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**IMPACT OF DISTRIBUTED GENERATION ON PROTECTION
DEVICE IN THE CONTEXT OF DISTRIBUTION NETWORK**

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Id Number: EITM/PR176057/12

A thesis submitted to the department of electrical and computer engineering in
partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE IN ELECTRICAL POWER ENGINEERING

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October 2025

Mekelle, Ethiopia

DECLARATION

I hereby declare that this MSc thesis entitled “Impact Of DG On Protection Device In The Context Of Distribution Network” is my original work and has not been submitted, either in whole or in part, for the fulfillment of the requirements for a master’s degree at this or other university. All sources of information and materials used in the preparation of this thesis have been properly cited and acknowledged.

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ACKNOWLEDGEMENTS

I would like to express my profound gratitude to my advisor, Dr. Zenachew Muluneh Hailemariam, for his exceptional guidance, constructive feedback, and continuous support throughout the course of this research. His expertise, patience, and encouragement have been instrumental in the development and completion of this work.

I am also sincerely grateful to my family and friends for their unwavering support, encouragement, and invaluable advice, all of which have greatly contributed to the successful completion of this study.

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LIST OF ACRONYMS

DG	Distributed Generation
PV	Photovoltaic
ICE	Internal Combustion Engine
CHP	Combine Heat and Power
OCR	Over Current Relay
CT	Current Transformer
CB	Circuit Breaker
PT	Potential Transformer
VT	Voltage Transformer
HMI	Human Machine Interface
SCADA	Supervisory Control and Data Acquisition
IEC	International Electro technical Commission
SPD	Surge Protection Device
DC	Direct Current
IOC	Instantaneous Over Current
DTOC	Definite Time Over Current
IDMT	Inverse Definite Minimum Time
TCC	Time Current Characteristic
SI	Standard Inverse
VI	Very Inverse
EI	Extremely Inverse
CTI	Coordination Time Interval
ICS	Interconnected System
TMS	Time Multiplier Setting
DOCR	Directional Over Current Relay
FCL	Fault Current Limiter
N/A	Not Applicable

ABSTRACT

The increasing integration of distributed generation (DG) into low voltage distribution networks has introduced significant protection performance challenges. Traditional non directional over current relays, designed for unidirectional power flow, often malfunction under DG operation due to changes in faults current magnitude, direction, and source contribution. This research investigates the impact of DG on relay performance and proposes effective mitigation strategy using coordinated and graded non directional relays. A 15kv radial distribution network with a total capacity of 24 MVA was modeled and simulated in DIgSILENTPowerFactory. A 6MW inverter based DG unit (solar PV and wind hybrid) was integrated at bus 47 to analyze its impact under various fault types (L-G, L-L, L-L-L) and locations. Three simulation scenarios were evaluated. 1) based case (without DG), 2) DG integrated case, 3) mitigated case (with DG and 11 coordinated non directional relays).

The performance was assessed using key metrics: fault current, relay operating time, coordination time interval (CTI), selectivity, directional behavior, and unwanted/missed trips. Results indicated that DG integration changed fault current, reversed current direction, and led to protection blinding, sympathetic tripping, islanding risk and loss of selectivity. After applying the mitigation scheme with 11 graded relays, selectivity fully recovered, and no false trips and missed trips occurred. The mitigation thus demonstrated that DG induced issues can be eliminated using only non-direction relays, provided proper coordination and setting adjustments are made. Furthermore, a practical method for current transformer (CT) ratio selection was developed to ensure adequate sensitivity without saturation under DG fault conditions.

The key contribution of this research lies in showing that reliable DG integration can be achieved through analytical coordination and relay grading, avoiding the need for expensive directional or adaptive relays. The findings are highly relevant for distribution utilities in developing regions seeking low cost and technically viable protection solutions for networks with moderate DG penetration ($\leq 25\%$).

Key words:

Distribution Generation (DG), protection relay, investigation, DIgSILENTPowerFactory, fault analysis, blinding, sympathetic tripping, islanding, mitigation, coordination, grading,

CHAPTER 1: INTRODUCTION

1.1 Back ground of the study

The global energy sector is experiencing a rapid transition toward sustainable and decentralized energy systems. One major contribution to this change is the increasing deployment of distributed generation (DG), especially from renewable energy source such as solar photovoltaic (PV) and wind power at the distribution level. These DG technologies are being integrated into existing distribution networks to enhance energy access, reduce power losses, and meet environmental targets. However, this evolution also poses new technical challenges, particularly in the area of distribution protection systems.

Traditional radial distribution networks have historically relied on simple protection schemes, typically consisting of a simple over current relay installed at the feeder head or substation. These relays are designed to detect and isolate faults based on the assumption of unidirectional power flow and predictable fault current magnitude. However, with the integration of inverter-based DG sources often contribute limited and variable fault currents, bidirectional power flow and the overall fault behavior of the system changes. Therefore, protection devices may fail to operate correctly can emerge to problems such as protection blinding, sympathetic tripping, and islanding risks.

These issues are further amplified in the context of distribution network expansion planning, where new loads, feeders and DG units are added alongside increasing DG penetration. If protection system are not re-evaluated and adapted to the changes, the reliability and security of the network can be severely compromised.

This study is designed to fill that gap. It focuses on investigating how solar and wind based DG integration affects the performance of a single traditional over current relay in ADWA radial distribution substation network. It also evaluates how graded and coordinated over current protection using multiple relays can be employed as an effective and scalable mitigation strategy. Modeling and Simulation work is carried out using DIgSILENT PowerFactory software, providing a realistic and analytical basis for understanding fault behavior and protection performance in both the existing and expanded system configurations.

1.2 Statement of the problem

The rapid growth of distributed generation (DG), particularly inverter based renewable sources such as solar PV and wind, has transformed modern distribution networks. While DG integration brings numerous benefits, including improved energy efficiency, reduced transmission losses, and enhanced reliability; it also introduces significant protection challenges. Traditional radial distribution networks are designed with unidirectional power flow, and protection systems, especially non directional over current relays, rely on predictable fault currents and fault direction.

The connection of DG alters both the magnitude and direction of fault currents, which can cause traditional relays to malfunction or operate incorrectly. Such impacts include protection blinding, sympathetic tripping, loss of selectivity, and islanding risks, all of which compromise network reliability and safety. Despite previous studies addressing DG protection challenges, most research focuses on directional relays or adaptive protection schemes, which are costly and complex to implement. There is a lack of practical studies demonstrating that coordinated and graded non directional relays can effectively mitigate DG induced protection problems in low voltage networks.

This gap is particularly critical for developing regions or utilities with limited resources, where cost effective and technically feasible solutions are required. Therefore, this study investigates the impact of DG on traditional over current relay performance in a 15kv distribution network and evaluates a mitigation strategy using coordinated and graded non directional relays. The aim is to provide a practical, low cost, and effective solution for ensuring protection system reliability in the presence of DG

1.3 Objectives:

1.3.1 General objectives of the study

To investigate the impact of solar and wind based DG on the performance of traditional over current protection devices in the context of distribution network and to develop suitable mitigation strategies.

1.3.2 Specific objectives of the study

- To assess the impact of DG integration on the performance of traditional over current relay, focusing on fault current variation and direction sensitivity.
- To identify and analyze DG induced protection challenges such as protection blinding, sympathetic tripping and islanding risks.
- To evaluate protection system behavior using six key performance metrics: fault current at relay, relay operating time, directional behavior, CTI, selectivity and unwanted/missed trips.
- To assess evaluation metrics under three protection scenarios: base case (no DG, single relay), DG case (with DG, single relay), and mitigated case (with DG and 11 coordinated relays).
- To analyze the response of protection systems under various fault conditions (L-G, L-L, and L-L-L) at multiple locations within a distribution network.
- To design, model and validate protection schemes that mitigate DG induced protection issues using coordinated fast and graded over current relay.

1.4 Methodology

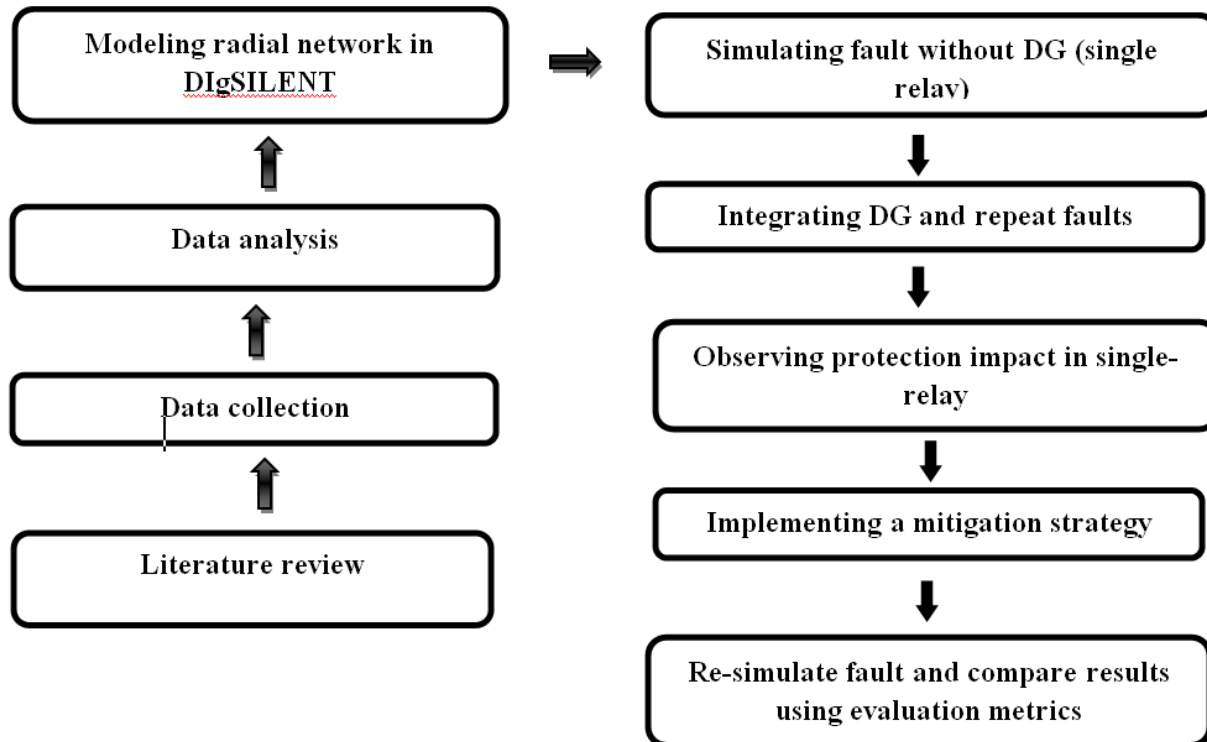


Figure 1. 1 Methodology

This research employs a simulation based methodology to investigate the impact of distributed generation (DG), specifically solar PV and wind, on the performance of protection relays in a radial distribution network. The entire analysis is conducted using DIgSILENT PowerFactory, a powerful for modeling, simulation, and analysis of power systems.

The study begins with the modeling of a standard 15kv radial distribution network, including loads, lines, buss and one over current relay in the base configuration. Next, inverter based solar PV and wind DG units are integrated at selected buses. To assess protection performance, various fault types (L-G, L-L and L-L-L) are simulated at multiple locations along the feeder.

Three simulation scenarios are evaluated

1. Base case: without DG, using a single non-directional over current relay.
2. DG integrated case: same network with DG connected, using the same protection
3. Mitigated case: DG is presented and the protection scheme is enhanced using coordinated and graded non directional relays.

Six key performance metrics are used to assess relay behavior in each case: fault current at relay, relay operating time, directional behavior, coordinated time interval (CTI), selectivity and unwanted/missed trips.

No.	Metric	Definition	Purpose
1	Fault current at relay	Magnitude of fault	check for blinding or insufficient current
2	Relay operating time	Time taken to trip during fault	Assess response speed
3	Directional behavior	Correct identification of fault direction	Avoid false trips in bidirectional systems
4	Coordinated time interval (CTI)	Time gap between primary and backup relay operation	Evaluate coordination
5	Selectivity	Trip only the faulted part of network	Ensure minimal service interruption
6	Unwanted/missed trips	Count of incorrect or absent relay operation	Measure protection reliability

1.5 Scope and limitations of the study

1.5.1 Scope of the study

This study focuses on investigating the impact of Distributed Generation (DG) integration on the protection performance of radial distribution network and evaluating mitigation strategies through relay coordination.

The study is conducted under the following defined boundaries:

- **Network type:** the analysis is based on a radial feeder system, which represents a typical distribution network with unidirectional power flow under normal condition.
- **Protection scheme:** the protection system under study involves over current relays only, initially a single relay, and later 11 coordinated non-directional relays placed at different feeder locations.
- **Renewable DG:** solar and wind integrated at specific location with varying penetration level.
- **Evaluation metrics:** the performance of the protection system is assessed using six key metrics: Fault current at relay, Relay operating time, Directional behavior, Coordination time interval (CTI), Selectivity and Unwanted/missed trips.
- **Simulation scenarios:** three scenarios are considered for comparison: Base case (no DG, single relay), DG case (with DG, single relay) and Mitigated case (with DG and 11 coordinated relays).
- **Fault types and locations:** the study includes simulation of three fault types (L-G, L-L, L-L-L) occurring at multiple fault locations (near substation, mid-feeder and end-feeder). In the mitigated case, faults are extended across 11 relay locations.
- **Mitigation strategy:** the primary mitigation strategy investigated is the grading and coordination of 11 over current relays through adjustment of pickup current, CT ratio and TMS.
- **Software/tools:** the software used in this study is DIgSILENTPowerFactory.

1.5.2 Limitations of the study

- DG type limited to solar and wind
- Network topology is fixed and radial
- All analysis is simulation based: no real time or hardware testing is performed
- Economic aspects are not included

1.6 Significance of the study

This study is significant in several technical, practical and academic aspects, as showed below:

- **Technical relevance to modern grids:** This research address one of the most critical challenges in today's power system the integration of traditional protection schemes with renewable DG. As the nature of fault current and power flow changes due to inverter based source, protection devices often fail to operate as intended.
- **Contributes to protection design best practices:**
Result provides practical guidance for distribution planner and engineers dealing with renewable integration, and limited protection infrastructure and making informed decision during distribution network expansion.
- **Practical simulation and analysis:**
The use of DigSILENTPowerFactory for modeling, simulation and protection coordination analysis adds practical value to the study. The results and methodologies developed can be used by utilities, consultants and researchers for real world protection system design.
- **Development of mitigation strategies:**
One of the key contributions of this study is the development of mitigation techniques such as fast and graded overcurrent coordination to address DG induced protection issues.
- **Introduces a six metric evaluation framework:** by using six distinct metrics (fault current at relay, relay operating time, directional behavior, CTI, SI and unwanted/missed trips), this work presents a structured and replicable methodology for analyzing protection system performance.

➤ **Bridges academic research with practical application:**

This research connects theoretical simulation with practical protection engineering, making the result applicable for both academic and real world implementation. It may also serve as a foundation for future research integration of other DG types and advanced protection philosophies.

1.7 Organization of the thesis

This thesis is organized into five chapters, each serving a specific purpose in overall study.

- **Chapter 1: Introduction:** provides an introduction to the study, outlining the background, problem statement, objectives and significant of DG impacted in protection devices.
- **Chapter 2: Theoretical background and literature review:** presents the theoretical back ground, and a comprehensive literature review, covering key concepts, existing research, and knowledge gaps related to this study.
- **Chapter 3: Design, modeling and simulation:** presents model ADWA radial network in DIgSILENT PowerFactory simulation software: simulate fault without DG (base case with single relay), integrated solar and wind based DG and repeat faults, observe protection issues in single relay system, implement 11-relay coordinated protection and re-simulate and compare results using metrics.
- **Chapter 4: Simulation result and discussion:** presents the simulation results: in base case – without DG (single over current relay), in DG integrate case – with solar and wind based DG, in mitigated case – coordinated protection with 11 relays and discussion of the finding.
- **Chapter 5: Conclusion and recommendation:** provides the main conclusions drawn from the study and finally recommendations and outlines directions for future research to address remaining challenges and explore further developments in this area

CHAPTER 2: THEORETICAL BACKGROUND AND LITERATURE REVIEW:

2.1 Overview of distributed generation (DG)

Distributed generation (DG) is referred to the decentralized generation of electricity from small-scale energy sources that are located close to the point of consumption, rather than at a large, centralized power plant[1]. DG units are typically connected to the distribution network or even directly to the consumer's premises, reducing the need for extensive transmission infrastructure. Various organization and researchers define DG slightly differently, depending on size, technology, location, and function. A commonly accepted definition is refers to electric power sources connected directly to the distribution network or on the customer side of the meter[2]. The common DG technologies are:

- a) Renewable sources: solar PV, wind turbines, small hydro, biomass
- b) Non-renewable: micro-turbines, internal combustion engines, fuel cells, combined heat and power (CHP) systems.

Table 2. 1 Classification of DG based on technologies

Renewable DG	Non-renewable DG
Solar PV	Micro-turbine
Wind turbines	Fuel cells
Small hydro	Internal combustion engine (ICE)
Biomass	Combine heat and power (CHP) system

❖ Characteristics of DG[3]

- **Proximity to load center:** DG systems are typically installed near or at the end-user's location. This reduces power losses associated with long distance electricity transmission.

- **Small to medium scale:** DG units generally range from a few kilowatts (KW) to tens of megawatts (MW) the size varies depending on the application, residential, commercial, or industrial.
- **Modular and scalable:** DG systems can be installed gradually to match load growth or specific power quality requirements. This modularity allows greater flexibility in planning and investment.
- **Diverse technologies:** DG involves a wide range of technologies, both renewable (e.g., solar, wind, biomass) and conventional (e.g., diesel generators, gas turbines), enabling greater resilience and energy mix diversification.
- **Grid –connected or standalone:** DG can operate in grid-connected mode (interacting with the main power grid) or in islanded mode (independent of the grid), offering backup power and reliability in remote areas.
- **Operational benefits:** DG can improve voltage profiles, reduce transmission congestion, enhance reliability, and submit investments in network upgrades.
- **Environmental benefits:** when based on renewable sources, DG contributes to the reduction of greenhouse gas emissions and local pollutants.
- **Challenges and impacts:** despite its benefits, DG integration poses technical challenges such as voltage regulation, protection coordination, reverse power flow, and impacts on system stability and reliability.

❖ **Type of distributed generation technologies**

Distributed generation technologies vary widely in terms of energy source, operating principle, scale, and application. Among the most commonly implemented types are solar photovoltaic (PV) systems, wind turbines, fuel cells, and micro-turbines. Each has distinct characteristics, advantages, and technical considerations[4].

2.1.1 Solar photovoltaic (PV) systems

Solar PV systems convert sunlight directly into electricity using semiconductor materials (commonly silicon-based). They are one of the most widely used DG technologies due to their scalability, modularity, and declining costs.

❖ **Key features**

- **Modular:** can be deployed at various scales from rooftop systems to large solar farms.
- **Intermittent:** output depends on solar irradiance; affected by weather and time of day.
- **Low maintenance:** No moving part; long operational life (20-30 years)
- **Environmentally friendly:** No emissions during operation.

❖ **Challenges:**

- Requires inverters to convert DC to AC for grid compatibility.
- May introduce voltage fluctuations in weak grids due to variability.
- Energy storage or grid support may be needed to handle intermittency.

2.1.2 Wind turbines:

Wind energy systems use the kinetic energy of wind to rotate turbine blades, which drive generators to produce electricity. They can be installed onshore or offshore, and are typically used in areas with favorable wind resources.

❖ **Key features**

- **Scalable:** ranges from small turbines for homes to utility-scale wind farm.
- **Variable output:** generation is dependent on wind speed, which fluctuates.
- **High efficiency:** modern turbines have efficiencies of 35-45%.
- **Environmental impact:** No emission, but may affect local wildlife and cause noise.

❖ **Challenges**

- Grid integration can be complex due to variability and unpredictability.
- Reactive power support may be required.
- May affect power quality in distribution networks.

❖ **Benefits of distributed generation[5]:**

- **Reduction in transmission and distribution losses:** DG units are located to the load centers, reducing the need to transmit electricity over long distances. This minimizes I^2R losses and improves overall system efficiency.
- **Deferral of network expansion:** by supplying part of the local demand, DG can defer or reduce the need for investment in new transmission lines, substations, and distribution infrastructure.

- **Improved reliability and resilience:** DG contributes to enhanced system reliability, especially during peak loads or grid outages. It can provide backup power and support for critical loads during emergencies.
- **Environmental benefits:** due to renewable sources like wind or solar, DG contributes to the reduction of greenhouse gas emissions, air pollution, and dependence on fossil fuels.
- **Voltage profile and power quality improvement:** properly placed DG units can support voltage levels along feeders and, enhancing power quality and reduce voltage drops.
- **Support for rural and remote electrification:** DG, particularly renewable-based and off-grid system, provides a cost-effective and accessible solution for rural areas and electrifying remote.
- **Energy efficiency through cogeneration (CHP):** some DG technologies, like fuel cells and micro-turbines allow combined heat and power (CHP) generation, maximizing the use of fuel and increasing overall system efficiency.
- **Customer empowerment and energy independence:** DG enables consumers to become prosumers, allowing more control over energy use and reducing dependence on centralized utilities.

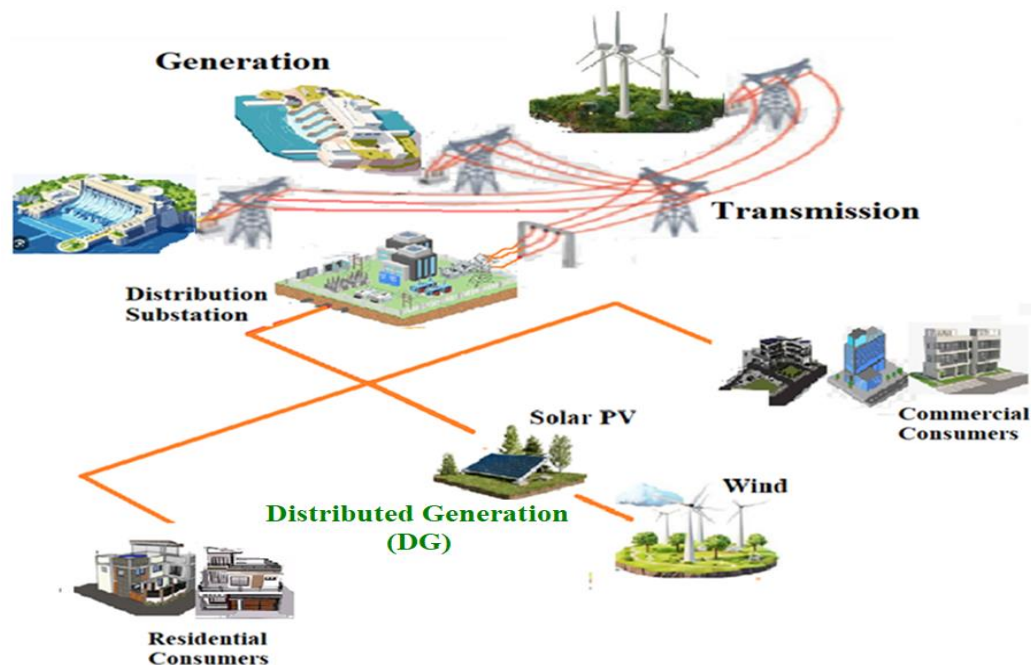


Figure 2.1 Integration of DG to distribution network

2.2 Overview of protection devices

In a distribution network, protection devices are essential for detecting abnormal conditions such as faults (short circuits, over current, overvoltage, etc.) and isolating faulty sections to protect equipment and maintain system stability. With the addition of distributed generation (DG), protection schemes become more complex due to bidirectional power flow, altered fault levels, and dynamic system conditions[6].

2.2.1 Over current protection

A protective relay is a device used in electrical power systems to detect faults (like overloads, short circuits, etc.) and initiate disconnection of the faulty part from the system. It helps protect equipment like transformers, generators, and transmission lines. Protection relays are sensing and decision-making devices that detect subnormal conditions and send trip signals to circuit breakers[7].

❖ Types of relays used in distribution systems

- **Over current relays (OCR):** detect current above preset limits.
- **Directional Over current relays:** consider direction of current flow vital with DG.
- **Distance relays:** operate based on impedance; used in longer feeders.
- **Differential relays:** relate currents at two ends of equipment; mostly for transformers.
- **Under/over voltage relays:** trigger when voltage is outside safe range.
- **Frequency relays:** detect frequency deviations caused by imbalance.

❖ Key function of protection relays

- Detect faults and abnormal conditions.
- Communicate with breakers to initiate isolation.
- Coordinate with other devices to ensure selective protection.

❖ Step-by step principle operation of overcurrent relay system

- 1) Current transformer (CT) senses this high current.
- 2) The overcurrent relay compares it to the set limit (let, 200A).
- 3) Since the current is way above 200A, the relay detects a fault.
- 4) The relay sends a signal to the circuit breaker.

- 5) The circuit breaker opens, cutting off power to the faulted line and preventing damage

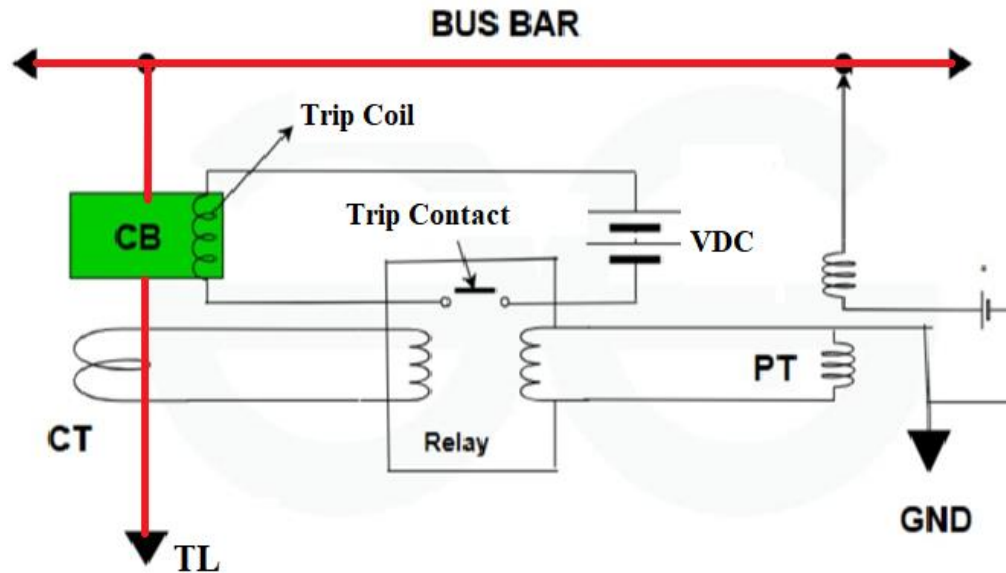


Figure 2. 2 principle operation of over current relay system

2.2.2 Devices of over current protection relay systems[8]

1. Over current relay (OCR):

This is the core logic device in the system.

❖ Function of OCR:

- Detects over current based on input from CTs and initiates tripping of the CB.

❖ Types of OCR:

- Electromechanical relays
- Static relays
- Numerical/Digital relays (modern and multifunctional)

❖ Features:

- Time delay settings.
- Inverse time characteristics.
- Communication ports.
- Event logging.

2. Circuit breaker (CB)

A circuit breaker is a switching device that automatically interrupts the flow of current in an electrical circuit when an abnormal condition (like an overload or short circuit) occurs. In over current protection system, the circuit breaker acts as the final interrupting element, receiving a trip signal from a protective relay (like an over current relay) to isolate the faulty section of the network[9].

❖ Purpose of CB in over current protection

- Interrupt fault current quickly to prevent equipment damage, fire or hazards.
- Work in coordination with relay to ensure selective and accurate tripping.
- Automatically isolate affected areas without affecting healthy parts of the network
- Enable manual switching for maintenance and control.

❖ Principle of operation:

The circuit breaker monitors current either directly (in self-contained breaker) or indirectly via a protection relay and current transformer (CT) setup. The general operation steps:

- 1) Current exceed preset limit (due to fault)
- 2) The CT detects the high current and feeds it to the OCR
- 3) The OCR evaluates the magnitude and direction of the fault current
- 4) If conditions are met, the relay sends a trip signal to the CB
- 5) The CB trips, opening its contacts and interrupting the fault current
- 6) Arc extinction occurs inside the breaker through different techniques depending on the breaker type.

Table 2. 2 Types of circuit breakers used in protection

No.	Type	Arc extinction	Voltage Range	Application
1	Air Circuit Breaker (ACB)	Air blast or air gap	Low/medium voltage	Industrial LV systems
2	Miniature Circuit Breaker (MCB)	Thermal-magnetic	Low voltage	Residential/panels
3	Molded Case Circuit Breaker (MCCB)	Thermal-magnetic	Up to 1000v	Industrial panels
4	Vacuum Circuit Breaker (VCB)	Vacuum chamber	Medium voltage	Indoor substation
5	SF6 Circuit Breaker	Sulfur hexafluoride gas	High voltage	Outdoor substations
6	Oil Circuit Breaker (OCB)	Oil arc suppression	Medium/high voltage	Old/outdoor installation

❖ **Key components of a circuit breaker:**

- Contacts: open/close to interrupt or allow current
- Arc chute/extinguisher: suppresses the arc formed during interruption.
- Trip coil/solenoid: electromechanical device that opens contacts when energized
- Operating mechanism: spring, motor or manual system to open/close breaker.
- Protective interface: receives input from relays (for modern breaker)

Table 2. 3 Circuit breaker Vs Relay role in protection

Protection function	Over Current Relay	Circuit Breaker
Fault detection	Yes	No
Decision logic	Yes	No
Trip initiation	Yes	No
Current interruption	No	Yes
Manual switching	No	Yes

3. Current transformer (CT):

A current transformer (CT) is an instrument transformer used to measure high currents by reducing them to a lower, manageable value. It provides a scaled down replica of the current flowing in the power system to protection relays and metering devices. In over current protection systems, CTs are critical components that allow relays to detect fault currents without being directly connected to high-voltage lines.

❖ Purpose of CTs in over current protection:

- Isolate measuring instrument and relays from high voltage circuits
- Step down high current to a standard secondary value (typically 5A or 1A)
- Provide accurate current representation to protective relays
- Enable safe operation and reliable fault detection

❖ Working principle of CT

The CT operates on the same principle as a transformer:

- It has a primary winding (often just one or a few turns – sometimes the power conductor itself).
- A secondary winding produces a current proportional to the primary current.
- Based on Faraday's law of electromagnetic induction, the changing current in the primary induces a proportional current in the secondary.

Formula:

$$I_p N_p = I_s N_s \text{-----} (2.1)$$

- I_p : primary current
- I_s : secondary current
- N_p : primary turns
- N_s : secondary turns

❖ Types of CTs used in protection

- 1) **Wound CT**: has separate primary winding
- 2) **Bar-type CT**: the conductor acts as a single turn primary
- 3) **Toroidal (window-type)** : no primary winding, the bus bar passes through the window

Table 2. 4 CT parameters important for over current protection

Parameter	Description
CT ratio	Primary current to secondary current (e.g., 1000:5A)
Burden	The load (impedance) connected to the CTs secondary
Accuracy class	Defines how accurate the CT replicates current
Knee point voltage	Critical for protection-class CTs; above this, CT core saturates
Saturation	In high fault conditions CTs may saturate and misrepresent actual current to relay

❖ **CT and relay coordination:**

- The CT provides input to the over current relay
- If the current exceeds a preset value, the relay initiates a trip signal to isolate the fault
- Proper CT selection and placement ensure that the relay functions accurately and selectively.
- Protection CTs must not saturate under fault conditions, or else the relay may fail to trip.

4. Potential transformers (PTs) / voltage transformers (VTs):

(Not directly used for over current detection but often involved in protection systems.)

- **Function:** step down voltage for metering and protection.
- **Relevance:** some relays (like directional or distance relays) require voltage input alongside current.

5. Auxiliary relays:

- **Function:** perform intermediate functions such as signal amplification, latching, or logic operations.
- **Usage:** interface between protection relay and trip coil or for alarm/trip indication
- **Types:** tripping relays, lockout relays (86 relays), and signal relays.

6. Trip circuit and trip coil:

- **Trip coil:** an electromechanical coil inside the breaker that opens the contacts when energized

- **Trip circuit:** includes relay output contacts, DC supply, interlocks, and wiring needed to energize the trip coil.

7. Control power supply/DC system:

- **Function:** provides reliable and isolated DC power (usually 24v, 48v, 110v or 220v DC) to protection relays, trip coils and auxiliary relays.
- **Includes:** battery banks, chargers. Fuses/breakers for protection

A loss of DC supply can disable the entire protection scheme:

8. HMI / SCADA Interface

- **Function:** human-machine interface to monitor, control, and configure protection settings
- Modern relays have built-in display panels or are connected to SCADA systems.

9. Communication modules/ protocol converters:

- Used in networked or automated substations
- Protocols: IEC 61850, mod bus, DNP3, etc.
- Function: allow remote access to relay status, event logs and trip commands.

10. Test switches / isolation links

- **Purpose:** allow safe testing, maintenance and simulation without removing wiring,
- **Used by:** maintenance personnel to inject test signals and monitor responses

11. Surge protection devices (SPDS) / Fuses

- **Purpose:** protect sensitive relay and communication equipment from overvoltage, lightning and surges.
- **Fuses:** also used I CT/PT secondary circuits.

12. Blocking / interlocking devices

- **Function:** prevent undesired tripping during certain system conditions (e.g., maintenance, backup operation).
- **Includes:** mechanical/electrical interlocks, logical software interlocks in numerical relays.

13. Load break switch / isolator

- Used for manual disconnection under no-load conditions.
- Not a protection device but used during maintenance or fault isolation.

Table 2. 5 summary of over current protection devices roles

No.	Device	Role in over current protection
1	CT	Senses current
2	OCR	Detects fault and sends trip signal
3	CB	Interrupts current flow
4	Aux Relay	Signal handling, backup trip
5	Trip coil	Opens CB on trip command
6	DC supply	Powers protection logic
7	SCADA/HMI	Monitoring and control
8	PT/VT	Voltage sensing (in complex schemes)

2.2.3 Fundamental requirement of protective relaying[10]:

- **Selectivity:** selectivity is the ability of the protective system to isolate only the faulty section of the power system while leaving the rest operational. This prevents unnecessary power outages and keeps the healthy parts of the system running.
- **Speed:** speed refers to how quickly the relay operates after detecting a fault. Faster operation minimizes damage to equipment and improves system stability and safety.
- **Sensitivity:** sensitivity is the relay's ability to detect even small abnormalities and operate accordingly. A sensitive relay ensures that even minor faults are detected before they escalate into bigger problems.
- **Reliability:** reliability means the protective relay will always function correctly when a fault occurs, and not operate when there's no fault (no false trips). It ensures protection is dependable.
- **Simplicity:** simplicity refers to the ease of design, installation, operation, and maintenance of the relay system. It is importance that simple systems are less prone to errors and easier to troubleshoot and maintain.
- **Economy:** economy means the protection system should be cost effective, providing adequate protection at a reasonable cost. It ensures that the protection does not become more expensive than the equipment being protected.

Table 2. 6 requirements of protective relay

No.	Requirement	Definition	Why it's important
1	Selectivity	Isolates only the faulty part of the system	Prevents unnecessary power outages
2	Speed	Fast response to faults	Reduces damage and improves system stability
3	Sensitivity	Detects even small faults	Prevents minor issues from becoming major
4	Reliability	Always operates correctly during faults	Ensures dependable protection
5	Simplicity	Easy to design, install, and maintain	Reduces errors and simplifies upkeep
6	Economy	Cost-effective protection	Balances performance with affordability

2.2.4 Types of over current relay

Over current relays are protective devices used in electrical systems to detect excessive current flow and act to isolate the faulted section. The three types of over current relays based on their time of operation are[11]:

1 Instantaneous over current relay (IOC):

It is explained that

- It trips the circuit immediately when the fault current exceeds a certain threshold.
- Used in areas where faults need to be cleared very quickly, like near generators or transformers.
- Operates in a definite time when current exceeds its pick up value.
- Its operation criterion is only current magnitude (without time delay).
- Operating time is constant.
- There is no intentional time delay.

- Coordination of definite-current relays is based on the fact that the fault current varies with the position of the fault because of the difference in the impedance between the fault and the source.
- The relay located furthest from the source operates for a low current value.
- The operating currents are progressively increased for the other relays when moving towards the source.

2 Definite time overcurrent relay (DTOC): it is explained that

- Operates after a fixed time delay once the current exceeds the preset value.
- The current must exceed the setting, and then the relay waits a set amount of time before tripping.
- It helps in coordination-so upstream breakers don't trip too fast before downstream ones.

Application:

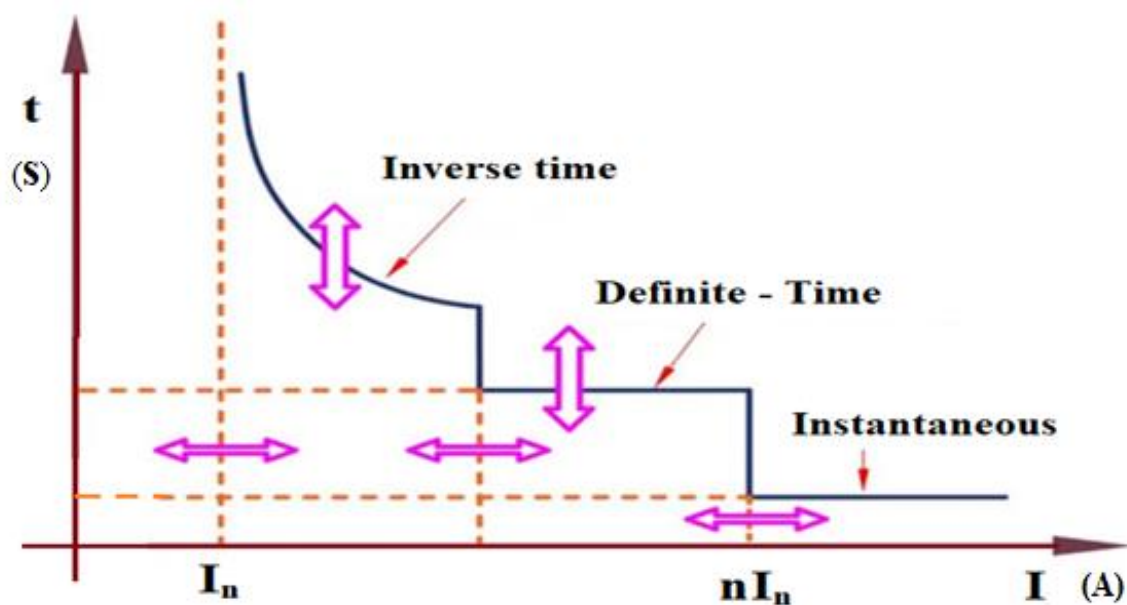
- Back up protection of distance relay of transmission line with time delay.
- Back up protection to differential relay of power transformer with time delay.
- Main protection to outgoing feeders and bus couplers with adjustable time delay setting.

3 Inverse time overcurrent relay (IDMT relay):

- It operates faster when the current is higher-i.e., the tripping time is inversely proportional to the fault current.
- The greater the fault current, the faster it trips.
- It allows coordination between relays depending on how close they are to the fault.
- Common in radial distribution systems.

Table 2. 7 type of over current relay based on their time and operation

No .	Relay type	Explanation	Time behavior	Usage	Delay type
1	IOC	Operates with no intention delay once the fault exceeds a certain threshold.	Trips instantly	Near faults	None
2	DTOC	Operates after a fixed time delay once over current is detected.	Fixed time delay	Simple loads	Constant
3	IDMT	the greater the fault current, the faster the trip time (used to coordinate protection devices)	Time reduces with fault level	Feeder and backup protection	Variable (inverse)

**Figure 2. 3** Types of over current relay

2.3 Impact of DG on over current protection system performance

The integration of distributed generation (DG) into distribution networks introduces significant challenges to the operation and protection relays. Protection relays, which are designed to detect and isolate faults based on current and voltage conditions, rely on predictable system behavior, typically unidirectional power flow and stable fault current levels. However, as DG penetration increases especially in correspondingly with rising load demand, the electrical characteristics of the network become more dynamic and complex. These changes can lead to several issues, including malfunction, under or over reach, false tripping, and delayed fault clearance. This studies the specific impacts of increasing DG penetration and load growth on protection relay performance, and reliability across various scenarios and system configurations[12].

2.3.1 Impacts of DG on fault current level

Protection relays operate based on expected fault current magnitudes. DG integration affects these magnitudes in complex ways[13]:

- Synchronous generators (e.g., small hydro, gas turbines) may contribute substantial short-circuit current, increasing total fault current beyond the design limits of relays or circuit breakers.
- Inverter-based DG (e.g., PV, wind) often provides limited fault current, typically 1.1 to 2 times nominal, which may be insufficient to trigger over current relays.
- Variation with DG location: DG closer to the load center may lead to lower fault current seen by upstream relays, potentially causing under-reaching or missed trips. These variations complicate relay coordination, especially for time-current or non-directional schemes. System-wide fault studies must be conducted during planning and after major DG additions to update relay settings accordingly.

2.3.2 Bidirectional power flow and its effects

Traditional radial networks assume one-way power flow that mean from substation to load. However, DG introduces bidirectional flows, especially when local generation exceeds local demand. Impact includes[14]:

- Non-directional relays may misinterpret power flow, causing faults to go undetected or result in incorrect tripping.
- Reverse power can change fault current paths, confusing upstream and downstream relay coordination.
- DG units can feed faults in both directions, potentially causing relays to trip outside of their designated zones.

2.3.3 Relay sensitivity, setting, and zone reach limitations:

Relay settings such as pickup current and time delays are based on predicted load flow and fault levels. DG affects these in several ways[15]:

- Reduced fault current levels from inverter based DG can make it difficult for relays to reach their set pickup thresholds.
- Relay under-reach may occur when fault current is lower due to DG absorbing part of the fault.

2.4 Mitigation strategy

To address the protection challenges introduced by increasing DG penetration and load demand, utilities and system planners must approve more advanced and adaptive protection strategies. These strategies aim to maintain system reliability, minimize false operations, and ensure fast and selective fault clearing under changing network conditions. This study presents key mitigation approaches that can be merged into future distribution network planning and design[16].

2.4.1 Implementation of over current protection relay

Implementation involves the installation, configuration, and activation of over current protection devices in a power system. This includes choosing suitable relays, setting their parameters, connecting them with CTs (current transformers), and integrating them into protection schemes[17].

❖ Implementation steps:

- 1) **System analysis:** determine the maximum short-circuit currents and locations.
- 2) **Relay setting calculation:** set thresholds based on protection coordination studies.

- 3) **Hardware selection:** choose appropriate CTs, relays, and breakers.
- 4) **Wiring and configuration:** connect CTs to relays, configure relay logic.
- 5) **Testing and commissioning:** perform primary/secondary injection tests and simulations.
- 6) **Monitoring and maintenance:** regular inspection to ensure performance.

2.4.2 Coordinating of over current protection relay:

Coordinating fast protection refers to the method of organizing and timing the operation of protection devices (like relays, circuit breakers, and fuses) so that the device closest to the fault operates first, while backup device operate only if the primary protection fails[18]. This ensures both speed and selectivity in fault clearance. Electrical power systems are complex, and faults can occur at many points. Simply installing fast-acting protection everywhere may result in unwanted outages in healthy parts of the system. Therefore, coordination ensures: fast clearance of faults, selective tripping (only the faulty section is isolated) and backup protection if the primary protection fails. This is achieved by setting time delays or current thresholds at different protection devices based on their location in the system. The farthest device from the source (closest to the fault) is set to trip first, with upstream devices acting as backups[19].

❖ Applications coordinating fast protection used in

- Distribution networks
- Industrial power systems
- Substations
- Transformer and feeder protection
- Renewable energy integration (wind, solar)
- Data centers and critical infrastructure

❖ Components are involved in coordination[20]

- Relays (instantaneous, time-delayed, directional)
- Current transformers (CTs)
- Voltage transformers (VTs)
- Circuit breakers
- Reclosers and fuses

- SCADA system for remote coordination

❖ **Goals of coordination.**

- Fast fault clearance at the point of occurrence
- Minimized impact on healthy parts of the network
- Backup protection for reliability
- System stability during fault and post-fault conditions

❖ **Advantages of coordination**

- Improved system reliability
- Minimized outage duration
- Protection for critical infrastructure
- Reduced risk of cascading failures
- Optimized equipment life by preventing unnecessary trips

❖ **Challenges of coordination**

- Complexity in large networks
- Changing load conditions affect coordination
- Coordination with multiple energy sources
- Digital relays require expert setting and maintenance

❖ **Modern trends in coordination:**

- Adaptive protection: relay setting change with system conditions
- Communication-aided schemes: IEC 61850GOOSE messaging
- AI/ML based coordination: predicts and adjusts in real-time
- Micro grid protection: Dynamic coordination due to multiple sources

❖ **Simple terms how relay coordination works[21]:**

Suppose there are three relays in a line:

- Relay 1 (feeder) – closest to load
- Relay2 (substation) – upstream
- Relay 3(main Breaker) – upstream from both

In a fault scenario near the feeder (R1):

- Relay1 should operate first because it's closest to the fault, if relay 1 fails to operate, relay2 should act next. Relay3 (farthest from the fault) should be the last backup. This sequence is called selectivity.

Table 2. 8 coordinating fast protection aspect and description

Aspect	Description
Goal	Fast, selective, and reliable fault clearance
Key devices	Relays, CTs, VTs, breakers
Key techniques	Time, current, directional grading
Applications	Utilities, industries, renewable, data center
Benefits	Reliability, safety, reduced downtime
Tools used	DIgSILENTPowerFactory

2.4.2.1 Overview of over current relay coordination

The goal of over current relay coordination is to ensure[22].

- Selective fault isolation (only the faulted section trips)
- Minimum system disruption
- Fast fault clearance for safety and equipment protection

To coordinate 11 overcurrent relays using DIgSILENT PowerFactory, each relay is set with

- Proper current transformer (CT) setting and over current setting
- Definite and inverse time delay settings
- Coordination for proper fault isolation hierarchy, this is the core of relay coordination

Setting up one over current relay, this one relay will be the first relay in the coordination chain.

1. Set up the network model:

❖ Create the single-line diagram

- Draw bus, lines, transformer, loads
- Place the relay logically

❖ Insert instrument transformers (CT)

- Inset > instrument transformer > CT

- Set CT primary/secondary ratio

❖ **Insert over current relay (OCR)**

- Insert > protection device > overcurrent relay
- Choose relay type (from manufacturer library, Alstom KCGG124-1A)

2. Configure relay settings: open the relay settings

❖ **Set current transformer (CT) parameters**

- CT primary
- CT secondary

❖ **Set over current relay (OCR) parameters:**

- Pickup current (I_p)
- Inverse time curve
- Time multiplier setting (TMS)
- Minimum Op time
- Pickup current in per unit (based on CT secondary)

3. Simulate fault and plot time-current characteristic (TCC) curves

❖ **Run a short-circuit analysis**

- Calculation > short-circuit calculation
- Fault type
- Fault location

❖ **Plot TCC curve**

- Protection > time-current characteristics
- Select relay and other to coordinate with
- Add fault current reference lines (vertical)
- Ensure the curve lies below upstream relays by at least 0.3sec margin.

4. Set up coordination hierarchy (for all 11 relays)

Extend the same process to the other 10 relays, working from downstream to upstream for each relay.

❖ **Set over current relay (OCR) parameters**

- CT ratio

- Pickup current
- Time curve
- Time multiplier setting (TMS)
- TCC plot
- Dynamic check

Table 2. 9 Steps for all 11 relays what to do for each relay in DIgSILENT

Steps	Action
1	Measure max load current on the branch
2	Choose CT ratio next standard size \geq load max * 1.2
3	Set pickup = 1.2 * load max
4	Convert pickup to pu = pickup/CT primary
5	Choose curve type (IEC SI)
6	Set initial TMS for farthest relay
7	Run TCC plot and simulate faults
8	Adjust TMS for upstream relays to maintain 0.3 – 0.5 sec delay
9	Run fault simulations to confirm coordination
10	Save setting and document everything

2.4.2.2 The important relay setting terms

1. Current load max:

The maximum continuous current expected on the line/feeder during normal operation. Understanding the maximum load current is critical for properly setting CT ratios and pickup values. We can find max load at each relay location by running a load flow (power flow) analysis of the distribution system. This tells the highest expected current (or power) each line/bus/relay will carry during normal, full-load operation, not during fault condition[23].

❖ Methods to find maximum load:

A. From load flow analysis (using simulation software, DIgSILENT)

Steps:

- Build one-line diagram: lines, buses, loads, source, DGs

- Assign load values: KW, KVAR or KVA at each load bus
- Run a load flow or power flow analysis
- Record the line currents or bus currents at each relay location. The outputs will be current in amps (for CT ratio), and power in KVA.

B. From load data (manual/estimation):

It estimated based on load demand[24]:

$$I = \frac{S_{load}}{\sqrt{3}V} \text{-----} (2.2)$$

Where:

- S_{load} = load in KVA
- V = line – to – line voltage
- I = line current

C. From utility/Field data:

Having access from actual utility or SCADA data

- Look at historical current readings
- Take the highest current observed on each feeder section

2. Current transformer (CT) ratio:

The CT ratio tells you how a current transformer steps down a high primary current (from the power system) to a safer, measurable secondary current (used by protection relays or meters)[25].

❖ **Goal:**

- Accurate measurement without CT saturation and within relay sensitivity range
- Steps down high currents to safe levels

❖ **Selection criteria:**

- Match the maximum expected load current + margin
- Consider fault current levels
- Choose from standard CT ratios

❖ **Understanding CT roles:**

- CT-3P : connected to 3-phase elements of the relay (R,Y,B lines)
- CT-3IP : connected to the ground element of the relay (for earth fault)

Formula

$$CT = \frac{\text{MaximumLoadCurrent}(A) * \text{SafetyMargin}}{\text{RelaySecondaryCurrent}} \text{-----} (2.3)$$

3. Pick up current (A):

The minimum current level at which the relay begins to operate (trip timer starts)[26].

❖ **Goal:**

- Prevent tripping during normal load but detect faults immediately.

❖ **Selection guidelines:**

- Set 20 – 30% above maximum load current to avoid nuisance tripping.

Formula:

$$I_{pickup} = 1.2 * I_{loadmax} \text{-----} (2.4)$$

4. Pickup (per-unit) :

The pickup current expressed as a fraction of the CT primary rating – a normalized value used in relay settings.

Formula:

$$I_{pu} = \frac{I_{pickup}}{CT_{primaryrating}} \text{-----} (2.5)$$

5. Curve type:

When configuring a relay, it expect to choose curve type

- IEC standard inverse (SI): Match the system type, equipment type and coordination needs.

❖ **Purpose why IEC Inverse use:**

- Easy coordination with upstream/downstream relays
- Flexible turning using TMS
- Faster tripping for high severity faults

6. Time multiplier setting (TMS):

A scaling factor used to adjust the relay operating time on its IDMT curve. Higher TMS values cause longer tripping times[27].

❖ **Goals:**

- Delay upstream relays enough to let downstream relays trip first
- Control speed of operation: it allows adjusting how fast or slow a relay operates for a given fault current.

Steps:

- Choose a base TMS for the farthest relay (R-10)
- For each upstream relay, increase TMS to ensure ≥ 0.3 s time margin at the same fault current.

Formula:

TMS is calculated from the inverse time curve equation:

For IEC inverse

$$T = TMS * \frac{k}{\left(\frac{I}{I_{pickup}}\right)^n - 1} \text{-----} (2.6)$$

Where:

- T =trip time
- TMS = time multiplier setting
- I = fault current
- I pickup = pickup current
- K: 0.14, n: 0.02 = constants based on relay curve type

It doesn't need to do this manually; DigSILENT PowerFactory can plot the TCC

7. Plug setting multiplier (PSM):

PSM is the ratio of the actual fault current to the relay's pickup current. It is also called multiple of pickup. It is a dimensionless number. It tells that how far above the relay's pickup point the current is

$$PSM = \frac{\text{faultcurrent}}{\text{relaypickupcurrent}} \text{-----} (2.7)$$

❖ **Purpose of PSM:**

- Determines relay tripping time: for inverse-time relays (e.g., in 1st stage $I > t$), the greater the PSM, the faster the relay trips

- Used in trip time calculation: the PSM is used in the standard inverse-time relay equations
- Helps with protection coordination: helps engineers select appropriate pickup settings and TMS values

Table 2. 10 Interpreting of PSM

PSM value	Meaning	Relay reaction
< 1	Below pickup	Relay does not trip
= 1	At pickup	Relay begins tripping
> 1	Fault current above pickup	Relay starts inverse-time operation
>> 1	Large fault	Relay trips faster

❖ Effects of PSM in trip time:

In inverse-time relays (like standard inverse curves), trip time is calculated as

$$t = TMS * \frac{k}{(PSM)^{n-1}} \text{-----} (2.8)$$

8. Relay protection stages[28]:

❖ Stage one:

It is operated when current exceeds pickup settings for a duration determined by inverse time curve. The general description of stage one is as follow:

- Name: I>/t>
- Curve type: inverse time
- Typical used: for overload and general fault protection
- Pickup current: lower pickup value to detect overload or general faults
- Time dial: adjusted to coordinate with downstream devices

❖ Stage two:

It is operated at a higher pickup current with a fixed time delay. The general description of stage two as follow:

- Name: I>>/t>>
- Curve type: definite time
- Typical used: for high fault current (instantaneous or fast tripping)

- Pickup current: higher pickup value to detect sever faults
- Time dial: fixed

2.4.2.3 Time current characteristic (TCC) curve:

Time Current characteristic (TCC) curve is a graphical representation that shows the relationship between the current through a protective device (typically expressed as a multiple of its pick up current) and the time it takes to operate or trip. It is used to understand how fast a protective relay will trip for various magnitudes of over current and to design coordinated protection schemes in power systems[29].

❖ Purpose of TCC curve

1) Selective protection

- Only the protective device closest to the fault should operate
- TCC curves help avoid unnecessary tripping of upstream relays or breakers.

2) Coordination of relays

- Ensures upstream and downstream relays operate in a logical time sequence
- The relay closest to the fault should trip first, while upstream relays back it up after a delay.

3) Grading of relays

- Grading means setting time intervals between relays to avoid overlap and ensure selective tripping.
- TCC curves are staggered so one relay acts faster than the next

4) Fault analysis and system studies

- Engineers can analyze and verify relay settings using TCC curves during design or trouble shooting.
- Engineers use simulation software (e.g., DIgSILENTPowerFactory, ETAP, POverWorld) to plot TCC curves.

❖ Features of a TCC curve

a) Inverse time characteristics:

- The shape depends on the relays time-inverse characteristic
- The curve slopes downward, showing faster operation for higher fault current.
- This is to insure quick clearing of severe faults

b) Axis:

- X-axis: current (multiple of pickup)
- Y-axis: time (seconds)

c) Types of TCC curves:

- Standard inverse (SI): for backup or less sensitive devices
- Very inverse (VI): for radial system with multiple levels of protection
- Extremely inverse (EI): for transformer secondary (higher fault current)
- Definite time

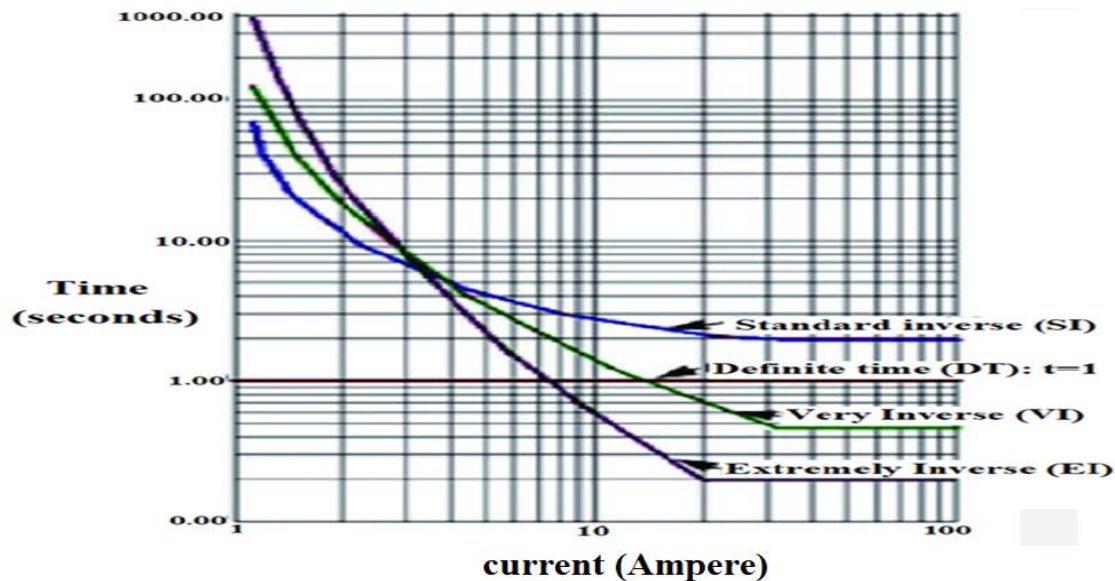


Figure 2. 4 Types of TCC curves

❖ **Coordination principle example**

Suppose there are three relays

- 1) Relay A (feeder) – closest to load
- 2) Relay B (substation) – upstream
- 3) Relay C (main Breaker) – upstream from both

TCC curves ensure their operating times don't overlap, so each gets a chance to clear the faults selectively.

Table 2. 11 TCC curves aspects and Description

Aspect	Description
Definition	Graph showing relay trip time Vs fault current
Purpose	Ensure selective, coordinated and timely tripping of relays
Application	Coordination of multiple relays in power systems
Key principle	Higher current and short trip time (inverse time characteristics)
Result	Improved system stability and minimized outage areas during faults.

2.4.2.4 Selection of DG location, relay placement and DG capacity

❖ Selection of DG location:

Place the DG where it creates measurable impact on:

- Fault current magnitude and direction
- Relay coordination and misoperation
- System stability (e.g., islanding, blinding)

❖ Identification of 11-relays/fault locations:

Relays should represent realistic positions where:

- Protection devices would exist (breakers, reclosers, fuses, etc.)
- Fault could occur
- it needs protection coordination to work properly

To evaluate protection behavior, place and simulate faults exactly at each relay locations. This allows:

- Measure relay operating time
- Test coordination between relays
- Evaluate selectivity, CTI, misoperations.

❖ DG capacity selection:

Selecting of the proper DG capacity for a radial feeder is critical for ensuring safe and effective integration both electrically and in terms of protection coordination.

DG capacity should choose based on a percentage of the total feeder load, typically:

- Low penetration: ≤ 15% of total feeder load – safe for most protection system.
- Medium penetration: 15% - 50% - may start impacting protection
- High penetration: > 50% - likely causes reverse current, islanding, coordination issues.

Step –by – steps method to select proper DG size:

- 1) Determine feeder load (peak load)
- 2) Decide penetration level
- 3) Check short-circuit contribution of DG
- 4) Match DG location and load support

1. Peak load:

Peak load is the maximum demand (in KW or MW) drawn by the feeder over a given period, typically measured in 15 - minute or 30 minute intervals[30].

❖ Methods to calculate peak load:

a) Use SCADA (AMI) smart meter data (preferred). If available, use real-time data systems:

- SCADA systems: provide real-time current and voltage
- AMI meters: provide detailed historical consumption data
- Smart meters: at individual consumers or at the feeder head

Steps to determine peak load

- Collect current (I) and voltage (V) readings over a period (e.g., 1 week or 1 month).
- Compute 3-phase power

$$P_{peak} = \sqrt{3} * V * I_{peak} * \text{power factor} \text{-----} (2.9)$$

b) Use feeder metering:

If there is a meter at the feeder breaker (substation), read the maximum demand or peak KW/KVA value directly from the log or display.

c) Sum of individual loads (if no real time data):

If real-time or historical data is unavailable use connected load and apply diversity factors.

$$\text{Estimated peakload} = \sum(\text{connectedload} * \text{demandfactor}) \text{--} (2.10)$$

Where

- Connected load: total installed capacity (KW) of all customers

- Demand factor: it is usually between 0.3 to 0.8, depending on customer type and region.

d) Use load curve or load duration curve:

It is used if there is a load profile (e.g., KW vs time for a week or month). Pick the highest value.

❖ **Criteria's for peak load :**

- Always consider seasonal variation, peak load in summer or winter may differ
- Ensure the power factor is included in calculating from current and voltage
- For DG sizing, use the peak demand to avoid over sizing the DG.
- Utilities often size feeders and transformers based on S (KVA/MVA).
- DG planning and energy analysis use P (KW/MW).
- Power factory is the key in translating

$$P = S * pf \text{-----} (2.11)$$

$$S = \sqrt{3} * V * I \text{-----} (2.12)$$

Where

- P : real power measured in KW or MW – it does the actual work (e.g., lighting, heating, motors)
- S: apparent power measured in KVA or MVA – it is the total power supplied, including reactive power.
- V : line – to – line voltage
- I : max current observed

2. DG penetration decision:

For DG sizing, it should be used the peak demand to avoid over sizing of the DG penetration level at initial and under sizing later[31].

Table 2. 12 DG penetration Vs protection impacts

DG penetration	Protection impacts
Low	<ul style="list-style-type: none"> • Minor fault current contribution from DG • may avoid directional relay • grid remains strong so: fault levels are predictable and directionality is mostly stable • coordination margin is easier to maintain across the 11 relays • CTI can be kept within safe bounds e.g., $CTI \geq 0.2s$,
Medium	<ul style="list-style-type: none"> • Possible miscoordination • reverse flow starts to matter
High	<ul style="list-style-type: none"> • Directional relays strongly recommended • Strong risk of blinding, islanding rises

3. Check short-circuit contribution of DG:

DG size alone is not enough. It also needs to consider how much fault current is contributes.

DG type	Fault current contribution
Synchronous generator	4 – 6 * rated current
Inverter-based (PV, wind)	1.1-1.3 * rated current

❖ For protection coordination, it needs to simulate:

- Fault current with DG and without DG
- How DG affects relay pickup, directionality, blinding, etc.

4. Match DG location and load support:

Make sure that DG should be:

- Does not exceed local feeder segment load (to avoid reverse flow)
- Supports local loads during islanding or faults (for simulation)
- For example, if DG is placed near R6, load near R6 is 400kw. Set DG 300 – 400 kw (for 100% support or slightly less)

Table 2. 13 Summary final recommendations selection of DG

Decision	Guidance
Choose DG capacity	Based on total feeder load
Select penetration level	<ul style="list-style-type: none"> • Low (for safety) • Medium (for challenge) • High (for edge case)
Validate in load flow + fault analysis	Always run simulation to confirm impact on relay settings.

2.4.3 Grading of over current protection relay

Grading refers to the method of setting the relay parameters (such as time delay and current pickup levels) to achieve proper coordination. Grading ensures the time current curves of different relays are appropriately spaced.. This process ensures selectivity, system stability, and minimizes outages. In electrical networks, over current relays are installed at different points (like feeders, transformers, substations). When a fault occurs, more than one relay may detect it. If all relays operate simultaneously, it could lead to widespread blackouts. To avoid this, relays are graded – usually in time, current, or both – so that: the relay nearest to the fault trips first (fastest) and upstream relays operate only if downstream protection fails (delayed backup)[32].

❖ Important of grading in power system protection:

Grading of over current relays is essential for the safe, reliable, and selective operation of power system protection. Here’s why it matters:

- **Selectivity:** Grading ensures only the faulted section of the system is isolated, minimizing the impact on the rest of the network. Without proper grading, a fault in one area could disconnect large, healthy parts of the system.
- **System stability:** Proper relay coordination avoids simultaneous tripping of multiple relays, which helps maintain voltage stability and continuity of supply.
- **Backup protection:** If the primary protection fails, graded upstream relays act as backup, improving system reliability.

- **Equipment safety:** Fast, selective clearance of faults prevents overheating, mechanical damage, or fire risks in cables, transformers, and switchgear.
- **Minimizing downtime:** Selective tripping allows quick restoration of unaffected areas and limits power outage duration.

❖ **Types of grading methods:**

1) Time grading:

Relays are set with increasing time delays the farther they are from the fault location (i.e. as you go upstream toward the source).

Purpose:

- Uses time delay for upstream relays
- Simple and widely used
- Common in radial systems

2) Current grading:

Relays are set to trip at different current levels. Downstream relays are set to trip at lower currents, upstream ones at higher currents.

Purpose:

- Relays are set with increasing pickup current upstream
- Effective only when fault current varies significantly by location

3) Time-current grading:

This uses inverse definite minimum time (IDMT) relays. Their trip time inversely depends on current; higher current – faster trip time relays are graded so their time current curves don't overlap, with a margin (e.g., 0.3sec) between curves. This is the most common method used in modern power system because it balances speed and selectivity.

Purpose:

- Combines both time and current for better selectivity
- Uses inverse time characteristics (e.g. IDMT relays)

Table 2. 14 grading aspects and description

No.	Aspect	Description
1	Objective	Selective and timely fault clearance
2	Main techniques	Time, current, time-current
3	Key settings	Pickup current, TMS, plug setting
4	Tools	DIgSILENT PowerFactor
5	Benefits	Reliability, minimized outage, system stability
6	Use cases	Distribution, industries, substations, renewable

2.5 Short circuit fault

A short circuit fault occurs when two or more conductors that should be at different electrical potentials come into direct contact or have a very low resistance path between them. This allows a large current (called fault current) to flow through the circuit, bypassing the normal load. Short circuit fault are one of the most common and dangerous abnormalities in power systems, potentially leading to equipment damage, fire or power outages[33].

❖ Causes of short circuit faults:

- Insulation failure between conductors
- Mechanical damage to cables or equipment
- Ageing of equipment and materials
- Weather condition – lightning, moisture, or wind
- Animal or plant contact
- Human error – poor installation, maintenance mistakes
- Overvoltage from switching or lightning surges

❖ Consequences of short circuit faults:

- Excessive current flow (can be many times normal load current)
- Overheating of cables, transformers, or machines
- Melting of conductors or insulation
- Tripping of protective devices

- Voltage dips or collapses
- Fire hazards and equipment failure
- Power outages, sometimes over wide areas

❖ **Types of short circuit faults:**

Short circuit faults are categorized based on the number and combination of conductors involved, they are broadly divided into:

1. Symmetrical faults (balanced faults)
2. Unsymmetrical faults (unbalanced faults)

1. Symmetrical faults (balanced faults)

❖ **Description:**

- Involve all three phases equally
- System remains balanced in terms of voltage and current
- Rare in practice but most severe in terms of damage
- Used as the basis for short circuit capacity calculations
- Its impacts are extremely high fault current, easier to analyze using simple per-phase methods

Example:

- Three - phase fault (L-L-L)
- Three – phase – to - ground fault (L-L-L-G)

2. Unsymmetrical faults (unbalanced faults)

These are more common in power systems and affect one or two phases.

a) Single line-to-ground fault (L-G)

- One phase comes into contact with ground
- Most common fault type (about 70% of faults)
- Causes unbalanced current and voltage

b) Line-to-Line fault (L-L)

- Two phases come into contact
- No ground involved
- Less common than L-G, but more severe

c) **Double line-to-ground fault (L-L-G)**

- Two phases come into contact with the ground
- More complex to analyze
- Can cause high current and equipment damage

❖ **Analysis:**

Unsymmetrical faults require symmetrical component analysis (positive, negative and zero-sequence networks)[34]

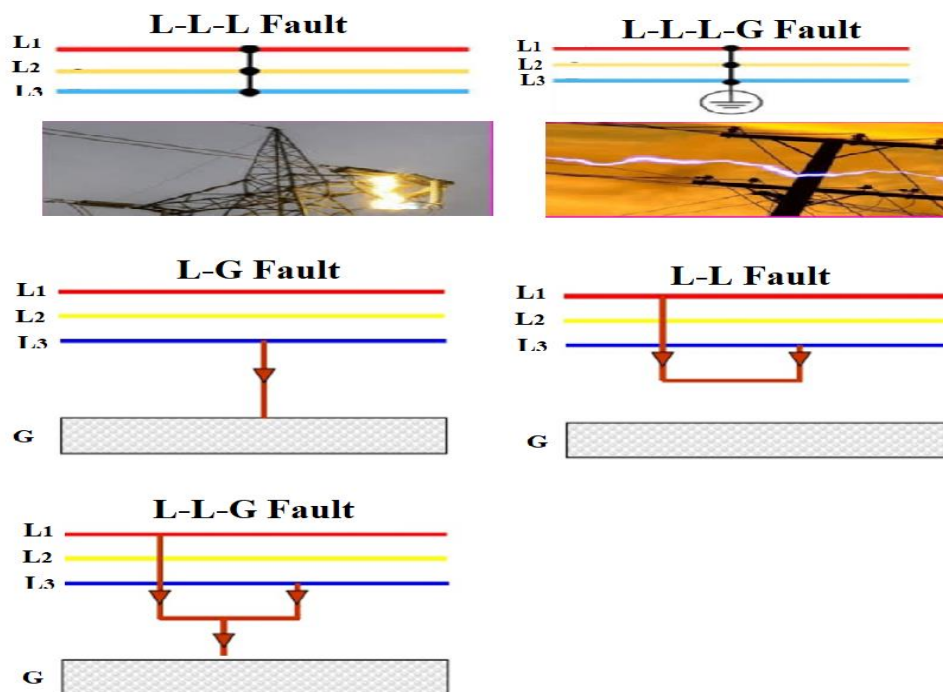


Figure 2. 5 Types of short circuit faults

❖ **Classification of based on duration:**

- Temporary faults: clear themselves automatically (e.g., lighting induced flashovers)
- Permanent fault: require intervention (e.g., tripping, repair)

❖ **Detection and protection:**

To protect against short circuit faults. The system uses

- Circuit breakers
- Fuses

- Protective relays
- Current transformers (CTs) and potential transformers (PTs)
- Ground and earthing systems

These devices isolate the faulty section quickly to minimize damage and keep the rest of the system stable.

2.6 Evaluation metrics:

To evaluate the impact of DG integration on protection system performance, six key metrics are considered[35].

- 1) Fault current at relay
- 2) Relay operating time
- 3) Directional behavior
- 4) Coordination time interval (CTI)
- 5) Selectivity
- 6) Unwanted/missed trip

Each metric is evaluated under three scenarios

- Base case: without DG and with single over current relay (OCR)
- DG case: DG integrated and with single OCR
- Mitigated case: DG integrated and 11-relays with proper coordination.

2.6.1 Fault current at relay:

Fault current is the current that flows through the relay during a fault (e.g., short circuit). In traditional system (without DG), fault current flows in a predictable direction and magnitude typically from the substation toward the fault.

❖ Purpose:

- To evaluate how DG (solar/wind) changes the magnitude and direction of the fault current seen by the relay
- Helps in identifying whether the relay can still detect faults reliably

❖ Key issues:

- DG may contribute to fault current from multiple directions, especially wind/solar via inverters.

- Fault current may decrease in some branches due to power flow reversal or impedance.

2.6.2 Relay operating time:

Time taken by the relay to operate (detect or trip) during a fault.

❖ Purpose:

- To assess whether relay operates fast enough
- Evaluate changes in operating time with and without DG
- Delayed operation can cause equipment damage or safety issues

2.6.3 Directional behavior:

Directional relays determine the direction of fault current flow (forward or reverse). This is critical when DG sources can supply fault current from the load side.

❖ Purpose:

- Identify fault in the correct zone of protection
- Prevent relays from tripping for fault outside their zone (reverse direction)

❖ Key concern:

Direction misoperation is a major issue in DG integrated systems; especially with inverter-based (they have different current behavior)

For example, without DG, fault current flows from substation to relay then to fault. With DG, DG near the fault sends current back toward the relay then relay might falsely trips in reverse direction.

2.6.4 Protection coordination time interval (CTI):

The time margin between the operation of primary and backup protection,

$$CTI = \text{backup relay time} - \text{primary relay time} \text{ ----- (2.13)}$$

CTI is not applicable in base case and DG case if there is only one single relay.

❖ Purpose:

- Ensures selective coordination: backup relay operates only if primary fails
- IF CTI is too small – risk of simultaneous tripping (loss of selectivity)
- If CTI is too large – delayed fault clearance
- In the mitigated case, CTI is used to assess how well the new coordinated relays operate.

Table 2. 15 CTI terms and description

Term	Description
Definition	The minimum time gap between a primary relay and its backup, to ensure coordination
Purpose	Avoid overlapping trips, ensure backup protection, maintain system selectivity
Effective CTI	Balance speed and reliability (e.g., 0.2 – 0,4 sec)

2.6.5 Selectivity:

the ability of the protection system to isolate only the faulted section of the network without affecting healthy parts.

❖ **Purpose:**

- To quantify coordination
- Indicate how well separated the relay operation are in time
- Only evaluate in the mitigated case to quantify how coordination among multiple relays improves fault isolation.

2.6.6 Unwanted trips/missed trips:

- Unwanted trip: relay operates for a fault outside its zone due to DG induced reverse flow.
- Missed trip: relay fails to operate because DG reduced fault current below pickup threshold..

❖ **Purpose:**

- To evaluate reliability and security of protection
- DG can cause reverse flows, making relays misinterpret fault.

2.7 Literature review of recent research papers

A large amount of research has been carried out investigating the issues related to addressing the limited electricity supply using DG and its impact, with respective solution provided to some extent in various books, journals, and papers. Some of the most relevant published papers I have used as framework for establishing the importance of my study and I filled the research gap accordingly are:

In 2023 Yildiz.[36] Presented improving directional over current relay coordination in distribution networks for optimal operation using hybrid genetic algorithm with sequential quadratic programming. This paper proposes a hybrid optimization approach combining genetic algorithm (GA) and sequential quadratic programming (SQP) to enhance the coordination of DOCRs in distribution networks. The method goals to optimize relay settings to improve system reliability and minimize operating times. While focusing on DOCRs, this study emphasizes the importance of optimal relay coordination. My thesis addresses this by indicating that non-directional relays, when properly coordinated and graded, can do similar improvements in system reliability without the complexity of directional relays.

In 2020 Vakili et al.[37] Proposed an algorithm to identify critical distance relays for transient stability studies. The study found that modeling only critical relays serves for accurate stability assessments, reducing the complexity of simulations. The authors concluded that identifying critical relays is essential for efficient stability studies. This thesis addresses this by demonstrating that properly coordinated non directional relays can achieve effective protection coordination, eliminating the need for identifying and modeling critical relays.

In 2024 roseromorillo et al.[38] Conducted a case study on the impact of inverter based DG on protection devices in medium voltage distribution network. They observed that inverter based DGs significantly reduce fault currents as seen by relays, which can result in blinding and misoperation. The author proposed an adaptive over current strategy to respond to the issue, but not explore multi relay coordination. My research addresses this limitation by not only

evaluating DG induced issues but also implementing and validating relay scheme that reinstates protection coordination using time graded relays.

In 2023 wang et al.[39] Developed a current differential protection scheme for distribution networks integrated with inverter interfaced DGs, considering the delay behavior of sequence component extractors. Their simulation confirmed that the proposed frequency-domain model improves fault detection sensitivity and relay selectivity under variable inverter based DG outputs. Although effective, the focus was solely on differential protection methods and did not address conventional over current relay coordination or practical schemes for extensive implementation. My work complements this by using standard relays and developing a realistic, cost effective mitigation strategy applicable to actual distribution networks with solar PV and wind DG.

In 2023, Agwa and EI-Fergany.[40] Presented protective relaying coordination in power systems covering renewable sources: challenges and future insights. This paper provides a broad review of optimal relay coordination (ORC) in distribution networks that include DGs. The authors highlight the challenges associated with bidirectional power flow and the impact of renewable sources on fault current levels. They discuss various strategies for optimizing relay settings to ensure system protection. The review underscores the complexities introduced by DGs in relay coordination. My thesis contributes by demonstrating that coordinated and graded non directional relays can achieve optimal protection coordination, offering a simpler and more cost effective solution compared to complex optimization strategies

In 2023 uma et al.[41] Developed an adaptive overcurrent protection scheme using Radial Basis Function Neural Network, adjusting relay settings dynamically to maintain coordination under DG influence. Results confirmed effective mitigation of misoperation and sympathetic tripping. The study, however, depends on real-time adaptive control systems. This thesis fills the gap by providing a simpler, cost effective solution using coordinated and graded non-directional relays, indicating that proper relay settings alone can mitigate DG induced challenges in a 15kv, 24MVA distribution feeder with 6MW inverter based DG.

In 2024 G. Mhagama et al.[42] Presented review on coordination of time over current relays in electrical distribution network. This paper reviews various methods for coordinating time over current relays (TOCRs) in electrical distribution networks, focusing on the challenges introduced by DG integration. It discusses traditional coordination techniques and the impact of DG on fault current levels and relay settings. The review underlines the need for effective coordination methods in the presence of DGs. My thesis addresses this by demonstrating that coordinated and graded non directional relays can achieve optimal protection coordination, providing a simpler and more cost effective solution compared to complex coordination methods.

In 2023 Ayvaz.[43] Analyzed the impact of varying levels of DG penetration on the coordination of directional over current relays (DOCRs). The study found that increased DG penetration leads to reduced coordination time intervals and potential misoperation of relays. The author concluded that adaptive protection schemes are necessary to address these challenges. This thesis addresses this gap by demonstrating that properly coordinated non-directional relays can maintain coordination, eliminating the need for adaptive schemes.

In 2020 Wu et al.[44] Proposed a deep reinforcement learning approach to design protective relays in DER rich networks. Results showed high adaptability and effective mitigation of DG induced protection challenges. However, the approach is computationally intensive and difficult to implement practically. This thesis fills the gap by offering a practical, simulation validated method using standard non directional relays, and avoiding complex AI based control while achieving similar protection reliability.

In 2024 NurAisyah et al.[45] Presented a review of adaptive over current protection in distribution networks with integration of distributed energy resources. This review explores adaptive over current protection schemes in distribution networks including distributed energy resources (DERs). It discusses the challenges posed by bidirectional power flows and variable fault current contributions from DERs, leading to issues in fault detection and protection coordination. The paper highlights the need for dynamic protection schemes that can adapt to changing network conditions. While adaptive schemes are discussed, my thesis offers a practical

alternative by demonstrating that coordinated and graded non directional over current relays can effectively maintain protection coordination without the complexity and cost associated with adaptive systems.

In 2021 Tariq et al.[46] Investigated DG effects on distribution system relay coordination and observed increased risk of sympathetic tripping and missed trips. The study concluded that conventional settings are insufficient for DG penetration levels. The gap filled by this thesis is the demonstration that 11 coordinated non directional relays with graded timing can restore coordination and prevent sympathetic tripping without requiring adaptive algorithms or directional relays.

In 2024 singh et al.[47] Examined over current protection challenges in micro grid systems with DG, highlighting that conventional relay settings often fail due to protection blinding and reverse fault currents. Their simulations confirmed that traditional relays misoperate when DG contributes to fault currents. They concluded that enhanced protection strategies are necessary for reliable operation. This thesis addresses the gap by showing that grading and coordination of non-directional relays can prevent blinding and sympathetic tripping, even under inverter based DG conditions.

In 2022, Eid et al.[48] Focused on optimal coordination of directional over current relays in microgrids operating in both grids connected and islanded modes, considering the use of fault current limiters (FCLs). Their study demonstrated improved relay coordination through optimization techniques. While valuable for microgrid applications, the paper does not specifically address inverter based DG behavior or propose a mitigation strategy using conventional relay schemes. My thesis contributes by focusing on practical relay configurations suitable for standard distribution networks and emphasizing mitigation of blinding, sympathetic tripping and islanding risks caused by solar and wind DGs.

A recent 2025 paper.[49] Titled optimal protection coordination for grid connected and islanded micro grids proposed a two stage optimization approach for coordinating overcurrent relays in

micro grids with DG and energy storage systems. While the paper achieved improvements in fault isolation using dual relay settings and fault current limiters, its complexity and micro grid centric focus make it less applicable to typical radial distribution networks. My research provides a simpler, scalable, and cost effective solution focused on inverter based DG integration in conventional distribution networks, which can be implemented with existing relay technologies.

In 2024 peng and zhao.[50] In their paper "the adaptability and challenges of protection relays, explored the use of a random forest machine learning algorithm for improving the protection of DG integrated systems. By combining IoT based data acquisition with the learning algorithm, the proposed system achieved fast response times (approximately 0.12 second) and high reliability, with a low misoperation rate of about 5%. While the results were promising especially in handling variability in DG outputs, the protection strategy is dependent on high speed communication infrastructure and machine learning platforms, which may not be practical or affordable for many conventional power distribution networks. In contrast, my thesis offers a grounded and implementable solution using traditional protective devices. It focuses on enhancing the coordination and selectivity of over current relays in distribution systems with inverter based DGs, offering an effective yet practical mitigation approach without the need for advanced communication or computational systems.

To overall conclusion, this research provides both technical and methodological contribution which distinguishes it from previous works that:

- The study modeled and analyzed three realistic operating scenarios in DIgSILENTPowerFactory:
 - 1) base case
 - 2) DG integrated case
 - 3) Mitigated case (11 coordinated relays)

Such a stepwise comparative approach clearly isolates and quantifies the effect of DG on each performance metrics (fault current, relay timing, directional behavior, CTI, selectivity and unwanted/missed trips).

- This makes the analysis more comprehensive, bridging the gap between electrical fault flow dynamics and protection selectivity.
- Offers a guideline for utilities to set pickup currents higher than DG fault contributions to prevent sympathetic tripping - a practical, field ready insight.
- Provided a practical CT ratio selection method considering both load and DG fault contributions.
- Developed a DG impact analysis framework using DIgSILENTpowerfactory for protection studies in radial networks.
- Provides a replicable DIgSILENT simulation framework for utilities and researchers to test DG impacts on any radial distribution network.
- Spreads the theoretical understanding of DG induced protection phenomena such as protection blinding, sympathetic tripping, loss of selectivity, linking them quantitatively to system parameters and relay characteristics
- Unlike prior studies that proposed directional relays or intelligent algorithms (ANN, fuzzy, or IEC 61850 based adaptive protection), this research shows that DG induced issues can be mitigated using only non-directional relays through proper grading, coordination and current setting optimization.
- The approach is cost effective and suitable for developing distribution systems where upgrading to directional relays is economically unfeasible.
- The thesis develops a practical method for CT ratio selection considering both the feeders' maximum load current and the increased fault current contribution due to DG.
- The study bridges a critical gap between academic protection design and real world utility constraints, offering a practical, scalable, and low cost solution for DG rich distribution networks.

CHAPTER 3: DESIGN, MODELING AND SIMULATION

3.1 Introduction

This chapter presents the detailed design, modeling and simulation methodology used to investigate the impact of DG on protection relay performance in a distribution network and the proposed mitigation scheme. All simulation was conducted using DIgSILENTPowerFactory, chosen for its robust capacities in modeling distribution systems, fault studies and protection coordination.

The chapter explains the modeling approach, input parameter definition and entry, DG integration, protection system setup, simulation scenarios and performance metrics, coordination of 11 relays as a mitigation strategy and illustrative figures to support understanding.

3.2 Case Study: Adwa distribution network model

3.2.1 Network overview

Adwa substation is located in central zone of TIGRAY region which is at a distance of 1006km from ADDIS ABABA, the capital of Ethiopia. ADWA substation is selected as the case study area and is connected to the interconnected system (ICS). It is supplied by one incoming from MEKELLE – ABYI ADI line which is operating at a voltage level of 132kv. This single 132kv incoming lines is connected to the single bus bar which is connected to two transformers. These transformers are three winding transformers with their capacity of 40/20/20 MVA and voltage rating of 132/66/15 KV. The distribution network is formed by seven radial feeders, namely feeder 1 (Adwa town), feeder 2 (ADIBERAK), feeder 3 (KUTEBA), feeder 4 (MARIAMSHEWITO), feeder 5 (GENDEFTA) with 15KV voltage rating outgoing feeders and feeder 6 (MAY KALAY) and feeder 7 (DABAGERIMA) are the other outgoing feeders with 33KV voltage rating from 66KV/33KV transformer. The overall model of the ADWA distribution substation network developed using DIgSILENTPowerFactory 15.1.7 software is illustrated in the figure 3.2 below.

3.2.2 Distribution network data

All necessary data like the capacity of the substation, peak load, type of fault and all interruption data of the medium voltage (15KV and 33KV) outgoing feeders are collected from the substation recorded data. Here below tables 3.1 and table 3.2 indicates that total number of the transformer and system data of the outgoing seven feeders respectively.

Table 3. 1 total number of transformers in Adwa substation

Substation	No. of transformer	Voltage level in KV	Capacity in MVA
Adwa	2	132/66/15	40/20/20
	1	66/33	9/6

Table 3. 2 distribution system 7 outgoing feeders' data

Outgoing feeders	Overhead lines type and size	Line length in KM	Voltage level in KV	Number of transformer	Total transformer capacity in KVA	Total number of customers
Feeder 1	AAC 3*95	37.12	15	107	24295	24219
Feeder 2	AAC 3*95	47.5	15	29	5140	7244
Feeder 3	AAC 3*95	6.2	15	14	15350	5833
Feeder 4	AAC 3*95	38.8	15	17	525	1627
Feeder 5	AAC 3*95	39.7	15	26	6225	5354
Feeder 6	AAC 3*50	56	33	5	575	1811
Feeder 7	AAC 3*50	61.8	33	4	800	1909
Total	-----	298	-----	202	52705	48997

Basic Data

Name: three winding transformer

Rated Power

HV-Side	120. MVA
MV-Side	80. MVA
LV-Side	80. MVA

Rated Voltage

HV-Side	132. kV
MV-Side	66. kV
LV-Side	15. kV

Vector Group

HV-Side	YN	Phase Shift	0. *30deg
MV-Side	YN	Phase Shift	0. *30deg
LV-Side	YN	Phase Shift	0. *30deg
Name	YN0yn0yn0		

Positive Sequence Impedance

Short-Circuit Voltage uk		Copper Losses	
HV-MV	10. %	HV-MV	10.5 kW
MV-LV	5. %	MV-LV	7.5 kW
LV-HV	3. %	LV-HV	5. kW

Zero Sequence Impedance

Short-Circuit Voltage uk0		SHC-Voltage, Real Part	
HV-MV	3. %	HV-MV	0. %
MV-LV	3. %	MV-LV	0. %
LV-HV	3. %	LV-HV	0. %

Figure 3. 1 Three winding transformer data entry interface in DIgSILENT

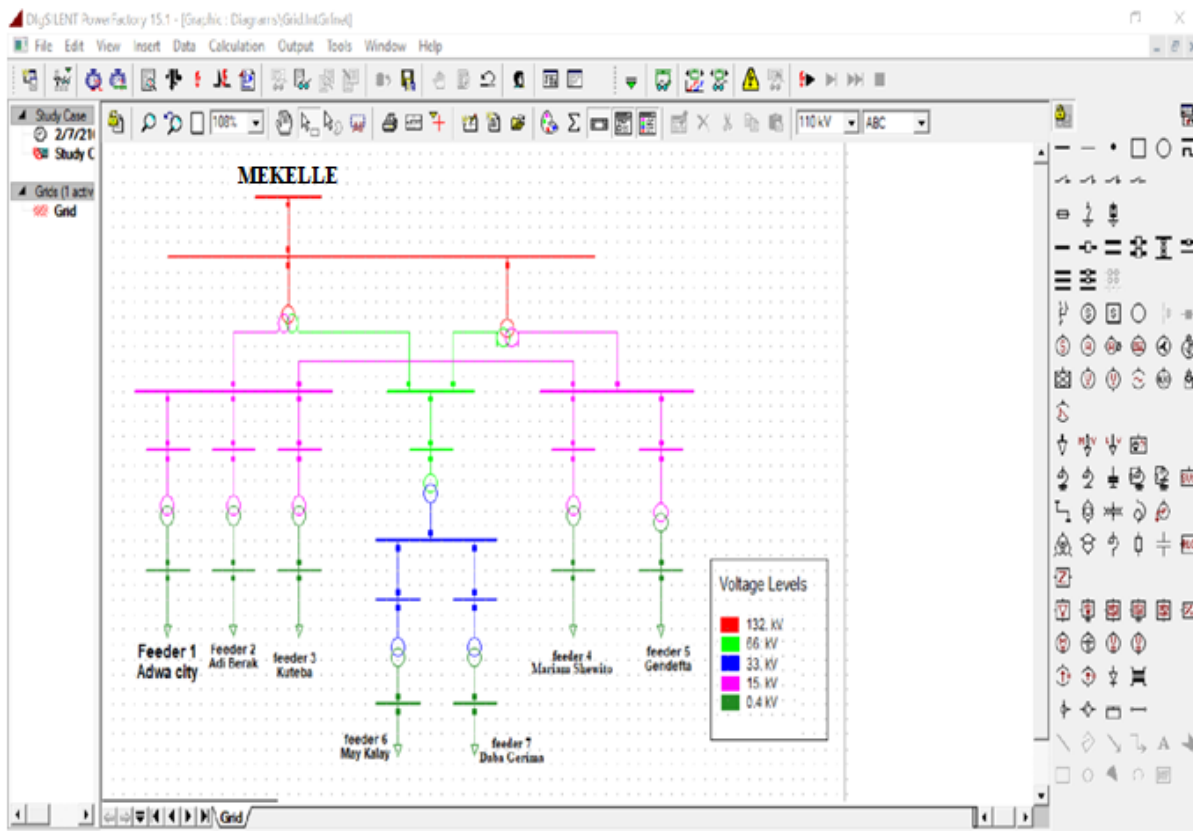


Figure 3. 2 Modeling of Single-line diagram of the Adwa distribution substation

3.2.3 Detailed model of feeder 1 (Adwa Town)

❖ Network configuration

The test network represents a typical 15KV radial distribution feeder supplied from a 132/15 KV substation transformer which is more loaded. The total load connected along the feeder is 24MVA, distributed among 73 main load buses. A 6MW inverter based DG (composed of 1MW solar PV and 5MW wind units) is connected at the mid feeder bus. The objective of the design is to evaluate how DG affects the performance of over current protection relay along the Adwa Town feeder under various fault scenarios. The entire system was configured as a radial feeder, where the main power flow direction under normal conditions is from the substation to the end bus. Each line section was modeled with its impedance was calculated according to the line length.

❖ Input data for the software

The electrical parameters shown in table 3.3 - Table 3.6 were entered into the corresponding DIgSILENT component windows. For instance, the line resistance and reactance per KM were multiplied by their respective length and inserted in the line parameters tab. The DG models were configured as inverter based static generators with specified active power, voltage control and power factory. Over current relay was modeled and linked to respective CT.

Table 3. 3 bus data of the 73 buss

Name	Voltage in KV	System type	Phase Technology
Bus bar	15	AC	ABC

Table 3. 4 external grid data

Description	Voltage in KV	Bus type	Angle in degree	Voltage set point in p.u
External grid	15 KV	SL	0	1.0

Table 3. 5 transmission line data

description	Rated voltage	Cable	Line length in km	type	AC resistance R_i (20 °c) (Ω/km)	AC Resistance R_o' (Ω/km)	Reactance X' (Ω/km)	Reactance X_0' (Ω/km)
D. line	15	Overhead line		AC	0.3242	0.3621	0.471	1.817

Table 3. 6 system data summary

Parameter	Symbol	Value	Unit	Description
System voltage	V_{LL}	15	KV	Nominal line to line voltage
Transformer rating	S_T	20	MVA	132/15 main transformer
Transformer Impedance	Z_T	8	%	Typical distribution transformer impedance
Feeder length	L	37.12	KM	Total feeder distance
Total load	S_{load}	24	MVA	Distributed along the feeder
Frequency	F	50	Hz	System frequency

Parameter	Value	Unit
Name	Line 1	
Rated Voltage	15	kV
Rated Current	0.4	kA
Nominal Frequency	50	Hz
Cable / OHL	Overhead Line	
System Type	AC	
Phases	3	
Number of Neutrals	0	
Parameters per Length 1,2-Sequence		
AC-Resistance R'(20°C)	0.3242	Ohm/km
Reactance X'	0.471	Ohm/km
Parameters per Length Zero Sequence		
AC-Resistance R0'	0.3621	Ohm/km
Reactance X0'	1.817	Ohm/km

Figure 3. 3 line -1 input data window in DIgSILENT

3.3 Distributed Generation (DG) modeling

3.3.1 DG Parameters

The 6 MW distributed generation (DG) unit consists of 1MW solar PV and 5MW wind generation modeled as inverter based sources using the static generator element in DIg SILENT. The DG operates at 15KV with a power factor of 0.95 and supplies active and reactive power to the mid feeder bus (BB-47). The PQ control mode was selected to maintain constant active and reactive power outputs. The DG contribution during faults was limited according to inverter control limits, which reflect realistic low inertia behavior.

3.3.2 Modeling of DG fault current contribution:

The contribution of distributed generation (DG) units to fault current depends strongly on the type of generator technology. In conventional synchronous generators, the fault current is high and transient, typically 4-6 times the rated current. However, inverter based sources such as photovoltaic (PV) and full converter wind turbines have limited fault current capacity, usually 1.1 – 1.3 times the rated current, due to electronic current control and protection limits within the converter.

In DIgSILENTPowerFactory, this behavior is modeled using the parameter I_k''/I_n , which represents the ratio of the initial symmetrical short circuit current (I_k'') to the rated current (I_n) of the DG unit.

General formula

$$I_{DG,fault} = k_{DG} * I_{DG,rated} \text{ ----- (3.1)}$$

$$I_{DG,rated} = \frac{S_n}{\sqrt{3} * V_n} \text{ ----- (3.2)}$$

Where

Symbol	Description	Typical value
$I_{DG,fault}$	DG fault current contribution (A or p.u.)	
$k_{DG} = \frac{I_k}{I}$	Fault current factor	1.1 – 1.3 (inverter)
$I_{DG,rated}$	Rated current of DG	
S_n	Rated apparent power of DG (VA)	
V_n	Rated line to line voltage (V)	

Table 3. 7 DG parameters

Parameter	PV DG	Wind DG	Unit/note
Rated power	1	5	MW
Rated voltage	15	15	KV
Rated frequency	50	50	Hz
Short circuit contribution	1.2	1.1	p.u of rated current
Power factory	0.95	0.95	Lagging
Inverter type	Grid following	Grid following	Voltage source inverter model
Control mode	PQ control	PQ control	Active/reactive power control
penetration			25%
Location	Bus-47	Bus - 47	Middle of feeder
Connection type	LV feeder	LV feeder	Point of common coupling

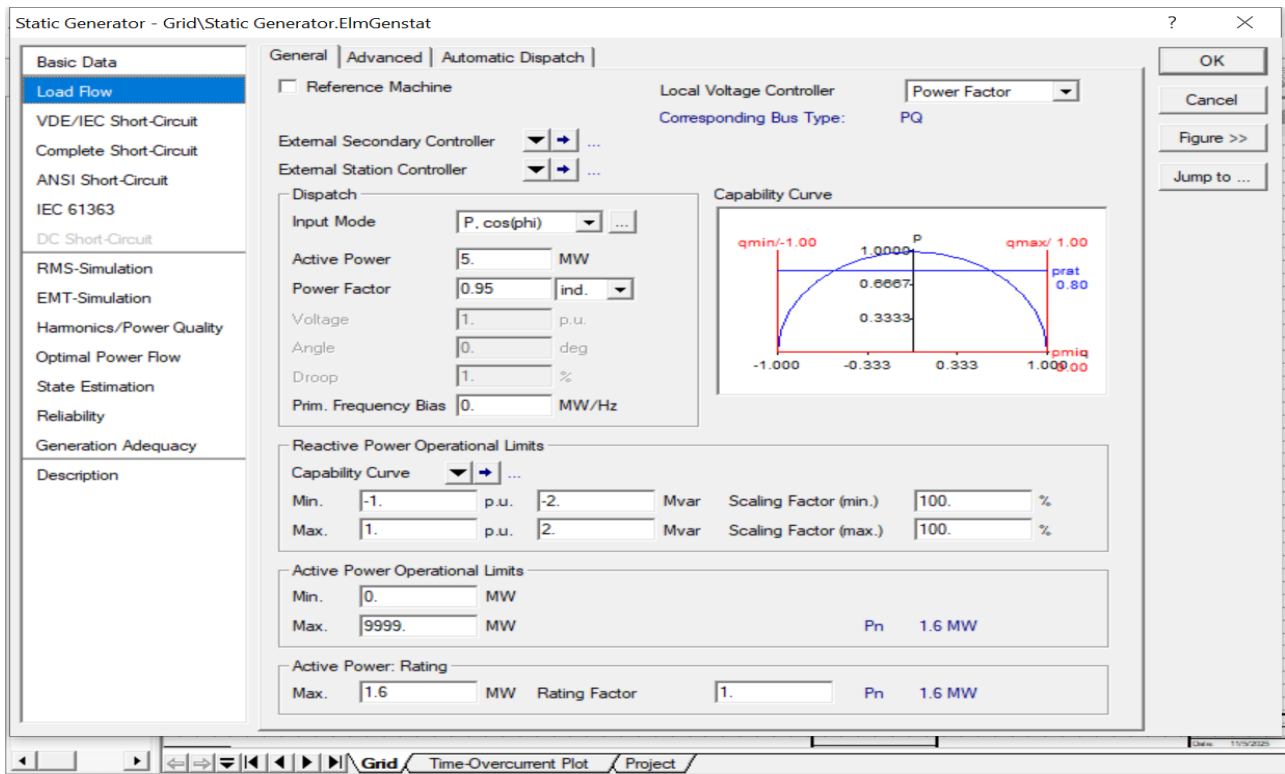


Figure 3. 4 DG parameter input window in DIgSILENT PowerFactory

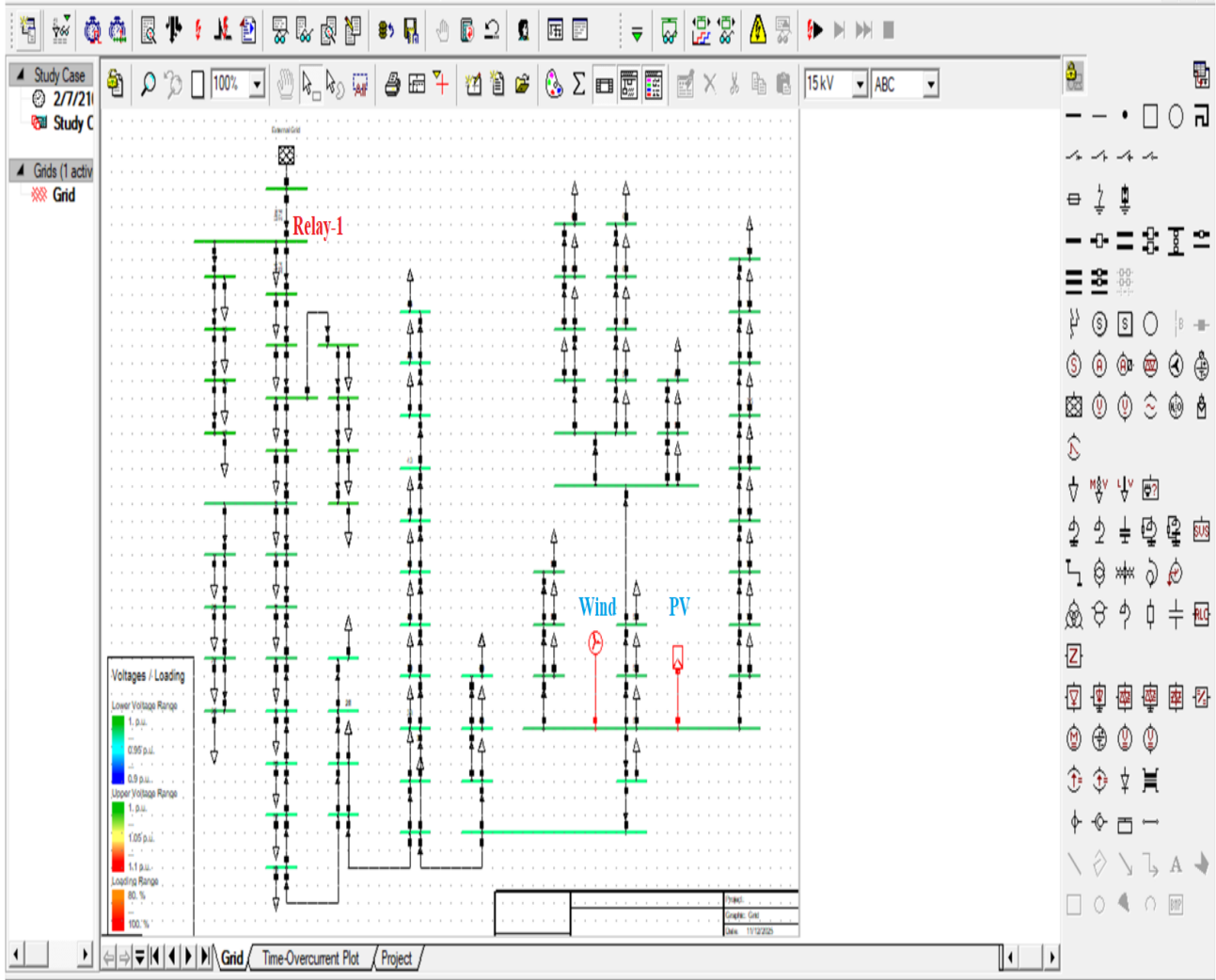


Figure 3. 5 Modeling of feeder 1 (Adwa town) with single relay and DG

3.4 Protection system configuration and modeling

In this study, the protection of the 15kv radial distribution feeder was modeled in DIgSILENT PowerFactory to evaluate relay performance under three scenarios. In the base case and DG integrated case, a single non directional over current relay (OCR) was configured to protect the main feeder. The relay was modeled to operate based on time current characteristics, responding to over current conditions beyond a defined pickup threshold. Since the network operates radial, the direction of current flow in the base case is unidirectional - from the grid toward the load - making a non-directional relay suitable for normal operation. However, once DG is integrated, fault currents may flow in both directions, creating performance challenges for such relay.

The modeled relay employs the inverse definite minimum time (IDMT) characteristic according to ISC 60255 standards. Key parameters include the pickup current (I_p), time multiplier setting (TMS), and curve type (standard inverse). The pickup current was selected based on 120% of the feeder maximum load current to prevent nuisance tripping under normal loading conditions. In DIgSILENT, these settings were entered through the "relay protection" dialog interface, where the relay type, characteristic curve, pickup current and time dial were defined.

The relay continuously monitors the line current through the associated current transformer (CT), which scales primary current to a measurable secondary level. The relay trips when the measured current exceeds the defined pickup threshold for a duration determined by its time current curve.

The performance of the relay in this single configuration serves as a benchmark for evaluating the impact of DG on protection sensitivity, fault detection time and selectivity.

3.4.1 Parameters of over current relay

Table 3. 8 key parameters of over current relay

Parameter	Symbol/unit	Description	Assigned value
Relay type		Non directional over current relay	Inverse Definite Minimum Time (IDMT)
TCC curve		Defines inverse time response according to IEC	Standard Inverse
Pickup current	Ip(A)	Current level above which the relay starts to operate	600A
Time multiplier setting	TMS	Adjusts the time delay on the IDMT curve for grading coordination	0.15
Rated current	In (A)	Nominal CT secondary current	1A
Reset time	Tr (s)	Time for relay to return to normal after current falls below pickup	0.1s
CT ratio		Primary/secondary ratio used to feed relay	600/1
Relay location		Installed at the main feeder (substation)	Feeder relay R1
Protection zone		Coverage area of the relay	Entire main feeder 1 line

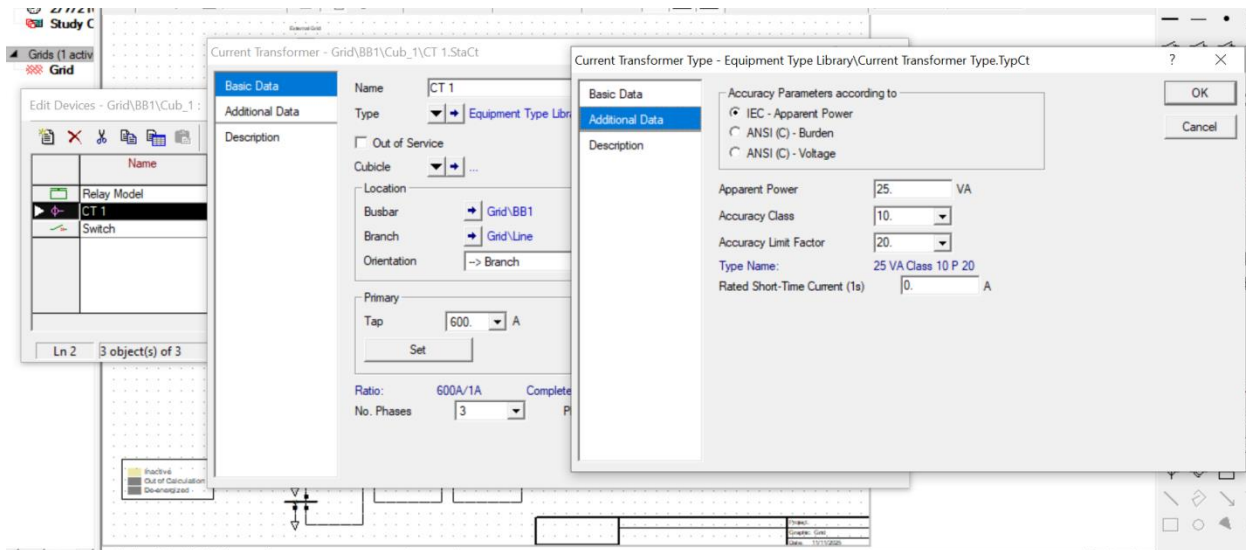


Figure 3. 6 Non directional relay data entry interface in DIGSILENT

3.5 Fault modeling and simulation setup

The fault modeling and simulation were performed in DIgSILENTPowerFactory to assess the impact of distributed generation (DG) integration on the feeders fault current behavior and relay performance. The objective was to analyze how fault location, fault type, and DG presence influence the magnitude and direction of short circuit currents within the 11kv distribution feeder.

The study focused on the non-directional over current relay installed at the grid substation feeder end. By systematically varying the fault location and DG status, the simulation captured the resulting changes in current magnitude, flow direction, and protection coordination.

3.5.1 Fault types

Different types of faults were simulated to represent common system disturbances that affect distribution network protection. The following fault categories were analyzed.

Table 3. 9 fault type and description

Fault type	Description	Characteristics	Protection impact
Three phase (L-L-L)	Balanced fault between all three phases	Produces highest current magnitude, symmetrical	Severe fault; used for worst case short circuit studies
Single line to ground (L-G)	Fault between one phase and ground	Unbalanced fault; contains zero-sequence current	Most common in distribution feeders
line to line (L-L)	Fault between two phase	Moderate current magnitude; no zero sequence component	May not trigger earth fault relay

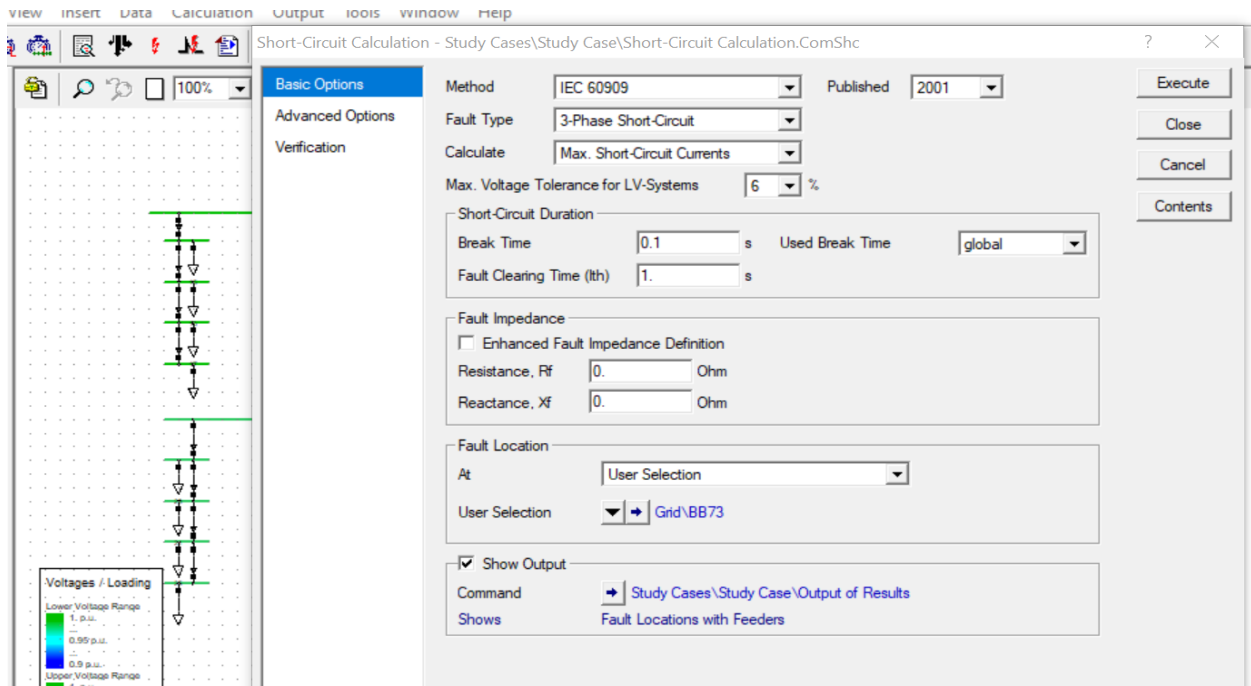


Figure 3. 7 fault setup and data entry interface in DlgSILENT

3.5.2 Fault locations

To assess the effect of fault position along the feeder, faults were applied at four distinct buses, representing critical point in the system:

Table 3. 10 fault location and description

Fault location	Description	Expected observation
Near grid	Fault at feeder start near source	Highest current magnitude, grid dominated fault
Mid feeder	Intermediate bus	Moderate current, partial DG contribution
Near load	Fault at near load	Possible current reversal and blinding of relay
Adjacent feeder	Fault beyond DG point	DG feeds into external fault (sympathetic tripping)

The results from these locations were used to identify the effects of DG placement on fault current direction, protection coordination, and sensitivity.

3.5.3 Fault current calculation

The theoretical short circuit current at the fault point is given by:

$$I_{fault} = \frac{E}{Z_s + Z_l + Z_f} \text{-----} (3.3)$$

Where

E = system phase voltage

Z_s = source impedance (grid + DG equivalent)

Z_l = line impedance up to fault point

Z_f = fault impedance

The total fault current at a bus is the vector sum of the grid and DG contributions:

$$I_{total} = I_{grid} + I_{DG,PV} + I_{DG,wind} \text{-----} (34)$$

This relation allows observation of how inverter based DGs, with limited current injection capability, affect overall fault magnitude and phase angle.

Table 3. 11 simulation parameters

Parameter	Setting	Purpose/remarks
System voltage	15kv	Base system voltage
Frequency	50hz	Standard network frequency
Fault impedance	0 ohm	Solid fault assumption
Simulation type	Steady state short circuit	To evaluate current magnitude and direction
DG fault contribution	PV: 1.2, wind: 1.1	Limited inverter fault current
Grid short circuit ratio	non directional over current	Subject of analysis
Relay type	Enabled (branch flow overlay)	To visualize current direction

3.6 Simulation scenarios and performance metrics

The simulation study was designed to systematically evaluate the effect of DG on the performance of over current protection relays under different network configurations. Three distinct scenarios were modeled and analyzed using DlgSILENTPowerFactory, each scenario was subjected to identical fault conditions and locations, as defined in the previous section, to ensure consistent comparison. The simulation results were then interpreted in terms of fault current variation relay operation time, directional behavior, selectivity.

3.6.1 Simulation scenarios

1. Scenario one: base case (without DG)

In this scenario, the 15KV radial distribution feeder operates conventionally without any distributed generation connected. Only one non directional over current relay (R1) is installed at the substation end. The fault current flows unidirectional - from the grid to the load - and the relay coordination follows the standard inverse definite minimum time (IDMT) characteristic. This case serves as the bench mark reference for evaluating normal protection performance, establishing baseline values for fault current, operating times.

2. Scenario two: DG integrated case:

In this configuration, a 6MW inverter based DG unit (solar PV and wind hybrid) is connected at bus 47 of the feeder. The same single non-directional relay from the base case is retained. The integration of DG alters the fault current magnitude and direction, introducing bidirectional power flow. This scenario is used to observe DG induced protection challenges such as protection blinding, sympathetic tripping and islanding risk. Measurements from this case quantify the deterioration in relay performance relative to the base case.

3. Scenario three: mitigated case (DG with 11 coordinated relays):

In this scenario, the DG remains connected at 47-bus, but 11 coordinated non directional over current relays (R1-R10) are strategically placed along the feeder and its laterals. The relays are graded using optimized pickup currents and TMS to restore proper coordination. This mitigation that relay grading and coordination can effectively eliminate false trips missed trips and improves selectivity.

3.6.2 Performance metrics for evaluation

To comprehensively evaluate relay behavior under the three scenarios, six quantitative performance metrics were defined and computed from DIGSILENT simulation outputs.

Table 3. 12 Relay performance evaluation metrics

Metrics	Description
Fault current	Magnitude of short circuit current at relay location
Relay operating time	Time taken by relay to trip for a given fault
Directional behavior	Indicates fault current direction at each relay location
Coordination time interval (CTI)	Time margin between operation of backup and primary relay
Selectivity	The protection system to isolate the faulted section
Missed/unwanted trips	Number of false or failed tripping observed during simulation

3.7 Mitigation scheme design and modeling

The mitigation scheme was designed to address the misoperation problems caused by DG integration. Instead of upgrading to costly directional or adaptive protection devices, the study developed a coordinated and graded non directional over current relay system to ensure proper protection selectivity, sensitivity, and reliability within the 15kv distribution feeder. A total of 11 relays were strategically placed along the main feeder, DG bus, and lateral branches. Each relay was configured with optimized pickup current (I_p), time multiplier setting (TMS), and current transformer (CT) ratio, based on its network location and load characteristics.

The coordination objective was to maintain a CTI 0.2s - 0.4s between primary and backup relays while minimizing total fault clearing time. The pickup current for each relay was selected 120% of its maximum load current, ensuring that relays remain stable under normal operating condition yet sensitive enough to detect low impedance faults. The TMS values were graded progressively from downstream to upstream to ensure selective tripping.

1.7.1 CT ratio selection

The selection of CT ratios for the 11 coordinated relays was performed to ensure accurate current measurement, relay sensitivity, and avoidance of CT core saturation during fault conditions. Each CT ration was determined based on the maximum load current and the expected fault current at its installation point within the distribution feeders. The general selection criterion used was that the CT primary rating should be 120% of the maximum expected load current, while the secondary current was standardized at 1A, in accordance with IEC 60044 - 1 and IEC 61869 - 2 standards.

The CT ratios were chosen considering the expected load current and maximum fault current at each relay point. Upstream relays near the substation used higher CT ratios to prevent CT saturation under large fault currents. Mid feeder and downstream relays used lower CT ratios to improve current sensitivity for low fault levels. Around the DG interface special attention was given to selecting CT ratios that can measure bidirectional current flow without distortion.

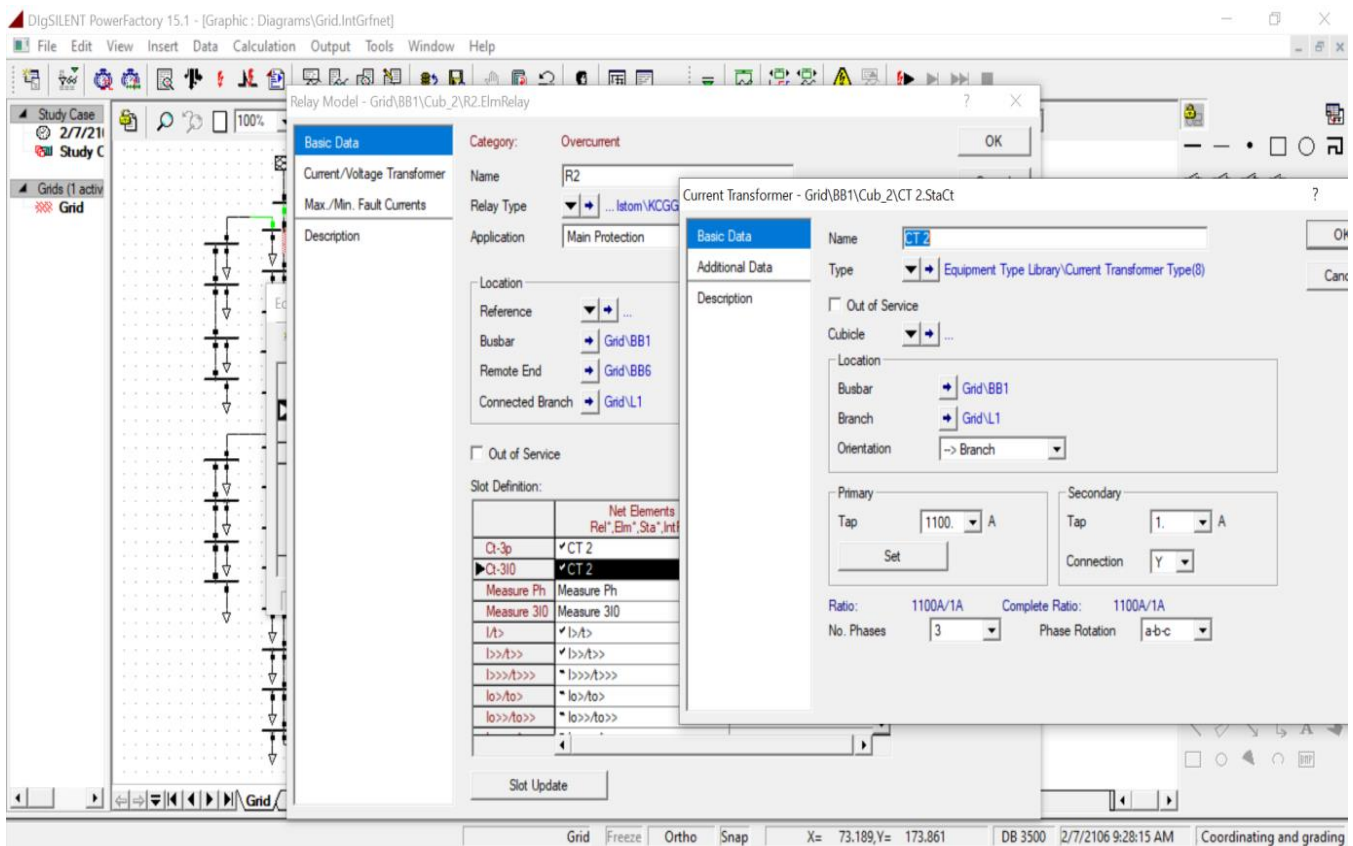


Figure 3. 8 over current relays protection coordination and data entry interface in DIGSILENT

Table 3. 13 current transformer (CT) data for 11 relay coordination and grading

NO	Protecti on device	Locatio n	Branch	Manufact urer	Model	Ratio (pri. A/sec. A)
1	R1	terminal	Terminal line	Alstom	KCGG142-1A	1200/1A
2	R2	BB1	Line 1	Alstom	KCGG142-1A	1100/1A
3	R2-1	BB1	Line 13	Alstom	KCGG142-1A	400/1A
4	R3	BB13	Line 5	Alstom	KCGG142-1A	1000/1A
5	R4	BB35	Line 36	Alstom	KCGG142-1A	500/1A
6	R5	BB42	Line 46	Alstom	KCGG142-1A	600/1A
7	R6	BB47	Line 55	Alstom	KCGG142-1A	500/1A
8	R7	BB47	Line 69	Alstom	KCGG142-1A	500/1A
9	R8	BB47	Line 52	Alstom	KCGG142-1A	500/1A
10	R9	BB56	Line 61	Alstom	KCGG142-1A	400/1A
11	R10	BB56	Line 65	Alstom	KCGG142-1A	400/1A

Table 3. 14 AlStom over current relay data for 11 relay coordination and grading

Relay	Stage (phase)	Current (pri.A)	Current (sec.A)	Current (p.u)	time	Characteristic
R1	I>/t>	1200	1	1	0.30	No. 1 - S130xDT (standard inverse)
	I>>/t>>	12000	10	10	0.42	Definite
R2	I>/t>	1100	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	11000	10	10	0.42	Definite
R2-1	I>/t>	400	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	840	2.1	2.1	0.42	Definite
R3	I>/t>	1000	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	5000	5	5	0.42	Definite
R4	I>/t>	500	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	1750	3.5	3.5	0.42	Definite
R5	I>/t>	1000	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	5000	3.8	3.8	0.42	Definite
R6	I>/t>	500	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	1600	3.2	3.2	0.42	Definite
R7	I>/t>	500	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	1350	2.7	2.7	0.42	Definite
R8	I>/t>	500	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	1100	2.2	2.2	0.42	Definite
R9	I>/t>	400	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	880	2.2	2.2	0.42	Definite
R10	I>/t>	400	1	1		No. 1 - S130xDT (standard inverse)
	I>>/t>>	800	2	2	0.42	Definite

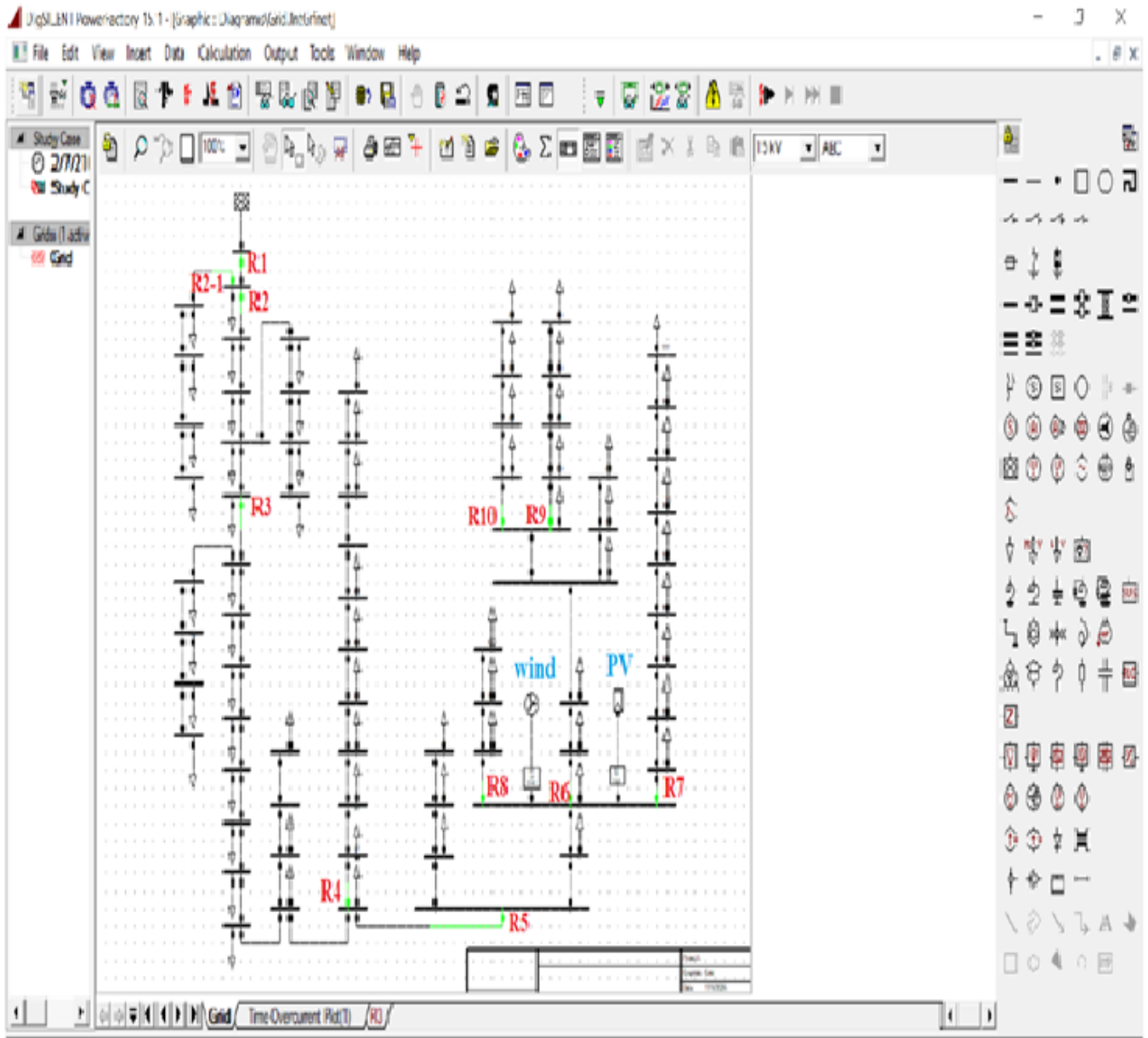


Figure 3. 9 Modeling of feeder 1 (Adwa town) with DG and 11 coordinated over current protection relay

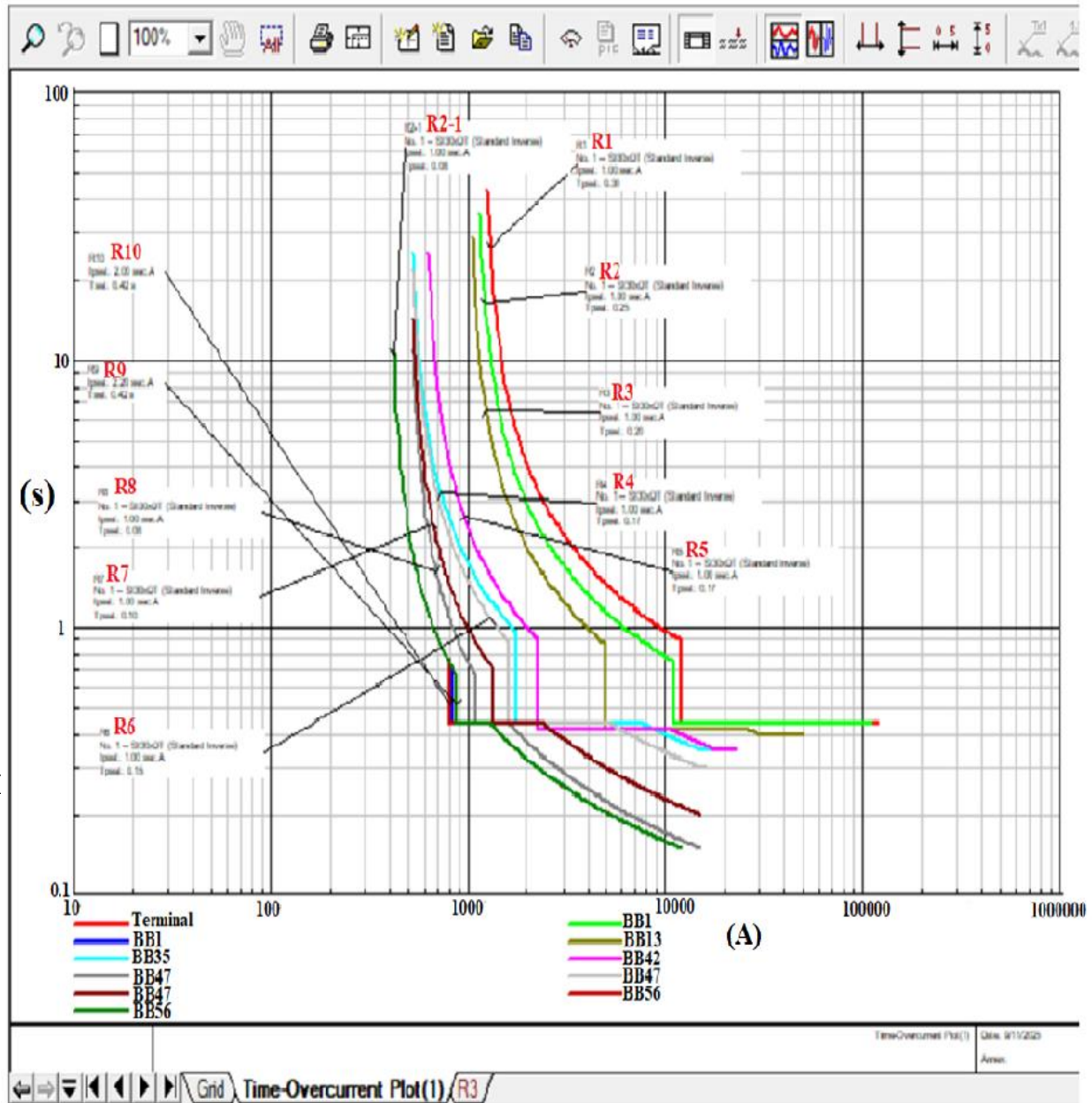


Figure 3. 10 Time- Current Characteristic curves (TCC) curve for all coordinated over current relays under normal conditions

CHAPTER 4: SIMULATION RESULT AND DISCUSSION:

4.1 Introduction:

This chapter presents the result obtained from the simulation carried out in DIg SILENT PowerFactory and discussed these effects of distributed generation (DG) integration on protection relay performance. The analysis covers three scenarios.

1. Base case (no DG)
2. DG integrated case (with DG and single non directional relays)
3. Mitigated case (coordinated 11non directional relays)

Each scenario is evaluated using the performance metrics defined in chapter 3 fault current magnitude, relay operating time, CTI, directional behavior, selectivity, and unwanted/missed trips. Finally, comparative results are analyzed to highlight how the proposed mitigation scheme improves protection reliability.

4.2 Base case scenario (No DG, single over current relay):

In the base case, the 15kv distribution network operates in a radial configuration with power flowing unidirectional from the substation to the loads. A single non-direction over current relay at the substation provides system protection.

4.2.1 Simulation result:

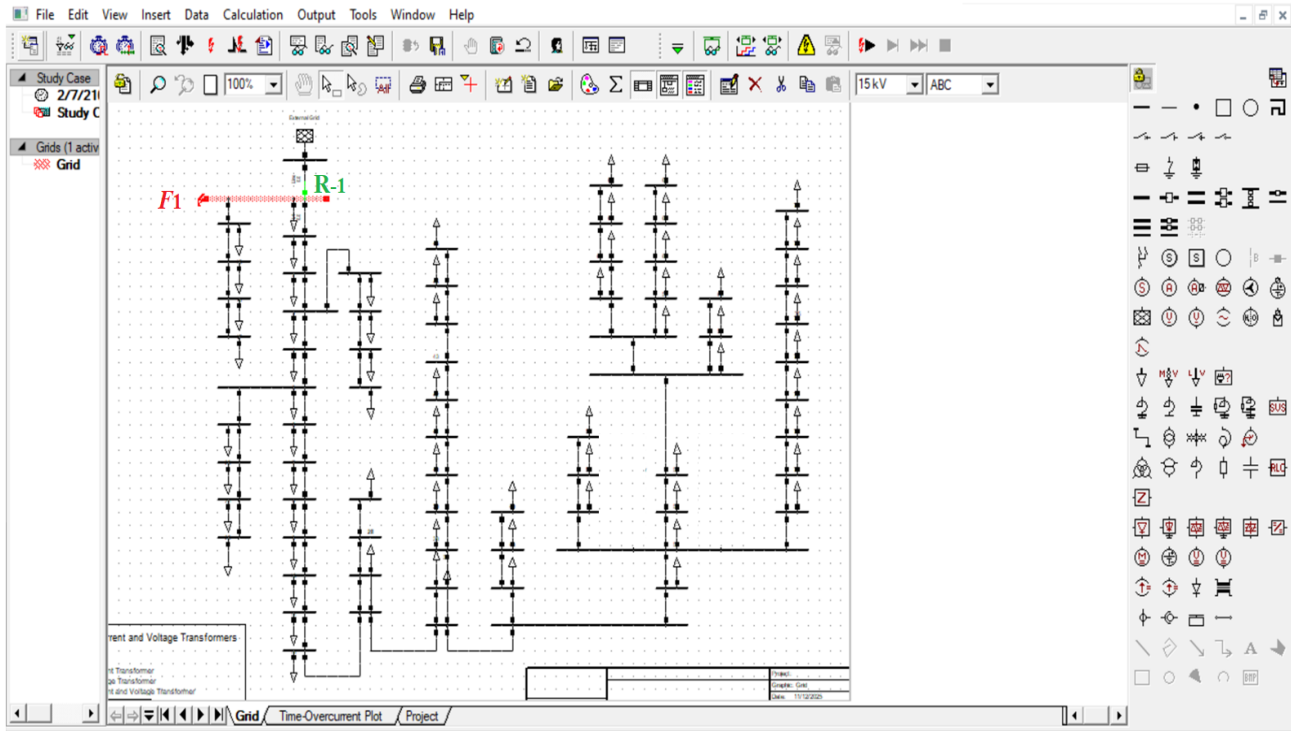


Figure 4. 1 Single-line diagram of the radial distribution feeder with a simulated L-G fault applied at near substation

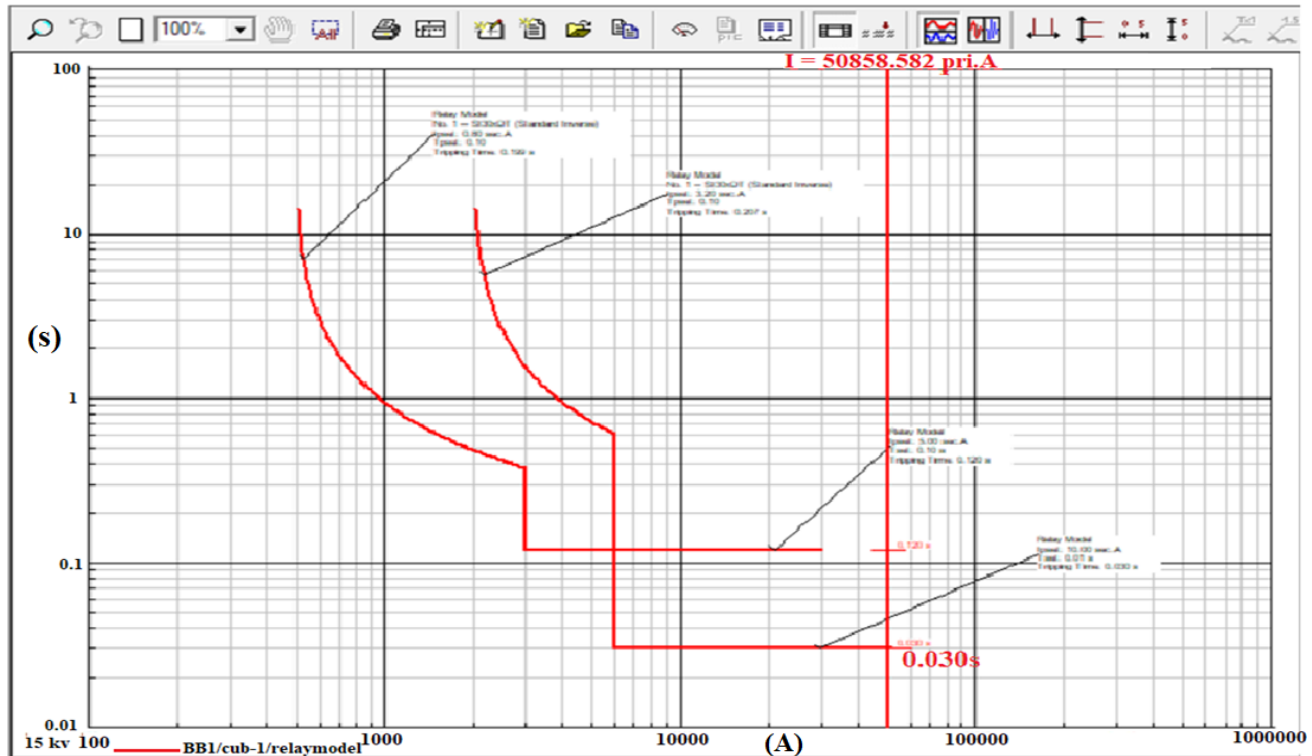


Figure 4. 2 Time-Current characteristic (TCC) curve showing relay operation for L-G fault at near of substation

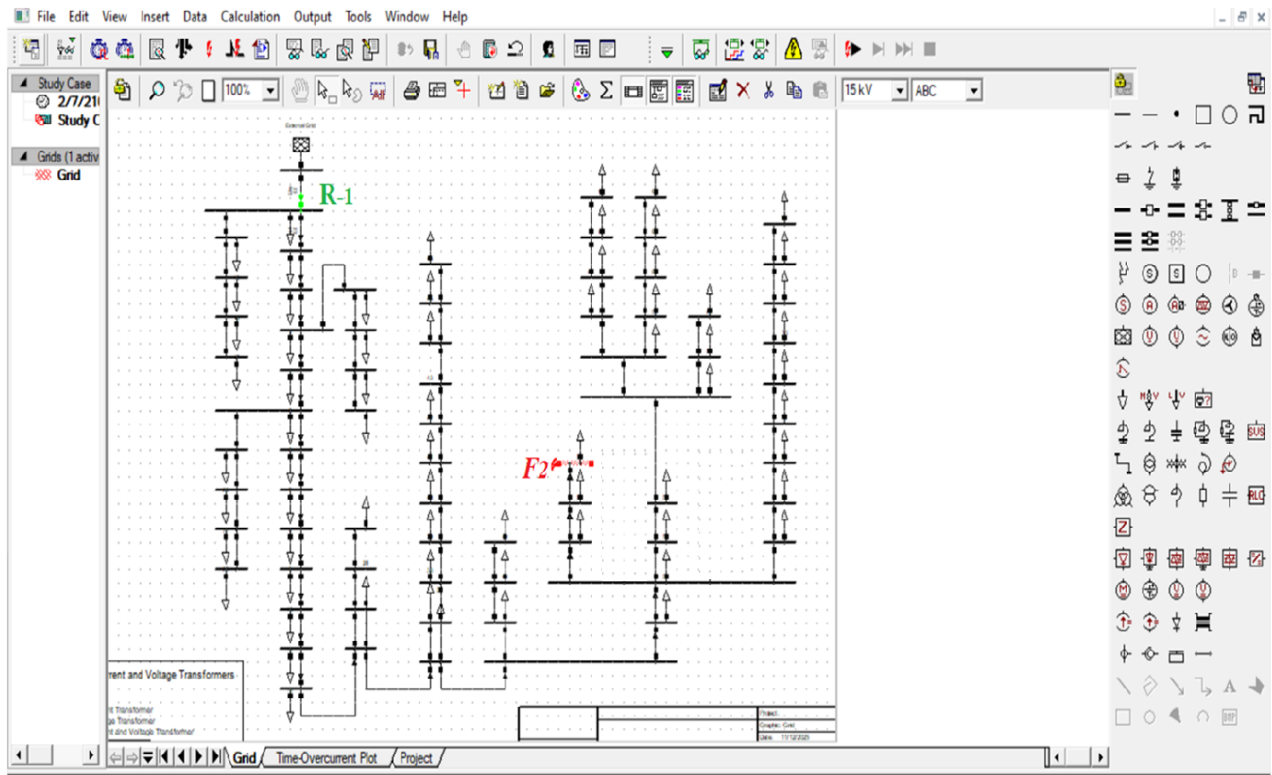


Figure 4. 3 single-line diagram of the radial distribution feeder with a simulated L-G fault applied at mid feeder

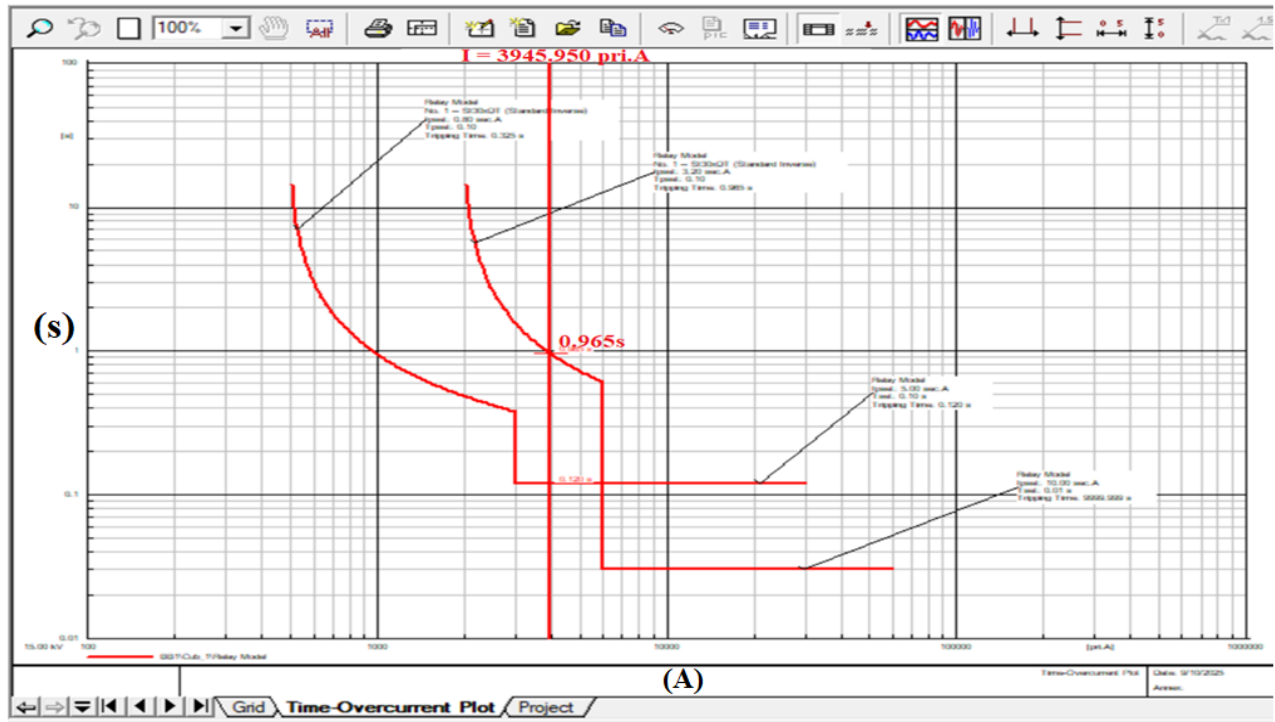


Figure 4. 4 Time-Current characteristic (TCC) curve showing relay operation for L-G fault at the mid of the feeder

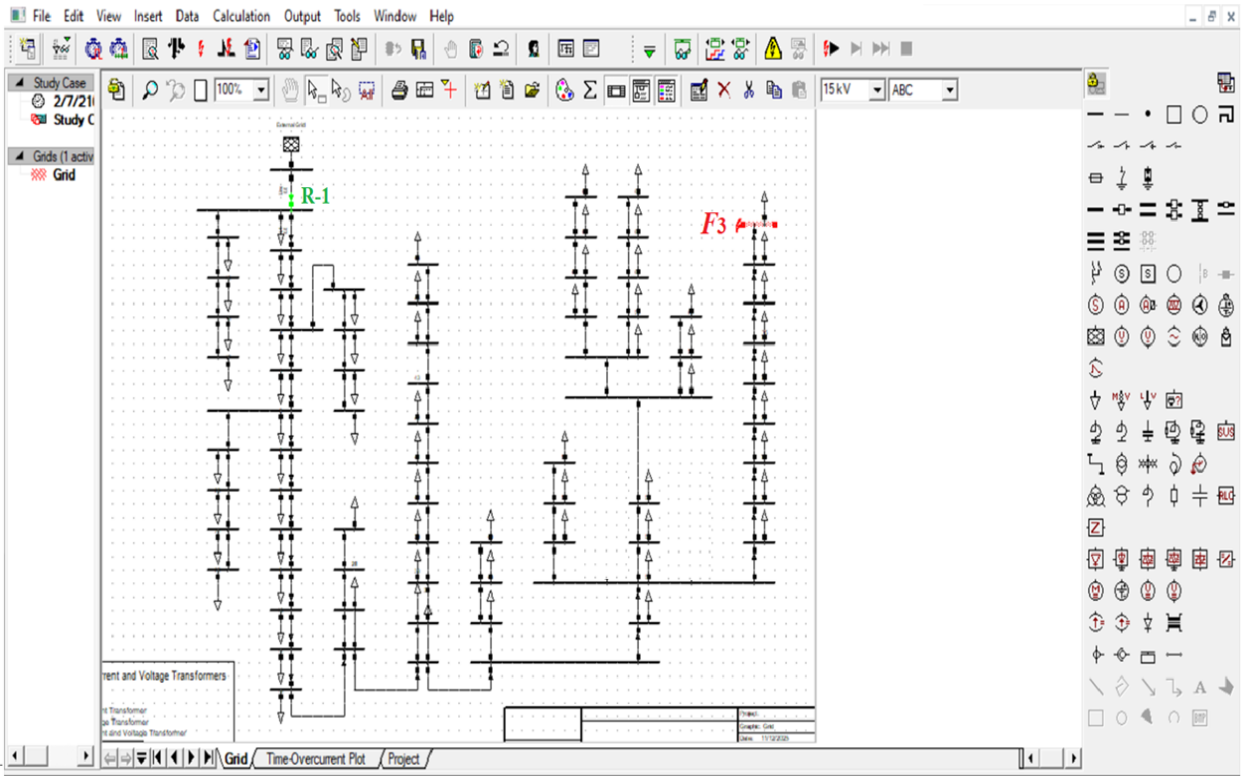


Figure 4. 5 Single-line diagram of the radial distribution feeder with a simulated L-G fault applied at the end of feeder

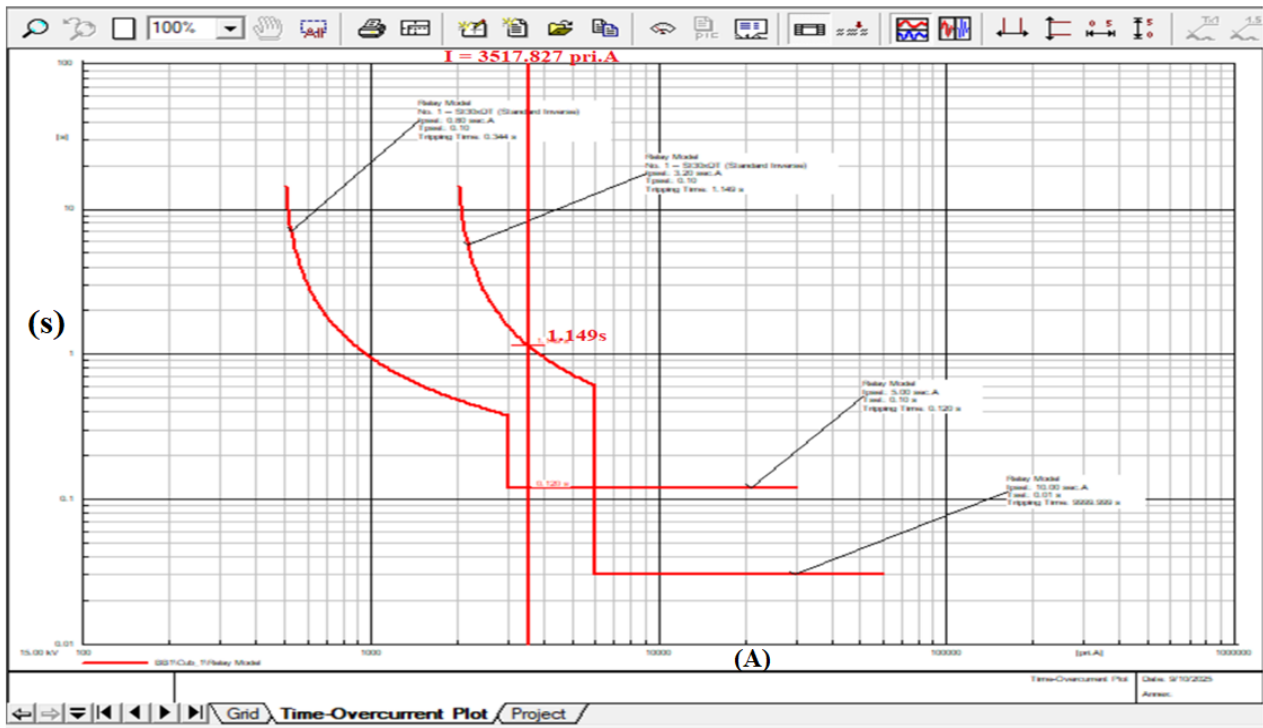


Figure 4. 6 Time-Current characteristic (TCC) curve showing relay operation for L-G fault at the end of the feeder

Table 4. 1 base case relay performance metrics

Fault type	Fault location	Fault current (KA)	Relay operating time (s)	Directional behavior	CTI	Sel.	Unwanted/missed trips
L-G	Near Substation (F1)	50.858	0.030	Forward	N/A	✓	No
L-G	Mid feeder (F2)	3.945	0.965	Forward	N/A	✓	No
L-G	End feeder (F3)	3.517	1.149	Forward	N/A	✓	No
L-L	Near Substation (F1)	70.160	0.030	Forward	N/A	✓	No
L-L	Mid feeder (F2)	5.760	0.630	Forward	N/A	✓	No
L-L	End feeder (F3)	5.144	0.703	Forward	N/A	✓	No
L-L-L	Near Substation (F1)	81.013	0.030	Forward	N/A	✓	No
L-L-L	Mid feeder (F2)	6.651	0.130	Forward	N/A	✓	No
L-L-L	End feeder (F3)	5.940	0.613	Forward	N/A	✓	No

4.2.2 Discussion:

In the base case, all faults resulted in predictable unidirectional fault current flowing from the source to the loads. The single relay correctly identified and isolated faults with no coordination or selectivity issues. The operating times ranged from 0.030 to 0.613s depending on fault location, consistent with the inverse time characteristics of the relay. Since DG was not connected, no current reversal, sympathetic tripping and islanding risk occurred.

The type and location of faults in the feeder network, along with the corresponding time-current characteristic (TCC) curve for the base case scenario, are presented from figures 4.1 – figure 4.6. The TCC curve illustrates the operating time of the over current relay (s) in response to different levels of fault current magnitudes. The finding results are summarized the table 4.1.

4.3 DG integrated scenario:

4.3.1 Introduction:

This section presents the simulation results and detailed analysis of the protection behavior of a distribution feeder integrated with inverter based DG source, including solar PV and wind units. The study was carried out using DIgSILENTPowerFactory to evaluate the effect of DG fault current contribution on a feeder equipped with a non-directional over current relay. The simulations were performed under different fault conditions to investigate protection phenomena such as, blinding of protection, current reversal, sympathetic tripping and islanding risk.

4.3.2 Simulation result:

In this scenario, a Distributed Generation (DG) unit is integrated into the radial distribution network while maintaining the original protection scheme – a single over current relay located at the substation. No additional relays or coordination adjustment are made.

The simulation aims to assess the performance of the existing relay under fault conditions in the presence of DG. Faults are applied at the feeder to observe the impact of bidirectional fault current contributions. The goal is to evaluate whether the single relay remains reliable and selective when DG is present.

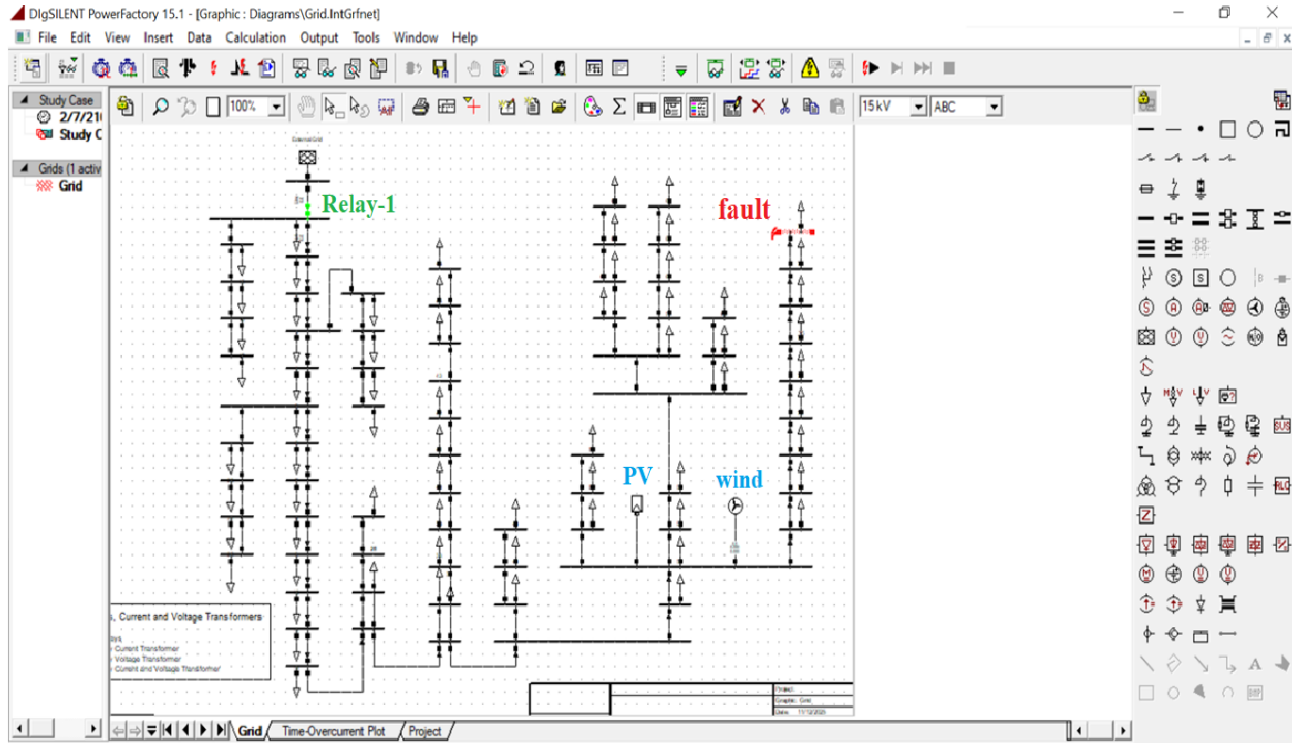


Figure 4.7 Single-line diagram of the radial distribution feeder with a Distributed Generation (DG) unit connected and fault are at downstream of relay

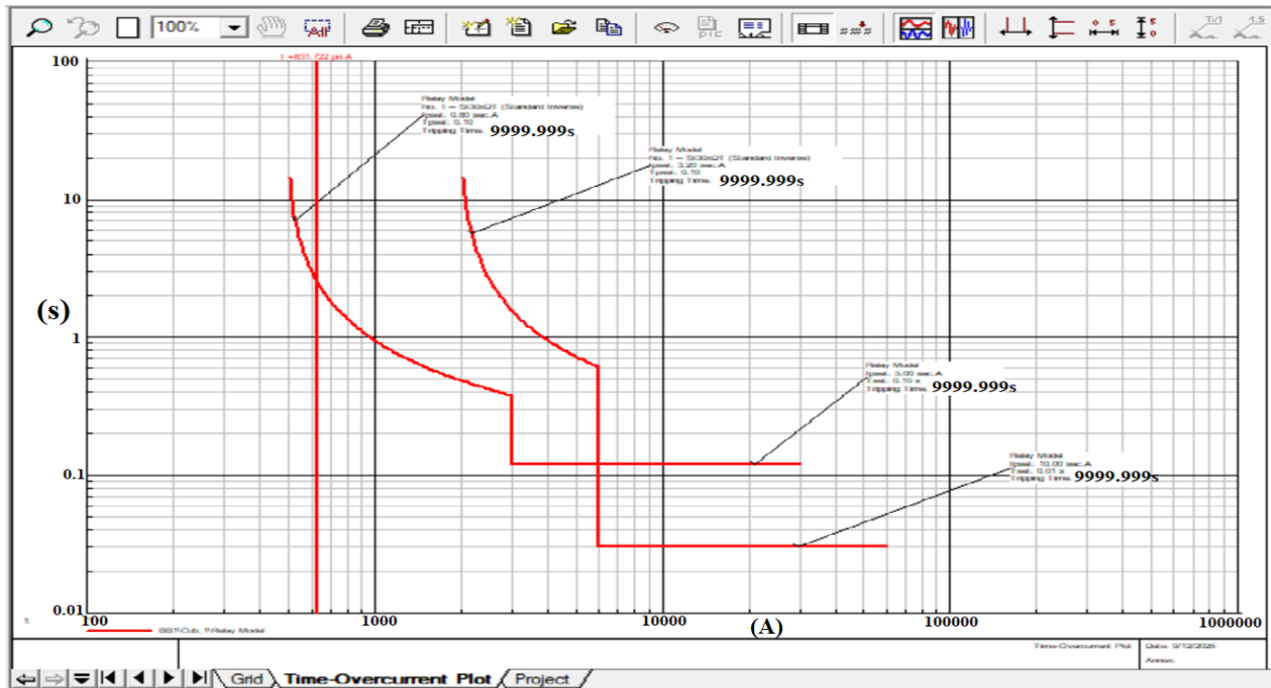


Figure 4.8 The TCC curve for DG-integrated scenario with a single over current relay under tripping

❖ Key observation and definitions

Observation	Definition	Impact on non-directional relay
Relay blinding is presented, where fault current from DG is insufficient to trigger the relay. Relay failed to operate for a fault at end-feeder due to fault current less than pickup setting	Blinding of protection: a situation in which a protective relay sees a reduced fault current and must fail to operate because the current is below its pickup threshold	Relay should under reach or fail to trip
DG introduces reverse current flow during faults. Non directional relays should misinterpret direction, tripping incorrectly or failing to trip	Current reversal: a condition where the fault current flows in the opposite direction from the normal power flow due to DG contribution.	relay cannot distinguish fault direction, potentially causing maloperation
DG fault current contribution into an external fault, leading to unnecessary relay tripping on a healthy feeder	Sympathetic tripping: Operation of a relay, in the case of a fault on an adjacent feeder, DG contribute fault current through the common bus, the non-directional relay on the health feeder senses this current and falsely identifies a fault within its zone, leading to undesired tripping.	DG fault contribution can cause relay trips unnecessary, disconnection of healthy section.
When the main grid is disconnected, the inverter based DGs maintain voltage and supply to local loads. In this islanded condition, the non-directional relay receives no grid current and cannot detect faults, creating safety hazards and potential equipment damage.	Islanding risk: Condition in which a portion of the network remains energized by local Generation after grid supply is lost.	Relay blind to islanded condition; unsafe energized section.

4.3.3 Discussion:

The simulation results clearly demonstrate the significant influence of inverter based DG on the performance of conventional feeder protection. When PV and wind sources were integrated at the downstream bus, the non-directional over current relay at the feeder origin experienced multiple operational challenges under various fault conditions. During faults far from grid (end, bus 73), the grid fault current contribution decreased substantially due to DG fault current injection limits, resulting in blinding of protection, where the relay's operating current barely exceeded its pickup threshold. This condition risks delayed or missed fault clearance. Additionally, current reversal was observed as DG injected current toward the fault, causing current flow opposite to the normal power direction. Because the relay is non directional, it could not differentiate between forward and reverse faults, increasing the possibility of maloperation.

In the case of a fault on a neighboring feeder (feeder 2), DGs contributed current into the external fault through the shared connection point, leading the relay to trip unnecessarily, a phenomenon known as sympathetic tripping. This misoperation can cause the disconnection of healthy feeders, reducing system reliability. Finally, during the simulated islanded condition, when the grid was disconnected, both PV and wind DGs continued to supply local loads, maintaining voltage on the feeder. The relay did not detect this condition since no grid current was present, revealing a significant islanding risk that poses safety and synchronization challenges.

Overall, these results highlight that traditional non directional over current protection is not sufficient for feeders with DG penetration.

4.4 Mitigated case(improved protection scheme):

In this scenario, a coordinated protection scheme with 11 graded non-directional relays was implemented. The relays were coordinated through pickup current and TMS adjustments to maintain a minimum coordination time interval between 0.2 - 0.4s.

4.4.1 Simulation results:

The type and their locations of faults within the feeder network, along with the corresponding time current characteristic (TCC) curve for the mitigated case scenario, are presented in figures below. The TCC curve demonstrates the operating behavior of the coordinated over current relay in response to various fault current magnitudes. The simulation outcomes, including evaluated metrics, are summarized in table 4.3.

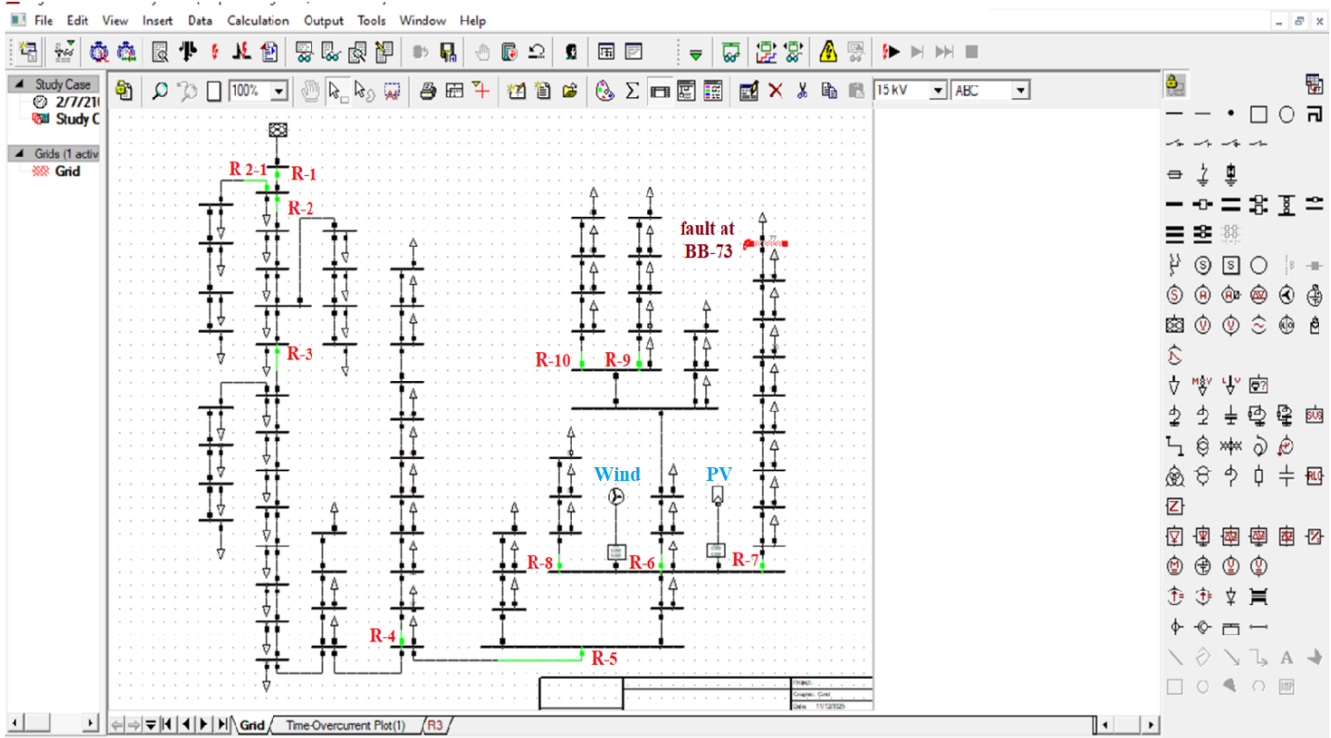


Figure 4. 9 Single-line diagram of the radial distribution feeder with a three phase fault applied at bus 73.

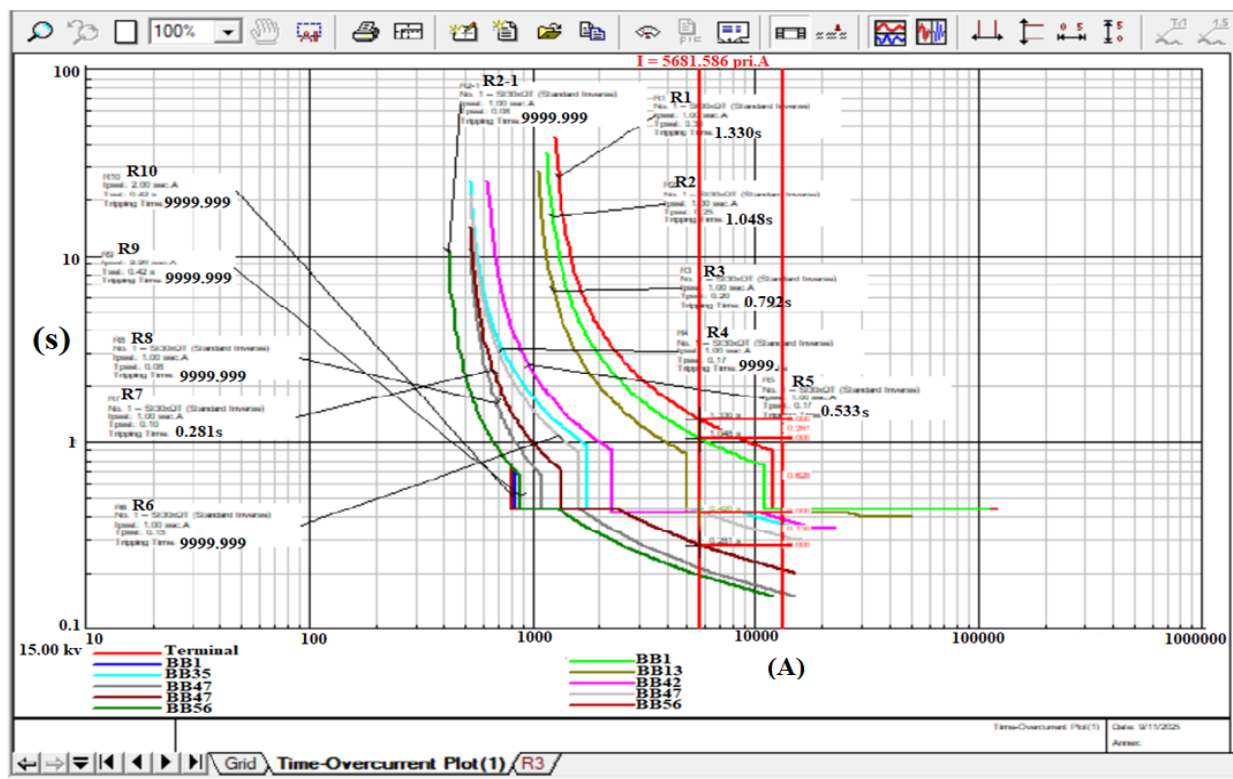


Figure 4. 10 TCC curve for a three-phase fault at the bus 73 of in coordinated case

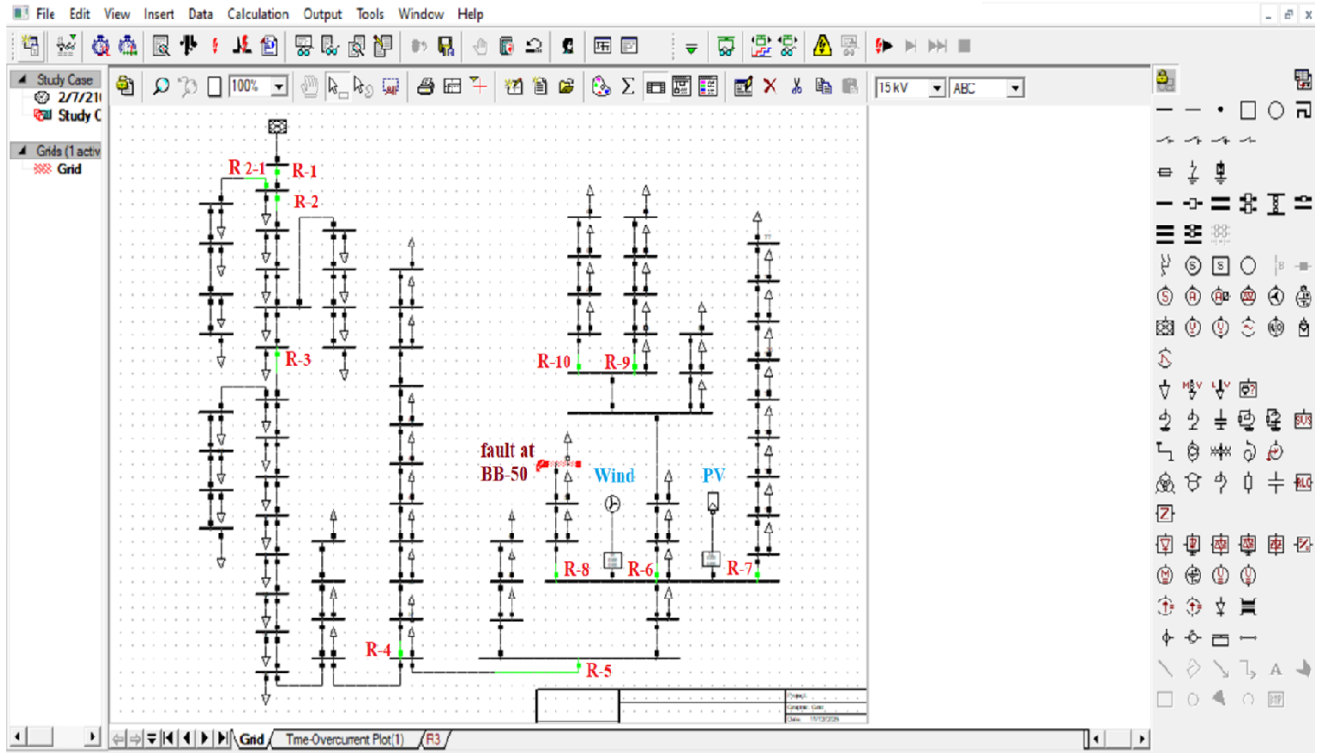


Figure 4. 11 Single-line diagram of the radial distribution feeder with a three phase fault applied at bus 50

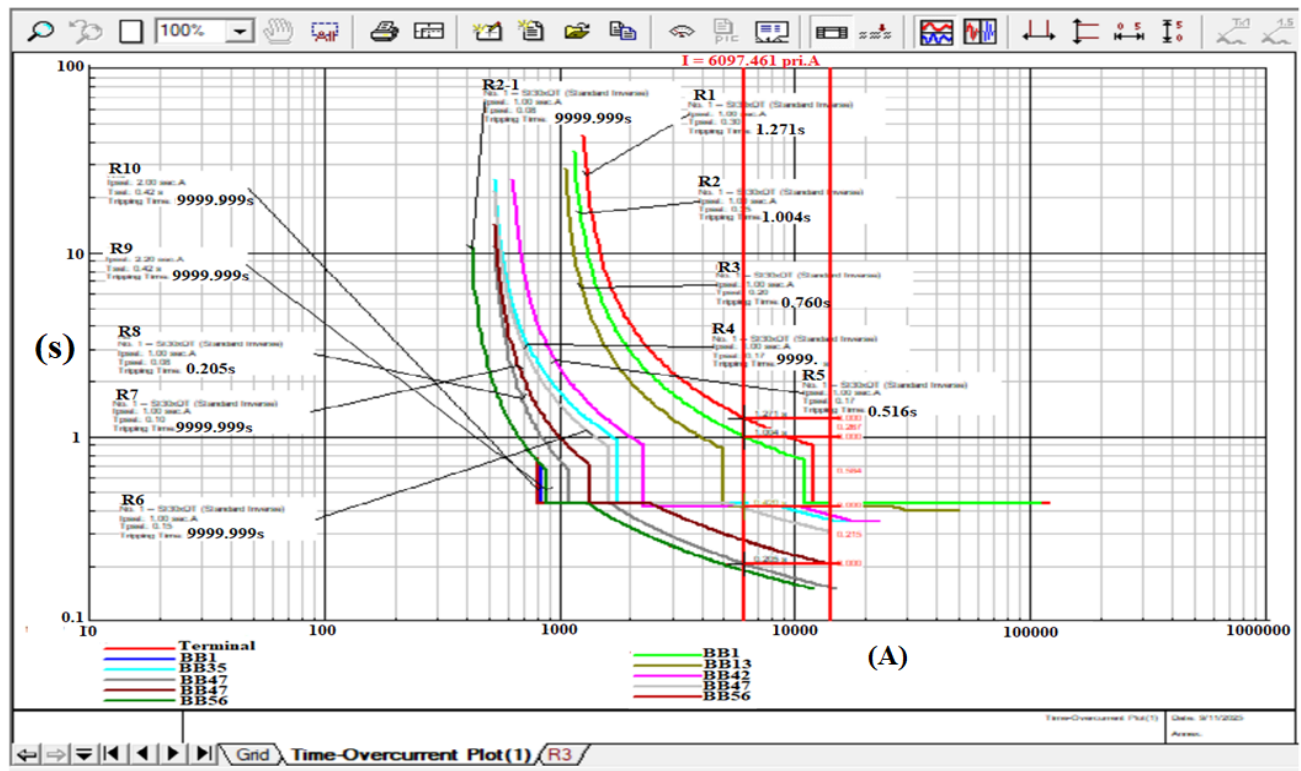


Figure 4. 12 TCC curve for a three-phase fault at the bus 50 of in coordinated case

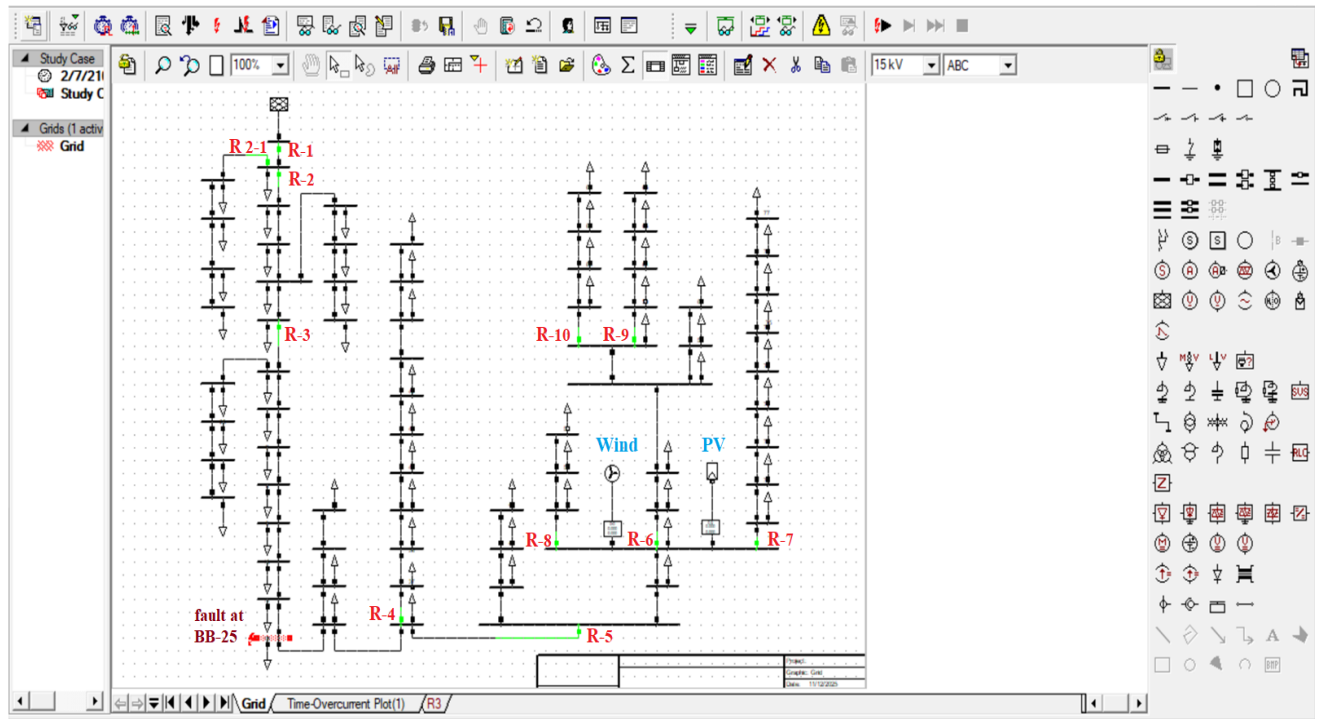


Figure 4. 13 Single-line diagram of the radial distribution feeder with a three phase fault applied at bus 25

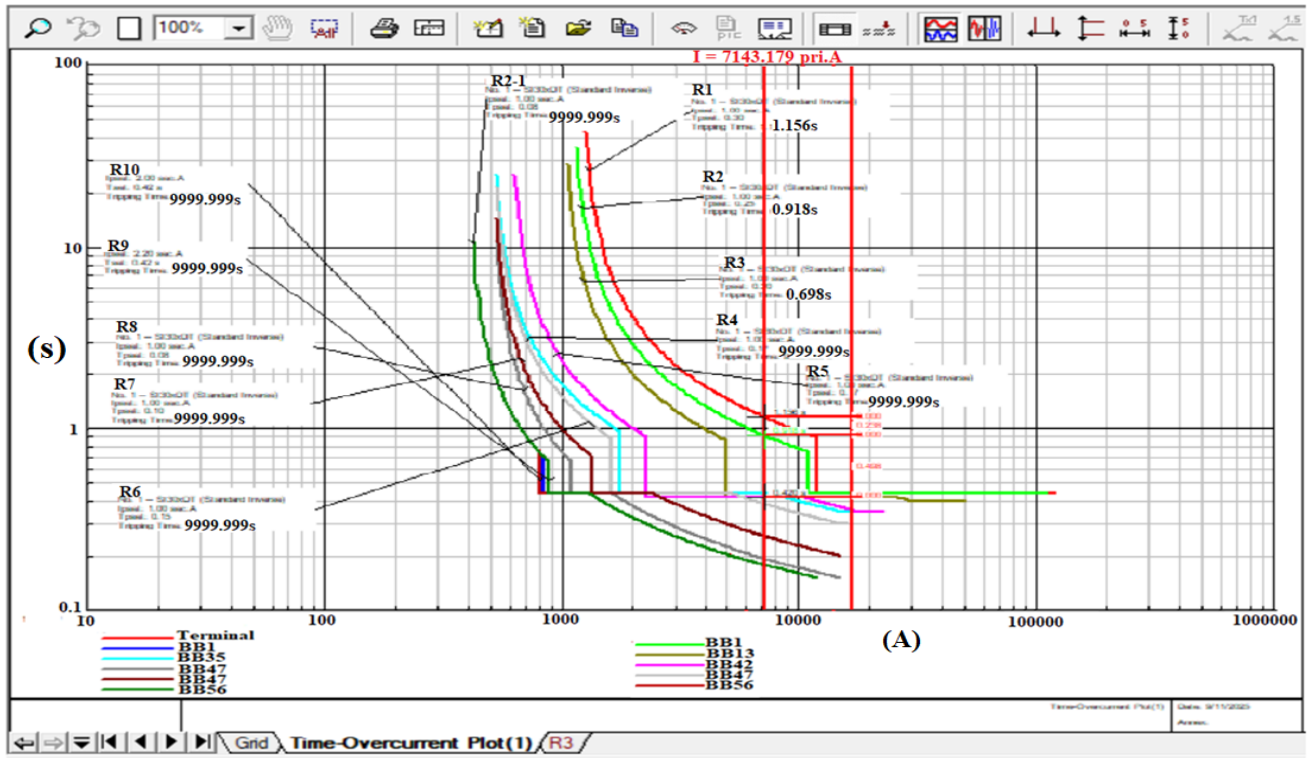


Figure 4. 14 TCC curve for a three-phase fault at the bus 25 of in coordinated case

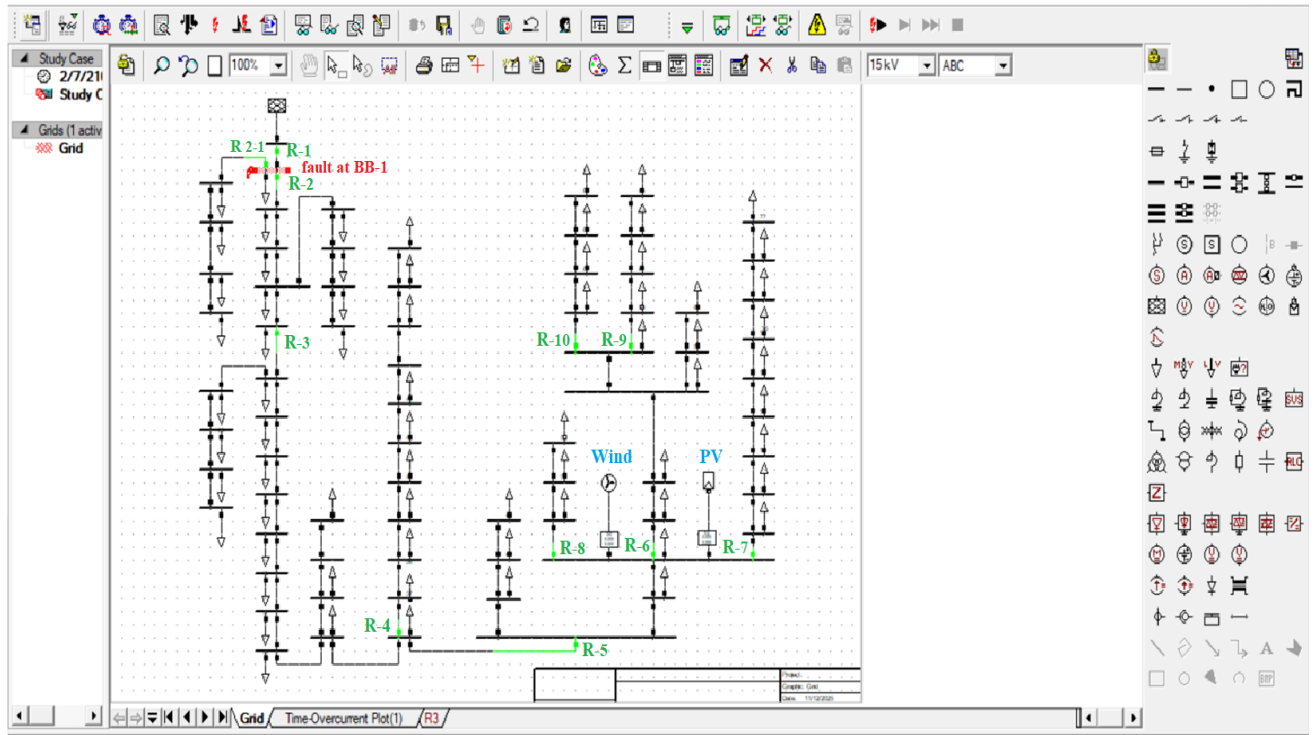


Figure 4. 15 Single-line diagram of the radial distribution feeder with a three phase fault applied at bus 1

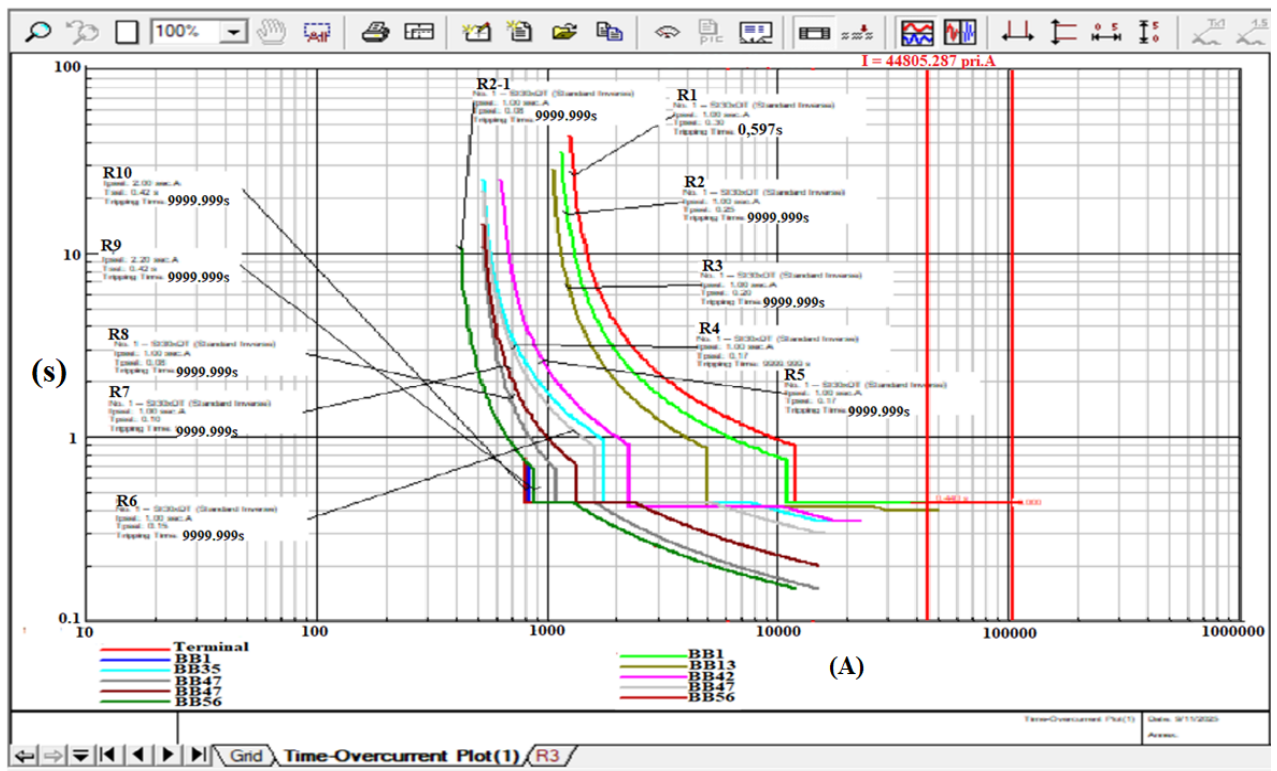


Figure 4. 16 TCC curve for a three-phase fault at the bus 1 of in coordinated case

Relay coordination principle for faults:

In the event of a fault, **F_{BB73}** occurring at the far end of the line, beyond relay R7, the relay coordination scheme ensures selective tripping of breakers in a time-graded manner.

- Relay R7, located at circuit breaker (7) closest to the fault, operates first with a time delay of 0.281 seconds.
- If R7 fails to operate, relay R5 at breaker (5) will trip next, with a higher time setting of 0.533 seconds, which includes the necessary coordination time delay.
- In the event that R5 also fails, relay R3 at breaker (3) – coordinated with R5 – will operate after 0.792 seconds.
- Should R3 fail to clear the fault, relay R2 at breaker (2) will respond next, with a further delayed setting of 1.048 seconds, ensuring proper coordination with R3.
- Finally, relay R1 at breaker (1), located farthest from the fault location, and is set with the longest delay. It will only operate if all upstream relays fail to clear the fault and if the fault current exceeds its pickup threshold.

Similarly, the fault **F_{BB64}** up to **F_{BB1}** has followed the same coordinated principle with fault, **F_{BB73}**.

To verify the relay coordination and its tripping time it must be applied 3 phase unbalance event on the different locations of the radial networks (**BB73**, **BB64**, **BB60**, **BB50**, **BB47**, **BB42**, **BB37**, **BB25**, **BB2**, **BB1** and Terminal) and verified its fault magnitude and relay tripping time as shown in table 4.2.

Since the magnitude of the fault current decreases, the fault moves away from the source.

Table 4. 2 Relay coordination and its tripping time for 3 phase unbalance event at different location of the radial network system.

3 phase unbalance fault location	Fault current (pri. A) in KA	Relay tripping time in second (s)										
		R10	R9	R8	R7	R6	R5	R4	R3	R2-1	R2	R1
BB 73	5.682	9999.	9999	999	0.2	9999	0.53	9999	0.792	9999	1.04	1.33
			.	9.	81	.	3	.		.	8	0
BB 64	5.747	0.192	9999	999	999	0.42	0.53	9999	0.787	9999	1.04	1.32
			.	9.	9.	0	0	.		.	1	0
BB 60	5.752	9999.	0.19	999	999	0.41	0.53	9999	0.786	9999	1.04	1.31
			2	9.	9.	9	0	.		.	0	9
BB 50	6.097	9999.	9999	0.2	999	9999	0.51	9999	0.760	9999	1.00	1.27
			.	05	9.	.	6	.		.	4	1
BB 47	6.329	9999.	9999	999	999	9999	0.50	9999	0.745	9999	0.98	1.24
			.	9.	9.	.	8	.		.	3	2
BB 42	6.850	9999.	9999	999	999	9999	0.49	9999	0.714	9999	0.93	1.18
			.	9.	9.	.	1	.		.	9	5
BB 37	6.757	9999.	9999	999	999	9999	9999	0.45	0.708	9999	0.93	1.17
			.	9.	9.	.	.	8		.	2	5
BB 25	7.143	9999.	9999	999	999	9999	9999	9999	0.698	9999	0.91	1.15
			.	9.	9.	8	6
BB 2	30.94	9999.	9999	999	999	9999	9999	9999	9999.	0.14	9999	0.62
	9		.	9.	9.	.	.	.		9	.	5
BB 1	44.80	9999.	9999	999	999	9999	9999	9999	9999.	9999	9999	0.59
	5		.	9.	9.	7
Terminal	5.682	9999.	9999	999	999	9999	9999	9999	9999.	9999	9999	9999
			.	9.	9.

Table 4. 3 Mitigated case relay coordination performances

Fault Location	Fault type	Fault current (KA)	Primary relay time (s)	Backup relay time (s)	Directional behavior	CTI	Sel.	Unwanted/ Missed trips
BB 73	L-L-L	5.682	0.281	0.533	Correct/forward	0.252	Yes	No
BB 64	L-L-L	5.747	0.192	0.420	Correct/forward	0.228	Yes	No
BB 60	L-L-L	5.752	0.192	0.419	Correct/forward	0.227	Yes	No
BB 50	L-L-L	6.097	0.205	0.516	Correct/forward	0.311	Yes	No
BB 47	L-L-L	6.329	0.508	0.745	Correct/forward	0.237	Yes	No
BB 42	L-L-L	6.850	0.491	0.714	Correct/forward	0.223	Yes	No
BB 37	L-L-L	6.757	0.458	0.708	Correct/forward	0.250	Yes	No
BB 25	L-L-L	7.143	0.698	0.918	Correct/forward	0.220	Yes	No
BB 2	L-L-L	30.949	0.149	0.615	Correct/forward	0.476	Yes	No
BB 1	L-L-L	44.805	0.597	-----	Correct/forward	-----	Yes	No
Terminal	L-L-L	-----	-----	-----	Correct/forward	-----	----	No

4.4.2 Discussion:

The introduction of 11 coordinated relays successfully mitigated DG induced protection issues. The coordination time interval (CTI) between each relay pair was maintained between 0.2 and 0.4s, satisfying IEC discrimination standards. The operating times became stable and consistent, and unwanted trips were eliminated. Although the relays remained non directional, proper grading and pickup current adjustment prevented misoperation due to current reversal. This demonstrates that DG induced faults can be mitigated even without directional relays, through effective coordination and current setting optimization.

4.5 Comparative analysis of the three scenarios:

4.5.1 Behavior comparison across three scenarios:

Table 4. 4 Summary comparisons across the three scenarios

Phenomenon	Base case	DG case	Mitigated case
Blinding	Not present – all fault current comes from the grid, relay sees full fault current.	Present – DG contributes fault current locally, reducing fault current seen by upstream relay. Possible under reach	Mitigated – proper relay settings and coordination ensure fault current is detected and relay trips reliably
Sympathetic tripping	Not present – no DG to feed external faults	Present – DG feeds fault current through relay to external fault. Possible false trips	Mitigated – Increases pickup above DG fault contribution
Islanding risk	Not present – no DG, grid loss leads to complete shutdown	Present – if rid disconnects and DG continues to energize local load, risk of unidirectional islanding	Mitigated – proper relay coordination ensure safe utility workers

4.5.2 Qualitative comparison:

- 1) Base case:
 - Stable operation, all relays function normally
 - Current direction consistent (forward)
 - No miscoordination since fault currents are supplied from one source. However, limited protection coverage with only one relay.
- 2) DG integrated case
 - DG introduces multiple current sources (grid + DG)
 - Fault current direction reverses near DG connection point
 - The non-directional relay cannot distinguish between forward and reverse current leading to
 - protection blinding: relay sees lower grid fault current due to DG support
 - sympathetic tripping relay trips for a fault outside its zone
 - islanding risk due to DG continue supplying when grid disconnected
- 3) Mitigated case:
 - Pickup current and TMS grading successfully restored coordination
 - Fault current direction no longer causes misoperation
 - CTI maintained between 0.2 - 0.4s, satisfying IEC standard
 - Relay operation becomes predictable and selective again
 - DG induced issues blinding, sympathetic tripping, false tripping and islanding risk are eliminated.

4.5.3 Conclusion on DG integrated scenarios:

The DG integrated scenario revealed that the inclusion of inverter based distributed generation significantly alters fault current characteristics and compromises traditional protection. Although DG improves voltage support and reliability in normal operation, during fault condition it:

- Increases local fault current magnitudes
- Causes reverse current flow toward the substation
- Leads to protection blinding in upstream relays
- Induces sympathetic tripping in adjacent relays

In general, DG integrated scenario is clearly concluded through the following table form

Investigated DG induced Challenges	Definition	Cause	Impact on relay protection	Resulting issue	Coordination/grading mitigation strategy
Bidirectional current	Fault current flows both ways (toward and from DG)	DG contribution during faults	Non directional relays lose discrimination	False or missed tripping	Adjust relay grading and pickup current according to DG location
Protection blinding	Relay sees reduced fault current	DG supplies part of fault locally	Relay sensitivity reduced	Fault not cleared in time	Lower relay pickup and TMS settings, adjust CT ratio
Sympathetic tripping	Healthy feeder relay trip during fault on another feeder.	DG back feed current through network	Unnecessary tripping of healthy feeder	Reduced reliability	Increases pickup above DG fault contribution;
Islanding	Portion of system remains energized after grid disconnection	DG continues supplying local load	Faults undetected in isolated section	Safety and stability risk	Fast grading and coordination with under voltage/frequency relays.

CHAPTER 5: CONCLUSION AND RECOMMENDATION:

5.1 Conclusion:

This research investigated the impact of distributed generation (DG), specifically solar PV and wind based sources, on the performance of protection relays in radial distribution networks. The study was carried out through simulations in DIgSILENTpowerfactory and evaluated using six key protection performance metrics.

The findings from the base case showed ideal relay performance with high fault current magnitudes, accurate relay operation, and perfect selectivity. However, when DG was integrated, significant protection issues were observed. These included reduced fault current levels, delaying relay operation, false tripping due to reverse power flow (sympathetic tripping), protection blinding, and islanding risks.

To address these issues, coordination and grading scheme was designed and implemented. The mitigated case showed substantial improvements across all six performance metrics, confirming the effectiveness of the proposed scheme. The results demonstrate that while inverter based DG can degrade traditional over current protection schemes, carefully designed coordination and grading protection strategies can restore system reliability and, protection performance.

To overall conclusion the simulation results demonstrate that:

- DG integration introduces fault current reversals and misoperation among traditional non directional over current relays.
- These issues manifest as blinding, sympathetic tripping, loss of selectivity and islanding risk.
- By applying coordinated CT ratio selection, graded pickup and TMS settings, and using multiple non-directional relays (11), the system regained protection stability and selectivity without requiring directional elements. Therefore, coordinated and graded non directional over current relays can effectively mitigated DG induced protection challenges in low distribution feeders when properly designed.

5.2 Recommendations:

Based on the finding, the following recommendations are made for utilities, engineers and researchers

- ❖ for utilities and practicing engineers
 - Before integration DG, conduct protection studies to assess impacts on relay performance.
 - Maintain pickup current settings higher than DG fault current contribution to prevent sympathetic tripping.
 - Use grading margins of $\geq 0.3s$ between relays to ensure proper selectivity.
 - Regularly review CT ratio selection to avoid saturation during high DG fault currents
 - Adopt non directional coordination as a low cost mitigation approach for moderate DG levels.
- ❖ For policy makers and system planners
 - Develop technical guidelines for DG interconnection that consider relay coordination and protection design.
 - Encourage use of simulation tools like DIgSILENT in DG integration approval processes.
- ❖ For researches
 - Extend this study by exploring adaptive, communication assisted, or hybrid protection schemes for networks with higher DG penetration ($>30\%$).
 - Investigate real time coordination algorithms that automatically adjust TMS settings during DG operation changes.
 - Incorporate different DG technologies (e.g., synchronous based, battery storage) to study dynamic fault current responses.
 - Validate the finding through hardware-in-the-loop (HIL) or field data testing.

5.3 Future research suggestions:

- **Investigation of protection in Complex network topologies:**
Extend the analysis to looped or meshed distribution systems, where coordination and fault directionality are more challenging compared to radial feeders.
- **Economic feasibility analysis of mitigation approaches:**
Conduct a cost benefit analysis comparing traditional and adaptive protection schemes, including investment in coordinated relays, directional relays and communication infrastructure.
- **Integration of fault current limiters (FCLs):**
Explore the application of FCLs as a mitigation strategy to reduce DG induced fault current levels and improve relay performance, especially in high penetration ($>75\%$) cases.
- **Communication -assisted protection for distribution networks:**
Assess the potential of IEC 61850-based communication protocols or synchro phasor-based to improve coordination in distributed protection systems.
- **Development of adaptive protection schemes:**
Investigate adaptive, AI based or real-time reconfigurable protection systems capable of dynamically adjusting relay settings based on system conditions and DG behavior.

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