



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

Abdulfetah Shobole¹, Mustafa Baysal², Mohammed Wadi³, Mehmet Rida Tur^{4*}

^{1,3} *Electrical & Electronics Engineering Department, Istanbul Sabahettin Zaim University, Halkalı Mahallesi, Halkalı Caddesi, Halkalı Kampüsü No:2, 34303 Küçükçekmece, Istanbul, Turkey*

² *Electrical Engineering Department, Yildiz Technical University, Davutpaşa St., 34220 Esenler, Davutpaşa, Istanbul, Turkey*

⁴ *Electrical Engineering Department, Mardin Artuklu University, Diyarbakır St. Yenişehir Campus, Mardin, Turkey*

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

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, spinning 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:

$$|I_{diff}| > k_1 |I_{bias}| + I_{s1} \quad \text{for } |I_{bias}| < I_{s2} \quad (1)$$

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

Where: I_{diff} is the differential current; I_{bias} is the bias current; k_1 is the percentage bias curve for slope-1 and k_2 is the percentage bias for slope-2. Thus, the setting of a differential relay involves determining the low operate condition (I_{s1}), the percentage bias curve slopes (k_1 and k_2), the restraining methods and the high operate conditions.

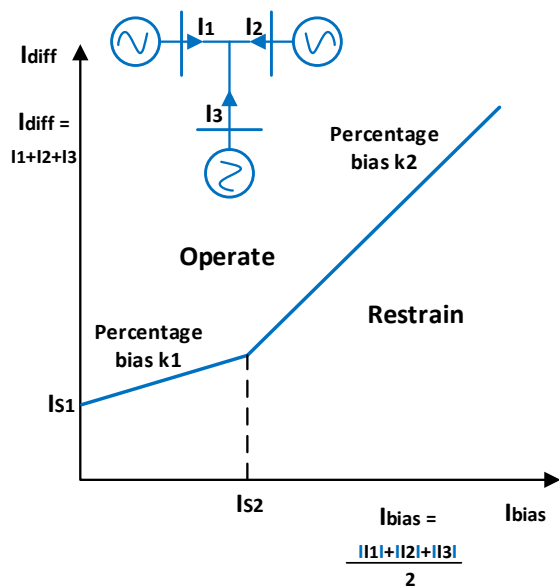


Figure 1. Dual Slope Bias Technique

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]:

$$\text{Sum of: } I_R = |I_1| + |I_2| + \dots + |I_n| \quad (3)$$

$$\text{Scaled Sum of: } I_R = \frac{1}{n} (|I_1| + |I_2| + \dots + |I_n|) \quad (4)$$

$$\text{Geometric Average: } I_R = \sqrt[n]{|I_1| \times |I_2| \times \dots \times |I_n|} \quad (5)$$

$$\text{The maximum of: } I_R = \max(|I_1| + |I_2| + \dots + |I_n|) \quad (6)$$

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 $\pm 10\%$, 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 [$\mu\text{F}/\text{km}$]; l = line length [km]; f = signal frequency [Hz]; U_{LL} = Line-Line voltage [V]

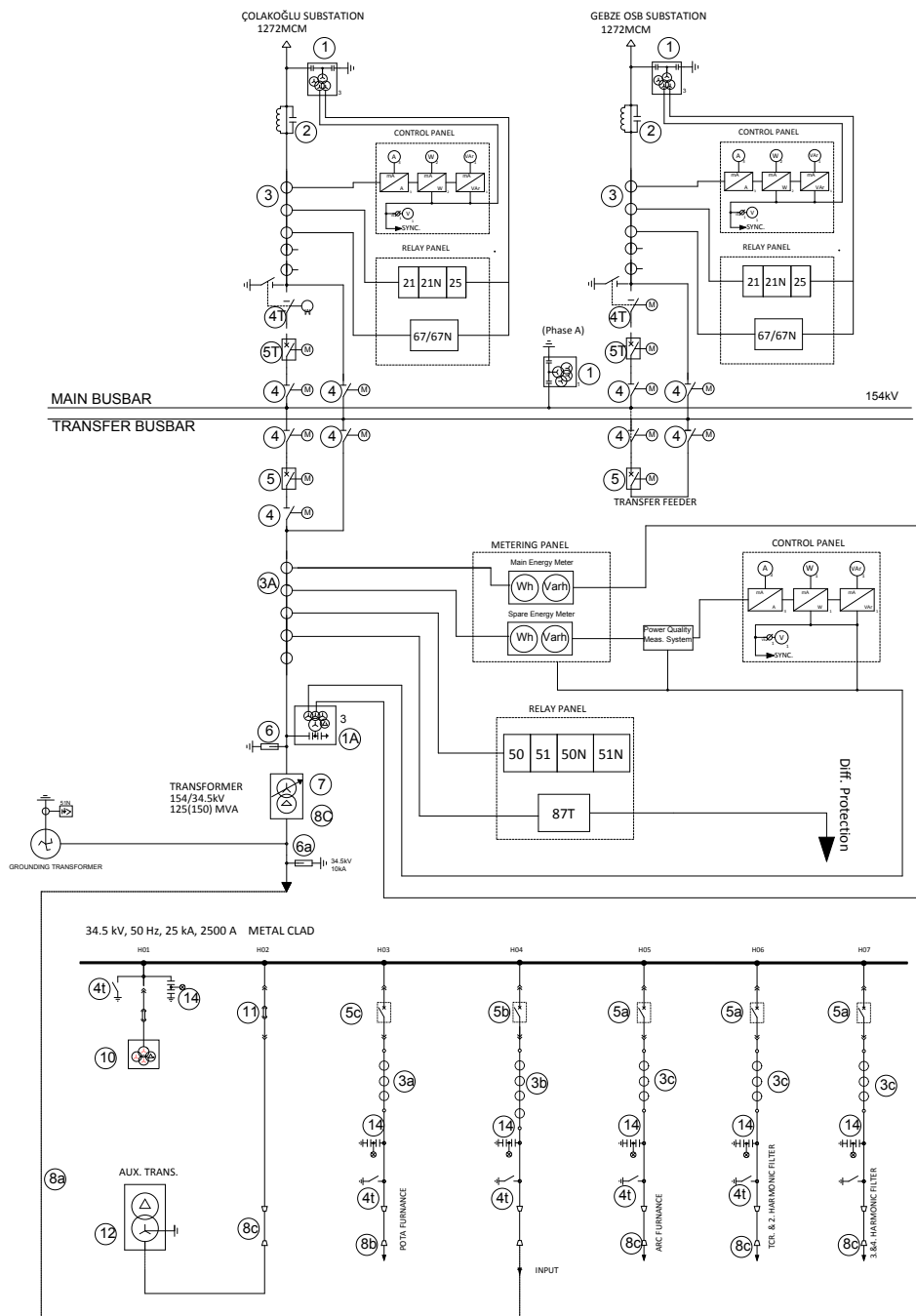


Figure 2. SKS Single Line Diagram [12]

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:

$$I_{154\text{ kV}} = \frac{150\text{ MVA}}{154\text{ kV} * \sqrt{3}} = 562.35\text{ A} \quad \text{and} \quad CT = \frac{800}{562.35} = 1.4226 \quad (8-9)$$

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:

$$I_{34\text{ kV}} = \frac{150\text{ MVA}}{34.5\text{ kV} * \sqrt{3}} = 2510.29\text{ A} \quad \text{and} \quad CF = \frac{3000}{2510.29} = 1.195 \quad (10-11)$$

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.

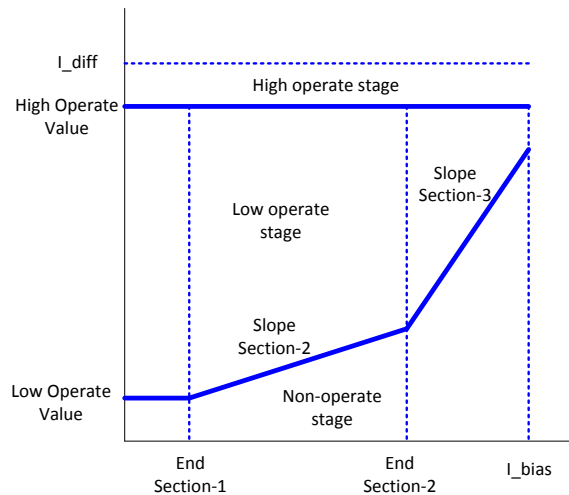


Figure 3. Operating characteristics of the DifP [6].

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° to 80° .

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).

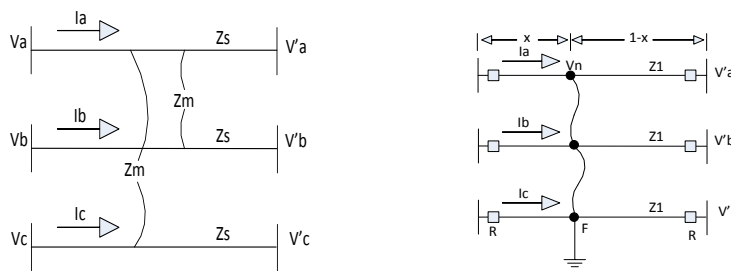


Figure 4. (a) A balanced Transmission System. (b) Three phase to the ground bolted fault

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

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

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]

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

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:

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

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:

$$x = \frac{Z_{app}}{Z_1} * L \tag{17}$$

Where L is the length of the line and Z_{app} 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).

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

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].

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

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

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

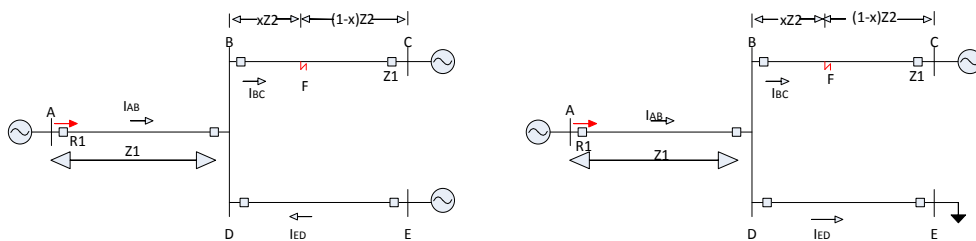


Figure 5. (a) Infeed (b) Outfeed Effect

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 ϕ and the line angle θ must be known. This is used to calculate the new reach as follows [6]:

$$AQ = \frac{AB}{\cos(\phi - \theta)} \quad (24)$$

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)

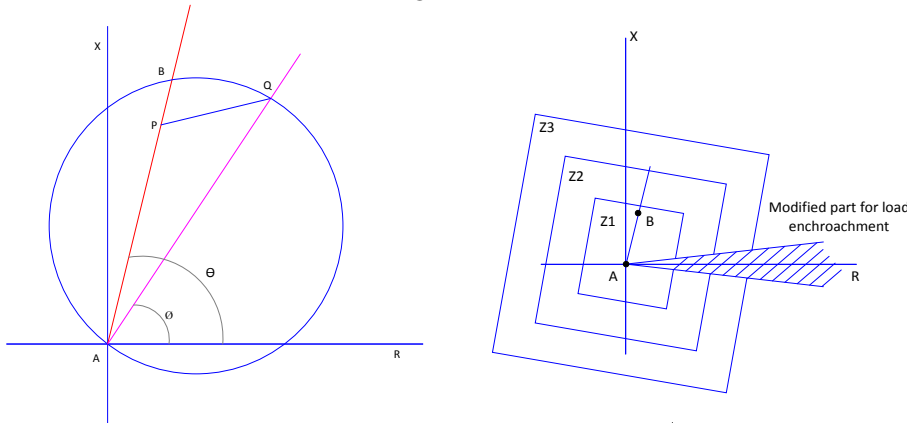


Figure 6. (a): Increased Arc Resistance Coverage [3]. (b) Relay Characteristic modification for the load encroachment.

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.

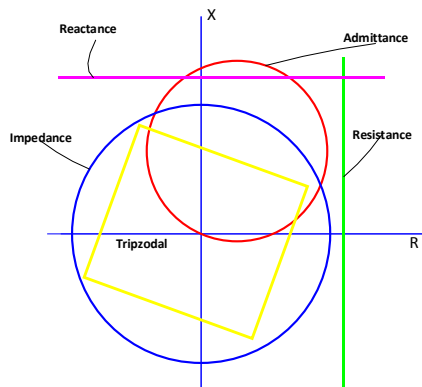


Figure 7. Zones of Protection in Distance Relaying

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.

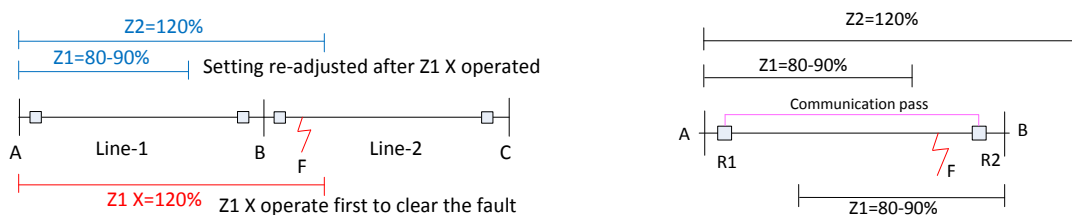


Figure 8. (a) Zone-1 Extension Schemes (b) Pilot aided protection schemes

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 covers 100% 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 . Zone-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:

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

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.

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

Zone-4 Phase Reach

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

$$Z_4 = 1.03 < 77.8^\circ$$

Zone Time Delay Settings

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

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

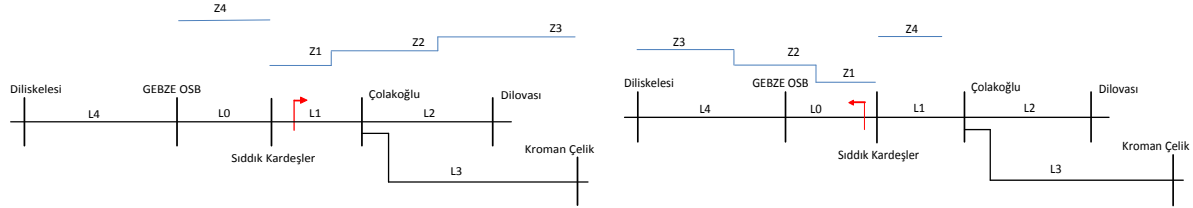


Figure 9. (a) ProC towards Kroman Çelik (b) ProC towards the Dil İskelesi

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:

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

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 (R_a), 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:

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

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 (R_a) 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 R_a and R_{TF} appear in the loop measurement as in Equation 27 [22].

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

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 ₁ ph	Phase fault resistive reach value - Zone 1	67	67	Ω
R ₂ ph	Phase fault resistive reach value - Zone 2	67	67	Ω
R ₃ ph	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 ₁ G	Ground fault resistive reach value - Zone 1	89	89	Ω
R ₂ G	Ground fault resistive reach value - Zone 2	89	89	Ω
R ₃ G	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.

REFERENCES

- [1] Electric Power Engineering Handbook, Electrical Power Substation Engineering, edited by John D. McDonald, 2nd edition, by Taylor & Francis Group, LLC. 2007.
- [2] Switch Gear and Substations, Siemens Energy Sector, Power Engineering Guide, Edition 7, 2014.
- [3] D. Barbosa, U. Chemin, D. V. Coury, and M. Oleskovicz, Power Transformer Differential Protection Based on Clarke's Transform and Fuzzy Systems, IEEE Transactions on Power Delivery Vol.26 Issue 2, April 2011 DOI: 10.1109/TPWRD.2010.2097281.
- [4] L. Hewitson, M. Brown and R. Balakrishnan, Practical Power System Protection, ISBN 0750663979 Elsevier, 11 December 2004.
- [5] E. Vazquez, I. I. Mijares, O. L. Chacon and A. Conde, Transformer Differential Protection Using Principal Component Analysis, IEEE Transactions on Power Delivery Vol. 23, Issue: 1, Jan. 2008, DOI: 10.1109/TPWRD.2007.911149
- [6] Network Protection and Automation Guide, Protective Relays Measurement and Control, ISBN: 978-0-9568678-0-3 Published by Alstom Grid, May 2011.
- [7] Dr. C.R. Bayliss, CEng FIET, B.J. Hardy, CEng FIET, Transmission and Distribution Electrical Engineering (Fourth Edition), Chapter 10 – Relay Protection Pages 287–359, 2012.
- [8] M. P. Gohil, J. Prajapati and A. Rabari, Differential Protection of Y-Y And Δ - Δ Connected Power Transformer, International Journal of Engineering Development And Research ISSN: 2321-9939 (RTEECE-2014) -17th, 18th January 2014.
- [9] K. Behrendt, D. Costello and S. E. Zocholl, Considerations for Using High-Impedance or Low-Impedance Relays for Bus Differential Protection, 49th Annual Industrial & Commercial Power Systems Technical Conference, <http://dx.doi.org/10.1109/CPRE.2010.5469509>
- [10] A. Guzman, S. Zocholl, G. Benmouyal and H.J. Altuve, A current-based solution for transformer differential protection. II. Relay description and evaluation, IEEE Transactions on Power Delivery, Vol. 17, Issue: 4, Oct 2002, DOI: 10.1109/TPWRD.2002.803736
- [11] J. Chen, J. S. Thorp, I. Dobson, Cascading dynamics and mitigation assessment in power system disturbances via a hidden failure model, International Journal of Electrical Power & Energy Systems Vol. 27, Issue 4, May 2005, Pages 318-326 <https://doi.org/10.1016/j.ijepes.2004.12.003>
- [12] Abdulfetah Shobole, Protection Coordination in Electrical Substation, Part-1 Over current, and Earth Fault Protection, Case Study of Siddik Kardeşler Substation (SKS), Istanbul, Turkey, in Press.

- [13] Relion Protection and Control 615 series Technical Manual, Document ID: 1MRS756887 Issued: 09-24 Revision: E Product version: 3.0, ABB, 2010.
- [14] S. Bagheri, Z. Moravej, G. B. Gharehpetian, Effect of transformer winding mechanical defects, internal and external electrical faults and inrush currents on performance of differential protection, IET Generation, Transmission & Distribution, Vol.11, Issue: 10, pp 2508 – 25207, 2017, DIO:10.1049/iet-gtd.2016.1239.
- [15] [Online] Available: <http://www.nptel.ac.in/courses/108101039/download/Lecture-20.pdf> [Accessed 17 09 2016].
- [16] [Online] Available: <http://www.nptel.ac.in/courses/108101039/download/Lecture-21.pdf> [Accessed 17 09 2016].
- [17] [Online] Available: <http://www.nptel.ac.in/courses/108101039/download/Lecture-22.pdf> [Accessed 17 09 2016].
- [18] [Online] Available: <http://www.nptel.ac.in/courses/108101039/download/Lecture-25.pdf> [Accessed 17 09 2016].
- [19] SIPROTEC 5 Application, DisP with tele-protection (pilot protection) on an OHL feeder.
- [20] [Online][https://www.pacw.org/fileadmin/doc/Ground_Distance_RelaysResidual_Compensation_JV.p df](https://www.pacw.org/fileadmin/doc/Ground_Distance_RelaysResidual_Compensation_JV.pdf) [Accessed 13 08 2017].A. Shobole, M. Baysal, M. Wadi and M. R. Tur “Effects of Distributed Generations’
- [21] Integration to the Distribution Networks Case Study of Solar Power Plant”, International Journal of Renewable Energy Research, Vol. 7, Issue 2, pp 954-964, 2017.
- [22] M. Wadi, M. Baysal and A. Shobole “Comparison between Open-Ring and Closed-Ring Grids Reliability”, 4th International Conference on Electrical and Electronics Engineering, Ankara, Turkey, 8-10 April 2017.