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Relay Coordination between Transformers in a typical power systems

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Abstract

In any power system network, protection should be designed such that protective relays isolate the faulted portion of the network at the earliest. The protective relay must be able to discriminate between fault condition and normal condition and they should perform only for specific protection for which it is designed.
The term relay co-ordination covers the concept of discriminating selectivity and backup protection as explained above. Co-ordination also includes protective device characteristics such as fuse, MCB's, circuit breakers as applicable. Relay co-ordination calculation module must consider the operating characteristics of relay normal operating and mechanical withstand characteristics of the equipment and must det. The optimum relay setting to achieve the objective of protecting equipment.
So thereby we need to protect the system by relay coordination ensuring continuity in the supply through simulation using ETAP software.

Index terms-- Overcurrent Protection, Relay Coordination, ETAP software.

I. INTRODUCTION

A Power System consists of various electrical components such as Generating units, transformers (Power and Distribution), transmission lines, isolators, circuit breakers, bus bars, cables, relays, instrument transformers, distribution feeders, and various types of loads.

The system must be protected against flow of heavy short circuit currents which cause permanent damage to the equipment's if not cleared within time sustainable time.

For this purpose circuit breakers and protective relaying is provided to disconnect the faulty section of the system.

Relay Coordination means that downstream devices (breakers) should trip before upstream breakers. This keeps the fault at or near the equipment that causes the inrush of current to occur. The overcurrent protective devices, the total impedance, the component short-circuit current ratings, and other characteristics of the circuit to be protected shall be selected and coordinated to permit the circuit-protective devices used to clear a fault to do so without extensive damage to the electrical components of the circuit. This fault shall be assumed to be either between two or more of the circuit conductors or between any circuit conductor and the grounding conductor or enclosing metal raceway.

It is strongly recommended that the design engineer objectively review the results of the overcurrent coordination study. If life safety, equipment protection, or selectivity goals have not been met, determine what could have been done differently. For instance, using switchgear equipped with power circuit breakers instead of switchboards equipped with molded case circuit breakers. Keep in mind there are inherent advantages and disadvantages between distribution systems and equipment. Engineers must know and understand these differences before equipment is purchased.

II. METHODOLOGY FOR COORDINATION

A. General Methodology

Protection coordination has been reviewed to achieve sensitivity, speed, selectivity and reliability to isolate faults from the rest of the healthy system and minimize the plant loss due to the faults under all foreseen system operation conditions. Instantaneous/definite time schemes for phase over current protection and earth fault protection of solidly earthed systems; and definite time schemes for earth fault protection of resistance earthed systems. Instantaneous/definite time schemes for phase over current protection and earth fault protection of solidly earthed systems; and definite time schemes for earth fault protection of resistance earthed systems.

B. Primary & Back-Up Protection

Primary Protection: The protective system, which is normally expected to operate in response to a fault in the protected zone.

Back-Up Protection*:* A protective system intended to supplement the main protection in case the later should be ineffective, or to deal with faults in those parts of the power system that are not readily included in the operating zones of the main protection.

C. Co-ordination Settings & Criteria

There are two basic adjustable settings on all inverse time relays; one is the current setting usually known as the Plug Setting Multiplier (PSM) and the other is Time Multiplier Setting (TMS).

Where,

Top = the required time of operation

Tm = the time operation at TMS=1.0 for maximum fault current.

The following will give the appropriate relay settings for any system:

1. Pick up current
2. Current setting
3. Plug setting multiplier (PSM)
4. Time setting multiplier (TSM)

1. **Pickup Current**: The current for which the relay initiates its operation or the threshold value of the actuating current above which relay operates is called pick up current of relay.
2. **Current setting**: The minimum pick up value of the deflecting force of an electrical relay is constant. Again the deflecting force of the coil is proportional to its number of turns and current flowing through the coil. Now, if we can change the number of active turns of any coil, the required current to reach at minimum pick value of the deflecting force, in the coil also changes. Current setting of relay is achieved by providing required number of tapping in the coil.
3. **Plug Setting Multiplier**: The actual rms current flowing in the relay expressed as the multiple of setting current or pickup current is known as plug setting multiplier.

   PSM=Secondary current /relay current setting (or)
   Fault current/relay current setting *CT Ratio.

4. **Time Setting Multiplier**: The term can be defined as the ten steps in which time can be set that is 0.1, 0.2… 0.9, 1.

D. Calculation of Relay Operation Time

For calculating actual relay operating time, we need to know these following operation.

1. Current setting.
2. Fault current level.
3. Ratio of current transformer.
4. Time / PSM curve.
5. Time setting.

Step – 1

From CT ratio, we first see the rated secondary current of CT. Say the CT ratio is 100 / 1 A, i.e. secondary current of CT is 1 A.

Step – 2

From current setting we calculate the trick current of the relay. Say current setting of the relay is 150% therefore pick up current of the relay is 1 × 150% = 1.5 A.

Step – 3

Now we have to calculate PSM for the specified faulty current level. For that, we have to first divide primary faulty current by CT ratio to get relay faulty current. Say the faulty current level is 1500 A, in the CT primary, hence secondary equivalent of faulty current is 1500/ (100/1) = 15

Step – 4

Now, after calculating PSM, we have to find out the total time of operation of the relay from Time / PSM curve. From the curve, say we found the time of operation of relay is 3 second for PSM = 10.

Step – 5

Finally that operating time of relay would be multiplied with time setting multiplier, in order to get actual time of operation of relay. Hence say time setting of the relay is 0.1.Therefore actual time of operation of the relay for PSM 10, is $3 \times 0.1 = 0.3$ sec or 300 Ms.

Method of defining shape of time-current Characteristic:

General expression for time-current characteristics, T=K/I^n-1

Approximate expression, T=K/I^n

For definite-time characteristic, the value of 'n' is equal to 0.

Following are important characteristics of overcurrent relay:

i. I.D.M.T.: t=0.14/I^0.02-1
ii. Very Inverse: t=13.5/I-1
iii. Extremely Inverse: t=80/I^2-1

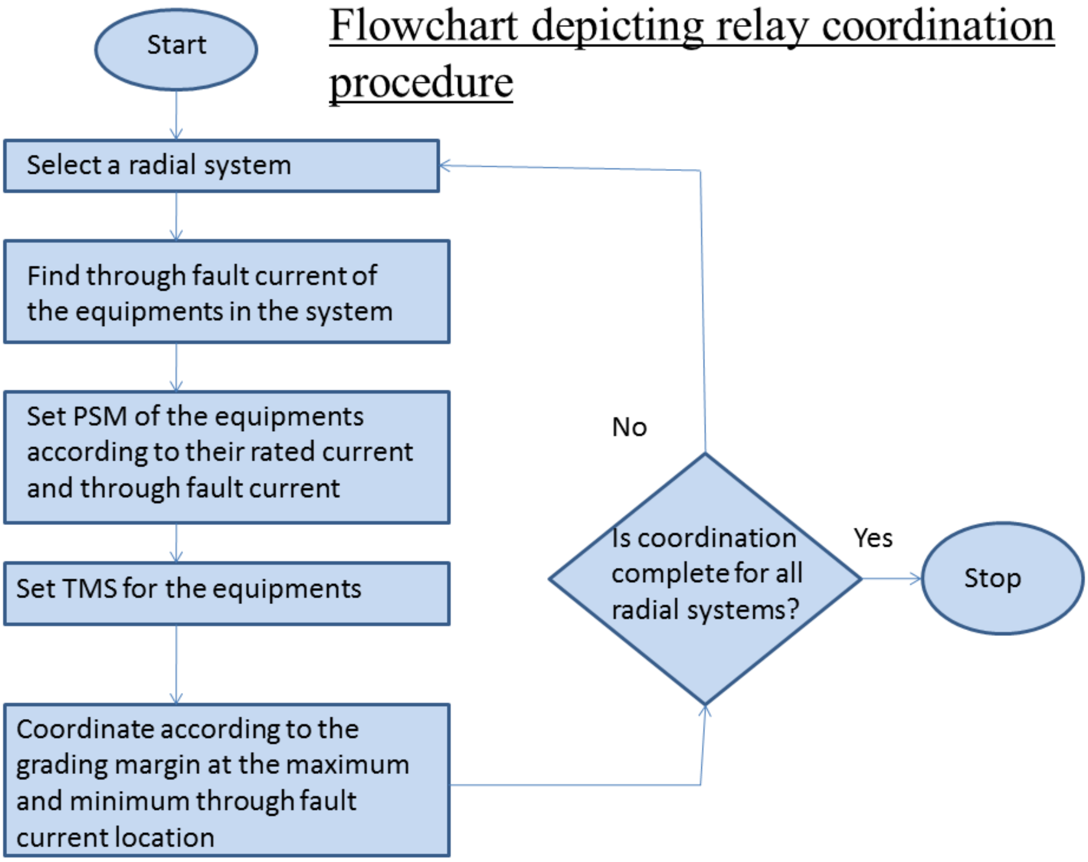

Figure 2.1 Flow Chart for Relay Coordination

III. SIMULATION

A. Typical Power system network:

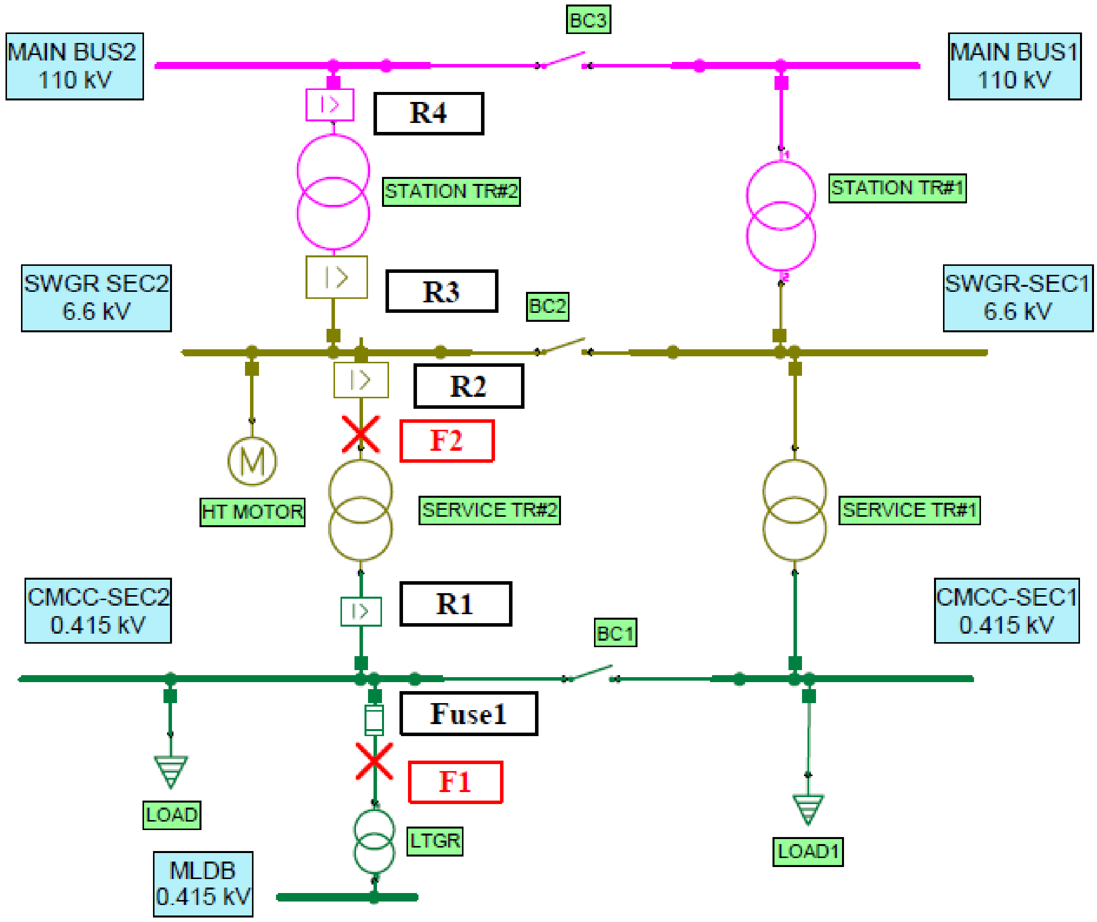

Figure 3.1 Schematic Representation of Network.

The given network consists of 2 step down transformers, 2 main bus system, and current transformer of respective turns according to the requirement, overcurrent relay, 5 feeders and 9 nodes connecting all the devices in the network and bus-coupler to connect the 2 buses. The given network is similar to the typical power system. It is the required network on which protective system for overcurrent protection is designed, short-circuit analysis are done and the given network is simulated in a ETAP software and relay coordination on the system is done with proposed relay setting for better efficiency of the protective devices in the given network.

B. Relay Coordination Results

In the existing system, the relay grading was not appropriate as the settings given to the relay were showing strange behavior, i.e. unnecessary tripping that were affecting the efficiency of the system.

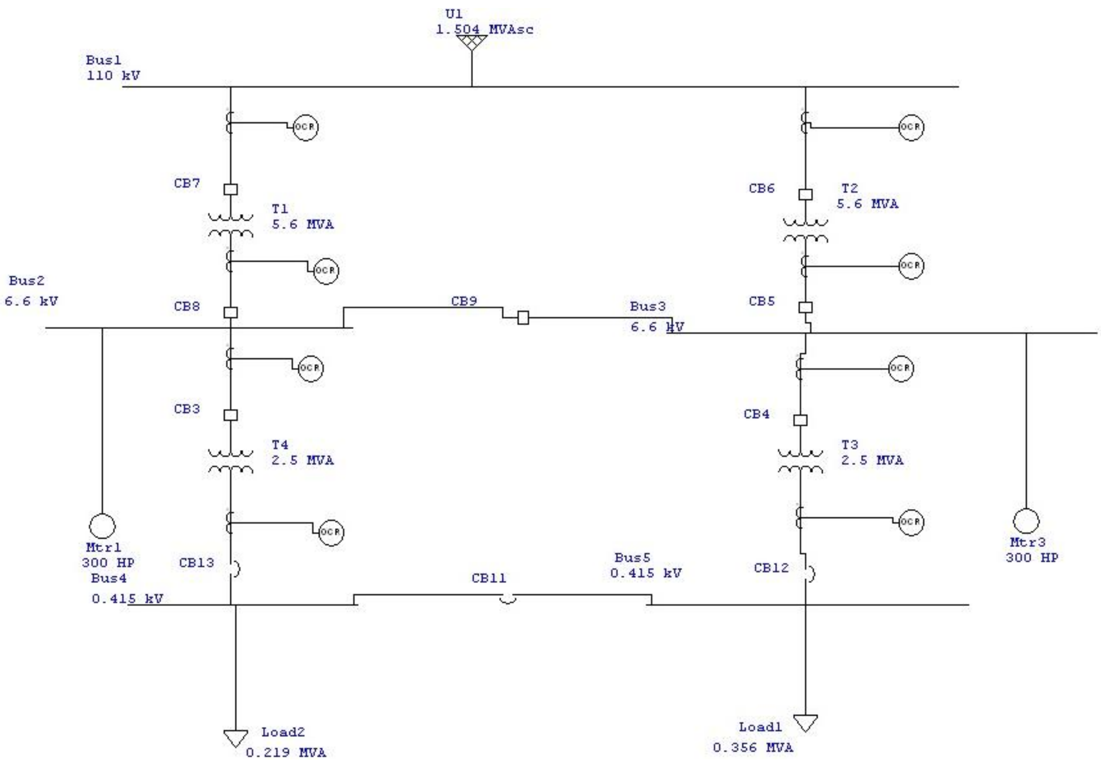

Figure 3.2 Modelled Network

So, we have provided the appropriate grading for relay tripping by providing a certain time lag between the operations of the two or more relays.

The above figure shows the results of the simulation in which the relay no. 6 and relay no. 4 are tripping at a time of 0.169s and relay no. 3 and relay no. 5 are tripping at 0.585s.So here we can conclude that the required time lag is 0.416s as coordinated.

Table 3.1 Relay Settings

S. No	Relay Name	Relay Type	Plug Setting Multiplier(PSM)	Time Dial Setting (TDS)
1.	R3	IDMT	2	0.556
2.	R4	IDMT	0.3	0.169
3.	R5	IDMT	2	0.556
4.	R6	IDMT	0.3	0.169
5.	R1	IDMT	40	-
6.	R2	IDMT	14	-
7.	R7	IDMT	14	-
8.	R9	IDMT	40	-

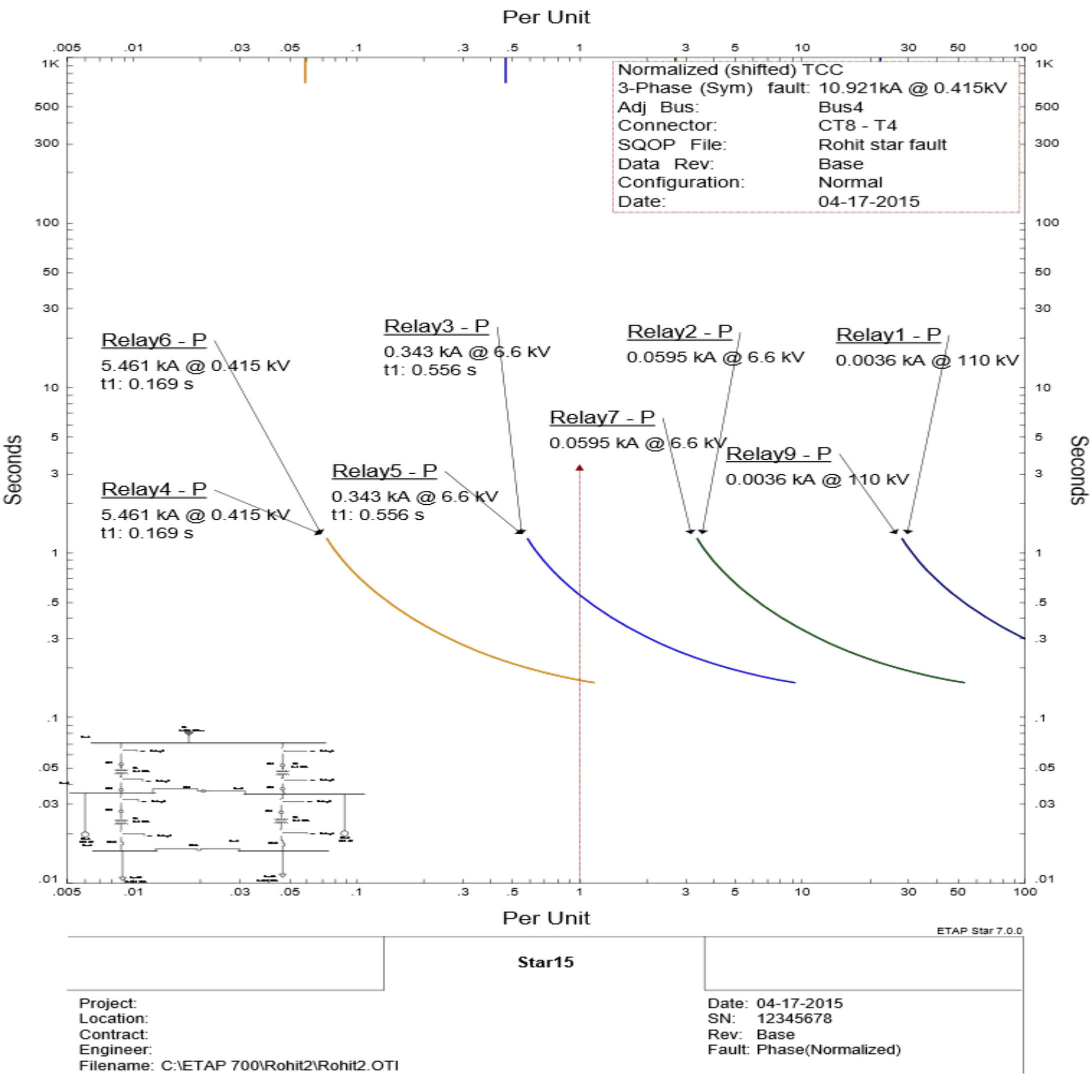

Figure 3.3 Simulation for Figure 3.2

IV. SYSTEM BENEFITS

A. Phasing out unnecessary tripping

When generators of two interconnected system lose synchronization because disturbances, heavy current flow through equipment and lines. This condition is like a short circuit. The flow of heavy current is known as power surge. The protective relay should be able to distinguish between a fault and a power surge either by is inherent characteristics or with the help of settings which are given manually. Thus we see that protective relay must be able to discriminate between those conditions and should phase out unnecessary tripping by a time-delay operation.

B. Dynamic Stability

It is like transient stability but here help of an external device is taken to regain the stability whereas in transient stability the stability was attained within the power system itself without the help of any external device. So, in our system the external devices are relays through which the system will regain the stability its dynamic operating conditions. In both cases,

i. When there is actual fault the relays will operate according to their time settings and the system dynamic stability will not be affected.
ii. If there is a surge and not a real fault then the relay will not operate unnecessarily and thus it will also result in stability of the system.

V. CONCLUSION

We studied a part of power system of the given system and its single line diagram. The fault current is inversely proportional to fault impedance up to the location of fault and the voltage level. The effect of lower voltage level is more than the effect of increase in fault impedance which causes the fault level to rise considerably as compared to the 11 kV level. Short circuit study is performed for various case scenarios as listed. The short circuit study carried out in accordance with IEC 255-3 normal inverse standards. Maximum short circuit currents at 110 KV are violated the switchgear short circuit current ratings in case1 and case 5 and c-factor 1.1 and case-1 with c-factor-1.the case-1 is the maximum fault current condition and thee cases is the normal operating scenario .However, it is recommended to upgrade the 110 KV switch gear short circuit rating to KA to ensure better safety.

For the three phase fault current at generating transformer primary the Relay will operate in0.91 sec on IDMT which is very long time and transformer may get damaged for thee high fault currents (i.e. for 37.4 KA). So it is recommended to provide instantaneous earth fault protection setting with 50ms.The instantaneous earth fault setting is to directional towards .Transformer side from 110 KV bus. It is mainly because for the earth faults on 110 KV bus (grid side faults). The relay on station transformer primary (110 KV) should not trip instantaneously. The directional earth fault is recommended at this location so that it will trip instantaneously for the faults on station transformer primary. The damage curve is much above the relay operating curve so the relay will protect transformer from all the through fault current condition.

Because of smaller lengths of cables on 110 KV side, distance protection is not feasible.it is recommended to provide cable differential protection on 110 KV grid lines. Hence the short circuit and relay coordination simulation of the given network is clearly depicted and simulated in the ETAP software. And fault analysis on the given network is studied and its relay characteristics graphs is clearly observed.

VI. REFERENCE

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