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Optimal Coordination of Overcurrent Relays using Gravitational Search Algorithm with DG Penetration

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***Abstract*—Modern distribution systems consist of various Distributed Generators (DG) to make reliable power system. In this DG integrated distribution systems, coordination of overcurrent relays is a big challenge for protection engineers. With the addition of DG, distribution system experiences change in the short circuit level of the system and thus earlier relay settings causes mal operation of relays. Nowadays, various programming optimization techniques are frequently used to find optimal relay settings of overcurrent (OC) relays. This paper presents a comparative study of Particle Swarm Optimization (PSO) and Gravitational Search Algorithm for the coordination of overcurrent relay for a system containing DG. A proper combination of primary and backup relay is selected to avoid mal operation of relays and unwanted outages when DG is penetrated. Practical cases with different DG penetration level and fault types are also thoroughly discussed. A four bus radial system is simulated in PSCAD/SIMULINK platform and programming is done using MATLAB software.**

Keywords— Distributed Generation, GSA, Overcurrent relay, PSO, Relay coordination.

I. INTRODUCTION

The main function of the power system protective devices is to detect and remove the selected faulty parts as fast as possible. To avoid the problems of malfunction of the main protection systems (fault in relay or in breakers), there should be an arrangement of backup protection. Backup protection may available either at the same station or neighboring lines with appropriate time delay. The coordination between primary and backup relay is achieved if the attributes of the relays satisfy the boundary limits. For selective tripping relay coordination is very necessary in power system protections and it also helps to determine the delay time of all backup relays. The relay must trip for a fault in its zone to avoid any mal operation of the protective devices. As per thumb rule of protection system, relay should not trip for a fault outside its zone except to back up a failed relay or circuit breaker. Backup protection must be coordinated with primary protection such that the primary protection has a sufficient time to remove the fault before the backup relay.

Conventional distribution systems are radial in nature. At this voltage level, most commonly used protections are overcurrent relays, reclosers and fuses [1-4]. Large numbers of relays are present in a distribution system. To maintain the reliability of the system the total relays operating time must be minimum with optimum time multiplier setting (TMS) and Plug Setting (PS) [5].

Several methods for the coordination of overcurrent relays are illustrated in available literatures. These methods can be summarised under three broad categories: trial and error [6], topological analysis method and optimization method [7], [8]. However, the first two methods do not strictly give optimal solutions, but these methods suggest one of the best possible solution. In the optimal methods, operating time of the relays are optimised against the coordination constraints, relay characteristic curves. In optimization of relays operating time, the limits of the relay settings should also considered as constraint.

Particle swarm optimization is a meta heuristic method that follows social behaviour of animals like bird flocking and is very efficient [9], [10]. It is based on movement and intelligence of swarm. It is a population-based search algorithm where each individual is referred to as a particle and represents the optimal solution. PSO strives to improve itself by imbibing the attributes of its successful peers.

The motivation of this paper is to discuss the relay coordination in a radial distribution system and effects of DG penetration on it. In the present study two cases of without and with DG have been taken. A latest optimization technique Gravitational Search Algorithm (GSA) has been applied to find the relay settings for both the cases. The results of this method is compared and found better than PSO technique which has been used by various researchers. Further two more cases are added (Case III and IV) which discusses the impact of DG penetration and fault types / fault current level on relay settings. A four bus radial system has been taken under consideration in which appropriate select of primary relay and backup relay in the quest of coordination is also described [1].

The problem adopted here is a constrained optimization problem. GSA is a new technique based on newton's laws of attraction.Gravitational Search Algorithm is defined as a population based heuristic algorithm briefly described in section IV..

II. Coordination of OC Relays in Radial System

Primary and backup are the two protection schemes incorporated in the radial system [11]. Sensitivity and Selectivity are two attributes of a relay that are of utmost importance for reliability and stability of any power system. With the inception of fault both primary and backup relay sees the fault current but primary relay is the first to issue the trip signal as it has been made more selective than backup relay.

The coordination time interval between the backup and the primary relay depends on various parameters like operating time of primary relay, operating time of circuit breaker associated with the primary relay, overshoot time of backup relay and signal travelling time.

In a radial system, power flow is unidirectional. But when the DG is penetrated in the system the power flow becomes bidirectional. Moreover, when a fault occurs, the directional feature of over current relay comes into picture [4].

III. Problem Formulation

The relay coordination problem of OC relays can be formulated as constrained optimization problem. The objective function of the problem is total operating time of all the relays present in the system. The function is to be minimized so that each relay operates in minimum time and reliability of the system is maintained. The formulated objective function which is denoted as 's' here is

$$\min s = \sum_{i=1}^{n} t_{i,k} \tag{1}$$

where n is the number of relays, $t_{i,k}$ is operating time of i^{th} relay for fault in k^{th} zone. The constraints to solve this optimization problem are divided in three sections [4], [5], and [12-13].

A. *Coordination criteria*

$$t_{bi,k} - t_{i,k} \geq \Delta t \tag{2}$$

where, $t_{i,k}$ is the operating time of primary relay at i for fault in zone k and $t_{bi,k}$ is the operating time of backup relay for fault in same zone and Δt is the coordination time interval (CTI)

B. *Bounds on relay operating time*

$$t_{i,k\,\min} \leq t_{i,k} \leq t_{i,k\,\max} \tag{3}$$

where, $t_{i,k\ min}$ is the minimum operating time of relay at i for fault in zone k and $t_{i,k\ max}$ is the maximum operating time of relay at i for fault in zone k. So bound on time multiplier settings (TMS) will be

$$TMS_{i,k\,\min} \leq TMS_{i,k} \leq TMS_{i,k\,\max} \tag{4}$$

C. *Bounds on Pickup current*

The minimum value of pickup current is determined by maximum load current seen by each relay. The maximum pickup current is determined by minimum fault current seen by each relay. This will impose bound on relay plug setting (PS) also which is given below as:

$$\begin{aligned} I_{p\,\min} &\leq I_p \leq I_{p\,\max} \\ PS_{\min} &\leq PS \leq PS_{\max} \end{aligned} \tag{5}$$

D. Relay characteristics

All relays are identical and assumed to have IDMT characteristic as [3], [4]:

$$t_{op} = \frac{\lambda(TMS)}{(PSM)^{\gamma} - 1}$$

$$t_{op} = \frac{\lambda(TMS)}{(I_{relay} / PS * CT_{sec\ rated})^{\gamma} - 1} \tag{6}$$

where, t_{op} is relay operating time, PS is plug setting. *TMS* is time multiplier setting, PSM is plug multiplier setting, I_{relay} is fault current seen by relay and $CT_{sec\ rated}$ is rated current of CT secondary. For normal IDMT characteristic relay, γ is 0.02 and λ is 0.14. Hence we have two parameters, TMS and PS to be determined using GSA.

IV. Gravitational Search Method

Gravitational Search Algorithm is a population based heuristic algorithm based on gravitational and Newton's law of motion. Agents are regarded to be bodies having variable masses [13]. Gravitational force between masses guides the movement of the agents. Every particle in the universe attracts every other particle with a force that is directly proportional to the product of their masses and inversely proportional to the square of distance between them [14]. Four parameters quantify each body in GSA: Position of the mass in d-th dimension, inertia mass, active gravitational mass, passive gravitational mass. The velocity of a body in a dimension is controlled by the gravitational and inertial masses. Moreover, the fitness value obtained through the application of this algorithm gives the value of these parameters [16]. The basic flowchart of GSA is given in Fig. 1.

V. Relay Coordination Using PSO and GSA

According to the problem formulation the main aim is to find the *TMS* and PS of all relays, so TMS and PS are variable here and the total operating time of all the relays for fault in any zone is taken as the objective function which is to be minimized. The objective function is found by incorporating the relay characteristic constraint (equation 6). The other inequality constraints are included in MATLAB coding of the two techniques. The range of TMS is taken as 0.08 to 1 and the range of plug setting is found individually. The minimum limit of PS is determined by maximum load current passing through any relay and maximum limit is determined by minimum fault current seen by each relay. The objective

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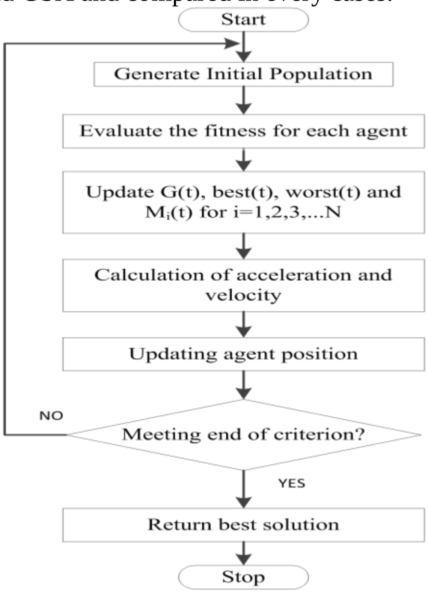
function i.e. the total operating time of all relays is minimized using PSO and GSA and compared in every cases.



a.

Fig. 1. Gravitational Search Algorithm

VI. Results

A 4 bus radial system is taken, in which the grid is of 25 MVA and standard line data's are taken. Two cases are taken here, utility only mode, grid connected mode with 20 % penetration of DG. In all cases PSO and GSA techniques are applied to find the optimum value of TMS and PS of six relays present in each feeder. This optimization is achieved in MATLAB platform. The complete problem formulation of case I is described here. Similar process is adopted for other cases.

A. Case I: Without DG

A 4 bus radial distribution system is modelled in PSCAD platform as given in Fig.2. The grid rating is 25 MVA, 161 kV and the transformer step downs the voltage to 11 kV. This system consists of six relays. The CT ratios of each relays are given in Table I. Faults are created at near end of each relays. Fault inception time is 1s and it is a sustained fault for 2s as shown in Fig.3.The objective function is derived using the equations given in section III.

TABLE I. C.T Ratios of each relays (Case I)

Relay No.	CT Ratio
1	1000/1
2	800/1
3	600/1
4	600/1
5	600/1
6	600/1

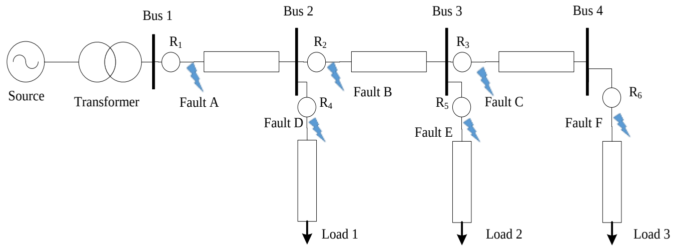


Fig. 2. Single source 4 bus radial system

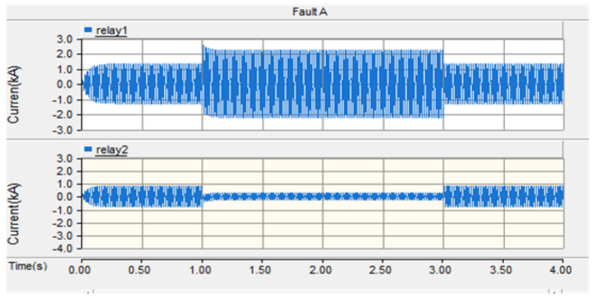


Fig. 3. Fault current in Primary side of CT for relay 1 and 2 for fault point A

In this case twelve variables are there, six TMS and six PS of each relays. There are five constraints due to coordination time interval between primary and backup relays. The CTI is set as 0.3s. First six variables, x_1-x_6 represents the TMS and x_7-x_{12} represents PS. The objective function obtained for this case is obtained by measuring fault currents at different location. It is given as:

$$top = \frac{0.14x_1}{(I_{r1}/x_7\times 1)^{0.02}-1} + \frac{0.14x_2}{(I_{r2}/x_8\times 1)^{0.02}-1} + ... + \frac{0.14x_6}{(I_{r6}/x_{12}\times 1)^{0.02}-1}$$

The optimal value of relays settings are given in Table II.

TABLE II. Obtained TSM and PS of relays using PSO and GSA (Case I)

Relay no.	TMS		PS	
	PSO	**GSA**	**PSO**	**GSA**
1	0.0840	0.1065	0.9985	0.9924
2	0.0800	0.0915	1.0742	1.0018
3	0.0800	0.1022	1.2461	0.9955
4	0.0803	0.1425	1.1453	1.0919
5	0.0919	0.0811	1.1011	1.2316
6	0.0801	0.0800	1.0427	1.0202
Total operating time (Sec)	**PSO**		**GSA**	
	15.01		**14.5616**	

The above results show that GSA technique is giving superior results than PSO. For better analysis of the values obtained from both methods, a comparison bar graph for both TMS and PS is drawn in Fig. 4 and 5. This comparison is added in the earlier version of paper referred as [1] for a clear picture of TMS and PS value variation, both in Case 1 and 2.

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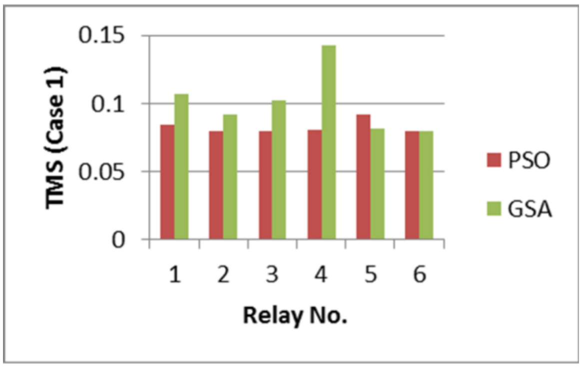

Fig. 4. TMS obtained from two techniques (Case I)

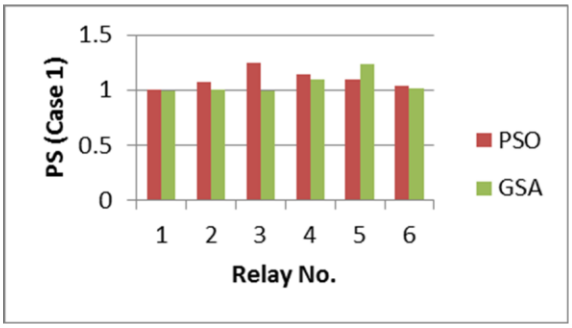

Fig. 5. PS obtained from two techniques (Case I)

Here TMS given by PSO is lesser than GSA for most relays while PS given by GSA is lesser than PSO. This is even relevant because after overall calculation, the total operating time from GSA is coming less and thus relays will operate fast.

The convergence graphs of both methods are given in Fig.15.and Fig.16. The values of TMS and PS obtained by GSA ensure that relay will operate in minimum possible time for fault at any location and coordination will be achieved. The values are applied in the overcurrent relay block of PSCAD. The model of overcurrent relay circuitry is shown in Fig.6.

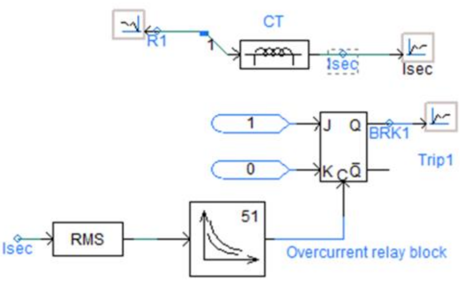

Fig. 6. Overcurrent relay circuit in PSCAD

Table III gives the operating time and coordination time interval of all relays for six fault positions. The trip signals of relays clearly justifies the calculated results (Fig.7-9)

TABLE III. OPERATING TIME OF RELAYS FOR DIFFERENT FAULT POINTS (CASE I)

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI(sec)
	Relay No.	Operating Time(sec)	Relay No.	Operating Time(sec)	
A	1	1.34	-	-	-
B	2	0.68	1	1.63	0.95
C	3	0.96	2	1.62	0.54
D	4	1.33	1	1.64	0.31
E	5	1.32	2	1.63	0.31
F	6	1.88	3	2.20	0.32

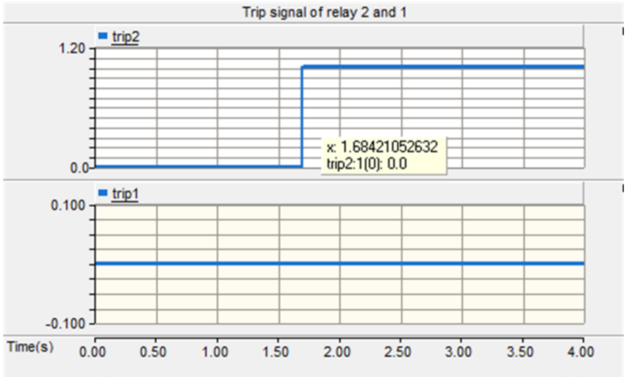

Fig. 7. Trip signals of primary relay 2 and backup relay 1 for fault at point B.

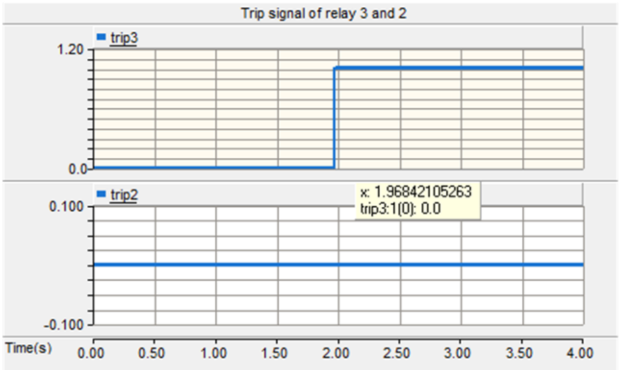

Fig. 8. Trip signals of primary relay 3 and backup relay 2 for fault at point C

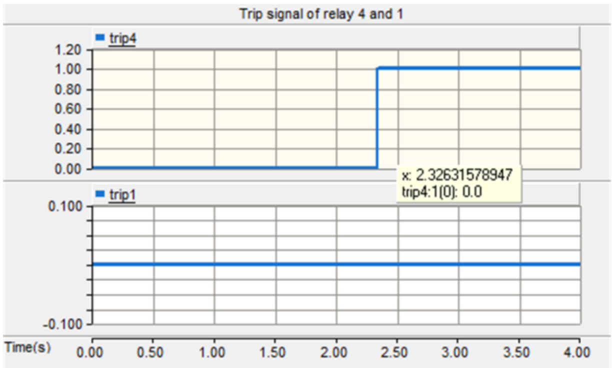

Fig. 9. Trip signals of primary relay 4 and backup relay 1 for fault at point D

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The Fig. 10 and Table III gives the coordination time interval of 0.95 sec i.e. when relay 2 failed to operate relay 1 took 1.63 sec to take over the tripping action.

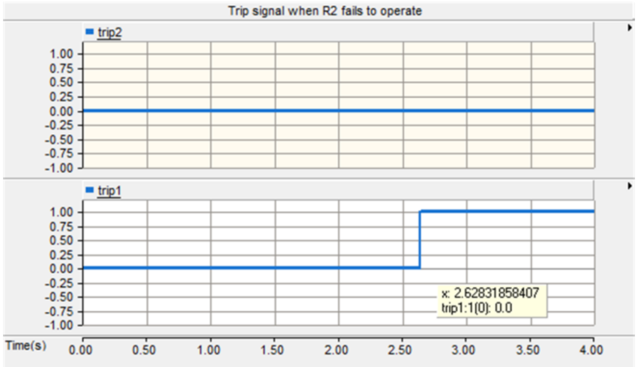

Fig. 10. Trip signal of backup relay 1 when primary relay 2 fails to operate at fault point B.

B. *Case II: With DG*

In this case a DG is added to the system at bus 3 at 20% penetration level. For this case Fig .11 clearly represents that fault current is changed in relay 2 for fault at point A [14], [15]. The relay settings are kept same. It is observed that now the CTI between the relays are changed. It violates the coordination time margin constraint as seen from Table IV, it is 0.14s and-1.16s for two cases. Thus a new setting of all relays are required before incorporating any DG into the system.

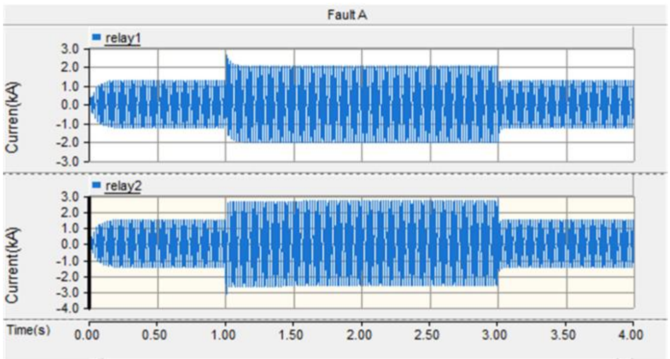

Fig. 11. Fault current in Primary side of CT for relay 1 and 2 for fault point A when DG is added at bus 3.

As seen from above table the CTI is less than 0.3 in last relay and is negative for relay 4 and 1. Therefore new settings of relays are found by formulating new objective function. In this case the primary backup relation of relays is also modified. For fault at point D, two backups will be there relay 1 and relay2. Relay 2 will sense more current than 1 because fault current contributed by DG will pass through relay 2. The TMS and PS of relays for DG added system using PSO and GSA is given in Table V.

TABLE IV. COORDINATION TIME INTERVAL OF RELAYS WITHOUT AND WITH DG

Primary Relay	Backup Relay	CTI (sec) (Without DG)	CTI (sec) (With DG)
2	1	0.95	1.39
3	2	0.54	0.50
4	1	0.31	**-1.16**
5	2	0.31	0.60
6	3	0.32	**0.14**

TABLE V. OBTAINED TSM AND PS OF RELAYS USING PSO AND GSA (CASE II)

Relay no.	TMS		PS	
	PSO	GSA	PSO	GSA
1	0.1160	0.0994	0.9179	0.9275
2	0.0947	0.1105	1.1522	0.9292
3	0.1124	0.1001	1.2630	1.4399
4	0.2619	0.0815	0.9106	1.2606
5	0.0800	0.1382	1.4318	1.4144
6	0.0800	0.0893	1.1449	1.0374
Total operating time (sec)	**PSO**		**GSA**	
	10.7336		**9.2148**	

The comparison bar graph from Fig. 12 and 13 tells that most of the TMS and PS values are less for the solution obtained by GSA method as compared to PSO. This again confirms that GSA is giving a better result, as the total operating time now is only 9.21 sec.

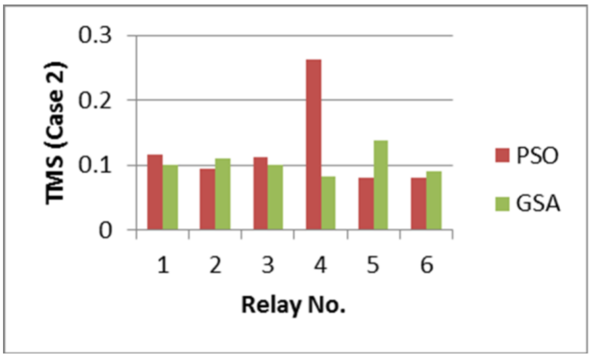

Fig. 12. TMS obtained from two techiniques for Case 2

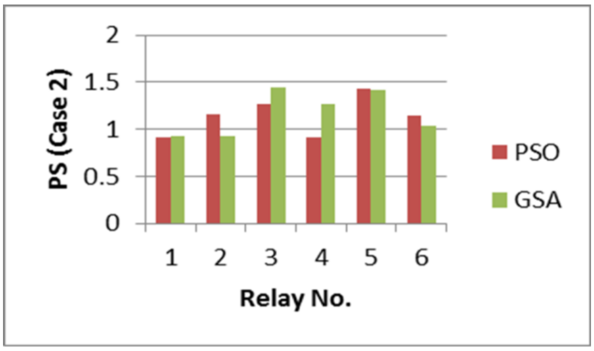

Fig. 13. PS obtained from two techiniques for Case 2

The convergence graph for this case is given in Fig. 17 and Fig. 18. This graph represents that GSA converges to a better

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solution than PSO i.e. gives better minimum operating time while maintaining every constraints. Although it can be seen that the number of iterations for PSO is quite less than GSA. Parameters used in both methods are given in Table VII. The values of TMS and PS are plotted with each iteration in Fig.19.-Fig.20. The overall operating time has decreased which clearly represents that with the addition of DG, relays have to be more sensitive and fast. These new settings of relay parameters should be updated after adding DG into the system. Operating time of each relay with updated setting is given in Table VI. Fig. 14 gives the trip signals for fault point B. Pre fault, during fault and cleared fault current is also shown in this figure.

TABLE VI. OPERATING TIME OF RELAYS FOR DIFFERENT FAULT POINTS (CASE II)

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	1.27	-	-	-
B	2	0.67	1	1.27	0.6
C	3	0.36	2	1.007	0.647
D	4	0.49	1	1.25	0.76
D	4	0.49	2	0.95	0.46
E	5	0.50	2	1.007	0.507
F	6	0.62	3	0.97	0.35

TABLE VII. MAJOR PARAMETERS OF OPTIMIZATION TECHNIQUES

PSO	GSA
Cognitive attraction= 0.5	Gravitational constant=100
Population size =100	Alpha=20
Number of particles=50	Number of agents=50

Effect of Load Current Variation on Relay Settings:

The load at different locations changes as per requirement in any distribution system. Therefore its effect on relay settings is also so important here. The Plug setting's lower bound depends on maximum load current. Here all the settings are according to the peak load current seen by each relays. For example, the peak load hour is generally between 6 PM to 10 PM (India). The plug settings are set once as per peak load current and it works for faults at any time of a day. This is because at any other time the load current is less than peak current and thus it will surely operate.

If load current changes i.e. a new load is added in the system then Plug settings should be changed because now peak load current is different from earlier case. Here we require an adaptive relay that can sense new load addition and upgrade its PS as per relay algorithm discussed here.

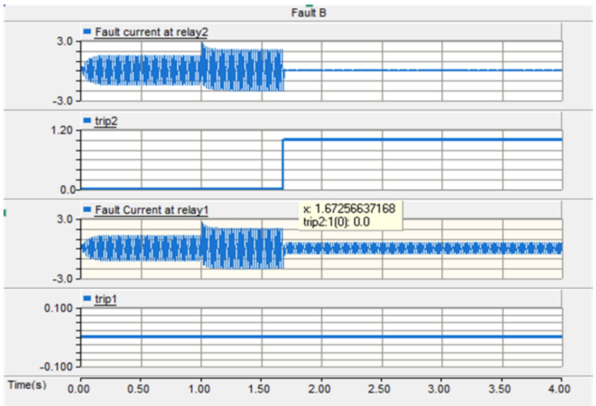

Fig. 14. Fault current and trip signals of primary and backup relay for fault point B.

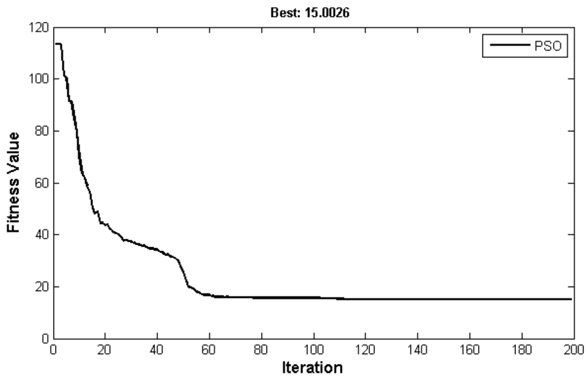

Fig. 15. Convergence graph for PSO (Case I)

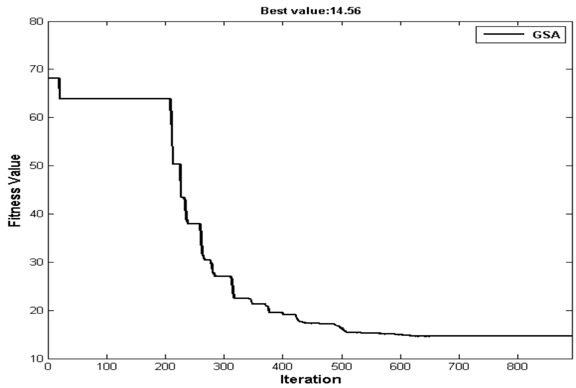

Fig. 16. Convergence graph for GSA (Case I)

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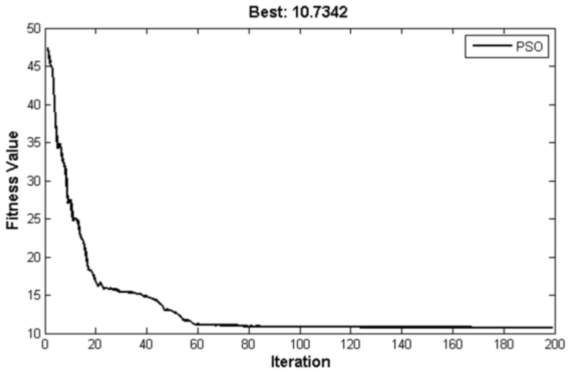

Fig. 17. Convergence graph for PSO (Case II)

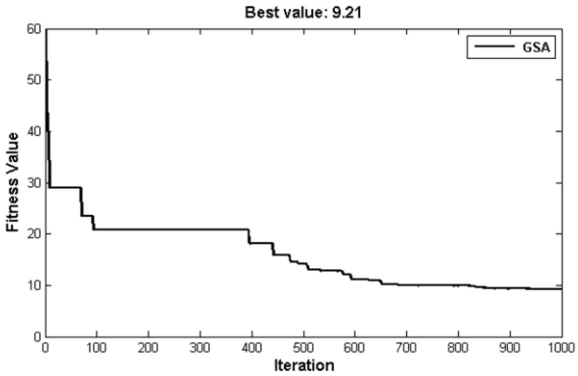

Fig. 18. Convergence graph for GSA (Case II)

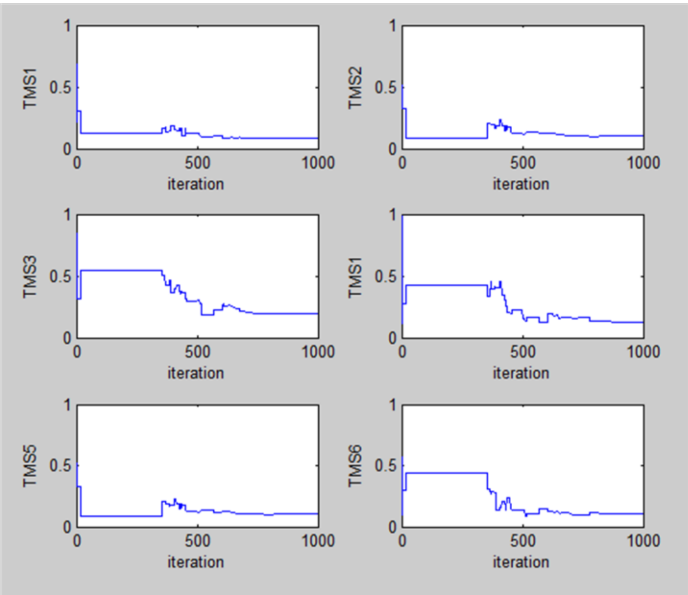

Fig. 19. TMS values in each iteration (Case II)

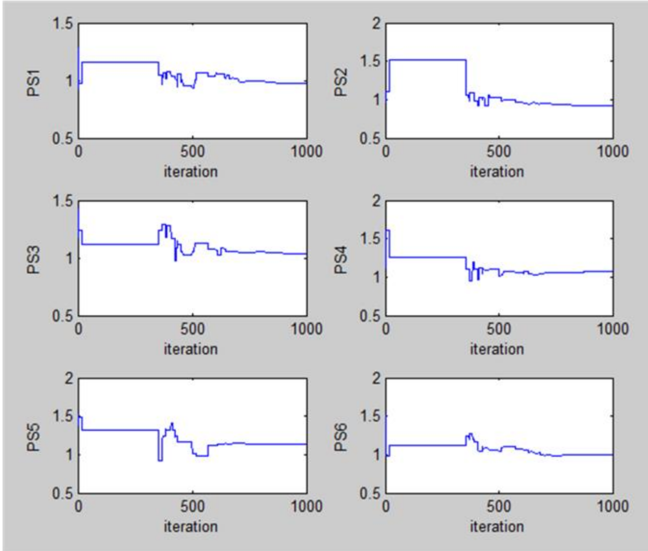

Fig. 20. PS values in each iteration (Case II)

C. Case III: With Different DG Penetration level

When the demand at some of the load centers increases, that extra load is managed either by increasing the main grid generation or by increasing the penetration level of DG available near the load center. Therefore, a case is discussed here explaining how a reliable relay operation can be assured if a fault occurs at any of these penetration level. The DG penetration level is given as [18]

$$\%DG_{Penetration\_Level} = \frac{P_{DG}}{P_{DG} + P_{Grid}} \times 100$$

According to [18] DG penetration is increased as per increase in load (active and reactive). A 50% load increment corresponds to 33.33 % of DG level which can be treated as maximum limit of penetration percentage. Here three different scenarios are taken with 23.3, 26.67 and 30 % (3.33 % step size) of penetration level.

The same network topology is used but source, load and line impedances are different from Case 2. The simulation is performed in MATLAB/SIMULINK platform therefore fault current magnitude is different in this case.

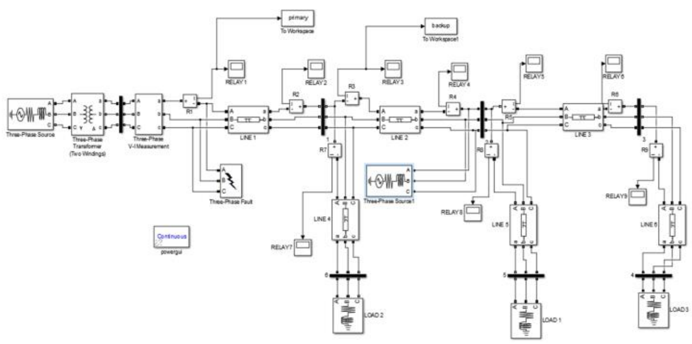

Fig. 21. 4 Bus DG system in SIMULINK

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For DG added system the currents contributing to fault current may have two directions. It was observed that with 23.3% DG penetration, although the overall fault current value are increased but for fault A the DG contribution to fault is very minimal thus R2 is not sensing any rise in current from its pickup value. Therefore it is not required to make it a Backup protection for R1. Same reason applies for fault location D. For example, as given in Fig. 22 the fault currents for location D is mentioned. Here we can see that relay 4 and relay 1 is experiencing a rise in current magnitude as soon faults occur at 0.2s. While R2 sees a dip in current amplitude which means relay 2 is not observing any fault. Thus for this penetration level there is no need to change pair of primary and backup

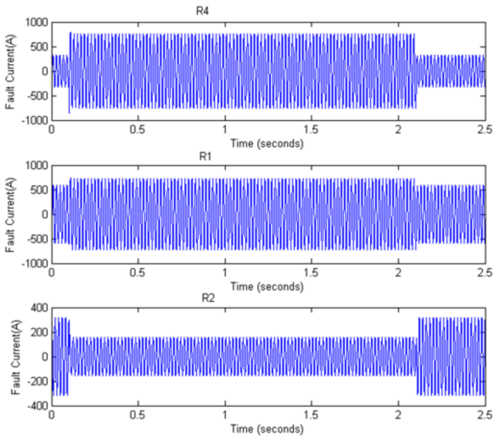

Fig. 22. Fault current seen by relay 4,1 and 2 at 23.3 % DG Level (location D)

Similarly, when penetration level is increased to 26.6% , for a fault at location D we again observe a dip in current level at relay 2 (Fig. 23) when fault incepts. After observing all fault locations, in this case also we don't observe any effect of DG penetration level. However it is obviously expected that with rise in DG penetration level the primary and backup relay selection has to be modified.

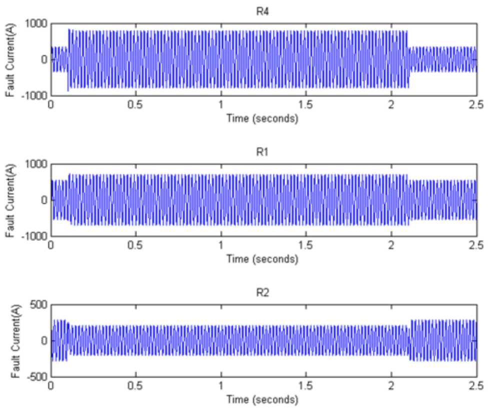

Fig. 23. Fault current seen by relay 4,1 and 2 at 26.6 % DG Level (location D)

The values of TMS and PS for 23.3 % and 26.6 % DG penetration are given in Table VIII.

TABLE VIII. OBTAINED TSM AND PS OF RELAYS USING PSO AND GSA (23.3 % AND 26.6 % DG PENETRATION LEVEL)

Relay no.	DG (23.3%)		DG (26.6%)	
	PSO	GSA	PSO	GSA
TMS1	0.3928	0.2882	0.2933	0.3380
TMS2	0.2616	0.2227	0.1827	0.1792
TMS3	0.1976	0.1322	0.1282	0.1247
TMS4	0.1142	0.1285	0.0841	0.1271
TMS5	0.0958	0.1060	0.0968	0.1075
TMS6	0.0829	0.0801	0.0802	0.0831
PS1	0.1003	0.1603	0.1436	0.1034
PS2	0.1037	0.1250	0.1639	0.1648
PS3	0.1201	0.2225	0.2523	0.2594
PS4	0.1808	0.2875	0.3908	0.1303
PS5	0.2928	0.2347	0.3502	0.2216
PS6	0.1529	0.1117	0.1343	0.1186
Total operating time (sec)	**8.106**	**7.6788**	**7.5151**	**7.309**

The operating time as well as CTI between relays is also obtained in Table IX and Table X for 23.3% and 26.6 % DG penetration level respectively. The CTI obtained in both cases are above 0.3s which means proper coordination is achieved. It can also be perceived that with rise in DG penetration level the operating time of relays has decreased. Like, at Fault B and C the relay operates after 0.74s and 0.48s respectively with 23 .3 % DG level while it get decreased to 0.69 s and 0.45 s when penetration rises to 26.6 %. This happens because gradually DG increases the total fault current level of the system and thus due to IDMT character of relay the operating time drops.

TABLE IX. OPERATING TIME AND CTI VALUES FOR 23.3 % DG PENETRATION

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	1.0225	-	-	-
B	2	0.7496	1	1.0533	0.3037
C	3	0.4809	2	0.7824	0.3015
D	4	0.5619	1	1.0522	0.4903
E	5	0.4013	2	0.7824	0.3811
F	6	0.2278	3	0.5310	0.3032

TABLE X. OPERATING TIME AND CTI VALUES FOR 26.6 % DG PENETRATION

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	0.9890	-	-	-
B	2	0.6902	1	1.005	0.3148
C	3	0.4544	2	0.7706	0.3162
D	4	0.3573	1	1.0142	0.6569
E	5	0.3762	2	0.7753	0.3991
F	6	0.2299	3	0.5453	0.3154

Now further the DG penetration is pushed to 30%. In this case DG effect was thoroughly seen. For fault at A, apart from Relay 1, Relay 2 also senses the fault because DG is also contributing in fault current now. Therefore R2 should be a

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bidirectional relay. The Fault current direction is explained in Fig. 24. For fault at B, we require one more directional relay R7 as shown in Fig. 25, and now both R2 and R7 will act as primary relay. R2 will ensure Fault isolation of Line 2 from main grid while R7 will isolate line 2 from Bus 3. So now system after Bus 3 i.e. (Load 2 and 3) will be powered by DG which is a kind of Islanded mode of DG operation while main grid will supply Load 1.The fault current seen by R2 and R1 for location D is shown Fig 26 which says that R4 should be backed by both R2 and R1. Thus after 30% penetration levels the primary and backup pair should be changed as given in Table XI. These features can be availed if we use an adaptive relay. The CTI and operating time of relays are listed in Table XI.

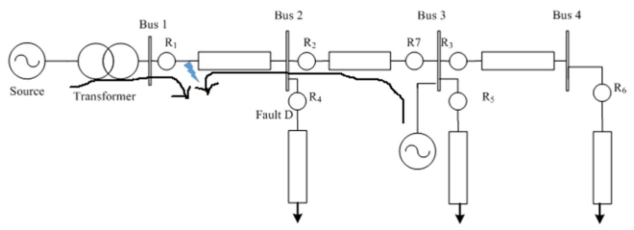

Fig. 24. Fault current directions from DG and Grid for fault A (30 % level)

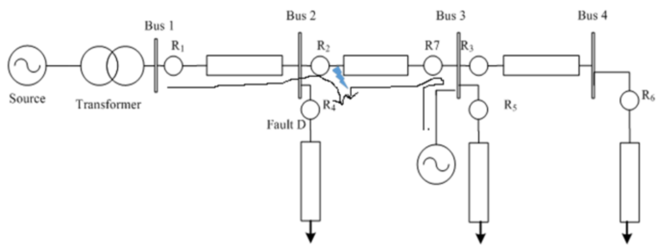

Fig. 25. Fault current directions from DG and Grid for fault B (30 % level)

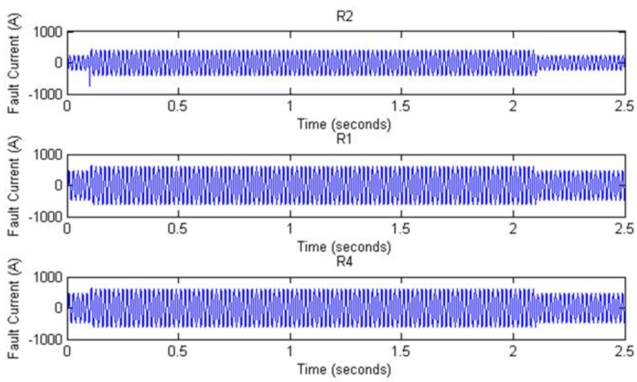

Fig. 26. Fault current waveform for fault location D (30% DG Level)

TABLE XI. OPERATING TIME AND CTI VALUES FOR 30 % DG PENETRATION

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	0.6157	2	0.9232	0.3075
B	2	0.7405	1	1.0271	0.3166
B	7	0.8046		-------	-------
C	3	0.3280	2	0.7879	0.4599
D	4	0.2370	1	0.6542	0.4172
D	4	0.2370	2	0.8267	0.5897
E	5	0.3477	2	0.7900	0.4423
F	6	0.3183	3	0.6679	0.3496

In 30 % penetration case a satisfactory CTI and operating time of relays are obtained. If we compare the operating time for this case and 26.6 % penetration case, we can see that it has further decreased in 30 % case. This is because the fault current level has increased.

DG Not Running Case:

A common problem of distribution system is relays reaction when DG is not running or not available and fault happens. Therefore it is essential to examine the response of relays in this case. For same settings with DG (30% Penetration), operating time and CTI of relays when DG is not running are observed in Table XII.

TABLE XII. OPERATING TIME AND CTI VALUES DURING DG FAILURE OR NOT RUNNING

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	0.4812	2	-	
B	2	0.5592	1	0.5010	**-0.0582**
C	3	0.5499	2	0.5792	**0.0293**
D	4	0.3127	1	0.5010	**0.1883**
D	4	0.3127	2	-	
E	5	0.4757	2	0.6443	**0.1686**
F	6	0.4473	3	0.5498	**0.1025**

From the results it is clearly visible that CTI is violated however it is a positive value for relay 4, 5 and 6. This implies that if a fault occurs at location D, E or F, the relays are still able to isolate the fault, but for location A, B, C this is not the case. Moreover, whenever there is a DG failure or it is not running a loss of generation command is sent to the main grid. In this case either load has to be reduced by performing a load shedding or the generation has to be increased from the main plant. So during this transient phase i.e. between DG failure and when generation is being increased or load is being managed if a fault occurs then CTI and operating time of relays will be as per Table VII. Once this phase is over the power demand and supply is balanced and relay settings of NO DG case can be updated in each relay to isolate any fault.

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D. Case IV: With Different Fault Current Types

The most common type of fault is Line to Ground (LG) fault which has been already discussed in above sections. However, it is important to analyze the relay behavior for other types of frequent faults i.e. Line to line (LL), (Line-Line to Ground) LLG. These faults imply high fault current levels and thus its impact on relay settings is observed below.

Line to Line (LL) and Line-Line to Ground (LLG) Fault:

The case with 26.6 % DG penetration level is again discussed here but with LL and LLG fault. We have obtained the operating time and CTI of relays present in phase A whose relay settings are already set for L-G fault.

TABLE XIII. OPERATING TIME AND CTI VALUES FOR 26.6 % DG PENETRATION FOR LL FAULT

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	0.7382	-	-	-
B	2	0.4751	1	0.7938	0.3187
C	3	0.3217	2	0.6127	0.2910
D	4	0.3075	1	0.7938	0.4863
E	5	0.3427	2	0.5116	0.1689
F	6	0.2142	3	0.4985	0.2843

TABLE XIV. OPERATING TIME AND CTI VALUES FOR 26.6 % DG PENETRATION FOR LLG FAULT

Fault Point	Primary Relay Unit		Backup Relay Unit		CTI (sec)
	Relay No.	Operating Time (sec)	Relay No.	Operating Time (sec)	
A	1	0.7270	-	-	-
B	2	0.4691	1	0.7938	0.3247
C	3	0.3015	2	0.5110	0.2095
D	4	0.3041	1	0.7938	0.4897
E	5	0.3354	2	0.5079	0.1725
F	6	0.2127	3	0.4887	0.2760

We can see from above Table that for LL or LLG fault we can use the LG fault relay settings. The CTI for fault at C,E and F is less than 0.3s but it is still positive, which means backup relay will always operate before primary. Since the range of CTI could be from 0.1 to 0.5s [17] these values are acceptable. Thus it is concluded that once the relays are set as per LG fault settings it will work fine with other unsymmetrical faults also i.e. LL and LLG fault. For three phase fault (LLL), the fault current magnitude is expected to be very high. In that case CTI may violate, but since its chance of occurrence is very less (5-6%), this type of fault is not discussed in this study.

VII. CONCLUSION

Two optimization techniques are used in this paper in order to find the optimal time multiplier setting (TMS) and Plug setting (PS) of six relays so that their total operating time can be minimized. The simulated fault current retrieved in PSCAD/MATLAB-SIMULINK is subsequently processed in MATLAB. The objective function is framed for two cases i.e. with and without DG. Further, it is minimized by maintaining the range of TMS of each relay as 0.08 to 1 and coordination time interval as 0.3s.The range of PS, determined for each relay is based on maximum load current and minimum fault current. Coordination is achieved in every case. The mal operation of relays due to presence of DG is thoroughly discussed and a comparative assessment of results is done. A demonstrative result is cited in a tabular form in order to reflect the superiority of GSA over PSO in the context of relay coordination objective. This represents that GSA is a potential optimization technique which can be applied for relay coordination task. Further two more practical cases, one with divergent DG penetration level and other with varying fault current level are also discussed. From the results it can be inferred that if the relays are adaptive in nature then it can judge the DG penetration level and update the relay settings obtained from the analysis. Once the relays are set as per settings given by GSA it will work for all types of asymmetrical faults that occur frequently in a system. Thus GSA is proved superior in these cases too.

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