional to system inertia. When a generator is lost in a system with low inertia, ROCOF may exceed the predefined settings. This could be interpreted as an islanding event by ROCOF relays and could trigger unnecessary tripping of CIGs. This single mis operation could create destabilization of the network [5].

- **Power swing protection**

The variation of power flow induced by disturbances like switching of transmission line or transformers, load or generator throw off etc. are known as power swings. Such disturbances cause changes in voltages and currents. Under/over voltage protection and overcurrent relays may interpret these even as fault and trigger unnecessary tripping. Power swing protection is deployed to differentiate such disturbances from a fault and block unnecessary tripping. The rate of change of impedance is considerably slower during a power swing compared to a fault. This information used to differentiate between power swing and fault in the protection scheme known as power swing blocking [5]. Since CIGs in its current setting do not provide any inertia, the rate of change of impedance is likely to increase during power swing. This creates a case for increased CIGs reducing reliability of power swing protection. Power swing protection scheme also monitors the stability of the swing. In presence of CIGs, some stable power swings could be mis-interpreted as unstable and mis operation of the protection devices could occur [5].

7 Commercially available techniques

A range of relay models from different manufacturers are utilized by TSOs in power grid to protect and control their transmission and distribution networks. The choice of specific relay model depends on the application requirements, voltage level, technical specifications like capacity, switching time, size, etc., compatibility with existing equipment, Compliance with industry standards and certifications, reliability, and quality. Some popular manufacturers and their commonly used relay models are listed below.

ABB:

- ABB RED670: Numerical protection relay

Siemens:

- Siemens SIPROTEC4, SIPROTEC5: Numerical relays with distance, differential and overcurrent protection, etc.

GE

- GE Multilin UR series
- GE Multilin D60 Line distance relay.

Schneider

- Schneider Electric MiCOM P Series

Schweitzer Engineering Laboratories

- SEL Series

In the following section, the provisions for detection and fault clearing with low fault current is discussed. The discussion is based on the functions available on some of the relay models presented above.

7.1 Current reversal protection

Fault current reversal protection (logic) is used when parallel lines are connected to common buses between a weak and a strong source. Overreaching permissive communication scheme can trip healthy line even when fault has been cleared on the faulty line. Such unwanted trip can be explained based on figure 14. Figure shows parallel transmission lines L1 and L2, connected between a strong source and a weak source. Transmission lines are equipped with relays R1, R2, R3 and R4 and breakers. For a fault in line L2 close to R4, as shown in the figure, fault current from the strong source will pass through R1, R2 and R3. Fault current from weak source will pass through R4 only. R1 and R2 will detect fault in forward direction and R3 will detect the fault in reverse direction. R4 will operate instantaneously, irrespective of communication signals. R2 detects fault in its zone 2 but waits for permissive signal from R4 to trip. R1 also detects fault in its zone 2 and issues a permissive signal with a time delay to R3.

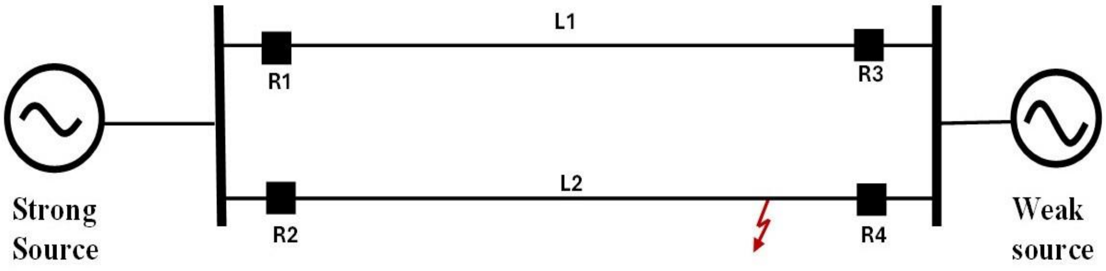

Figure 14. Parallel transmission line between two sources

After the opening of breaker near R4, the fault currents are redistributed. When R4 opens, the fault current that was passing through R3 will reverse its direction and the fault current from weak source will flow through L1 and to the fault in L2. R2 is still connected due to time delay. During this time if the communication signal from R1 to R3 is not reset, R3 will keep reading fault in forward direction and will trip unnecessarily. The false trip on unfaulted line due to current reversal can be prevented using a logic to detect current reversal.

7.2 Weak end infeed protection

Operation of permissive communication scheme depends on whether the relay can detect sufficient minimum fault current. An open breaker on one end or a weak source can make fault current too low for a relay to detect. Fault current is initially distributed, causing low fault current in one end. Later when the fault is cleared in the strong end, fault current increases in the weak end. Then, the relay detects fault in zone 1 of the weak end and issues a trip command. Relays use weak end infeed (WEI) echo logic to tackle this issue. When the distance protection elements fail to detect the fault in weak end, WEI function of relays sends back the received signal to the stronger end.

7.3 Instantaneous residual overcurrent protection

Instantaneous earth fault protection provides good selectivity and speed of tripping when the fault current is restricted to a specified level by impedance of some object [26]. In relays like RED670, this setting is dedicated to operating for the faults in the protected object only, ensuring selectivity. The residual currents that are used by the protection device are calculated with the help of SLG and LLG fault current on a line in a meshed system. The fault current calculation can be explained by the figure 15 and 16. Here, a transmission line with impedance Z_L is shown in between two sources. Z_A and Z_B are source impedances on the sides A and B respectively. R1 is a relay on the home end. Fault current is calculated for the fault at end B, a remote end, and end A.

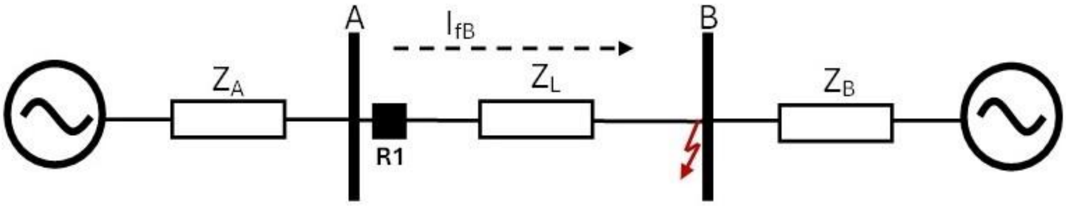

Figure 15. Fault current from bus A to bus B

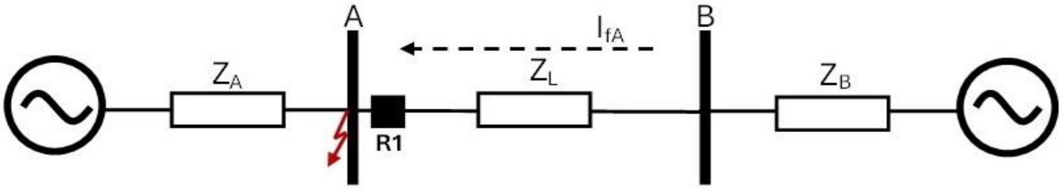

Figure 16. Fault current from bus B to bus A

For fault current I_{fB} at end B, Z_A in higher source impedance operational state and Z_B in lower source impedance operational state is used. Conversely, for fault current I_{fA} at end A, the setup uses high source impedance operation state for Z_B and low source impedance Z_A. The function operates for a defined range of current. The minimum theoretical current setting (I_{min}) is given by (3).

$$Imin \geq Max(I_{fA}, I_{fA}) \qquad (3)$$

However, in practice, the current setting is 30% above the theoretical value accounting for safety margin against static inaccuracy, possible transient overreach and inaccuracy of instrument transformers under transients and system data. A base current value is taken based on the capacity of a protected object and is used as reference for current setting. The percentage of base current is used for protection setting.

7.4 Four step residual overcurrent protection

The four step residual overcurrent protection scheme, available on RED670, is used for sensitive earth fault protection of transmission lines. It is more sensitive for resistive earth faults compared to distance protection. This function offers up to four individually settable steps of flexible current operating levels and time delays. It can function in either directional or non-directional modes. A non-directional mode is used when a protected object cannot feed the fault. When selectivity and fast fault clearance is required, especially in a meshed and effectively earthed transmission system, directional mode is preferred. The directional function commonly uses voltage polarizing quantity which is decided in the settings. Selectivity between different overcurrent protection schemes is achieved through coordination of their operating times. This function in the relays also offer various time characteristics but for optimal coordination, all residual overcurrent protection schemes should use the same time characteristic. Therefore, multiple standardized inverse time characteristics, such as IEC and ANSI standards, are used.

Various reset characteristics are also available in this protection scheme. Four step residual overcurrent protection should reset once fault current level is below operation level unless a delayed reset is desired. Current operating level can be also changed for some time using a setting of a multiplication factor. This function also has the setting of second harmonic restrain. This setting can be useful when there is a power transformer getting energized and a large inrush current flow in. Such inrush current can have residual current component accompanied by significant second harmonic component that create the risk of unwanted operation. A restrain signal can be created to prevent unwanted trip.

The four step residual overcurrent protection can be used to protect a transmission line in a meshed and effectively earthed system. Relays measure residual current and uses a directional function for the protection of the line. Residual voltage is internally generated from three phase set of potential transformers and used as polarizing quantity. The four-step approach of this protection scheme helps in detecting low earth fault current by providing a structured and hierarchical response to varying fault conditions, including those with low current levels. The four steps are described below:

Step 1: Directional Instantaneous function

The relay calculates the fault on the remote busbar and sets the trip threshold above the calculated value. The relay adjusts for the condition if a line connected to the remote end is disconnected or a power transformer is disconnected. If a parallel line is present with mutual zero sequence impedance and a fault occurs on that line, the residual current can be greater than it would be for an earth fault on a distant busbar. The highest calculated residual current is taken for the current setting. This function is highly sensitive to immediate faults, preventing overreaching the protected lines.

Step 2: Directional function with short time delay

This function incorporates a time delay of about 0.4 second and detects earth fault on the line not covered by step 1. This function ensures that the entire line is covered and does not operate for faults on other lines connected to remote busbar. The trip threshold is set considering minimal earth-fault current and ensuring selectivity with adjacent protection. By ensuring the entire line is covered, step 2 enhances the detection of faults with lower current levels that may not trigger an instantaneous response.

Step 3: Directional function with longer time delay

This function is usually set with a slightly longer time delay, often 0.8 second. It ensures selective tripping for earth faults with certain fault resistance and prevents step 2 from being triggered. The trip threshold is selected based on the settings in step 2 on the faulted line and maintains selectivity with other earth-fault protection in the network. This step ensures the low earth fault currents are selectively detected.

Step 4: Non-directional function with long time delay

This function detects and trips for high resistance earth and series faults. The current threshold is typically set around 100A. A predefined time delay of 1.2 - 2 second or current dependent inverse time delay characteristics is used for higher selectivity.

The four-step approach in this protection, especially steps 3 and 4 are tailored to detect low fault currents. The directional function is useful in detecting direction of fault currents in case of distributed generation. The adjustable settings with current levels and time delays allow it to be tuned to the specific characteristics of CIGs. This flexibility ensures that the protection settings can be optimized for lower fault currents, enhancing the sensitivity and reliability of protection scheme. The standardized inverse time characteristics helps in coordination with other protection devices in the system, easing the process of protection coordination and making the operation effective.

7.5 Sensitive directional residual protection

In high impedance grounded systems, magnitude of earth fault current is much smaller compared to short circuit currents. So, the fault detection for an overcurrent protection scheme has been a challenge even in the past. Since earth fault currents are independent of fault location, making fault detection more complicated, earth fault protection achieves selectivity through time selectivity [26].

The directional residual overcurrent and power protection functions can be set to detect earth faults in high impedance networks and give selective tripping commands. The residual current function uses residual current component and cosine of the angle between the residual voltage and the residual current. Residual current function gives better sensitivity. The residual power protection function uses residual power component as expressed in (4). Here, $3I_0$ and $3U_0$ are residual current and residual voltage component and ϕ is the angle between them. It is often compensated with the characteristic angle. compensating with a characteristic angle in the context of directional residual current or power protection involves setting a specific phase angle to enhance the sensitivity and selectivity of fault detection.

$$P = 3I_0 \,.\, 3U_0 \,.\, \cos \phi \tag{4}$$

The characteristic angle is chosen based on the type of network. In isolated networks, the residual current is shifted by -90º compared to the reference residual voltage. Hence, the characteristic angle is set at -90º. Resistance earthed or petersen coil earthed networks use the residual current component that is in phase with residual voltage with a characteristic angle of 0º. Directional residual power function is applicable in high impedance earth networks and can be used for inverse time characteristics.

This function can be configured for a non-directional residual current with either definite or inverse time delay. It also has a neutral point voltage feature. This can be utilized for non-directional sensitive backup protection.

The sensitive earth fault protection function is intended for scenarios where the fault current exceeds typical high impedance levels but is lower than LL short circuit currents. When configuring this protection, it is crucial to consider zero sequence impedance, and the fault resistance in the system. For systems with high impedance earthing, earth fault current and the neutral point voltage are calculated based on the desired sensitivity. The fault impedance determines the sensitivity in this case. The characteristic angle is adjusted according to the system type. The relay is configured to measure residual current and voltage, with settings for base current, base voltage, and base power. The operation mode can be configured to measure the directional current component, $3I_0.\cos\phi$, or the residual power component $3I_0.3U_0.\cos\phi$. Additionally, the relay includes settings for residual current release level, residual voltage release level and definite time delays. The characteristic angle and relay open angle are adjusted to optimize fault detection sensitivity and selectivity, ensuring accurate fault identification and appropriate trip response.

7.6 Line differential protection

Line differential protection can be a good choice in short and medium transmission lines and cables to achieve the best selectivity and sensitivity compared to other protection schemes. This protection scheme is best for fault detection when the earth fault is highly resistive in nature. High sensitivity can be achieved with line directional protection and faults can be cleared instantaneously. It is impervious to current reversal due to faults happening in parallel line as discussed above in current reversal logic section [26]. The ABB RED670 can be used for line differential protection on multi terminal lines. It can be used with a one-and-a-half breaker configuration where the relay is fed from two CTs. When the relay receives current input form two different CTs without adding the measured currents, the current differential algorithm considers possible bias current from both CTs. This makes sure that correct restrain is possible. Figure 17 shows multi terminal breaker configuration with protection zones used for line differential protection. R1, R2 and R3 are the relays used near bus bar A, B, and C.

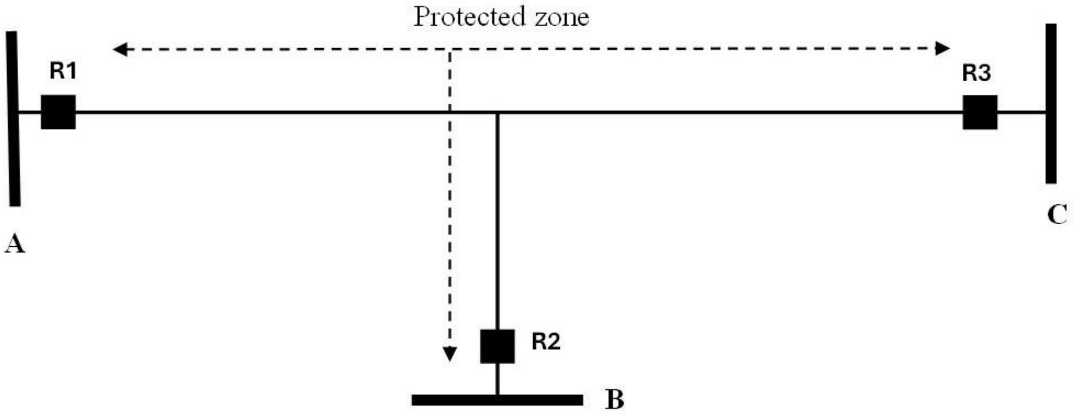

Figure 17. Line differential protection applied to multi terminal lines.

Capacitances between conductors and earth create charging current which can be falsely interpreted by the relay as differential value. To avoid this, differential protection includes a charging current compensation feature. This feature measures and subtracts the steady-state differential current under normal conditions, which in turn reduces the differential current to near zero. In the event of a fault, the pre-fault differential current values are frozen and updating resumes 50 milliseconds after normal conditions are restored. This introduces a minor error in differential current calculation during fault conditions, but it is negligible and does not negatively impact protection sensitivity. In the case of a low resistive short circuit, the voltage at the fault location drops to near zero, reducing the charging current. The frozen pre-fault current value results in an overestimation of the charging current, but the bias current remains high enough to maintain stability. For high resistive faults, the voltage reduction is minimal, and the pre-fault differential current remains an accurate estimate of the actual charging current. Overall, when the pre-fault charging current is subtracted, it enables setting the minimum differential current without considering charging currents, thus achieving maximum sensitivity without compromising stability during external faults.

The RED670 uses 64 kbit/s communication channels in line differential protection for exchange of telegrams between the relays at line end. These telegrams carry information about current sample values, time signature, block command, trip command, and other signals. Time synchronization of these sampled current values is critical for numerical line differential protections. This is achieved using the echo method in systems where send and receive times are equal. If the network has asymmetrical transmission times, Global positioning system (GPS) synchronization is necessary.

Line differential protection evaluates the current from all ends in three different block analysis i.e., percentage restrain differential analysis, second and fifth harmonic analysis and internal/external fault discriminator. The result of this analysis is used to issue trip signals. In percentage restrained differential operation, the operating signal is generated by taking the vector sum of all the measured currents for each phase independently. And for restrain current, the greatest phase current reading of any CTs is taken. This function is set on/off with this setting. In harmonic analysis, when the harmonic content in the differential current exceeds the predefined threshold, the restrained differential operation is blocked. But, in case the negative sequence fault discriminator classifies a fault as internal, the harmonic restraint is overridden. This function comes into practice when there is a high impedance object, like a transformer, in the protected zone. The transformer inrush currents have high second order harmonic content. Transformer over-excitation can increase the fifth order harmonic content in the excitation current, potentially reaching up to 100 times the normal level [26]. The secondary side of CT can see rise in second and fifth harmonic due to saturation. A percentage value indicating the ratio of the second harmonic content to the fundamental frequency in the differential current is set to override the harmonic restraint.

8 Power grid codes

The organization or regulatory authority responsible for the operation of power systems develops and enforces various technical standards and regulations to govern planning, design, construction, and operation of the grid. Such a set of regulations are called grid codes. Operators of any section of the grid must abide by these codes to maintain grid reliability, efficiency, and safety in all phases, i.e., generation, transmission, and distribution. The rules to maintain control and stability of the grid during normal condition and during abnormalities is one of the key aspects covered in grid codes. It includes requirements for frequency control, voltage control, fault ride through, etc. Technical requirements for connection of a new renewable or traditional generator are also specified in the grid code. It establishes standards for power qualities like voltage and harmonics. They also mandate protection schemes to ensure safety of the system during abnormalities like faults and overloads. Provision for grid planning and development, system modeling, system reinforcement, coordination among grids, etc., are also covered in grid code.

Grid codes that were developed when power systems were predominantly centralized and dominated by conventional generation sources often lack provisions to accommodate evolution of power systems. Where voltage and frequency support and control are dominant features, Provisions like fault current support from CIGs are not dealt with as much importance. However, Various organizations and TSOs have declared the rules and standards for connection and operation of CIGs to the power grid. In this section, sections of such codes pertaining to short circuit contribution is discussed.

European Network Codes (ENCs):

An interconnected EU internal energy market is crucial for ensuring security of energy supply and affordability to all customers. ENCs were formulated to make sure all consumers could afford a secure supply of electricity. Grid operation and trading rules used to be carried out nationally in the past but increasing cross border networks among European countries meant a European network code was necessary for effective management of electricity flow in the network. These network codes govern cross-border electricity market transactions and regulations on development and operation of network.

The European Commission takes input from public commission like European Network of Transmission System Operators for Electricity (ENTSO-E) and Agency for Cooperation of Energy Regulators (ACER) and makes priority list of new proposals and adopts them for network code. Such proposals are checked by authorities like Electricity Cross border committee and national energy ministries and adopted after approval of Council of the EU and the European Parliament.

ENCs include codes for emergency and restoration, demand connection, high voltage direct current (HVDC) provision, etc. However, very few provisions have been included in the requirement for converter interfaced generators regarding the fault current requirements in requirement for generators code. It is mentioned in Article 1 of [27], that it “lays down the requirements for grid connection of power-generating facilities for synchronous power generation modules or power park modules and ensures integration of renewable electricity sources.” The regulations that have set out detailed rules regarding connection of new generators in the grid do not have exclusive provisions for fault current contributions from CIGs. However, there are provisions for power park modules (PPM). PPMs are individual units or a group of units that are either non-synchronously connected to the system or connected with a converter interface, with a single connection point to a distribution, transmission, or HVDC system [27].

The power generating modules (PGM) are categorized in different types based on voltage level of connection point and maximum capacity or threshold proposed by TSO. They are required to comply with the codes based on their types. Type A, type B and type C have connection points below 110kV, and Type D has connection point at or above 110kV. Type D can be connected below 110kV as well if maximum capacity is at or above threshold specified for different regions. The maximum capacity for each type is different for different regions of Europe and the maximum capacity thresholds for types B, C and D need to be approved by regulatory authority or member state. The modern and revised grid codes tend to have stricter requirements for the PPMs that are larger in size and are connected to higher voltage [28].

According to European grid code, PPMs are required to have a fault ride through (FRT) capability, where they should not disconnect due to undervoltage before the fault is cleared [27]. The PPMs are required to stay connected to limit the loss of generation after a fault to avoid propagation of voltage disturbance across large area [29] unless the internal protection scheme requires disconnection. For type B and type D PPMs, each TSO must specify a voltage time characteristics that describes a condition under which generators can stay connected and operate stably during and after faults in the transmission system. The FRT requirement is however specified through a generic voltage-time profile that shows a minimum transient voltage drop that a CIG should withstand. Figure 18 shows the voltage time profile in the European grid code but some freedom is awarded to national TSOs [28]. The minimum voltage between fault clearing time may be between 0.5-0.15 pu and the fault clearing time may be 0.14-0.15s. The minimum voltage level is 0 for type D PPM. The voltage recovery time may be 1.5-3s and at 0.85p.u., voltage is considered recovered. The internal fault protection schemes must not override FRT responsibility [27], [28], [29], [30].

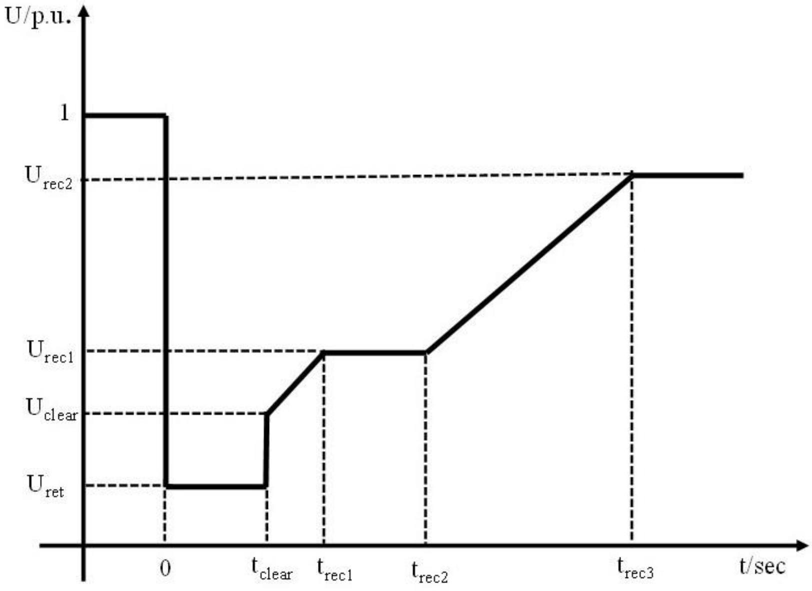

Figure 18. Fault ride through profile of a PPM [27].

TSOs are required to publicize calculation of minimum short circuit capacity at the point of connection pre and post fault. For asymmetrical faults however, TSOs can specify the FTR capabilities for PPMs [27]. The protection system should remove faults within the time specified by FRT. Hence, quick fault removal becomes even more crucial.

Systems operation code [31] lays down regulations for “safeguarding operational security and efficient use of the interconnected system”. This code has a provision for short circuit current management. It allows each TSO to establish the maximum short circuit current that exceeds the rated capability of protection devices, as well as the minimum short circuit current necessary for the proper operation of protection equipment. This provision gives freedom to the TSOs to explore new protection schemes in increasing the presence of CIGs. TSOs are also required to calculate short circuit current and evaluate the impact of neighboring TSOs.

There is no clear provision to address the reduced fault current in the codes mentioned above but the possible solutions are being explored. The technical report, “High Penetration of Power Electronic Interfaced Power Sources and the Potential Contribution of Grid Forming Converters” by ENTSO-E [32], emphasizes on the challenges imposed by CIGs in fault level. A significant reduction in fault level can lead to protection system malfunction and reduced system stability and ensuring adequate system strength in high CIG scenario is crucial for stable voltage and frequency operation. The document presents two possible solutions, grid forming converters (GFCs), which can contribute to creating system voltage and fault level, and synchronous condenser (SC), which can provide additional fault current and system inertia. Grid codes of different countries have different provisions for fault current and some countries have started to specify the requirement for fault current in detail. However, much work still remains to be done in having a desired fault current response from the CIGs and having a proper standard [32].

Different TSOs are continuously updating their grid codes and integrating CIGs like wind plant but the harmonization among different codes is not achieved yet [28], [30]. As allowed by European grid code, TSOs have adopted some of the FRT provision and voltage time profile but have taken different approaches in others. For a type D PPM, UK and German grid codes have adopted the 0.14s and 0.15s recovery time at 0 pu. The UK grid code, however, does not have a voltage recovery time after 0.14s and has other provisions for above 0.14s faults. The Danish and Irish grid codes do not have a minimum 0pu voltage and have a longer recovery time[28]. The grid codes prioritize reactive power injection from CIGs during active fault for voltage support allowing reduction of active power output during this time. However, recovery of active power after clearance of the fault is equally significant so that active power imbalances do not cause any frequency deviations [28].

The Swedish grid code does not clearly specify the characteristics of fault current injection from CIGs [33], but some Nordic TSOs have introduced some fault current requirements for CIGs [34]. Nordic TSOs use models of power plants to study the required tuning and control of the converters. In case the tuning is not sufficient, grid forming capabilities and grid supporting devices can be enforced through grid codes. Grid code updates in Nordic region can be expected to take a long time due to legal and administrative approval requirements, development of the devices and implementation in the power plants [34].

German grid code [35], on the other hand, is often referenced in literatures regarding fault clearance in CIG dominated system for its new codes regarding negative sequence current control for unbalanced faults. Typically, negative sequence current is suppressed by control systems in CIGs but negative sequence current is unaffected by zero sequence mutual coupling and is sensitive to high resistance earth faults [25], [36]. Reference [5], [25] explores the negative sequence current control requirement in the German grid code which shows its effectiveness in fault detecting in high CIG scenario. The magnitude of negative sequence current injected by the CIG controller is proportional to negative sequence voltage by a factor of characteristic proportional gain, k [36], [37]. When value of k is selected between 2 and 6, CIG may emulate negative sequence behavior of a SG by 1/k pu as negative sequence reactance with current rating limitation [36], [37]. However, reference [36] argues that the negative sequence injection has limitations due to controller of CIG. The negative sequence current injection depends on the current limiter of the inverter and the injection is subject to a time delay. The CIG controller takes some time, usually one to two cycles, to measure voltage unbalance before injecting negative sequence current. This delay could impact speed of protection equipment operation [36]. None the less, the simulation results in [5], [25], [37] show that injecting negative sequence current can reduce the possibility of misoperation of protection schemes based on negative sequence quantities. The study found that the instantaneous negative sequence overcurrent protection performs better due to higher level of negative sequence current. The issue with directional negative sequence overcurrent protection and fault identification logic were the altered angular relationship between positive and negative sequence current after inception of the fault. This issue was also mitigated by the new provision in German grid code through negative sequence current injection provision.

9 Promising technologies and required support

Due to the global push for more renewable energy, the share of RESs has been increasing every year. And as a result, protection systems for microgrids, distribution and transmission systems with CIGs and limited fault current has been a major field of research. In this section, some available technologies and some promising technologies are discussed. Some of these technologies are already available, some are in different stages of field test, and some are part of promising research. In any case, they need various support for them to be commonly implemented. Findings from the research, their pros and cons, and their suitability to mitigate the protection challenges introduced by integration of CIG are discussed in this section.

9.1 Fault current limiting technologies

As discussed in section 6, traditional protection schemes based on detecting high fault current are not suitable in distribution systems with integration of CIGs. Limiting fault current contribution from CIGs is one of the protection strategies employed in protection coordination of distribution systems. Some of such schemes are explained below:

9.1.1 Voltage monitoring based protection

In this method, voltage at the point of common coupling (PCC) is monitored during fault period to reduce fault current contribution from CIGs [38]. If the monitored voltage at PCC bus drops below 0.88 p.u., then (6) and (7) is used to control the reference converter current. Even low penetration of CIGs can cause relay miscoordination in distribution system, but this simple strategy can solve the problem of miscoordination adjusting converter output according to severity of fault.

$$I_{ref} = \frac{P_{\mathrm{desired}}}{V_{\mathrm{pcc}}} \text{ for } V_{\mathrm{pcc}} \geq 0.88 \text{ p.u.} \tag{6}$$

$$I_{\mathrm{ref}} = kV_{\mathrm{pcc}}^{\mathrm{n}} I_{\mathrm{max}} \quad \text{for } V_{\mathrm{pcc}} < 0.88 \text{ p.u.} \tag{7}$$

Where I_{ref} is converter reference current, P_{desired} is the desired output power, V_{pcc} is the voltage at PCC, The maximum output current at V_{pcc} of 0.88 pu is I_{max}, k and n are constants.

An easy solution to eliminate impact of DGs in protection coordination is to cut off all DGs during the fault. However, reducing converter current can make it unnecessary to completely block DGs. This method is effective for fulfilling FRT requirements and avoiding nuisance tripping and power delivery interruptions during the short-term disturbances like switching.

9.1.2 Fault current limiters

Distribution systems are usually protected with inverse time directional overcurrent relays, but the introduction of CIGs has created issues as discussed in chapter five. Fault current limiters (FCL) have been used as solution to restore the reliability of overcurrent relays in distributions system with distributed generation. This is a series connected device which provides low impedance when the system is operating normally and high impedance during the fault and blocks fault current contribution from DGs. This device enables use of overcurrent relays as intended during system protection design. The need to alter the settings every time a new DG is added is redundant [39], [40].

Reference [41] investigates the appropriate location for installation of various types of fault current limiters. Solid state FCLs, which is based on switching semiconductor switching device on/off to achieve the desired response, is deemed best for maintaining protection coordination. Resistive and saturated iron core superconducting FCL can be used to maintain integrity of overcurrent protection in distribution feeders in presence of current harmonics. They can also be used in transmission networks to keep fault current within tolerable levels when new power plants are installed. Various research has been done regarding the optimization and efficiency of resistive, impedance/reactance based, and super conductor based FCLs but the high cost, cooling requirements and size has made the application of FCL very limited [9], [40].

9.2 Distance protection in distribution system

The addition of CIGs to the distribution system may necessitate an improved feeder protection scheme. Using directional elements in relays can enhance their sensitivity and improve the overcurrent protection scheme. Distance relays, which are inherently directional, feature instantaneous trip elements and fixed protection zones. Therefore, they are not affected as much by changes in network topology. Even if the fault current level changes at the point of connection in the bus upstream of a feeder, the impedance of the protected section of the feeder remains constant because the current and voltage in the protected area remain unchanged. Although primarily used in transmission networks, this characteristic makes distance relays suitable for use in distribution feeders as well [42].

Time overcurrent and instantaneous overcurrent protection are dominant in distribution systems. Times overcurrent protection utilizes overcurrent relays to detect and isolate fault based on magnitude and duration of the current. These relays operate with time delay that is inversely proportional to the fault current. For remote, permanent faults, it operates while coordinating with other protection devices. It utilizes timed pickup threshold value to isolate the fault. A high-set instantaneous overcurrent element is often used in distribution feeders to limit damage and ensure safety for faults occurring close to the protected devices. A sensitive low-set instantaneous overcurrent element is used in fuse saving schemes where the instantaneous overcurrent schemes trips the breaker downstream of the faults to prevent melting of the fuses. The breakers are reclosed after a certain time delay [42].

According to [42], the characteristics of distance element can be adjusted to enhance protection of distribution system. The high-set instantaneous overcurrent elements can be substituted with quadrilateral distance elements, while the low-set instantaneous elements can be replaced with instantaneous mho elements. The time overcurrent elements are managed by mho elements. In this setup, mho elements play a key role in controlling both low-set instantaneous and time overcurrent elements. These changes provide enhanced fault protection while retaining all qualities of the elements that are replaced. Mho and quadrilateral distance relays can differentiate between forward and reverse faults. The quadrilateral distance elements can better discriminate between different types of faults and provide more precise fault locations. It enhances the system's ability to identify fault locations and better coordinate between upstream and downstream relays. Distance relay can quickly discriminate the temporary fault and maintain fuse saving scheme of instantaneous overcurrent. Distribution system faults are mostly high impedance faults because of short length but distance relay in feeder protection can provide improved protection for closed in faults [42]. However, in presence of higher penetration of CIGs, distance relay faces under and overreach issues [9]. On the other hand, distance relays are more technical to coordinate and replacing existing over current relays or adding new distance relays can be costly.

9.3 Adaptive protection

A conventional protection scheme needs to be adjusted manually on site when there is a change in system condition. An adaptive relaying on the other hand, is a protection scheme that dynamically adjusts its trip settings in real-time based on parameters like local measurements of current and voltage and the number of active CIGs. This adaptability enhances the relay's accuracy and reliability in handling the fluctuating power and voltage conditions characteristic of CIGs [20], [43]. According to [43], adaptive protection scheme has evolved from localized basic applications like adaptive distance relay to technologies covering wide area. The required technology for its implementation includes a digital relay with intelligent electronic device (IED), computing and communicating device, communication protocol for IEDs and the algorithm for setting adjustments. Phasor measurement units (PMUs) measures bus angels and frequency at high sampling rate. They are used for wide area monitoring, protection and control (WAMPC) to monitor transmission network over large area. It enables operators to acquire information about the system before any disturbances and can be considered an enabler of the adaptive protection scheme [43].

The adaptive protection scheme has become a widely researched topic as possible solution to the changes in grid brought by integration of CIGs. Multiple algorithms have been proposed in multiple protection approach. Reference [9] reviews control and protection method across the power system and how the changes in operating condition due to integration of CIGs has necessitated adaptive protection schemes. Some adaptive algorithm considers voltage/current ratios and wind source impedance. They adapt to wind farm loading levels, voltage level, fault resistances, and source impedance but fail to account for mutual coupling in zero-sequence components. Whereas other equation-based algorithm using derived equations affecting the power system during faults. These adaptive techniques are reliable but involve complex calculation. Some adaptive protection uses AI to analyse signals from PMUs and analyses it to extract various information. The AI techniques include decision trees, fuzzy logic, and neural networks. Some examples of such algorithms are explained in the following section.

Reference [20] discusses the development of an adaptive setting scheme for distance relays protecting transmission systems connected to wind farms. This scheme uses local measurements of current and voltage, along with the number of active generating units, to dynamically adjust relay settings. The approach involves calculating positive and zero sequence impedances and using these to determine apparent impedance through distribution factors and compensating factors. Various scenarios are simulated, including varying wind farm loading levels, voltage levels, source impedance, and system frequency. The study highlights significant errors in protection decisions when using fixed settings, pointing to the need for adaptive schemes. The adaptive method accurately adjusts to changes in power transfer angles, voltage amplitude ratios, source impedances, and frequencies. An algorithm is proposed that estimates voltage and current phases, computes equivalent impedances, and generates trip boundary conditions for decision-making. Simulations demonstrate that the adaptive scheme accurately estimates impedance under various conditions, such as changes in grid impedance and wind farm loading levels, making the proposed method promising for ensuring reliable protection of transmission systems connected to wind farms.

Reference [19] proposes an adaptive distance relay setting for parallel transmission networks that connect wind farms to the grid, addressing the challenges posed by mutual coupling of parallel lines and the presence of a unified power flow controller (UPFC) to tackle mutual coupling. The study focuses on a line-to-ground fault scenario, which can be extended to other types of faults. The system comprises a wind farm connected to the grid via two parallel lines. The adaptive scheme involves measuring apparent impedance, calculating pre-fault and post-fault currents, and estimating sequence impedances to determine the trip boundary. The algorithm estimates voltage and current phasors, computes equivalent impedance, and adjusts the trip boundary accordingly. Testing showed that the algorithm-maintained accuracy within 5% error for varying fault resistances and lengths during line to ground faults. Mutual coupling significantly affects trip boundaries and zero sequence components, while UPFC placement influences the trip characteristics. Additionally, the algorithm successfully distinguished between power swings and faults, demonstrating its reliability in adaptive protection.

Reference [44], on the other hand, introduces a theory for a data mining-based intelligent differential relaying system for transmission lines that incorporate FACTS devices, UPFC, and wind farms. It proposes a wide area differential protection scheme utilizing the extended Kalman Filter (EKF) and PMUs. The presence of UPFC complicates setting the threshold current for differential schemes due to its control variations, while wind farm integration introduces weak source conditions that can affect performance. The EKF algorithm is chosen for its superior phasor measurement capabilities. The system uses post-fault features to create a decision tree with 21 differential features, including changes in voltage, current differences across sequences, and reactive power differences. The EKF estimates fundamental frequency and sequence parameters to derive differential features. Performance is assessed using two measures: yield (ratio of correct fault cases to total faults predicted) and dependability (ratio of fault cases predicted to total faults). Tests on a 400 km transmission line with a UPFC in the middle were carried out under varying wind speeds and voltage conditions. The results showed nearly 100% yield and dependability compared to power differential which varied from 80% to 98% depending on type of fault and wind speed. The proposed scheme outperformed traditional power differentials, maintaining high dependability across various fault types and wind speeds.

Despite the promising findings from various research, there are very few examples of application of such scheme on the transmission level. According to [43], a German TSO integrated an adaptive protection function during their control centre update. This function, when paired with overhead line monitoring, adapts system limits in response to climatic conditions and alters protection device settings to match varying short circuit levels. An efficient adaptive protection scheme integrates algorithms, communication system and shared information [45]. While various research has presented promising algorithms, restrictions in sharing information has limited the commercial availability of adaptive protection. Lack of a universal communication protocol can create interoperability challenges among devices from different manufacturers [46]. Adaptive protections are very much dependent on communication system and time synchronization. IEC 61850 communication protocol can provide seamless communication and data share that helps in dynamic communication among IEDs and solve the interoperability issues [46] [47]. While the most promising implementation of adaptive protection in microgrids are the on that follows the IEC 61850 protocols, the reliability of the scheme is still dependent on communication links failure and threats of cyber attacks [48]. Since the effective adaptive algorithm depends on exchanging information between IEDs, safety against cyber attacks is important. Other characteristics that must be considered is the delay in changing settings. Delays in changing settings can range from milliseconds to seconds. This delay might be acceptable in distribution systems but could be problematic in transmission systems with short critical clearing time [45]. The reviewed research in this thesis project were done in simple network in lab environment. It would be beneficial for commercial development and wide implementation if adaptive protection were studied in real and complex network for all kind of faults and voltage levels [46].

9.4 Permissive overreach

The POTT scheme ensures fast and selective relaying over the entire line and is very efficient with low bandwidth requirement through a single communication channel [21]. The operation of distance protection scheme and POTT has been explained in the sections above. But the POTT scheme faces several problems related to communication, and impedance measurement with integration of CIG. Reference [36] provides some issues related to application of POTT in presence of CIG at one of the two end of the protected line. In the events when a CIGs are the sole source of short circuit current in the remote end, the primary concern is ensuring the dependability of the POTT scheme for phase faults. Echo logic function and DTT are present to make sure the protection scheme is reliable. The echo logic allows the home end breaker to trip a few cycles slower if the remote end breaker fails to operate for an internal fault and sends a DTT to the remote end breaker. A minimally set phase overcurrent supervision at both ends, slow under voltage protection at the end with CIG can act as a backup measure if the distance relay or communication fails. A zero sequence overcurrent scheme coupled with a zero sequence voltage polarized directional relay can be used as back-up protection for ground faults in case the communication channel in POTT scheme breaks down. The reference calls these steps “rudimentary safeguards to improve reliability” of distance protection.

Reference [21] talks about the impact of varying impedance in a type IV WTGs and challenges of achieving non-delayed trip over the full length of transmission line. The unreliable impedance measurements and the need for backup protection have been discussed in the paper. The issue of misoperation of POTT is more stark during balanced faults near the WTG [21]. The paper proposes a modified POTT scheme that uses regular impedance-based relays at the remote end of the line and incorporates a fault detection mechanism at the WTG substation that does not rely on impedance measurements. Rather, it uses a fault current waveshape attributes that are unique to type VI WTGs to accurately detect fault direction. The paper proposes a current classification technique that analyses peak to peak value of fault currents to distinguish between fault current from type VI WTG and from the rest of the power system. It is suggested that this method prevents maloperation for reverse faults and ensures accurate, non delayed tripping across the entire line length.

9.5 Travelling wave protection

Higher penetration of CIGs in the grid has reduced grid inertia making faster fault clearing even more critical. In this changing scenario, the protection system must act fast as well as be less sensitive to rapidly changing dynamics introduced by intermittent nature of RES [49]. The travelling wave (TW) based protection scheme is one of fast protection scheme based on detection of the high frequency electromagnetic pulses caused by any disturbances in the power system [50]. The high frequency electromagnetic transient waves in the range of 2kHz to 10MHz, capable of travelling in speed close to the speed of light, are detectable in less than 1ms [49], [50].

TW based protection scheme utilizes the TW produced during disturbance to classifying and locating faults in the transmission line [49], [50], [51]. Such scheme is classified into single ended and double ended approaches based on communication infrastructure they use. The double ended schemes use a communication link to transmit the arrival time of TWs between local and remote terminal. This information is used to identify fault location. However, the dependency on communication links makes TW protection schemes less reliable, as any compromise in the communication link can cause the protection scheme to fail. On the other hand, single ended scheme determines the fault location by analysing the arrival times of the initial TW and the first reflected TW from the fault point. Hence, eliminating the dependency on communication infrastructure for reliability. Both methods have been a subject of research from a long time. TW based protection schemes have been used in research in schemes like distance protection, differential protection, etc., in all voltage levels. However, only a few have been commercially manufactured and used. SEL-T401L and SIPROTEC 7SE20 being such commercially available relays. A TW protection scheme based on TW analysis through differentiator smoother filters is one such commercially produced device [49]. This device uses differential function, incremental quantity distant element and TW based transfer trip elements and can trip in between 1-5ms. The devices compare the polarity of TW detected in two ends of the protected line. The internal faults are have same polarity and the external faults have opposite polarity [49], [51]. On this basis, the differential function locates the fault.

Apart from the speed of fault detection, TW based protection system is independent of the fault current magnitude [49]. This characteristic makes TW scheme very attractive prospect for the protection scheme in CIG dominated power system. The scheme is not sensitive to type of fault and fault resistance. It is also applicable in a system with line compensation devices. The accuracy of the fault location is about 60 meters, saving time in clearing permanent faults [49], [51]. If standard CTs are used, fault can be located within half a kilometre and adding the TW fault locators is not expensive. TW based protection scheme can give significant advantage and eliminate source of error compared to impedance based protection [51]. However, This scheme has several challenges and limitations which are discussed in [50]. Fault that occurs at zero crossing of voltage does not produce any TW. This protection scheme is suitable for long lines and challenging for relays to detect fault within few kilometres from the terminal. This is due to frequent TW reflections that overlap, complicating fault detection. Each change in impedance, due to connections in the circuit, affects the TWs by causing partial transmission and reflection, distorting the signal recorded by the relay. The scheme also faces difficulty in differentiating between a lightning strike that causes a flashover and one that doesn't, as well as distinguishing between true faults and surges caused by surge arresters, which can appear as faults to the relay [50].

A questionnaire that was asked to TSOs in [50] concluded that the TW based equipment are not widely used and the use is mainly focused for fault locating. It also concluded that the TSOs are waiting for large scale integration and standardization of the relays. TW based method uses digital communications and GPS based time synchronization which is critical for this protection system [50]. TW based protection equipment are manufactured by various manufacturers with different data models and communication protocols and has created interoperability challenges [52]. This has highlighted the need for universal standard. Various IEC 61850 based model has been proposed to standardize the communication among such devices. A literatures reviewed in [52] discusses the application of IEC 61850 for wide area protection based on traveling waves. A new logical node is developed to calculate fault distances using initial traveling wave arrival times and waveforms, and to facilitate information exchange with remote substations. This node and its data objects comply with IEC 61850 standards. This model was successfully used to achieve data in a 220kV grid in China, simplifying the system complexity for larger networks and aiding in the detection of low-disturbance faults [52]. It can be expected that relays with standard TW function will be more popularly in near future to meet the changing needs of the power grid protection [50].

9.6 Line differential protection

Line differential protection is a commercially available protection scheme today. Its operation method has been discussed in chapter six. Current differential protection is widely used due to its excellent selectivity on internal faults. It can be a better choice for protection of short lines where impedance might not be enough for proper functioning of distance relays [53].

However, its wide implementation on transmission line has faced challenges like sampling misalignment and communication delays that arises during phasor synchronization and time delay in the communication channel and line charging currents [54], [55]. Multiple studies have been done to face the challenges of current differential protection. A technique for power differential protection, where power flowing through two ends of the protected line are compared for difference, is investigated in [54]. Application of GPS technology and development of new algorithms that operate on quantities that have some dependence on current phasors are often used to tackle the issue of phasor synchronization [54]. Reference [56] proposes a phase angle and cosine angle comparison scheme and aims to compensate for phase angle error created by line charging currents. Whatever the solution is, a reliable communication cable is of utmost importance to the line differential protection scheme.

ENTSO-E has laid out some requirements for use of current differential protections in high voltage networks in [53]. A current differential protection should be accompanied by distance protection as a back-up whether it is on a radial line or a meshed network. Distance and directionalized inverse time zero sequence overcurrent protection are preferred as back-up against the failure of communication channel [36]. The differential protection should be a biased current type which restrains for CT errors, charging currents, communication and frequency deviation. Specific CTs that fulfills the relay requirements and does not saturate within the first 5ms of the fault occurrence should be used. The communication between relays must activate within 30ms because current differential relays used in 400kV must operate within 30ms of fault inception. ENTSO-E actually discourages the use of GPS signal for synchronization due to lack of control of the signals. It also mandates that the delay in the communication system should be less than 10ms and the pickup times of the end relays must not be 1ms apart from each other. In case redundancy is used, it is suggested to use double line differential protection with fully and physically redundant communication channels.

9.7 Grid forming converters

Grid forming converters (GFCs) are advanced power electronic devices that act as a voltage source and are capable of autonomously controlling their output frequency and voltage. The active control of the frequency and voltage can reduce the dependency on mechanical inertia as GFCs act as frequency oscillations damping source as well as source of inertia [57]. They can operate independently or in coordination with the grid. GFCs possess the capability to emulate SGs in terms of voltage support, frequency support and fault current infeed [32]. Due to such qualities, the role and potential of GFCs in power systems in CIG dominated power systems has become a prominent topic of research and development in recent years. While such converters are currently popular in microgrids, future developments aim to integrate them in production of CIGs and HVDC links.

A traditional grid following converters, which synchronizes their output with the grid voltage and frequency, can be represented as a controlled current source with a high parallel impedance. GFCs are controlled in closed loop to function as ideal voltage with low series impedance source and specified amplitude and frequency [58]. Due to the low output impedance, they require precise synchronization to operate in parallel with other GFCs.

Reference [58] provides example of UPS as an example of such converters. Normally, it is decoupled from the grid during normal operation but in case the grid supply is cut off, UPS forms grid voltage. GFCs in microgrid provide reference voltage for CIGs and loads that lies nearby while in no-load condition [58], [59].

The studies on effectiveness of GFCs during faults show positive results but the performance evaluation seem complex [32]. The behavior of GFCs depends upon fault location and fault type [60]. Due to their nature as voltage sources with impedance, GFCs can experience unwanted overcurrents during faults, risking hardware damage. Traditional current limitation methods for standalone GFCs, using PI controller saturation, can lead to stability issues. An alternative is using virtual impedances to stabilize the converter and avoid excessive current references [61]. The virtual impedance method involves adjusting the reference voltage based on a fictitious variable impedance to prevent high current signals in the control loops. Variable virtual impedance have also been explored to enhance critical clearing time and ensure stability during faults, though challenges remain, particularly with sustained faults [62]. A control approach called virtual synchronous machine was developed to mimic the characteristics of traditional SGs while avoiding their drawbacks, such as a tendency for oscillations [60].

ENTSO-E technical report [32] and [60] mentions that the GFC should inject both negative and positive sequence current otherwise limited by the overcurrent capacity of converter. The protection system needs sufficient fault current in the first 20-30ms after the inception of fault but in cases of 100% penetration of CIGs, fault current of sufficient amplitude is required within 5ms [32], [63]. Experimental results in [64] illustrates the FRT behaviour of GFCs under different fault scenarios, highlighting compliance with some draft grid codes requiring a response within 5ms of fault occurrence. Results from such studies suggest that all the challenges can be delt with careful selection of converter control strategy and the selected solution should contribute significant fault current within one cycle of fault inception [60].

The adoption of GFCs faces technical, economic and commercial challenges. New features or control strategies like virtual synchronous machine have shown its effectiveness in some extreme cases but more research is necessary before their commercialization and implementation [65]. While there is a need of more investment in R&D to determine potential and usability of GFCs, its cost and effectiveness compared to traditional solutions like SCs are still in evaluation phase [32]. A benchmark system for development of suitable process for testing and validating is a current topic of discussion among TSOs, manufacturers and academia [59]. Successful integration of GFCs may require updates to grid codes and the creation of ancillary services markets to provide revenue streams for GFC capabilities. This could involve mandatory requirements or incentives for developers to invest in GFC technologies [32].

9.8 Synchronous condensers

CIGs lack stored kinetic energy and have limited reactive support during voltage dip. This has led to challenges in maintaining system frequency, angular stability, and voltage stability during disturbances. These challenges have highlighted the use of SCs in the future grid can become a potential solution [66]. SCs are SGs without a prime mover and their inherent inertia and electromagnetic coupling to the grid allows them to absorb or release kinetic energy [66]. Their excitation system can provide reactive power support to maintain voltage stability. Their short circuit current response is also comparable with SGs. They can also inject negative sequence current during unbalanced faults. Operating SCs in parallel with CIGs in remote location can solve the protection issue brought by fault current response of CIGs [36], [60].

The SCs have been used for ancillary services from as far back as 1910s but were once considered obsolete [67]. Recently, however, they have been used for increasing short circuit strength near HVDC installations [67], [68]. So, the usefulness of SCs by building new ones or converting existing or discontinued into SC units in the modern power systems has resurfaced [68]. Reconfiguration of generating SGs at the end of life cycle for standalone functionality with reactive power support capabilities is gaining popularity [69]. The extension of lifespan of existing devices needs to be checked for mechanical and electrical reconstruction and modernization. Since the turbine is decoupled as it is not necessary, a new startup system is implemented. A pony motor with variable frequency drive is considered enough for starting [69]. Electrical parts, however, need a little more modification and new installations. Installation of startup frequency converter and modification of generator protection and synchronization and excitation equipment is necessary [69]. Startup frequency converters bring the generator to overspeed. Then they are switched off before synchronizing SGs to the grid. After synchronization, these devices can automatically provide voltage and short circuit support.

Reference [68] provides some example of how the SCs have been used in modern power grids. A 626MW heat and coal fired unit in Ensted power plant in Denmark stopped generating in 2013 due to wind power plants meeting the energy demands. The plant is now used as a SC for stability support made possible by reusability of existing equipment. Similarly, two retired units of Huntington beach generating station in California, USA were also converted into SCs for voltage support. The voltage support was made necessary due to retirement of San Onofre Nuclear Generating Station which had un-stabilized the grid. In another example, The Danish TSOs installed SCs that could deliver up to 900 MVA of SCC in three substations. This project is considered very important for a power grid like that of Denmark that consists of large share of CIG like WTGs. Whether replacing the fossil fuel plant or reusing the old components, these examples highlight how SCs can be a very good solution to meet the targets of sustainable energy transition.

However, SCs are sometimes overlooked due to high operating cost, maintenance requirements and low efficiency. The field current of a conventional machine needs to be tripled from no-load to full-load operation [70]. In this process, field winding insulation is subjected to significant heating. The SC loses efficiency and degradation and, ultimately, failure of insulation due to the heat [68], [70]. A High Temperature Superconductor Dynamic SC, which consists of a rotor wound with high temperature superconductor rotor, is a possible alternative to a conventional SC. Such device are more efficient and require less maintenance [70]. Another way to maximize the effectiveness of SCs in increasing short circuit strength of the grid is presented in [67]. The short circuit current available in the local bus is dependent on the sub transient reactance of the synchronous machine and leakage impedance of the transformer. The sub transient reactance is fixed per unit on the condenser base. So, the other option is to reduce the transformer leakage impedance. Generally, reducing the leakage impedance of a transformer is more cost-effective than increasing the condenser's capacity to achieve a specified short circuit capacity [67].

10 Discussion

The increasing integration of CIGs into modern power systems presents unique challenges in maintaining grid stability and reliability. Traditional protection schemes, originally designed for SG dominated systems, encounter significant issues when applied in networks with high CIG penetration. The fault current study on the power system model highlighted the urgency to address the lack of fault current in the energy transition. The loss of fault current of up-to 60% was observed in the studied scenarios and the aim of this chapter is to examine the current strategies and preparations to tackle the issue. This chapter critically examines the impact of CIG integration on protection schemes, the current strategies outlined in grid codes, standards, and usable functions in available protection equipment. This section concludes with exploration of promising technologies and principles, evaluating their usability and the necessary support for successful implementation.

The integration CIGs into distribution networks poses significant challenges to traditional protection systems, which were designed for radial, unidirectional power flows with predictable fault currents from SGs. CIGs introduce variable and limited fault currents, leading to critical issues such as bidirectional fault currents, blinding of protection, and sympathetic tripping. The use of fuse can also be expected to change due to lack of high fault current. These phenomena undermine the reliability of conventional overcurrent protection, as relays may fail to detect faults or may trip unnecessarily, isolating healthy sections of the network.

On transmission systems, low and variable fault currents from CIGs disrupt the reliability of overcurrent and distance protections. Distance relays, dependent on impedance measurements, face underreach and overreach due to the fluctuating infeed from CIGs, complicating fault detection and relay coordination. The problem is exacerbated while using memory-polarized mho distance relays, which rely on pre-fault conditions to measure impedance and detect faults. In systems with a high penetration of CIGs, the internal impedance of the CIGs can vary significantly, causing inconsistencies in the relay's operation. This variability in impedance, coupled with the phase angle differences between load current and fault current, makes it challenging for distance relays to maintain accurate zone settings, leading to potential misoperation. The absence of negative-sequence currents in CIGs undermines fault identification and directional elements disrupting the traditional fault identification logic. Incorrect fault identification can lead to misidentification of the faulted phase, potentially leading to incorrect relay operation. In traditional systems, where the negative sequence components are significant and consistent, this approach works effectively. However, in systems with high CIG penetration, the fault current often lacks sufficient negative sequence components, compromising the reliability of directional elements. This can result in incorrect fault direction determination, leading to potential misoperation and reduced effectiveness of the protection scheme. Communication schemes like POTT relies on directional elements to detect faults and send trip commands to remote relays. However, if the directional negative sequence element misoperates, it can cause cascading failures in the protection scheme. For instance, if a directional negative sequence overcurrent relay fails to send a permissive trip signal due to incorrect fault direction determination, the POTT scheme may fail to trip for in-zone faults, potentially leading to widespread system instability. These issues underscore the need for adaptation of new protection strategies.

Low fault current is not a new problem in the power system and protection equipment have been dealing with them for long time. High fault impedance and weak end infeed have limited fault current even in the SG dominated systems. The protection techniques discussed in chapter 6 offer robust framework for addressing challenges posed by low fault current. The residual overcurrent protection and weak end infeed methods are particularly effective in scenarios where traditional overcurrent protection may fail due to insufficient fault currents. The weak end infeed logic and sensitive directional residual overcurrent protection are specifically designed to detect and manage faults in high impedance earthed networks, where fault currents are typically lower than in conventional systems. The four-step residual overcurrent protection scheme, with its multiple time delays and directional settings, provides a nuanced approach to fault detection that ensures both selectivity and sensitivity, even in complex meshed systems. Despite their advanced capabilities, these protection techniques face several limitations when dealing with low fault currents, necessitating additional support to ensure reliable operation. One major limitation is the reliance on accurate current and voltage measurements, which can be compromised by issues such as CT saturation, transient conditions, and the presence of harmonics. The harmonic analysis and charging current compensation features help mitigate these issues but may not eliminate the risks of misoperation, particularly in systems with complex configurations or significant dynamic changes. The line differential protection scheme is well-suited to detect high resistance fault, but its use is limited to medium and short transmission lines. Moreover, the effective implementation of these protection schemes often requires high-speed communication networks and precise time synchronization, as seen in the line differential protection scheme. So, the studied schemes might be useful in detecting low faults in the CIG dominated power system, but it needs updates and integration of advanced technologies for continuous monitoring, real-time data analysis, and adaptive settings adjustments.

The grid codes studied in this project did not have explicit requirements or direction for fault detection in limited fault current scenario, but the FRT requirements makes it very clear on the roles a CIG is expected to play during fault. The thesis outlines some updates in grid codes, particularly those related to FRT capabilities and voltage support during faults. These requirements ensure that CIGs remain connected to the grid during faults, contributing to voltage stability and reducing the likelihood of cascading failures. For instance, the introduction of stricter FRT requirements mandates that CIGs must withstand certain levels of voltage dips without disconnecting from the grid. This requirement is crucial for maintaining grid stability during faults but also presents challenges for protection schemes, as it changes the dynamics of fault currents during and after the fault event. The economic viability part was not explored in this thesis project, but FTR requirements can be expected to add technical complexity and cost to the developer.

In response to the challenges posed by CIG integration, grid codes and standards have evolved to address the new protection requirements. Some codes have started mandating reactive power control and negative sequence component injection. While the results are promising in the fault detection, clearance and stability support, their implementation are equally challenging. For instance, reactive power control can be particularly challenging for

CIGs, which may not naturally produce or consume reactive power in the same way as SGs. This could necessitate the use of additional equipment, such as STATCOMs or capacitor banks, which could increase costs and complexity. The German grid code's mandate for negative sequence current control in CIGs helps mitigate these issues, ensuring that fault detection and protection schemes function correctly. But the lack of global adoption could be due to the technical challenges and increased cost of implementation. The regional differences in grid code requirements can also pose significant challenges in integration of new CIGs. Different countries and regions have developed their own sets of rules, leading to a lack of standardization. This fragmentation can be a barrier to the widespread deployment of CIGs, as equipment vendors and power producers must navigate a complex landscape of varying regulations. The inconsistencies can have its implications in increased cost for vendors, who must develop different system for different customers, and complications for TSOs and traders in interconnected grid system.

Grid codes have often evolved in response to problems that have already manifested, rather than anticipating future challenges. This reactive approach has led to a piecemeal development of regulations, which can result in inconsistencies and gaps in protection and control strategies across different regions and grid operators. However, opportunities for improvement have been identified for development of more adaptive and dynamic grid codes. As the penetration of CIGs continues to grow, grid codes will need to become more flexible, allowing for real-time adjustments based on grid conditions, generation mix, and demand. For instance, the integration of advanced monitoring, communication, and control technologies could enable grid codes to evolve in real-time, improving the grid's ability to handle variability and uncertainty. However, such an approach would also require significant investments in infrastructure and a shift in regulatory philosophy, which could be challenging to achieve.

The reviewed study in chapter 9 suggests that while existing standards provide a solid foundation, they may need to be revised or expanded to accurately reflect the behaviour of modern power systems with high penetration of RES. The need for revised approaches that account for reactive current injection during faults and the importance of grid code compliance are underscored. The proposed enhancements to the standard, such as using a variable value for current sources based on grid code requirements, are recognized as potential solutions. However, the chapter also highlights the challenges in implementing these standards, such as the need for more detailed modelling of CIGs, the potential for increased complexity in fault current calculations and dependency in the location of the fault. This necessitates further research and the development of more sophisticated tools and techniques to ensure that the standards remain relevant and effective in the evolving energy landscape.

The techniques of dealing with fault current in distribution system especially with the presence of DG might be different to the transmission system. The idea of limiting the fault current during a fault is a bit counter intuitive to the idea of fault detection and clearance. But the use of voltage monitoring based protection and fault current limiters makes the protection coordination much easier to the grid operators. These techniques also allow for seamless addition of new DGs. However, addition of new DGs and effectiveness of such protection scheme is subject to other variables like fault current level on the grid itself. Such technologies might be too costly for a distribution system. Distance protections are less sensitive to changes in network topology, and they might provide better discrimination between faults. But the low impedance fault is common in distribution system and implementation of distance protection might require significant adjustment of protection strategy. Some adaptive protections have been used in distribution system in grid connection or island mode, but the issue remains with suitability at all conditions. Some do not perform well during dynamic condition and transients, other are dependent on system size. Sometimes, the required communication and relays are too expensive for a distribution system.

The adaptive protection’s ability to dynamically adjust its settings in real-time measurements and system conditions makes it well suited for transmission systems. It enhances reliability and accuracy of relays, yet its use is not widespread at transmission level. This could be attributed to its over reliability in communication system and susceptibility to cyber security threats. Other protection schemes that provide good selectivity in CIG dominated system like POTT schemes also might also be susceptible to communication safeguarding challenges. The need for backup protection measures for POTT and the complexity of ensuring dependable operations during balanced faults near WTGs remain significant hurdles. In such scenario, travelling wave-based protection seems like the best solution since its independent of fault current magnitude, and capable of detecting faults within milliseconds. However, the scheme's reliability is affected by factors such as overlapping wave reflections, sensitivity to lightning strikes, and challenges in distinguishing between true faults and surges.

GFCs and SCs attempt to emulate characteristics of SGs and resolve the issues due to limited fault current. GFCs can independently provide voltage and frequency support, fulfil FRT requirements injecting reactive power, reduce dependency on mechanical inertia, effectively “forming” a grid. But their performance during faults is complex to evaluate and has complex control requirements. Additionally, GFCs must be carefully integrated into existing power systems to avoid conflicts with other control mechanisms, particularly in hybrid grids where both SGs and GFCs are in operation. SCs can show same fault current behaviour as SGs. Connection of new SCs and conversion of old SGs to SCs has shown promising result in improving fault current capacity of the grid in various locations. The implementation, however, is costly in installation and operation, less efficient and requires strategic planning of location.

The techniques and principles studied in this thesis project can be divided into two main categories. The first focuses on ensuring that the lack of fault current from CIGs does not disrupt existing protection schemes. Fault current limiting technologies, GFCs, SCs, and FRT requirements with negative sequence injection, all aim to maintain detectable fault currents for use with available protection schemes. The second type explores novel and communication-assisted schemes, such as adaptive protections, line differential protections, and traveling wave protections, which are designed to detect reduced fault currents in scenarios with high CIG penetration. The research and examples studied suggest that the development trend may be leaning more toward the first approach. However, both approaches demonstrate their effectiveness, though each requires additional support for wider implementation.

- **Sustainability and ethical aspects**

  An important ethical aspect relevant to this project defined by the IEEE ethical code of conduct is to uphold the highest standards of integrity, responsible behaviour, and ethical conduct in professional activities. During this project, I sought, accepted, and offered honest criticism of technical work, and acknowledged and corrected errors. I have also credited properly the contributions of others. Everyone’s ideas were taken into consideration on how to make the project better and their contribution was properly acknowledged. A good comparison has been made between different protection techniques and their advantages and limitations has been highlighted rather than favouring a solution put forward by one researcher/vendor.

  The problems defined in this report are introduced by a move to provide clean and green energy to all. So, the technique and principles mentioned in this report are enablers of the energy transition and sustainable energy goals. The safety of living beings and safety of the power grid will always be important whatever the source of energy is and whatever transition the power system goes through. The stability of the grid can be at risk due to the variability and instability introduced with higher penetration of renewables. The effective implementation of the techniques discussed in this report like communication-based protection scheme or increasement of short circuit capacity of the grid will build good platform for penetration of more renewable resources and maintaining system integrity. Replacement and phasing out of the fossil fuel-based sources by renewables, will have positive impact on the environment help achieve sustainability goals.

11 Conclusions and recommendations

This chapter aims to draw the conclusion from the thesis work. While the scope of study was limited, several leads were found that could be followed up for deeper understanding of the problem and finding efficient solutions. Such leads are pointed out in the suggestion section for further study.

11.1 Conclusions

The decreasing domination of SGs and integration of more CIGs will change the characteristics of the fault current present in the grid. While the fault current magnitude was observed to be reduced significantly at transmission level, reduced negative sequence current and wide range of phase angle can be expected. Variable fault current contribution, lack of negative sequence current, variable range of phase current angles and voltage angle jumps will be a common occurrence in the future power system. This phenomenon creates a reason to revamp the protection system designed mostly for unidirectional power flow in a SG dominated system.

Traditional overcurrent and distance protections are particularly vulnerable in CIG-dominated systems, while residual overcurrent protection and line differential protection are less effected. However, their effectiveness is often contingent on additional support systems, including high-speed communication networks and precise synchronization.

Grid codes have begun to evolve with new requirements in response to the challenges. FRT requirements, reactive power control and negative sequence current control particularly aim to mandate characteristics of a CIG during fault. All these requirements have shown promising result but the economic and technical complexities of implementing these new standards pose additional hurdles for widespread adoption.

Technologies like GFCs and SCs offer promising solutions to the issue of limited fault currents but come with significant implementation challenges. Adaptive protections and advanced schemes like traveling wave-based protection show potential but require further refinement to ensure widespread adoption in modern grids. Some of the available products face interoperability issue due to lack of standards that sets universal regulation for equipment vendors.

In summary, while significant progress has been made in adapting protection technologies to accommodate the changes introduced by CIGs, challenges remain. High costs, size limitations, complex performance evaluations, communication and cybersecurity concerns, and the need for standardization are among the key obstacles that must be overcome for these technologies to be widely adopted. The ongoing research and development in this field are crucial for fault detection and clearing in modern power systems in the face of increasing renewable energy integration.

11.2 Recommendations

This thesis has summarized findings based on the reviewed literature, textbooks, codes, standards to on how fault current contribution from CIGs can impact existing protection system. While it was not exclusive, the study mostly focused CIG like WTG integrated on a transmission system. However, several possibilities for further study were identified and are listed below.

- Study on series compensated lines and HVDC link could be interesting. Protection of such lines are challenging to begin with. Integration of CIGs can be expected to add more complexity.
- The focus on this study was on grid. So, the effectiveness of promising solution in case an island is created due to fault is not studied. GFCs can be expected to perform well in island mode due to its inherent grid forming nature. But it is recommended to investigate other technologies and principles in island operation for better understanding of their adaptability.
- Some of the TSOs have already experienced issues in protection schemes in distribution network with overcurrent protection schemes and in transmission system with reach calculations [71]. It is recommended to research how they solved the issue and effectiveness of the applied methods.
- TSOs, DSOs and equipment vendors are actively doing research and development in this area. They keep most information confidential due to security reasons or until a product is fully developed or patented. But it would be interesting if they could be interviewed on ongoing research works.

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