Univerza v Ljubljani
Fakulteta za elektrotehniko
Tržaška 25, 1000 Ljubljana, Slovenija

# Overcurrent protection

Seminar paper

Razdelilna in industrijska omrežja

Mentor: Student:

Prof. dr. Grega Bizjak, univ. dipl. inž. el. Genc Baruti

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**List of abbreviations used**

CT – current transformer

VT – voltage transformer

RTD – resistance temperature detector

RALF – rated accuracy limit factor

IOC – instantaneous overcurrent

DOC – definite time overcurrent

IDMT – inverse definite minimum time

CB – circuit breaker

# Abstract

*The aim of this seminar paper is to give a review on overcurrent protection. First, development of relays is described. Furthermore, protection relay is shortly described, then basic objectives of protecting the power systems are described. Furthermore, current transformers are shortly described. In the end, overcurrent protection is fully described.*


# 1. Introduction

Relay development begins with electromechanical relays. Over the past decades, static relays were used, while nowadays microprocessor relays are used.

Electromechanical relays are the oldest generation of relay and have been in use for a long time, they started to be used from 1900 until 1963. These relays have earned a reputation for accuracy, safety, and reliability.

*Figure 2.1.1 Electromechanical relay*

*Figure 2.1.2 Static relay*

Static relays represent the second generation of the relays. These relays have started to be used around the early 60's. The term static means that the relay does not have mechanical moving parts in it. Compared to electromechanical relays, static relays have a higher life expectancy, then they have a reduction in noise during operation and react faster in case of any failure.


*Figure 2.1.3 Microprocessor relay*

Microprocessor relays represent the latest generation of relays, the most advanced generation of relays. Their use began about two decades ago. Microprocessor technology allows these relays to have features like static relays and even more. In these relays, the signals of currents and voltages from current and voltage transformers first are processed as analog signals and then converted to digital signals for further processing.

# 2. What is protection relay?

Protection relay is a smart device that receives data compares them with reference values, and delivers results. Incoming data can be current, voltage, resistance or temperature. Results can include visual information in the form of indicator lights and/or an alphanumeric display, communications, control warnings, alarms, and power on and off. The diagram below answers the question of what is the protection relay.

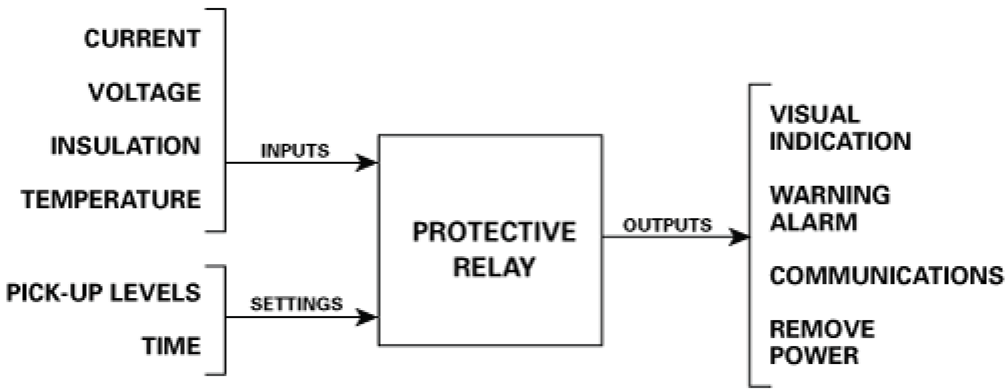



*Figure 2.1.1 Incoming and outgoing data of relay*

## 2.1 Input data

Relay needs information from the system to take a decision. These data can be collected in various ways. In some cases, the cables in the area can be connected directly to the relay. In other applications, additional equipment needed to convert the measured parameters as in a form that can relay process. These accessories can be carrier current transformers, voltage transformers, RTD (Resistance Temperature Detector) or other equipment.

## 2.2 Reference values

Many protection relays have adjustable parameters. The user sets the parameters so that the relay respond to the parameterization limit. Relay compares input values with the values of these parameters and responds accordingly.

## 2.3 Processes

Once entries (data) are connected and the parameters are set in the relay, the relay compares these values and takes a decision. Depending on the needs of different types of relays are available for various functions.

## 2.4 Outputs (Results)

Relay has different ways of communicating. In typical relay, order will act on a switch (relay contact) to indicate that an input value has exceeded a parameter, or relay can provide a notification by a visual feedback such as an instrument or LED. One advantage of the electronic relays is the ability to communicate with a network or PLC.

# 3 Basic objectives of protecting the power system

The main objective of protecting the power system is to provide quick isolation of the power system's area with fault, in order that shock in the rest of system to be minimized and to be intact for as long as possible. In this context, there are five basic aspects of the protection relay application.

Before we talk for them, it should be noted that the use of the term protection does not mean that protective equipment can prevent problems, such as errors and equipment failures or electrical shocks due to unintentional human contact. It cannot predict problems. Protection relays operate only after an abnormal or intolerable situation that has occurred. This protection does not mean prevention, but rather, minimizing the duration of the problems and limitations of damages, the time of interruption, and similar problems.

Five basic aspects of protection relay application are:

1. Reliability: security that protection will function correctly.
2. Selectivity: maximal continuity of service with minimum disconnection system.
3. The speed of operation: the minimum duration of the fault, damage to equipment and system instability.
4. Simplicity: minimum protective equipment and related circuits to achieve the objectives of protection.
5. Economy: maximum protection with minimum cost.

## 3.1 Reliability

Reliability has two aspects, safety and security. Safety is defined as "the security levels which a relay will function properly". The security has to do with "the level of security that a relay will not act wrongly." In other words, safety it shows protection system's ability to work properly when required, while the security is the ability to avoid unnecessary operations during normal operation.

## 3.2 Selectivity

Relays have a designated area known as the primary protection zone, but they can operate properly on responses to conditions outside this zone. In these cases, they provide backup protection for the area outside the primary area. Selectivity (coordination of the relay) is the application process and the establishment of relay protection that surpasses other relays that they can act as quickly as possible within their primary area of operation but has delays in the reserve area. This is necessary to allow the primary relay to operate in the reserve area.

## 3.3 Speed

Of course, it is desirable for the protection to isolate the problem area as quickly as possible. In some applications, it is not difficult, but in some other, especially when selectivity is involved, faster operation can be achieved by more complex protection and higher costs.

## 3.4 Simplicity

A relay protection system should be simple and direct as much as possible. Each unit or added components, which may provide improved protection, but it is not necessary under the protection requirements should be considered very carefully.

## 3.5 Economy

It is essential to have maximum protection with minimum cost, and the cost is always a major factor. The protection system with the lowest cost cannot be trusted, moreover, it can involve greater difficulties in the installation and its operation, as well as higher maintenance costs.

# 4 Current transformers

Current transformer (CT) is a type of measuring transformers which is designed to produce alternative current in the second winding that is proportional to the measured current in the primary winding.

Current transformers reduce currents of high voltage systems to a much lower value and provide a convenient way to safely monitor the flow of current in transmission lines using a standard ampere meter. The working principle of current transformers is the same as an ordinary transformer.

Unlike ordinary transformer, the current transformer has one or several windings in the primary winding, while secondary winding, on the contrary, may have a greater number of windings. In the secondary winding are normally selected to pass currents of 1A or 5A.

## 4.1 Current transformers for protection

There are two requirements of current transformers for protection: they must have the rated accuracy limit factor (RALF) and an adequate accuracy class for the application.

The rated accuracy limiting factor (RALF) represents the ratio between the accuracy of limiting current to the primary nominal current:

$$RALF = \frac{I_{1l}}{I_{1n}}$$

where the primary limiting current is the current for which the error is less than 5% for the accuracy class 5P or 10% for the accuracy class 10P.

Based on the IEC standards, the rated accuracy limit factor has the following values: 5 - 10 - 15 - 20 – 30

Rated output at rated secondary is the value, marked on the rating current plate, of the apparent power in VA that the transformer is intended to supply to the secondary circuit at the rated secondary current.

# 5 Overcurrent protection

Transmission and distribution systems are exposed to overcurrent flow into their elements. In an electric power system, overcurrent or excess current is a situation where a larger than intended electric current exists through a conductor, leading to excessive generation of heat, and the risk of fire or damage to equipment. Possible causes for overcurrent include short circuits, excessive load, transformer inrush current, motor starting, incorrect design, or a ground fault. Therefore, for normal system conditions, some tools such as demand - side management, load shedding, and soft motor starting can be applied to avoid overloads. In addition, distribution systems are equipped with protective relays that initiate action to enable switching equipment to respond only to abnormal system conditions. The relay is connected to the circuit to be protected via CTs and VTs according to the required protection function.

In order for the relay to operate, it needs to be energized. This energy can be provided by battery sets (mostly) or by the monitored circuit itself.

## 5.1 Overcurrent relays

The basic element in overcurrent protection is an overcurrent relay. The ANSI device number is 50 for an instantaneous overcurrent (IOC) or a Definite Time Overcurrent (DTOC) and 51 for the Inverse Definite Minimum Time. There are three types of operating characteristics of overcurrent relays:

- Definite(Instantaneous)-Current Protection,
- Definite-Time Protection and
- Inverse-Time Protection.

## 5.2 Definite(instantaneous)-current protection

This relay is referred as definite(instantaneous) overcurrent relay. The relay operates as soon as the current gets higher than a preset value. There is no intentional time delay set. There is always an inherent time delay of the order of a few milliseconds.

The relay setting is adjusted based on its location in the network. The relay located furthest from the source, operates for a low current value. Example, when the overcurrent relay is connected to the end of distribution feeder it will operate for a current lower than that connected in beginning of the feeder, especially when the feeder impedance is larger. In the feeder with small impedance, distinguishing between the fault currents at both ends is difficult and leads to poor discrimination and little selectivity at high levels of short-circuit currents. While, when the impedance of feeder is high, the instantaneous protection has advantages of reducing the relay's operating time for severe faults and avoiding the loss of selectivity.

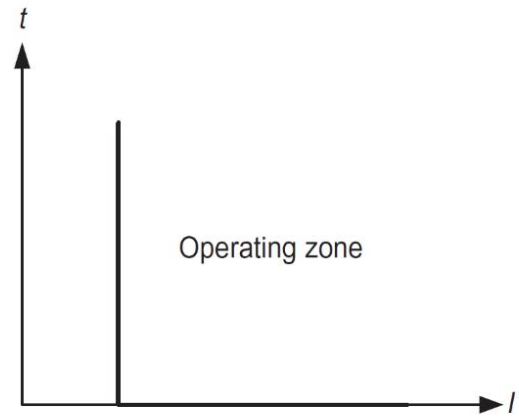


*Figure 5.2.1 Definite-current characteristic*

## 5.3 Definite-time protection

In this type, two conditions must be satisfied for operation (*tripping*), current must exceed the setting value and the fault must be continuous for at least a time equal to the time setting of the relay. This relay is created by applying intentional time delay after crossing pick up value of the current. A definite time overcurrent relay can be adjusted to issue a trip output at definite amount of time after it picks up. Thus, is has a time setting and pick up adjustment. Modern relays may contain more than one stage of protection each stage includes each own current and time setting. The settings of this kind of relay at different locations in the network can be adjusted in such a way that the breaker closest to the fault is tripped in the shortest time and then the other breakers in the direction toward the upstream network are tripped successively with longer time delay.

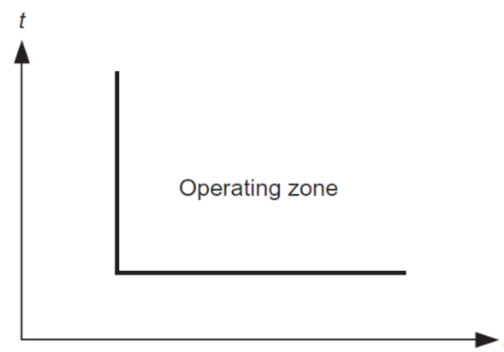


*Figure 5.3.1 Definite-time characteristic*

The disadvantage of this type of protection is that it's difficult to coordinate and requires changes with the addition of load and that the short-circuit fault close to the source may be cleared in a relatively long time in spite of its highest current value.

Definite time overcurrent relay is used as a backup protection of distance relay of transmission line with time delay, backup protection to differential relay of power transformer with time delay and main protection to outgoing feeders and bus couplers with adjustable time delay setting.

## 5.4 Inverse-Time Protection

In this type of relays, operating time is inversely changed with the current. So, high current will operate overcurrent relay faster than lower ones. They are available with standard inverse, very inverse and extremely inverse characteristics. Inverse Time relays are also referred to as Inverse Definite Minimum Time (IDMT) relay. The operating time of both overcurrent definite-time relays and overcurrent inverse-time relays must be adjusted in such a way that the relay closer to the fault trips before any other protection. This is known as time grading. The difference in operating time of these two relays for the same fault is defined as discrimination margin.

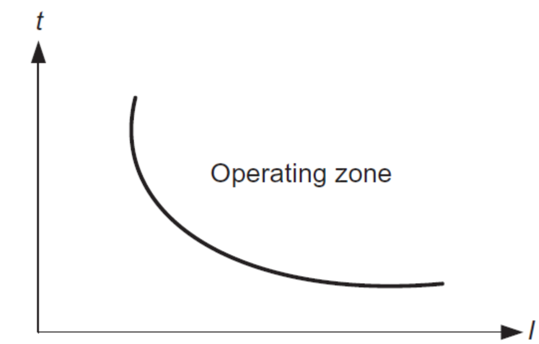


*Figure 5.4.1 Inverse-time characteristic*

The adjustment of definite-time and inverse-time relays can be carried out by determining two settings: time dial setting and pickup setting. The time dial setting adjusts the time delay before the relay operates whenever the fault current reaches a value equal to, or greater than, the relay current setting. The time dial setting is also referred to as the time multiplier setting. The tripping characteristics for different TMS settings using the IEC 60225 are shown in the table to the right.

| Relay Characteristic | Equation (IEC 60255) |
|---|---|
| Standard Inverse (SI) | $t = TMS \times \frac{0.14}{I_r^{0.02} - 1}$ |
| Very Inverse (VI) | $t = TMS \times \frac{13.5}{I_r - 1}$ |
| Extremely Inverse (EI) | $t = TMS \times \frac{80}{I_r^2 - 1}$ |

*Table 5.4-1 Definition of standard relay characteristics*

Pickup setting is used to define the pickup current of the relay by which the fault current exceeds its value. It is determined by:

$$Pickup\ setting = \frac{K_{ld} \times I_{nom}}{CT}$$

where:

$K_{ld}$ – overload factor,

$I_{nom}$ – nominal rated current, and

$CT$ – current transformer ratio.

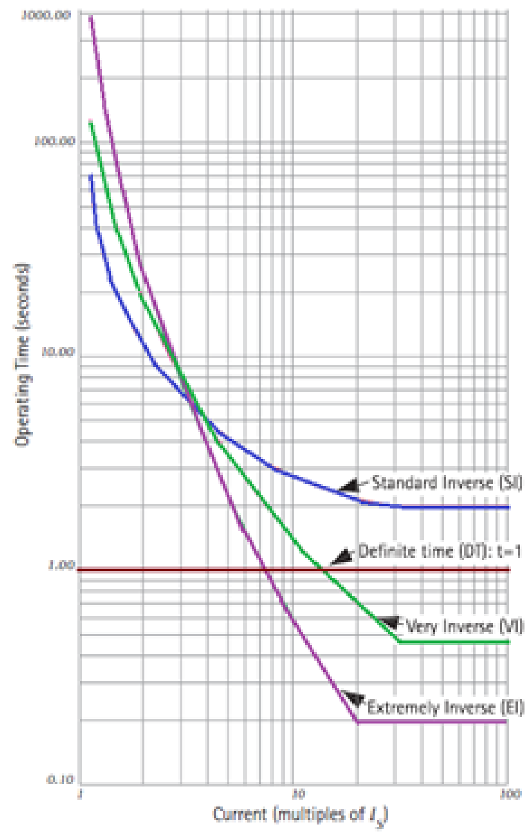



*Figure 5.4.2 Types of inverse-time characteristics*

As we can see from the Fig. 6.4.2 the VI curve is much steeper and therefore the operation increases much faster for the same reduction in current compared to the SI curve. Very inverse overcurrent relays are particularly suitable if there is a substantial reduction of fault current as the distance from the power source increases.

With EI characteristic, the operation time is approximately inversely proportional to the square of the applied current. This makes it suitable for the protection of distribution feeder circuits in which the feeder is subjected to peak currents on switching in, as would be the case on a power circuit supplying refrigerators, pumps, water heaters and so on, which remain connected even after a prolonged interruption of supply.

# 6 Coordination of overcurrent relays

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. According to [1], the data required for a relay setting study are:

- a one-line diagram of the power system involved, showing the type and rating of the protection devices and their associated current transformers,
- the impedances in ohms, percent or per unit, of all power transformers, rotating machine and feeder circuits,
- the maximum and minimum values of short circuit currents that are expected to flow through each protection device,

- the maximum load current through protection devices,
- the starting current requirements of motors and the starting of induction motors and
- the transformer inrush, thermal withstand and damage characteristics.

The relay settings are first determined to give the shortest operating times at maximum fault levels and then checked to see if the operation will also be satisfactory at the minimum fault current expected. Also, according to [1] the basic rules for correct relay co-ordination can generally be stated as follows:

- whenever possible, use relays with the same operating characteristic in series with each other
- make sure that the relay farthest from the source has current settings equal to or less than the relays behind it, that is, that the primary current required to operate the relay in front is always equal to or less than the primary current required to operate the relay behind it.

Among the various possible methods used to achieve correct relay co-ordination are those using either time or overcurrent, or logic coordination. The common aim of all three methods is to give correct coordination.

## 6.1 Time-Based Coordination

In this method, an appropriate time setting is given to each of the relays controlling the circuit breakers in a power system to ensure that the breaker nearest to the fault opens first. The closer the relay is to the source, the longer the time delay. A simple radial distribution system is shown in Figure 7.1.1 to illustrate the principle.

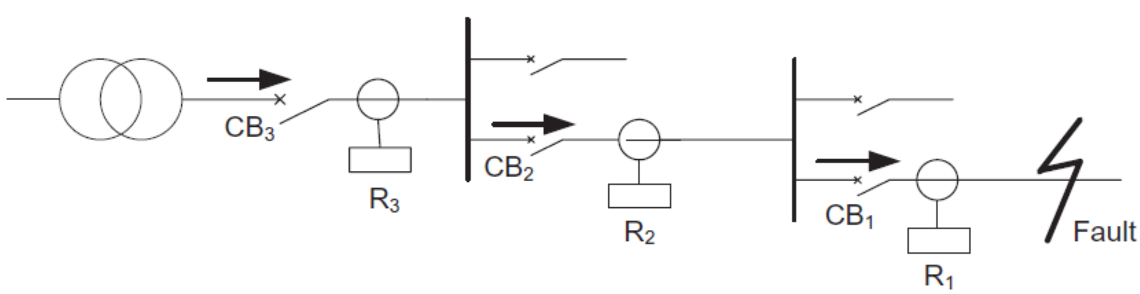



*Figure 6.1.1 Fault detection by three protection units*

As seen from the Figure 7.1.1 the fault is detected by protection relay $R_1$, $R_2$ and $R_3$. The relay $R_1$ operates faster than $R_2$, which operates faster than relay $R_3$. When $CB_1$ is tripped and fault is cleared, relays $R_2$ and $R_3$ are in standby position.

The coordination interval is the difference in operating time $\Delta t$ between two successive protection units, which is given by the summation of $t_c + t_r + 2Dt + m$, where $t_c$ is the breaking time of downstream CB, which consist of the breaker response and arching time. $t_r$ is the upstream protection overshoot time, $Dt$ is the time delay tolerance and $m$ is the safety margin. A typical value of safety margin is 110ms for a coordination interval of 0.3s.

The advantage of this coordination system is simplicity and providing its own backup, for example, if relay $R_1$ fails, relay $R_2$ is activated for $\Delta t$ later. The main disadvantage of this method of coordination is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level (MVA) is highest.

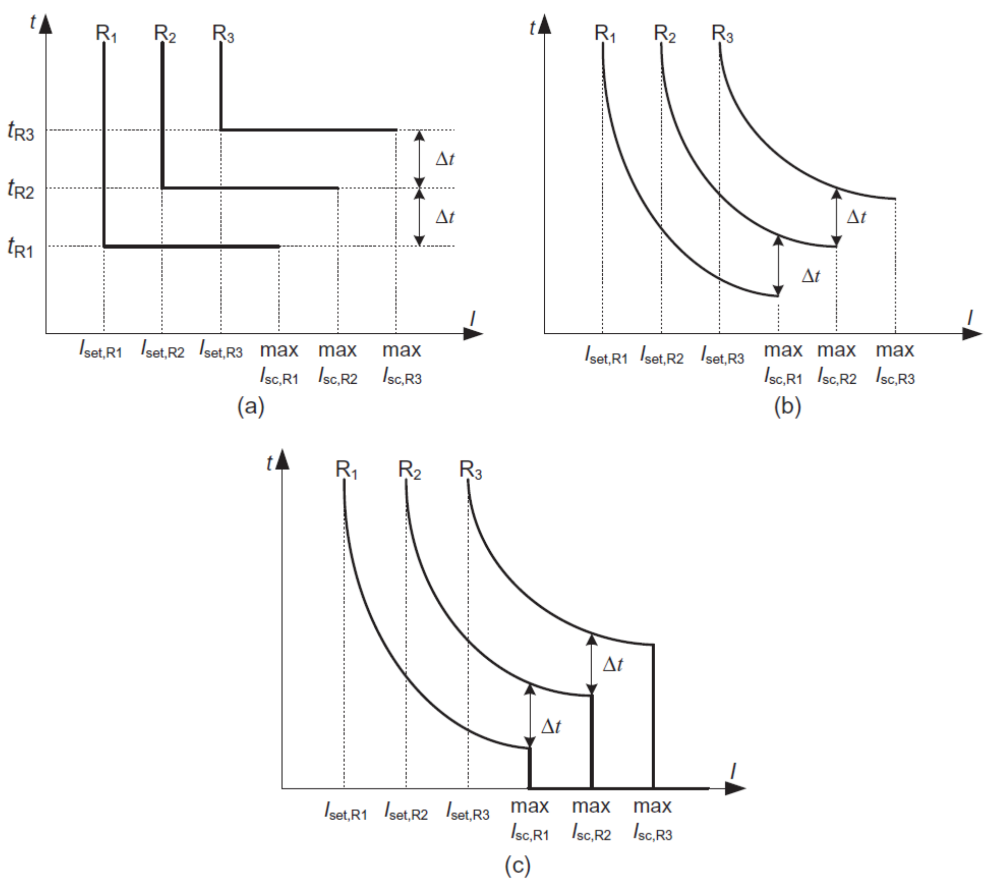



*Figure 6.1.2 Time - delay coordination for (a) definite - time protection, (b) IDMT protection, and (c) combined inverse - time and instantaneous protection.*

The principle of time-based coordination is applied to radial distribution systems. The time delays set are activated when the current exceeds the relay settings. Three types of time delay are applied according to protection characteristics definite-time, inverse-time, and combined inverse-time and instantaneous protection systems.

## 6.2 Current-Based Coordination

Discrimination by current relies on the fact that the fault current varies with the position of the fault because of the difference in impedance values between the source and the fault. Hence, typically, the relays controlling the various circuit breakers are set to operate at suitably tapered values of current such that only the relay nearest to the fault trips its breaker. It is installed at the starting point of each section. The threshold is set at a value lower than the minimum short - circuit current caused by a fault downstream (outside the monitored area). This system can be used advantageously for two line sections separated by a transformer as in Figure 7.2.1 since it is simple, economical, and tripping without time delay. To ensure coordination between the two protection units $R_1$ and $R_2$, the current setting of $R_2$, $I_{set,R_2}$, must satisfy the relation 1.25 (max $I_{sc,R_1}$)< $I_{set,R_2}$<0.8 (min $I_{sc,R_2}$), where max $I_{sc,R_1}$ represents the maximum short-circuit current at relay $R_1$ referred to the upstream voltage level, and min $I_{set,R_2}$ is the minimum short - circuit current at $R_2$. The tripping curves are shown in Figure 7.2.1 b. Time delays are independent and $t_{R_2}$ may be less than $t_{R_1}$.

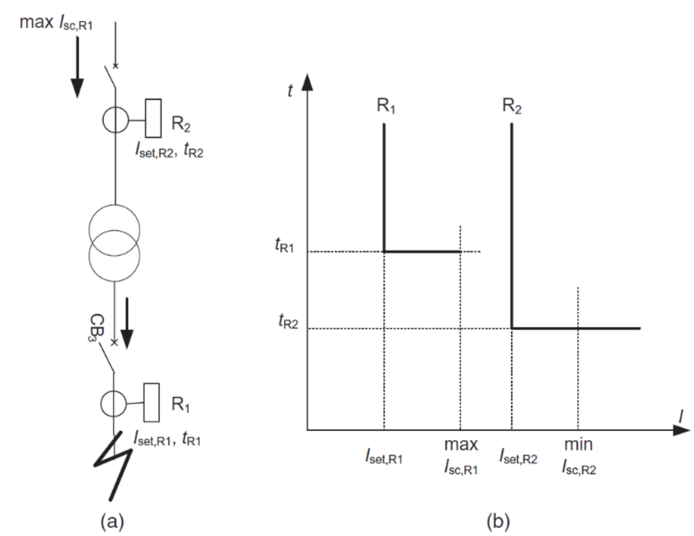


Figure 6.2.1 Current-based coordination. a) Line diagram; b) tripping curves

On the other hand, current-based coordination has drawbacks where the upstream protection unit $R_2$ does not provide backup for the downstream protection unit $R_1$. In addition, practically, in the case of MV systems except for sections with transformers, there is no notable decrease in current between two adjacent areas. Therefore, to define the settings for two cascading protection units and ensuring the coordination is difficult.

## 6.3 Logic Coordination

Each of the two methods described so far has a fundamental disadvantage. In the case of discrimination by time alone, the disadvantage is due to the fact that the more severe faults are cleared in the longest operating time. Logic coordination it is designed and developed to solve the drawbacks of both time-based and current-based coordination. With this system, coordination intervals between two successive protection units are not needed. Furthermore, the tripping time delay of the CB closest to the source is considerably reduced.

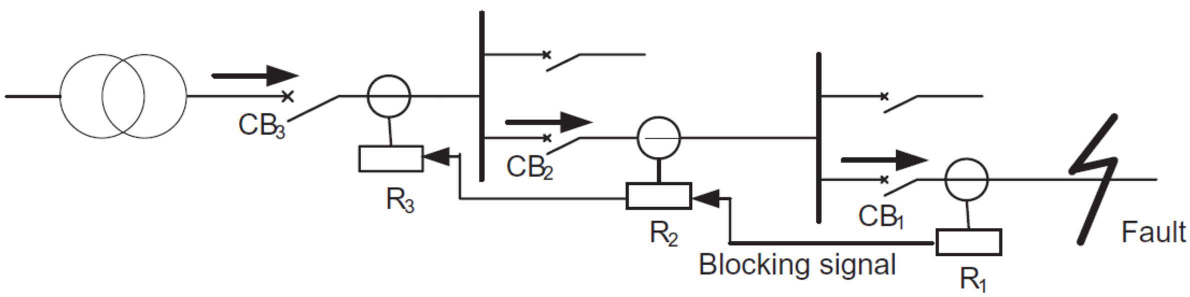



*Figure 6.3.1 Logic coordination principles*

When a fault occurs on the system shown in the figure above, the relays that are in an upstream way from the fault ($R_1, R_2, R_3$) are activated, while the relays on downstream way are not. Each relay that is activated by the fault sends a blocking signal to the relay which is in an upper level as an order to increase the upstream relay time delay. In this case, the circuit breaker $CB_1$ is tripped since the relay $R_1$ has not received a blocking signal from the downstream level.

Therefore, the relay $R_1$ will send a blocking signal to relay $R_2$, which in turn sends a blocking signal to $R_3$. This tripping order given by $R_1$ is provided after a delay time $t_{R_1}$ and the duration of blocking signal to $R_2$ is limited to $t_{R_1} + t_1$, where $t_1$ is the sum of opening and arc extinction time of $CB_1$. In this way if $CB_1$, fails to trip, the relay $R_2$ gives the tripping order at $t_{R_1} + t_1$, as a backup protection. If there is fault between $CB_2$ and $CB_1$, the relay $R_2$ will operate after a time delay $t_{R_2}$.

A disadvantage of logic coordination is that in order to implement it requires extra wiring for transmitting the blocking signal between the protection units, in which causes difficulties for long links as the protection units are far apart from each other.

# 7 Questions

1. **What is main objective of protecting the power system?**

   The main objective of protecting the power system is to provide quick isolation of the power system's area with fault, in order that shock in the rest of system to be minimized and to be intact for as long as possible.

2. **Which are the five basic aspects of protection relay application?**

   Five basic aspects of protection relay application are: Reliability, Selectivity, Speed of Operation, Simplicity and Economy.

3. **Describe shortly Reliability?**

   Reliability has two aspects, safety and security. Safety it shows protection system's ability to work properly when required, while the security is the ability to avoid unnecessary operations during normal operation.

4. **What is pickup setting?**

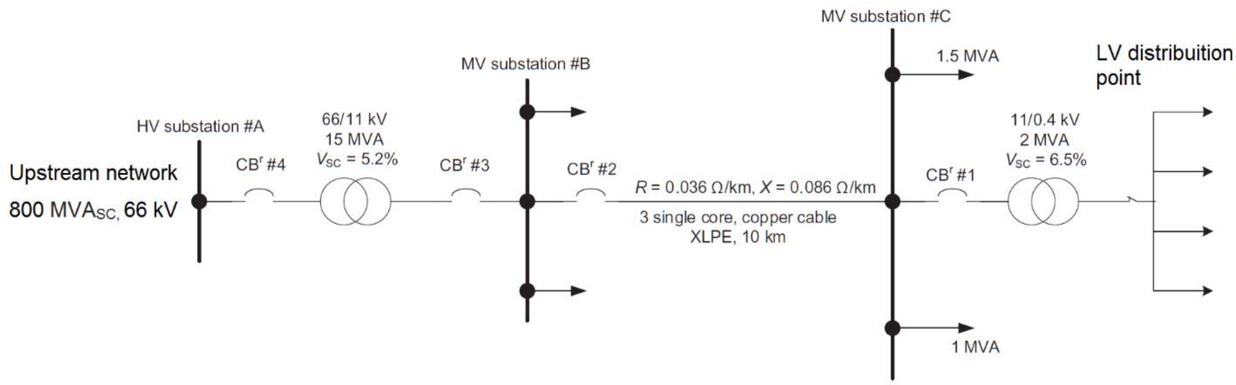
   Pickup setting is used to define the pickup current of the relay by which the fault current exceeds its value.

5. **Which are the types of operating characteristics of overcurrent relays?**

   Definite(Instantaneous)-Current Protection, Definite-Time Protection and Inverse-Time Protection.

# 8 Calculation task

For the given system, calculate nominal rated current and short-circuit level, and pickup setting, for the coordination of the overcurrent protection at positions C, B and A. Current transformers ratios are: $CT_1 = 300/5$, $CT_2 = 600/5$, $CT_3 = 800/5$, $CT_4 = 400/5$ and overload factor is $K_{ld} = 1.5$.




**Solution**

Nominal current calculation for CB's:

$$I_{nom,1} = \frac{2 * 10^6}{\sqrt{3} * 11 * 10^3} = 105\ A$$

$$I_{nom,2} = \frac{(1.5 + 2 + 1) * 10^6}{\sqrt{3} * 11 * 10^3} = 236.2\ A$$

$$I_{nom,3} = \frac{15 * 10^6}{\sqrt{3} * 11 * 10^3} = 787.3\ A$$

$$I_{nom,4} = I_{nom,3} * \frac{11}{66} = 131.2\ A$$

Short circuit current at each CB:

$$Z_{upstream} = \frac{(66 * 10^3)^2}{800 * 10^6} = 5.44\ \Omega$$

$$Z_T = \frac{5.2}{100}\frac{(66 * 10^3)^2}{15 * 10^6} = 15.1\ \Omega$$

$$Z_{BC} = 0.086 * 10 * \left(\frac{66}{11}\right)^2 = 30.96\ \Omega$$

Then,

$$I_{FC} = \frac{66 * 10^6}{\sqrt{3} * (30.96 + 15.1 + 5.44)} = 739.9\ A$$

$$I_{FB} = \frac{66 * 10^6}{\sqrt{3} * (15.1 + 5.44)} = 1855.2\ A$$

$$I_{FA} = \frac{66 * 10^6}{\sqrt{3} * 5.44} = 7004.6\ A$$

So, for each relay the pickup setting is:

- Relay 1: $Pickup\ setting = 1.5 * 105 * \frac{5}{300} = 2.625\ A$, thus we set at 3 $A$.
- Relay 2: $Pickup\ setting = 1.5 * 236.2 * \frac{5}{600} = 2.95\ A$ , thus we set at 3 $A$.
- Relay 3: $Pickup\ setting = 1.5 * 787.3 * \frac{5}{800} = 7.38\ A$, thus we set at 8 $A$.
- Relay 4: $Pickup\ setting = 1.5 * 131.2 * \frac{5}{400} = 2.46\ A$, thus we set at 3 $A$.

# 9 Conclusion

The importance of relay protection in power systems is evident, especially nowadays where power supply requires reliable and secure systems.

New generations of relay protection systems based on digital technology provide greater opportunities to protect the electric equipment, power grid, and consumers as end users of electricity.

As we have seen from above there is not a definite option which overcurrent protection to use. We can combine the operating types of this kind of protection, but the only thing is that we have to careful when choosing the protection and making it possible that the protection will isolate the fault in the fastest possible time and not cause any damage to the other side of the network.

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