Effect of Distributed Generation Capacity on the Coordination of Protection System of Distribution Network

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***Abstract*- Conventional power distribution system is radial in nature, characterized by a single source feeding a network of downstream feeders. Protection scheme for distribution system, primarily consisting of fuses and reclosures and, in some cases, relays, has traditionally been designed assuming the system to be radial. In last year extra attention applied in use of distributed generator units in distribution networks. The integration of distributed sources into existing networks brings up several technical, economical and regulatory questions. The connection of distributed generators (DG) to distribution networks also influences the performance of the networks and the impact depends on the number, location and size of injected DG. The presence of distributed generators in the distribution network can cause the mis-coordination of the protection system. In order to overcome this problem, one can change the relay setting based on the number and location of DGs in the network. In this paper, another approach is selected in which, the capacity of DG at each node is determined in such a way, that the mis-coordination does not happen. The proposed method is explained in two cases. In the first case, just one DG at each node is considered, but in the second case existence of two or more DGs in separate nodes is taken into account. The simulation result are presented and discussed in a typical distribution network.**

***Index Terms*- Distributed generator, distribution network, protection equipment coordination, DG capacity.**

I. Introduction

Connection of distributed generators directly to distribution systems has become a common practice worldwide. The connection of DGs brings a great change to configuration of the utility distribution network. As a result, this leads to a big challenge for its control and protection system [1-3]. Capacity and location of DG in the network have much influence on the protection system. Some of the often-quoted benefits of DG include the following:

1) Emergency backup during sustained utility outages
2) Reduced voltage sags
3) Increased reliability
4) Potential utility capacity addition deferrals

At present standards for interconnecting DG to network, mostly are based on the principle that DG shouldn't bring influence upon the normal operation performance for the utility protection and control system [4,5]. When a DG is connected into the network then levels of short circuit changed, so relay settings should be changed and if DG is disconnected relay setting should back to previous state, for doing these a lot of communication links require that usually not available in distributed network [6]. This paper presents an analysis to the protection for the radial distribution system with DG. A method for determining the distributed generators capacity has been suggested that these units do not cause loss of coordination of relays.

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II. Relay Coordination of Conventional Protection

Fig. 1 shows a simple radial distribution power system, where GS is the grid system, A, B, C, D, E are the nodes of system and their corresponding loads are load1, load2, load3, load4, load5 respectively. When a fault occurs at the network, inverse over-current protection is adopted.

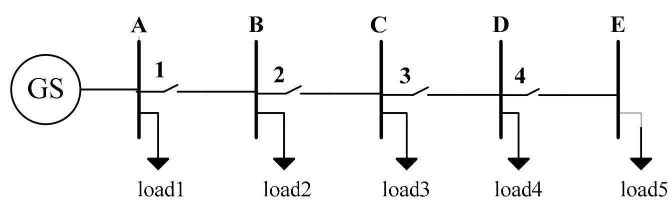

Fig.1. Simple radial distribution power system

The general operational characteristics of relays correspond to IEC standard which is expressed by the following equation:

$$t_{\mathrm{i}} = \frac{0.14 TMS_i}{\left(\dfrac{I_{fi}}{I_{pickup_i}}\right)^{0.02} - 1} \quad (1)$$

Where:

TMS_i = *time multiplier setting of relay i*

I_{fi} = *fault current seen by relay i*

$I_{pickupi}$ = *pickup current of relay i*

For coordination of relays at first the pickup currents are set. The user can select pickup current in a range that the minimum value is the largest between the current corresponding to the minimum available tap and the product of the maximum load current by a security factor (usually 1.1 until 1.3 for phase protection) and the maximum value is the least value between the current corresponding to the maximum available tap and the product of the minimum fault current by a security factor(usually 0.8). In this network, relay 3 is backup of relay 4, relay 2 is backup of relay 3, and relay 1 is backup relay 2. Minimum difference required for the operation time of any pair of primary/back up relays for a given fault named coordination time interval (CTI). CTI depends on some factors such as the circuit breaker operation time, delay and return time of the measuring element, etc. After determining pickup current, the time multiplier settings are set. Relay 4 give the lowest TMS, for relay 3 with a fault occurred at node D, the time of operation of relay 3 should larger than that of relay 4 at least by CTI and for other relays we act similarly.

III. Effect of DG at The Traditional Protection

The coordination of relays has changed, due to the number, location and capacity of DG interconnected. The following cases are analyzed in this paper.

A. Single DG interconnected

Fig. 2 shows DG1 located at bus A. Let's consider first at the network without DG1. A three phase fault occurs in section DE, relay 1, 2, 3 and 4 will sense downstream fault and relay 4 should operate. Relay 3 is backup of relay 4. If the relay 4 for any reason does not operate, after CTI relay 3 should operate. While DG1 injected, for a fault at downstream, e.g., a fault in section DE, relay 1, 2, 3 and 4 will see the downstream fault current, which is greater than that without DG1. Then, relay 4 will clear the fault and the sensitivity will be improved because of the larger fault current. But if fault current is greater than allowable current limit coordination between relay 3 and relay 4 not hold.

Allowable current limit is margin that if fault current be higher than this range, difference between operating time of main and backup relay will lower than CTI and interference in the operation of the relay is a probable. The situation will be similar for a given fault in section AB, BC or CD [7].

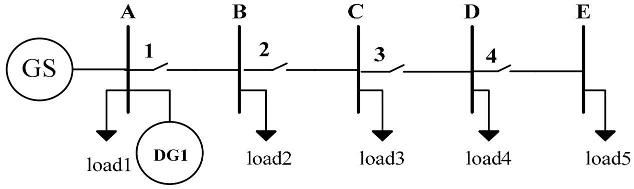

Fig. 2. Distribution system with DG1 located at bus A

Fig. 3 shows DG2 located at bus B, for a downstream fault, condition of relays are the same as before but for a fault in section AB, relay 2, 3, 4 will never see the upstream fault current, while relay 1 will sense a downstream fault current and if the fault current value is more than the set value relay 1 operates. Meanwhile, DG2 and the downstream loads will form an island.

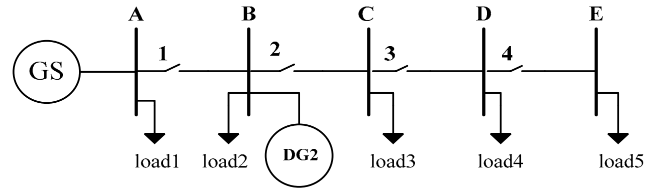

Fig. 3. Distribution system with DG2 located at bus B

B. Multiple DGs interconnected

Fig. 4 shows DG1 and DG2 which are located at bus B and C respectively. For a downstream fault of DG3, condition of relays is the same as previous section. Relay 1 is backup of relay 2. For a fault at section BC relay 2 operates before relay 1 and for a fault at section AB, relay 1 should be operate before relay 2 and here relay 2 is backup relay 1 so correct operation of relays depends on the amount of fault current. Fault current magnitude depends on the sizes of DG2 and DG3 [7]. Based on the above explanation it can be concluded that the number, location and capacity of DG interconnected to network can affect on relay coordination. In this paper determination of capacity of DG is investigated.

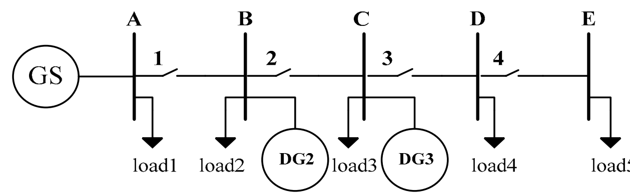

Fig. 4. Distribution system with DG2 and DG3 located at bus B and C

IV. Determination of DG Capacity

The aim of this section is to determine the maximum and minimum capacity of DG connected to each node such that the mis-coordination of over-current relays do not happen, e.g., DG1 located at bus C and a three phase fault occurs in front of relay 4. Fig. 5 shows network in this position. Relay 4 is required to operate before relay 3 and if relay 4 doesn't operate, relay 3 eliminating fault after CTI. With presence of DG for downstream fault if current is greater than allowable current limit, coordination between relays 3 and 4 will be lost. Thus, the capacity of DG should be determined as the fault current will be lower than allowable current limit. To solve this problem the maximum DG capacity that can be placed in the bus C is determined.

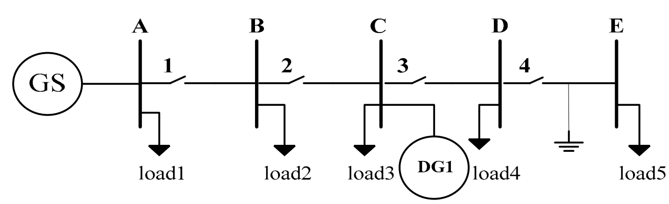

Fig. 5. Distribution system with DG1 located at bus C and a three phase fault occurs in front of relay 4

For determining the maximum capacity of DG at bus C, at first a DG with a predetermine capacity is connected to bus C. Then the three-phase fault is considered in front of relay 4. Now fault currents flow through the relays 3 and 4 are recorded. Change the capacity of DG1 and repeat the above section. Using the fault current recorded and equation 1, the operation time of relays 3 and 4 are calculated, for fault at bus C. In order to keep the coordination, the operation time interval between relays 3 and 4 should be greater than or equal to CTI. Therefore, maximum capacity that provide above limitation is selected as maximum capacity of the DG at bus C. If the DG capacity located at bus C is bigger than determined capacity, coordination between relays 3 and 4 will be lost. For a downstream fault, DG with determined capacity can keep the coordination between relays 3 and 4. After determining the maximum capacity of DG at bus C, the maximum capacity of DG at bus A and B are determined similary.

For determining the maximum capacity of DG at bus A, three phase fault is considered in front of relays 2, 3 and 4. For each fault the maximum capacity of DG at bus A is found. The lowest values will be the maximum capacity of DG at bus A. After determining the maximum capacity of DG in the each bus, the minimum capacity of DG should be determined.

For this purpose, DG located at bus B, and it is assumed that the phase-to-phase fault at upstream bus is occurred (for example, bus A). DG capacity should be have a quantity that relay 1 senses the fault current and operates. For determining the minimum capacity of DG at bus B, first definite capacity DG located at bus B. phase-to-phase fault occurs at node A. Now fault current flow through the relays 1 recorded. Change the capacity of DG and repeat the above section. Using the fault current recorded and equation 1, the operation time of relay 1 are calculated, for fault at bus A. Therefore, The lowest values selected as minimum capacity of the DG at bus B. Fig. 6 shows DG located at bus B and a phase-to-phase fault occurs at node A.

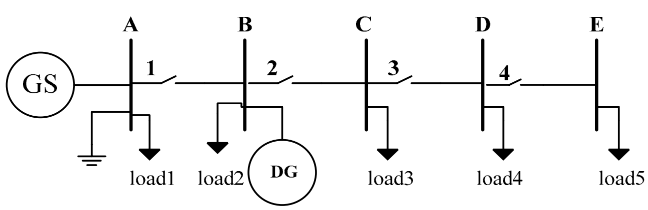

Fig. 6. Distribution system with DG located at bus B and a phase-to-phase fault occurs at bus A

Minimum capacity of DG at other bus determined similarly. After determining minimum and maximum capacity of DG for each bus, several DGs interconnected is investigated, e.g., DG2 and DG3 located at bus B, C respectively. Three phase fault occurs at bus A. Fig. 7 shows network in this position. Relay 1 should sense the fault current and operate before relay 2 and in order to keep the coordination, the operation time interval between relays 1 and 2 should be greater than or equal to CTI.

At first definite capacities of DG2 and DG3 are located at bus B and C respectively. Three phase fault occurs at node A. Now fault current flow through the relays 1 and 2 are recorded. Change the capacity of DG2 and DG3 and repeat the above section. Capacity of DG2 and DG3 are between maximum and minimum capacity that determined from previous section. Using the fault current recorded and equation 1, the operation time of relays 1 and 2 are calculated, for fault at bus A. The capacity of DGs that relay 1 operates before relay 2 and the operation time interval between relays 1 and 2 greater than or equal to CTI are selected.

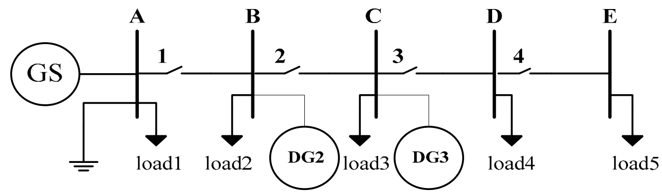

Fig. 7. Distribution system with DG2 and DG3 located at bus B, C and a three phase fault occurs at bus A

Fig. 8 shows DG2 and DG3 located at buses B and C respectively. Three phase fault occurs in front of relay 4. Fault current flow through the relays 3 and 4 are recorded. Change the capacity of DG2 and DG3 and repeat the above section. Capacities of DG2 and DG3 are capacity that determined from previous section. Using the fault current recorded and equation 1, the operation time of relays 3 and 4 are calculated, for fault at bus D. The capacity of DG is selected in a manner that the difference between operation times of relays 3 and 4 is greater than or equal to CTI.

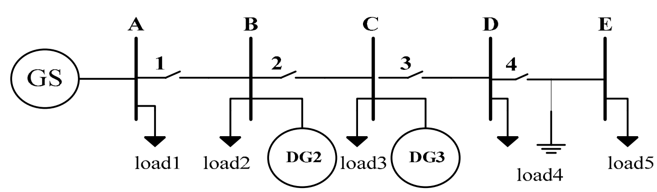

Fig. 8. Distribution system with DG2 and DG3 located at bus B and C and a three phase fault occurs in front of relay 4

V. Simulation Result

A typical 11kV radial distribution system with topology as shown in Fig. 9 is considered. All bus loads are 1MW. The power factor of DG is 0.9 lagging. For each feeder segment R= 0.25Ω/km, X=0.785Ω/km. Relays are coordinated without presence of DG. Relay 4 is set to operate instantaneously with operating time 0.02 and relay 1, 2 and 3 have TMS 0.39, 0.32 and 0.18. CTI is 0.3. For modeling of sample network DigSilent software is used.

In this paper three DGs located at bus A, B and C. Capacity of each DG can be 0.01, 0.1, 1, 2, 5, 7 and 10 MW. At first the minimum and maximum capacity of DG at mentioned buses are calculated. For example DG located at bus B and three phase fault in front of relay 4. Fault current flow through the relays 3 and 4 are recorded until operation time interval between relays 3 and 4 greater than or equal to CTI. Increase

DG capacity then three phase fault move in front of relay 3 and operation time of relays 2 and 3 are calculated.

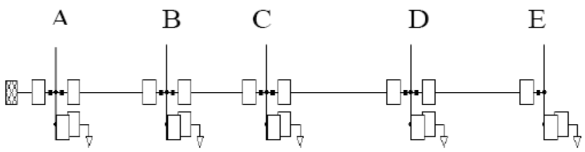

Fig. 9. Modeling sample network in DigSilent software

Table I shows results for a three phase fault in front of relay 4 and Table II shows the same ones for a three phase fault in front of relay 3. In Table I, t_3 and t_4 are the operating time of relays 3 and 4 respectively and Δt is difference between operating time of two relays. I_{CD} is fault current at line CD when the DG is installed at node D. In Table II, t_2 is operating time of relay 2.

TABLE I
OPERATION TIME OF RELAYS FOR THREE-PHASE FAULT IN FRONT OF RELAY 4

DG Capacity(MW)	$I_{CD}(A)$	$t_3(s)$	$t_4(s)$	Δt (s)
0.01	1200	0.651	0.02	0.631
0.1	2290	0.482	0.02	0.452
1	2740	0.45	0.02	0.42
2	3800	0.4	0.02	0.38
5	5500	0.356	0.02	0.326
7	6360	0.341	0.02	0.321
10	7050	0.331	0.02	0.311

TABLE II
OPERATION TIME OF RELAYS FOR THREE-PHASE FAULT IN FRONT OF RELAY 3

DG Capacity(MW)	$I_{CD}(A)$	$t_2(s)$	$t_3(s)$	Δt (s)
0.01	1260	1.43	0.634	0.796
0.1	2510	0.982	0.465	0.517
1	3060	0.9	0.432	0.468
2	4450	0.777	0.38	0.397
5	7850	0.642	0.321	0.321
7	8410	0.629	0.315	0.314
10	9670	0.603	0.303	0.3

From the results presented in Tables I and II, it can be seen that maximum capacity can be located at bus B is 10 MW. For determining minimum capacity of DG at bus B, phase to phase fault occurs at node A. Relay 1 operation is shown in Table III. In Table III, I_{BA} is fault current at line BA.

TABLE III
OPERATION TIME OF RELAY FOR PHASE-PHASE FAULT AT NODE A

DG Capacity(MW)	$I_{BA}(A)$	operation=1 Miss operation=0
0.01	170	0
0.1	370	1
1	681	1
2	1120	1
5	2420	1
7	2930	1
10	3850	1

Table III shows minimum capacity of DG that can be located at bus B is 0.1 MW. The above procedure is repeated for buses A and C. Table IV shows maximum and minimum capacity of DGs that can be located at bus A, B and C.

TABLE IV
DG CAPACITY

Bus	*Minimum capacity (MW)*	*Maximum capacity (MW)*
A	0	1
B	0.1	10
C	0.1	2

After determining maximum and minimum capacity of DG at bus A, B and C individually, one DG located at bus B and another at bus C. Three phase fault occurs at node A. Operation time of relay 1 and relay 2 are calculated. For this fault, relay 1 should be operated before relay 2. Table V and Table VI show the obtained results. In Table V and Table VI, I_{BA} is fault current at line BA and I_{CB} is fault current at line CB, t_1 and t_2 are the operating time of relay 1 and relay 2, respectively, and Δt is difference between operating time of two relays. After determining the capacity of DG from previous section, three phase fault occurs in front of relay 4 and operating time of relays 3 and 4 for these capacities are determined.

TABLE V
THREE PHASE FAULT AT NODE A AND TWO DGS AT BUSES B AND C

state	*DGB capacity(MW)*	*DGC capacity(MW)*	I_{BA} (A)	I_{CB} (A)
1	0.1	0.1	5070	3370
2	0.1	1	3970	2190
3	0.1	2	4960	3250
4	1	0.1	5510	3300
5	1	1	4460	2130
6	1	2	5400	3180
7	2	0.1	5320	1540
8	2	1	5680	2010
9	2	2	6520	3010
10	5	0.1	8450	1310
11	5	1	8700	1720
12	5	2	9320	2580
13	7	0.1	8950	1270
14	7	1	9190	1670
15	7	2	9770	2510
16	10	0.1	1011	1180
17	10	1	1032	1550
18	10	2	1082	2340

TABLE VI
OPERATION TIME OF RELAYs FOR THREE PHASE FAULT AT NODE A AND TWO DGS AT BUSES B AND C

state	$t_2(s)$	$t_1(s)$	$1 = t_1 < t_2$ $0 = t_1 > t_2$	$\Delta t(s)$
1	0.865	1.003	0	___
2	1.047	1.108	0	___
3	0.878	1.012	0	___
4	0.872	0.972	0	___
5	1.06	1.164	0	___
6	0.886	0.98	0	___
7	1.264	0.985	1	0.279
8	1.093	0.961	1	0.132
9	0.906	0.914	0	___
10	1.396	0.837	1	0.559
11	1.187	0.829	1	0.358
12	0.970	0.811	1	0.16
13	1.424	0.821	1	0.603
14	1.207	0.814	1	0.393
15	0.982	0.799	1	0.183
16	1.496	0.790	1	0.706
17	1.259	0.785	1	0.474
18	1.015	0.774	1	0.241

The capacities that difference between operating time of relays is greater than CTI are accepted. Table VII shows the results.

TABLE VII
OPERATION TIME OF RELAYS FOR THREE-PHASE FAULT IN FRONT OF RELAY 4 AND TWO DGS AT BUSES B AND C

DG capacity(MW)	DGC capacity(MW)	I_{CD} (A)	$t_3(s)$	$t_4(s)$	$\Delta t(s)$
5	0.1	7200	0.329	0.02	0.309
5	1	7570	0.324	0.02	0.304
7	0.1	7480	0.325	0.02	0.305
7	1	7850	0.319	0.02	0.299
10	0.1	8100	0.318	0.02	0.298
10	1	8400	0.315	0.02	0.295

With presence of DG at bus B and C, another DG located at bus A. Fault located in front of relay 4 and operation of relays 3 and 4 investigated. Finally, we consider seven different modes for the capacity that presence DG with these capacities keeps coordination of relay in network. The capacity of DG is shows in Table VIII.

TABLE VIII
DG CAPACITY

state	*DGA(MW)*	*DGB(MW)*	*DGC(MW)*
1	0.01	5	0.1
2	0.01	5	1
3	0.01	7	0.1
4	0.1	5	0.1
5	0.1	5	1
6	0.1	7	0.1
7	1	5	0.1

VI. CONCLUSION

Distributed generators in distribution network cause loss of coordination of relays. e.g., in distribution network with DG for downstream fault operation of relay may be interface and for upstream fault miss operation of relay for fault current is possible. To solve this problem, in this paper a method for determining the distributed generators capacity has been suggested that these units do not cause loss of coordination of relays. The capacities of DGs are determined as follows:

(1) Various capacity of DG located at mentioned bus. For downstream fault operation of relays may be interface.

For any downstream fault determining maximum capacity of DG, the minimum of these maximums determine maximum capacity of DG for that bus.

(2) Various capacity of DG located at mentioned bus. For upstream fault miss operation of relay for fault current is possible. For any upstream fault determining minimum capacity of DG, the maximum of these minimums determine minimum capacity of DG for that bus.

(3) Several DG located at bus together. In this state investigate operation of relays.

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