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Abstract

Protection and control systems are the backbone of modern utility reliability. As electric grids grow more complex, integrating renewables, digital substations, and extreme weather adaptation, the ability to prevent outages depends on how intelligently utilities monitor and respond to faults[35]. The electric grid is growing more complex, not just in scale but in behavior. Integration of renewables, extreme weather risks, aging infrastructure, and bi-directional energy flows mean fault detection and response must be both faster and smarter[35].

This article discussed the importance of protection, DC supply systems, the role of battery banks in modern protection systems, battery chargers, DC distribution systems. This article also discussed the use of circuit breakers in protection systems, including the trip coils, closing coils, auto-recloser etc. Also discussed in this article is transformer protection and control. The transformer vector group, differential protection, Buchholz protection, overcurrent protection, thermal protection, earth fault protection, etc

The role of Supervisory Control and Data Acquisition (SCADA) and substation automation in modern protection systems was equally discussed. The use of automation systems in power system protection and control has helped power engineers to detect and isolate faulty power systems early, which has helped mitigate the extent of damage caused during faults. The integration of protection systems, automation systems, and modern digital systems is important for an efficient and reliable power system.

1.0 Introduction

Electrical protection and control systems are engineered to detect and mitigate faults in power distribution networks, ensuring uninterrupted operation and equipment longevity. These systems combine hardware (e.g., relays, circuit breakers) with software for real-time analysis and response. They are indispensable in industries where power reliability is critical, such as energy, manufacturing, and infrastructure [33].

Modern systems leverage digital technologies like IoT and AI to enhance predictive maintenance and fault localization. Standards such as IEC 60255 and ANSI C37.90 define their performance requirements, ensuring interoperability and safety across global markets [33].

A typical system comprises sensors, protective relays, circuit breakers, and a central control unit. Sensors monitor parameters like current, voltage, and temperature. When anomalies exceed predefined thresholds, relays trigger circuit breakers to isolate the faulty section, minimizing downtime [33].

The control unit processes data from multiple points, enabling coordinated responses such as load shedding or generator activation. Advanced systems use communication protocols like IEC 61850 for seamless integration with SCADA (Supervisory Control and Data Acquisition) systems, providing remote operability and diagnostics [33]**.**

With the advent of Digital technology, electrical control and protection systems have moved from the traditional electro-mechanical design to a more advanced digital and automated systems. Technologies such as SCADA, IOT, and Digital Twins have transformed how substations are monitored and operated.

2.0. Substation DC Supply

2.1. Introduction

The most critical component of a protection, control and monitoring (PCM) system is the auxiliary dc control power system [1], which is very important for the supply of direct current (DC) for the energization of the coil. The DC power supply is not responsible for either transmission or distribution of electric power. It is mainly useful in the area of protection and other auxiliary control system, failure of the dc control power can render fault detection devices unable to detect faults, breakers unable to trip for faults, local and remote indication to become inoperable [1].

In many cases, the dc system is not redundant, which makes reliability an extremely important consideration in the overall design [1].The reliability of the DC power supply plays a key role for the effective operation of the protection system. Alternating current (AC) supply is not usually used for this purpose, because during power failure to the power system, the supply of the AC supply is interrupted. The auxiliary dc control power system consists of the battery, battery charger, distribution system, switching and protective devices, and any monitoring equipment [1]. Proper design, sizing, and maintenance of the components that make up the dc control power system are required [1]. The battery bank helps guarantee the supply of a continuous power supply.

2.2. Components of a Substation DC System:

A substation DC supply system consist of battery bank,battery charger,DC distribution board,monitoring equipment and thr various DC loads connected to the Dc supply source [1,2].

2.2.1. Battery Bank

What is a battery bank?

Batteries are elements designed to store direct current (DC) that can be used when needed. In the industrial field, a battery bank is an electrical energy storage system made up of several connected batteries[4].

These battery banks are used to ensure the operational continuity of a substation or any critical equipment and industrial processes, and also help stabilize the power supply during power outages, power failures or high consumption peaks[4].

Characteristics of battery banks

Battery banks have different characteristics depending on their application and the type of battery used. Among the most important qualities are the following[4]:

Storage capacity and voltage: the amount of energy that a battery bank can store must be proportional to the power supply demand and the requested autonomy time. In addition, each battery, cell or monobloc has a specific voltage, for example, 2V in lead-acid batteries [4] are connected together to achieve a voltage of 110V and 220V DC been used mostly in .

Design flexibility: generally, the capacity of a battery bank is measured in ampere-hours (Ah), determined by the amount of energy it can store. This capacity must be modulable by connecting batteries in series or in parallel in order to adapt the system to different voltage and energy requirements, considering environmental and operating conditions [4].

Protection and useful life: the structure of a battery bank must be protected by metal enclosures. In addition, management systems, such as the Equalizer, help to ensure optimum performance and long service life. The latter is influenced by the depth of discharge, and moderate use is recommended to preserve battery capacity in the long term [4].

Types of battery banks

There are several types of battery banks according to their characteristics, use, and performance required, for example[4]:

Lead acid batteries:

They are the most common and economical as they have a wide range of industrial applications such as UPS and backup systems. However, these batteries charge slowly and can store between 70 to 85% of electrical energy[4].The lead-acid battery is preferred for substation use.

Gel batteries:

They are a type of sealed lead-acid battery that offers greater safety and requires less maintenance compared to traditional lead-acid batteries. Their gel electrolyte significantly reduces the risk of leaks and spills, making them ideal for applications where safety is paramount. They also have a longer service life and greater tolerance to deep discharges[4].

Lithium or lithium ion batteries:

These are more expensive than the others, because they deliver higher efficiency, durability, energy density and require very little maintenance. Because of these characteristics, lithium ion batteries have recently been the most widely used in electric cars and are more attractive for solar power banks[4].

Nickel cadmium batteries:

Nickel-cadmium batteries, such as NiCd and NiMH, were pioneers, but have been overtaken by other technologies. NiCd batteries are common in portable electronic devices due to their endurance, but have a limited lifetime. These batteries offer improvements, but their capacity and cycle life are inferior to those of lithium batteries, which dominate the market today[4].

2.2.2. Battery Charger

A Battery Charger is an important element of auxiliary power systems (APS) , which supplies DC Supply to the Substation DC Loads and at the same time continuously charges the Substation Battery Set[5].As earlier mentioned the charger is responsible for supplying DC voltage to the battery bank and ensures the battery bank is constantly charged at all times via its control system. The capacity of the battery bank; represents equipment of vital importance for the system of its own services of direct current in a substation[1].Requires inspection, operation, and calibration or adjustment routines fundamentally.

Chargers are not just “battery maintainers”—they are the primary DC source during normal operation. IEEE 946 covers charger/rectifier sizing and regulation, ripple considerations, ground detection, and distribution[2]. Good practice is to size the charger(s) for the entire continuous load plus the required recharge current within a specified time after a discharge event[2]. Where availability is critical, use parallel redundant chargers with output isolation, coordinated setpoints, and alarms[2].

It is advisable to have two chargers for purposes of backup, thereby providing greater reliability to the power system direct[4].Redundancy should extend beyond rectifiers. Many utilities deploy two independent battery/charger/DC-panel sections at the same nominal voltage, with a normally open bus-tie so that a single failure does not compromise all tripping and control. This approach increases availability and simplifies maintenance; the tie can be closed under supervision when needed [4].

Monitoring and compliance round out a robust design. NERC PRC-005 requires a documented Protection System Maintenance Program that includes station DC supplies, with defined activities and intervals. Utilities may adopt time-based maintenance or qualify performance-based intervals where permitted [4].

Battery monitors and ground-fault detectors are key enablers: IEEE 1491 describes which parameters add diagnostic value (cell or unit voltage, string current, internal resistance/conductance, temperature, ripple, and ground-fault indication) and how to specify monitoring systems. Tie alarms into SCADA so operators see degraded conditions early[4].

Different modes in which the Battery Charger Operates

There are two modes: Boost Mode and Trickle or Float Mode[5]:

1) Trickle or Float Mode:This is Constant Voltage Mode, by which it supplies Trickle-Charging Current to Battery as well as Station Load[5].

i) Even though there is no load on the Battery, there is a Local Discharge which drains the Battery. In this mode, BC Floats the Batteries at 2.25 V Per Cell with a Stabilization of + 1% of the Floating Voltage, so as to keep the Battery in fully Charged condition all the time and compensate for the local discharge[5].

ii) Supplies Constant Voltage to the Substation DC Load.

2) Boost Mode:

It can be used in CC or CV Modes.

It is used for charging the Battery in quick time, after a full or a partial Battery Discharge[5].

2.2.3. DC Distribution Board

Power Distribution Board is designed to provide multiple voltages to support Power, Circuit Breaker, over Ethernet, Battery charging, PLC power, and Ethernet Switch power[6]. The DC distribution panel receives its DC power supply from the battery. The primary function of the substation DC distribution Board is to distribute DC power to all electrical equipment inside the substation that requires a DC power supply, through the various connected feeders. They are usually protected by DC breakers or fuses.

2.3 Operation of Substation DC Supply System.

In Substation Whether it is MV or HV, DC supply is used for Protection, Metering, monitoring, and measurement purposes [7]. We all know that our whole distribution system is AC so why is DC supply used in the substation? DC can be stored in a battery; DC is less complex as it has only magnitude [7].

Substations use DC power supply because a lot of essential devices in the substation rely on DC power source for it supply. Devices like trip coils, relays, alarms, SCADA, and control circuit breakers must remain energized during periods of supply interruption. If an AC supply is used in a substation, if used for protection, during a fault condition where the whole system has no power supply, all connected relays will be turned off, making it difficult to extract fault data or “Disturbance recorder” from the numerical relay to analyze the fault and conclude anything about fault. So, something is necessary that is available in blackout conditions to restore your system [7].

DC Voltage level can be 24V, 48V, 110V and 220V DC.

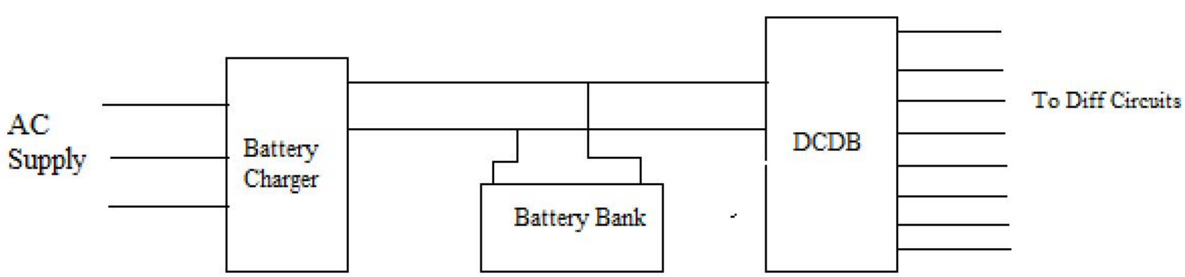


Figure 2.1 DC Supply system.

Operation principle

DC power supplies are essential for substations, as they power various control systems and devices [8]. From battery banks to other powered systems, a consistent and reliable DC power supply is indispensable in substations. While many wonder why a DC supply is needed instead of an AC supply, the answer lies in its unique advantages and versatility [8].

While most devices and consumer electronics rely on AC energy for power, portable substations continue to operate on DC energy. DC supply has been widely used in substations and portable power applications for many years. The primary reason for using a DC supply in substations is to ensure a continuous power supply throughout the control circuit. DC power is reliable, easily directed from a battery source, and facilitates portable substation solutions [7].

The Alternating Current (AC) auxiliary in the substation feeds the battery bank charger directly. The charger, with the aid of its electronic components, converts the AC supply to DC, which is used to supply the substation DC loads and to charge the battery bank. If the AC power supply to the substation is cut off or fails, the battery bank instantaneously takes over to supply all the connected DC loads in the substation without these devices experiencing any form of interruption. Essential devices like SCADA, protection relay, circuit breaker trip and close coils, emergency lighting, communication equipment, and control circuits will all continue to function without interruption. As soon as the AC power supply is restored to the substation, the battery charger resumes supplying the DC load and also charging the battery.

What the DC System Must Do

Trip and close breakers and operate lockout relays and motor operators. These actions must be available even when the AC station service is unavailable. Guidance documents for low-voltage auxiliary systems emphasize that DC auxiliaries are a critical substation function to ensure safe operation during disturbances[2].

Power protection and control. Protection relays, logic, and interlocking depend on the DC bus and are explicitly recognized as part of the Protection System. NERC PRC-005 includes the “station DC power supply associated with a protective function, including station batteries, battery chargers, and non-battery-based DC power supplies,” placing maintenance and documentation obligations on owners [2].

Keep the substation visible and controllable. SCADA RTUs/IEDs, time sources, and communications often ride on the station DC (sometimes via DC/DC converters), so the DC system is fundamental to situational awareness and remote control when it matters most. The substation auxiliary guide frames these AC and DC auxiliaries together as the foundation of operability [2].

Nominal DC voltages commonly selected for power applications include 24 V, 48 V, 125 V, and 250 V, with use depending on device ratings, distance, and fault-tolerance requirements (for example, 125 Vdc for trip/close circuits and 48 Vdc for communications). IEEE design practice addresses coordination, ride-through, and component voltage ranges for such systems.

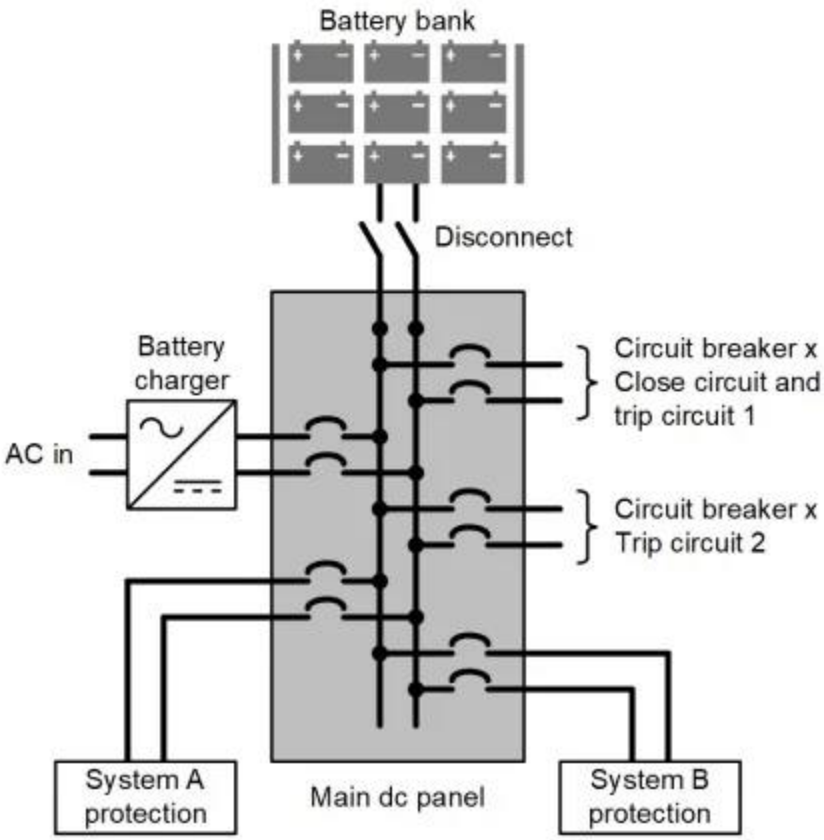


Figure 2.2 Typical DC system. Image used courtesy of Schweitzer Engineering Laboratories (SEL).

2.4 DC Loads in a Sub-Station:

1. Circuit breaker trip and close coil
2. Protective Relay
3. Switchgear controls
4. SCADA and Remote terminal unit
5. Emergency Lighting
6. Alarm systems.
7. Fire detection and security system
8. Fire detection and security system.

2.5 Substation Battery Sizing

Batteries are the lifeline to substations, providing backup power. I'm going to go over a typical substation battery sizing calculation[34].

We'll take it step by step, highlighting the key factors you need to consider for various substation loads. But first, let's take a moment to appreciate the vital role these batteries play in keeping our world electrified[34].

Substations are the heart of the power grid, transforming voltage levels and ensuring we have electricity to light up our homes and charge our devices. Without them, we'd be left in the dark. That's why substations rely on batteries to guarantee their essential operations can function around the clock [34].

Determine the load profile over the autonomy period

Size a battery bank to have sufficient capacity to provide the required energy over the autonomy period, accounting for:

(i)System voltage

(ii)Temperature

(iii) Aging

(iv) Maximum depth of discharge

(v) Rate of discharge

Steps of battery sizing for 220V

Data

1. Type of battery = Valve Regulated Lead Acid type

2. Nominal Battery Voltage (NBV) = 220 V

3. No of cells = 220/2 = 110 Nos As each VRLA cell has a voltage of 2 V (approx.)

4. End cell voltage after discharge (for Discharge Rate of C10) = 1.8 V

5. Load cycle considered

a. Continuous load (Control & Relay Panel) = 10 hours

b. Emergency load (Lighting) = 1 hours

c. Momentary load (Simultaneous Tripping) = 1 min

6. Average electrolyte temperature = 24 Deg.C.

7. Load Determination

Sl	Equipment / Panel	Quantity	Load per Unit (W)	Total Load (W)
a	33 kV Twin Feeder Control & Relay Panel	6	120	6 × 120 = 720
b	33 kV Bus Section Control & Relay Panel	1	61.5	1 × 61.5 = 61.5
c	33 kV Capacitor Bank C&R Panel	2	57.5	1 × 61.5 = 61.5
d	220/33 kV Transformer LV Side C&R Panel	2	98.5	2 × 98.5 = 197
e	220 kV Line C&R Panel	1	137.5	1 × 137.5 = 137.5
f	220/33 kV Transformer HV Side C&R Panel	2	168.5	2 × 168.5 = 337
g	33 kV Bus Coupler Panel	2	200	2 × 200 = 400

h	220/33 kV Transformer RTCC Panel	1	79.5	1 × 79.5 = 79.5
i	Switchyard SAS Panel (RTU)	1	52	1 × 52 = 52
j	Synchronizing Panel	1	86.2	1 × 86.2 = 86.2
k	Battery Charger	2	200	2 × 200 = 400
l	Fire Fighting System	2	15	2 × 15 = 30
m	PLCC & FOTE	2	240	2 × 240 = 480
n	Miscellaneous DC Loads	—	—	0
	Total Load a+b+c+d+e+f+g+h+i+j+k+l+m+n			3095.7 W

Total continuous load current (L1)

= Total continuous load / Battery voltage = 3095.7 /220 = 14.07 A

2.6. Reliability and Portability

DC power remains a reliable source for portable applications. The battery can provide a continuous supply until fully discharged, while generators can recharge the battery, ensuring a consistent power flow from other sources while the system is being recharged[8].

3.0 Circuit Breaker Control and Protection

3.1 Introduction

Every time you flip a switch and a light comes on, you're at the receiving end of a chain that began at a power plant, climbed to hundreds of kilovolts for long-distance transmission, was stepped down at one or more substations, and finally arrived at your premises at a usable voltage[9]. That chain — generation, step-up, transmission, step-down, distribution, delivery — is the power system. It is also, at every point, exposed to faults:

insulation that fails, trees that fall across lines, lightning that strikes, animals that bridge a gap, equipment that simply wears out[9].

When a fault happens, enormous energy concentrates at one spot in milliseconds. Left alone, it damages expensive equipment, starts fires, and can injure or kill people. Power system protection — also called protective relaying — is the discipline that detects these abnormal conditions and removes the affected part of the system quickly and accurately, before the damage spreads[9].

It is often described as a blend of science, art, and skill: science because it rests on circuit theory and fault analysis, art because two competent engineers can defend different settings, and skill because it is only as good as the person applying and commissioning it. The purpose statement is refreshingly simple and has not changed in a century[9]:

Prevent injury to personnel.

Minimize damage to system components.

Limit the extent and duration of service interruption.

The protection of a substation as evolved over the years from electro-mechanical devices to intelligent and computer-aided systems capable of monitoring the protection system in real time.

3.2 Objective of Substation Control and Protection

The main purpose of a substation is simple: it helps move electricity safely and efficiently from where it is generated to where it is used. A substation receives power, changes the voltage when needed, controls the flow of electricity, and protects the power system from faults[10].In other words, an Electrical Substation is like a control center in the power grid. It does not usually generate electricity by itself. Instead, it makes sure electricity can travel long distances, reach the right places, and be delivered at a usable voltage for homes, factories, commercial buildings, renewable energy projects, and public infrastructure[10].

Electricity often travels a long way before it reaches users. To reduce power loss during long-distance transmission, electricity is usually sent at very high voltage. But that high voltage is not suitable for most equipment, buildings, or local power networks [10]. This is where a substation comes in. A power substation can step voltage up for transmission or step it down for distribution. For example, electricity may leave a power plant at one voltage, be increased for long-distance travel, and then be reduced again near a city, industrial park, or residential area [10]. Without substations, the grid would be less efficient, less stable, and much harder to protect. Substations help keep power supply reliable, reduce energy waste, and make electricity safer for everyday use [10].

Electrical faults can happen because of short circuits, overloads, lightning, insulation failure, or equipment problems. A substation uses circuit breakers, relays, surge arresters, fuses, and grounding systems to detect and isolate these faults quickly [10]. This protection is not just about equipment. It also helps reduce fire risk, improve worker safety, and avoid long power outages [10]. The primary objective of a substation control and protection system is for safe and reliable operation of the power system. The protection system also ensures that equipment failures and disturbances are reduced. A good and reliable protection system detects quickly and isolates all affected sections of the power system before they cause damage to the system.

The control system of a substation enables engineers and operators to monitor the equipment performance and operate the substation equipment. Modern systems now monitor and control the equipment in real time. Operators can check voltage, current, transformer temperature, breaker status, and fault alarms without being on site all the time[10].

3.3. Components of a Substation Control

Substation components are essential for the safe and efficient operation of power systems, including transformers, circuit breakers, busbars, insulators, and relays. These parts help manage voltage levels, protect against faults, and ensure the stable distribution of electricity[11].

Main substation components include **power transformers**, **circuit breakers**, **busbars**, **current transformers (CTs**), **potential transformers** (PTs), **isolators**, **lightning arresters**, and **control panels**. These elements work together to transform, protect, and distribute electricity safely from transmission to distribution levels[11].

Power transformers are responsible for stepping down high-voltage electricity for safer distribution[11]. Transformers in substations utilize electromagnetic induction to convert high-voltage electricity to lower levels, making it safe for use in homes and businesses. Oil-immersed cores with windings facilitate efficient power transfer, while cooling methods such as fans or natural convection regulate temperature and prevent overheating [11].

Circuit breakers automatically interrupt faulty currents, preventing damage to essential equipment[11]. Circuit breakers are primarily responsible for connecting and disconnecting power circuits during normal operation and faults. They can rely on automatic operation, that is, they receive commands from protection relays, and manual operations, where operators manually open or close the breakers. Protection relays send commands to open the breaker during fault conditions.

Circuit breakers in substations are vital for protecting the grid from electrical faults. They quickly detect and isolate fault currents, such as short circuits or overloads, to prevent damage to equipment [11]. Different types, including SF6, vacuum, and oil breakers, each offer distinct advantages in fault interruption and maintenance requirements[11].

Protective relays are key to the safety of substations. They monitor electrical parameters like current, voltage, and frequency, detecting faults such as overcurrents or earth faults. When a fault is detected, the relay automatically trips the circuit breaker, isolating the faulty section and preventing further damage [11].

With digital relays becoming more common, they offer faster, more precise protection by using advanced algorithms to selectively isolate faults. Busbars facilitate power distribution, and relays detect operational issues, allowing for quick response and system protection [11].

Busbars and insulators are critical components in electrical distribution and system safety [11]. When selecting busbars, factors such as current rating and fault-withstand capacity are important considerations. Insulators, on the other hand, should be chosen based on creepage distance to prevent flashovers, especially in areas with high pollution [11].

Materials such as copper and aluminum are commonly used for busbars, each offering a balance between cost and conductivity [11]. insulation testers help verify the dielectric strength of insulators, ensuring they can withstand high-voltage conditions without failing. These tests are essential for confirming the reliability of substation components and preventing costly system outages [11].

The current transformer evaluates the system's higher currents by taking samples using a current transformer. These condensed samples accurately reflect the system's natural high currents. These employees install and maintain protection-related current relays, typically with low operating current ratings[12].

Potential Transformer

Like a current transformer, potential substation protection equipment samples high voltages from a system. It delivers low voltage to relays for a protection system and low-rating meters for voltage measurement. This low-voltage measurement comes from the AC system's high voltage. It reduces the expense of the measurement device [12].

Lightning arrester

A distribution's most important safety feature is a lightning arrester. It protects people and costly equipment from lightning strikes. During lightning strikes, the system prevents excess electricity from accumulating and discharges it to the ground. These are put between a line and the earth close to the equipment [12].

Capacitor bank

Because these capacitor banks serve as a source of reactive power, they can lessen the phase gap between voltage and current. They will boost the supply's capability for ripple current. It steers clear of the system's negative traits. A cost-effective solution exists to preserve power factors and correct power lag issues.

3.4. Substation Protection System.

In real-world power systems, a single power plant often supplies electricity to a large region—serving homes, schools, hospitals, factories, and more. A wide-area power outage can cause severe inconvenience and significant economic loss. Ensuring the stable and reliable operation of the power system is therefore essential [13]

In power distribution, electrical substations play a key role in ensuring that electricity reaches different customers efficiently and safely [12]. These modern substations play a vital role in electric power systems. They convert, control, and distribute electrical energy from one power source to another [12].

Substations house crucial equipment that manages electrical flow. They protect infrastructure and maintain operational safety. Substation protection equipment includes various incoming and outgoing circuits [12].

The substation protection system is designed such that its relays, with the aid of current transformers, voltage transformers can detect abnormal conditions and disconnect the system from the fault, so as to prevent damage to the system.

A protection relay is an intelligent device used to monitor electrical parameters such as current, voltage, frequency, and phase angle. When it detects abnormal conditions—such as overcurrent, short circuit, or voltage instability—it sends a trip signal to the circuit breaker, isolating the faulted section from the rest of the system [12].

In a substation, the protection relay functions as the “nervous system” of the grid—detecting faults rapidly, pinpointing their locations accurately, and ensuring system stability and safety [12].

Main Types of Substation Protection Relays

(1) **Overcurrent Relay (OCR)**

Function: Detects when current exceeds a preset value, indicating overload or short circuit.

Applications: Transformer protection, feeder protection, motor overload protection[12].

(2) **Earth Fault Relay (EFR)**

Function: Detects leakage current caused by insulation breakdown or ground faults.

Applications: Transformer winding protection, cable insulation monitoring.

(3) **Distance Relay (Impedance Relay)**

Function: Measures the impedance between the relay and the fault location; lower impedance indicates a fault closer to the relay.

Applications: Transmission line protection in high-voltage substations.

(4) **Differential Protection Relay**

Function: Compares the current entering and leaving an electrical component (e.g., transformer, generator); any difference indicates a fault within the protection zone.

Applications: Transformer differential protection, generator protection, busbar protection.

(5) **Directional Overcurrent Relay (DOCR)**

Function: Detects overcurrent and determines the fault current’s direction.

Applications: Parallel feeder systems, ring networks.

(6) **Overvoltage/Undervoltage Relay**

Function: Monitors voltage levels and trips when voltage exceeds or drops below acceptable limits.

Applications: Voltage regulation in substations, generator protection [12].

(7) **Frequency Relay**

Function: Detects abnormal frequency deviations, indicating generator load imbalance.

Applications: Generator and grid protection in power plants and substations[12].

(8) **Digital (Microprocessor-Based) Relay**

Function: Integrates multiple protection functions in one device, offering advanced settings, self-diagnostics, and communication features.

Applications: Modern intelligent substations, automated power grids.

During a short circuit fault, earth fault, or equipment failure, the installed protection relays detect the signal with the aid of the current or voltage transformer and compare it with its set values and determines weather to isolate the system. If the parameters received exceed its set limit or tolerance margin, the relay issues a trip signal to the circuit breaker [12].

A current transformer in a substation is a precision instrument transformer that samples the high primary currents flowing through transmission and distribution circuits and scales them down to standardized low-level outputs, typically five amps or one amp, suitable for feeding protective relays, metering equipment, and monitoring systems without exposing sensitive instrumentation to dangerous high-voltage circuits. CT accuracy class and burden rating are critical selection parameters because errors in current measurement directly compromise the sensitivity and selectivity of differential protection, overcurrent relays, and revenue metering systems that depend on accurate fault current detection to operate correctly[12].

Operation, Maintenance, and Fault Handling of Protection and Automation Devices

(1) **Pre-Commissioning Checks**

Before a protection relay or automation device is put into service, it must undergo a series of thorough checks to ensure all functions are intact and capable of executing protection and control tasks accurately and promptly[12].

Key checks include:

- Inspecting the exterior and internal components for damage.
- Verifying correct wiring.
- Confirming protection settings match specified values.
- Ensuring no personnel are present in the circuit during commissioning.
- Checking relay enclosures and seals for integrity.
- Restoring all secondary circuit connections.

Commissioning/Decommissioning Sequence:

- Ensure AC power supply is stable.
- Sequentially energize DC power, checking relay contacts, signal lights, and meters for accuracy.
- Engage the protection link panel and measure terminal voltages.
- For shutdown, follow the reverse sequence.

- Routine patrol inspections by on-duty personnel are essential to maintain safe and reliable operation.

(2) Operation and Maintenance [12]

- During operation, regular inspections are required to confirm normal conditions and address potential abnormalities.
- Daily Inspection Items:
- Verify status of secondary circuits and link panels.
- Check relay cases, contacts, indicator lamps, and signal relays for irregularities.
- Ensure switches, isolators, fuses, and connecting plates are correctly positioned and in good contact.
- Inspect protective indicator lamps, signal relays, and meters for abnormal readings.

- Confirm relay coils, terminals, and wiring insulation are intact.

Functional Testing:

In addition to daily patrols, periodic functional testing is vital. A protection relay tester can simulate various fault conditions in the power system and verify that the relay responds correctly by issuing fault signals and operating as intended [12].

Whether located near power plants or integrated into local grids, substations are designed to withstand extreme operating conditions. Properly maintained substation protection equipment is crucial for ensuring the smooth operation of electrical generation, transmission, and distribution. Investing in high-quality components and safety measures helps optimize system performance while protecting workers and assets [12].

(3) **Fault Handling and Recordkeeping**

When an abnormality occurs, follow established procedures to record the relay's operation and, if necessary, remove the device from service. For example[12]:

- If the relay itself malfunctions or risks false tripping.

- If the AC voltage circuit in a protection device fails.

Such cases require immediate corrective measures and prompt reporting to the responsible supervisor.

(4) Operational Status Verification

Special attention should be given to microprocessor-based protection and automatic transfer devices[12]:

- Confirm display and indicators are accurate.
- Check for overload, overheating, or unusual odors.
- Inspect device panels for alarm signals.

A healthy relay should have no abnormal messages on the LCD, no lit fault LEDs, and a green "in service" indicator illuminated[12].

Verify link panels are correctly clamped and remote control switches are in the proper position[12].

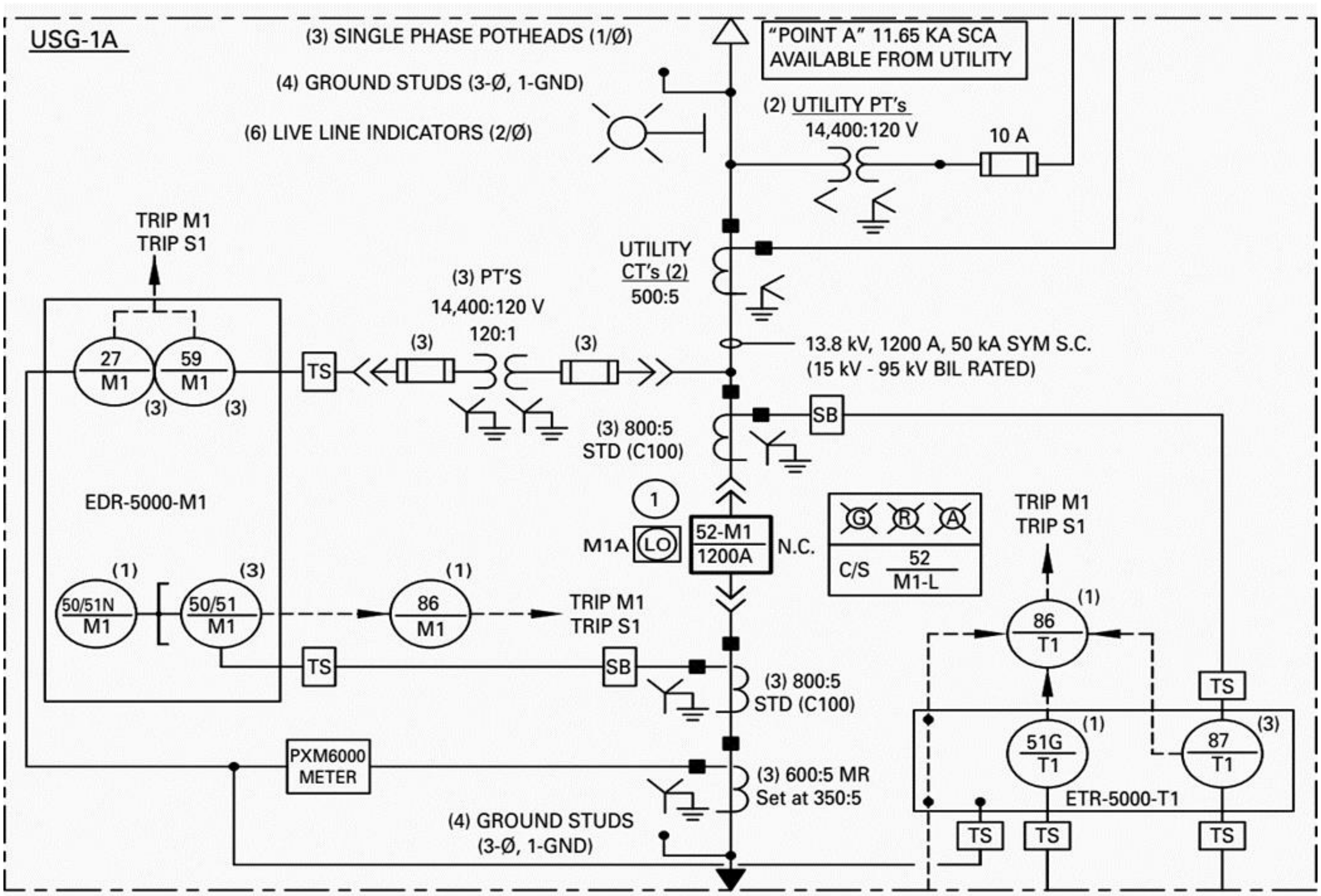


Figure 3.2. Single line diagram of a Protection system

3.5. Major Protection Function

Modern substation has several protection functions incorporated in it. This is done for an effective and well-coordinated protection system.

1. Overcurrent Protection

2. Earth Fault Protection.

3. Differential Protection

4. Distance Protection

5. Busbar Protection

6. Breaker Failure Protection

7. Transformer Protection

8. Overvoltage and undervoltage protection

9. Overfrequency and underfrequency protection

10. Thermal overload protection.

Each of the various protection systems is designed to detect a specific fault in the power system. They operate in coordination with other protection systems for an effective protection.

Most substation now has adopted automated substation, to help monitor and control the substation. The automated substation helps improve the efficiency of the operating and monitoring system, with minimal human intervention.

4.0. Advance Protection System of a Substation

4.1. Introduction:

Modern electrical substations are the backbone of reliable power transmission and distribution networks [14]. As the power grid becomes increasingly complex with renewable integration, inverter-based resources, digital automation, and cybersecurity concerns substation protection design must evolve to ensure system reliability, safety, and operational resilience[14].

Protection engineering is one of the most critical disciplines in substation design[14]. It ensures that faults are detected instantly and isolated with minimal disruption to the rest of the power system [14]. Without properly designed protection schemes, faults could propagate across the network, damage expensive equipment, and cause widespread outages [14].

The design and operation of the protection system is such that they respond to faults efficiently. They have both the primary protection system and also the backup protection system for the purpose of both reliability and efficiency.The backup protection system is expected to respond and protect the system, should in case the primary protection system fails. The advance protection system include the circuit breaker failure protection; the auto-recloser system; The synchronization system; The differential protection system; The distance protection system and also modern communication system. The substation protection design integrates advanced relaying, SCADA systems, fault analysis methodologies, and modern digital relay technologies to create highly reliable protection architectures for transmission and distribution networks[14].

4.2 Objectives of The Advanced Protection System:

The primary objective of using the advance protection system is to achive the following:

(i) To achieve a better operational reliability and protection of primary substation equipment [14].

(ii) Protect Personnel and the general public from electrocution[14] in the event of faults, insulation breakdown, earth leakage etc.

(iii) Help maintain power system stability [14].

(iv) Prevent equipment damage during fault condition [14].

(V) Minimize time of service interruption and fault clearing time [14].

(vi) The advanced protection system help provide backup protection,in the event that the primary protection system fails.

(vii) Provide automatic disconnection and restoration during period of faults and temporal faults

(viii) Provide intelligent substation automation using using AI,SCADA system and Digital Twins.

A protection system monitors electrical quantities such as [14]:

- Current
- Voltage
- Frequency
- Power flow
- Impedance
- Temperature
- Phase angles

These measurements are continuously analyzed by protective relays to determine whether the system is operating normally or experiencing abnormal conditions [14].

If a fault occurs, the relay sends a trip command to a circuit breaker, isolating the faulted equipment or transmission line [14].

This automated response typically occurs within milliseconds, preventing cascading failures across the power system [14].

4.3. Circuit Breaker failure protection (50BF)

If a breaker fails to be triggered by a tripping order, as detected by the non-extinction of the fault current, this backup protection sends a tripping order to the upstream or adjacent breakers [15].

Breaker Failure Protection is also called Local Breaker Backup (LBB) Protection or Stuck Breaker Protection or Back Tripping Protection. As the name suggest, it is a back protection when circuit breaker fails to operate when a relay sense the fault and send trip signal to Circuit Breaker. ANSI code is 50BF[16].

During a fault situation, the protective relay on detecting a fault sends a trip command to the breaker responsible for tripping the fault. The breaker is expected to open within an average time of 50milliseconds.If the breaker fails to trip within the set time, the breaker failure relay initiates the backup tripping, by tripping another breaker.

Main objective of Protection System is to clear the fault with:

i) Minimum Time delay. Ideally it should be 0 msec but practically it takes 2-3 cycles so that

damages to power system is minimum. 0 msec means no intentional time delay[16].

ii)Minimum disruption to the Power System. It means that only faulty section should be isolated from rest of the healthy system [16].
For example, in figure (i) as the fault is in the section BC so protection system should isolate section BC only.

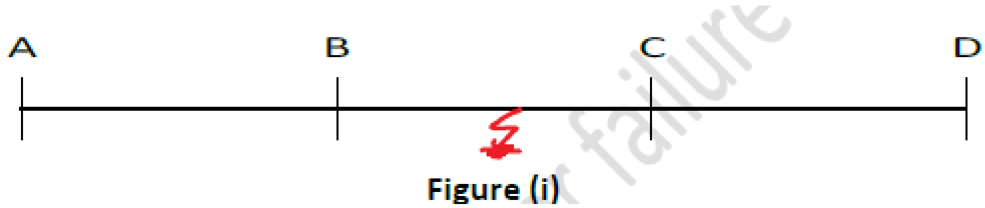


Figure 4.1

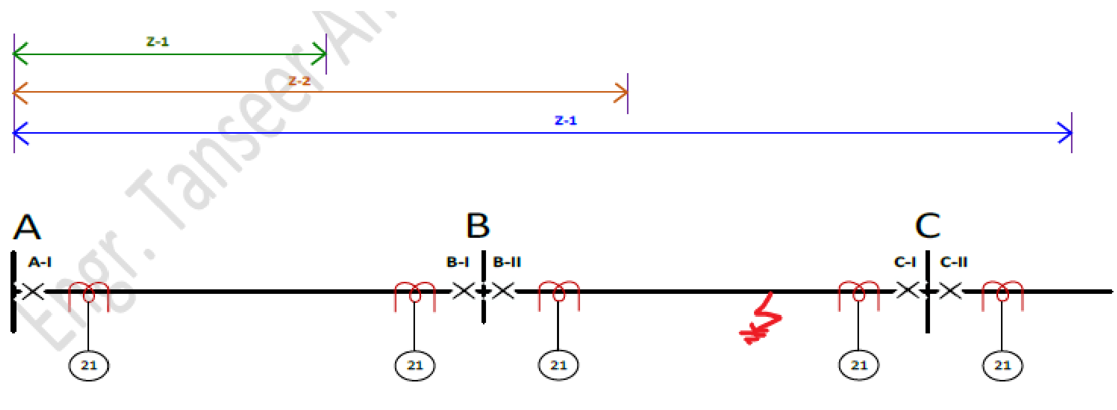
There are two kinds/forms of backup protections [16]:

1. Remote Backup

2. Local Backup

Remote Backup Protection:

In Distance Protection/Relay, Zone-2 and Zone-3 are Remote Backup Protection[16]



(ii)

Suppose a fault occur in section BC. For this, relay at location B-II and C-I should operate and trip their respective circuit breaker and isolate section BC[16].

Let relay at C-I operates and issue trip command to its circuit breaker and it opens. But due to some reasons circuit breaker at B-II doesn't open. Possible reasons can be [16]:

i. Relay doesn't sense the fault.

ii. Relay senses the fault but output contact of relay doesn't make.

iii. Relay sense the fault and output contacts of relay also make but breaker doesn’t open.

In short, CB doesn’t open at B-II. So, fault will be continuously fed from the end A and will damage the system [16].

For the above fault, relay at A-I will also sense/pick-up the fault in Z-3 and will isolate the fault after 700 msec. Here Z-3 act as Remote Backup but it is slow which is one of the disadvantages of remote backup[16].

Advantages of Remote Backup[16]:

a) It is not affected by the local station condition. If we make backup at station B (local backup) and if there is any problem in circuit breaker itself than local backup will not work. Remote Backup is independent of local station condition[16].

b) It takes care of both the failure i.e. Relay and CB failure (at station B)[16].

Disadvantages of Remote Backup:

a) It is slow as we have seen that Z-3 clears the fault in 700msec [16].

b) It has limited discrimination, as for the fault in section BC, it also trips the section AB [16].

Local Backup Protection:

Consider the same fault as in Figure (ii). As previously discussed, let relay at C-I operate and issue a trip command to its circuit breaker, and it opens, but the circuit breaker at B-II doesn’t open[16].

We have two scenarios[16]:

i. Relay doesn’t sense the fault. To counter this problem or to provide backup, we use a 2nd relay (Duplicate protection or relay backup). In grid Main-1 and Main-2 or Distance protection Set-I and Set-II are used, usually of different manufacturers.

ii. Relay sense the fault and issue trip command to CB but CB doesn’t open. For this we duplicate the tripping coil of Circuit Breaker (two trip coils) and install Breaker Failure relay.

From the above discussion it is clear that two types of Local Backup can be considered:

a. Relay Backup- Provision of duplicate main protection schemes (Distance Relay Set-I and Set-II) [16].

b. Circuit Breaker Backup- Cannot Duplicate the circuit breakers due to economical and technical reasons. For example, two circuit breaker in series or parallel. If one doesn't operate than other will etc [16].

- We duplicate trip coils but physical mechanism (spring, pneumatic etc) for both the trip coils remains the same. Failure is still possible [16].

- Our problem of local backup is not solved only by the above, so we use Breaker Failure Relay.

Advantages of Local Backup[16]:

a) It is fast as compared to Remote Backup

b) It can make discrimination between the faulty section and healthy section.

Disadvantages of Local Backup:

a) It is affected by the local station condition. Like if Set-I doesn't sense the fault Set-II may not

also sense the fault as both are affected by the local conditions.

b) Accidental operation chances are there. Due maintenance work tripping may occur for

example BF relay Stage-II operate.

4.4. Auto- Reclosing Protection (ANSI 79)

1. **Automatic Reclosing (ARC)** Core Function Automatic Reclosing (ARC) is a protection relay in power systems that attempts to reclose a

circuit breaker after a fault is cleared, distinguishing between transient faults (e.g., lightning strikes, tree contact) and permanent faults (e.g., equipment damage) [17].

2. **Automatic reclosing operation steps**

Step 1: Fault Detection & Trip   When a short-circuit or ground fault occurs, protection relays (e.g., overcurrent, distance protection) detect abnormal current/voltage and trigger the circuit breaker to trip (typical response time: 20ms–100ms)[17].

Step 2: Dead Time Delay

After tripping, the system enters a ”dead time” to allow arc extinction or transient fault recovery (typical delay):

Overhead lines: 0.3s–1s (IEC 62271-1)

Cable lines: 1s–5s (due to higher likelihood of permanent faults)[17]

Step 3: Reclosing Attempt

After the delay, the ARC issues a closing command to the breaker.

If the fault has cleared (transient), normal power supply resumes [17].

Step 4: Lockout Decision

If the fault persists (permanent), the protection trips again and locks out ARC (no further attempts) to avoid repeated short-circuit stresses (standards: typically 1–3 reclosures allowed) [17].

The Auto-reclosing can be:

- Single-Shot
- Double-Shot
- Triple-Shot
- Multi-shot

Setting Techniques include:

- Dead time
- Reclaim time

- Number of reclosing attempts
- Lockout time

3. Key technical parameters of automatic reclosing

Reclosing attempts: Usually 1–3 (IEEE C37.104 allows up to 4)

Success rate: >80% for transient faults in overhead lines

Activation logic: Requires breaker status, voltage absence, and protection signals (IEC 61850 compliant) [17]

4. Typical applications of automatic reclosing

Transmission lines: Rapid recovery after lightning strikes (success rate >90%)

Distribution automation: Coordinates with FTUs (Feeder Terminal Units) for fault isolation

Renewable plants: Anti-islanding protection for collector lines[17]

5. Safety & Design Considerations

Synchronism check: For double-ended lines, verify voltage magnitude/phase (<10° deviation)

Anti-pumping protection: Prevents breaker cycling on permanent faults (mechanical/electrical)

Communication-aided: Fiber-optic differential protection can shorten delays (e.g., 0.1s)

Note: Always disable ARC during maintenance and follow the “de-energize, test, ground” safety protocol (GB 26860) [17].

4.5 Synchronism-Check Protection (ANSI 25)

This function checks the voltages upstream and downstream of a circuit breaker and allows closing when the differences in amplitude, frequency and phase are within authorized limits [18].

Improper synchronization of electrical sources can have damaging effects on a power distribution system, resulting in electrical and mechanical transients that can destroy prime movers, generators, transformers and other critical components [19].

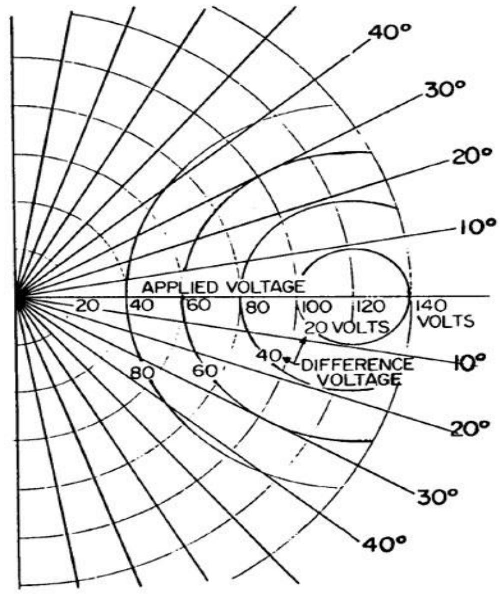
Synchronism (sync) relays are used to verify that the voltages on either side of a circuit breaker are in the proper phase and magnitude relationship. The relay will permit a closing operation when both the bus and line voltage are approximately normal, equal, in phase, and of the same frequency[19].

The primary application of the sync check relay is in situations that require verification of synchronism prior to closing a circuit breaker. These scenarios include the paralleling of a generator to a system, reestablishing an interconnection between two parts of a power system, and supervision of fast motor bus transfer schemes, high-speed reclosing schemes, etc.[19]

Basic Sync Check Principles

Closing characteristics of the sync check relay are determined by the magnitude of vector difference voltage setting, typically anywhere from 0-80 volts at the relay. A smaller difference voltage setting allows for a more restrictive synchronization criteria[19].

The time delay setting determines how long that the two sources must be synchronized before the relay output contacts will transfer. The time delay is influenced by the difference voltage setting and is commonly set in a range between 1-15 seconds[19].



Typical voltage difference closing characteristic. Photo: ABB[19].

Should the two sources fall out of synchronization before the end of the time delay, the timer will reset to zero and the output contacts will not transfer. A longer time delay setting will therefor allow a more restrictive synchronization criteria[19].

Frequency is another critical factor in the synchronization process that requires a slip of 0.1Hz or less between sources to obtain relay operation. Longer time delays will require sources match their frequency within this tolerance for longer as exceeding 0.1Hz will restart the time delay[19].

Relay manufacturers provide curves for maximum slip frequency at which closing will occur as a function of the relay's time delay and difference voltage setting[19].

Modes of Operation for Sync Check Relays

Synchronism check relays may be equipped with several different operating conditions in addition to the "normal" sync check function to allow closing of the output contacts when either the line or bus is dead.

The basic options provided are:

Hot Bus – Dead Line (HBDL)

Hot Line – Dead Bus (HLDB)

Combined – HBDL or HLDB

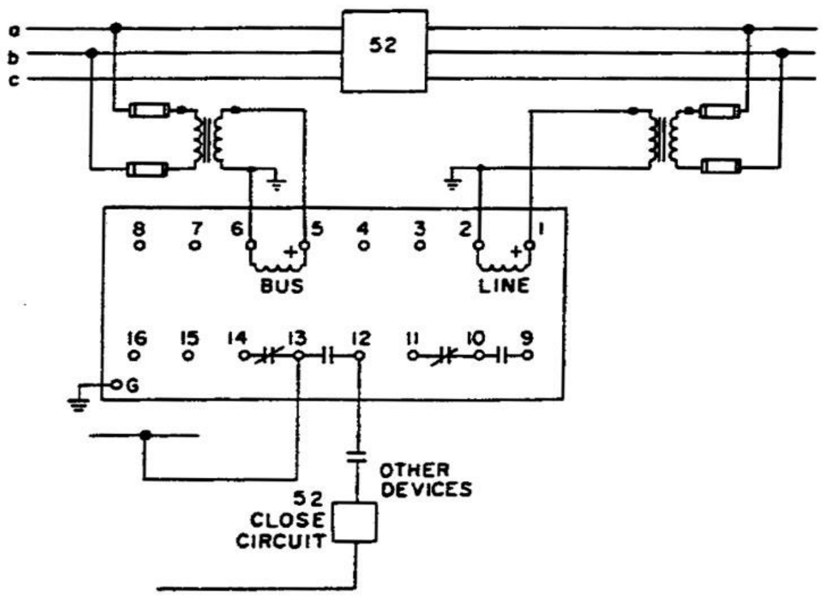


Figure 4.3. Basic test connections for Sync Check (25) Relays. Photo: ABB[19]

Check functional operation of each element used in the protection scheme[19]:

(1)Determine closing zone at rated voltage.

(2) Determine maximum voltage differential that permits closing at zero degrees.

(3)Determine live line, live bus, dead line, and dead bus set points.

(4)Determine time delay.

(5)Determine advanced closing angle.

(6)Verify dead bus/live line, dead line/live bus and dead bus/dead line control functions.

Functional Testing

In addition to the inspection and testing of protective relays, it may be desirable to prove the correct interaction of all sensing, processing, and action devices as a complete unit by means of system functional tests[19].

Lock-out relay and block close circuits should be tested, along with relay self-test, power supply failure, and trip coil monitor alarms back to SCADA. Bus restoration and/or transfer switches should be verified as functional[19].

Built in test functions allow for simple verification when both sources to the relay are energized and in sync. With self-test equipped relays, pushing a button will typically simulate a loss of synchronization and return the output contacts to their de-energized position. When the button is released, the relay will pickup and start the timing process before returning the contacts to the energized position[19].

The self test function should never be used as a substitute for secondary-injection tests[19].

Upon completion of testing, control circuits and current transfer circuits should be restored to normal operation. Verify that all systems are left in normal operating mode or position, transfer and restoration schemes are enabled, and monitoring and protection devices are operational[19].

Characteristics [18]

- adjustable and independent set points for differences in voltage, frequency and phase
- adjustable lead time to take into account the circuit-breaker closing time
- 5 possible operating modes to take no-voltage conditions into account.

4.6. Distance Protection:

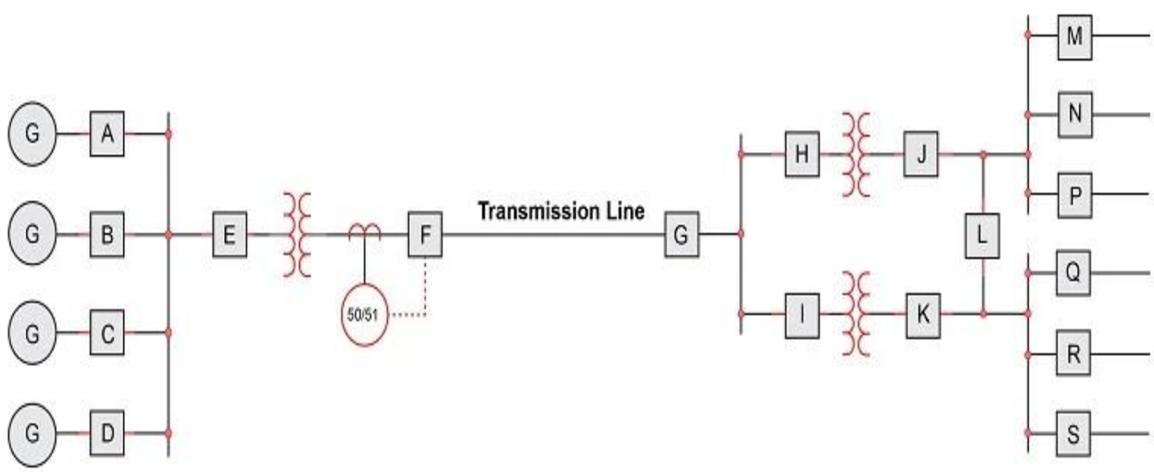
What Is a Distance Protection Relay?

Distance relaying is used to detect faults on long-distance lines, pinpointing not only the fault condition but also measuring the distance between the current sensing mechanism and the fault location in the wire[20].

A form of protection against faults on long-distance power lines is called distance relaying, so named because it is actually able to estimate the physical distance between the relay's sensing transformers (PTs and CTs) and the location of the fault. In this way, it is a more sophisticated form of fault detection than simple overcurrent (e.g. 50 or 51 relay). The ANSI/IEEE number code designation for distance relaying is 21[20].

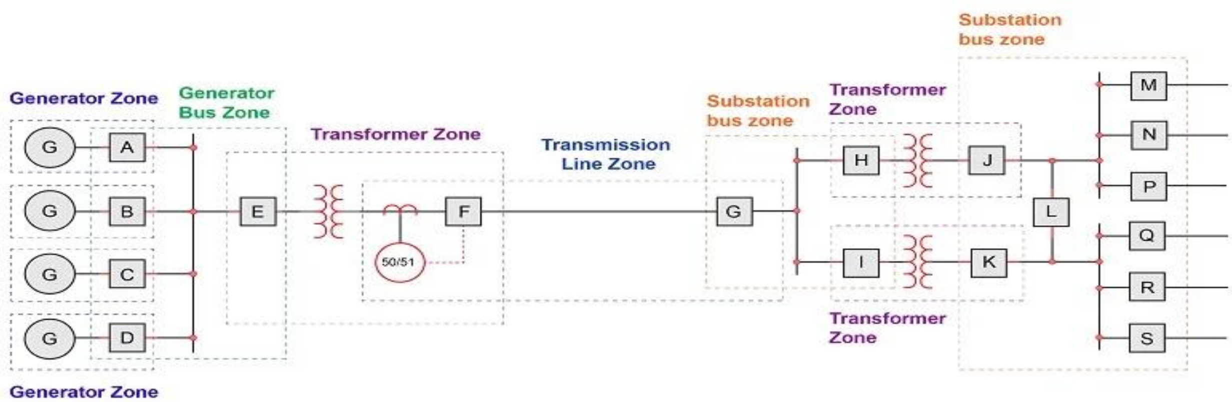
Distance Relay Reach

In order to understand the rationale for distance relaying on transmission lines, it is useful to recognize the limitations of simple overcurrent (50/51) protection. Consider this single-line diagram of a transmission line bringing power from a set of bus-connected generators to a substation at some remote distance. For simplicity's sake, only one protective relay is shown in this diagram, and that is for breaker "F" feeding the transmission line from the generator bus[20]:



The purpose of the overcurrent relay tripping breaker "F" is to protect the transmission line and associated equipment from damage due to overcurrent in the event of a fault along that line, and so the relay must be set appropriately for the task[20]. The amount of fault current this relay will see depends on several factors, one of them being the location of the fault along the transmission line. If we imagine a fault occurring on the line near breaker “F,” the fault current will be relatively high because it is close to the generator bus and therefore experiences little transmission line impedance to limit current[20]. Conversely, if we imagine a fault farther out on the transmission line (closer to breaker “G”), the amount of current caused by the fault will be less, even for the exact same type of fault, simply due to the added series impedance of the transmission line’s length (if I=$\frac{V}{Z}$ and “Z” increases while line voltage “V” remains the same, “I” must decrease). Any similar fault further downstream of the generators – such as a fault in one of the transformers in the substation – will draw even less current through breaker “F” than a similar fault on the transmission line for the same reason of greater series impedance [20].

An important concept in protective relaying is that of protection zones. Protective relays exist to protect the power system from damage due to faults, and they do so by tripping circuit breakers to interrupt the flow of power to a fault [20]. However, in the interest of maintaining power to customers, it is best for protective relays to only trip those breakers necessary to clear the fault, and no more[20]. Thus, protective relays are designed to trip specific breakers to protect limited “zones” within the system. In this next single-line diagram, we show the same system with rectangular zones overlaid on the system components [20]:



This zone diagram makes it clear that breaker “F” and its associated overcurrent relay should only act to protect the transmission line from fault-induced damage[20]. If a fault happens to occur within one of the transformer zones within the substation, we would prefer that fault be cleared by the protective relays and breakers for that transformer alone (i.e. either breakers “H” and “J” or breakers “I” and “K” depending on which transformer faults), in order that power be maintained in the rest of the system[20]. This means the overcurrent relay controlling breaker “F” needs to be sensitive to faults within the transmission line zone, but insensitive to faults lying outside of the transmission line zone[20]. If the 50/51 relay happened to overreach its zone and trip breaker “F” because of current sensed from a fault in one of the substation transformers, it would unnecessarily cut power to the entire substation, with a loss of power to all loads fed by that substation [20].

At first, the problem of overreaching may seem simple to solve: just calculate the maximum fault current in the transmission line due to any worst-case fault outside of that zone, and be sure to set the overcurrent relay so that it will only trip at some current greater than that amount, or set it so it will trip after a longer time delay than the substation relay(s) will trip, to give the substation relays a chance to clear the fault first [20].

The weakness of this approach is that fault location is not the only factor influencing fault current magnitude[20]. Another important variable is the number of generators in service at the time of the fault. If one or more of the generators happens to go off-line, it reduces the generator bus’s ability to supply current to a fault [20]. Another way of saying this is that the power source’s impedance changes with the number of generators on-line. This means any given fault downstream of breaker “F” will cause less fault current than it would if all generators were on-line [20].

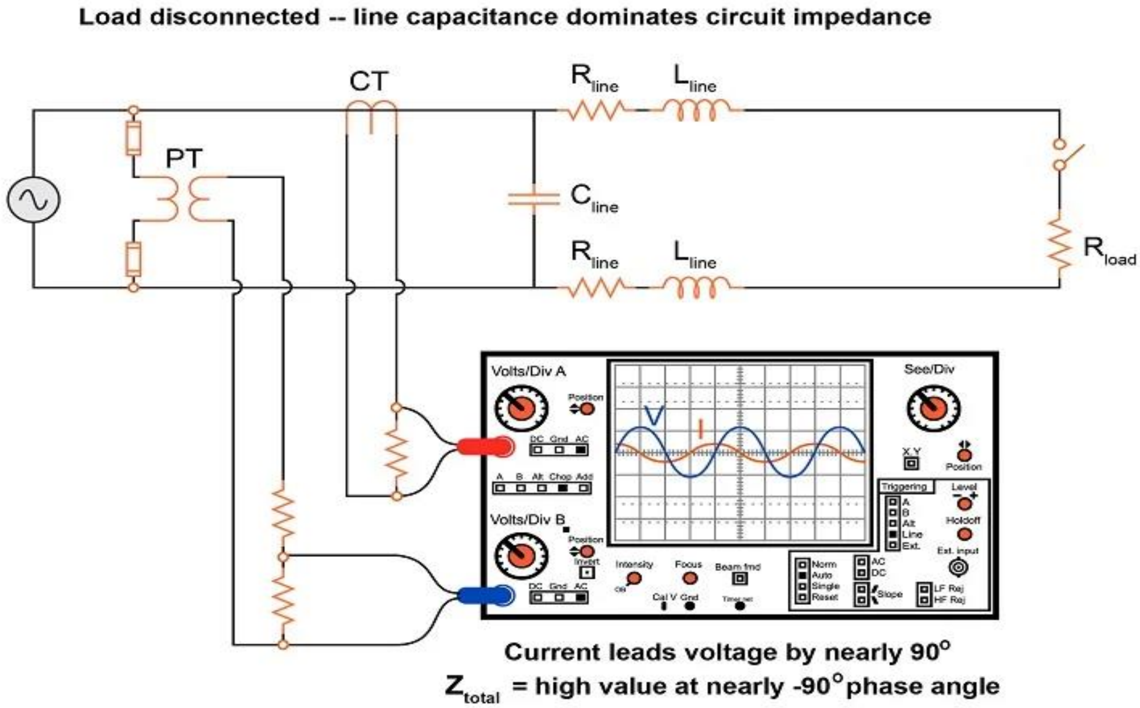
This causes a problem for the “reach” of the overcurrent relay controlling breaker “F.” With reduced current capacity from the generator bus, the same relay setting that worked well to protect the transmission line zone will now be too high for faults lying toward the far end of that line[20]. In other words, the overcurrent relay may underreach and fail to trip breaker “F” because the amount of fault current for a transmission line fault is now less than what the relay has been set to protect against, and all because we happen to have fewer generators on-line to supply power [20]. The impedance of the transmission line and fault may be precisely the same as before, but the overcurrent relay will not trip because the circuit's total impedance has changed due to fewer generators being on-line [20].

We see that the location of a fault within a long-distance power distribution system cannot be reliably detected by sensing current alone[20]. In order to provide more consistent and reliable zone protection for the transmission line, we need a form of protection better able to discriminate fault location[20]. One such method is to measure the impedance of the protected zone, based on current and voltage measurements at the entry point of power into that zone [20]. This is the fundamental concept of distance protection: calculating the impedance of just the protected zone, and acting to trip breakers feeding power to that zone if the impedance suggests a fault within the boundaries of that zone [20].

Line Impedance Characteristics

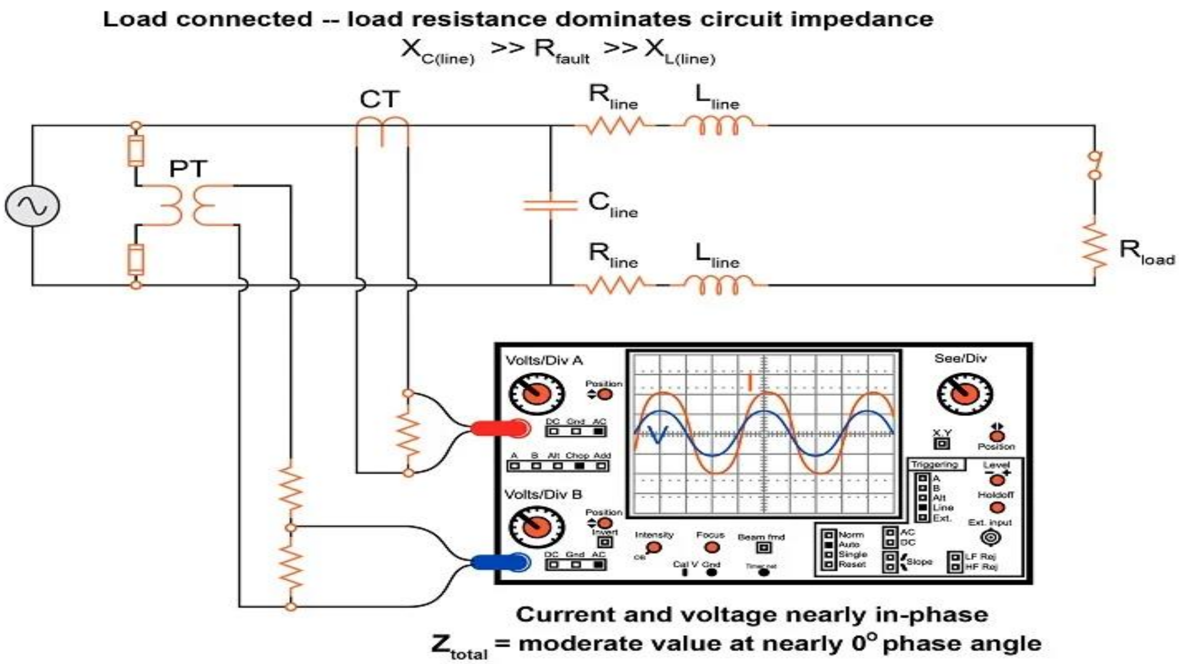
Capacitance, inductance, and resistance are all naturally present along miles of power line conductors: capacitance due to electric fields existing within the separation of the lines from one another and from earth ground by the dielectric of porcelain insulators and air; inductance due to the magnetic fields surrounding the lines as they carry current; and resistance from the metal conductors' length [20].

The capacitive nature of a power line is evident when that line is open-circuited (i.e. no load connected). For the next few schematic diagrams, only a single phase (one "hot" conductor and one "neutral" conductor) will be represented for the sake of simplicity [20]:

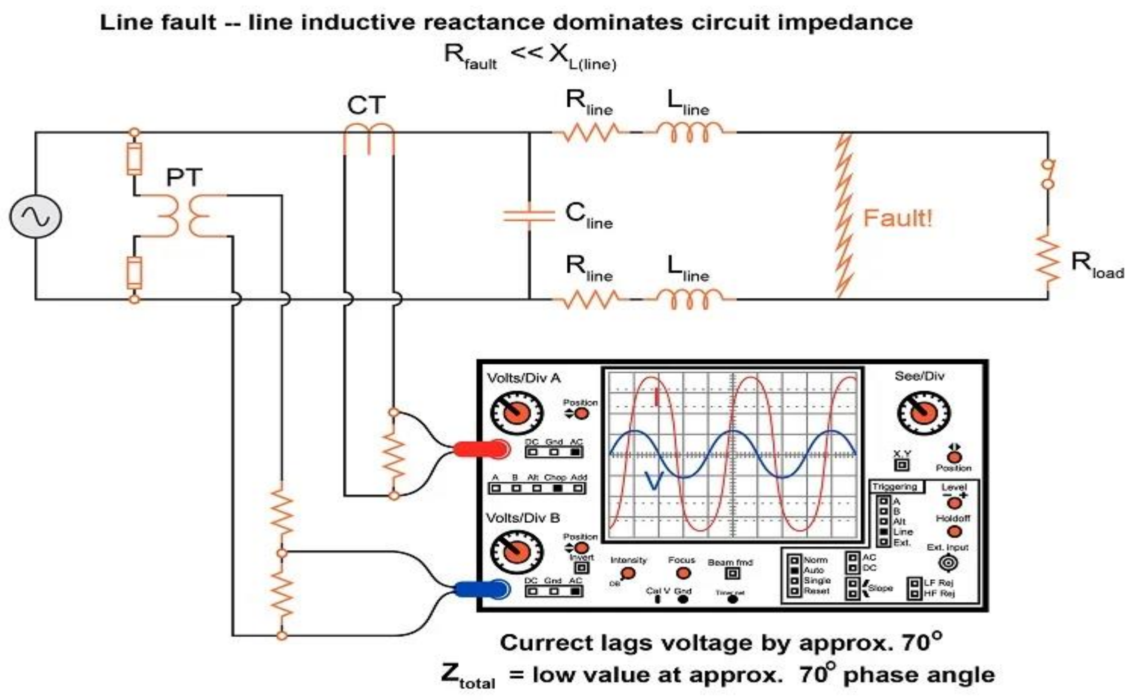


Here, an oscilloscope shows the relative magnitudes and phase shifts of the voltage and current waveforms, allowing us to make determinations of total circuit impedance ($Z=\frac{V}{I}$)[20].

Under typical load conditions, the resistance of the load draws a much greater amount of current than an open-circuited line draws due to its own capacitance[20]. More importantly, this current is nearly in-phase with the voltage because the load resistance dominates circuit impedance, being substantially greater than the series reactance caused by line inductance while being substantially less than the parallel capacitive reactance[20]:

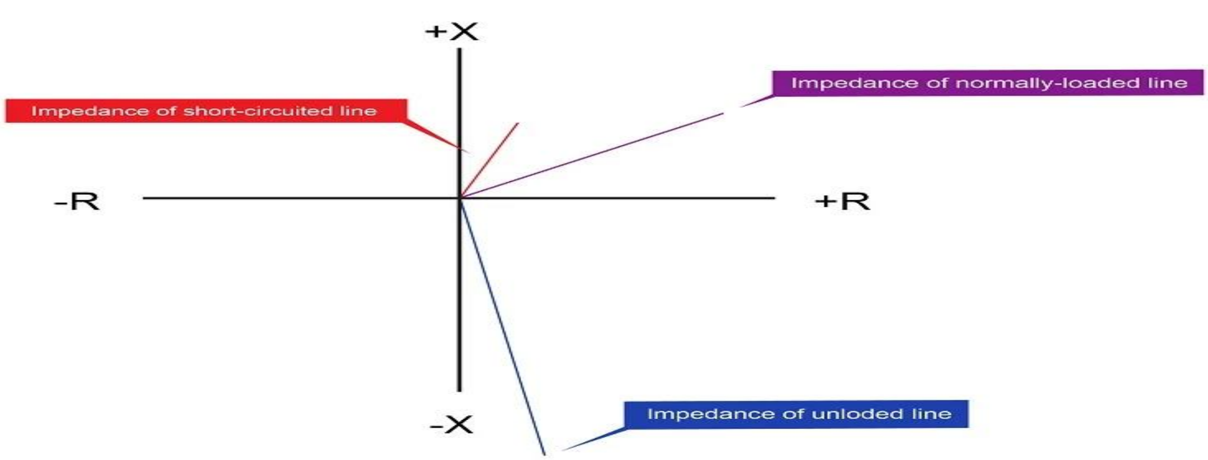


A significant fault behaves like a very low resistance connected in parallel. This not only decreases total circuit impedance but also shifts the phase angle closer toward +90º because now the line inductive reactance is substantial compared to the resistance of the fault[20]. Real transmission lines tend to exhibit shorted impedance phase angles nearer 70 degrees rather than 90 degrees, owing to the effects of line resistance. The exact line impedance phase angle depends on conductor size and separation[20]:



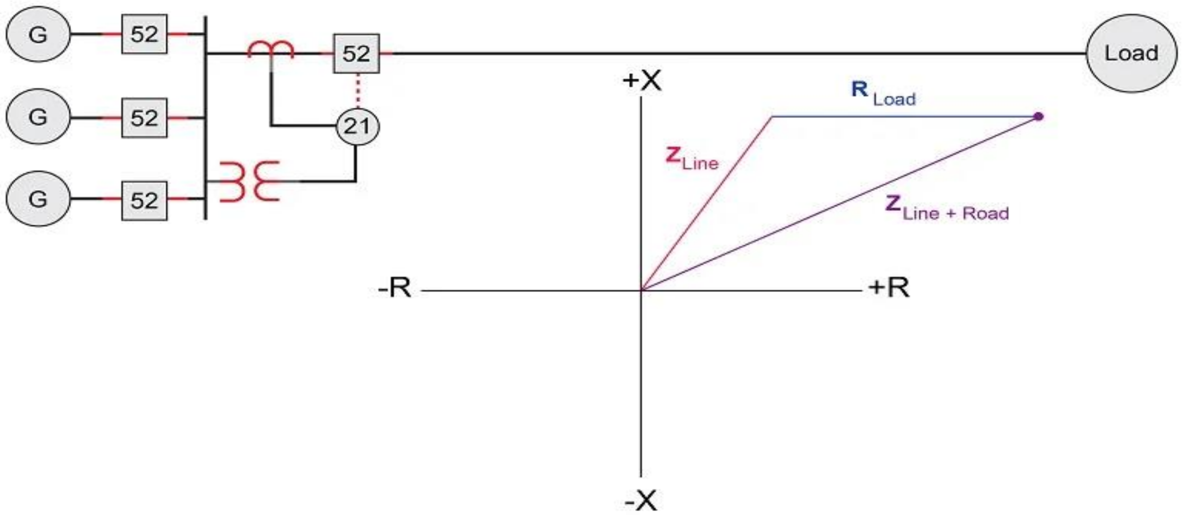
Using Impedance Diagram to Characterize Faults

Oscilloscope displays showing the raw voltage and current waveforms are clumsy representations of line impedance. Better visual representations for impedance exist, the most popular being a phasor diagram for line impedance with resistance (R) on the horizontal axis and reactance (X) on the vertical axis, commonly referred to as an R-X diagram. The three line examples shown in the previous section using the oscilloscope are shown in phasor format here[20]:



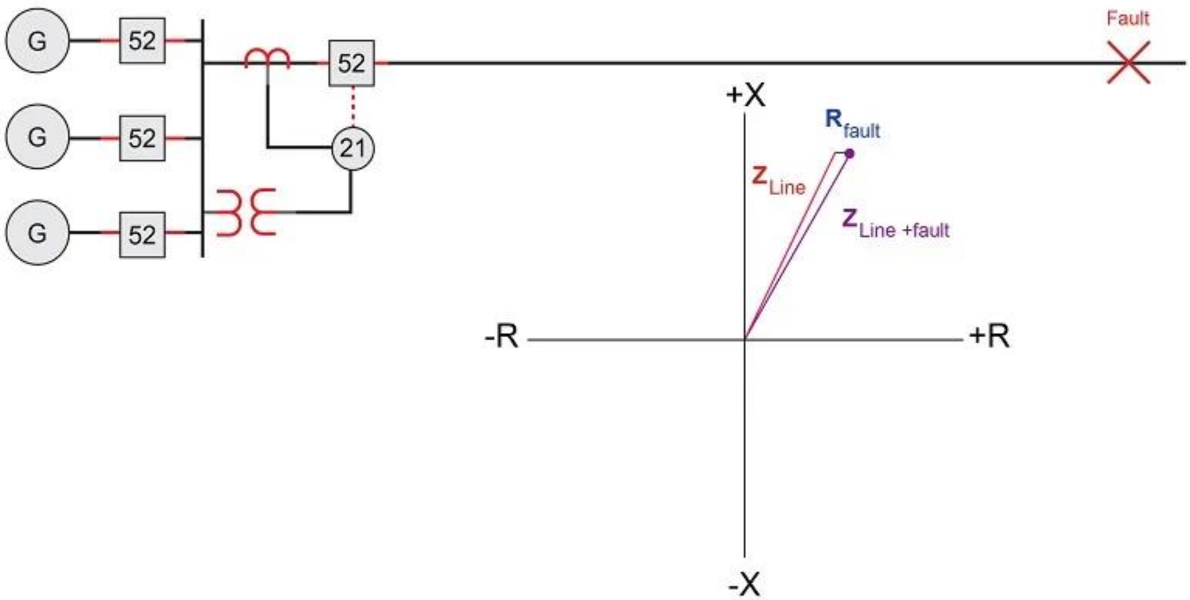
Keep in mind that these phasors represent impedance, and as such a short-circuited (faulted) condition is shown as a short phasor, while an unloaded condition is shown as a long phasor. It should also be noted that these impedances, while calculated from measurements of voltage and current, do not change unless the line, load, or fault characteristics change [20]. If the system voltage were to sag due to a generator problem, for example, the impedance phasor representing the combined effects of line and load impedance would not be altered [20]. Any protective relay operating on impedance would therefore ignore such changes, and trip only if the line's characteristics were to change. This is precisely the behavior we need from a "distance" relay, enabling it to discriminate line faults better than a simple overcurrent relay ever could [20].

For a normal load condition, the impedance phasor will be significantly longer than that of the line's full length (i.e. much higher impedance) with an angle significantly less than that of the line impedance alone[20]:

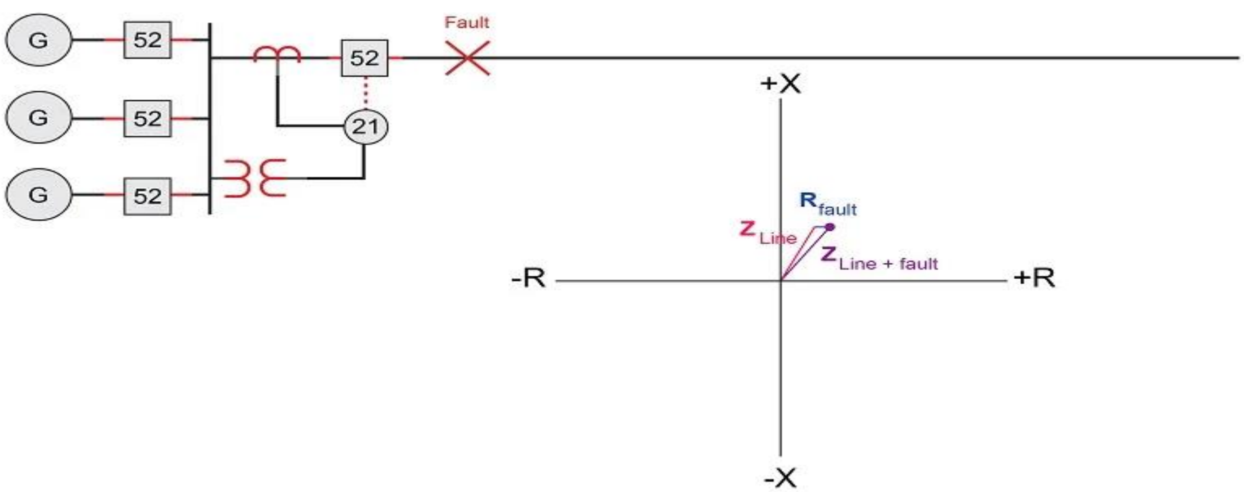


Short-circuit faults at various locations along a transmission line will cause the impedance phasor to vary primarily in magnitude and angle[20]. Recall that during fault conditions, the resistance and reactance of the power line itself is the dominant impedance limiting fault current. The actual fault is predominantly resistive, with a very small impedance value[20].

For a fault far removed from the relay, the impedance phasor will be long (i.e. relatively high impedance) with angle nearly equal to that of the line impedance alone[20]:

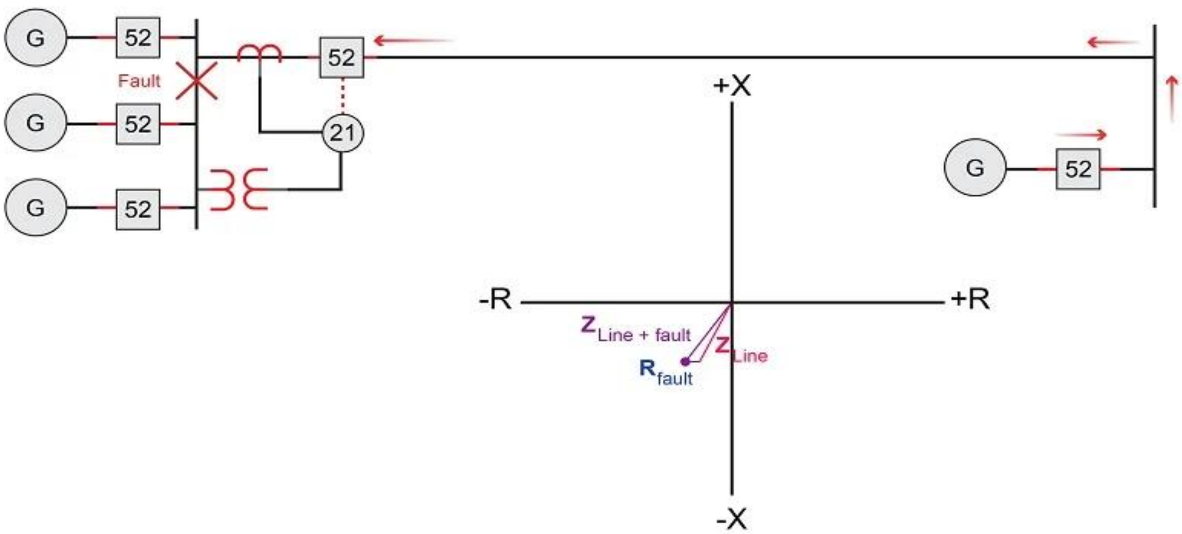


For a fault closer to the relay, the impedance phasor will be short (i.e. low impedance) with angle slightly less than that of the line impedance alone[20]:



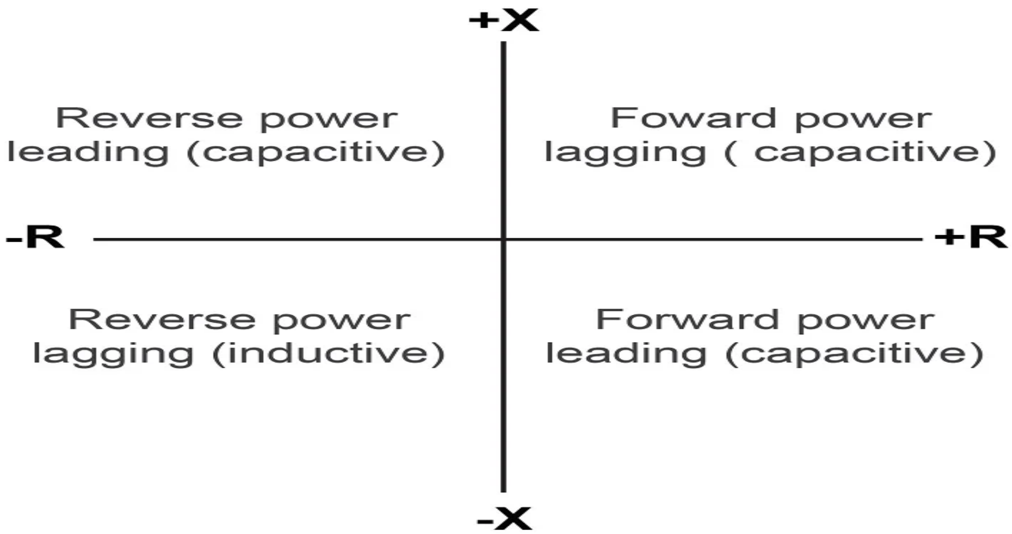
he goal of a distance relay (ANSI/IEEE code 21) is to trip its circuit breaker(s) if a fault occurs within its programmed "reach" and to ignore both normal operating loads and faults lying outside its reach[20].

If additional sources of electrical power are connected to the far end of the transmission line, it is possible for the distance relay to sense reverse power flow. Consider a case where a short-circuit fault occurs on the generator bus shown in this single-line diagram[20]:



A fault to the left of the distance relay manifests as high current and low voltage just like a fault on the transmission line, but since the current waveform is inverted (180^0 phase shift) due to the opposite direction of fault current, the impedance phasor ends up in an entirely different quadrant of the R-X diagram[20]. If the goal of the distance relay is to protect the transmission line, we need it to ignore such faults, because to operate on such a fault would be an example of overreach, the distance relay "reaching into" the generator bus zone where it should be concerned with the transmission line zone [20].

Each of the R-X diagram's quadrants may be labeled in terms of power direction and power factor, either "lagging" (predominantly inductive) or "leading" (predominantly capacitive)[20]:



4.7. Transformer Differential Protection (ANSI 871)

I. Transformer Differential Protection /Working Principle

The working principle of the Transformer Differential Protection Relay is based on Kirchhoff's Current Law. This law states that the sum of currents entering a node is zero. Ideally, for a healthy (non-faulted) transformer, the current entering the primary winding should equal the current leaving the secondary winding (after accounting for the transformer's turns ratio and phase shift) [21].

1. Core Concepts:

Differential Current (Operate Current): The vector sum of the currents entering all terminals of the protected transformer zone. Restraining Current (Restrain Current): A measure, often the scalar sum or a maximum value, of the currents used to bias the relay and prevent operation during external faults or normal load conditions[21].

2. System Configuration:

The protection system consists of Current Transformers installed on all sides of the transformer (e.g., High Voltage HV and Low Voltage LV sides) and the Transformer Differential Protection Relay itself. The CT polarities must be oriented towards the transformer to ensure correct current direction measurement [21].

3. Operating Logic:

During Normal Load or External Faults: Although the magnitude and phase of the currents on the transformer's different sides are different, after internal compensation within the relay (for ratio and phase angle), their vector sum is theoretically zero.

In this condition, the Differential Current ≈ 0, while the Restraining Current is significant. Since the differential current is much smaller than the restraining current, the relay does not operate.

During Internal Faults:

The fault point creates an additional fault current supplied from all sides of the transformer.

This disturbs the balance between the currents entering and leaving the transformer zone, causing the vector sum (the differential current) to become significantly large.

In this condition, the Differential Current >> 0.

When the differential current exceeds the set threshold and satisfies the operating characteristic curve, the relay identifies an internal fault and issues a trip command [21].

4.Challenges to Overcome:

In practice, the following factors can cause a "spurious" differential current under non-fault conditions, which the relay must discriminate against and restrain[21]:

CT Errors and Saturation: CTs may saturate, especially during external faults, causing distortion of their secondary current[21].

Transformer Magnetizing Inrush Current: When a transformer is energized, it can draw a large, harmonic-rich magnetizing current.

Transformer Tap Changer Operation: Changes the actual transformer ratio, disrupting the balance of the CT secondary currents[21].

Modern digital differential protection relays address these issues by employing a Percentage Restraint Characteristic (Ratio Differential Characteristic) supplemented by Harmonic Restraint[21].

A typical percentage restraint characteristic curve is illustrated below[21]:

```
   I_d (Differential Current)
       ^
       |    / |-------- Operate Region
       |   /  |
       |  /   |
I_op3 >|-/----|------------ Slope S2
       | /    |
I_op2 >|/-----|------------ Slope S1 (Often a fixed value, e.g., 0.2/0.25/0.3)
       |/     |
I_op1 >|------|------------ Minimum Pickup Current (I_pu)
       |
       +-----------------------------------------------> I_r (Restraining Current)
              I_r1      I_r2
```

Characteristic Curve Explanation:

Minimum Pickup Current (I_pu): The threshold value; the protection can only operate if the differential current exceeds this value.

Percentage Restraint Region: The operate current threshold increases as the restraining current increases. This ensures that during external faults (high restraining current), the protection remains stable even if some differential current exists due to CT errors[21].

Harmonic Restraint: The relay analyzes the harmonic content of the differential current. Magnetizing inrush current contains a high percentage of second harmonic. If the second harmonic content exceeds a set value (typically 15%-20%), the relay blocks the differential protection to prevent maloperation[21].

II. Transformer Differential Protection /Functions

The primary functions of the Transformer Differential Protection Relay are:

Rapid Isolation of Internal Faults: Acting as the primary protection, it detects and clears various internal faults within the transformer windings, leads, and bushings, such as phase-to-phase faults, turn-to-turn faults, and ground faults, with high sensitivity and speed.

Prevention of Fault Escalation: By rapidly isolating the faulted equipment, it prevents the fault from developing further, which could cause catastrophic damage to the core asset and maintains stability for the rest of the power system[21].

Improved System Reliability: By selectively isolating only the faulted transformer, it minimizes the extent of the power outage[21].

III. Transformer Differential Protection /Setting Calculation

Setting calculations are critical to ensure the correct and reliable operation of the protection relay. The following outlines the calculation steps and considerations for key settings. Please note that specific formulas and recommended values may vary slightly depending on the relay manufacturer and applicable engineering standards; the following provides general principles [21].

Basic Parameter Definitions:

I_transformer: Rated current of the transformer

I_ct: Rated secondary current of the CT (typically 1A or 5A)

n: Transformer ratio compensation factor (handled by relay software)

I_diff: Differential Current

I_rest: Restraining Curren

Step 1: Calculate Rated Currents and CT Secondary Currents

Calculate the rated current for each side of the transformer (HV, LV) and refer them to the CT secondary side [21].

I_sec = I_transformer / I_ct

Step 2: Determine the Minimum Pickup Current

This setting is used to override the maximum steady-state unbalanced current during normal transformer operation (caused by CT errors and tap changer operation).

Formula: I_op1 = k * I_transformer

Where:

I_op1 is the Minimum Pickup Current (also called I_pu), typically expressed as a multiple of the transformer's rated current.

k is a reliability factor, typically between 0.2 and 0.5. For modern digital relays, 0.2 or 0.3 is common [21].

Step 3: Determine the Initial Restraint Slope

This slope is used to override the unbalanced current under light external fault or load conditions [21].

Formula: S1 = k1

Where:

S1 is the Initial Restraint Slope.

k1 is the slope percentage, typically set between 0.15 and 0.30 (i.e., 15% to 30%). A common setting is 0.25 or 25% [21].

Step 4: Determine the Maximum Restraint Slope

This slope ensures stability during severe external faults where CT saturation is likely [21].

Formula: S2 = k2

Where:

S2 is the Maximum Restraint Slope.

k2 is the slope percentage, typically set between 0.50 and 0.80 (i.e., 50% to 80%). A common setting is 0.60 or 60%.

The breakpoint I_r2 is typically set above 5-10 times the rated current [21].

Step 5: Harmonic Restraint Settings

Used to discriminate against magnetizing inrush current.

2nd Harmonic Restraint: Typically set to block the protection when the ratio of the second harmonic component to the fundamental component in the differential current exceeds a threshold [21].

Setting Range: Typically 15% to 20%.

5th Harmonic Restraint: Used to identify transformer over-fluxing conditions. Typically set between 30% and 40% [21].

Step 6: Instantaneous Differential Element

This is an unrestrained, high-set differential element for high-speed clearing of severe internal faults[21].

Formula: I_inst = k_inst * I_transformer

Where:

I_inst is the Instantaneous Differential pickup value.

k_inst is a multiplier, typically set between 8 and 12 times the rated current to override the maximum possible magnetizing inrush current [21].

Calculation Example (Simplified):

Assume a transformer with a rated current of 1000A, and CT ratio of 1000/5A.

CT Secondary Rated Current: 1000A / (1000/5) = 5A

Minimum Pickup Current I_op1: Using k=0.3, I_op1 = 0.3 * 5A = 1.5A (relay setting value).

Initial Restraint Slope S1: Set to 0.25 or 25%.

Maximum Restraint Slope S2: Set to 0.60 or 60%, with breakpoint I_r2 set to 5 * 5A = 25A.

2nd Harmonic Restraint: Set to 18%.

Instantaneous Differential: Using k_inst=10, I_inst = 10 * 5A = 50A.

5.0 Transformer Control and Protection

5.1 Introduction

Power transformers are critical in the power grid. They have a long lead time for repair and replacement. Consequently, transformer protection has to limit the damage to a faulted transformer [22]. Some protection functions, such as over-excitation protection and temperature-based protection can identify operating conditions that may cause transformer failure [22].

When protecting power transformers, it can be challenging to maintain security during current transformer (CT) saturation for external faults while detecting low-magnitude internal faults[23].

It’s often difficult to find a one-size-fits-all solution. Most transformer operations rely on modular, scalable, reliable, and sustainable transformer protection schemes[23]

Failures in transformers can be classified into:

- Winding failures due to short circuits (turn-turn faults, phase-phase faults, phase-ground, open winding)
- Core faults (core insulation failure, shorted lamination)
- Terminal failures (open leads, loose connections, short circuits)
- On-load tap changer failures (mechanical, electrical, short circuit, overheating)

5.2 Transformer monitoring and Control System

The transformer “control systems” are systems that has been set out to help control a power transformer and ensure it operates within its designed set criteria. Transformer monitoring automatically monitors various operating characteristics to make sure they are functioning properly. Transformer monitors collect data and send alarms to notify the user if something looks off [24].

There is a wide range of transformer monitors available that can detect the symptoms of transformer failure by monitoring the cooling system, load tap changer, dissolved gas, bushing power factor and capacitance, partial discharge, oil levels, pressure, temperatures, and more [24].

The primary objectives of transformer monitoring and control include:

(i) It helps maintain the transformer system voltage within tolerance limits.

(ii) It helps to monitor and regulate the transformer temperature.

(iii) Helps to monitor and regulate the total load connected to the transformer.

(iv) The monitoring system monitors the oil temperature and the insulation level

(v) The monitoring and control system helps to regulate the tap changing system.

(vi) The alarm system helps monitor and signal the operators in the event of faults.

(vii) The control and monitoring system supports the SCADA system.

5.3 The Transformer Vector Group

AC voltage is applied to the transformer’s primary coil, causing a current to flow through it. This coil is wound around an iron core, which provides a path for the flow of a changing magnetic flux. The changing magnetic flux induces a voltage on a secondary coil wound around the iron core [25]. The secondary voltage phase depends on how the coils are wound around the core. The induced voltage may be in-phase or 180o out of phase of the primary voltage [25].

A three-phase transformer has more coils wound around the core, one for each winding. Thus, there are more options for how to connect the windings. The connection type changes the phase relationship between the two voltages [25].

5.3.1. Three-Phase Transformer Configurations

A three-phase transformer has three primary and secondary windings, each wound around an iron core, making three sets for the three-phase power that must flow through the transformer. This same setup can be realized by externally connecting three different single-phase transformers' windings. The windings on each side, primary and secondary, can be connected in delta and star configurations [25].

In the delta configuration, the polarity end of a winding is connected to the non-polarity end of another winding. This gives a closed ring connection between the three windings. Phases are taken from the common coupling points between the windings[25].

In the star configuration, all windings' non-polarity ends are connected to form a neutral point. The polarity ends of the windings are taken as the phase terminals[25].

We can get a total of four configurations by varying the primary and secondary winding connections. For example, if the primary winding of a transformer is configured in a star connection, the secondary winding might have the same configuration (star) or different (delta). The different connections can yield transformers with delta-delta, star-star, delta-star, and star-delta configurations[25].

With similar primary and secondary winding configurations (star-star and delta-delta), the secondary voltage waveform is completely in phase with the primary waveform. This is called the "no phase shift" condition [25].

With different primary and secondary winding configurations (star-delta and delta-star), the secondary voltage waveform is 30o out of phase with the primary waveform, and the condition is called a 30-degree phase shift. This condition presents a problem when connecting two three-phase transformers in parallel. In such cases, it is important to ensure that there is no relative phase difference between the secondary voltage waveforms of the two transformers. Otherwise, a short circuit would occur whenever the transformers are energized [25].

5.3.2. Winding connection designations using Vector Groups

The International Electrotechnical Commission (IEC) introduced Vector Groups to solve the classification issue for three-phase transformers. Vector Groups are used to designate winding connection information for the two windings (low-voltage and high-voltage) and the phase relationship between them [25].

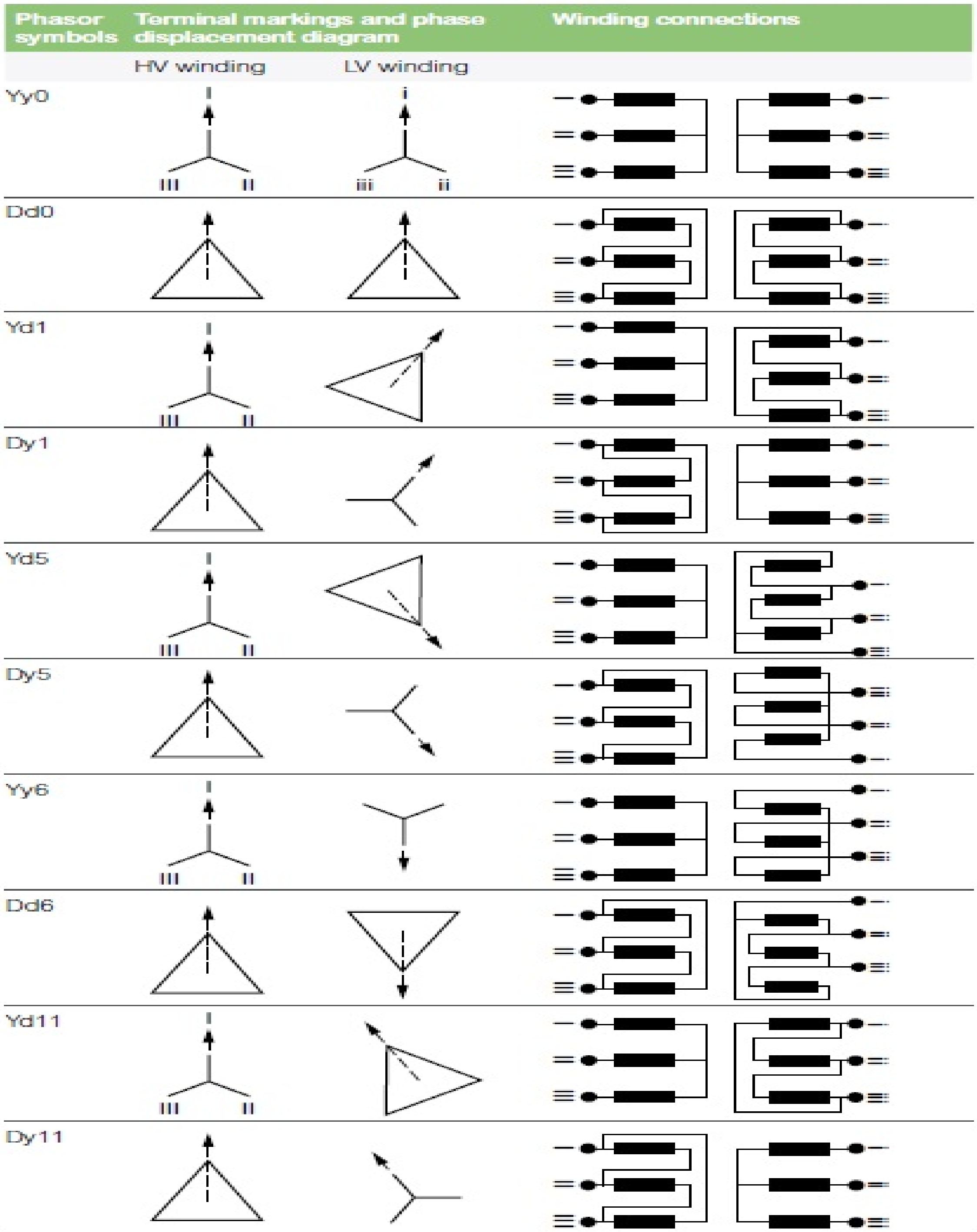


Figure 5.6 Vector Groups of Three-phase Transformers:

5.4 Tap Changing Control

In modern power systems, transformer tap changers are critical for maintaining voltage stability in distribution networks, ensuring reliability, and protecting equipment. Tap changers are used in voltage-regulating and power transformers to adjust the transformer's turns ratio, ensuring consistent voltage levels under varying load conditions[26].

5.4.1. Basic Function of a Transformer Tap Changer

A transformer tap changer is a mechanism that allows the connection to different points on a transformer's windings, effectively changing the transformer tap. By altering the number of active turns, it adjusts the voltage ratio between primary and secondary windings[26].

This adjustment is essential in both high-voltage power transformers and distribution transformers to maintain voltage within specified limits. Tap changers are particularly useful in networks with fluctuating loads or distributed generation sources[26].

5.4.2. How do voltage adjustment tap changers work?

The proper use of tap changers on a transformer requires selecting the tap setting which is closest to the actual value of the incoming voltage supply. This will ensure the output voltage feeding the load remains at the desired nameplate value[27].

Let’s assume the incoming voltage at the transformer is too low. To fix this, the tap setting is adjusted by rotating the tap changer in the HV cabinet to a lower voltage setting. When the tap changer is moved to a lower voltage position below the nominal tap, small sections of the primary winding are disengaged, which alters the ratio of primary to secondary windings. By lowering the amount of turns on the primary coil and leaving the secondary coil the same, the resulting new ratio yields a higher voltage on the secondary side, bringing the sagging voltage level back up to where it should be[27].

figure 5.3 below shows how the rotation of the tap changer engages and disengages different sections of the primary coil. Most larger transformer coils have the tap adjustments at the center of the coils (Figure 5.3), but we’ve also included Figure 5.4. with the taps located at the end of the coil (more common on smaller transformers) to help simplify the concept of tap adjustment.[27]

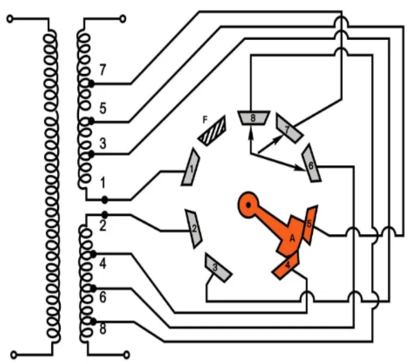


Figure 1

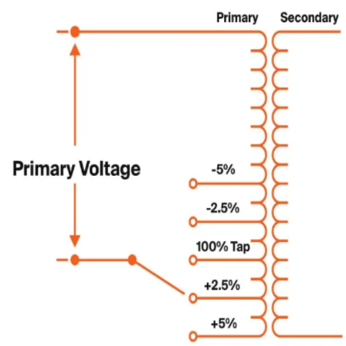


Figure 2

Figure 5.3(fig1) figure 5.4(figure 2)

5.4.3. Types of Transformer Tap Changers

Transformer tap changers can be broadly classified into two categories:

a) De-energized Tap Changers (DETCs)

Also known as de-energized tap changers, these devices adjust the transformer tap only when the transformer is offline. DETCs are simpler, cheaper, and have lower maintenance requirements, but cannot respond to real-time load fluctuations.

Key components of DETCs include:

Selector switches to choose the desired tap

Mechanical linkages to connect transformer windings

Indicators for tap position

DETCs are often used in distribution networks where voltage regulation does not require continuous adjustment [27].

b) Load Tap Changers (OLTC)

Load tap changers (OLTCs) can adjust the transformer tap under load conditions, without interrupting the power supply. This capability makes them essential in power distribution systems and voltage regulators for maintaining stable voltage [27].

OLTCs consist of:

Diverter switches that momentarily carry current during tap transitions

Selector switches that select the new tap

Mechanical or motor-driven mechanisms

These load tap changers OLTC allow smooth voltage regulation, reduce system losses, and improve the reliability of power transformers in dynamic load environments [27].

5.4.4. Benefits of tap Changers control

1.Dynamic Voltage Control: OLTCs allow real-time adaptation to load changes.

2. Extended Transformer Life: Smooth transitions reduce mechanical stress on transformer windings.

3. Improved Power Distribution: Voltage stability ensures reliable operation of downstream equipment.

4. Energy Efficiency: Proper voltage regulation reduces losses in the distribution network.

5.5. Transformer Cooling System

Electric transformer cooling is the process of removing the waste heat produced at the transformer winding and safely transferring/disposing that waste heat into the surrounding environment. If we do not remove this waste heat safely and efficiently into the surrounding, the transformer winding insulation can melt and and short circuits caused by excess heat can cause the transformer to explode [28].

There are several transformer cooling types being developed based on your transformer design, size, capacity, and the industrial standard or requirements. All these methods are specifically designed and only work for a particular transformer and satisfy specific standards [28].

5.5.1. Different Transformer Cooling Methods

There are a total of six different transformer cooling methods that have been designed, developed and are being used around the globe. Each method was designed and developed to meet your specific needs and is being used only for specific type, size, and capacity of your transformer [28].

1. Natural Air Cooling (AN)

The natural air transformer cooling methods remove heat from our transformer winding through the natural convection of heat into the surrounding air. It is one of the dry type transformer cooling methods and there is no mechanical or special heat transferring mechanism in place to remove heat [28].

Heat produced at transformer winding is transferred to the surrounding air through the process called free convection. Air then relying on the natural flow of air takes the heat away from the transformer winding [28].

This method of transformer cooling is only suitable for your small low capacity transformers that do not produce much heat. Heat produced in these transformer windings is never high enough to melt insulation, cause short circuits, or start fires or cause explosions [28].

2. Forced Air Cooling (AF)

The forced air based transformer cooling method works very similar to the natural air cooling method. It is also one of our dry type transformer cooling methods. There is only one difference and that is that the air is forced on the transformer winding to remove [28].

This method also follows the methods of convection to remove heat from transformer winding but its forced convection and these methods remove much more heat and much faster [28].

A transformer cooling fan is usually installed on the transformer that forces the air to pass through the duct and onto the transformer winding. Faster the air flow over the winding, more heat it will remove and more cooling effect can be produced [28].

This type of transformer cooling is used in our small to medium capacity transformers where heat generated is enough to melt insulation if not removed. Heat here is not high enough to instantly cause fire or explosion but need forced removal for efficient working [28].

3. Oil-Based Cooling Systems

There are two main types of transformer based on how they are cooled. One is dry type transformers where there is no liquid fluid used for cooling purpose and then there are oil type transformers where a transformer cooling oil is used for cooling purpose [28].

In our oil type transformers, the transformer winding is always kept dipped inside the oil which works as a medium of heat transfer. Winding is placed inside the transformer tank and then the tank is filled up to the top with transformer cooling oil [28].

Heat produced at the transformer winding during the operation is first absorbed by the transformer cooling oil, heated oil then transfers that heat to the transformer tank that has transformer cooling fins. Then usually free or forced convection is used to remove heat from the transformer tank [28].

3.1. Oil Natural Air Natural (ONAN)

In the oil type transformer category, oil natural air natural cooling method is the first type that removes heat from transformer winding using free convection methods. Heat produced at your transformer winding is first absorbed by the transformer oil [28].

Oil absorbs heat using the principle of free convection and then transfers that heat to the transformer tank using the same free convection mode of heat transfer. Transformer tank has specially designed transformer cooling fins that can facilitate heat transfer from the transformer tank to the surrounding atmosphere [28].

Here this heat transfer is done again using free convection mode of heat transfer where heat from the transformer tank body is transferred to the surrounding air. That is why this method is called oil natural air natural cooling methods, because all cooling is done naturally without any involvement of mechanical mechanism for forced convection [28].

This method of transformer cooling is only applied to your transformers that produce low heat at their winding. This heat is higher in value than the air natural type transformer cooling method by not high enough to need any force convection. Still heat produced here is enough to cause fire if there is not enough transformer cooling oil inside the transformer tank[28].

3.2. Oil Natural Air Forced (ONAF)

The second method in our oil type transformer cooling systems is the oil natural air forced method. In these methods, oil absorbs heat from the transformer winding using the principle of free convection. Oil once heated high enough starts to transfer that heat to the transformer tank body [28].

Transformer tank body is specifically designed with transformer cooling fins to facilitate the transfer of this heat from transformer cooling oil to the tank body using the principle of free convection. Once the heat is transferred to the tank body, from there heat is transferred to the surrounding air using a method of forced convection [28].

In forced convection, air is forced to pass over the tank body and transformer cooling fins at high speed thus quickly removing heat from the tank body. A transformer cooling fan is used to force air onto the tank body and fins. In this force convection, higher the speed of the air passing over the body and transformer cooling fins higher will the heat removed and cooling effect produce [28].

3.3. Oil Forced Air Forced (OFAF)

Third type in our oil type transformer cooling systems is the oil forced air forced type transformer cooling. In this system two different mechanical mechanisms are used to force the liquid oil and air to remove heat from the transformer winding through the principle of forced convection[28].

First the heat produced at the transformer winding is removed from the winding by oil through the mode of forced convection. Transformer cooling oil in the transformer tank is forced to move either in circular motion or in a confined path by a heavy duty oil pump. The moving oil when passed over the transformer winding absorbs heat and based on forced convection principle, higher the speed of the oil greater will be the heat removed [28].

The oil, after absorbing heat from the transformer winding, transfers it to the tank body using the same principle of forced convection. The transformer tank body is specifically designed with fins to facilitate the transfer of heat to and from the tank body[28].

Heat once transferred to the transformer tank is transferred to the surrounding again by the mode of forced convection. A transformer cooling fan is used to force air to pass over the body and transformer cooling fins of the transformer tank, thus removing all the heat. Same principle of higher the air flow more will be the heat removed will be applied here[28].

Due to the presence of the dual cooling mechanism for a single transformer, the heat removed in these methods is higher than the previous two oil type transformers. This method is used in all types of heavy duty transformers where heat produced is always high enough to cause serious fire and explosion if the entire transformer is not cooled properly[28].

3.4. Oil Forced Water Forced (OFWF)

Fourth and most advanced type of oil type transformer cooling system is the combination of oil forced water forced transformer cooling methods. In this method oil cooling is combined with the water cooling mechanism instead of air cooling. This method, like previous methods, used the principle of forced convection to transfer heat from winding to the outer atmosphere[28].

At first heat generated at the transformer winding is absorbed by the oil throughout the principle of forced convection. Oil is forced to move within the transformer tank by a large oil pump. Faster the oil moves greater and quicker it will absorb heat from the transformer winding[28].

Oil after absorbing heat from the winding is forced to pass through a separate specially designed heat exchanger. In that heat exchanger, water purified through deionized water treatment systems is used as heat transferring fluid and it absorbs all the heat from the oil through the process of forced convection[28].

Heat exchanger is usually a shell and tube type heat exchanger where hot oil moves in tubes of the exchanger where water present in the shell surrounds the oil carrying tubes. Heat transferred from oil to tubes to water to the shell and into the outer atmosphere through the process of forced convection [28].

This type of cooling system is used in specially designed transformers for specific applications where performance and system reliability is top priority. This method does offer higher efficiency and performance in transformer cooling but has high maintenance and operation cost. Heat exchangers need regular inspection and continuous maintenance for optimal performance[28].

5.6 Transformer Protection

Transformer protection basically divided into two types. One is Electrical Protection and it is designed based on Electrical parameters like Current, Voltage, Frequency, and Impedance. The second type of protection is Mechanical Protection and it is designed based on Mechanical parameters like Temperature, Pressure, Density, etc[29]

5.6.1. Transformer-Electrical Protection Types:[29]

Over Current/Earth Fault-50/51Protection

Under Impedance/Distance relay Protection-21

Differential Current Protection-87

Restricted Earth fault Protection-64H

Three Phase Overload Protection-49

Over Fluxing Protection-24

Over Voltage-59/Under Voltage-27 Protection

5.6.2. Transformer-Mechanical Protection Types:[29]

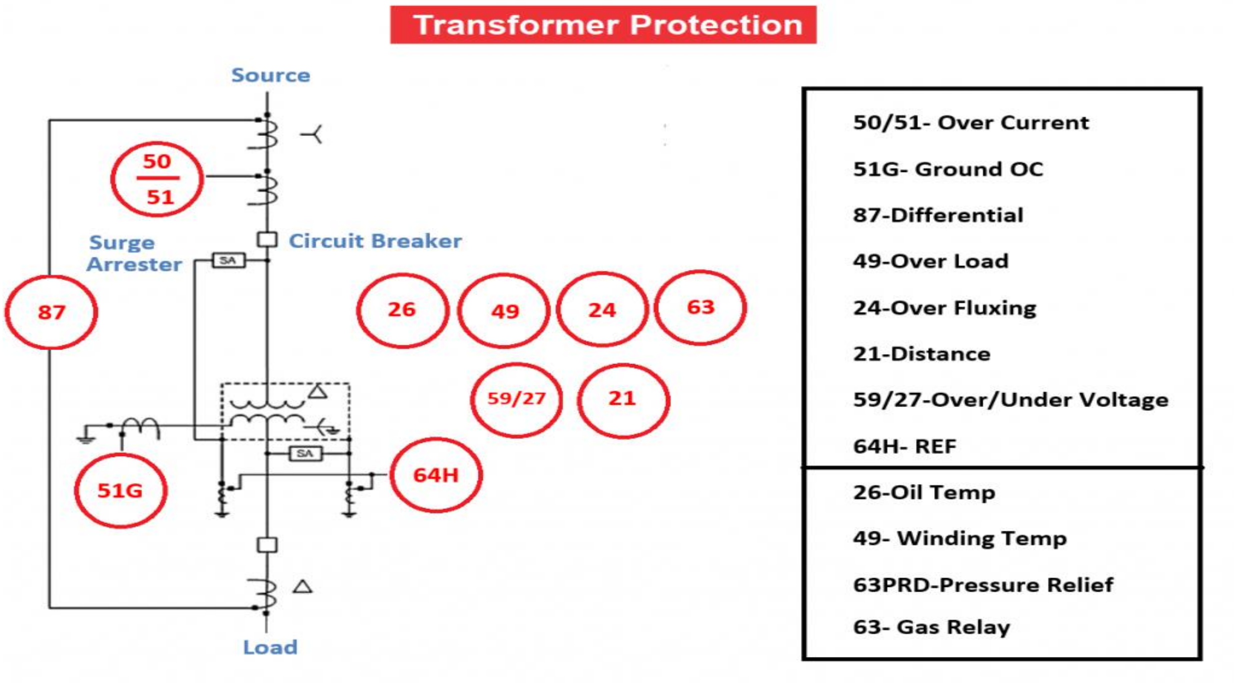
Oil Temperature Indicator-26

Winding Temperature Indicator-49

Oil Pressure Relief-PRV-63PRD

Gas Accumulation using Gas Accumulation Relay (Buchholz Relay)-63

5.6.3. Transformer Protection



1. Over Current/Earth Fault Protection:

HRC fuses are used for small transformers rating below 10 MVA. Above that overcurrent relays are used as primary protection if differential protection is not used. If differential protection is used Overcurrent protection is used as backup protection[29].

Overcurrent Earth fault protection operates when the current in any one of the phases is exceed the maximum value of the setting.

Types of OC protection[29]:

50 – Instantaneous Overcurrent

51 – Time Overcurrent Phase

50G – Ground Fault Instantaneous

51G – Time Ground Fault/ Standby Earth Fault

Numerical Overcurrent (50)/Earth fault (51) protection relay settings

Overcurrent relays should not trip in the following conditions[29].

During the period of magnetising current inrush– During switching of load, the load takes a sudden surge of magnetising inrush current [29].

Short-time load-Cold load pickup-To avoid tripping during switching on the Circuit Breaker[29].

Through Faults-For load side faults, usually 3-phase short circuit OC relay should not pick up before operating any other protection relays [29].

Three-phase overload– For permitted values of three-phase overload, the overcurrent relay should not pick up.

2. Under Impedance/Distance Relay Protection:

OC protection is not suitable for providing backup protection for transformers connected to networks. In this case, Under Impedance or Distance relay protection is required when there is a large difference between the maximum and minimum short circuit fault MVA [29].

3. Differential Current Protection:

A differential protection relay compares the phase currents on both sides of the transformer to be protected. If the differential current of the phase currents in one of the phases exceeds the setting of the stabilized operation characteristic or instantaneous protection stage of the function, the relay provides an operating signal[29].

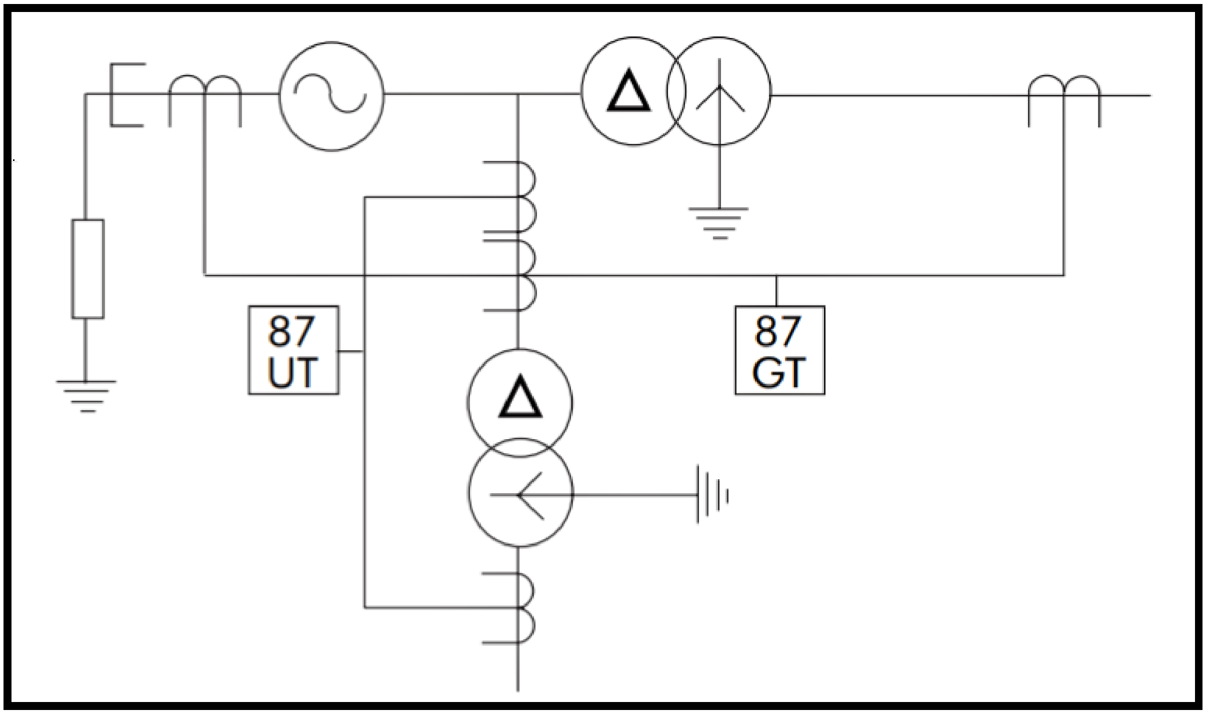
Over-current protection is used as a backup for differential protection.

Differential protection protects the transformer from

1. Winding short circuit faults.

2. Inter-turn faults.

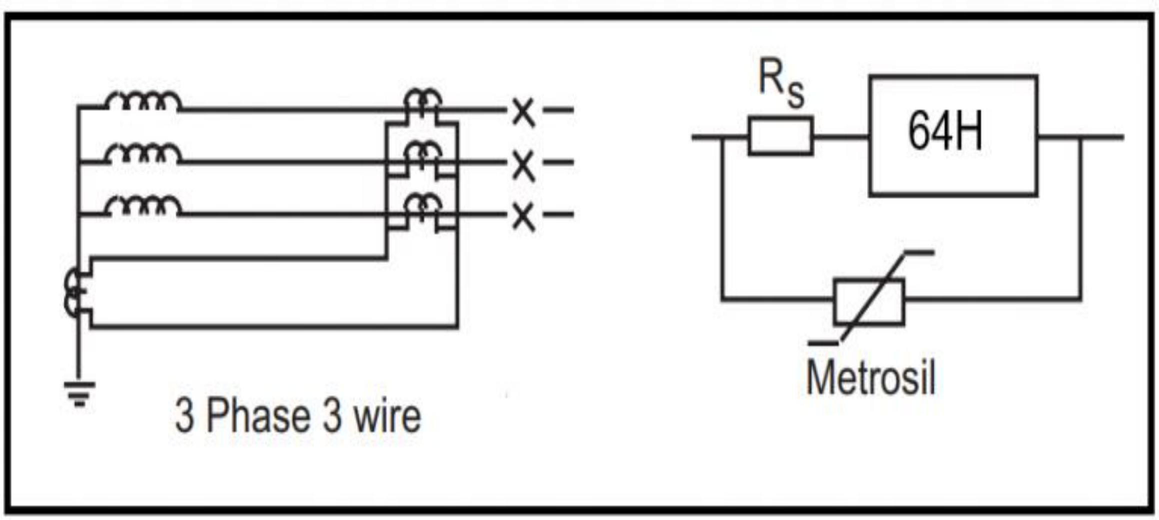
The application of Differential current protection for Generator Transformer (GT) and Unit transformers (UT) is shown in below fig.



4. Restricted Earth Fault Protection:

Differential protection provides Protection for only 80 percent of the winding and the rest of the protection will be provided by REF. It protects the transformer winding from earth fault [29].

REF provides protection in the zone between Transformer Star side winding and its Neutral Terminal which is earthed. It senses the fault current only in this particular zone so it is called Restricted protection[29].



The earth fault current is sensed from the bushing CTs of the phases and neutral side CT which may be either bushing CT or by the external CT in case of resistive earthing[29].

REF protection is implemented using a set of Phase Current Transformers and Neutral Current transformer along with Metrosil and Stabilising Resistors explained in detail here[29].

5. Three Phase Overload Protection :

Provides protection against possible damage during overload conditions.

Overload protection is provided by a Thermal overcurrent relay (49). This relay uses the Thermal time constant of the transformer and maximum allowable continuous overload current (IMAX) in the inverse time characteristic[29].

6. Over Fluxing Protection:

Over Fluxing or Over Excitation leads to transformers overheating and getting damaged. A V/Hz Over excitation relay is used for transformers that are likely to operate at a too high voltage or at a too low frequency. Generator transformers can be overexcited during acceleration or deceleration of the turbine. The maximum allowable V/F ratio is 1.1 times the rated V/F ratio[29].

7. Over Voltage Protection:

Over and Under voltage protection relay offers protection against abnormal phase voltage conditions[29].

The complete protection details using Over(59)/Under(27) voltage relay

Transformer Mechanical Protection:

1. Oil Temperature Trip Relay:

This relay senses oil temperature when an internal fault like insulation failure in one phase of winding and shorted or a local hotspot is generated, so the produced temperature is transferred to oil, and oil gets heated. When the oil temperature increases and exceeds a set value, this oil temperature relay operates[29].

2. Winding Temperature Trip Relay:

Winding temperature indicator indicates temperature, which is proportional to load current plus top oil temperature of the transformer. The indicator is provided with two/four mercury switches. One is used for alarm, second is used for the trip, third for fan control, and fourth for Pump. The temperature settings of the switches are different from each other for discrimination[29].

When the temp exceeds the max. Set temp the trip contact actuates and de-energizes the transformer[29].

3. Pressure Relief Valve (PRV):

In case of a severe fault in the transformer, the internal pressure may build up to a level, which may result in an explosion of the tank. To avoid such a contingency a Pressure relief valve is fitted on the transformer. Normally, the pressure relief device valve PRD will be mounted on top of the transformer [29].

If pressure arises inside a transformer and exceeds a pre-set pressure limit, the pressure safety valve PRD opens its valve clap, which is held by a spring and releases the internal pressure until it declines. After a decrease in the pressure, the pressure valve clap moves back to its original position and closes completely[29].

4. Buchholz Relay:

It is basically a Gas-actuated relay. During the normal operation of the transformer, the Buchholz relay is completely filled with oil. In the event of any internal fault, gas bubbles are produced in the transformer tank and gas is accumulated in the relay chamber on the way to the conservator[29].

This is a double element relay, which detects minor or major faults in a transformer. The first (alarm) element will operate after a specified volume of gas has accumulated. The second (trip) element will operate if a rapid loss of oil occurs in the event of serious faults inside a transformer[29].

6.0 SCADA And Substation Automation

6.1. Introduction

Substation automation is the management of protection, control, monitoring, and measurement functions in a transformer substation through an integrated system. These systems are designed to minimize human error, reduce fault response times, and increase grid reliability[30].In traditional systems, an operator had to be physically present on site to see the status of a circuit breaker or measure the oil temperature of a transformer. With automation, this data is digitized at millisecond-level resolution [30].

Supervisory Control and Data Acquisition (SCADA) systems have evolved significantly from standalone operations into network architectures that communicate across long distances [31]. Moreover, their implementations have shifted from custom hardware and software to standard hardware and software platforms. These have led to a reduced operational, maintenance and development costs and helps management to plan, supervise, and make important decision by providing real-time information. SCADA systems are nowadays widely used in most industrial processes, power generation and distribution, and even facilities such as nuclear fusion [31]. Power utilities around the world have increasingly adopted to the Automation of power systems to improve operational efficiency and provide a more reliable supply to its customers [31].

SCADA systems are used to monitor and control a plant or a grid. Data is transferred between a SCADA central host computer and a number of Remote Terminal Units (RTUs). A SCADA system collects data, transfers the information to a central site, then alerts the plant or grid if any fault occurs, carry out critical analysis, and also display the information in an organized way. These systems can be either relatively simple, or very complex. Nowadays, wireless technologies are widely deployed for purposes of monitoring, and more and more systems are monitored using the infrastructure of Local Area Network (LAN)/Wide Area Network (WAN)[31].

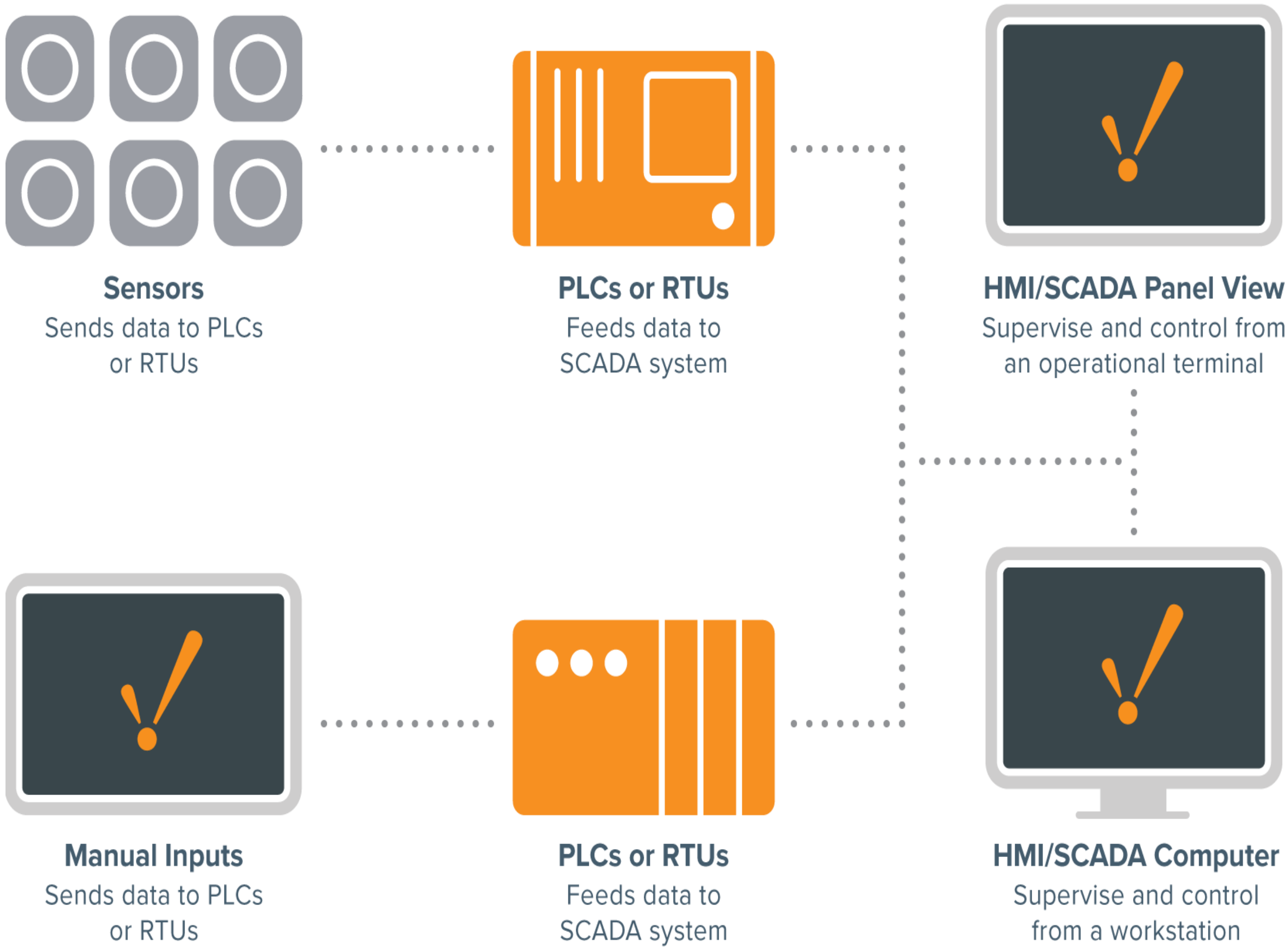
6.2. Overview of SCADA

Supervisory Control and Data Acquisition (SCADA) systems are used for controlling, monitoring, and analyzing industrial devices and processes. The system consists of both software and hardware components and enables remote and on-site gathering of data from the industrial equipment. In that way, it allows companies to remotely manage industrial sites such as wind and solar farms, because the company can access the turbine data and control them without being on site[32].

The basic SCADA architecture begins with programmable logic controllers (PLCs) or remote terminal units (RTUs). PLCs and RTUs are microcomputers that communicate with an array of objects such as factory machines, HMIs, sensors, and end devices, and then route the information from those objects to computers with SCADA software. The SCADA software processes, distributes, and displays the data, helping operators and other employees analyze the data and make important decisions [32].

For example, the SCADA system quickly notifies an operator that a batch of product is showing a high incidence of errors. The operator pauses the operation and views the SCADA system data via an HMI to determine the cause of the issue. The operator reviews the data and discovers that Machine 4 is malfunctioning. The SCADA system's ability to notify the operator of an issue helps him to resolve it and prevent further loss of product [32].

It is Important to state here that SCADA does not monitor all the system processes continuously. However, SCADA monitors connected equipment, retrieves operational or system data, and equally sends electrical signals to remotely connected equipment. Its Supervisory function enables electrical operators and engineers to monitor several substations simultaneously



6.3 Objectives of SCADA in Power Systems

Objectives of SCADA in power system protection include:

1. Real-time monitoring of the power system.

2. Rapid response to faults and fault isolation

3. Event recording and data acquisition

4.It helps enhance the safety of electrical engineers.

5. It improves operational reliability.

6.It can be used for predictive maintenance.

7. It enhances decision-making and help decision makers in better planning.

8. Helps reduce operation and maintenance costs.

6.4. Major Components of SCADA System

Five key hardware components make SCADA systems work

1. Sensors and Actuators

Sensors measure physical parameters like temperature, pressure, flow rate, level, and proximity and convert them into signals understandable by computers [33].

Common industrial sensors include resistance temperature detectors (RTUs), thermocouples, load cells, level transmitters, and optical infrared units. Actuators receive control signals from controllers and perform actions like opening valves, starting motors, and raising dampers to operate field equipment [33].

2. Remote Terminal Units

A remote terminal unit (RTU) is a microprocessor-based field controller that interfaces directly with sensors and actuators in the field. RTUs acquire telemetry data from sensors and transmit it over communication networks to the central SCADA server. They can also receive control commands from the master system to operate connected actuators [33].

3. Programmable Logic Controllers

Programmable logic controllers (PLCs) are robust industrial computers specialized for industrial control and automation tasks. PLCs process input signals from field devices and transmit appropriate output signals to control actuators, including valves, motors, and switches. In a SCADA system, PLCs act as intermediaries between sensors/actuators and master terminal units (MTUs)[33].

4. Master Terminal Unit

The MTU is the central server of the SCADA system, housing both the hardware and software. Industrial rack-mounted computers like distributed control systems (DCS) or PLC-based systems are reliable and redundant.

The MTU aggregates telemetry from field devices, processes and archives it with time stamping, runs data analytics, hosts human-machine interface (HMI) visualization software, and facilitates the distribution of data across the network. It also issues supervisory commands to PLCs and RTUs based on logic or operator actions [33].

The MTU enables centralized coordination of distributed sites[33].

5. Data Communication Infrastructure

The data communication infrastructure provides connectivity between the field instruments, controllers, central SCADA computers, HMIs, and corporate networks [33].

7.0. Conclusion

Electrical control and protection systems are very important for a safe, efficient, and reliable operation of a power system. The control and protection system serves as the main pillar of a modern power system, thereby ensuring efficient and reliable operation of the system. Most times, equipment like transformers, circuit breakers, and power lines are considered the main components of a power system, but it is the coordination of the control and protection systems that helps in their effective operation and helps to detect faults that could damage them. On detecting such faults, it sends commands to disengage this important equipment from the faulty system.

The Importance of the DC system cannot be overemphasized in a power system. The DC system provides an uninterrupted power supply to the protection system required for the operation of the system. They also serve as a source of power to the communication system and SCADA system.

Advanced protection systems were also discussed in this article. The use of auto-reclosers and other advanced functions in the protection system was also discussed, and how these improved technologies have helped to improve the protection system.

Modern power protection and control systems are adopting the use of SCADA systems, Digital twins for substation automation, and control and protection systems. With the aid of these technologies, operators and engineers can monitor power systems and substations remotely and also act proactively in the event of faults. The addition of artificial intelligence, the Internet of Things, and Adaptive protection systems has helped in creating a new generation of proactive protection systems, as well as a predictive maintenance culture.

With these recent advancements in technologies, future substations are expected to be autonomous, capable of self-monitoring, fault detection, and also able to proffer solutions to system failures even before they happen. Electrical engineers are not just expected to know about power systems but also need knowledge of communication engineering and artificial intelligence.

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