Scientific Journal of Impact Factor (SJIF): 5.71
e-ISSN (O): 2348-4470
p-ISSN (P): 2348-6406
International Journal of Advance Engineering and Research Development
Volume 5, Issue 03, March -2018

Relay coordination of Industrial plant

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Abstract - *Relay coordination is one of the integral parts of power system analysis in industrial power system. Any new plant is being plane or existing plant load demand increases protection devices coordination is required for selective and fast isolation of faulty section without affecting remaining area. Short circuit analysis is the pre requisite for relay coordination as short circuit current is required for relay setting. In this paper, relay coordination of 6.6 kV industrial plants is presented using Electrical Transient Analysis Program -7.5.5(ETAP). Symmetrical breaking current at different nodes of power systems are used relay coordination. The plant is supplied by two existing generators of 16.5 MW and one more generators of 11.8 MW are newly installed. Black start facilities of TG's are provided by external grid support. Existing load of 17.5 MW is expanded to 24 MW. Load flow analysis and short circuit study of this plant have been conducted and it is suggested G2 and G3 configuration of generation. Therefore, protection coordination is performed for G2+G3 configurations using ETAP.*

Keywords- *Relay coordination, ETAP, Phase Fault, Earth fault, Relays*

I. INTRODUCTION

The following points may be considered while coordinating operation of different relays in a radial system; (1) the co-ordination starts from the extreme downstream protection which may be a FUSE. (2) The discrimination interval for the relay immediately above the fuse is decided by the fuse positive tolerance, relay negative tolerance, relay overshoot and a safety margin. A minimum co-ordination interval of 0.2 second is to be maintained between the relay and the fuse. (3) as far as possible, co-ordination interval of 0.3 second is to be maintained between two relays to ensure proper discrimination. This time includes the breaker operating time, relay errors, relay overshoot and a safety margin. (4) In coordinating electromechanical over current relays, the desired coordination interval is kept in range of 0.3 to 0.4 seconds, whereas, in static or microprocessor-based relays, coordination interval range are 0.2 to 0.3 seconds [1-5].

The discriminating interval between two relays should be taken in to consideration are; (1) for industrial plants, the operating time of the extreme upstream relay in the plant, considered along with its breaker opening time at the incoming power supply fault level, is governed by the max time permitted by the power supply authority and equipment ratings at that fault level. (2) For power plants the operating time of the extreme upstream relay is determined by the switchgear rating. Since the switchgear normally has a 1 sec rating, the maximum relay operating time should not exceed about 0.9 sec. at this switchgear fault level [1-5].

Procedures can also be considered to simplify relay co-ordination are; (1) Use of very inverse and extremely inverse relays on downstream feeders. (2) Reduction of the co-ordination interval to 0.25 sec. in case of very high speed operating circuit breakers. (3) Elimination of the co-ordination interval between two relays which will not cause power interruption to other loads such as co-ordination of relays on the primary and secondary of transformers and co-ordination of relays on the breakers at the sending and receiving end of the tie/radial feeder. (4) The differentially connected scheme for relays on incoming feeders can be considered in cases where selective tripping is required and where the number of co-ordination intervals can be reduced [1-5].

On any particular bus, amongst relays on various outgoing feeders, the relay with the highest operating time is to be considered for co-ordination with the relay on the incoming feeder. It shall also be ensured that the relay on the incoming feeder feeding loads will not trip for the starting condition of the largest rated motor [1-5].

Instantaneous relays on the primary side of the transformer feeder shall be set above the through-fault level on the secondary side to prevent the relay from operating for a secondary side fault. Generally, the setting adopted should account for CT errors, relay errors as well as the over-reach of the instantaneous relay [1-5].

Where inverse time relays with highest instantaneous settings are provided on outgoing transformer / motor feeders, the IDMT relay on the incoming feeder shall be co-ordinate with the operating time of the instantaneous relay to bring down the bus fault clearing time. However, with IDMT relay characteristics selected in this manner for the incoming feeder, it should be ensured that grading is obtained with the outgoing feeder IDMT characteristic as well [1-5].

The operating time of the relay on an incoming feeder at the respective switchgear fault level shall be such that the operating time of the immediate back up relay considered together with its breaker opening time, shall not exceed the short time rating of the switchgear, which is normally 1 sec. Whenever there is a substantial difference between the system fault level and the switchgear rating, the incoming feeder relay and the immediate back up relay operating time at the system fault level are permitted to increase, based on the I^2t criterion as may be necessary for co-ordination with downstream relays. For example, if the fault current at the switchgear of 1sec rating is 'Y', then the relay operating time at the bus fault level 'X' can be increased to $(Y/X)^2$ x 1sec [1-5].

Directional relays when used for duplicating incoming feeders can be set low since they need not be graded with downstream protection.

II. BASIC GUIDELINE FOR GRADING

2.1 Current and Time Setting

Choose current setting for all relays. This choice is arbitrary to a large extent but must take into account maximum load currents and legitimate short time overloads caused by, for example, the starting of large motors.

Setting current as above is related to primary system currents. Most relays, however, are connected to the system through current transformers, and the combination is to be regarded as a single entity. Thus a relay having a rated current of 5A and a setting of 150% would have a current setting of 7.5A. If the relays were operated from a current transformer having a ratio of 300/5, it would have a primary setting of 7.5 X (300/5) = 450A [1, 2, 5, 6].

Provided the rated current of the relay is identical with the secondary rated current of the current transformer, the percentage setting can be applied directly to the primary rating of the CT; hence, also in the above example Primary Setting = (150/100) X 300 = 450A.

Where the choice of relay settings is preferred to be low, it is the primary setting that is implied. Primary setting currents should be graded so that the relay farthest from the power source has the lowest setting and each preceding relay back towards the source has a higher setting than that following. Not only does this ensure that relay and CT errors do not produce a range of current value within which mal-discrimination may occur but also it allows for loads which may be taken from the intermediate substations [1, 2, 5, 6].

For calibration by time grading, knowledge of maximum and minimum fault current expected through each circuit is essential. Time grading for inverse time current systems should be calculated at the maximum possible fault current for each grading stage. After grading it has to be checked whether the relays operate positively for minimum fault currents [1, 2, 5, 6].

2.2 Earth fault relay setting

Unrestricted earth fault relays are normally connected in the residual circuit of line transformers and are insensitive to three phase load. They can, therefore, be given settings lower than full load. Over current relays connected in phase circuit must be capable of carrying the full load current continuously without operating and hence must be set higher than full load. Under their operating conditions, however, both types of relays should withstand, without damage, the effects of the maximum fault current likely to be experienced for the duration of their time settings. In solidly earthed systems, the earth fault current is nearly of the same order as the phase fault current. Consequently, the earth fault relays with a lower setting than the phase fault relays are required to dissipate more heat for a given time setting than the over current relays [1, 2, 5, 6].

So it is desirable to use earth fault relay with a setting range of 20% - 80% (to be set at 30% or 40%) in solidly earthed systems whilst 10% - 40% setting range relays can be used in non-effectively earthed system. In case where the ground resistivity is high due to which the earth fault current will be limited even when the system is solidly earthed, relays with lower settings (say 2% - 5%) are necessary. But the trend in such cases will be the application of definite time earth fault relays comprising instantaneous over current relay and a timer, the instantaneous over current relay being of low VA consumption [1, 2, 5, 6].

III. GENERAL RELAY SETTING CRITERIA

The relay co-ordination, short circuit studies and load flow studies are based on the normal operating condition of two generators operating in parallel and feeding the entire Plant load. The grid supply is OFF. There is no export of Power. Some other relay setting criteria are as follow;(1) All Co-ordination curves are drawn on 6.6 kV base for the over current relays.(2) The earth fault relay co-ordination is different for different voltage levels.(3) The Co-ordination of relays started from the farthest downstream equipment and is gradually worked up to the incomer of highest voltage system where power is being received from generator. (4) Over-current relay settings have been made in such a way that the relays do not operate during motor starting conditions even if transformer is fully loaded. (5) Fault currents for the relay co-ordination are worked out based on the direct axis transient reactance (X'd) of the generators. This is as per recommendations of IEEE for conducting relay co-ordination study.(This is due to the fact that reactance of each generator would increase from its sub-transient reactance (X"d) to its transient reactance in about 2 cycles (i.e. 40 msec) while IDMT relays operate in around 250-400 msec after fault inception [1, 2, 4, 5].

Some more relay setting criteria are; (1) The motor starting current considered for the relay settings is based on vendor data, where ever data is not available, the motor starting current for the HV motors is considered as 500% and for LV motors as 600%. (2) The fault currents are calculated on ETAP software 7.5.5. (3) Co-ordination time interval between adjacent upstream and downstream relay is considered as 0.25-0.3sec. (4) Instantaneous over current relay on the high voltage side of transformer is set such that it doesn't operate for faults on the secondary side of the transformer. It is also checked that the instantaneous setting is above the magnetizing inrush of the transformer considered as 6 times the transformer full load current. (5) Intentional co-ordination time is not provided between the operation of the transformer secondary and the transformer primary over current relays for secondary faults at all HVSBs, to reduce the overall operating time of the upstream relays in the system. (6) Intentional co-ordination time interval is not provided between the tie breakers to reduce the overall operating time of the upstream relays. (7) It is ensured that relay on the incomer of individual PCC/HVSB will not pick up during starting of the largest motor. (8) Intentional co-ordination time interval is not provided between the earth fault relays on tie breakers to reduce the overall operating time of the upstream relays [1, 2, 4, 5].

The authenticity of the relay settings recommended is totally dependent on the value of CTR considered for calculations as per the information and drawings from industrial plant. Any discrepancy in CTR values and system changes shall be liable for erroneous tripping or un-graded tripping [1, 2, 4, 5].

IV. RELAYS

4.1 CURRENT OPERATED DISC REALY (GP)

Different relays are used for industrial power system protection are CDG-11, CDG-12, CDG-13, CDG-14. Improved version of theses relays CDG21 to CDG64 are also utilized to fulfill different protection requirement. To provides selective over current and earth fault protections, CDG-11 is used with A.C machine and power systems. It is characterized by heavily damps inverse definite minimum time/current characteristic. CDG 21 is improved version of CDG 21 where CDG 11 equipped with instantaneous feature. CDG-31 is the 3 phase version of CDG-11and CDG-61 is the improved version of CDG-21 for 3 phase supply.CDG 12 have different characteristic such as it is characterized by long inverse definite minimum time/ current characteristic. CDG 22 is improved version of CDG 12 where CDG 12 equipped with instantaneous feature. CDG-32 is the 3 phase version of CDG-12 and CDG-62 is the improved version of CDG-22 for 3 phase supply. CDG 13 have different characteristic such as it is characterized by very inverse definite minimum time/ current characteristic. CDG 23 is improved version of CDG 13 where CDG 13 equipped with instantaneous feature. CDG-33 is the 3 phase version of CDG-13 and CDG-63 is the improved version of CDG-23 for 3 phase supply. CDG 14 have different characteristic such as it is characterized by extremely inverse definite minimum time/ current characteristic. CDG 24 is improved version of CDG 14 where CDG 14 equipped with instantaneous feature. CDG-34 is the 3 phase version of CDG-14 and CDG-64 is the improved version of CDG-24 for 3 phase supply [18].

4.2 CURRENT OPERATED ATTRACTED ARMATURES RELAY (CAG12, 12C)

CAG 12/12C is a standard attracted armature relay with adjustable settings. CAG 12/12C is used in applications where instantaneous phase or earth fault protection is required. CAG 12C, which is provided with a normally closed contact, finds application in special cases such as distance schemes [18].

4.3 ICM21 (Inverse-Time Over current & E/F Relays- electro mechanical types)

This is the ABB made electro mechanical inverse-time over current & e/f relays similar to ALSTOM make CDG Relay [18].

4.4 SPAM150C (Motor protection relay)

This microprocessor based relays are used for protection of high/low voltage big size motors. It have some unique feature such as; (1) Versatile, multifunction motor protection relay for the protection of AC motors (2) All-in-one relay featuring thermal overload protection, thermal start-up supervision, stall protection or time over current protection (3) High-set over current protection, low-set earth fault protection, incorrect phase sequence and phase unbalance protection, loss-of-load protection and supervision of multiple start-ups (4) A whole set of measured fault parameters recorded in memory at relay operation (5) Numerical readout of set values, measured values, recorded maximum fault current values, indications and status information [8].

4.5 SPAC320C (motor feeder terminal protection relay) and RAMDE (motor protection relay)
Both relay are old version of motor protection relay SPAM150C. All features are more or less similar to SPAM150C, excepting some technological advancement [9, 10].

4.6 SPAC310C (Feeder terminal protection relay)
This relay is old version of the combined phase and neutral over current relays of the SPAJ140C. All features are more or less similar to SPAJ140C, excepting some technological advancement.

Primary advantages of all of this MMBPR (multifunction, microprocessor-based protective relays) are; (1) Lower initial cost (2) Low-burden devices. (3) lower maintenance costs (4) Comprehensive metering and self testing. (5) Fault diagnostics/sequence of events (6) control system integration (7) Wider and continuous settings range. (8) Performance (sensitivity and speed) [9].

V. RELAY SETTING CALCULATION (FEEDER PROTECTION)

5.1 PHASE FAULT (Transformer secondary setting)
For feeder protection relay two parameter plug setting (PS) and time multiplier setting (TMS) require.

Plug setting (PS): - set PS according to load and CT ratio.
For motor/transformer feeder max current=Itrf +Imst
Itrf (transformer full load current) = KVA/kV*√3,
Imst (Biggest motor starting current) = (5 or 6)*kw/0.8*kV*√3.
Plug Setting = Imax/CTR.

Time setting (TMS):-TMS value derives from fault current at relay point, CT ratio and calculated value of plug setting.
PSM=If/CTR*PS
Find value of operating time from graph or using following equation of different relay characteristic using PSM for TMS=1.

Top=0.14*TMS/ (PSM^0.02-1) for IDMT (inverse definite minimum time)
Top=13.5*TMS/ (PSM-1) for VI (very inverse)
Top=80*TMS/ (PSM^2-1) for EI (extremely inverse)
Top=120*TMS/ (PSM-1) for LI (long time inverse)
TMS=Top require/Top at PSM & TMS=1.
Obtain value of PS and TMS use for setting. Switch group setting also require for microprocessor relay.

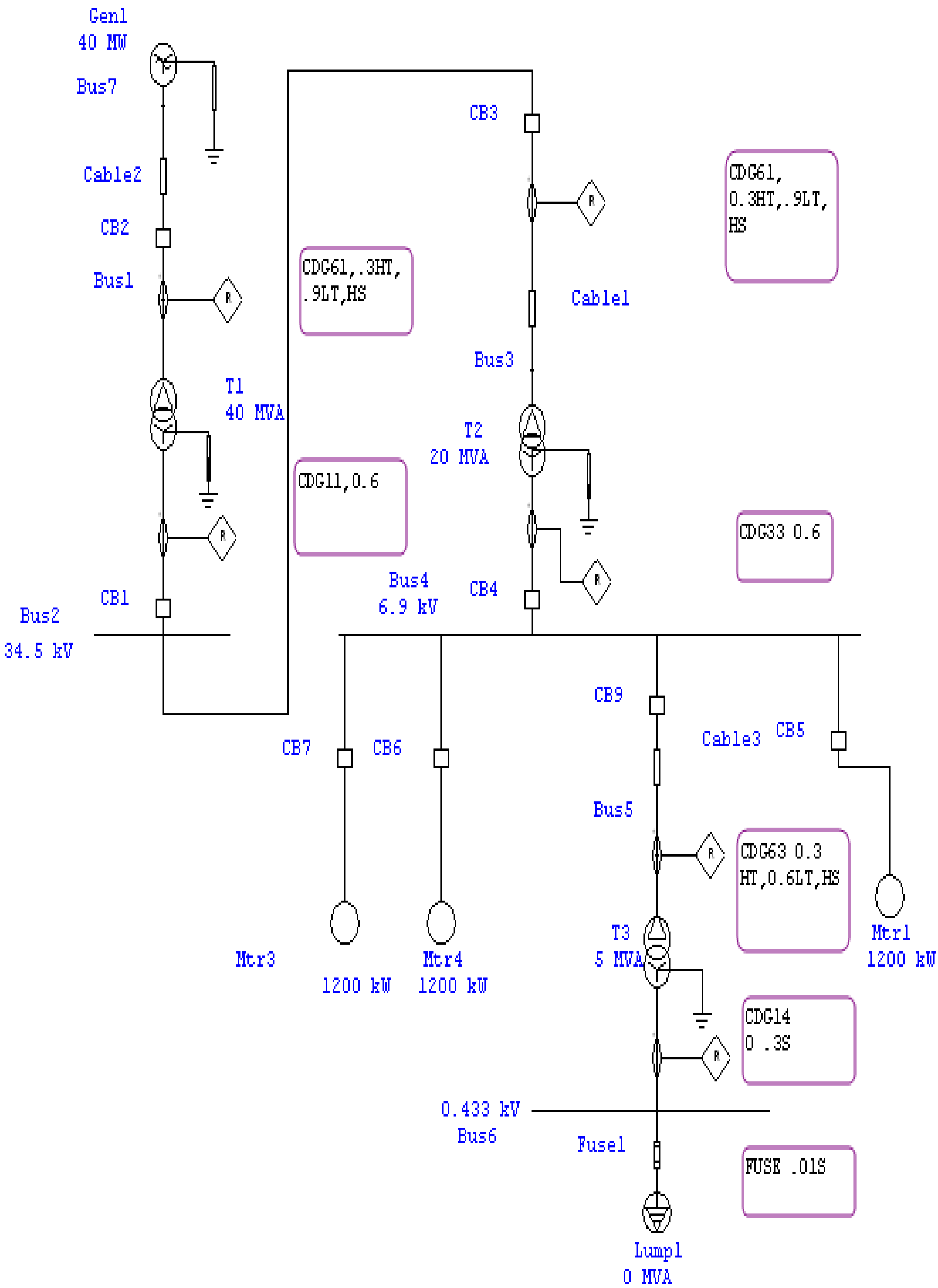
5.2 PHASE FAULT (Transformer primary setting)
Three protection setting are done to relay located at transformer primary such as high set at instantaneous trip, H.T Primary long time protection and through fault setting at H.T for L.T. Fault back-up protection.

5.2.1 High Set Setting=If2*1.3/CTR**,** Instantaneous trip.
Where, If2 is reflected value of L T fault Current at H.T when fault occur at transformer secondary. High set is always with Instantaneous trip.H.T.long time providing back up protection for H.T.High set.

5.2.2 H.T. Primary (long time) setting.
Find value of PS and TMS using same procedure to transformer secondary setting, except used H.T.fault current instead of L.T.Fault current.

5.2.3 through fault setting (L.T.Back-up)
This setting provides backup protection to L.T.fault. Find value of L.T fault current reflected at H.T
If2=If1/voltage transformation ratio.

Find value of PS and TMS using this fault current (If2) and match with P.S and TMS of H.T. Primary (long time) setting. If it doesn't match then recalculate with different Value of PS. Simulation diagram for phase fault and earth fault are shown in fig.5.1 and fig.5.2.

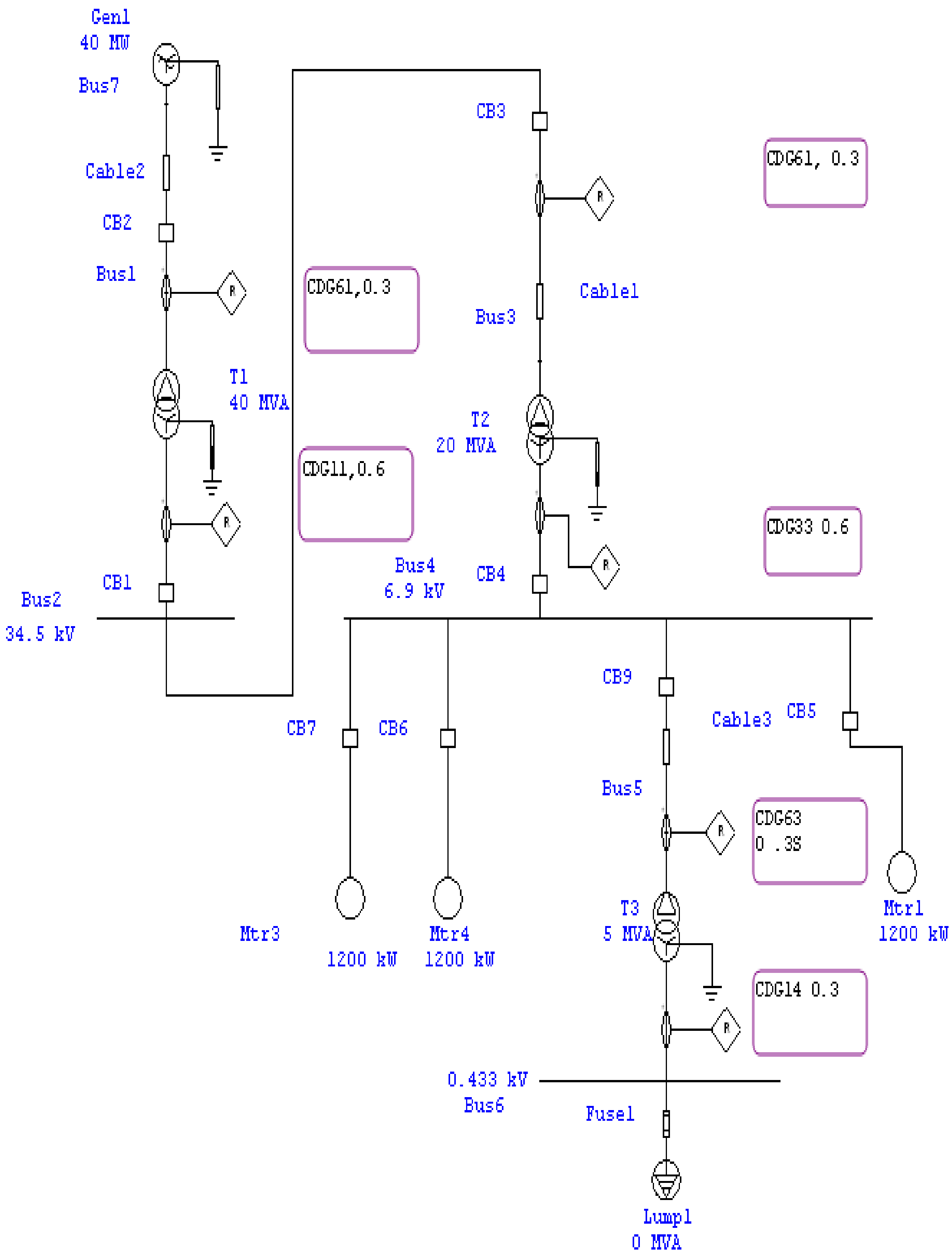


5.1 Phase Fault Setting

5.3 GROUND FAULT

Relay setting procedure similar to phase fault relay except PS will be take 0.1 to 0.4 instead of 1, 1.5, 1.75,2.
For effectively grounded equipment, L-G fault current use for calculation. PS will be taking 0.3 or 0.4 due to technical limitation. If ground resistivity high, than it will be take 0.1 or 0.2.

In solidly earthed systems, the earth fault current is nearly of the same order as the phase fault current. Consequently, the earth fault relays with a lower setting than the phase fault relays are required to dissipate more heat for a given time setting than the over current relays. For non effective grounding limited value of fault current **Ilg=Kv/√3*R** use for calculation. PS will be taken 0.1 or 0.2. Ground fault current can't reflect at primary side of Δ/Y transformer so that coordination will be ended at secondary only.



5.2 Ground Fault Setting

5.4 SETTING (MMBPR)
5.4.1 MOTOR PROTECTION RELAY (MMBPR) SPAJ150C [8]

Start-up supervision unit ($Is^2.ts$) = Is/In, ts
- **Is/In** = Motor start current as multiple of the rated current In. Setting range = 1.0...10.0 x In
- **Ts=** Motor start time setting in seconds. Setting range = 0.3...80 s.

High-set over current unit=I>>/In, t>>.
- **I>>/In** =High-set over current setting. Setting range = 0.5...20*In
- **t>> =** High-set stage operates time in seconds Setting range = 0.04...30 s. usually set=at minimum (0.04s).

Incorrect phase sequence unit setting
- T=Operate time for the incorrect phase sequence current protection. Setting range = < 1s.

Undercurrent unit= I</ IΘ, t<.
- Under current unit normally bypass, except special applications where the loss of load indicates a fault condition, e.g. with pumps or conveyors.

Cumulative start-up time counter= ∑tsi(s), Δ∑ts(s/h).
- **∑tsi(s) =** Time-based start inhibits counter setting in seconds. Setting range =5...500 s. usually set=10s.
- Δ∑ts(s/h) = Rate of the start time counter. Setting range = 2...250 s/h. usually set=2.

Switch group (protective function/characteristic selection)
- SGF(1…8)=(11001110) Checksum=115(factory setting)
- SGB(1…8)=(00000000) Checksum=0(factory setting)
- SGR1(1…8)=(10000001) Checksum=129(factory setting)
- SGR2(1…8)=(01011111) Checksum=250(factory setting)

SGF are used for protective function selection, SGB for blocking specific function by external command. The switch groups SGR1and SGR2 are used to divert desired output signals to the related output relays.

5.4.2 COMBINED O/C & E/F RELAY SPAJ140C [9]
- Phase over current unit
1. Low-set over current stage = I>/In, t>, k (TMS).
2. High-set over current stage =I>>/In, t>>.
- Earth-fault unit
1. Low-set earth-fault stage =I0>/In, t0>, k (TMS).
2. High-set earth fault stage = I0>>/In, t0>>.

Setting procedure of phase over current unit and earth fault unit are similar to electromechanical relay except high-set earth fault stage. High-set earth fault stage generally bypasses.

Switch group (protective function/characteristic selection)
- SGF1 (1…8) = (11000110), (01000010), (10000100) Checksum=99(NI), 66(VI), 33(EI).
- SGF2(1…8)=(00000000) Checksum=0 (factory setting)
- SGB(1…8)=(00000000)Checksum=0 (factory setting)
- SGR1(1…8)=(11010101) Checksum=171 (factory setting)
- SGR2(1…8)=(10100101) Checksum=165 (factory setting)

SGF1 and SGF2 use for protective function and relay characteristic selection, SGB for blocking specific function by external command. The switch groups SGR1and SGR2 are used to route desired output signals to the corresponding output relays. Relay coordination are performed considering all of these above setting and following are output.

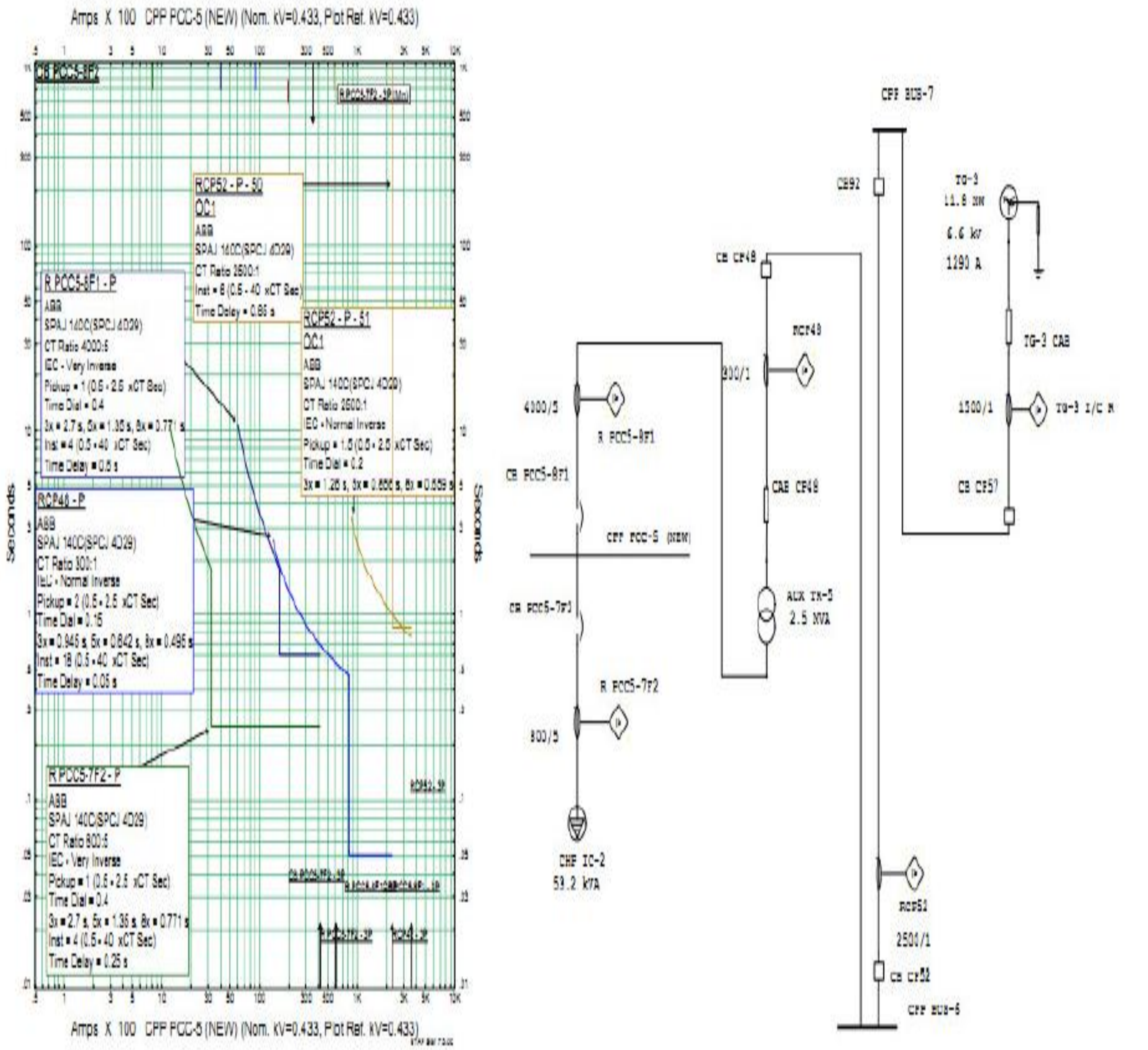
VI. RELAY COORDINATION OUTPUT IMPLEMENTATION (PLANT)

Following modification in existing protection system are suggested after relay coordination. Relay coordination diagram of phase fault and ground fault for only one PCC are presented here as diagram of whole can't accommodate here.

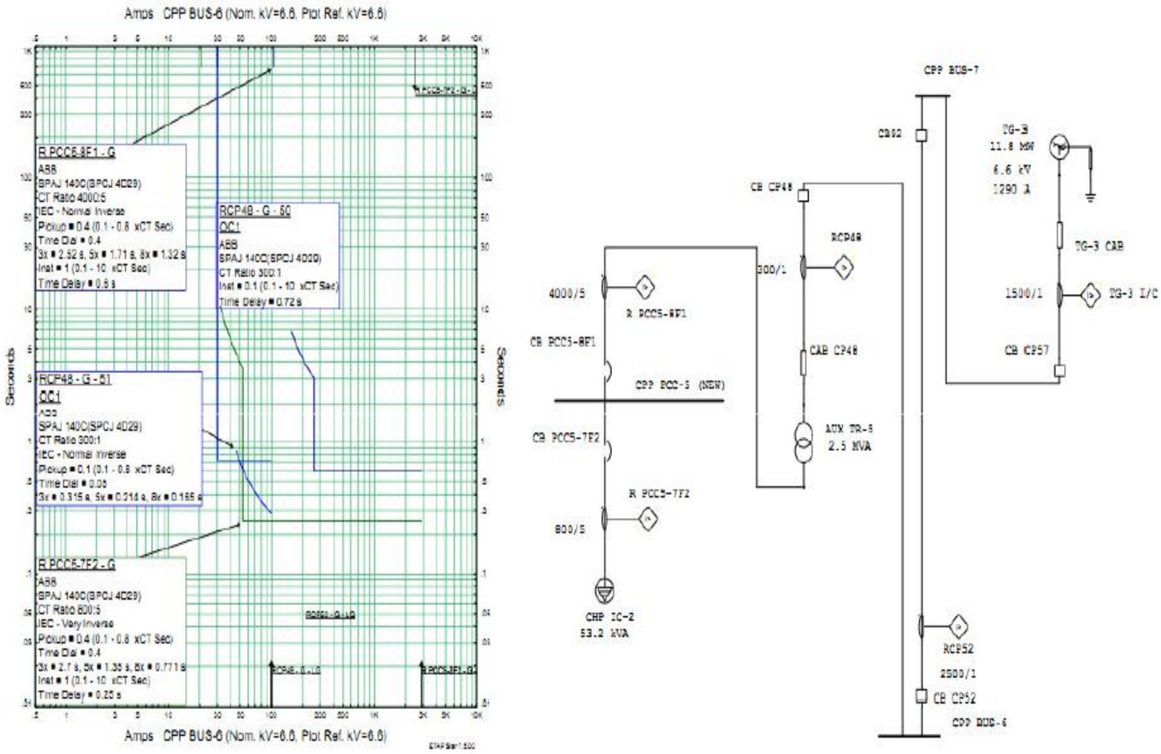
1. Generator Protection Relay (REM 543) Setting for over Current and Earth Fault Protection have been reviewed and need to be changed as per the recommended settings given in the generator protection relay setting table. Other setting like Differential, O/V,U/V,O/F,U/F, phase Unbalance, Reverse power, loss of excitation have not been reviewed.
2. Over current protection provide by voltage restrained unit of generator protection unit (over current relay type CDV-62) instead of normal over current because some time value of steady state fault current is below FLC and it cannot be detected by normal IDMT or DMT over current relay.

3. All outgoing feeder at 6.6 kV main bus have different CTR from 500/1 to 300/1 but earth fault current is limited to 100 A, so it needs to be changed.
4. Some motor feeder CTR are too much high and does not match with motor protection relay setting to give appropriate protection so it needs to be changed.
5. At some HTDB panel have SPAJ115C for transformer REF protection, but not in service. Almost all transformer rating is 2 or 3 MVA so REF protection require for better sensitivity. REF Protection Operate in 25 ms and performed well when small percent of winding earth nearby LT star point. Also it is stable to LT unbalance
6. Unit protection (differential protection) of all generators extended up to Outgoing cable and panel. Or separate O/C and E/F is provided to cable when cable length more than 1 KM at critical location.
7. Faulty electromechanical relay should be replaced by microprocessor relay for better protection.
8. RAMDE and SPAC320C relay is old version motor protection relay SPAM150C. So setting procedure is similar to SPAM150C.
9. SPAC310C relay is old version of feeder protection relay SPAJ140C. So setting procedure is similar to SPAJ140C.
10. ABB Make ICM 21 is Electromechanical O/C & E/F relay similar to ALSTOM make CDG relay. Fuse is always operated instantaneously so that it is difficult to coordinate with other protective device when coordination does not start from fuse.
11. When higher PS setting requires CDG31 replaced by CDG34 and when higher TMS require reverse will be true.

Coordination graphs for phase fault and earth fault of one PCC are showm in fig 6.1 and fig 6.2.



6.1 Relay coordination diagram (Phase fault)



6.2 Relay coordination diagram (Earth fault)

CONCLUSION

Protection coordination is performed using ETAP for every PCC and MCC of industrial plant. New operation philosophy G2+G3 (this operating philosophy suggested by load flow and short circuit analysis) with expanded load of 24 MW is considered for relay coordination. It is found that some of the discrepancies in selected protective device and relays. Additionally some areas are unnecessary protected by some redundant protection scheme and some area is unprotected. To considering all these facts, some modifications are suggested for better coordinated operation of protective system.

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