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Fundamentals of Modern Electrical Substations – Part 1, Part 2, Part 3

Course No: E02-010
Credit: 2 PDH

Boris Shvartsberg, Ph.D., P.E., P.M.P.



Continuing Education and Development, Inc.

P: (877) 322-5800
info@cedengineering.com



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Introduction

One of the main goals that every electrical utility company has is transportation of electrical energy from the generating station to the customer, while meeting the following main criteria:

- High reliability of power supply
- Low energy cost
- High quality of energy (required voltage level, frequency etc.)

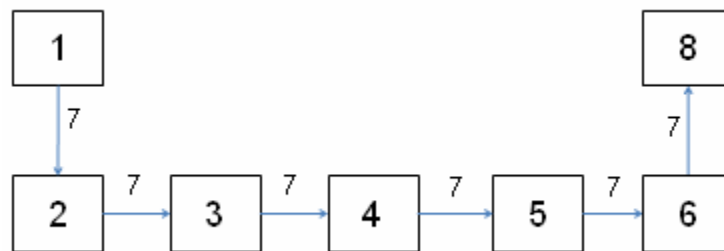
Part 1 of this course series is concentrated on demonstrating how modern power systems are arranged to accomplish all these goals; what place electrical substations have in the overall power system structure; and how important they are for reliable and effective operation of power systems.

Part 1 also provides an overview of substation major equipment, explaining the mission, and arrangement of each component.

To better understand the importance of electrical substations, let's start with a discussion about the structure of the power systems and their main components.

Power System Structure

The typical power system structure is shown in Fig. 1.



Where:

- 1 = Generator
- 2 = Generating station's step-up transformer substation
- 3 = Extra high voltage step-down transformer substation
- 4 = High voltage step-down transformer substation
- 5 = Distribution substation
- 6 = Distribution Transformer
- 7 = Transmission and Distribution Lines
- 8 = Customer

Fig. 1. Power System Structure and Main Components.

The elements from 2 to 7 are the components of the utility company Transmission and Distribution (T&D) Systems, with typical power system voltages as follows:

- Generation: Up to 25 kV
- Transmission: 115 – 1500 kV
- Subtransmission: 26 – 69 kV
- Distribution: 4 – 13 kV
- Customer: Up to 600 V

Justification for Voltage Transformation

As we can see from Fig.1, along the route from the source to the customer, electricity is undergoing numerous transformations, with generating voltage getting stepped-up to transmission level with a follow-up decrease down to distribution and eventually customer levels. Why do we need to do it? As previously mentioned, the utility company wants to keep energy costs down. One of the ways to do it is to reduce power and energy losses, which may be accomplished by raising the voltage level, because power losses ΔP have a functional relationship with voltage level described in the following equation:

$$\Delta P = F (S^2 x L / V^2) \quad (1)$$

Where:

- S = transported apparent power
- L = distance to the customer
- V = system voltage level

As we can see, there is a reverse proportion between power losses and voltage level in the 2nd degree. For example, if we increase voltage 10 times, power losses will be 100 times smaller.

Another benefit from raising the voltage is a reduction of voltage drop, which is related to voltage level ΔV as follows:

$$\Delta V = F (S x L / V) \quad (2)$$

Having a smaller voltage drop in the system helps the utility company to meet its other objective – to provide the customer with a high quality electrical energy meeting specific voltage level requirements.

That's why we increase voltage for transmission of electrical energy, but after it is delivered to the area where customers are located, we gradually lower the voltage to the safe utilization level (208/120 V, for example). Obviously, electrical transformer substations are playing a major role in accomplishing this task. The number of steps in

raising and lowering the voltage is being defined through optimization studies performed by utility company planners.

Mission of Substations

Electrical Substations have the following mission to accomplish:

- Step-up and step-down voltage transformation
- Connection of separate transmission and distribution lines into a system to increase efficiency and reliability of power supply
- Sectionalizing of power system to increase its reliability and operational flexibility – substation called “switching substation”

Let’s discuss the meaning of sectionalizing of power system, the reasons for it, and the benefits that it has using as an example power line connecting two substations shown in Fig.2.

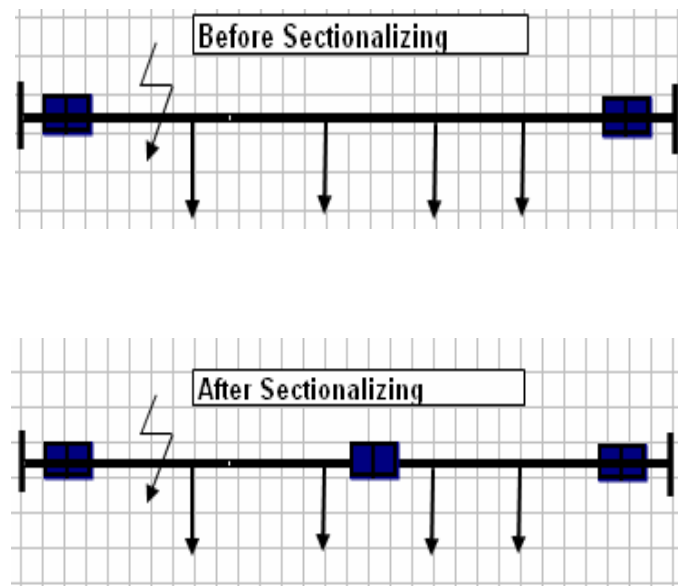


Fig.2. Sectionalizing of Power Systems.

As we can see, this line has circuit breakers on both ends and four taps feeding the customers (later we’ll talk about circuit breakers in a greater detail). Before sectionalizing, any fault on the line would lead to circuit breakers on both ends of the line opening (tripping) to isolate the fault. When it happens, all four customers will lose power supply. Let’s assume that we install another breaker in the middle of the line (see Fig.2 “After sectionalizing”); i.e. split the line in two sections or sectionalize it. If we do it, the same fault on the line will again lead to the opening of two adjacent breakers to isolate the fault: one installed in the beginning and one in the middle of the line. The

difference is that after the fault is isolated, one half of the line still remains in service feeding two out of four customers. So, by sectionalizing the line, we increased reliability of customer power supply.

Main Components of Substations

To fulfill their mission, substations include the following components:

- Power Transformers
- Circuit Breakers
- Disconnecting Switches
- Circuit Switchers
- Instrument Transformers
- Bus
- Relays and Instruments
- Auxiliary A.C. and D.C. Systems
- Overvoltage and Lightning Protection Systems
- Grounding System
- Remote Control and Operation Systems

Each of these components has its own tasks to accomplish, which we'll discuss in a greater detail in the next several sections of the course.

Power Transformers

Power transformers are needed to fulfill the main duty of substations: step-up and step-down voltage transformation. The following main components of transformers may be listed:

- Windings
- Core
- Tank
- Bushings
- Insulating medium (oil, gas)
- Cooling system (fans, pumps)

The different types of transformers may be distinguished based on following:

- Connections between the windings:
 - Transformers - Windings linked magnetically, isolated electrically
 - Autotransformers - Windings linked magnetically, connected electrically
- Number of windings:

- Two-winding transformers, for example 138/26 kV
- Three-winding transformers (every winding has a different voltage), for example, 138/26-13kV
- Transformers with a low voltage split windings (low voltage windings have the same voltage), for example: 138/13-13 kV
- Number of phases:
 - Single-phase
 - Three-phase
- Cooling class:
 - OA – liquid-immersed, self-cooled
 - OA/FA, OA/FA/FA - liquid-immersed, self-cooled/forced air cooled – has one or two sets of fans
 - OA/FA/FOA - liquid-immersed, self-cooled/forced air cooled/forced air – forced liquid cooled – has fans and oil pumps

The cooling options mentioned above are for power transformers using liquid insulation between their windings and transformer tank. Usually, the mineral oil is used for insulation and heat transfer from the windings. The higher the transformer load is, the higher the temperature of insulating oil will be. Because there is a maximum temperature for each type of insulating oil that can't be exceeded without oil losing its insulating abilities, there is a maximum transformer load that may be carried respectively. To increase transformer loading capabilities, the insulating oil should be cooled off to keep its temperature below the limit. This cooling is provided by the application of radiators, forced air cooling systems (fans) and forced liquid cooling systems (oil pumps). Each transformer may have several stages of cooling to allow for a gradual load increase. As an example, let's consider three-phase two-winding transformers shown in Fig. 3 and 4.



Fig. 3. 13/4 kV 6.0/9.0 MVA OA/FA Transformer



Fig. 4. 138/13 kV 27/36/45 MVA OA/FA/FA Transformer

13/4 kV transformer (see Fig. 3) has one set of cooling fans, as well as load ratings of 6.0 MVA without fans and 9.0 MVA with fans running. 138/13 kV transformer (see Fig .4) has 2 sets of fans, as well as load ratings of 27 MVA without fans, 36 MVA with one set of fans and 45 MVA with two sets of fans running. Transformer fans are usually operated automatically through control schemes based on the use of oil temperature sensors.

Voltage Transformation Equation

The following relationship exists between transformer primary (V_P) and secondary (V_S) voltages and primary and secondary winding numbers of turns:

$$V_P / V_S = N_P / N_S$$

Where:

N_P = Primary winding number of turns

N_S = Secondary winding number of turns

Example:

230/13 kV single-phase step-down transformer has a primary winding with 300 turns. How many turns a secondary winding should have?

Solution:

$$230/13 = 300 / N_S \Rightarrow N_S = (300 \times 13) / 230 = 17$$

Circuit Breakers

The mission of circuit breakers is an interruption of load and rated short circuit current for circuit protection. They are widely used to sectionalize power systems (see Fig. 2). The main components of circuit breakers are:

- Interrupter
- Bushings
- Insulating medium (oil, gas)
- Bushing current transformers
- Operating mechanism

Circuit breakers may be designed for either outdoor or indoor installation. Examples of different circuit breakers are shown in Fig. 5 through 7.



Fig. 5. 230 kV Outdoor 2000 A Circuit Breaker



Fig. 6. 26 kV Outdoor 2000 A Circuit Breaker



Fig. 7. 26 kV Indoor Switchgear Draw-out Type 2000A Circuit Breaker

Disconnecting Switches

The mission of disconnecting switches is to isolate de-energized circuits. This is mostly required when we need to take either circuit or equipment (breaker, transformer, etc.) out of service for repair or maintenance and need to provide safe visible breaks on both sides of the de-energized element of the power system. What is important here is to remember that disconnecting switches cannot interrupt neither fault nor load current, and that is their major functional difference from the circuit breakers. However, because of these limited functions, disconnecting switches are much cheaper than circuit breakers.

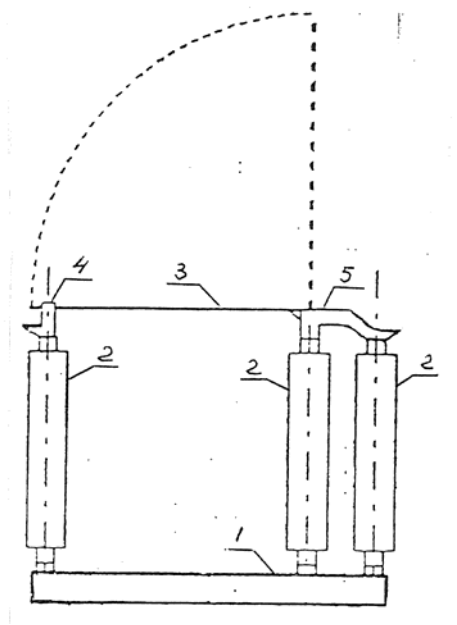
The main components of disconnecting switches are:

- Post insulators
- Live parts
- Operating mechanism

The following types of disconnecting switches may be listed:

- Vertical break
- Double break
- Center break
- Side break
- Group operated (all 3 phases open simultaneously): Manually or motor operated
- Hook-stick switches (each phase open individually): Manually operated using the insulated stick

Examples of some of these switches are shown in Fig. 8 through 10.



- 1 = Base
- 2 = Post Insulators
- 3 = Blade
- 4 = Jaw
- 5 = Hinge end

Fig. 8. Single Pole of Vertical Break Air Switch



Fig. 9a



Fig. 9b

Fig. 9. 230 kV 2000 A Double Break Disconnecting Switch
in Closed (a) and Open (b) Positions



Fig. 10. 4 kV Disconnecting Switch with Insulating Barriers between Phases

Circuit Switchers

So far, we've discussed two major substation switching devices: circuit breakers which can interrupt any load and rated fault current, as well as disconnecting switches which practically cannot interrupt any current. Very often, we need a switching device which is functionally located somewhere in between: it can interrupt any load and some fault current, and at the same time, can safely isolate the circuit. This device is called a circuit switcher. Its mission is to interrupt the load and rated short circuit current up to 20 kA. The main components of the circuit switchers are:

- Interrupter
- Isolating disconnecting switch
- Operating mechanism

An example of a typical circuit switcher is shown in Fig. 11. This device has the interrupting part of a circuit breaker and the isolating part of a disconnecting switch.



Fig.11. 230 kV 1200 A Circuit Switcher
Substation Bus Systems

All substation elements (transformers, breakers, disconnecting switches etc.) should be electrically connected in accordance with a planned substation arrangement. This connection is provided by substation bus system. There are the following main types of substation busses:

- Open air rigid bus
- Strain bus
- Gas insulated (GIS) bus
- Cable bus

Let's consider all these types and discuss what they consist of and what their strengths and weaknesses are.

1. Open Air Rigid Bus:

- Main components:
 - Supporting structures: frames, columns
 - Post insulators
 - Bare copper or aluminum conductor: tubular, busbar, cable
 - Connectors: bolted or welded
- Advantages:
 - Simplicity
 - More economical
 - Ease of trouble shooting
 - Short repair time
- Disadvantages:
 - Lower reliability
 - Exposure to weather, animal contact, etc.
 - Need for a large land area
 - Frequent maintenance

The examples of a typical open air rigid bus and connector used to assemble it are shown in Fig. 12 and 13, respectively.



Fig. 12. 138 kV Open Air Bus on Post Insulators



Fig. 13. Bolted Aluminum T-Conector 4"IPS Main to 4"IPS Tap

2. Strain Bus:

- Main components:
 - Supporting structures: towers, frames
 - Strain insulators with hardware
 - Flexible aluminum or ACSR (aluminum with a steel core) conductors
- Advantages:
 - Need for a smaller land area
 - Simplicity
 - More economical
 - Ease of trouble shooting
 - Short repair time
- Disadvantages:
 - Lower reliability
 - Exposure to weather, animal contact, etc.
 - Frequent maintenance

The examples of a typical strain bus and insulator assembly are shown in Fig. 14 and 15, respectively.



Fig. 14. 230 kV Strain Bus on Steel Towers



Fig. 15. 230 kV Strain Insulator Assembly

3. Gas Insulated Bus (GIB):

- Main components:
 - Center copper or aluminum conductor
 - Supporting insulators
 - Insulating gas (SF₆, air)
 - Metal enclosure
 - Bushings
 - External supporting structures
- Advantages:
 - Higher reliability
 - Protection from weather, animal contact, etc.
 - Need for a small land area
 - Low maintenance (especially for SF₆ bus)
- Disadvantages:
 - High cost
 - Inability to detect a gas leak (SF₆ bus)
 - Difficult troubleshooting
 - Long repair time

Example of 230 kV GIB termination is shown in Fig. 16.

4. Cable Bus:

- Main Components:
 - Cable (solid dielectric)
 - Terminators
 - Conduits or trays for installation
 - Supporting structures



Fig. 16. 230 kV Gas Insulated Bus

- Advantages:
 - Higher reliability
 - Protection from weather, animal contact, etc.
 - Need for a small land area
 - Low maintenance
- Disadvantages:
 - High cost
 - Difficult troubleshooting
 - Long repair time

The typical cable bus terminal is shown in Fig. 17.



Fig. 17. 138 kV Solid Dielectric Cable Bus Terminal

Instrument Transformers

To adequately operate power system, it is very important to measure its main electrical parameters (voltage, current, power, etc.) which is done by using voltmeters, ammeters, wattmeters, etc. All these typical instruments are designed for very low currents (usually up to 5 amperes) and voltages (usually up to several hundred volts). At the same time, real currents and voltages in power systems are measured in thousands of amperes and volts, respectively. Obviously, these values should be reduced to make them compatible with nominal values of common instruments, which may be done using instrument transformers whose mission is: accurate primary value (current and voltage) step-down transformation for relaying and metering circuits, as well as isolation between primary and secondary circuits (mostly for safety reasons).

The following standard secondary values are used for metering purposes:

- Currents: 1A or 5A
- Voltages: 115V or 120V phase-to-phase or phase-to-neutral

Depending on the arrangement of instrument transformers, the following types may be noted:

- Current transformers:
 - Free standing type (see Fig. 18)
 - Slip-on bushing type (see Fig. 19)
- Voltage transformers:
 - CCVT's (coupling capacitor voltage transformers) (see Fig. 20)
 - Potential transformers (see Fig. 21)



Fig. 18. Free Standing 138 kV 2000/5 A CTs



Fig. 19. 230 kV 2000/5 A Bushing CT



Fig. 20. 345 kV CCVT



Fig. 21. 26 kV Potential Transformers

Overvoltage Protection

One of the most common abnormal conditions in any power system are overvoltages which may take the form of surges from switching substation equipment and impulses from lightning strikes. Because these overvoltages may damage expensive elements of the power system (substation power transformers, transmission cables, etc.) an adequate overvoltage protection is installed to avoid it.

The main means of overvoltage protection are:

- Lightning arresters
- Protective gaps

The principle of operation of both arresters and protective gaps is based on diversion of overvoltage surges and impulses into the substation ground grid before they reach the protected equipment. The example of a typical surge arrester protecting a power transformer is shown in Fig. 22, where the surge arrester is the two-section porcelain column with a corona ring on the top.



Fig. 22. 230 kV Lightning Arrester

Equipment Installation Options

All substation equipment may be split in two groups: major and control. Let's define what kind of equipment belong to each of these groups and how they may be installed:

Major and Control Equipment Defined:

- Major equipment:
 - Power transformers
 - Switching equipment
 - Instrument Transformers
 - Overvoltage protection equipment

- Control equipment:
 - Relay protection systems
 - Metering systems
 - Auxiliary AC/DC Equipment
 - Alarm and remote control systems

Major and Control Equipment Installation Options:

- Major equipment :
 - Free standing
 - Switchgear
 - Unit substations (includes all substation components: transformer, switching equipment, etc. in one compact module)
 - Located in station control building
 -
- Control equipment:
 - Located in station control building
 - Unit substations
 - Switchgear

Examples of different equipment installation options are shown in Fig. 23 through 27.



Fig. 23. 26 kV Switchgear (Outside)



Fig 24. 4 kV Switchgear (Inside)



Fig. 25. 26/13 kV 9.0 MVA Unit Substation

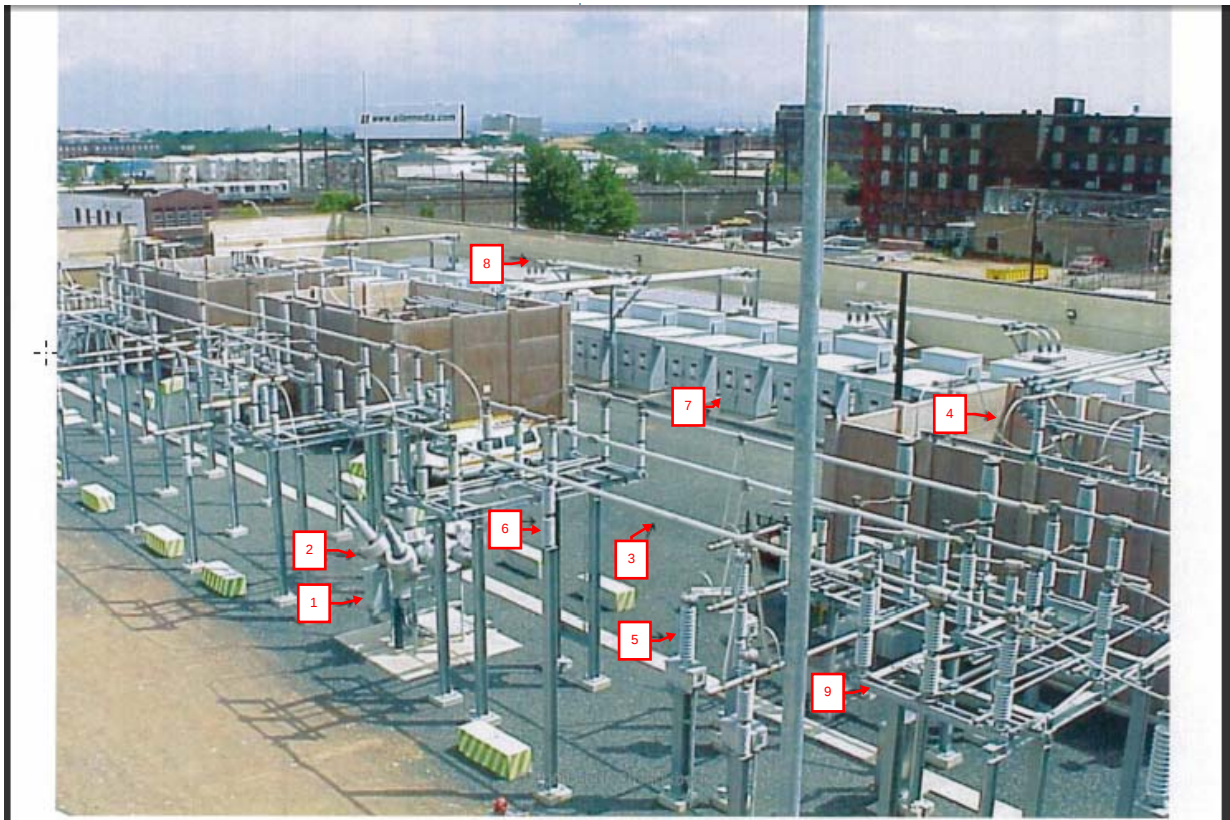


Fig. 27. 138/4 kV Substation, Including:

1 = 138 kV Circuit Breaker; 2 = 138 kV Bushing CTs; 3 = 138 kV Rigid Bus,
4 = 138/4 kV Transformer; 5 = 138 kV CCVT; 6 = 138 kV Post Insulator,
7 = 4 kV Switchgear; 8 = 4 kV Rigid Bus; 9 = 138 kV Disconnecting Switch

Conclusion

Part 1 of this course series provided an overview of modern electrical substations and their major components; concentrating on substation importance for reliable and effective operation of power systems to enable you to:

- Understand how power systems are arranged and what the transmission and distribution (T&D) system structure is.
- Identify the mission of substations and their place in the overall T&D structure.
- Understand what a substation consists of, and what each piece of a major equipment is for, including the following items:
 - Power Transformers
 - Switching Equipment
 - Substation Bus System
 - Instrument Transformers
 - Means of Overvoltage Protection
- Know the arrangement of each major equipment component and its installation options.



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Fundamentals of Modern Electrical Substations

Part 2: Electrical Substation Auxiliary and Control Systems

Course No: E03-013

Credit: 3 PDH

Boris Shvartsberg, Ph.D., P.E., P.M.P.



Continuing Education and Development, Inc.

P: (877) 322-5800

info@cedengineering.com

Introduction

Part 2 of the course “Fundamentals of Modern Electrical Substations” is concentrated on substation auxiliary and control systems which play a major role in allowing all station equipment to function properly, thus, fulfilling the main substation mission to support reliable and effective operation of power systems.

The following auxiliary and control systems will be considered, including explanations of their mission, operation principles and arrangement:

- Relay Protection
- Metering Systems
- Auxiliary AC/DC Power Systems
- Station Alarm and Remote Control Systems

Relay Protection

This section provides an overview of relay protection philosophy. Its mission is to detect abnormal conditions in power systems, which would in the following actions:

- Alarm
- Isolation of defective part of the system through operation of circuit interrupting devices

Any relay protection system should meet the following criteria:

- Sensitivity: ability to detect all abnormal conditions for which the system is designed to detect
- Selectivity: ability to initiate isolation of only the defected parts of the power system
- Reliability: ability to operate with minimum failures of maloperations
- Economical effectiveness: ability to fulfill all necessary functions at a minimal cost
- Improved redundancy: application of primary and back-up relay systems for important equipment

The following are the main components of a relay system:

- Relays
- Control and test switches
- Auxiliary transformers
- Terminal blocks
- Cabling & wiring

A relay is a device that receives information from instrument transformers about power system values (mostly currents and voltages), monitors the information, and acts on it when deviations from originally preset values (settings) occur. For example, an overcurrent relay will monitor the current in the circuit it is protecting, and adjusts the current values if they become higher than the original settings. Undervoltage relay will monitor the voltage and make the necessary adjustments when the voltage is lower than the original setting, etc.

The following are the main types of relays:

- Electromechanical
- Microprocessor

They may be installed on:

- Relay racks
- Relay panels

For example, Fig. 1 indicates electromechanical relays installed on relay racks. Similarly, Fig. 2 indicates microprocessor relays installed on the panel.



Fig. 1. Examples of Electromechanical Relays Installed on Relay racks



Fig. 2. Microprocessor Relays Installed on the Panel

There are numerous types of relay protection schemes with the most popular being:

- Overcurrent Protection
- Distance Protection
- Differential Protection:
 - Current differential protection
 - Voltage differential protection
- Undervoltage Protection
- Overvoltage Protection
- Underfrequency Protection

Let's consider some of these schemes in a greater detail starting with the most popular.

Overcurrent Protection

Its objective is to detect current levels higher than a predetermined value (relay setting). The following are various types of overcurrent protection:

- Instantaneous
- With time delay
- Directional – operates when:
 - Measured current is higher than the setting
 - Power flows through the system element in a certain direction
- Non-directional

Let's discuss the reasoning behind the different types of overcurrent protection using, as an example, the power system shown in Fig.3. This power system consists of two (2) lines, three (3) substations and six (6) circuit breakers.

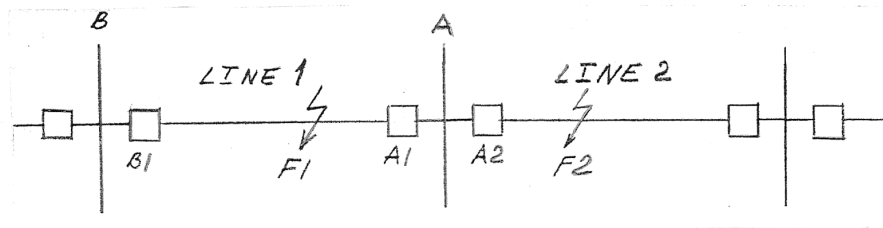


Fig.3. Example of Power System Protected by Overcurrent Protection Scheme

The main goal of correctly selecting a relay protection scheme is to deenergize a failed part of the power system sooner than later, as having a fault condition in the system longer than necessary is damaging for the equipment and unsafe for personnel. At the

same time, the smallest possible part of the system (adjacent to the fault) should be taken out of service to reduce the number of customer outages.

Given the aforementioned, let's consider a fault F1 on the line L1, which connects substations A & B. The best way to deenergize the fault is to trip breaker B1 at substation B and A1 at substation A, and we want it to happen almost immediately (for modern relays, it may take a few cycles, let's say, 6 cycles, which for a 60 Hz system amounts to 0.1 s). However, breaker A2 at Substation A will see the same current as breaker A1 and, unless we delay its tripping, it will open simultaneously with breaker A1, taking the whole substation A and its customers out of service, which is not acceptable. For that not to happen, a tripping of breaker A2 for faults on Line 1 should be delayed compared with the tripping of breaker A1, so A1 will trip first and the protection scheme will abort the tripping of A2, because the fault is not fed from substation A anymore.

Another way to provide a selectivity for the operation of breakers A1 and A2 in this example is to use a directional scheme, which differentiates a direction of power flow from the bus into the line (allowed to trip) from another flow direction which is from the line into the bus (trip is blocked). Based on this principle, for example, for fault F2 on line L2 directional protection will allow only breaker A2 to trip, but A1 will stay closed leaving substation A in service, which is exactly what we wanted to achieve.

The simplest overcurrent protection is installed on low voltage breakers that typically exist inside our homes. For example, if a receptacle and its wiring are designed for a 15A current, but we attempt to plug into this receptacle a device consuming 20A, the corresponding breaker will trip to avoid overheating of wiring that may result in a fire. Consequently, we will have to unplug the device causing the problem, find the breaker box and reset the breaker.

Advantages of overcurrent protection are:

- Simplicity
- Low cost

Disadvantages:

- Difficulties with coordination between relay systems

Distance Protection

To address the coordination difficulties that may occur in overcurrent protection, a distance protection scheme may be used. The objective of this scheme is to detect the impedance levels that are lower than predetermined values (relay settings).

The most popular type of distance protection is a step-distance relaying scheme for line protection, which consists of three distance relays or one 3-zone relay with the following zones of protection, shown in Fig. 4:

- Zone 1 covers 70-80% of the line, instantaneous trip
- Zone 2 covers 120-150% of the line, 20-30 cycles time delay (T2)
- Zone 3 covers 200% of the line and higher, 60 cycles and higher time delay (T3)

Advantages of distance protection are:

- Better sensitivity and selectivity

Disadvantages:

- Higher complexity and cost

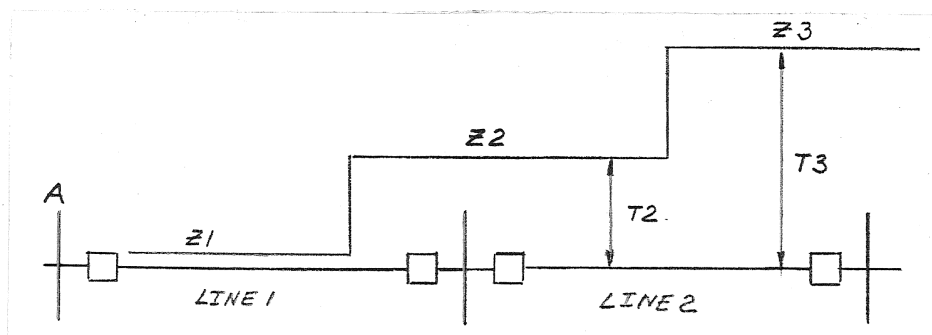


Fig. 4. Zones of Protection for a Typical Distance Protection Scheme

Differential Protection

For further improvement of relay protection schemes, let's consider a differential protection which has the following objective: differentiation between external and internal faults in reference to protected equipment by comparing the direction of currents on boundaries of protected equipment:

- For power lines – on both ends of the lines
- For transformers – on high and low voltage sides

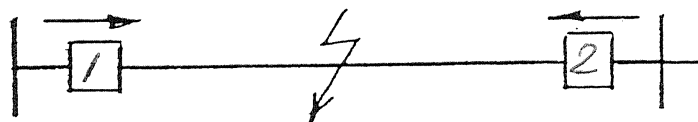


Fig. 5a. Current Directions during Internal Fault

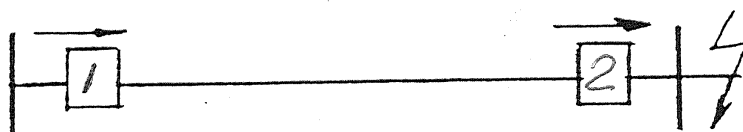


Fig. 5b. Current Directions during External fault

Logic of this type of protection may be explained using the line shown in Figures 5a and 5b:

- For internal fault, currents on both ends of the line are directed from the bus into the line. As a result, breakers 1 and 2 will trip clearing the fault.
- For external fault, current on one end (breaker 1) is directed from the bus into the line, but on another end (breaker 2) from the line into the bus. As a result, only breaker 2 will trip, but breaker 1 will stay closed and the line between breakers 1 and 2 will stay in service.

Advantages of differential protection:

- High accuracy
- High speed of clearing the fault

Disadvantages:

- Relative complexity
- Need in communication between ends of the line

Breaker Failure Protection

Besides specific types of relay protection that we've already discussed, there are some additional typical schemes that may supplement any kind of protection to improve overall reliability and flexibility of power system operation. Let's consider these supplemental schemes starting with a breaker failure protection. We already know that relay protection is supposed to localize and deenergize the faulted part of the system by tripping the circuit breakers closest to the location of the fault. But what will happen if the breaker that is supposed to trip, fails to do it (for example, because of some mechanical malfunction), or even worse, fails itself? Unless we do something different, the initial fault location will remain energized and the power system will be subjected to abnormal currents and voltages that may lead to serious equipment damage and unsafe conditions for personnel.

That's why, besides the regular line or transformer relay protection system, we need to install a breaker failure protection, whose mission is:

- Isolation of the faulted element of the power system if the circuit breaker associated with this element:
 - fails to clear the fault
 - fails itself

The logic of the breaker failure scheme of operation is as follows:

- Detection of fault current
- Initiation of a timer to give the closest to the fault circuit breakers opportunity to isolate it
- Tripping of all remote breakers after time delay (usually 6 to 15 cycles), if the fault is not isolated

As an example, let's consider a fault F1 on the line L1 in the system shown in Fig.6:

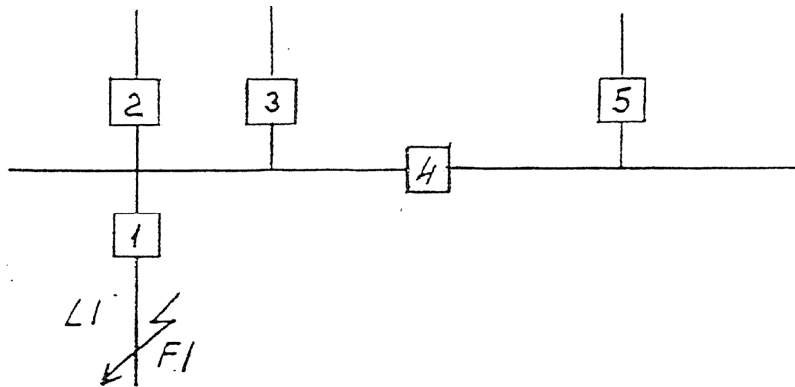


Fig. 6. Power System to Illustrate a Breaker Failure Protection Operation

Let's make an assumption that breaker 1 failed to clear the fault F1. In this case, a Breaker Failure Protection will trip adjacent breakers 2, 3 and 4. The corresponding logic diagram is shown in Fig. 7.

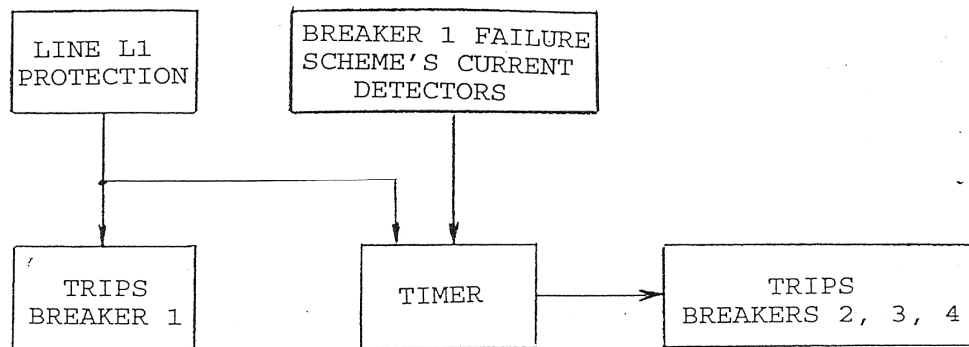


Fig. 7. Logic Diagram of Breaker Failure Protection Operation in Sys. Shown in Fig. 6.

Reclosing

Faults in power systems may be transient (temporary) or permanent. The example of a temporary fault is a tree branch falling on the overhead wires and after that, either going on fire or falling on the ground. In any case, the reason causing the fault disappears, but

the line remains deenergized because the line relay protection reacted on the original fault and tripped the breakers on both ends of the line. To avoid lengthy customer outages, we certainly would like to restore service to the customers and close the breakers if the fault passed. But the problem is that we never know if the fault is temporary or permanent. All we can do is close the breakers back after the relay protection tripped them, hoping that the fault is indeed temporary and the breakers will not trip again. This approach attempts to close the breakers after the fault is performed by a reclosing scheme whose mission is:

- Expeditious return of faulted power line back to service by reclosing of previously tripped circuit breakers (time delay is 6-24 cycles, depending on the voltage level of the line)

The following are the types of reclosing results:

- Successful – Fault is transient, breakers remain closed
- Unsuccessful – Fault is permanent, breakers trip again and stay open

Because faults on underground cables are almost always permanent, reclosing is applied only to overhead lines where a chance of a temporary fault (based on statistics) is about 70%.

Here are the following types of reclosing:

- Single shot – one reclosing attempt is made, usually on transmission lines
- Multi-shot – several reclosing attempts are made, usually on the low voltage lines
- Dead-line – reclosing on the deenergized line
- Synchro-check – reclosing on the energized line when voltages on both sides of the open breaker are in phase

Let's discuss the sequence of service restoration for an overhead line with two breakers shown in Fig. 8.

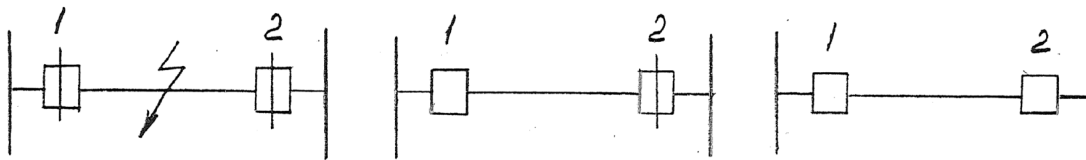


Fig. 8. Application of Reclosing for Restoration of Service

Let's assume that there is a fault on the line resulting in Breakers 1 & 2 tripping to isolate the fault. After a time delay, breaker 1 recloses (dead-line reclosing). If the fault persists, breaker 1 trips, breaker 2 (which has a synchro-check reclosing scheme) doesn't reclose because, from one side of it, voltage is 0, but from the other side, it is at a nominal level. If breaker 1 stays closed, breaker 2 recloses (again, through synchro-check reclosing) and stays closed.

Like any other relay scheme, reclosing has advantages and disadvantages as follows:

- Advantages: A high rate of successful reclosings (about 70% for overhead lines as mentioned earlier) allows to minimize customer interruption and expeditiously return the power system back to normal operation
- Disadvantages: If the fault is permanent, the circuit breaker has to interrupt a short circuit current again, which puts additional stress on the breaker and may lead to breaker failure, necessity for additional maintenance, etc.

Transfer Trip System

Another supplemental relay scheme that we want to consider is a Transfer Trip System, whose mission is to trip remote circuit breakers to increase speed of fault clearing or support a breaker failure scheme operation. To understand the benefit from a transfer trip system, let's consider a power system shown in Fig. 9, which is protected by a 3-zone step distance protection shown in Fig. 4.

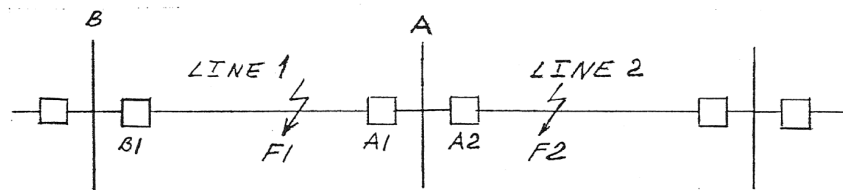


Fig. 9. Transfer Trip System Operation

Let's assume that fault F1 has the following location:

- Zone 1 of substation A distance protection
- Zone 2 of substation B distance protection

If this is the case, a fault clearing without a transfer trip system will be performed as follows:

- Trip of Breaker A1 is initiated instantaneously
- Trip of Breaker B1 is initiated with Zone 2-time delay

At the same time, we would like breaker B1 to trip without a delay as well to reduce a fault duration in the system. To make it happen, we need distance protection at Zone 1 of substation A, in addition to tripping of breaker A1 instantaneously to initiate a transfer trip system which would trip B1 instantaneously as well.

Transfer trip systems have the following pros and cons:

- Advantage: Increased speed of fault clearing

- Disadvantages:
 - Need for additional equipment (transmitters, receivers, etc.)
 - Need for communication channels

Communication Channels for Relay Protection

As we saw before, there are several relay schemes that are based on exchange of information between different parts of the power system (both ends of power lines, for example), which require establishment of some kind of channels to provide a media for communication of relay protection systems.

Specific areas of application for these communication channels are as follows:

- Line differential protection schemes
- Transfer trip schemes

The following types of channels are currently used:

- Power line carrier channels
- Fiber optic cables
- Pilot wire

Let's discuss these channels in a greater detail. The first type is a power line carrier (PLC) channel, which is based on transmission of high frequency signals (30 – 300 kHz) via overhead and underground power line conductors. The main issue that should be resolved in order to transmit a high frequency signal over the same wires and cables, which are used for transmission and distribution of AC power with 60 Hz frequency, is to direct a strong communication signal into relay systems which are communicating instead of it being mixed up with power frequency, getting dispersed into power equipment and attenuated. To have it accomplished, the PLC system includes numerous components shown in Fig. 10.

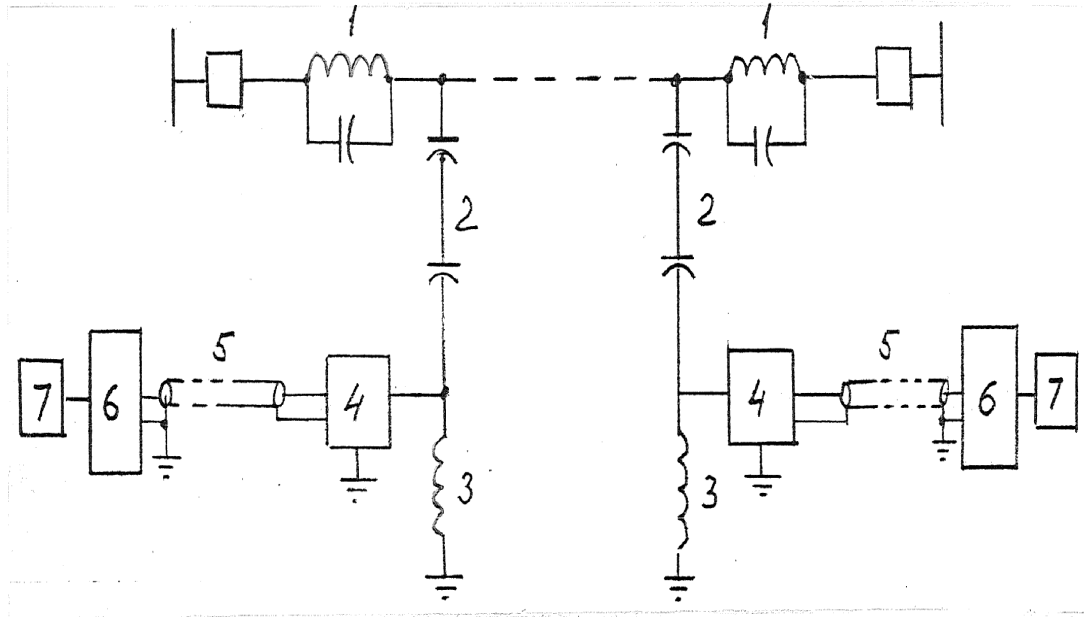


Fig. 10. Power Line Carrier Channel Line-up

Let's go through the following PLC components installed on each end of the line and their functions:

- Wave trap 1 prevents loss of communication signal into the station bus by providing:
 - High impedance for carrier frequency signals
 - Low impedance at power system frequency (50 or 60 Hz)
- Coupling capacitor 2 couples communication signals to power line, usually combining this function with serving as a CCVT (Coupling Capacitor Voltage Transformer)
- Drain coil 3 directs PLC signal into a line tuner by providing:
 - High impedance for carrier frequency signals
 - Low impedance for power system frequency (50 or 60 Hz) capacitive current
- Line tuner 4 provides a low impedance path for carrier frequencies
- Low loss coaxial cable 5 connects the line tuner with transmitter/receiver 6 and relay scheme 7

To better understand the logic behind the selection of different elements of a PLC system, let's, for example, design a wave trap which consists of inductor L and capacitor C connected in parallel (see Fig. 11).

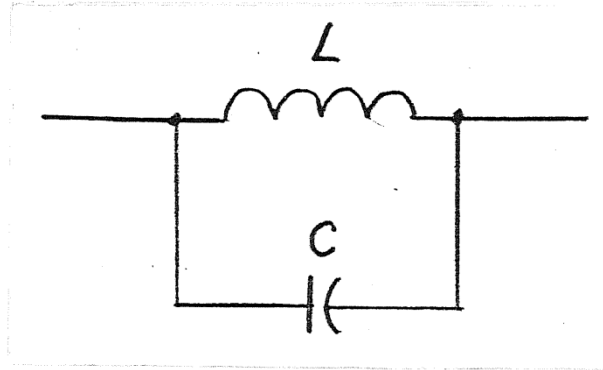


Fig. 11. PLC Wave Trap Schematic

The total impedance Z of this parallel contour may be found using coil and capacitor reactive impedances, $X(L)$ and $X(C)$ respectively, as follows:

$$Z = X(L) \times X(C) / (X(L) - X(C)), \quad (1)$$

where

$$X(L) = \omega \times L, \quad X(C) = 1 / (\omega \times C), \quad (2)$$

where, $\omega = 2\pi f$, and f is the carrier frequency (30 – 300 kHz)

As we can see from equation (1), a wave trap impedance for a carrier frequency signal reaches infinity ($Z = \infty$) if the following condition is met:

$$X(L) = X(C) \quad (3)$$

Using equation (3), let's for example calculate a capacitance C of wave trap for the following conditions:

- Coil inductance $L = 0.2 \text{ mH}$
- Frequency $f = 120 \text{ kHz}$

Solution:

Substituting $X(L)$ and $X(C)$ in equation (3) with their values from equation (2), and using $\omega = 2\pi f$, we obtain the following equation:

$$2\pi f \times L = 1 / (2\pi f \times C) \quad (4)$$

And from equation (4), capacitance C may be found as follows:

$$\begin{aligned} C &= 1 / (2\pi f \times 2\pi f \times L) = 1 / ((2 \times 3.14 \times 120,000 \text{ Hz})^2 \times 0.0002 \text{ H}) = \\ &= 0.0088 \times 10^{-6} \text{ F} = 0.0088 \text{ } \mu\text{F} \end{aligned}$$

Different examples of wave traps are shown in Fig. 12 and 13.



Fig. 12. 138 kV CCVT with 3000 A Wave Trap



Fig. 13. Free Standing 138 kV 2000 A Wave Trap

PLC has the following pros and cons:

- Advantages:
 - Low cost
 - Simplicity

- Disadvantages:
 - Attenuation of signal
 - Low speed of transmission

Because of these deficiencies, PLC is losing its former popularity by being replaced with more modern types of communication channels, most notably, fiber optic cables whose mission is transmission of light signals via optical fibers (long strands of very pure glass about a diameter of a human hair). The example of a fiber optic cable is shown in Fig. 14.

The installation options for fiber optic cables are as follows:

- Multi fiber cables pulled inside underground ducts
- As a FOG wire (combination of multi-fiber cable with steel shield wire) strained on transmission line towers
- Multi fiber cables hanged on distribution line poles



Fig. 14. 24-fiber Cable¹

Communication based on the application of fiber optic cables has the following pros and cons:

- Advantages:
 - High speed of signal transmission
 - High accuracy
 - Low attenuation of signal

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- Disadvantages:
 - High cost
 - Long restoration time after mechanical failure

The last type of communication channels to be mentioned is a pilot wire which is based on the use of actual (metallic) line installed between communicating relay systems. One of the pilot wire options is the use of a leased phone line for relay communication. Being in use for many years, relay schemes with a pilot wire communication became obsolete and, because of relatively low reliability of the channel, are frequently being replaced with systems based on the use of fiber optic cables for communication.

Metering Systems

To operate and maintain power systems efficiently, it is very important to have accurate information about system values, and the mission of metering systems is to provide this information. However, real power system currents and voltages may reach very high numbers (thousands of amperes and volts respectively). To measure these values, they need to be reduced to much lower numbers that metering equipment can safely handle. For voltages a nominal value is usually 120 V, phase-to-neutral or phase-to-phase, and for currents nominal values are 1 A or 5 A. As discussed in Section 1 of this course, this transformation of currents and voltages is performed by instrument transformers which have their secondary windings connected to both relay and instrument equipment.

All metering equipment may be split in the following functional groups:

- Indicating – provides information about present values of electrical quantities, for example:
 - Ammeters – measure current
 - Voltmeters – measure voltage
 - Ohmmeters – measure resistance, impedance
 - Wattmeters – measure active power
 - Varmeters – measure reactive power
 - Frequency meters
- Recording – records the value of measured electrical quantities over a period of time, for example:
 - Watt-hour meters – record amount of active power spent or transferred over period of time
 - Var-hour meters – record amount of reactive power spent or transferred over period of time
 - Demand meters – record the maximum average load over period of time
 - Oscillographs, digital fault recorders – monitor currents and voltages at different parts of the station to help with fault investigation

Based on how the measured information is presented, the following types of metering equipment should be mentioned:

- Analog – information is read from the scale (see example in Fig. 15)
- Digital – information is read in real numbers from LED screen (see example in Fig. 16)

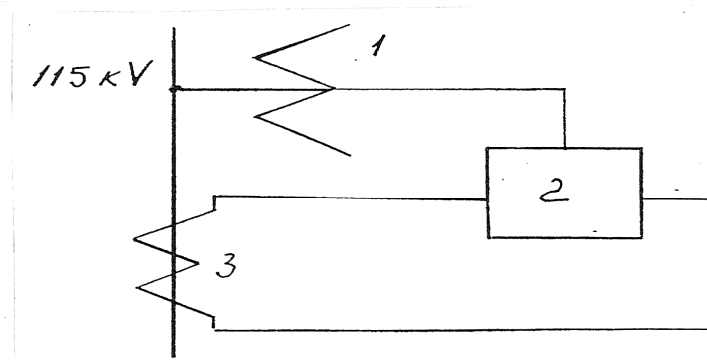


Fig. 15. Analog Single-Phase Voltmeter



Fig. 16. Digital Multi-value Instrument

As mentioned above, all metering equipment are connected to secondary windings of current and voltage transformers (for example, a typical wattmeter connection is shown in Fig. 17), and are using secondary currents and voltages to measure real primary electrical quantities. Let's discuss how this is performed.



1- Voltage Transformer; 2 – Wattmeter; 3 – Current Transformer

Fig. 17. Wattmeter's Connections to Measure Active Power in 115 kV Line

The following main equations are used to measure primary values by using the corresponding secondary quantities:

$$I_S = I_P / N_I \quad V_S = V_P / N_V \quad (5)$$

where:

I_P , I_S – Primary & Secondary Currents;
 V_P , V_S – Primary & Secondary voltages;
 N_I , N_V – Current & Voltage transformation factors

For a better understanding of the process, let's consider the following problem:

What is the actual apparent power S flowing through the 26-kV wye connected circuit, if phase ammeter and voltmeter readings are 3 A and 70 V, respectively, $N_I = 2000/5$ and $N_V = 26,400/120$ (both values are line voltages)?

Solution:

As we know, a three-phase power S may be found using primary phase current I_P and voltage V_P as follows:

$$S = 3 \times I_P \times V_P \quad (6)$$

Using equation (5), it may be rewritten in the following way:

$$S = 3 \times I_S \times N_I \times V_S \times N_V \quad (7)$$

Finally, plugging into equation (7) the actual numerical values given in the description of the problem, we obtain the following result:

$$S = 3 \times 3 \times (2000/5) \times 70 \times (26,400/120) = 3 \times 3 \times 400 \times 70 \times 220 = 55.44 \text{ MVA}$$

Auxiliary AC/DC Power Systems

For a normal operation, many substation components (including both major and control equipment) require some low voltage power supply (AC or DC) which is provided by auxiliary AC and DC power systems, respectively.

Let's review them both starting with the AC system. Its main components are:

- Station light and power transformers
- Automatic and manual transfer switches
- A.C. cabinets
- Cabling and wiring

The following are the examples of substation A.C. loads:

- Lighting
- Heaters
- A.C. motors for substation equipment:
 - Voltage regulators
 - Transformer cooling (fans, oil pumps, etc.)
 - Operators for switching equipment (breakers, circuit switchers, etc.)
- Battery chargers

Now let's conduct a similar review of an auxiliary DC system. Its main components (shown in Fig. 18) are:

- Batteries
- Battery chargers
- Battery fuse boxes
- D.C. cabinets
- Cabling & wiring



Fig. 18. Substation Auxiliary DC Equipment

The following are the examples of substation D.C. loads:

- Circuit breaker trip coils
- Indicating lights
- Emergency lighting
- Relay protection control circuits
- Alarm circuits
- D.C. motors for substation equipment

Substation engineers should size all the components of both auxiliary AC and DC systems based on analysis of all substation auxiliary loads.

Substation Alarm and Remote Control Systems

For effective and safe operation and maintenance of substations, utility companies' personnel should be alerted about all abnormal system conditions. This mission is fulfilled by substation alarm systems.

Alarms may be triggered by the following conditions:

- Equipment parameter deviation from normal leading to a possible failure:
 - High insulating oil temperature
 - Low oil level (oil leak)
 - High gas content in oil
 - Low isolating gas pressure (gas leak)
- Switching equipment trip by relay protection because of:
 - Fault in the system (short circuit, overvoltage, etc.)
 - Maloperation of relay protection
- Station fire

Alarms may be either local to alert personnel located at the substation, or remote to make centralized operating personnel aware of abnormal conditions detected at the station.

The following are the main components of the alarm systems:

- Sensors
- Visible alarms:
 - Annunciators
 - Lights
- Audible alarms:
 - Bells
 - Horns
- Transmitters and receivers for remote alarms

The example of a substation annunciator installed on a relay rack is shown in Fig. 19.



Fig. 19. 6- Window Substation Annunciator

As mentioned above, utility centralized operational personnel are getting alerted about abnormal conditions at the substation by remote alarm systems. But besides being aware of things going wrong, an operator should have capabilities to obtain additional information (system electrical quantities at the station, for example) and initiate necessary system changes to normalize the situation (operate switching equipment, for example). All these functions are fulfilled by remote control and operation systems whose mission is to provide remote control, indication and metering capabilities to utility operational personnel.

The main components of remote control and operation systems are as follows:

- At substation: Remote terminal units (RTU's)
- At dispatcher center: Centralized remote control unit
- Interface: fiber optic cable, radio, phone line, etc..

Conclusion

This course provided an overview of modern substation auxiliary and control systems, concentrating on their major role in supporting reliable and effective operation of power systems to enable you to:

- Describe the mission of relay protection systems and criteria they need to meet
- List types of relay protection schemes
- Explain what breaker failure protection and reclosing are for
- Identify the main components of power line carrier communication system
- Understand the principle of signal transmission using fiber optic cable
- Know the difference between analogue and digital types of metering equipment
- Calculate a real value of electrical system parameters using readings of meters and instruments
- Know the mission and main components of auxiliary A.C. and D.C. systems
- List the types of conditions triggering station alarm



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Fundamentals of Modern Electrical Substations - Part 3

Course No: E03-014
Credit: 3 PDH

Boris Shvartsberg, Ph.D., P.E., P.M.P.



Continuing Education and Development, Inc.

P: (877) 322-5800
info@cedengineering.com

Introduction

Part 3 of the course “Fundamentals of Modern Electrical Substations” is concentrated on substation engineering aspects, which may be very challenging and require from utility companies engineers a very diverse knowledge and experience to address these aspects.

The following topics include a description of specific problems associated with them as well as possible resolution options:

- Reliability Analysis
- Typical Substation Switching Systems
- Insulation Coordination
- Substation Safety and Fire Protection
- Substation Design Issues
- Substation Insulator’s Performance Improvement

While this list of topics does not include all technical issues that substation engineers may encounter, it provides a good idea about their complexity and importance for effective operation of power systems.

Reliability Analysis

As we discussed in Part 1 of this course, one of the main goals for every electrical utility company is to provide a high reliability of power supply to the customers. To accomplish this task, the company may invest in a power system infrastructure such as replacing the obsolete equipment, building additional power lines, etc. However, in order to select the most effective measures in reliability improvement, it is necessary to compare their effectiveness which explains the importance of reliability analysis.

Let’s familiarize ourselves with the basics of reliability theory which may be applied to any system, not only to power systems.

For a start, we need to discuss how to calculate the probability of failure for a single element of the system (for example, transformer, line, etc.). The following equation may be used to accomplish this:

$$p = \lambda r / 8,760 \quad (1)$$

Where:

p - probability of the element to be unavailable

λ - rate of failure (in failures per year)

r - average downtime per failure (in hours per failure)

and 8,760 represents a number of hours in a calendar year.

Now, let's discuss a probability of failure for the system consisting of numerous elements, starting with a series system, shown in Fig. 1.

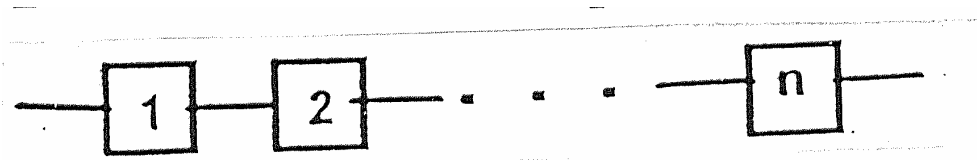


Fig. 1. System, Consisting of Elements Connected in Series

If a probability of failure for each element is p_1 , p_2 , etc., the probability of failure for the whole system may be found using the following equation:

$$P_{\Sigma} = p_1 + p_2 + \dots + p_n = \sum_{i=1}^n p_i$$

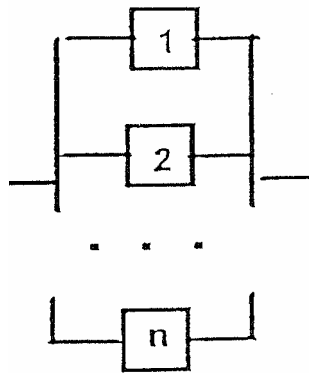


Fig. 2. System, Consisting of Elements Connected in Parallel

For a parallel system of elements, shown in Fig. 2, a similar equation for a probability of system failure may be written as follows:

$$P_{\Sigma} = p_1 \cdot p_2 \cdot \dots \cdot p_n = \prod_{i=1}^n p_i$$

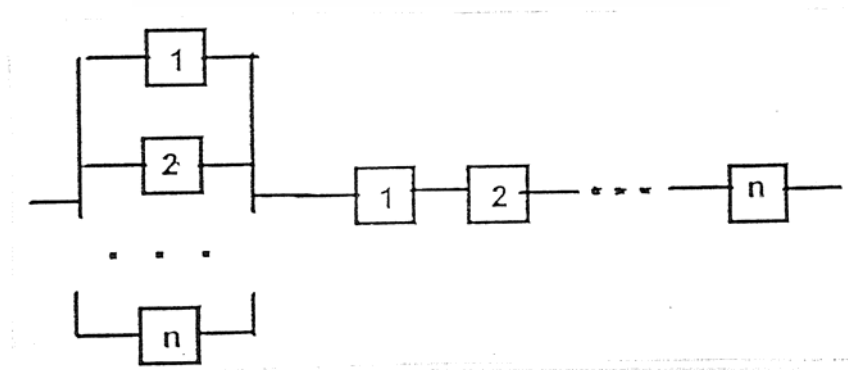


Fig. 3. System Consisting of Both Series and Parallel Elements

And finally, for a parallel-series system, shown in Fig. 3, the probability of system failure may be found from the following equation:

$$P_z = \prod_{i=1}^n P_i + \sum_{i=1}^n P_i$$

For a better understanding of reliability analysis, let's demonstrate it for the system, shown in Fig. 4.

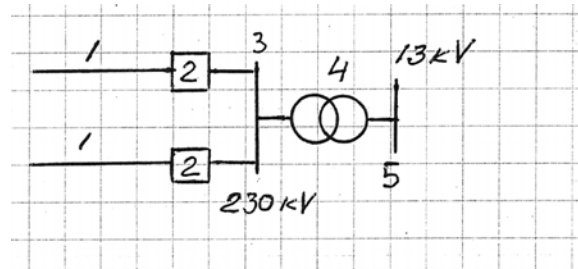


Fig. 4. Schematic of 230 – 13 kV Power System

The following reliability data is known for all system components:

	λ , failures/year	r, hours
1 - 30 mi long 230 kV line	0.05/mi	10.00
2 - 230 kV circuit breaker	0.06	8.00
3 - 230 kV bus	0.01	16.00
4 - 230/13 kV transformer	0.012	80.00

Assuming that for 13 kV bus 5, we need to find an expected downtime per year D_f because of loss of power supply, let's start with the calculations of probability of equipment unavailability:

- $P_1 = 0.05 \text{ fail./mi} \times 30 \text{ mi} \times 10 \text{ hr} / 8760 \text{ hr} = 0.00171$
- $P_2 = 0.06 \text{ failures} \times 8 \text{ hr} / 8760 \text{ hr} = 0.000055$
- $P_3 = 0.01 \text{ failures} \times 16 \text{ hr} / 8760 \text{ hr} = 0.0000182$
- $P_4 = 0.012 \text{ failures} \times 80 \text{ hr} / 8760 \text{ hr} = 0.0001095$

Now let's create a reliability analysis diagram for a power system shown in Fig. 4, considering how a failure of each element will affect the power supply for 13 kV bus 5. Obviously, if any one of 230 kV lines fails, relay protection will trip the corresponding breaker, and 13 kV bus will be fed through 230 kV bus and 230/13 kV transformer from 230 kV line remaining in service. So, 230 kV line elements (1) should be connected in parallel as far as 13 kV bus reliability is concerned.

If any of the 230 kV breakers fails, a breaker failure protection will trip another breaker and as a result, both 230 kV lines will be disconnected, and 13 kV bus will be deenergized. So, the 230 kV breaker elements (2) should be connected in series. The

same logic applies to 230 kV bus and 230/13 kV transformer elements; failure of each of them will lead to 13 kV bus losing power supply. Therefore, elements 3 and 4 should be connected in series as well. Based on the performed analysis, the overall reliability diagram may be drawn as follows:

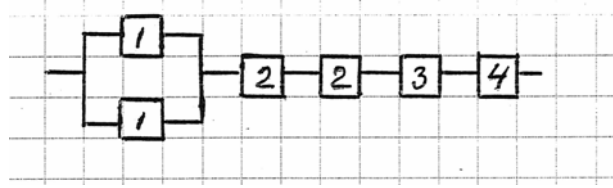


Fig. 5. Reliability Analysis Diagram

Now, using equations for reliability of systems consisting of elements connected in series and parallel, the overall probability p_5 of the 13 kV bus losing power supply may be found as follows:

$$\begin{aligned} P_5 &= P_1 \times P_1 + P_2 + P_2 + P_3 + P_4 \\ &= 0.00171 \times 0.00171 + 0.000055 + 0.000055 + 0.0000182 + 0.0001095 \\ &= 0.00024 \end{aligned} \quad (2)$$

And finally, an expected downtime per year D_f for the 13 kV bus 5 is:

$$D_f = P_5 \times 8760 \text{ hr} = 0.00024 \times 8760 \text{ hr} = 2.11 \text{ hr}, \quad (3)$$

Which means that during every calendar year the 13 kV bus is expected to be out of service 2.11 hours on average. This value seems to be small enough not to require any further actions, but it is still useful to discuss how reliability of a power system may be increased. One of the options is to provide a back-up for one of the system single elements. To see what effect it may have on the downtime of the 13 kV bus in our previous example, let's assume that we added another 230/13 kV transformer (element 6) to serve as an independent back-up for transformer 4. From the previous example, the probability of transformer 6 being unavailable is:

$$P_6 = P_4 = 0.0001095$$

Keeping in mind that now if one of the transformers fails and the second one is still going to feed the 13 kV bus, equation (2) for probability of this bus being out of service may be rewritten as follows:

$$\begin{aligned} P_5 &= P_1 \times P_1 + P_2 + P_2 + P_3 + P_4 \times P_6 \\ &= 0.00171 \times 0.00171 + 0.000055 + 0.000055 + 0.0000182 + 0.0001095 \times 0.0001095 \\ &= 0.0001311 \end{aligned}$$

Accordingly, equation (3) for the expected downtime of 13 kV bus in any given year will be as follows:

$$D_f = P_5 \times 8760 \text{ hr} = 0.0001311 \times 8760 = 1.15 \text{ hr}$$

So, D_f was reduced by a little more than 1 hr, and financial analysis should define if this improvement in reliability of customer power supply is worth the investment on the additional transformer.

Another way to improve reliability of a power system is to upgrade the substation switching system. With that said, let's familiarize ourselves with the different types of the substation switchyard arrangement presently used by utility companies and compare their advantages and disadvantages.

Typical Substation Switching Systems

Let's start our review of substation switching systems with the simplest one called "Single Straight Bus System" shown in Fig. 6.

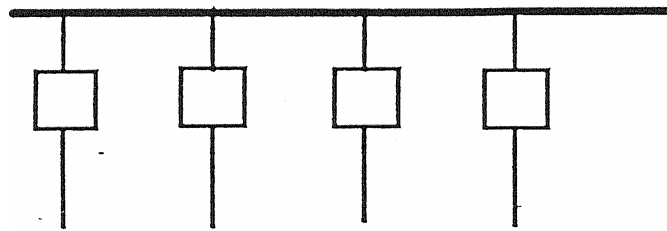


Fig. 6. "Single Straight Bus System"

This bus arrangement has the following advantages:

- Lowest cost
- Simplicity
- Easily expandable
- Small land area required

However, there are the following disadvantages as well associated with this system:

- Lowest reliability out of all switching systems
- Bus or breaker fault causes loss of the entire station
- Breaker removal for maintenance causes loss of corresponding line

Because of these deficiencies, single straight bus switching systems are rarely used for modern new substations. However, substations built more than 20 years ago still often have them. Even today, depending on how the whole system with interconnections between substations is arranged, straight bus may be considered for a specific substation if reliability of the whole grid is acceptable.

The next substation bus arrangement that we want to consider is a "Single Sectionalized Bus System", shown in Fig. 7, which provides a little bit more reliability and flexibility than just a straight bus without a sectionalizing breaker.

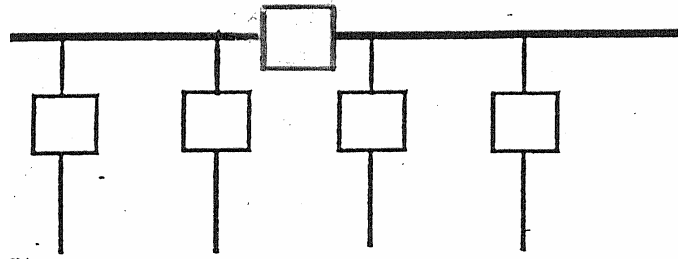


Fig. 7. Single Sectionalized Bus System

As we discussed in the Part 1 of this course, the main benefit of sectionalization of power systems is a reduction of customer outages associated with the the fault on the line, transformer, etc. This is exactly the case here. Comparing systems shown in Fig. 6 and 7, we can clearly see that if for a bus without a section breaker, a failure of any line breaker on the bus will lead to the outage of the whole station; whereas, for a bus with a section breaker, this type of fault will lead to the outage of only half of the station. The only situation when the whole station will be switched off is when a bus section breaker fails.

Let's summarize pros and cons for a single sectionalized bus system:

- Advantages:
 - Low cost
 - Simplicity
 - Easily expandable
 - Small land area required
 - Higher reliability than single bus system
- Disadvantages:
 - Additional breaker required
 - Sectionalizing breaker fault causes loss of the entire station
 - Breaker removal for maintenance causes loss of corresponding line

The next bus system to consider is a “Transfer Bus System”, shown in Fig. 8, which besides the main bus has a transfer bus connected to it through a transfer breaker.

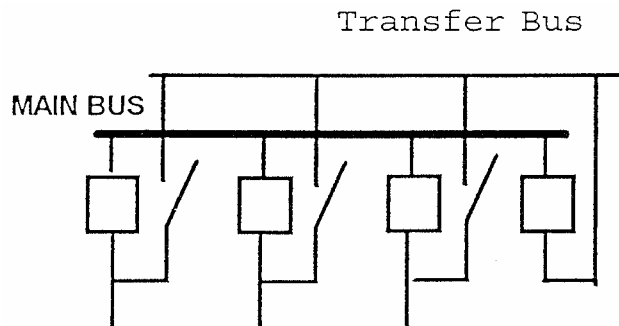


Fig. 8. Transfer Bus System

Compared with both previously discussed single straight bus options, a transfer bus system provides more operational flexibility because it allows taking any line circuit breaker out of service while leaving the corresponding line energized. As you can see from Fig. 8, after line breaker is disconnected on both sides (for simplicity purposes breaker disconnecting switches are not shown), the transfer disconnect will get closed and the transfer breaker will temporary protect the line whose permanent breaker is taken out of service. While representing a slight improvement from operational standpoint compared with single bus systems, a transfer bus arrangement has even lower reliability than a sectionalized bus, because as it was the case for a bus without a section breaker shown in Fig. 6, a failure of any breaker in a transfer bus system will lead to an outage of the whole substation.

Let's summarize advantages and disadvantages for a transfer bus system:

- Advantages:
 - Reasonable cost
 - Fairly small land area required
 - Any line stays in service during breaker maintenance
- Disadvantages:
 - Additional breaker is required
 - Any breaker or main bus fault causes loss of the entire station

Because of low reliability, all of the above mentioned switching systems lost their former popularity and are rarely used at modern substations. One of the more reliable and widely used bus arrangements is a ring bus system, shown in Fig. 9, which has two breakers associated with each outgoing circuit. Fault on any circuit will lead to both associated breakers tripping and breaking a ring which is acceptable.

If any of the breakers fail, the adjacent breakers will trip and two circuits will be taken out of service, not the whole station, as it was the case for a straight bus without section breaker and a transfer bus system. If we need to take any breaker out of service for maintenance or repair, the circuit will stay energized unlike it was for both single straight busses with or without section breaker, where taking out the line breaker leads to the outage on the line as well.

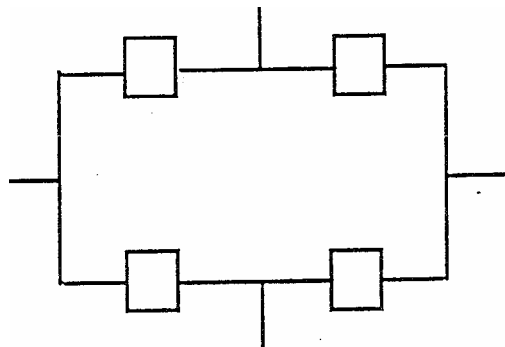


Fig. 9. Ring Bus System

Let's summarize pros and cons for a ring bus system:

- Advantages:
 - Flexible operation
 - High reliability
 - Double feed for each circuit
 - Any breaker may be removed without affecting the service
- Disadvantages:
 - Breakers should have high current rating based on a total load
 - Difficult to arrange
 - Any line fault trips two breakers

If reliability analysis shows that a ring bus is not reliable enough, the next step in increasing redundancy of power supply is application of a “Breaker-and-a-half” system, shown in Fig. 10.

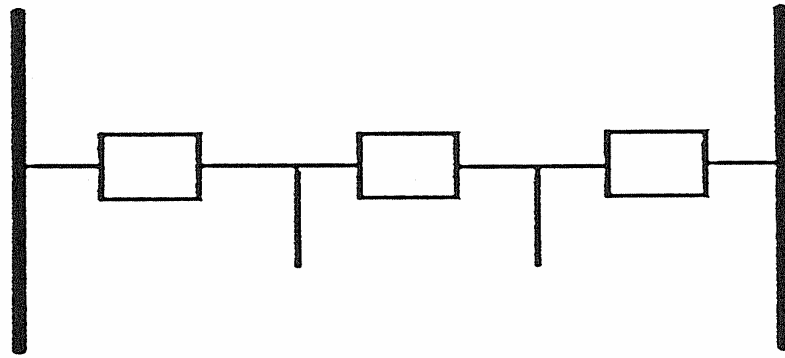


Fig. 10. Breaker-and-a-half Switching System

The strange name for this bus arrangement is based on the fact, that each bay of these switching systems (there is one bay shown in Fig. 10, but usually substation switchyard consists of several bays) has three (3) breakers for two (2) circuits. So, if you want to find formally how many breakers are associated with each circuit, this number will be $3/2$, or there are 1.5 breakers per circuit. Unlike it was the case with a ring bus system, where a failure of any breaker leads to taking 2 circuits out of service, for a breaker-and-a-half arrangement, only a failure of a middle breaker in the bay will lead to losing 2 circuits connected on each side of this breaker. For a failure of a breaker connected to any of the tie busses (left or right), only one circuit associated with this breaker will be switched off.

Advantages and disadvantages of a breaker-and-a-half system may be summarized as follows:

- Advantages:
 - Flexible operation
 - High reliability
 - Double feed for each circuit

- Any breaker may be removed without affecting the service
- Tie bus fault doesn't interrupt service to any circuit
- All switching done with circuit breakers
- Disadvantages:
 - 1 ½ breakers required per circuit
 - Complicated relaying

Again, if based on reliability analysis we still need a higher redundancy than breaker-and-a-half arrangement is providing, there is one more option left: it is so called “Double bus – double breaker”, shown in Fig. 11.

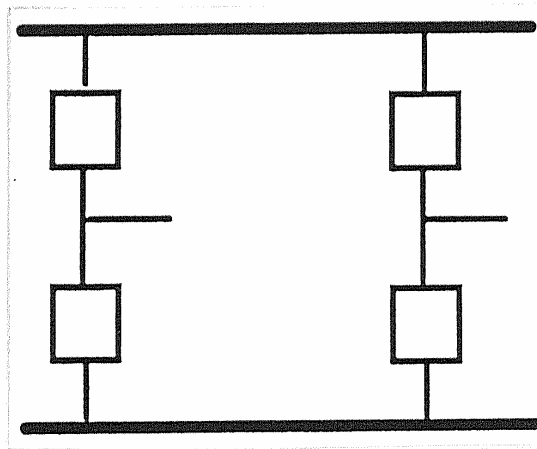


Fig. 11. Double Bus – Double Breaker System

As a step forward reliability wise, with a double bus – double breaker system, a failure of any breaker will never lead to the loss of more than one circuit, while for a breaker-and-a-half a failure of a middle breaker resulted in two circuits being switched off.

Let's summarize pros and cons of a double bus – double breaker switching system:

- Advantages:
 - Flexible operation
 - Very high reliability
 - Double feed for each circuit
 - Any breaker may be removed without affecting the service
 - Bus fault doesn't interrupt service to any circuit
 - All switching done with circuit breakers
 - Only one circuit is lost for breaker failure
- Disadvantages:
 - High cost
 - Two breakers required for each circuit

Finalizing our discussion about typical substation switching systems, I wanted to emphasize that selection of any specific bus arrangement needs to be based on financial analysis because any increase in reliability will lead to extra costs, and this investment should be justified before the more reliable switching system is chosen.

Insulation Coordination

Another important engineering task is to provide proper insulation for all substation elements. Let's start discussing this subject by answering the following basic questions:

- **What is insulation?** Insulation is a dielectric material (not conducting current)
- **Where is insulation required?** For all substation components it is required between:
 - Energized parts of different phases and/or circuits
 - Energized parts and the ground
- **What is required from insulation?** It should withstand without failure any voltage level in the system it is designed for.

For any system voltage, there is a certain standardized parameter called BIL (Basic Insulation Level) which defines if insulation is adequate. BIL is a specific insulation level expressed in kilovolts of the peak value of a standard lightning impulse, which insulation should withstand. For consistency purposes, it is accepted that this standard impulse reaches the peak value of voltage in 1.2 μ s and drops to the 0.5 of peak value in 50 μ s. There are specific BIL values required for each voltage system. For example, for the 26 kV system, a required BIL is 200 kV; for 138 kV, it is 650 kV; and for 230 kV it is 900 kV.

BIL requirement has a very significant impact on substation design because it introduces the required minimum phase-to-phase and phase-to-ground clearances. For example, for a 138 kV system (650 kV BIL), a minimum phase-to-phase clearance is 62" and phase-to-ground is 50".

Insulation of substation equipment should be coordinated to ensure that elements (for example, surge arresters) which are supposed to protect other equipment (for example, transformers) will fail first diverting overvoltage into the ground grid. This principle is illustrated in Fig. 12, where Curve B corresponds to impulse strength of the equipment insulation, and curves A & C represent characteristics of protective devices (surge arresters). As we can see, a withstand voltage of device A is higher than the one for B, but a withstand voltage of device C is lower than the one for B. From these facts, we may conclude that device C will protect the equipment, but device A will not.

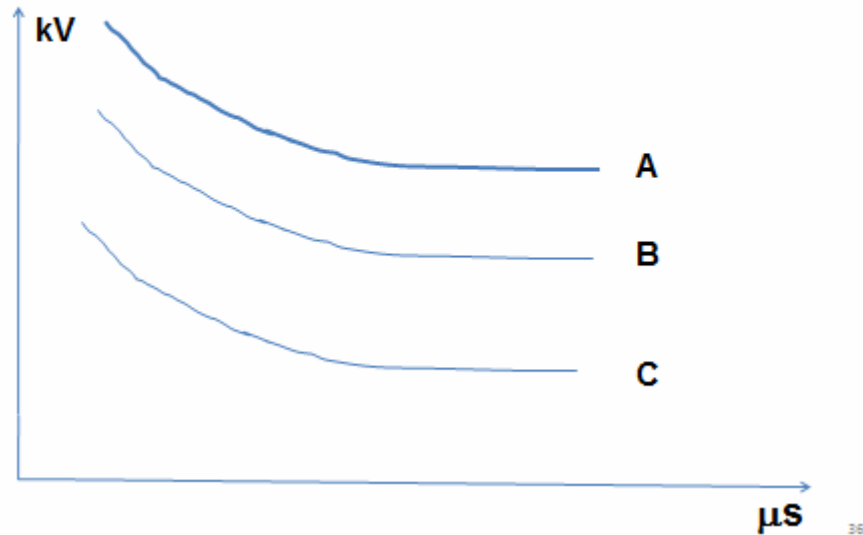


Fig. 12. Insulation Coordination

Substation Safety and Fire Protection

Another extremely important substation engineering aspect is associated with safety and fire protection. It is fair to say that safety is always a No. 1 priority in substation design, operation and maintenance. Unlike the case where a higher reliability required a larger investment, we can't put a price tag on safety since there is no such thing like working conditions being more or less safe. It should always be 100% safe to work at or visit the substation. There are numerous laws, rules, codes, etc. governing safety requirements; of the most important being "IEEE Standard C2-2012. 2012 National Electrical Safety Code®" (NESC®) [1]. The main mission of all these regulations is safeguarding of personnel from hazards arising from the installation, maintenance or operation of substation equipment. Safety standards contain requirements for:

- Enclosure of electrical equipment
- Rooms and spaces
- Illumination
- Floors, floor openings, passageways, stairs
- Exits
- Installation of equipment:
 - Protective grounding
 - Guarding live parts
 - Working space above electrical equipment
- Specific rules for installation of all typical substation equipment

All these measures are based on common sense and the goal to provide a safe environment for substation personnel. The following requirements may be mentioned as an example:

1. Enough clearance from energized parts should be provided to avoid accidental contact with them. If that can't be met, live parts should be guarded or enclosed.
2. A minimum height from the ground to any ungrounded part of an electrical installation should be 8'-6", so a person staying on the ground can't touch a substation element or its part which may become energized accidentally. For example, the bottom of a post insulator supporting an energized bus does not normally have any potential. However, if bus flashover to the ground over insulator occurs, touching the bottom of the insulator may become unsafe. That's why an 8'-6" distance from the bottom of insulator to the ground should be provided.
3. There should be sufficient illumination for personnel to clearly see their surroundings and perform any work safely. Required illumination levels are specified in NESC® [1].
4. All passageways and stairs should be wide enough for personnel to navigate them safely, adequate railing should be provided, and floor openings should have guard rails.
5. Exits should be clearly marked and evacuation routes should be free from obstructions. Depending on the function of the building (for example, control house), it may require several exits to avoid personnel being trapped during equipment fault, fire, etc.
6. All substation metallic structures, fences, and equipment tanks should be connected to a station ground grid which should be designed to ensure that step and touch potential values are lower than the ones stipulated in the applicable standards.

Another important topic related to safety is substation fire protection whose mission is to protect substation personnel, equipment and buildings from fire and prevent fire from spreading. As it was with safety, there are numerous guides and standards for substation fire protection.

The following means of fire protection are used:

- Separation of equipment
- Installation of protective fire walls
- Deluge systems
- Application of fire retardant materials for substation buildings
- Fire alarm system
- Installation of oil retention pits for oil containing equipment

- Appropriate substation design to prevent fire from spreading from one part of the station to another; for example, avoidance of uneven substation surface profile

The example of a fire wall protecting different substation components from fire is shown in Fig. 13.



Fig. 13. 138 kV Cable Oil Pump House with a Fire Wall

Substation Design Issues

Building a new substation or retrofitting the old one is a complex process full of design and engineering tasks to be worked on. The main steps in Substation Design and Engineering are as follows:

- Selection of a substation switching system: ring bus, breaker-and-a-half, etc. based on reliability requirements
- Preparation of a key plan which should show the location of all components of a substation and their interconnections, as well as steel structures, control house, fire walls, driveways, fence and property line
- Selection and ordering of equipment, which is usually done in a utility company by a designated group of equipment experts who specify transformers, breakers, etc., request bids from approved vendors, evaluate the bids, place the order with a winning bidder, and participate in testing and commissioning of equipment
- Engineering support for licensing and permitting which includes preparation of necessary drawings sealed by Professional Engineers, testifying at public hearings at the municipalities where a new substation is planned to be built, ordering of noise studies and selecting means of noise mitigation if needed

- Civil and Structural design which includes:
 - pile design
 - foundations
 - steel structures
 - control house
- Electrical layout design which includes:
 - Positioning of equipment
 - Bus design
 - Design of manhole and conduit system
 - Design of auxiliary A.C. power system
 - Selection of D.C. batteries and battery chargers
 - Layout of control house
 - Grounding and lightning protection design
- Control design which includes:
 - Relay protection and instrumentation system schematics and wiring diagrams
 - Relay racks or panels
 - Remote control and metering (SCADA – system control and data acquisition)
- Construction support which includes a resolution of technical problems discovered during construction, ordering of additional materials, etc.

Because selection of equipment is one of the most critical tasks in substation engineering, let's discuss this process in a greater detail, starting with the following examples of major equipment ratings:

- Power transformer ratings:
 - Capacity including overload capability
 - Cooling class
 - Frequency
 - Primary and secondary voltage
 - Phase relation between primary and secondary voltages
 - BIL for both high and low voltage sides
 - Voltage regulation requirements: load and no-load taps
 - Transformer impedance
 - Sound level
- Circuit breaker ratings:
 - Rated maximum voltage
 - Rated continuous current
 - BIL
 - Rated short circuit current
 - Interrupting time
 - Rated frequency

- Current transformer (CT) ratings:
 - BIL
 - Rated current
 - Rated frequency
 - Number of taps and ratio for each tap
 - Accuracy class
 - Type (bushing CT, free standing, etc.)

To better understand a process of equipment selection, let's discuss an example of choosing 138 kV Line #3 Circuit Breaker, shown in Fig. 14, assuming that the following information about the system is available:

- Continuous current for all the lines:
 - Line #1 – 1,000 A,
 - Line #2 – 1,500 A,
 - Line #3 – 800A
- 3-phase fault current on the bus is 46.5 kA, contributions from the lines:
 - Line #1 – 24.5 kA,
 - Line #2 – 12 kA,
 - Line #3 – 10 kA
- Projected Substation load growth is 25%
- Available breaker ratings:
 - Continuous current: 1,200 A, 2,000 A, 3,000 A
 - Short circuit interrupting capability: 40 kA, 50 kA

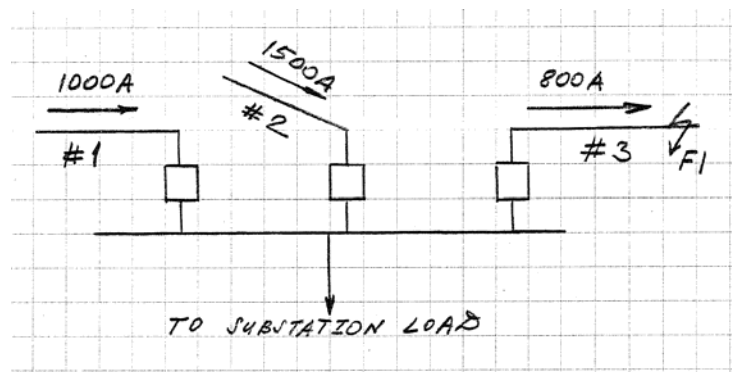


Fig .14. Power System for Example of 138 kV Breaker Selection

Solution:

1. Future load considering 25% growth:
 $(1000 \text{ A} + 1500 \text{ A} - 800 \text{ A}) \times 1.25 = 2,125\text{A}.$

2. This load may be fed from Line #3 through its circuit breaker if lines #1 and #2 are switched off. So, the breaker should be sized to carry at least 2,125 A. Closest available continuous rating meeting this requirement is 3,000 A.
3. Maximum 3-phase fault current that Line #3 breaker needs to interrupt may be calculated by deducting from a total bus fault current a contribution from line #3, i.e. $46.5 - 10 = 36.5\text{kA}$
4. Closest short circuit current interrupting rating and meeting requirement to be at least 36.5 kA is 40 kA
5. This is a summary of the selected circuit breaker ratings:
 - 5.1. Rated maximum voltage – 138 kV
 - 5.2. Rated continuous current – 3,000 A
 - 5.3. BIL – 650 kV
 - 5.4. Rated short circuit current – 40 kA

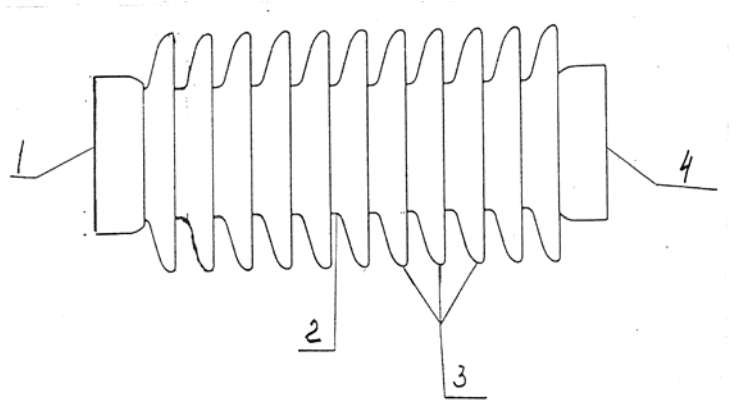
As you can see, selection of equipment for a specific application requires an input data which may be obtained from system studies. Such data include power flows, load projection, short circuit current calculations, etc., which are usually performed by utility company planners.

Substation Insulator's Performance Improvement

As we discussed before, insulation needs to be provided between energized parts and the ground as well as between phases of the same circuit or different circuits. One of the substation components providing a required insulation between energized conductors and grounded structures are Substation Insulators whose main types are as follows:

- Station post insulators
- Equipment (transformer, breaker) bushings
- Equipment (CCVT, surge arrester, etc.) insulating columns

Insulator materials are either porcelain or polymer. For each insulator, there are numerous electrical and mechanical properties specified, which are used by substation designers and engineers in their calculations. Typical porcelain station post insulator is shown in Fig. 15.



1 – Cap; 2 – Porcelain body; 3 – Skirts (Petticoats); 4 - Base

Fig. 15. Station Post Insulator

Substation design is based on the assumption that substation insulators will retain their insulating abilities. In reality, there are numerous factors that may affect insulator performance, thereby making them unsuitable for an intended application.

Let's discuss the most common problems related to substation insulators and possible ways to resolve them.

One of these problems is icing which represents a build-up of ice along the surface of the insulators, thereby bridging petticoats and resulting in flashovers along the surface of the insulators and in equipment damage. Icing may be prevented by the following measures:

- Insulator surface coating (usually silicon) which prevents ice buildup
- Application of “high creep” insulators with longer than standard skirts which prevents ice bridging
- Installation of creepage extenders which are mostly used on existing insulators after it was discovered that they are susceptible to icing. Post insulators with extenders are shown in Fig. 16
- Application of RGI (resistance graded insulators) which have a conductive coating, providing a path for leakage currents and warming a surface of insulator body, thereby preventing icing



Fig. 16. 138 kV Post Insulators with Creepage Extenders

The next problem with insulators frequently encountered by substation maintenance personnel is pollution which represents a deposit of pollutants (salt, dust, ashes, etc.) on the surface of insulators, resulting in flashovers, tracking along the surface of insulator and ultimately leading to insulator and equipment damage. The main remedy for pollution is naturally cleaning and washing of insulators, which needs to be done periodically as a part of substation maintenance.

Another serious problem associated with insulator maintenance is prevention of animal contacts with energized substation busses and bare cables. The most common animal intruders are squirrels and raccoons who for some reason are often climbing on substation structures and touching conductors while bypassing the supporting insulators. Usually this problem is associated with distribution voltages up to 26 kV.

The consequences of these encounters are flashovers leading to equipment damage. The following measures may be used to prevent animal contacts:

- Installation of rubber boots, sleeves, etc. over bus connectors
- Insulation of bare conductors using insulating tape, conduits
- Application of insulating paint over metal surfaces: transformer tank, etc.

An example of implementation of these measures is shown in Fig. 17.



Fig. 17. 13/4 kV Transformer 13 kV Bushings and surge arresters with rubber boots

Conclusion

This part of the course provided an overview of modern substation engineering aspects, concentrating on a detailed description of typical issues and their possible resolution options to enable you to:

- Analyze reliability of power supply systems
- Describe typical substation switching systems, their advantages and disadvantages
- Understand basics of insulation coordination
- Clearly understand the importance of safety in substation design and engineering
- List means of substation fire protection
- Describe steps in substation design and engineering
- Select substation equipment
- Describe how to improve substation insulator's performance

References

1. IEEE Standard C2 -2012. 2012 National Electrical Safety Code® (NESC®).