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A Hybrid Methodology for Relay Settings in Distributed Generation Penetrated Networks

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ABSTRACT

Radial distribution networks are usually passive with unidirectional flow of current. However, the integration of Distributed Generation (DG) transforms the network to an active one with bidirectional flow of current. The challenge in protection scheme for such system is the coordination of the over current relays by appropriate selection of parameters to satisfy the requirements of sensitivity, selectivity, reliability, and speed. Relay coordination in these networks is usually framed as a constrained non-linear optimization problem which determines the optimal setting parameters which are constant for the associated over current relays. This paper proposes a novel online adaptive scheme which considers the dynamic behavior of the system when there is variation in line flow and change in fault currents due to the penetration of DG in the networks. The proposed hybrid algorithm determines the optimal relay settings for various line flows and fault levels of the system by fuzzy decision tool and optimizes the time setting by linear optimization. To validate the algorithm, tests were carried for a Canadian benchmark distribution system which is the IEEE-9 bus network and simulated in ETAP for relay coordination.

Keywords: *DG, Relay-coordination, ETAP*

1. INTRODUCTION

The rapid increase in the power demand urges the penetration of DG into the distribution network. In view of cleaner and efficient energy, renewable DG sources are particularly being given the prime importance to integrate into distribution network. Generally, the traditional distribution networks are single sourced with radial configuration with unidirectional power flow. Intervention of the DG units causes bidirectional power flow in the system which impacts the existing system in many ways. One of the major issues is in the area of protection. The short circuit capacity, magnitude and direction of fault current, contribution to the fault current by the primary source change due to the presence of DG. Hence it affects the protection coordination of the protective devices of the utility as well as DG. The main problems encountered are blinding of protection, false tripping of relays, failed reclosing and loss of mains protection. The severity of these problems depends on the location, the technology, the mode of operation and the penetration level of the DG in the network. It also depends on the location of the fault.

Over current protection relaying is the main scheme of protection designed for a traditional distribution network. It utilizes two main parameters viz. plug multiplier setting (PMS) determined by the pickup current value of relay and the time setting multiplier (TMS) which decides the operating time of the relay. These two parameters are generally found with certain assumptions. For a system with DG intervention the conventional method fails as it is suitable only for unidirectional flow of current. The parameters obtained with traditional network will make protective scheme of the system non compatible in the presence of DG. This give rise to solving the problem using optimization techniques. Many researchers have worked on this issue and several works have been brought forth in the past [1] [2]. Linear programming technique has been used in [3] but this is limited to linear constraints. Over current relay parameter settings have been analyzed in intervals of time using interval linear programming in [4]. Dual simplex methods have been employed in [5]. For an optimal distribution network with DGs placed in optimal location, the relay settings are considered as constraints to maximize the penetration of DG and are evaluated using Genetic Algorithm [6]. Relay settings will change the values to the required configuration depending on the presence or absence of DG in adaptive mode which may require change of protective device [7] [8]. Harmonic constraint limits have been considered in [9]. Superconducting Fault Current Limiters (SFCLs) were suggested to curtail the fault currents injected by DGs and maintain the relay coordination [10].

DGs have to be placed optimally in the network so that the losses are minimized and voltage profile is maintained. Considering the known location and capacity of DG the relay parameters can be optimized to get a fixed set of values. Fixed value of DG cannot be compromised when there is a need in expansion of the network for increase in load demand. Some researchers considered only synchronous based DGs as they have prominent impact in the fault level when it comes to contribution to fault current. Intermittent type DGs also impact the fault levels and it cannot be neglected for their small contribution to fault. Another factor the distribution networks face is frequent load changes which will also vary the line current. Hence, relay current setting cannot be considered as a static parameter as it changes with load. Many research works had focused on optimizing the PMS and TMS parameters using a single optimization problem which becomes more complex for a large network increasing the number of decision variables. This will increase the overall tripping time due to computational delay. This paper proposes a scheme to mitigate the above-mentioned issue for an optimally placed DG for different penetration levels. The algorithm is tested for an IEEE Canadian benchmark distribution system with 9 buses. Simulations were carried in

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ETAP with optimized parameters to validate the coordination between the relays for the network configurations.

Section 2 describes the proposed methodology. Section 3 explains how the Plug multiplier is set through fuzzy decision module. In Section 4, the optimization of Time multiplier setting is explained. Section 5 discusses the results of the experimental evaluation on the test network using ETAP. The conclusion of the proposed work is given in Section 6.

2. PROPOSED METHODOLOGY

The proposed adaptive over current protection scheme considers the above mentioned facts to improve relay sensitivity based on changes in the network configuration. The algorithm proposes a digital relay to adapt the new change where the relay setting current is obtained with line current which changes as per the configuration of the system. The digital relays are compatible to program with real time operating values as it can store data. The real time current values based on network condition is monitored periodically and transmitted through communication interface in SCADA system equipped in automated distribution systems. Based on the periodical measurement of the line current values, the relay setting current is determined using Fuzzy inference system (FIS) and the time setting parameters are then optimized. The proposed methodology ensures minimum relay operating time without violating the coordination of relays. The algorithm is divided into two modules which separately optimize the relay setting current and the operating time so that the computational delay too is minimized. The flowchart of the proposed methodology is shown in Fig.1

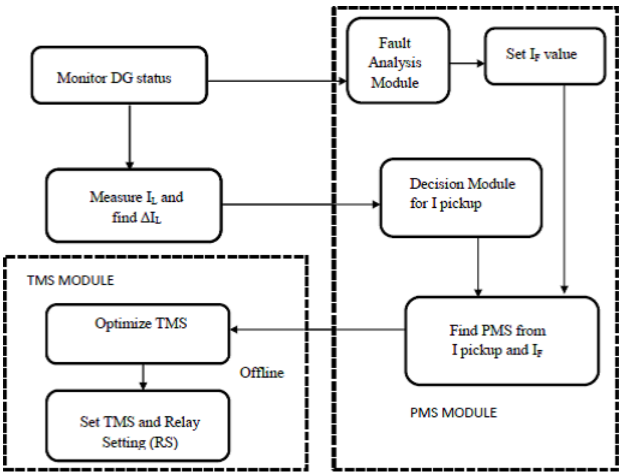

Fig. 1. Flowchart of the proposed methodology

The inverse-time OCR is widely used for feeder protection as it operates very quickly for a fault near the source. The time of operation of this relay is inversely proportional to fault current. The OCR transfers a trip signal when the fault current exceeds a pre-determined pick-up current. The various relay characteristics as per IEEE-OCR standard C37.112 are: Moderately Inverse, Very Inverse, and Extremely Inverse. Its inverse-time current characteristic is expressed by as

$$T_0 = TMS\left[\frac{A}{(PMS)^{\,p}-1}+B\right]-----------(1)$$

where A, B, p are relay characteristics constants. It is a nonlinear constrained optimization problem. The proposed methodology divides the problem into two sub problems in which Plug Multiplier Setting (PMS) is determined by FIS and Time Multiplier Setting (TMS) by simple linear optimization.

3. DETERMINATION OF PMS

PMS module has two sub modules, the decision module which determines the pickup value and the fault analysis module which determines the fault current. The online current measurement and the penetration level of DG is taken for a specified time interval. The change in line current due to intervene of DG helps to find the pickup current of relay while the penetration level decides the fault current to be set for that particular relay. Variation in the line currents due to penetration of DGs are given in Fig.2

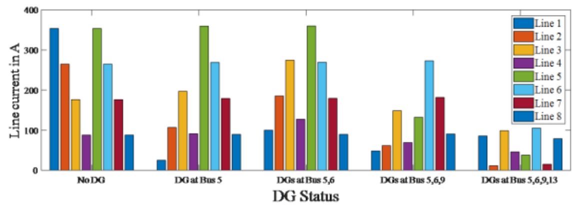

Fig. 2. Variation in line currents with change in penetration of DGs

DECISION MODULE

The line current and change in line current are given as inputs to the FIS which gives pickup as output. The line current (I_L) is represented as five membership functions namely Very Small (VS), Small (S), Large(L), Very Large (VL) and Very Very Large (VVL) and change in line current (ΔI_L) is represented by four membership functions namely VS, S, L, VL. The pick-up value is represented by five membership functions (VS, S, L, VL, VVL). Load flow analysis for different penetration levels of DG is performed to get the variation of line currents by ETAP. This helps in deciding the universe of discourse for the membership functions of the inputs and output in the FIS. Fig.3 shows the membership functions of the inputs and output in FIS. The rule base is framed such that when there is a very small variation in line current, the pickup value does not have significant variation but when the variation is more, the pickup value is reduced so that the relay acts faster. When the pickup value is smaller, the operating time of relay is faster and relay acts robustly. Hence instead of static higher pickup values, here dynamic pickup values are used. The pickup value determined in this module takes care of avoiding false tripping due to short overload condition and improves the sensitivity of relay, so that even for the

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smallest value of fault current, relay becomes sensitive. The fuzzy rule base is given in Table. I

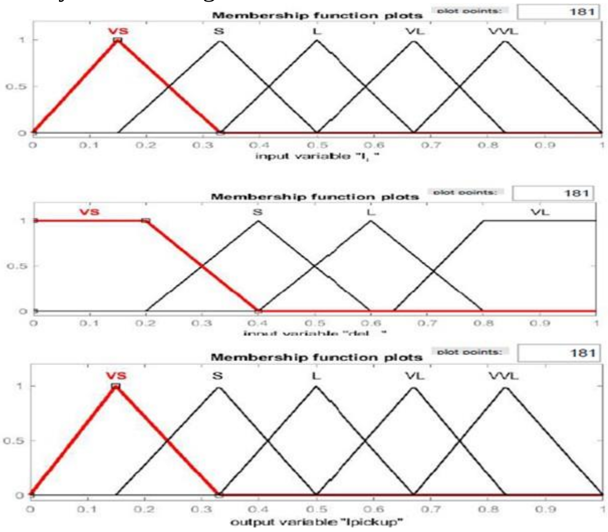

Fig. 3. Membership functions for the inputs and output in fuzzy decision module

TABLE I Fuzzy rule base for Pickup values

$I_L/\Delta I_L$	VS	S	L	VL
VS	VS	VS	VS	VS
S	S	S	VS	VS
L	L	L	S	S
VL	VL	VL	S	S
VVL	VVL	VVL	L	L

FAULT ANALYSIS MODULE

The status of DG is also monitored in the same time interval and the penetration of DG helps to find the fault current seen by relay. There are eight fault locations identified on each section of the feeder. The fault current seen by the relays for the given penetration of DG is determined by fault analysis module. In this the corresponding relay which see the maximum fault current for its corresponding fault location is determined. Thus the PMS for each relay is calculated and with the knowledge of CT ratios, the Relay Settings (RS) are determined. The time delay between the intervals for measurement is provided sufficiently so that the system gets stabilized to choose the stable line current with the change in configuration of the network

4. DETERMINATION OF TMS

In the TMS module, the relay operating time is minimized to determine the optimal TMS value. The constraints for this optimization are the Coordination Time Interval (CTI) values and TMS limit values. The optimization problem is formulated with minimization of the relay operating time (both in primary as well as in backup zones) as an objective function satisfying these constraints (i) TMS limits (ii) Coordination Time Interval (CTI), which is the difference between the operating time of relays in backup and primary zones taken as 0.2s.

$$Optimise\ T_o = \sum_{k}^{N_L} \sum_{i}^{N_R} T_{k,i} \text{-------------} (2)$$

where N_L = Number of fault locations and
N_R = Number of Relays
$T_{k,i}$ = Operating time of ith relay for kth fault subject to constraints
(i) $TMS^{min} \leq TMS_i$
(ii) $TMS_i \leq TMS^{max}$
(iii) $T_{o,b} - T_{o,p} \leq CTI_i$, for all values of i
CTI_i = Coordination Time Interval for the i^{th} relay pair
$T_{o,b}$ = Relay operating time for backup relay
$T_{o,p}$ = Relay operating time for primary relay.
As the PMS value is already determined, the objective function becomes a linear function of TMS values alone with the above mentioned constraints. This can be easily solved by the linear optimization technique.

5. RESULTS AND DISCUSSIONS

The test network [12] is shown in Fig.4, a Canadian urban benchmark distribution system with 115 kV utility grid with X/R ratio as 6 and MVA_{SC} as 500 MVA. The utility supplies to two parallel feeders with four loads on each through the utility transformer 115 kV/12.47 kV, 20 MVA. Four DGs with each 2 MVA rating are connected to the network through a 20MVA, 0.48 kV/12.47 kV step-up transformers. The optimal locations for DGs are determined by priority-based sensitivity factors approach which minimizes the system losses and maintains nominal voltage at buses. The penetration level is varied from 2 MVA to 8 MVA. The optimal DG locations are found to be at buses 4, 5, 6, 9. Based on the change in line currents, the pickup value is

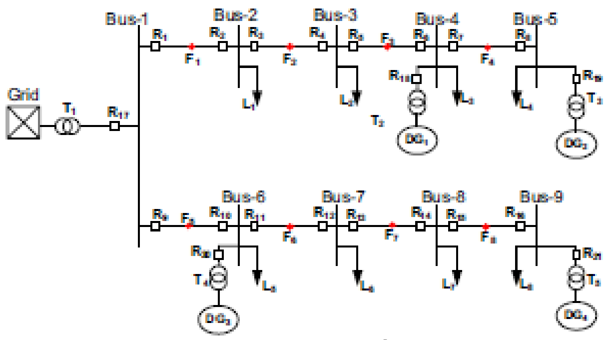

Fig. 4. Test network

determined in the fuzzy decision module. Fig.5 shows the rule base viewer for different load changes. The line currents and the change in line currents are normalized in the range (0,1). For an example as shown if the line current in the rule base is 0.39 A and change in load is very small say 0.323A, the pickup value is not varying significantly. When change in line current is significantly high, the pickup value reduces to

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0.243A. So, the relays are adaptable to the changes and are selective and sensitive too. The rules are verified by simulating for an interval of 6s with two samples per second. The corresponding pick up value of relay-5 for this interval of time is given in Fig.6.The line current varies from 49A to 79A during this interval and 12 samples are measured. When there is no significant change in line current, the pickup value adapts to the line current with a margin for momentary overload condition. The last interval from 5.5s to 6s shows a momentary condition which has a slight increase in line current up to 79 A due to overload and the pickup current too increases slightly in correspondence to the increase. As the pickup value is not constant but adapts to the change in line current, this will reduce the relay operating time and hence relay acts faster.

The incoming of DG at different locations changes the system condition which causes the variation in fault current. Each line has two directional over current relays such that near end bus relays operate for downstream current flow and far end bus relays operate for upstream current flow. Initially when DGs are not connected the upstream relays does not operate as there will not be bidirectional flow of current. When DGs are connected the upstream relays operate based on the location of fault.

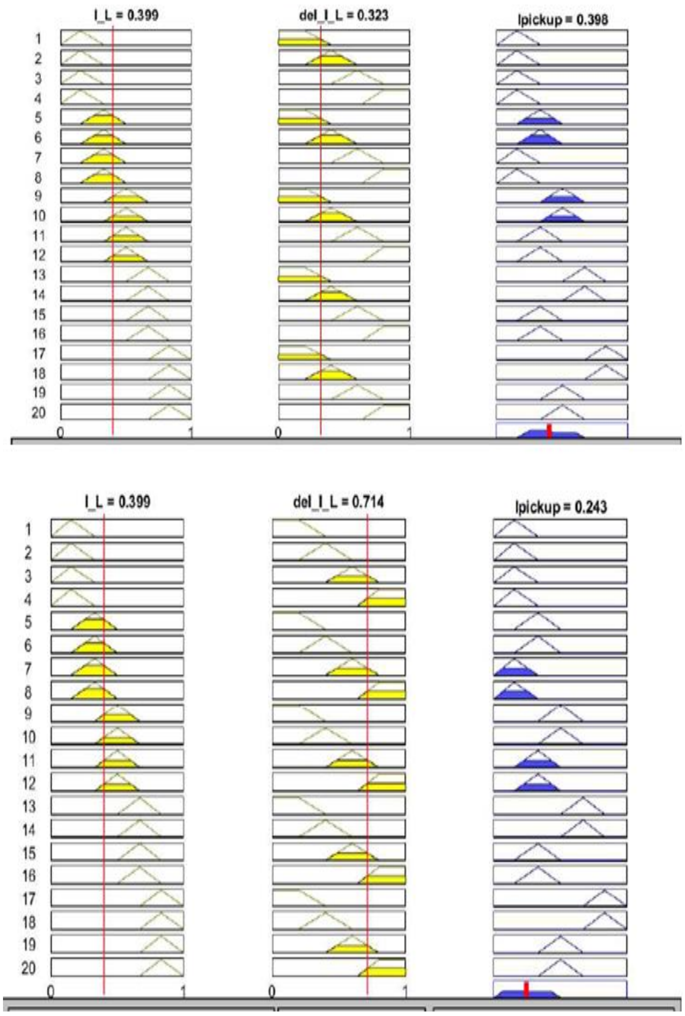

Fig. 5. Fuzzy rule viewer

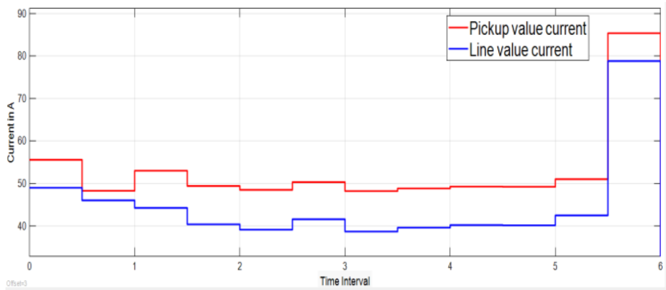

Fig. 6. Pick up value for relay 5 for change in line current measured for a given time interval

The PMS module thus determines the PMS value from the pickup value and the maximum fault seen by the relay. Then the TMS values are optimized by linear optimization technique in offline to minimize the total relay operating time. The optimized relay settings are tabulated in Table. II for varying DG penetration.

TABLE II
Optimal setting values TMS and RS for varying DG penetration

RELAYS	0%		12.5%		25%		37.5%		50%	
	TMS	RS	TMS	RS	TMS	RS	TMS	RS	TMS	RS
1	0.23	2	0.356	0.5	0.356	0.6	0.396	0.5	0.52	0.16
2	-	-	0.01	0.5	0.01	0.88	0.01	0.5	0.01	0.25
3	0.17	1.5	0.224	0.6	0.224	1	0.259	0.5	0.15	0.6
4	-	-	0.106	0.9	0.106	1.5	0.141	0.8	0.12	1
5	0.09	1	0.097	1	0.097	1.5	0.114	0.8	0.12	1
6	-	-	0.169	1.2	0.01	1.8	0.219	1	0.21	1.2
7	0.01	0.5	0.01	0.5	0.169	0.6	0.01	0.5	0.01	0.45
8	-	-	0.263	1.3	0.263	1.3	0.289	1	0.29	1.1
9	0.23	2	0.273	2	0.273	2	0.389	0.67	0.28	2
10	-	-	-	-	-	-	0.347	0.8	0.61	2.4
11	0.17	1.5	0.2	1.05	0.2	1.13	0.221	1.05	0.22	1.12
12	-	-	-	-	-	-	-	-	0.06	2.3
13	0.09	1	0.112	0.8	0.112	0.86	0.12	0.86	0.12	0.86
14	-	-	-	-	-	-	-	-	0.01	0.25
15	0.01	0.5	0.01	0.5	0.01	0.5	0.01	0.3	0.01	0.45
16	-	-	-	-	-	-	-	-	0.29	1
17	0.53	1	0.613	0.5	0.613	0.5	-	-	0.53	1
18	-	-	0.362	1	0.362	1	0.362	1	0.36	1
19	-	-	-	-	0.433	1	0.433	1	0.26	1
20	-	-	-	-	-	-	0.539	1	0.22	1
21	-	-	-	-	-	-	-	-	0.44	1

For different penetration levels, the relay settings change adapting to the configuration of the system. The sequence of operation of the relays was studied in ETAP to analyze the CTI values for each relay pair and it is given in Table. III. It is observed that for all possible fault locations, the relays are well coordinated. When there is no DG penetration, the upstream fault relays do not operate as there is no bidirectional flow of current and so it has only 8 relay pairs. When DGs are present, the number of relay pairs increase depending on the fault location and DG location. When 50 % DG penetration is there in the network, a maximum of 22 relay pairs have to be coordinated.

The corresponding Time current curves (TCC) obtained from relay coordination analysis in ETAP star coordination module for 37.5% DG penetration is given in Fig.7. For one parallel feeder the primary relay R-7 operates at 0.023s and the corresponding backup relay for the line R-5 operates at 0.307s which gives the CTI as 0.2836s. Similarly, for a given fault current of 2 kA in another feeder, the primary relay R-15 operates at 0.0275s and the backup relay for that line which is R-13 operates at 0. 495s.The CTI for this pair is 0.46s which again satisfies the coordinating constraint. Thus, when validated with ETAP simulation, for all the relay pairs under all fault situation the CTI is sufficient enough to coordinate the relay operation.

TABLE III
CTI values for varying DG penetration

Fault	Relay pairs	0%	12.5%	25%	37.5%	50%
F1	R1-R17	0.579	0.583	0.619	0.504	0.67
F1	R1-R10	-	-	-	-	1.14
F1	R2-R4	-	0.217	0.215	0.298	0.237
F2	R3-R1	0.21	0.299	0.333	0.311	0.617
F2	R4-R6	-	0.2	0.207	0.2	0.213
F3	R5-R3	0.207	0.286	0.219	0.329	0.304
F3	R6-R8	-	0.41	0.214	0.2	0.207
F3	R6-R18	-	-	0.201	0.324	0.370
F4	R7-R5	0.202	0.2	0.201	0.235	0.231
F4	R7-R18	-	0.265	0.599	0.798	0.558
F4	R8-R19	-	-	0.2	0.2	0.237
F5	R9-R17	0.579	0.737	0.732	0.510	0.62
F5	R10-R12	-	-	-	0.435	0.210
F5	R10-R20	-	-	-	-	0.471
F6	R11-R9	0.21	-	-	0.381	0.203
F6	R11-R20	-	-	-	0.721	1.19
F6	R12-R14	-	-	-	-	0.207
F7	R13-R11	0.207	0.2	0.204	0.230	0.222
F7	R14-R16	-	-	-	-	0.239
F8	R15-R13	0.202	0.231	0.231	0.246	0.247
F8	R16-R21	-	-	-	-	0.340
T_o(s)		2.396	3.628	4.175	5.922	8.733

Table.IV gives the comparison of total relay operating time for different penetration levels of DG obtained by the proposed method with Genetic Algorithm and Differential Evolution algorithm. The optimal settings obtained through the proposed method coordinates the primary and secondary relays well in the respective fault feeder and also there is reduction of almost 20% to 32% in the overall operating relay time when compared with GA method and 31% to 48% reduction with DE method. The results of GA and DE method were tested with the same assumptions and conditions as done with the proposed method for the discussed test network.

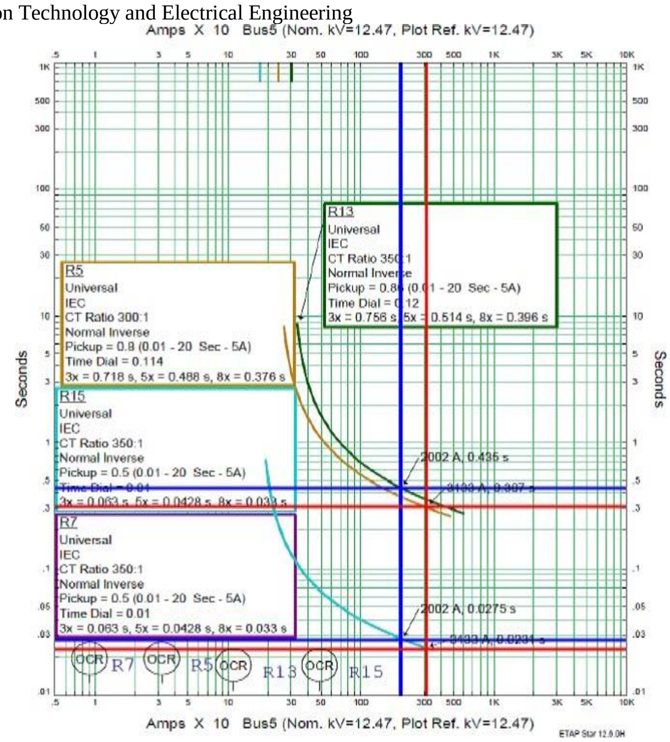

Fig. 7. TCC in coordination module of ETAP with 37% DG penetration

TABLE IV
Comparison of total operating time of all the relays for all fault locations in seconds

DG Penetration	GA method	DE method	Proposed method
12.5%	5.4	7.03	3.628
25%	5.81	7.5	4.175
37.5%	8.54	10.4	5.922
50%	10.91	12.7	8.733

6. CONCLUSION

The existing optimal approaches generally do not consider the changes in the network when there is change in load and varying DG penetration. So, the desirable relay coordination is not achieved. This paper proposes a hybrid approach to mitigate the above mentioned issues so that the overcurrent relays are adaptable to the network changes. It is to be noted that these optimal settings are obtained irrespective of the location and size of DGs for any fault condition in the system. This paper limits to CTI as minimum of 0.2s but the upper limit is not considered. So, for future scope the upper limit for the CTI can be considered.

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