GU J Sci 30(4): 180-198 (2017)

Gazi University

Journal of Science

http://dergipark.gov.tr/gujs

Protection Coordination Practice in Electrical Substation Part-1 Overcurrent and Earth Fault Protection - Case Study of Siddik Kardesler Substation (SKS), Istanbul, Turkey

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Article Info

Received: 26/12/2016
Accepted:14/08/2017

Keywords

Earth Fault Protection
Over Current Protection
Protection Coordination
Electrical Substation

Abstract

Protection coordination is the heart of all power systems. To ensure a quality and reliable operation of the power systems, an electrical fault must be cleared within a short time. This can be achieved by proper coordination between the protection relays. In Siddik Kardesler Substation the MV voltage feeders' protection is provided by overcurrent relays. This paper is principally concerned with practical protection coordination of the electrical substation by using Siddik Kardesler Substation substation as a case study. In the Part-2, distance and differential protection will be discussed. Finally, after test and commissioning, the substation is successfully energized without a problem.

1. INTRODUCTION

The power system is among very complex systems which consist of many expensive types of equipment. Especially, Electrical Substations (ESS) are among the critical components of the power system and the availability of a power system is based on their performance. For example, the switching and fault clearing actions of power systems are performed by the ESS. ESS are interconnected by transmission line to make the power system meshed or networked increasing the reliability [1]. Thus, they represent a huge capital investment which has to be operated securely and reliably to minimize the payback period.

Some of the roles of substations in power systems are [2, 3]:

• Stepping up the voltage at generating stations to high voltage levels (generating station);
• Changing between the voltage levels within the high-voltage system (system stations);
• Stepping down to a distribution or medium-voltage level. (distribution stations);
• Interconnect the same voltage levels and etc.

Substations can be either Air Insulated (AIS), Gas Insulated (GIS), compact or hybrid based on [3], the function and location of the power supply, environmental and climatic conditions, specific requirements regarding the locations, and cost and space limitations. A GIS uses sulfur hexafluoride (SF6) to provide insulation while the AIS uses atmospheric air [3, 6]. GIS is more compact structure, reliable and requires less maintenance compared to AIS. In addition, the service life of GIS is longer compared to AIS. But GISs are expensive than AIS and mostly used where space is expensive or not available.

As an important component of power systems, substations are required to operate safely all through their lifetime. The arc-current generated during fault can burn and weld copper conductors of transformer and machines' core laminations in a very short time [6]. In addition, the insulation may break down, causing the flow of current between phases or phase to ground. Consequently, an adequate protection system which detects faults and disconnects elements of the power system during

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a fault is an essential design subject of the power system. The protection system cannot prevent the occurrence of the fault, but they should act immediately after the occurrence of the fault. The protection system is an arrangement between protection equipment (like relays, fuses, etc.) and other devices (like transformers, circuit breakers, batteries, etc.) which are vital to accomplishing a specified function depending on the protection principles applied [6].
This paper is concerned with the protection coordination (ProC) study of Siddik Kardesler Substation (SKS) which is an AIS type. The protection study is planned to be presented in two parts (Part-1 and Part-2) the first part is concerned with over current and EFPs of the SKS. The second part is concerned with the differential and distance protection aspects of the SKS. This paper (Part-1), is outlined as follows; the components of the SKS and its protection arrangements will be discussed in sections 2 and 3 respectively. The important over current relay characteristics will be discussed in section-4. The overcurrent coordination study of SKS with necessary procedures will be discussed in section-5. Finally, the EFP will be discussed in section-6.

2. COMPONENTS OF THE SKS

The SKS consists of 154 kV and 34.5 kV components that serve numerous purposes. Components like circuit breakers, isolators, current transformers (CTs), surge arrestors, power transformers, meters, control, relay equipment and etc. are shown symbolically upon the substation's single line diagram as shown in Figure 1. In Tables 1 and 2 brief descriptions of these components are provided.

Table1. *Components of Substation (154 kV)*

154 kV components of substation		
Code	***Name***	***Description***
1/1A	Voltage Transformer	Used to convert the voltage from HV to the level that can be used for protection, control, automation devices and etc.
2	Lin Traps	Used for Power Line Carrier (PLC) Communication.
3/3A	Current Transformer	Used to convert from very high current to the level that can be used for protection, control, automation devices and etc.
4T	Isolator with Grounding blade	For no load opening and closing, and isolate the downstream device to be worked on. The grounding blade is used to ground the isolated part for more safety.
5	Circuit breaker	Make and break all currents within the scoped of their rating.
5T	Circuit Breaker with Auto-reclosing	Circuit breaker with auto-reclosing capability.
4	Isolator	For no load opening and closing, and isolate the downstream device to be worked on.
6	Surge Arrester	To discharge high voltages caused by lightning strikes or switching operations and earth faults.
7	Power Transformer	To transform the voltage level from 154 kV to 34.5 kV.

Table 2. *Components of Substation (34 kV)*

34 kV Components of the Substation		
Code	***Name***	Description
8c/8b/8c	Cable	Medium Voltage (MV) XLPE underground cable for transporting the energy.
6a	Surge Arrestor	MV surge arrestor.
5a/5b/5c	Circuit Breaker	MV circuit breaker.
3a/3b/3c	Current Transformers	MV current transformer.
14	Voltage Indicator	Indicates the availability of voltage on each phase.
4t	Grounding Switch	Used to ground the isolated part for more safety.
10	Voltage Transformer	MV voltage transformer.

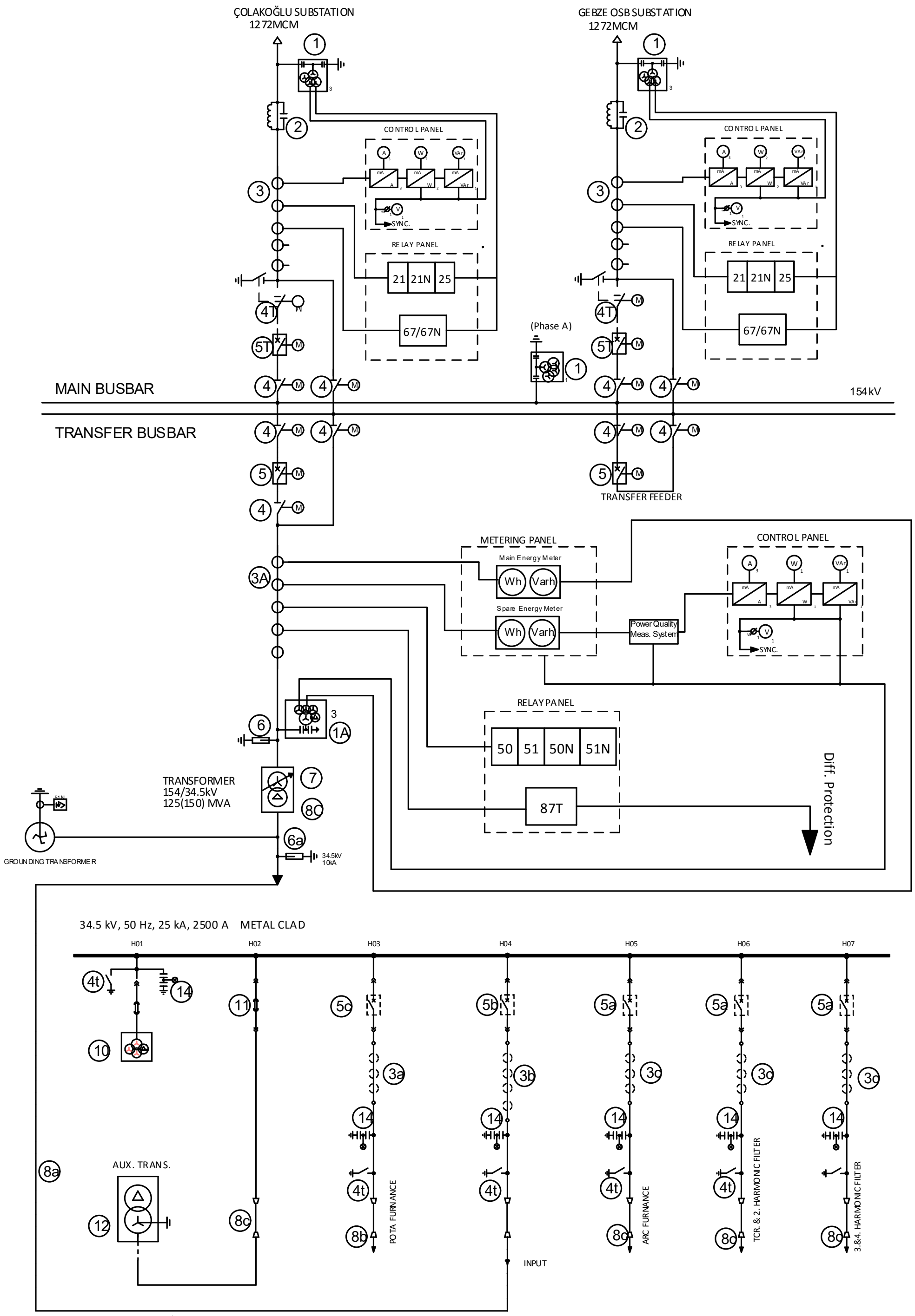


Figure 1. Siddik Kardeşler Substation Single Line Diagram.

3. PROTECTION ARRANGEMENTS OF THE SKS

In Figure 1 protection functions used in SKS are indicated by the American National Standards Institute (ANSI) codes. Based on the single line diagram shown in Figure 1, the protection arrangements for the SKS are as follow:

1. For the 154 kV incoming transmission lines, distance protection (21/21N), directional OCP (67/67N) and frequency protection (25) are implemented.
2. Differential protection (87T), over current and earth fault protections (50/51/50N/51N) are implemented for the power transformer.

3. For the MV outgoing feeders, over current and earth fault protections (50/51/50N/51N) are implemented.
4. Auxiliary Transformer is protected by MV fuse.

4. CHARACTERISTICS OF OVERCURRENT PROTECTION RELAY

4.1. Selectivity

The protection relays have to operate in a way that should provide adequate selectively by isolating the fault through opening the circuit breakers. This requires coordination of protection functions between the protective relays. Time grading, current grading or unit protection methods are commonly used to provide the required coordination between the relays.
In the time grading method, the protection relays in successive zones are arranged in time so that only the relays near to the fault operate first. For this purpose, definite time relays are used and it is independent of the level of fault current. However, as a disadvantage, the relay near to the source (with highest fault level) clears the fault with longer time delay.
Current based grading takes the advantage of variation of fault current at different parts of the network. The variation of impedance according to the location between the fault point and the source is the main cause of the fault current variation. In order to use this approach; there must be an appreciable impedance between the two relaying points.
To overcome the limitations of current based and time-based grading, the inverse time overcurrent relay characteristic was developed. The inverse time characteristics are defined by standard curves. In Table 3, for example, IEC 60255 standard characteristics are shown. In addition, in the modern protection relays, there is also an option for the user to define their own time-current characteristics [7-9].

Table 3. *IEC 60255 Standard Characteristics [6]*

Relay Characteristics	Equations (IEC 60255)
Standard Inverse (SI)	$t = TMS * \frac{0.14}{(I_r)^{0.02} - 1}$
Very Inverse (VI)	$t = TMS * \frac{13.5}{I_r - 1}$
Extremely Inverse (EI)	$t = TMS * \frac{80}{I_r^{2} - 1}$
Long Time Standby Earth Fault	$t = TMS * \frac{120}{I_r - 1}$

Where: Ir = I/Is, Is is the relay setting current, I is the measured current, TMS is the Time Multiplier Setting. High-set instantaneous element is used to reduce the tripping time and improve the system grading at high fault currents. This becomes very effective when the source impedance is not large enough when compared to the protected circuit impedance [6].

4.2 Speed

Relays are expected to operate as fast as possible to maintain the reliability of supply by getting rid of each fault before it spreads to healthy systems, causing in loss of synchronism and the blackout of the power system [6]. Speed is the characteristics of the relay which is related with how fast it has to operate to clear the fault.

4.3 Sensitivity

Additionally, relays must be sensitive enough to identify minimum operating fault level (current, voltage, power etc.).

4.4 Reliability

Furthermore, protection relays are required to be highly reliable, by reducing the risk of failure to trip (dependability) and risk of over tripping (security).

4.5 Directionality

For the parallel feeders, line with two end feeds and ring networks, the OCP cannot provide selectivity. Therefore, directional control facility can be included to the protection relays to provide better selectivity [10]. To determine the direction of the fault current, voltage data is required. The connection of the voltage and current information to the relays depends on the phase angle between the voltage and current to be applied to the relay at unity system power factor [6]. In numerical or digital relays, phase displacements can be obtained by software in contrast to electromechanical and static relays in which the phase displacements are obtained by applying the voltage and the current inputs to the relay [11-12].
The commonly used standard connection for the relays is 90° Quadrature Connection [6]. In this type, two forms of connections are available based on the Relay Characteristic Angle (RCA). The RCA is the angle by which the voltage applied to the relay is shifted to produce maximum sensitivity to the relay. These connections are:

4.5.1 90°-30° Characteristic (30° RCA)

This is obtained by connecting the Phase-A current (Ia) to the phase-A relay element and the Vbc voltage is displaced by 30o in a counter-clockwise direction. In this connection type when the current lags the phase to neutral voltage by 60o the maximum sensitivity will be produced. The correct directional tripping can be obtained for current angle 30o leading to 150o lagging; as shown in Figure 2 (a).

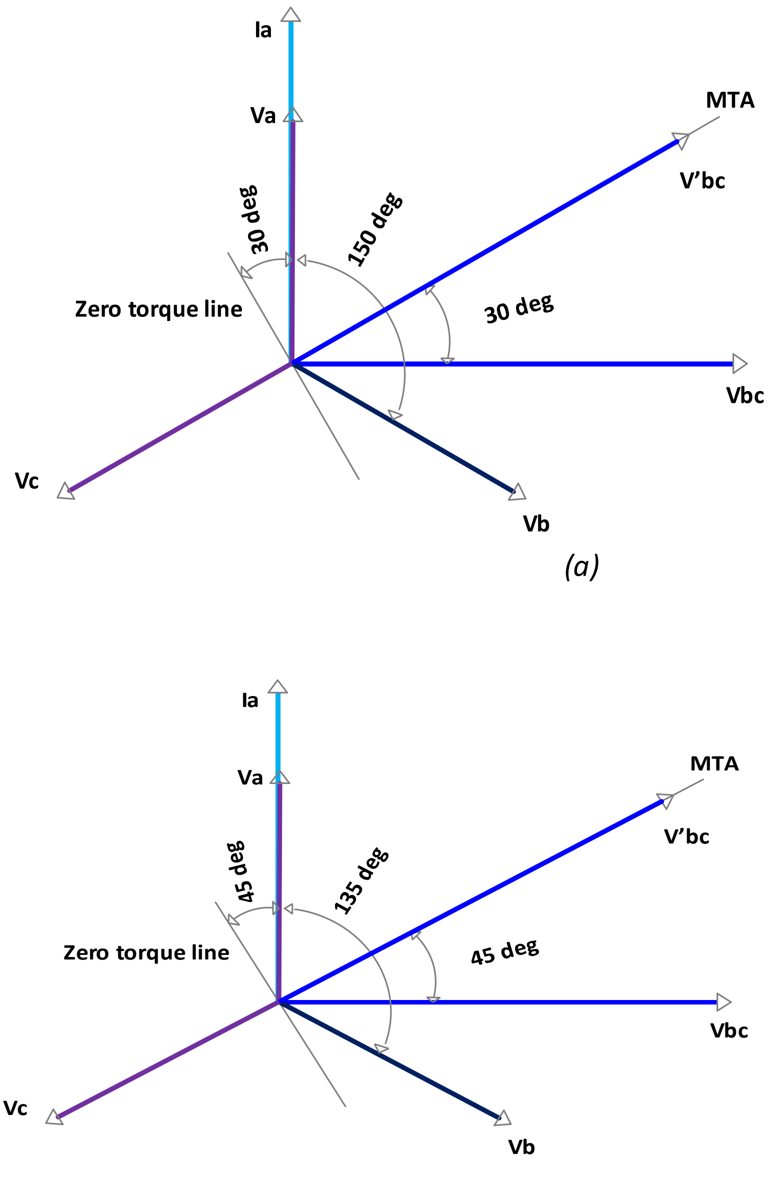


Figure 2. *(a). Vector Diagram for the 90°-30° Connection, (b). Vector Diagram for the 90°-45° Connection*

4.5.2 90°-45° Characteristic (45° RCA)

In this case, phase-A current (Ia) is connected to the phase-A relay element and Vbc is shifted by 45° in a counter-clockwise direction. In the SKS directional over current and EFP (67/67N) are used as the backup protection for the distance relay (21/21N) [10]. The maximum sensitivity is produced for the 45° current lagging from system phase to neutral voltage. The correct directional tripping zone is from 45° leading to 135° lagging as shown in Figure 2 (b).

5. OVERCURRENT PROTECTION COORDINATION STUDY

The coordination study between overcurrent relay requires the following data [6, 12, and 13]:
1. The single line diagram of the system with rating and type of protection system specified on it.

2. The impedance of power system components like cables, transmission lines, transformers, rotating machines and etc.
3. The minimum and maximum short circuit currents estimated to flow through each of the protection relays.
4. The maximum load current through each of the protection device.
5. Starting currents of different types of motors.
6. The thermal withstands, transformer inrush, and damage characteristics curves.
7. The curve showing generators' fault current rate of decay.
8. The current transformers' performance curves.

5.1 Fault Current

For the protection relay coordination, distribution of the fault current throughout the network has to be known. Especially the minimum and the maximum short circuit currents have to be calculated through each relaying points. Short circuit fault study for the coordination of protection relays in the practical application involves the following steps [6]:
1. Identifying the possible operating conditions and stability limits by using network diagram and available data.
2. Calculating minimum and maximum fault currents for each type of fault through each relaying points.
3. Calculating the fault current distribution in the network, especially through each relaying point.
Based on the above steps, the protection system and the classes of protection, such as high or low have to be determined. During the occurrence of the fault in power system, the three-phase current and voltage are no more balanced except in three phase short circuit faults. Therefore, the protection engineer is concerned with symmetrical faults and asymmetrical faults involving phase-to-phase and one or two phases to earth faults [8, 13].
For the analysis of unbalanced fault conditions, balanced symmetrical components are used. Symmetrical components can also be used to detect different types of faults and differentiate between the faults. For example, zero sequence and negative sequence voltages and currents are used mostly in non-directional or directional earth fault OCPs settings. In this study, the analysis of symmetrical components will not be discussed. However, the symmetrical components (voltage and current) which are available in different type of faults are summarized in Table 4.

Table 4. *Symmetrical Components and Fault Types*

Sequence Currents	Single Phase to Earth Fault	Phase-Phase Fault	Phase-Phase to Earth Fault	Three Phase Fault	Three Phase to Earth Fault
I_1	x	x	x	x	x
I_2	x	x	x		
I_0	x		x		

Turkish electricity transmission corporation (TEİAŞ) publishes the maximum and minimum short circuit currents and power each year. The short circuit currents which are taken from the published data [14] for 'Gebze Industrialized Zone' as well as 'Çolakoğlu Substations' are summarized in Table 5. These values are used in the short circuit analysis of the SKS. In this study, the short circuit analysis is realized by using the ETAP power system analysis software. The impedance data of the line, cable, and transformer used in this study can be referred as systems data. Based on these data and the short circuit current from the network side, the short circuit analysis is conducted and the results are summarized in Table 6. The fault current will decrease from the TEİAŞ 154 kV towards the 33 kV side as shown in Table 6. The software can calculate the maximum and minimum fault current through each relaying points based on the IEC 60909 method or other standards. For this study, IEC 60909 method is used.

Table 5. *Minimum and Maximum Short Circuit Currents of the Source Network*

Substations	**Maximum (kA)**		**Minimum (kA)**	
Fault Types	Single Phase	Three Phase	Single Phase	Three Phase
Gebze OSB	26,5	30	16,2	18,4
Çolakoğlu	21,1	23,2	16,9	18,8

Table 6. *Minimum and Maximum Short Circuit Currents of the SKS.*

Busbar	**Maximum (kA)**		**Minimum (kA)**	
	Single Phase	Three Phase	Single Phase	Three Phase
154 kV busbar	30.5	33	25.2	23.6
33 kV busbar	12.9	14.9	12.5	14.4
Arc-Furnace	12.5	14.5	12.2	14
Pota-Furnace	12.5	14.4	12.1	14
TCR and 2nd Harmonic Filter	12.7	14.7	12.4	14.3
3rd and 4th Harmonic Filter	12.7	14.7	12.1	13.9
Auxiliary Transformer	12.8	14.7	12.4	14.3

5.2 Load Current

The protection relay must be set above the maximum load currents for the stable operation. Consequently, the maximum load currents for the system has to be determined before determining the relay setting. The maximum load current through each feeder is calculated by the well-known power formula as follow:

$$I_L = \frac{S}{V * \sqrt{3}} \tag{1}$$

Where: IL is per phase maximum load current; S is the apparent power; V is per phase voltage. The maximum load currents at each relaying points are summarized in Table 7.

Table 7. *Maximum load current*

Feeders	**Pota Furnace**	**Transfor. Feeder**	**Arc Furnace**	**TCR and 2nd HF**	**3rd and 4th HF**
Power (MVA)	12	150	72	100	60
Current (A)	200.82	2510.29	1204.9	1673.53	1004.12

5.3 Instrument Transformers

Proper protection design starts with the selection of appropriate instrument transformers (voltage and current). Instrument transformers supply the relays with current and voltage for measurement and protection purposes by converting the high magnitude current and voltages to the compatible quantities to be injected to the relays.

5.3.1 Current Transformer (CT)

CTs are classified as metering and protection type CTs. The metering CTs are used for the application which requires very high accuracy over the normal range of the load current. Protection CTs are required to operate at many times the full load current (with an error between 5%-10%) [9, 14].

➢ *Current Transformer Ratio*

The CTs has to be selected based on the maximum load current on the primary side and the maximum secondary current under fault condition (generally, 100 times rated secondary current). Additionally, the thermal withstand current during fault must be considered. Based on IEC 60255 standard, the thermal withstand current of the current input has to be 100-times nominal current (100xIn). For example, for the system with fault current of 25 kA, the lowest possible CT rated current must not fall below 25 kA / 100 = 250 A. Consequently, the selection of the primary rated current of 300 A is correct.

➢ *Current Transformer Saturation*

The accuracy of CT depends on the fault current through the primary of the CT. For very high currents, the saturation occurs and the relation between the primary and secondary currents will be no more linear. The point where the linearity is lost is known as knee/excitation point (Figure 3). For correct operation, all the measured values obtained from the relay must be red when the CTs are operating in their linear mode (unsaturated CTs). Thus, appropriate selection of CTs for the relays has to be made in order not to saturate under the applied current.

➢ *Procedures for the Selection of CTs*

The following steps have to be followed for the selection of CTs.

1. It has to be ensured that the primary rating of the CT is greater than or equal to the expected full load current.
2. It has to be ensured that the CT can derive the attached burden (total load resistance of secondary circuit) during maximum fault current without saturating. The burden is calculated as follow:

$$R_B = R_{sCT} + R_{wr} + R_{rb} \tag{2}$$

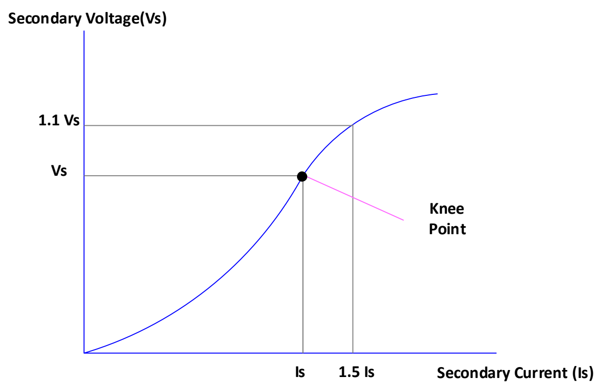


Figure3. *Excitation Curve, CTs Secondary Voltage vs. Secondary Current*

Where: RB is the burden resistance, RsCT is the CT secondary resistance, Rwr is the connection wire resistance, Rrb is relay burden resistance. In order to check whether CT will saturate under the maximum fault current or not, the CT secondary voltage under fault condition has to be determined as follow:

$$CTsv = \frac{R_B * I_{scMax}}{CT\ Conversion\ Ratio} \tag{3}$$

Where: CTsv is the CT secondary voltage and, IscMax is the maximum fault current.
The resulting value from equation (3) is plotted on the CT excitation curve and if it is below the knee point of the CT there would be no saturation and if it is above the knee point there would be saturation. Based on the above procedures, all the CTs in the SKS are determined.

5.3.2 Voltage Transformer (VT)

There are two types of voltage transformers which are used in power industry, namely electromagnetic and capacitive voltage transformers. Electromagnetic voltage transformers are used for accurate metering and used for lower level voltage applications. Capacitive voltage transformers are used for high-voltage transmission line applications. It consists of coupling capacitors, compensating reactor, step-down transformer and Ferro-resonance suppression circuit as shown in Figure 4.

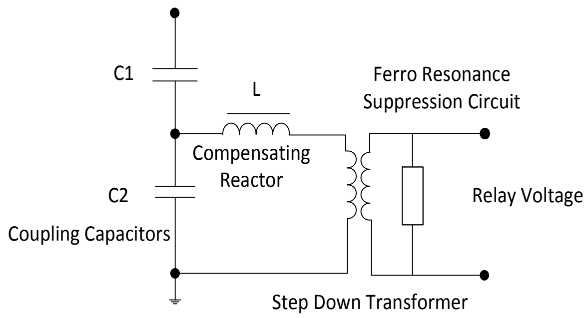


Figure 4. *Capacitive Voltage Transformers*

In voltage transformers, accuracy class and the burden rating are very important. The common accuracy class and the burden ratings are given in Table 8. The voltage transformers used in the SKS for both medium voltage and high voltage are fulfilling the accuracy requirements as per the standard.

Table 8. *Typical Voltage Transformer Accuracy Class and Burden Ratings*

Potential Transformer Accuracy Class			
Common Classes (IEEE)	**Accuracy**	**Designations (IEEE)**	**Accuracy maintained below**
1.2	98.8-101.2%	W	12.5 VA
0.6	99.4-100.6%	X	25 VA
0.3	99.7-100.3%	Y	75 VA
Burden Rating		Z	200 VA
		ZZ	400 VA

5.4 Coordination Procedure

The protection relays have to be set to not operate for the maximum load current but must operate at the minimum expected fault current. Furthermore, the overload protection can also be provided by the relays. It is recommended to use relays with the identical operating characteristics in succession. In addition, the relay which is furthest from the source must have a current setting which is equal to or less than the primary current required to operate the relay behind it. Furthermore, for the relays to operate correctly, sufficient time has to be left which is referred to as grading margin. The grading margin depends on the following factors [8, 13]:

- circuit breaker’s fault current interrupting time
- relay timing errors (variation from the characteristic time delay curve)
- the overshoot time of the relay
- CT errors

- the final margin on completion of the operation

At the relaying point under consideration, initially the grading is carried out for the maximum fault level, but it is checked if the grading margin exists for all current levels between relay pickup current and maximum fault level. Fixed grading margin is popular, but for low fault current levels, it is better to calculate the grading margin at each relaying points. Thus, a proper minimum grading time interval, CTI, can be given as [6]:

$$CTI = \left[\frac{2E_R + E_{CT}}{100}\right] t + t_{CB} + t_0 + t_S \tag{4}$$

Where: ER = relay timing error (as defined in IEC60255-4), ECT = allowance for CT ratio error (%), t = nominal operating time of relay nearer to fault (sec), t_{CB} = CB interrupting time (sec), t_O = relay overshoot time (sec), t_S = safety margin (sec).

5.5 SKS Overcurrent Coordination

For the OCP coordination of the SKS, the protection arrangement shown in Figure 1 has to be referred. The IEC normal inverse characteristic curve is chosen for the inverse time protection relay. Firstly, the operating time and time multiplier setting (TMS) for the furthest relay from the source has to be determined. The smallest available TMS in the relay has to be selected if there are many relays to be coordinated in series (e.g. for REF 615 ABB relay, TMS=0.05 can be used). Then, if the tn, TM'n, In, Ipn are downstream relay's operating time, time multiplier setting, maximum fault current and peak up current respectively, the operating time of the of this relay can be calculated as:

Table 9. *Typical Relay Timing Errors – Standard IDMT Relay [6]*

Times	**Relay Technology**			
	Electro-Mechanical	Static	Digital	Numerical
Typical basic timing error (%)	7.5	5	5	5
Overshoot time(s)	0.05	0.03	0.02	0.02
Safety margin(s)	0.10	0.05	0.03	0.03
Typical overall grading margin-relay to relay(s)	0.40	0.35	0.30	0.30

$$t_n = TMS_n * \frac{0.14}{\left(\frac{I_n}{I_{p_n}}\right)^{0.02} - 1} \tag{5}$$

If fixed grading margin is selected for the coordination, which is about 200 ms for the modern IEDs, the time multiplier setting and operating time of an immediate upstream relay can be calculated as follows:

$$TMS_{n+1} = \frac{t_n + 0.2}{\frac{0.14}{\left(\frac{I_n}{I_{p\_n+1}}\right)^{0.02} - 1}} \tag{6}$$

$$t_{n+1} = TMS_{n+1} * \frac{0.14}{\left(\frac{I_{n+1}}{I_{p_n+1}}\right)^{0.02} - 1} \tag{7}$$

Where: I_n is the fault current for the downstream relay; I_{n+1} is the fault current for the upstream relay. $Ip_{\_n+1}$ the pickup current for the upstream relay; TMS_{n+1} is the time multiplier setting for the upstream relay.

Table 10. *Setting Results for MV Protection Relays*

Feeders	*Function*	*Pickup Current*	*TMS*	*Curve (IEC)*	*Time(s)*	*In*
H03/ Pota Furnace, 33 kV	51	0.6 x In	0.3	Normal	-	400/1
	50	4.9 x In	-	Definite Time	0.05	400/1
H04/ Transformer, 33 kV	51	0.9 x In	0.36	Normal	-	3000/1
	50	4 x In	-	Definite time	0.05	3000/1
H05/ ARC Furnace, 33 kV	51	0.46 x In	0.3	Normal	-	3000/1
	50	2 x In	-	Definite time	0.05	3000/1
H06/ TCR AND 2nd HF, 33 kV	51	0.6 x In	0.3	Normal	-	3000/1
	50	2.5 x In		Definite Time	0.05	3000/1
H07/ 3rd and 4th HF, 33 kV	51	0.77 x In	0.3	Normal	-	3000/1
	50	3.4 x In	-	Definite time	0.05	3000/1
Transformer 154 kV	51	0.77 x In	0.45	Normal	-	800/1
	50	3.5	-	Definite time	0.05	800/1

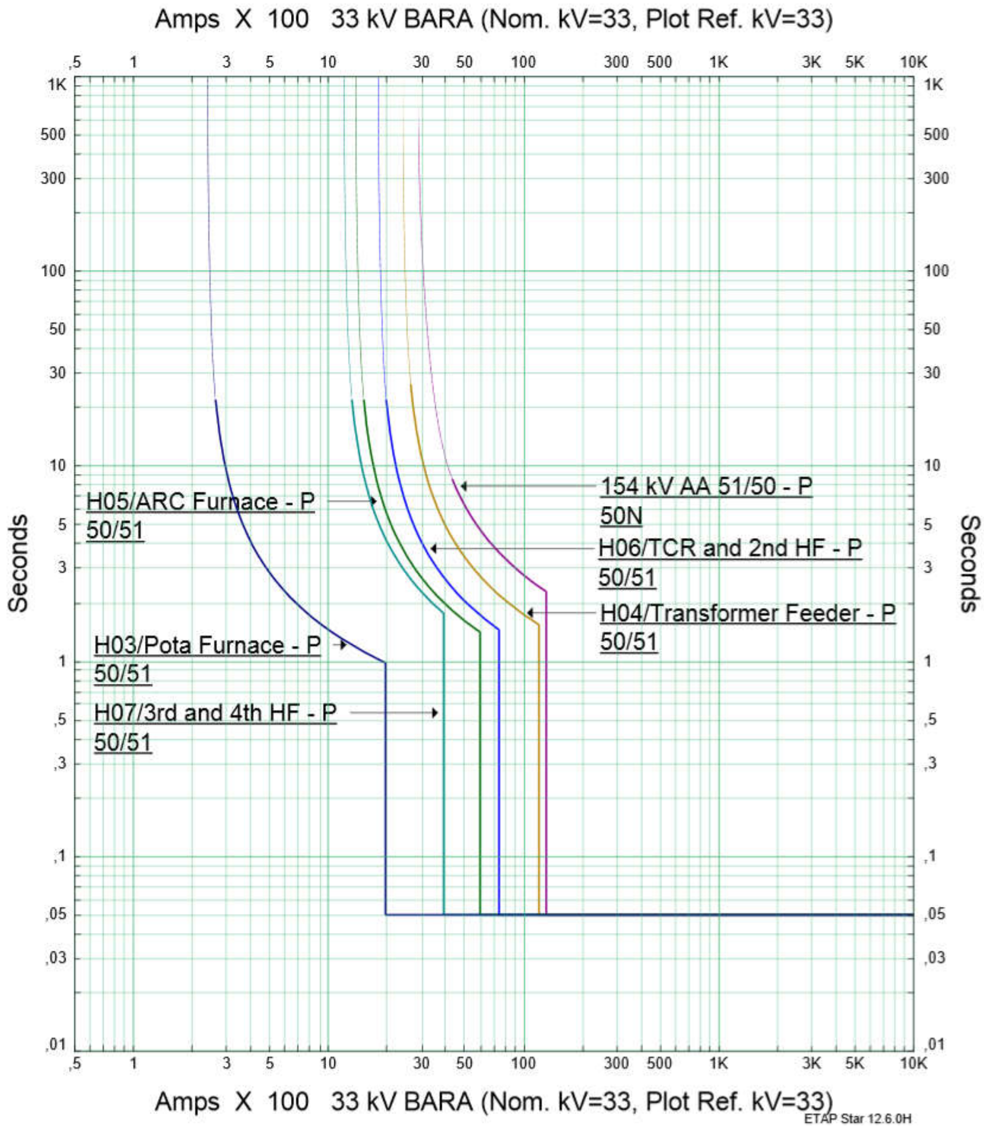


Figure 5. *SKS Relays Coordination Curve*

In the SKS when the maximum fault current occurs at the load terminal, the MV feeders' relays which are nearer to the source than the load feeders' relays have to give 0.5-second gap to ensure the load feeders' relay to operate. By following the above procedures (equations 6-8), this corresponds to TMS of 0.3. The pickup currents are chosen as 1.1 times the maximum load currents. By using equations (6) to (8) the time multiplier settings for all the relays are determined and summarized in Table 8. In Table 8, the pickup settings are normalized with a ratio of current transformer primary currents. The coordination curve is shown in Figure 5. The curve shows the proper coordination between the relays, for example, the upstream relays (154 kV transformer feeder protection) operates only after the MV feeder protection fails to operate for the fault happening on MV side. In addition to the time inverse, short circuit protection is realized by definite time function. The current setting is determined so that it is below the minimum short circuit current and above the load current. The pickup settings and time delay settings are shown in Table 8.

6. EARTH FAULT PROTECTION

Earth fault is the most frequent one of all faults. Its protection is provided by the relay which has a response to the residual current. The load current must not affect the relay that is used for the EFP. Earth contact resistance or neutral earthing impedance can limit the earth fault current. Consequently, to take into consideration this low-level current, the earth fault relay is set to the minimum earth fault current or 20-40% of full-load current flowing through the system being protected [15-17]. Furthermore, similar to the directional OCP, directional earth fault overcurrent can be applied in the following situations [17, 18]:

- when the OCP is done by directional relays,
- in insulated-earth networks or in Petersen coil earthed networks,
- when the sensitivity of EFP is insufficient.

6.1 Influence of Earthing Nature on the Earth Fault Protection

The nature of zero sequence currents which are produced during earth fault is influenced by the method of earthing. Thus, zero sequence currents and voltages which are utilized for the earth fault detection depend on the system connections to the earth and the potential difference between the earthing points resulting in a current flow in the earth paths. In the following sections, the effect of earthing types on the EFP and the techniques to be used for detecting earth fault will be discussed.

6.1.1 Earth Fault Protection on Insulated Networks

In the insulated network, there is no earth fault current pass, so the whole system may remain operational under earth fault condition. The system has to be designed to withstand the high steady-state and transient overvoltage. The disadvantage of such network is the difficulty of detecting earth fault current. In modern relays, the following methods are available.

6.1.1.1 Residual Voltage Method

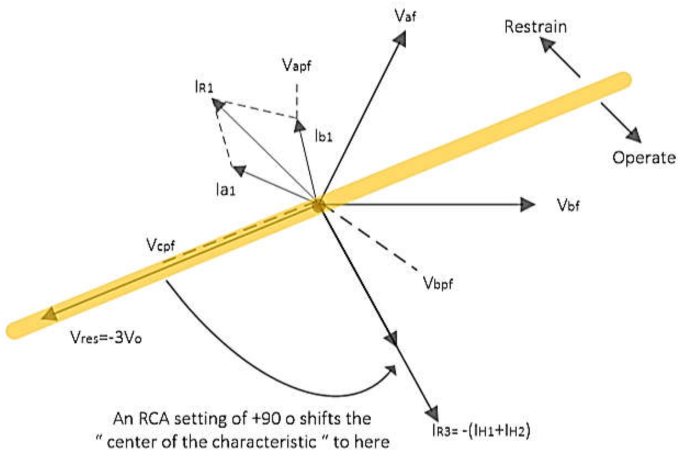
The un-faulted phase voltages magnitude increases by a factor of $\sqrt{3}$ and their sum is no longer zero during the occurrence of single phase to earth fault. Consequently, the earth fault can be detected by the residual voltage element. The advantage of this method is that CTs are not used and only the voltage is being measured. However, the unbalanced voltage happens on the whole affected system and it is difficult to provide any discrimination.

6.1.1.2 Sensitive Earth Fault Method

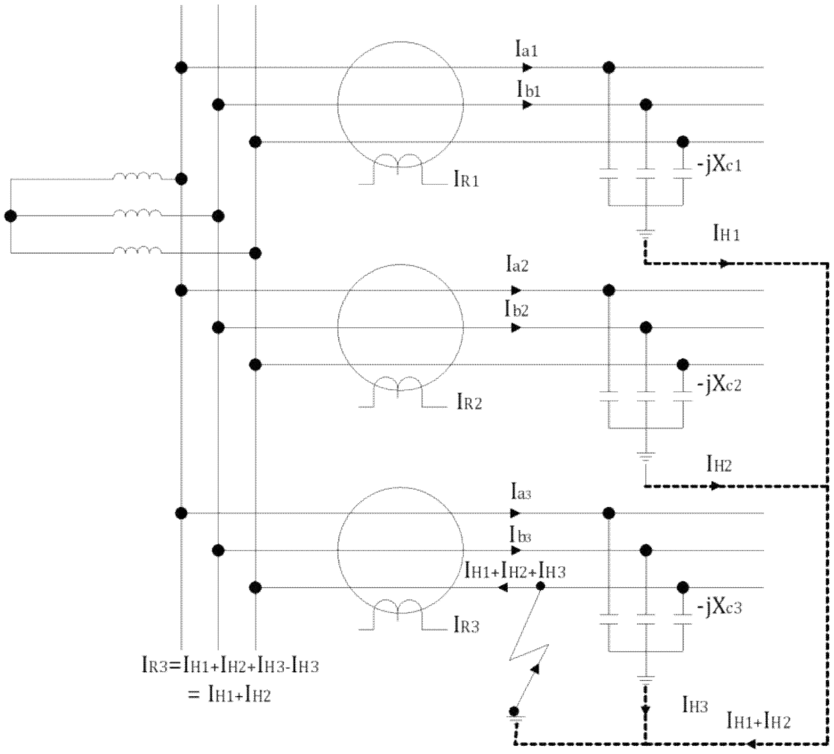
This method is based on detection of imbalance charging currents per phase and mostly used in MV networks. According to this mechanism, the relays on the healthy feeders detects the unbalance in charging currents for their own feeders. In contrast, the relay in the faulted feeder detects the charging currents in the rest of the system, with the current of its' own feeders, canceled out ($I_{H1}+I_{H2}$ for feeder-3 of Figure 5).

In the insulated network due to the capacitive effect, the unbalance current on the un-faulted feeders leads the residual voltage by 90º.

- Due to the fault, the phase to earth voltage and consequently the charging current of healthy phases rise by $\sqrt{3}$ .The resulting residual current will be three times the steady-state charging current per phase.
- Using the advantage of opposite current flow direction between the residual currents on the un-faulted and faulted feeders, discrimination can be provided by using directional earth fault relay.
- To make the residual current seen by the relay lie within the operating zone, the residual voltage which is used as the polarizing quantity is shifted by 90° as shown in Figure 6.



(a)



(b)

Figure 6. *(a). Phasor diagram for insulated system with phase (b) C-earth fault [6]*

6.3.2 Earth Fault Protection on Petersen Coil Earthed Networks

In the Petersen coil earthed systems, reactance which is equal to the system capacitance to ground is used to earth the system (Figure 7). Under steady state conditions, similar to the insulated system, no earth fault current results when a single phase to earth fault occurs.

By using Figure 7 the following equations can be derived.

$$I_f = -I_B - I_C + \frac{V_{an}}{jX_L} \qquad 0 = -I_B - I_C + \frac{V_{an}}{jX_L} \qquad \frac{V_{an}}{jX_L} = I_B + I_C \tag{8}$$

$$I_L = I_{H1} + I_{H2} + I_{H3} + I_F \qquad I_{R3} = I_{H3} + I_F \qquad I_{R3} = I_L - I_{H1} - I_{H2} \tag{9}$$

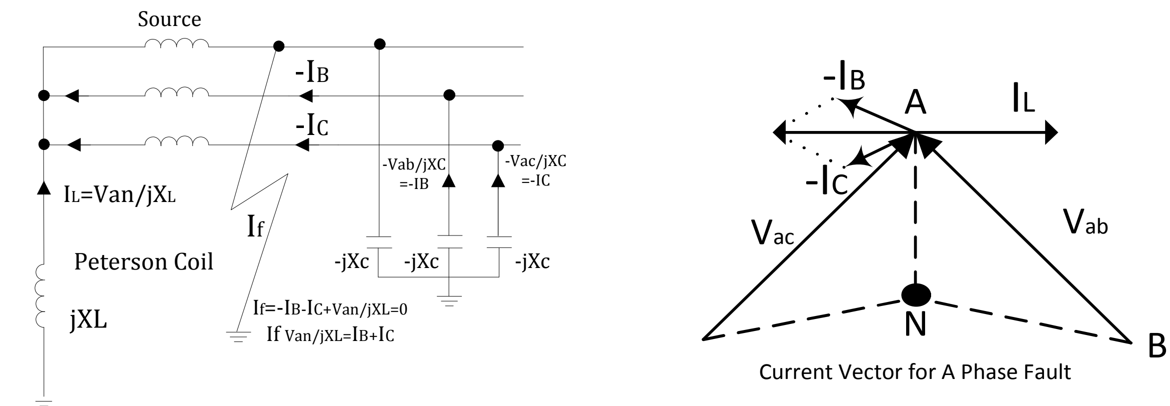


Figure 7. *Earth fault in Petersen Coil Earthed System [6]*

By using equation (9) and Figure *8*. Considering Figure 8, the magnitude of the residual current I_{R1} equals to three times the steady-state charging current per phase. In contrast, the residual current on the faulted feeder is equal to I_L - I_{H1} - I_{H2}. For the residual voltage (V_{res}) polarization, the residual current phase is shifted by an angle less than 90^o on the faulted feeder and greater than 90^o on the healthy feeders due to the presence of resistance effect.

If directional relay with RCA of 0^o is used, the faulted feeder through falls in the 'operate' area while the residual current healthy feeder falls in the 'restrain' area of the relay characteristic. Therefore, in order to increase the angular difference between the residual signals and to ensure a measurable earth fault current, a resistance can be inserted in parallel with the Petersen Coil. It was already mentioned that the method of system earthing also affects the Relay Characteristic Angle (RCA). In the practical applications, there are varieties of grounding systems. The corresponding the RCA values to be used for such systems are listed as follows:

- 0^o RCA can be used for the resistance-earthed system,
- -45^o RCA can be used for the solidly-earthed distribution system and
- -60^o RCA can be used for the solidly-earthed transmission system.

Table 11. *EFP Setting for the SKS.*

H03/ POTA FURNACE, 33 kV					
Function	Pickup Current	TMS	Curve	Time Delay(Second)	In
50N	0.1 x In		Definite Time	0.5	400/1
H04/ TRANSFORMER FEEDER, 33 kV					
Function	Pickup Current	TMS	Curve	Time Delay(Second)	In
50N	0.05 x In		Definite Time	1	3000/1
H05/ ARC FURNACE, 33 kV					
Function	Pickup Current	TMS	Curve	Time Delay(Second)	In
50N	0.03 x In		Definite Time	0.5	3000/1
H06/ TCR AND 2^{nd} HF, 33 kV					
Function	Pickup Current	TMS	Curve	Time Delay(Second)	In
50N	0.04 x In		Definite Time	0.5	3000/1
H07/ 3^{rd} and 4^{th} HF, 33 kV					
Function	Pickup Current	TMS	Curve	Time Delay(Second)	In
50N	0.03 x In		Definite Time	0.5	3000/1

In the SKS the ground fault protection is provided by instantaneous EFP function (50N). The relay used is REF 615 OCP [19]. The setting is selected by considering the maximum unbalance current which is about 20% of the load current. Based on single line diagram of Figure 2 the EFP current and time settings are given in Table 13 and the corresponding characteristic curves are shown in Figure 9.

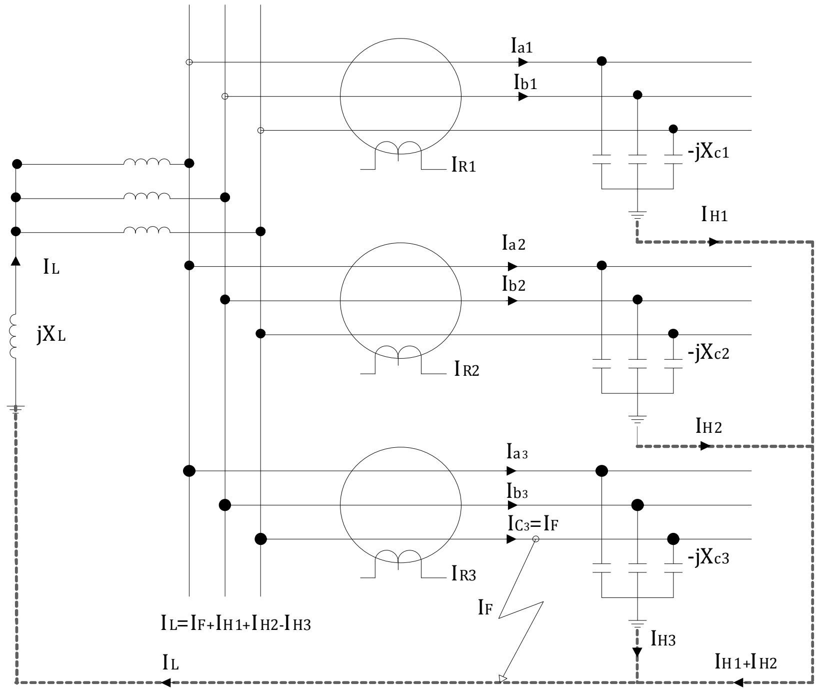


Figure 8. *Distribution of currents during a C-phase-earth fault on radial distribution system [6]*

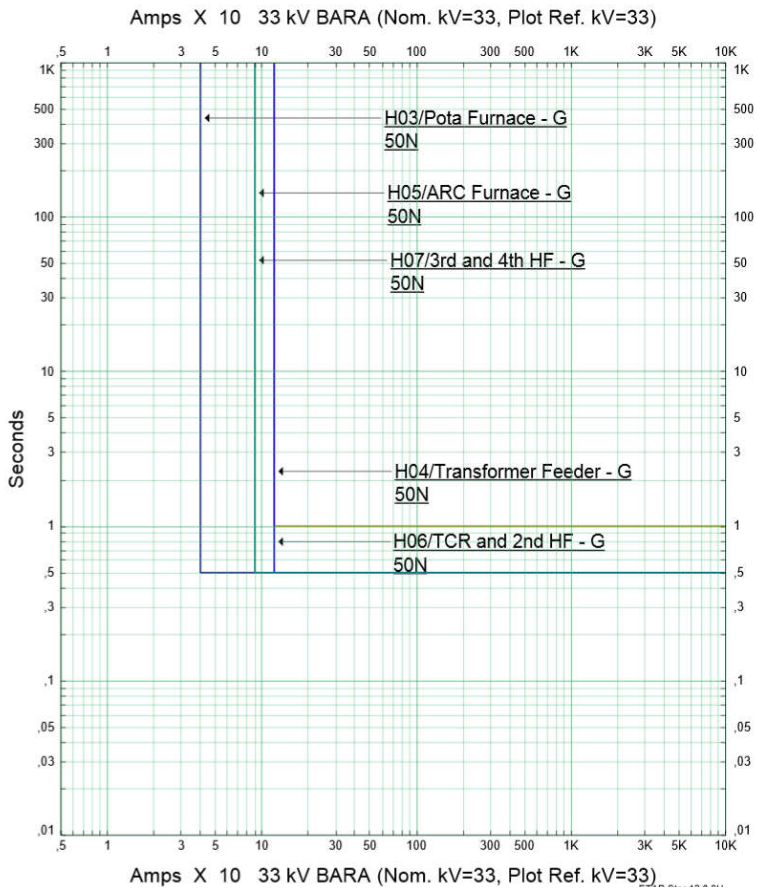


Figure 9. *Ground Fault ProC Curve*

7. CONCLUSION

The electrical power system is expensive investments which have to be designed, implemented and operated with great care so that it provides valuable results. ESS is one of the components of such investment which requires detailed engineering work from its design phase to the implementation phase. If proper protection system design procedure is not followed, the fault currents that may result from abnormal conditions can damage the components of this expensive investment within a fraction of minutes. Thus, during substation design stage, detailed analysis of the system, like a short circuit and load analysis has to be made. Based on the analysis results, protection systems, equipment and techniques have to be properly determined before the implementation stage. This involves the selection of appropriate circuit breakers, fuses, isolators, instrument transformers, protection relays, etc. Moreover, proper coordination among these equipments is a crucial task which has to be handled by protection engineer. In this paper, the proper steps for designing protection system is discussed with a practical case study of SKS project. The engineering steps start from load analysis and short circuit study, which is discussed in this study. The selection of appropriate instrument transformers is also among the fundamental steps for proper operation of the protection system. Based on the requirement of the system to be protected, over-current, differential and distance protection schemes are implemented in the study. However, the distance and differential protection will be covered in the part-2 of this paperwork. Overcurrent and EFP are the earliest protection to be used for the protection of power systems. The engineering issues related to overcurrent and EFP are discussed in detail. In addition, this protection system is designed and implemented for the SKS by providing the necessary coordination among the protection relays. Generally, this paper discussed the necessary engineering steps to be followed for the currently used protection schemes for the modern IEDs. The results from the coordination study are implemented to the substation protection relays. After the necessary test and commissioning of the protection system, SKS is successfully energized.

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Protection Coordination in Electrical Substation Part-2 Unit Protections (Differential and Distance Protection) -Case Study of Siddik Kardesler Substation (SKS), Istanbul, Turkey

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Article Info

Received: 23/12/2016
Accepted:14/08/2017

Keywords

Differential Protection,
Distance Protection,
Protection Coordination,
RED 615
MiCOMho P443

Abstract

Power systems must be protected against faults to ensure quality and reliable generation, transmission and distribution of power systems. Power system protection is provided by the protection relays. This paper is the second part of the Protection Coordination study for the Siddik Kardesler Substation. The protection for transmission lines, transformer, bus bars and customer feeders is provided by overcurrent protection, differential and distance protection schemes. In this paper, issues related to the Differential Protection and Distance Protection for the substation will be discussed. Finally, the test and commissioning have been conducted and the substation is successfully energized without a problem

1. INTRODUCTION

Electrical substations are where the power can be pooled from generating plants, distributed and transformed, and supplied to the load points [1, 2]. In electrical substations, the power transformers are used to change from one voltage level to the other based on the need. For example, in generating stations step-up transformers are used and in the distributing stations, step-down transformers are used. Power transformers are among the critical components which must be protected from faults and damages. A power system was modeled using alternative transients program software to obtain operational conditions and fault situations [3, 4].

In addition, the transmission lines incoming to and out going from the electrical substation are a very important part of the power system which has to be provided with proper protection from the faults. However, the time or current graded overcurrent protection scheme is not sufficient enough to provide the necessary protection for the transformers and transmission lines due to the following reasons. Firstly, they are not suitable to protect complex systems (for example meshed network). Mostly transmission lines interconnecting the electrical substation form a meshed network. Secondly, the setting leads to a minimum tripping times for the faults far from the source and maximum near the source where the fault current is very high.

Due to the above-mentioned drawbacks, unit protections which are designed to respond only to fault conditions occurring within a clearly defined zone are developed. The unit protections are faster than the time grading method. Unit protection method is required to operate in a stable manner by remaining

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unaffected by conditions external to its own zone of protection. Differential and DisP are used as the main protection for transformers and transmission lines while over current protections are used mostly as backup protection. DifP is considered as a unit protection and mostly used for the protection of transformers, bus bars, underground cables and transmission lines. Considering the critical faults, the algorithm is proved using PSCAD / EMTDC simulations in a three-phase power system [5]. For example, in the SKS, transformer protection is provided by a transformer differential relay (87 T). This protection scheme is more selective and fast compared to the other protection. The current transformers are put at the all ends of the equipment to be protected (unit) and the current information is provided to the differential relay. Communication is also used to exchange the current information between the differential relays located at different places in the system.

The impedance of the transmission line is proportional to the length of the line, by measuring the impedance till the reach point (predetermined point) thus, fault protection can be provided. The transmission line ranging from 1 km to 750 km can be protected by distance relay. This is achieved by dividing the voltage at the relaying point and the fault current then comparing it with the apparent impedance of the reach point. SKS is 100 MVA, 154/34.5 kV step down substation supplying an industrial load of arc furnace in Istanbul, Turkey. In this paper firstly DifP will be discussed and the setting values for the SKS will be determined. Finally, the DisP will be discussed and protection coordination settings for the distance relay in the SKS will be provided.

2. DIFFERENTIAL PROTECTION

Differential protection is based on the difference of the current entering and leaving the region to be protected [6-9]. It depends on well-known Kirchhoff Current Law, which states that the sum of the current at a node equals to zero. In principle, the differential relay must not trip under normal operating conditions and for the fault outside its zone of protection. However, due to current transformer accuracy error, the relay may trip for the through-fault conditions. Through-fault conditions are the faults which are outside the region to be protected. So there must be a method to make the relay more sensitive to current differences at low current levels and secure at high current levels. External failures provide transformer differential protection that provides safety for rush and over discharge conditions and provides reliability for internal failures [10]. Investigates the effects of some model parameters on global dynamics and evaluates possible mitigation measures. These parameters include system load level, latent error probability, spinnig reserve capacity and control strategy [11]. The most common solution is to use the percentage differential characteristics. The absolute differential current is plotted on the y-axis and the restraining current will be plotted on the x-axis as shown in Fig.1. The percentage differential curve can be with the single or dual slope. The curve of Fig. 1 is a dual slope curve.
For the bias technique shown in the Fig.1, the trip criterion can be defined as:

$$|I_{diff}| > k_1|I_{bias}| + I_{s1} \qquad for \ |I_{bias}| < I_{s2} \tag{1}$$

$$|I_{diff}| > k_2|I_{bias}| - (k_2 - k_1)I_{s2} + I_{s1} \qquad for \ |I_{bias}| > I_{s2} \tag{2}$$

Where: Idiff is the differential current; Ibias is the bias current; k1 is the percentage bias curve for slope-1 and k2 is the percentage bias for slope-2. Thus, the setting of a differential relay involves determining the low operate condition (Is1), the percentage bias curve slopes (k1 and k2), the restraining methods and the high operate conditions.

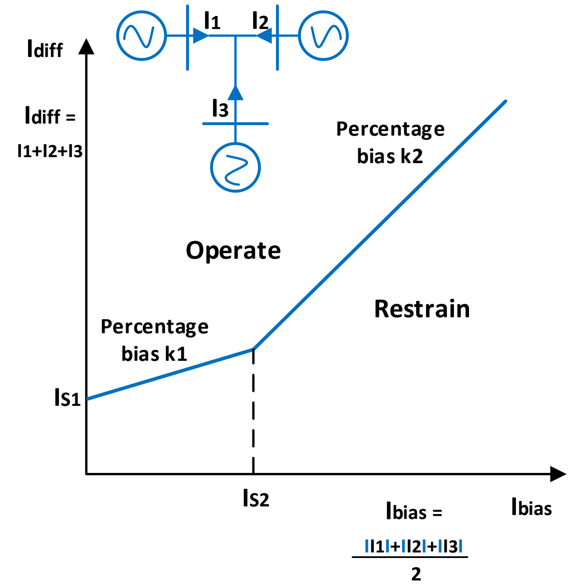

Figure 1. *Dual Slope Bias Technique*

2.1. Restraining Current

The common restraining current calculation methods are sum of, scaled sum of and geometric average which are given as follows [6]:

$$Sum\ of\colon\ I_R = |I_1| + |I_2| + \cdots + |I_n| \tag{3}$$

$$Scaled\ Sum\ of\colon I_R = \frac{1}{n}(|I_1| + |I_2| + \cdots + |I_n|) \tag{4}$$

$$Geometric\ Average\colon\ I_R = \sqrt[n]{|I_1|x|I_2|x \ldots x|I_n|} \tag{5}$$

$$The\ maximu\ of\ \colon\ I_R = max(|I_1| + |I_2| + \cdots + |I_n|) \tag{6}$$

These methods are used by different relay vendors and there is no any significant advantage of one of these methods over the other.

2.2. The Slope of the Percentage Differential Curve

Percentage bias k_1

To determine the slope of the percentage differential curve, the CT error has to be drawn on the curve. For example, if each CT has an error of +/-10%, by considering +10% error for the CT on one side of the unit to be protected and -10% error for the CT on the other side of the unit to be protected, the slope of 20 % percent has to be drawn on the curve as shown in Fig. 1 (percentage bias k_1). As shown in Fig. 1, any region above the slope is an operate region.

Percentage bias k_2

When CT saturation occurs, there is the possibility of false tripping as the current may fall into operate region for through-faults. To overcome this problem, steeper slope (k_2) is used after pre programmed breakpoint (maximum overload operating current, I_{s2}). The resulting shape is known as dual slope percent differential characteristics as shown in Fig. 1. Slope-2 is determined by determining the CT saturation from maximum fault current. The slope-2 is set in such a way the relay will not operate under CT saturation conditions.

2.3. Low Operate Conditions

Finally, system errors are used to set the low operate condition, not to operate under extreme light load conditions. The system error includes the cumulative error of CTs and the analog to digital converters. This can be determined from the difference of actual current and the current read by the relay. In addition, for the underground cable protection, the capacitive charging current has to be considered in determining the low operate condition.

To make the relay not operate from the effects of line charging current, the setting of low operates condition must be at least 2.5 times the steady-state charging current [6]. On a real and healthy line, the differential current is equal to the capacitive load current of the line (I_C) [6].

$$I_{Diff} = I_c = 2 * \pi * f * C * \frac{U_{LL}}{\sqrt{3}} \tag{7}$$

Where: C is neutral line capacitance per [μF/km]; l = line length [km]; f = signal frequency [Hz]; U_{LL} = Line-Line voltage [V]

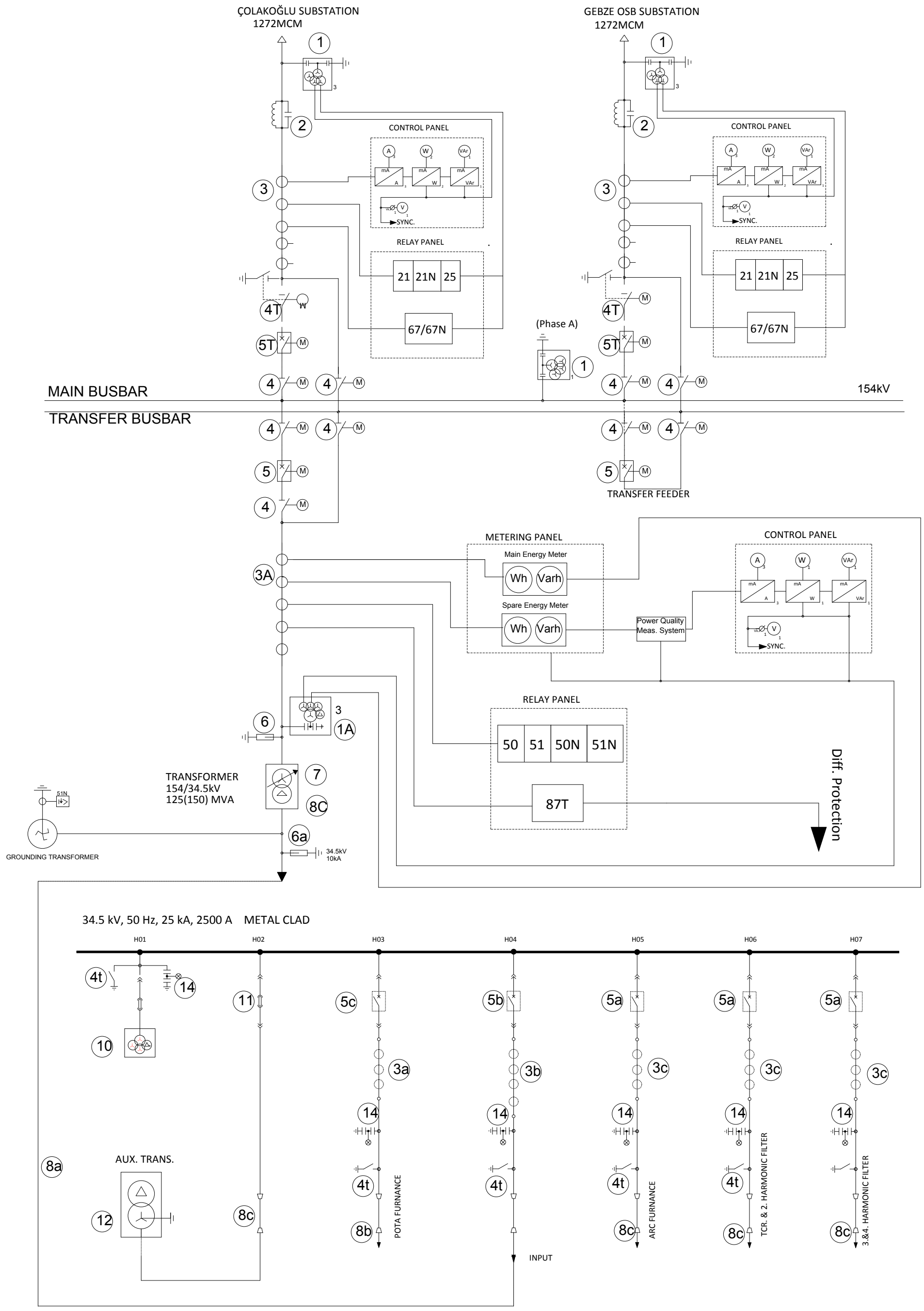

Figure 2. SKS Single Line Diagram [12]

If the capacitive charging current is very large and hence the low-operate condition needs to be set to a very high value. To avoid this, facility of subtracting the charging current from the measured value is provided in some relays. Phase –segregated current differential is used in digital or numerical relays where the currents are compared on per phase base at each relay. Fiber optic communication is used to exchange the pilot currents between the relays. When the DifP is used for the protection of the power transformer, the transformation ratio, transformer vector grouping, transformer tap changer and magnetizing inrush currents have to be considered [5]. The magnitudes of the currents on the primary and secondary sides of the transformer are inversely proportional to its turn ratio. In addition, the vector group creates a phase difference between the primary and secondary currents which have to be handled by phase correction. Depending on the position of the tap changer, the magnitude of the primary and secondary currents will vary. Due to this fact, the mean tap position should be taken for the calculations.

2.4. SKS Power Transformer Feeder Protection by Red 615

The ABB RED 615 differential relay is used for the protection of the power transformer in the SKS. The single line of the SKS is shown in Fig.2 for the reference purpose. The description of the single line diagram is available in [13].

As shown in Fig. 2, the transformer is connected to the transformer protection cubicle by 34.5 kV XLPE underground cable. Since the length of the cable is 50 m, the effect of charging current can be neglected for this feeder. By considering the maximum unbalanced load current, the low-operate setting of 20% can be used.

2.4.1. CT Ratio Correction

Furthermore, the current transformer ratios at the two ends of the transformer are not the same. Thus, for the RED 615 relay, CTs ratio correction has to be applied as follows [14]:

1. The current on the 154 kV side of the transformer can be calculated as:

$$I_{154\,kV} = \frac{150\,MVA}{154\,kV * \sqrt{3}} = 562.35\,A \qquad and \qquad CT = \frac{800}{562.35} = 1.4226 \tag{8-9}$$

The 154 kV side current transformer ratio is 800/1. Thus, the correction ratio for 154 kV side CT can be calculated as (9).

2. Similarly, on the 34.5 kV, the load current is given by:

$$I_{34\,kV} = \frac{150\,MVA}{34.5\,kV * \sqrt{3}} = 2510.29\,A \;\; and \; CF = \frac{3000}{2510.29} = 1.195 \tag{10-11}$$

The MV side current transformer ratio is 3000/1. The correction factor (CF) is given by (11).

2.4.2. Inrush Detector

During initialization of the transformer, the inrush current flows and this current may reach more than 10 times of the full load current. This current occurs in the source or primary side of the transformer causing unbalance to the differential relay. The second harmonic detection method is used to block the mal-operation of the differential relay due to inrush current. In modern transformer differential relays or blocking for other harmonics like for example the 5th are also provided.

2.4.3. Zero Sequence Current Filtering

DifP will see a zero sequence current for an external fault if an earthing transformer or earthed transformer winding is available within the zone of protection. This may result in incorrect operation of the differential relay. Due to this fact, zero sequence current filtering is necessary. Generally, selectable software zero sequence filter is typically employed in a digital or numerical relay. The relay percentage differential curve is also shown in the Fig. 3. Based on the above discussions and engineering practices the values of the setting are determined and summarized for the RED 615 as shown in Table 1.

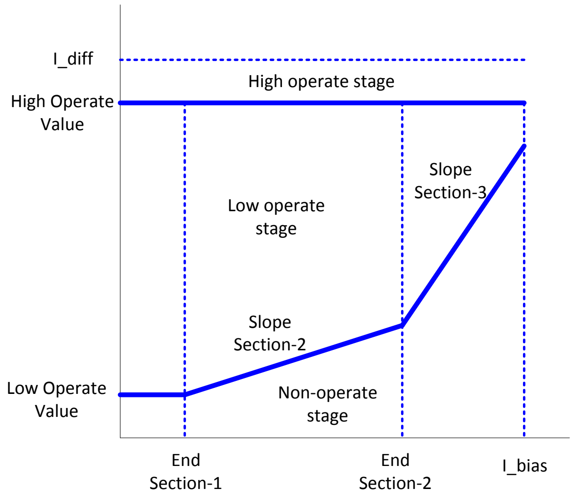

Figure 3. *Operating characteristics of the DifP [6].*

Table 1. *The Parameters for RED 615*

Parameter	Value
High Operate Value (%IR)	600
Low Operate Value (%IR)	20
Slope Section-1 (%)	30
End of Section-1 (%)	150
Slope of Section-3 (%)	60
Start Value 2.H	15
Start Value 5.H	35

3. DISTANCE PROTECTION

The transmission line impedance is proportional to the length of the line. Consequently, by measuring the impedance till the reach point (predetermined point), fault protection can be provided. This is achieved by dividing the voltage at the relay point and the fault current and comparing it with the apparent impedance of the reach point. The advantage of DisP is its independence from the variation of the source impedance.
The performance of DisP is based on the accuracy of reach and the operating time. The reach accuracy is the factor of the level of voltage presented to the relay and the method used to measure the impedance. In addition, the impedances actually measured by a distance relay depend on the type of fault, the fault impedance of the loop measured, the fault resistance, the symmetry of line impedance and the circuit configuration (single, double or multi terminal circuit). Furthermore, the angle is also important in order to incorporate directional selectivity in DisP. For the lines with 150 kV and above typical positive sequence, Z_1 angle varies from 75^o to 80^o.

3.1. Distance Relay Protection Configurations

Phase relay and ground relay are the two major categories of distance relay. There are 10 types of shunt faults against which a system has to be protected. These are a 3-phase fault -1 types, L-L fault -3 types, S-L-G faults- 3 types and L-L-G fault -3 types. Consider three phase balanced transmission line as shown in Fig. 4 (a).

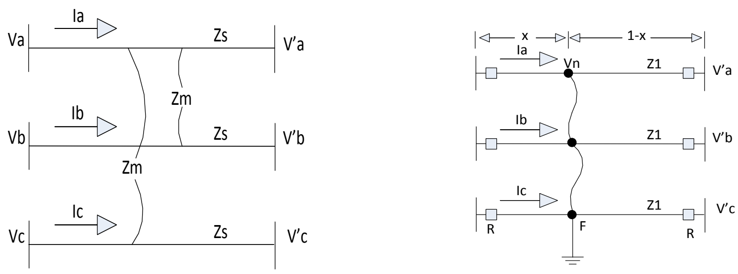

***Figure 4**. (a) A balanced Transmission System. (b) Three phase to the ground bolted fault*

The sequence current, impedance and the voltage of this transmission line can be expressed as follows [15-17].

$$\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix}, \begin{bmatrix} Z_0 \\ Z_1 \\ Z_2 \end{bmatrix} = [Z_s \quad Z_m]\begin{bmatrix} 1 & 2 \\ 1 & -1 \\ 1 & -1 \end{bmatrix}, \begin{bmatrix} \Delta V_0 \\ \Delta V_1 \\ \Delta V_2 \end{bmatrix} = [Z_0 \quad Z_1 \quad Z_2]\begin{bmatrix} I_0 \\ I_1 \\ I_2 \end{bmatrix} \quad (12\text{-}13\text{-}14)$$

A fundamental requirement of distance relaying is that the relay input voltages and currents have to be configured in such a way that for any type of bolted fault ($Z_f = 0$), the apparent impedance seen by the relay is given by xZ_1.

3.1.1. Phase Relay Configuration

By using equations (1) -(3) and Fig. 4 (b), it can be proved that [15-17]

$$\frac{V_a}{I_a} = \frac{V_b}{I_b} = \frac{V_c}{I_c} = \frac{V_1}{I_1} = xZ_1 \quad (15)$$

Thus, a relay monitoring line current and phase voltages can locate faults by using equation (15). From equation (15), it can be observed that when a fault occurs the current magnitude increases and the voltage decreases, this reduces the impedance. But under normal conditions the impedance is high. This is used to locate the fault easily. Alternatively, for a relay monitoring, phase-to-phase voltage and the difference of phase currents, equation (15) can be extended as:

$$\frac{V_a - V_b}{I_a - I_b} = \frac{V_b - V_c}{I_b - I_c} = \frac{V_c - V_a}{I_c - I_a} = \frac{V_1}{I_1} = xZ_1 \quad (16)$$

Traditionally the relay configured as in equation (16) can also locate phase to phase faults. In addition, the distance to the fault is given by:

$$x = \frac{Z_{app}}{Z_1} * L \quad (17)$$

Where L is the length of the line and Zapp is the impedance seen by the relay.

3.1.2. Ground Relay Configuration

Different input configuration from phase fault relays (3-phase and L-L) is required for the traditional ground fault relays [14-16]. The configurations are given in equation (18).

$$xZ_1 = \frac{V_a}{I_a + mI_0},\ xZ_1 = \frac{V_b}{I_b + mI_0},\ xZ_1 = \frac{V_b}{I_b + mI_0} \quad \text{Where, } m = \frac{Z_0 - Z_1}{Z_1},\ I_0 = \frac{I_a}{3} \quad (18)$$

Thus, the relays configured for equations (16) and (18) can detect all the 10 faults (3-phase fault, L-L faults, S-L-G faults, L-L-G faults).

3.2. Infeed and Outfeed

Equations (15)-(18) are based on the assumption of balanced bolted fault condition. Furthermore, the effects of infeed and outfeed are not considered. In the practical situation, this assumption is not valid. If we take Fig. 5 as an example, the impedance the relay R1 sees for the fault at F is not equal to Z_1+xZ_2 due to the remote in-feed. If remote in-feed is considered, the impedance seen by relay R1 can be derived as follows [15-17].

$$I_{BC} = I_{ED} + I_{AB} \tag{19}$$

$$V_{R1} = I_{AB} * Z_1 + (I_{ED} + I_{AB}) * xZ_2 \tag{20}$$

$$Z_{R1} = \frac{V_{R1}}{I_{AB}} = Z_1 + xZ_2 + \frac{I_{ED}}{I_{AB}}.xZ_2 \tag{21}$$

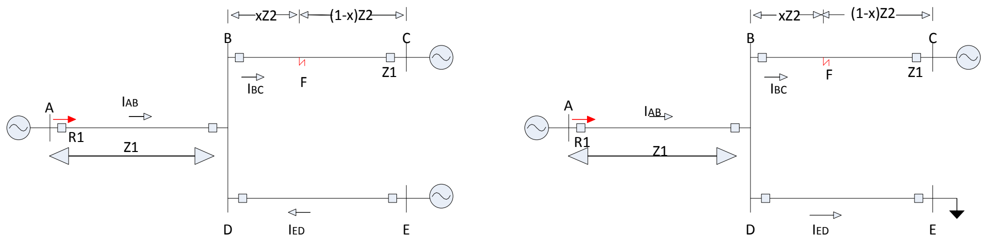

Figure 5. *(a) Infeed (b) Outfeed Effect*

Infeed effect is shown in Fig. 5 (a) and the relay R1 sees an equivalent increase in apparent impedance as proved by equations (19-21). The relay sees fault the shifted from its actual location. For example, the fault which happened in zone-2 may be shifted to zone-3. This compromises the selectivity of zone-2. However, due to the infeed effect, the fault location as observed to the relay will not be shifted to zone-1 and does not compromise selectivity of zone-1. Consider Fig. 5 (b) where the generator G_2 is replaced by the load, then:

$$I_{BC} = I_{AB} - I_{ED} \tag{22}$$

$$Z_{R1} = \frac{V_{R1}}{I_{AB}} = Z_1 + xZ_2 - \frac{I_{ED}}{I_{AB}}.xZ_2 \tag{23}$$

Equation (23) shows the impedance decrease due to outfeed. In other words, the fault perceived by relay R1 is closer than its actual location. This may cause the instantaneous operation of the relay R1 for the fault occurring on the backup line, thereby compromising selectivity of zone-1. Due to this fact, zone (Z1) of distance relay is always set below 100%-line impedance.

3.3. ARC Resistance Effect

The fault angle affects the impedance reach of the relay. At the system operating frequency, the relative values of transmission line's resistance (R) and inductance (X) will determine the fault angle. The transmission line fault may involve arc or an earth fault involving additional resistance due to fault through vegetation or tower footing resistance. Due to this condition of the fault, the value of the resistive component of fault impedance may increase changing the impedance angle. Thus, if the characteristic angle of the relay is set to the line angle, the relay will under-reach under resistive fault conditions. In order to avoid the under-reach and accept a small amount of fault resistance, in some cases the relay characteristic angle (RCA) is set less than the line angle. However, while setting the relay, the difference between the relay characteristic angle Ø and the line angle θ must be known. This is used to calculate the new reach as follows [6]:

$$AQ = \frac{AB}{Cos(\emptyset - \theta)} \quad (24)$$

Where: AQ is the relay impedance setting; AB is the impedance of protected line; PQ is arc resistance as shown in Fig. 6 (a). In addition, the arc resistance can be calculated by the following empirical formula.

$$R_a = \frac{28.710}{I^{1.4}} L \quad (25)$$

R_a = arc resistance (ohms), L = length of arc (meters), I = arc-current (A)

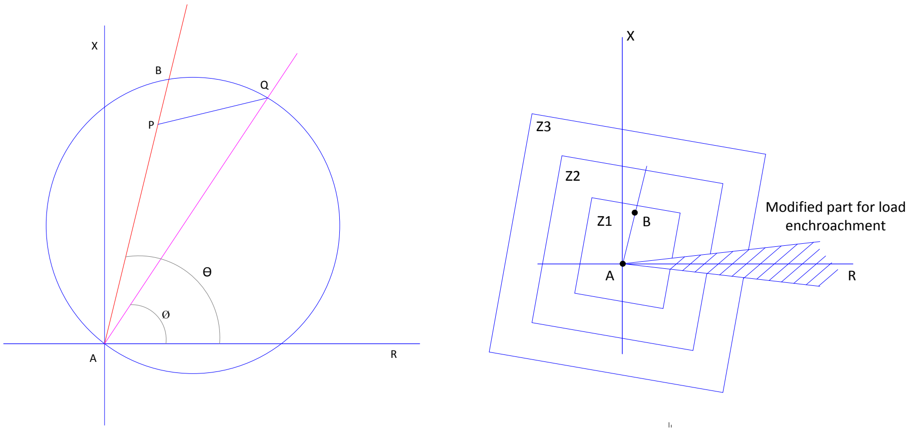

Figure 6. *(a): Increased Arc Resistance Coverage [3]. (b)Relay Characteristic modification for the load encroachment.*

3.4. Load Encroachment

The impedance seen by the relay can be expressed in terms of the apparent power and the voltage as follow:

$$Z_R = \frac{V^2}{S} \quad (26)$$

The impedance seen by the relay is directly proportional to the square of the voltage and inversely proportional to the apparent power. During peak load conditions the voltage will drop and the apparent power increases as well. This results in the decrease of the impedance seen by the relay. If the impedance is seen by relay within the zones of protection due to large load decreases, then the relay will trip the circuit breaker. Under such circumstances, the relay is said to trip on load encroachment. Tripping on load encroachment can even initiate cascaded tripping and compromises security. This may even lead to blackouts.

It is necessary to prevent the wrong operation of the relay for load encroachment. Most of the time, loads have large power factor and this leads to large R/X ratio, while faults are more or less reactive in nature and the ratio X/R is quite high. This feature can be used to identify the load encroachment condition. During relay setting, its characteristic can be modified by excluding the area in an R–X plane, which corresponds to a high power factor.

3.5. Power Swing Detection, Blocking and Out-Of-Step Relays

It is not desired for distance relay to operate under power swing conditions whether the swing is stable or not. The distance relays mostly equipped with swing detection and blocking mechanisms. Relay Characteristic modification for the load encroachment as shown in Fig.6 (b). The idea behind detecting a power swing is that the change in apparent impedance seen by relay due to fault occurrence is faster than the change in impedance due to power swing. The change in impedance during the swing is a slow process due to the inertia of the generators. Thus, this time discrimination can be used to distinguish swings from faults. The detailed discussion on the topic is available in [18].

3.6. Zones of Protection in Distance Relaying

For the selective clearing of faults on the transmission lines, zones are defined in the distance relaying. The zones of protection in distance relaying can be impedance, admittance (mho), reactance or resistive as shown in Fig.7. The zones of protection can be programmed to operate in the forward (looking into the line) or reverse direction (looking out of the line). Impedance zone (blue circle on Fig. 7) of protection is the circle with center at the origin. The radius is the reach of the distance relay. It is non-directional and mostly used for the generator backup protection. Reactance zone (pink horizontal line on Fig. 7) is used when the impedance of the fault has a very high resistive component which indicates that there is a load on the transmission line and the fault is most likely not on the transmission line but on the load.

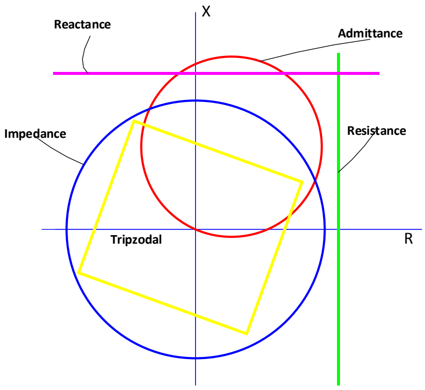

Figure 7*. Zones of Protection in Distance Relaying*

Resistance zone (green vertical line on Fig. 7) is used when the fault impedance contains a very high reactance component which indicates the availability of little load on the transmission line. The admittance zone (red circle on Fig. 7) is commonly used in the protection relays and it is inherently directional. Most modern numerical relays allow the user to modify the shape to suit their application. These zones serve different functions like for example to exclude the fault on the load lenticular shape is used; to selectively isolate the fault occurring near to the location of measurement and not to operate for the fault behind the location of measurement expansion element is used, etc. [6,15].

3.7 Distance Protection Schemes

All the schemes used in DisP falls either in pilot aided schemes or non-pilot aided schemes. The distance relays which are used in pilot aided schemes communicate with each other to determine the fault. The relays in non-pilot schemes do not communicate with each other, rather they use time delay and other forms of coordination to operate selectively.

3.7.1. Non-Pilot Aided Schemes

There are two types of non-pilot aided schemes. These are stepped protection schemes and zone-1 extension protection schemes.

3.7.1.1. Stepped Distance Schemes

This scheme is considered as the fundamental for other protection schemes. It consists of four zones of protection. The first zone of protection (Zone-1) is under reaching which protects 80-90% of the first transmission line. This zone is also set without time delay. Therefore, if the fault occurs on the first line the distance relay must be sure that the fault is on the transmission line and operate without time delay. Due to CTs/ PTs accuracy limit, inaccurate line impedance data and assumptions while deriving equations for the relay, zone-1 do not protect the last 10-20% of the line which is known as an end zone [19].
Sufficient margin to account for non-zero fault impedance and other errors in relaying is provided by zone-2 and zone-3. The zone-2 is also known as overreaching. For the primary positive sequence (Z_P) and

the shortest backup impedance (Z_B) of the line, zone-2 is set to reach Z_P + 0.5 Z_B. For the too short back up the line, then it is likely that $Z_P + 0.5Z_B$ will be less than $1.2Z_P$. In such a case, zone-2 is set to $1.2Z_P$. But, it must not overlap with zone-2 on the backup line if the zone-2 of the first line is extended above the 50% of the shortest backup line. If the overlapping is unavoidable, other schemes like pilot schemes are used. The time delay for zone-2 is from 0.25 – 0.4 second. Zone-1 and Zone-2 have the capability of protecting the entire length of the transmission line. Zone-3 is set to about 220% of the protected line if line-1 and line-2 have the same impedance or it can be set to the longest of the lines connected to the first line. The time delay of 1 second can be used for Zone-3. Zone-4 is used as the back protection of adjacent transmission lines in the reverse direction and it must allow zone-1 and zone-2 of the first line to operate first. Thus, it is usually set 20-40 % of the impedance with a time delay ranging from 0.75-1 second.

3.7.1.2. Zone-1 Extension

This protection scheme is the enhancement of the stepped distance schemes for the transient nature of the faults. For example, during the lightning strike of the transmission line, due to ionization of the air, the resistance between different phases of the line reduces causing fault current to flow. If the circuit breaker opens the line, the fault will be cleared, the ionized air will be removed, creating no more pass for the current to flow. When the circuit breaker is closed the transmission line will resume its normal operation. The difference of the stepped scheme and the zone-1 extension scheme is that in the zone-1 extension scheme as shown on Fig.8 (a), the zone- 1 setting will be increased to over reach about 120% of the protected line. During the first occurrence of the fault according to zone-1 extension scheme, the relay will trip and clear the fault even if it is in the adjacent line. If the fault was transient, this will remove the fault and the transmission line will resume its normal operation. The relay will then immediately adjust itself to the stepped scheme. If the fault is permanent, the relay will clear the fault by using its zone-1 and zone-2 of its stepped schemes based on the location of the fault on the transmission.

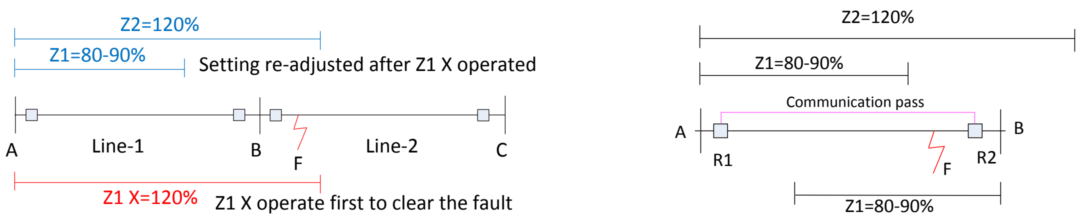

Figure 8. *(a) Zone-1 Extension Schemes (b) Pilot aided protection schemes*

When the auto-reclosing duration is expired the distance relay will switch again to the zone-1 extension scheme.

3.7.2 Pilot Aided Schemes

When the fault happens in the middle of the transmission line, the relays at the two ends of the line will automatically clear the fault with their zone-1 protection. But if the fault happens at one end of the line, the relay near to the fault trips with zone-1 (R2 on Fig.8 (b)) while the relay on the other side trips with zone-2 (R1 in Fig. 8 (b)). The fault current from the non-tripping side of the transmission line will continue (from R1 side till zone-2 operates).

The pilot schemes are devised to improve the performance of stepped schemes, especially for the faults occurring at the terminals of the transmission lines. So there must be a communication pass as shown in Fig. 8 (b) between the relays at the two ends of the line in order to exchange information about the occurrence of the fault. Direct Under-Reaching Transfer Trip (DUTT), Permissive Under-Reaching Transfer Trip (PUTT), Direct Over-Reaching Transfer Trip (POTT) and Hybrid Permissive Over-Reaching Transfer Trip (HYBRID POTT) are the most common types of pilot schemes. The discussion of these pilot schemes is available in [6].

3.8. Minimum Length of Line

In order to determine the minimum line length to be used in DisP the following checking's has to be done:

1. The voltage sensitivity of the relay for fault in the zone-1 for the minimum length of the line must be sufficient enough,
2. The zone-1 omics resistance of the fault referred to the secondary side quantities of the CTs and VTs has to fall in the impedance range of the relay and
3. The appropriate earth fault loop impedance has to be used for the earth faults.

3.9. Setting Calculation for the SKS

The SKS is connected by two transmission lines to the rest of TEİAŞ network. One transmission line is going towards the GEBZE organized industrial zone substation and the other is going towards the ÇOLAKOĞLU substation as shown in Fig. 9. MiCOMho P443 DisP relay is used in this project. Fig. 9 (a) shows the protection for 85% of L_1 is provided by zone-1. In addition, zone-2 and zone-3 give additional protection to other regions besides their backup protection to L_1. The protection of zone-2 covers100% of L_1 and 50% of L_2 towards ÇOLAKOĞLU substation. The protection of zone-3 covers 100% of L_1 and 100% the longest line connected to L_1 in this case which is L_2. Zon-4 gives backup protection to 100% of L_0 in the reverse direction towards the GEBZE substation. Similarly, for Fig. 9 (b), 85 % of L_0 is primarily protected by zone-1. Additionally, zone-2 and zone-3 provides backup protection to another transmission line. The protection for 100% of L_0 and 50% of L_4 is provided by zone-2 in the direction of GEBZE substation. The protection of 100% of L_0 and L_4 is provided by zone-3 in the direction of Diliskelesi. In all the above cases the operation time for zone-1, zone-2, and zone-3 are selected as 0 ms, 400 ms, 800 ms and 2000 ms respectively. In the following section, the settings are calculated as follows for the arrangement shown in Fig. 9 and MiCOMho P443 DisP relay.

3.9.1. Protection Coordination towards Kroman Çelik and Diliskelesi

Line Impedance

The positive and zero sequence impedances for lines shown in Fig.9 are given in Table 2. Since basically, the distance relays depend on the impedance measurement, the values given in Table 2 very important for the setting calculation in the distance relaying. In the general term, the impedance which lower than the actual impedance of the line is an indication of the fault in the distance relaying.

Table 2. *Zero and positive sequence impedance of the lines*

Line	Length (km)	Z0	Z1
L0	13,094	1,092+j5,035	3,822+j17.23
L1	3,7330	1,090+j4,912	0,311+j1,436
L2	2,0100	0,500+j2,600	0,100+j0,800
L3	21,584	6,300+j28.400	1,800+j8,300
L4	11,000	3,200+j14.500	0,900+j4,200

Zone-1 Phase Reach

The required Zone-1 reach is 85% of the line impedance:

$Z1 = 0.85 * 1.469 < 77.8^0 \qquad Z1 = 1.249 < 77.8^0$

Zone-2 Phase Reach

The required reach for zone-2 is the protected line plus 50% of the next line.

$Z2 = 1.469 < 77.8^0 + 0.5 * 0.806 < 82.9^0 \quad Z2 = 1.871 < 78.9^0$

Zone-3 Phase Reach

The required reach for zone-3 is the protected line plus 100% of the next longest line.

$Z3 = 1.469 < 77.8^0 + 8.493 < 77.8^0 \qquad Z3 = 9.962 < 77.8^0$

Zone-4 Phase Reach

The required reach is 20 % of the next transmission line which is found in the reverse direction.

$Z4 = 1.03 < 77.8^0$

Zone Time Delay Settings

The time delay for each zone can be assigned as follows:

$T_{Z1} = 0\ ms, T_{Z2} = 400\ ms, \quad T_{Z3} = 800\ ms, T_{Z4} = 2000\ ms$

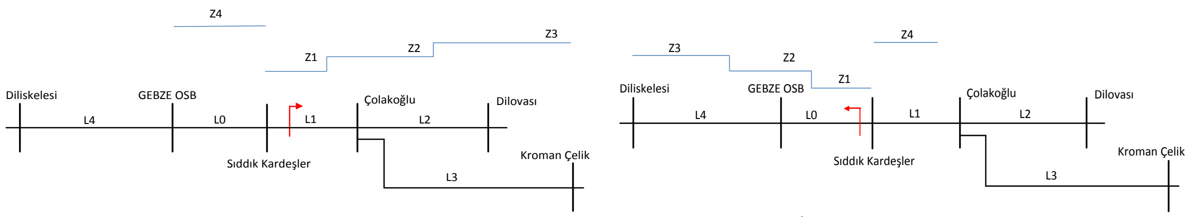

Figure 9. *(a) ProC towards Kroman Çelik (b) ProC towards the Dil İskelesi*

Residual Compensation

Based on the discussion in section 3.1.2, the zero sequence and positive sequence impedances seen by the relay are different when the earth fault occurs. For earth faults, in the residual path of the earth loop circuit, a residual current (derived as the vector sum of phase current inputs ($I_a + I_b + I_c$)) is assumed to flow. However, the relays used are calibrated in terms of the positive sequence impedance of the protected line and it is different from the earth fault impedance. Thus, compared to positive sequence reach for the corresponding phase fault element, a multiplication factor of (1 + kZN) which is discussed in [15-17,20] has to be used to extend the earth loop reach. Hence, the earth fault reach of the relay requires zero sequence compensation as follow:

$$k = \frac{1}{3}\left(\frac{Z_0}{Z_1} - 1\right) = \frac{1}{3}\left(\frac{5.031 < 77.5^0}{1.469 < 77.8^0} - 1\right) \; k = 0.808 < -0.4^0$$

Phase Fault Resistive Reach Settings

The resistive reach settings for each zone can be set independently of the impedance reach settings while using the quadrilateral characteristic. The maximum amount of additional fault resistance for which a zone will trip regardless of the fault within the zone is represented by resistive reach setting. The following constraints have to be imposed upon resistive reach settings:

- It must be greater than the maximum expected phase-phase fault resistance (principally that of the fault arc) [6]. The length of the arc can be assumed as 1.5 times the conductor spacing and the minimum arc current is 1 kA [6]. The arc impedance (Ra), can be calculated by the empirical formula in equation (25) as follow.

$$R_a = \frac{28707}{1000^{1.4}} * 7 = 13\,\Omega$$

- If load encroachment is not applied, it must be less than the apparent resistance measured due to the heaviest load on the line [6]. For the maximum load current of 800 A, the resistance due to maximum load (R_{HL}) can be calculated as:

$$R_{HL} = \frac{154\,kV}{\sqrt{3} * 800} = 111\,\Omega$$

Consequently, the fault resistive reach setting can be selected as:

$60\%\ R_{HL} = 67\Omega$

Earth Fault Resistive Reach Settings

The total resistance that must be covered during earth faults is the sum of arc resistance (Ra) and the total loop resistance of the fault (R_{TF}) [21].
A safety factor of 20% and division factor ($1 + R_E/R_L$) are included as Ra and RTF appear in the loop measurement as in Equation 27 [22].

$$R_{EZ1} = 1.2 * \frac{R_{arc} + R_{TF}}{1 + \frac{R_E}{R_L}}\ \Omega \quad \text{This can be approximated as } 80\%\ R_{HL} = 89\ \Omega \tag{27}$$

After all the above steps are followed, the setting values are summarized in Table 3 for the relay looking towards Kroman Çelik Substation (Fig. 9 (a)).

Table 3. *For SKS distance relay looking towards Kroman Çelik-Diliskelesi*

Relay Parameter	**Description Kroman Çelik L_1, Diliskelesi L_0**	**Value L_1**	**Value L_0**	**Units**
ZL_1 (mag)	L0 positive sequence impedance (magnitude)	1.469	5.152	Ω
ZL_1 (ang)	L0 positive sequence impedance (phase angle)	77.8	77.8	deg
ZL_0 (mag)	L0 zero sequence impedance (magnitude)	5.031	17.649	Ω
ZL_0 (ang)	L0 zero sequence impedance (phase angle)	77.5	77.5	deg
KZ_0 (mag)	L0 default residual compensation factor (magnitude)	0.808	0.809	Ω
KZ_0 (ang)	L0 default residual compensation factor (phase angle)	-0.4	-0.4	deg
Z_1 (mag)	Impedance reach setting of zone 1 (magnitude)	1.249	4.379	Ω
Z_1 (ang)	Impedance reach setting of zone 1 (phase angle)	77.8	77.8	deg
Z_2 (mag)	Impedance reach setting of zone 2 (magnitude)	1.871	7.3	Ω
Z_2 (ang)	Impedance reach setting of zone 2 (phase angle)	78.9	77.8	deg
Z_3 (mag)	impedance reach setting of zone 3 (magnitude)	9.962	9.447	Ω
Z_3 (ang)	Impedance reach setting of zone 3 (phase angle)	77.8	77.8	deg
Z_4 (mag)	Zone 4 reach impedance setting (magnitude)	1.03	1.469	Ω
Z_4 (ang)	Impedance reach setting of zone 4 (phase angle)	77.8	77.8	deg
R_1ph	Phase fault resistive reach value - Zone 1	67	67	Ω
R_2ph	Phase fault resistive reach value - Zone 2	67	67	Ω
R_3ph	Phase fault resistive reach value - Zone 3	67	67	Ω
TZ_1	Time delay - Zone 1	0	0	sec
TZ_2	Time delay - Zone 2	0.4	0.4	sec
TZ_3	Time delay - Zone 3	0.8	0.8	sec
TZ_4	Time delay - Zone 4	2	2	sec
R_1G	Ground fault resistive reach value - Zone 1	89	89	Ω
R_2G	Ground fault resistive reach value - Zone 2	89	89	Ω
R_3G	Ground fault resistive reach value - Zone 3	89	89	Ω

4. CONCLUSION

The electrical power system is an expensive investment which has to be designed, implemented and operated with great care to provide valuable results. Electrical substations are among the component of this investment which requires detailed engineering work from its design phase to the implementation phase. Power transformers which are used in the substation to change between the voltage levels are protected mainly by the differential relay. The DifP is the fastest unit protection scheme which must not operate for the fault outside its protection zone (through fault conditions). False tripping of a differential relay due to through fault is avoided by using a percentage differential curve. Consequently, the differential relay settings involve the determination of the pickup currents and the slopes of the percentage differential curves. In addition, CT ratio correction, inrush setting, and phase angle corrections are included in the setting parameters. ABB relay RED 615 is used in this project and the setting parameters for this relay are determined in this work. Furthermore, the transmission line which transfers energy from one place to another is protected by distance relay which is placed in the electrical substation. As the length of transmission line is proportional to its impedance, DisP relays are commonly employed to protect both phase and ground faults (phase and ground relay configurations). The ground relay configuration involves residual compensation factor. Infeed and out feed effects, arc resistance effect, load encroachment and power system disturbances like power swings have to be considered while calculating the DisP settings. DisP by using a non-pilot scheme involves the stepped schemes and the zone-1 extension schemes. In this project, MiCOMho P443 relay is used and settings are calculated. The results from the coordination study are implemented to the substation protection relays. After the necessary test and commissioning of the protection system, the SKS is successfully energized.

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