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Planning the Coordination of Directional Overcurrent Relays for Distribution Systems Considering DG

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***Abstract*—Introduction of distributed generation (DG) to the power system may lead to nonselective protection actions. For every future DG installation, the relay settings need to be modified to guarantee protection coordination that can lead to numerous changes in relay settings. This paper presents a novel approach to plan relay protection coordination considering future DG installations. Thus, this paper aims at proposing a method capable of optimally identifying one set of relay settings valid for all possible future DG planning scenarios. The proposed algorithm is formulated as a linear programming problem and the simplex algorithm is utilized to solve it. The proposed approach is tested on the distribution part of the modified meshed IEEE 14-bus system and the IEEE 13-bus radial test system. Comparative studies have been conducted to highlight the advantages of the proposed approach under various planning scenarios considering application of fault current limiters.**

***Index Terms*—Coordination time interval (CTI), fault current limiters (FCLs), linearization, protection coordination.**

I. Introduction

CONVENTIONAL unidirectional power flow between utility and consumer is no longer valid due to distributed generation (DG) interconnection. Furthermore, the direction of the fault current is also influenced by the introduction of DG to the system, which consequently affects the performance of protection devices. The protection system should isolate the minimum number of elements in a system in order to ensure secure operation of the unaffected part. In all types of distribution systems, for each fault location there exists a primary relay, which should operate as fast as possible, coordinated with a back-up relay. Traditionally radial systems are protected by overcurrent relays (OCRs) and fuses, however, meshed distribution systems are protected using directional OCRs (DOCRs). Installation of the DG units influences both the level and direction of short circuit currents, which may lead to nonselective protection actions. Consequently, the relay settings have to be frequently revised to accommodate for sequential increase in DG penetration.

Different optimization techniques can be employed to determine the settings of the relays. Several formulations have been proposed in order to solve the protection coordination problem. In [1] and [2], the problem is formulated as a linear programming (LP) problem with pick-up current settings defined as the parameters. On the contrary, in [3], the protection coordination problem is formulated as a nonlinear programming (NLP) problem with both relay settings being the decision variables of the problem. Additionally, in [4], a mixed integer NLP approach is presented. Finally, with respect to the formulation, deterministic or heuristic optimization techniques can be utilized to solve the protection coordination problem. According to the presented formulations those techniques include, two-phase simplex [5], sequential quadratic problem [3], genetic algorithm [6]–[7], particle swarm optimization [8], and evolutionary algorithm [9].

Majority of the work presented in the literature optimizes the relay settings assuming that the DG capacity is known [10]–[13]. One major problem is that the optimized relay settings in such case will only be valid for those specific DG capacities. In other words, any new DG addition will require an update to the existing relay settings [14], [15]. The studies proposed in [7], [12], [14], and [15] consider a predefined DG capacity and thus any changes in the DG capacity will require modifications in the existing relay settings. With the current interest in smart grids, it is expected that there will be more frequent interconnection of DGs, which in such case will result in numerous changes in relay settings. In order to plan smart grids, taking into account future possible DGs, a different approach to the protection coordination problem needs to be developed that can plan the relay settings such that the number of changes in a protection system is minimized.

This paper proposes a novel method to determine the optimal settings of the DOCRs that are feasible for all possible future DG capacities. Consequently, it provides to the utility planners one set of relay settings valid for different capacities of DG units varying between zero and the maximal desired capacity. The protection coordination problem is formulated as a LP problem and is solved using the simplex algorithm. A comparative analysis is conducted to highlight the number of changes in protection system required to accommodate for changes of DG capacities if the settings are not well planned. The simulations are conducted on the distribution part of the modified IEEE 14-bus system and the IEEE 13-bus

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radial distribution system. The structure of this paper can be described as follows. First, the formulation of the optimization problem is presented and described. The following section describes the test system under study and the optimization techniques used to solve the formulated problem. Thereafter, the results of the conducted simulations are presented. The penultimate section examines the influence of the fault current limiters (FCLs) on the obtained results. The conclusion is drawn in the last section.

II. Proposed Formulation for Planning Protective Devices Settings

Planning studies typically determine the maximum DG capacity to be installed in distribution systems [10], [16], [17]. In distribution systems, the penetration level of DG usually increases gradually up to the maximum utility planned limit. Consequently, it is important to plan the settings of the protective devices that can cope with this gradual increase in DG penetration. In this paper, it is assumed that the maximum planned DG capacity by the utility at location n is known and will be denoted as $S_{\mathrm{DG}n_{\max}}$. The objective is to determine the relay settings that will maintain protection coordination among possible DG installations within $S_{\mathrm{DG}n_{\max}}$. For example, assuming that the maximum planned DG installation at a specific bus is 5 MVA, then the protective devices should guarantee proper coordination for DG capacities of values between 0 and 5 MVA (for example, relays should be coordinated for $1, 2, \ldots, 5$ MVA). As mentioned earlier, protection coordination studies only consider one set of DG capacities and thus there is no guarantee that the relays will be coordinated for other combinations of DG installations. To address this, the protection coordination optimization model is modified by including coordination constraints that correspond to all possible DG combinations (within the utility planned maximum capacity) as follows:

$$t^{b}_{ij,s} - t^{p}_{ij,s} \geq \mathrm{CTI}\ \forall i, j, s \tag{1}$$

where i denotes the fault location and j denotes the relay identifiers. The $t^{p}_{ij,s}$ and $t^{b}_{ij,s}$ are respectively the operating times of primary and back-up relay for the fault at location i and for combination s of DG capacities. The maximum limit on s will depend on the number of DG locations and the resolution by which the DG capacity is varied. For example, for a two DG case and considering 10% resolution the total number of all possible scenarios "s" will be 121. Coordination time interval (CTI) is a minimum required time between operation of primary and back-up relay and in this paper it is set to 0.2 s. In this paper, all DOCRs are equipped with an inverse time-current function, consistent with the IEC 255-3 Standard, which is represented by

$$t_{ij,s} = \mathrm{TDS}_j \frac{A}{\left(\frac{I_{\mathrm{SC}ij,s}}{I_{pj}}\right)^{B} - 1} \tag{2}$$

where I_{pj} denotes the predefined pick-up current setting of relay j, while $I_{\mathrm{SC}ij,s}$ is the short circuit current passing through relay j for fault location i and combination s of DG capacities. A and B are the relay characteristic constants, while TDS_j is the time dial setting for relay j. The objective of the optimization model is to minimize the total operating time of the primary and backup relays for all fault locations while satisfying the coordination constraints [14]. The equation below describes the objective function

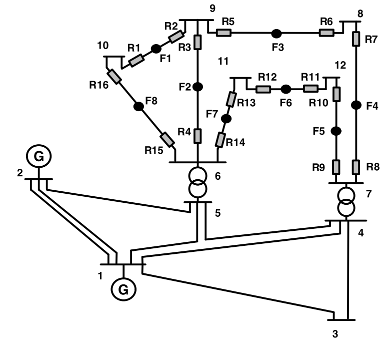

Fig. 1. Single line diagram of the modified IEEE 14-bus system for protection coordination studies.

$$\text{Minimize} \quad T_{OPR} = \sum_{i=1}^{N}\sum_{j=1}^{M}\sum_{s=1}^{L}\left(t^{p}_{ij,s} + t^{b}_{ij,s}\right) \tag{3}$$

where N is the set of all fault locations, M is the set of all system relays, and L is the set of all examined combinations. Furthermore, an additional set of constraints is imposed on the relay time dial settings as follows:

$$\mathrm{TDS}_{\min} \leq \mathrm{TDS}_j \leq \mathrm{TDS}_{\max}\ \forall j \tag{4}$$

where $\mathrm{TDS}_{\max}$ and $\mathrm{TDS}_{\min}$ are the upper and lower limits on the relay j time dial setting, respectively. $\mathrm{TDS}_{\max}$ and $\mathrm{TDS}_{\min}$ are set to 0.05 and 1, respectively. The values of the pick-up current settings are determined based on the maximum possible load current and the minimum short-circuit current passing through each relay.

III. System and Simulation Setup

This section presents the details about the test system under study and the developed algorithm with the respective utilized solver. The test systems under study are described in Section III-A. The latter Section III-B provides an insight into the proposed algorithm.

A. Description of the Test System Under Study

The presented simulations are performed on the distribution part of the modified IEEE 14-bus system shown in Fig. 1. The modified system is not equipped with reactive power compensators which are present in the IEEE 14-bus system. The transmission part of the system is supplied by the generators connected to buses 1 and 2. The distribution part of the system is fed through two transformers connected at buses 6 and 7. Detailed data of the system with the connected loads are given in [18]. The proposed approach is applied also to the IEEE radial 13-bus test system. Detailed data of the system are given in [19]. In the presented studies, all of the considered DG units are synchronous based generators with 9.67% subtransient reactance. Furthermore, all applied DG units are

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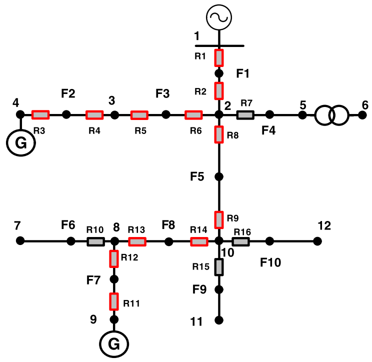

Fig. 2. Single line diagram of the IEEE 13-bus test system for protection coordination studies.

connected through step-up transformers with a 5% subtransient reactance. The meshed system is equipped with 16 DOCRs, corresponding to the indicators R1–R16 in Fig. 1 while the radial system is equipped with 12 DOCRs (marked in red) and four OCRs marked in Fig. 2.

Analysis is conducted for bolted symmetrical faults at the midpoint of each line in the distribution system. Fault locations are marked in Figs. 1 (for the IEEE 14-bus system) and 2 (for the IEEE 13-bus test system).

B. *Description of the Developed Algorithm and Solvers*

Fig. 3 illustrates a flowchart of the proposed approach for planning the relay settings. The parameters to be defined for the proposed algorithm include the planned maximum DG capacity at a desired locations, DG capacity resolution and predefined pick-up current settings. Since the algorithm is designed to satisfy the various possible DG combinations within the maximum planned capacity, the impedance matrix Z_{bus} is constructed for every s combination. Fault analysis is performed and the optimal TDS relays settings are determined using the simplex algorithm. The obtained settings can guarantee proper protection coordination for all DG sizes within the planned DG capacity. The simplex algorithm is considered one of the most popular algorithms used for solving LP problems. The constraints applied to the objective function form a convex polytope which determines the feasible region. The optimal solution is located at one of the polytope's vertices. The simplex algorithm begins at a specific vertex and searches along the edges of the polytope until it converges to the optimal solution. More details on the simplex algorithm can be found in [20].

It is worthy to note that the proposed approach considers three phase bolted faults while planning for the relays settings. The study can be further extended to consider zero sequence relays settings. In such case, the type of grounding as well as transformer connections will need to be taken into consideration. A comprehensive study that considers all type of faults will be considered in future work.

IV. Simulation Results

Two case studies are presented in this section to highlight the advantages of the proposed approach. For the first

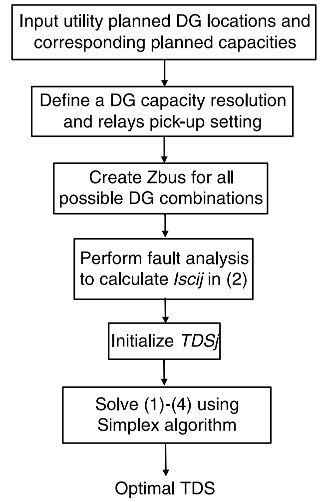

Fig. 3. General flowchart of the proposed approach.

TABLE I
OPTIMAL DOCRs SETTINGS FOR DG UNITS AT BUSES 6 AND 7 CONSIDERING A FIXED DG SIZE

Relay	DG at bus: 6, 7					
	Size 1: 3MVA	Size 2: 3MVA	Size 1: 4MVA	Size 2: 4MVA	Size 1: 5MVA	Size 2: 5MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.12674377	0.378	0.1280975	0.378	0.1293967	0.378
2	0.13229029	0.158	0.13338	0.158	0.1344126	0.158
3	0.10121522	0.3365	0.1026316	0.3365	0.104001	0.3365
4	0.16990667	0.0375	0.1720032	0.0375	0.1740314	0.0375
5	0.13710101	0.3165	0.1386175	0.3165	0.1400746	0.3165
6	0.09619516	0.0845	0.0970732	0.0845	0.0979008	0.0845
7	0.13638221	0.4925	0.1380362	0.4925	0.1396285	0.4925
8	0.11757575	0.1025	0.1183346	0.1025	0.1190452	0.1025
9	0.11479315	0.2785	0.1159466	0.2785	0.1170517	0.2785
10	0.13927003	0.1195	0.1404683	0.1195	0.1416046	0.1195
11	0.1328078	0.2945	0.1341552	0.2945	0.1354443	0.2945
12	0.11840677	0.236	0.1194606	0.236	0.1204653	0.236
13	0.20201747	0.042	0.203743	0.042	0.2053953	0.042
14	0.07995988	0.2795	0.081435	0.2795	0.0828707	0.2795
15	0.13825935	0.2155	0.1396357	0.2155	0.140951	0.2155
16	0.10428847	0.1535	0.1052791	0.1535	0.1062222	0.1535

case study, the protective devices are optimally coordinated considering only the maximum planned DG capacities. On the other hand, the second case study takes into account possible combinations of DG capacities within the maximum planned amount (the proposed approach). For comparison the results of four scenarios that consider two DG locations are examined.

A. *Optimal DOCRs Settings—Case 1 for the IEEE 14-Bus System*

In this case study, it is assumed that there are two candidate locations for DG installation. Tables I, III, and IV present the optimal settings obtained considering three scenarios with different DG locations. Table I considers buses 6 and 7 to be the candidate DG locations. By examining the three scenarios presented in Table I it can be seen that the optimal TDS settings will vary depending on the amount of DG capacity planned for each location. Similar conclusions can be drawn from Tables III and IV. Thus, if a system is designed considering a fixed DG size of 3 MVA an additional 1 or 2 MVA

TABLE II
NUMBER OF POSSIBLE VIOLATIONS CONSIDERING A 10% DG CAPACITY RESOLUTION

Buses:	No. of violatons
6 and 7	263
9 and 12	627
8 and 11	508

TABLE III
OPTIMAL DOCRS SETTINGS FOR DG UNITS AT BUSES 9 AND 12 CONSIDERING A FIXED DG SIZE

Relay	DG at bus: 9, 12					
	Size 1: 3MVA	Size 2: 3MVA	Size 1: 4MVA	Size 2: 4MVA	Size 1: 5MVA	Size 2: 5MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.1351669	0.378	0.1385444	0.378	0.14158113	0.378
2	0.1350289	0.158	0.1368121	0.158	0.13844457	0.158
3	0.0996268	0.3365	0.1004614	0.3365	0.10122898	0.3365
4	0.1561976	0.0375	0.1536316	0.0375	0.15096404	0.0375
5	0.1333147	0.3165	0.133473	0.3165	0.13353809	0.3165
6	0.1374111	0.0845	0.1492191	0.0845	0.15993039	0.0845
7	0.1317551	0.4925	0.1318293	0.4925	0.13183254	0.4925
8	0.1474862	0.1025	0.1564893	0.1025	0.16475104	0.1025
9	0.1280613	0.2785	0.1323002	0.2785	0.13603256	0.2785
10	0.1439137	0.1195	0.1463698	0.1195	0.14863942	0.1195
11	0.135953	0.2945	0.1381529	0.2945	0.14020934	0.2945
12	0.1301765	0.236	0.1340598	0.236	0.13749672	0.236
13	0.1989696	0.042	0.1995103	0.042	0.19991413	0.042
14	0.0782125	0.2795	0.078874	0.2795	0.07939806	0.2795
15	0.142804	0.2155	0.1454476	0.2155	0.14792222	0.2155
16	0.1234578	0.1535	0.1288855	0.1535	0.13359928	0.1535

TABLE IV
OPTIMAL DOCRS SETTINGS FOR DG UNITS AT BUSES 8 AND 11 CONSIDERING A FIXED DG SIZE

Relay	DG at bus: 8, 11					
	Size 1: 3MVA	Size 2: 3MVA	Size 1: 4MVA	Size 2: 4MVA	Size 1: 5MVA	Size 2: 5MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.1282060	0.378	0.1296586	0.378	0.1309023	0.378
2	0.1463127	0.158	0.1510929	0.158	0.1554278	0.158
3	0.1017478	0.3365	0.1030182	0.3365	0.10413115	0.3365
4	0.1672143	0.0375	0.1679741	0.0375	0.16853489	0.0375
5	0.1387656	0.3165	0.140219	0.3165	0.14140816	0.3165
6	0.1152833	0.0845	0.1213987	0.0845	0.12699639	0.0845
7	0.1365556	0.4925	0.1378918	0.4925	0.13903661	0.4925
8	0.1322126	0.1025	0.1370372	0.1025	0.14146157	0.1025
9	0.1188311	0.2785	0.1207304	0.2785	0.12234556	0.2785
10	0.1615635	0.1195	0.1686364	0.1195	0.17503921	0.1195
11	0.1341667	0.2945	0.1354336	0.2945	0.13645805	0.2945
12	0.1311083	0.236	0.1357875	0.236	0.1401471	0.236
13	0.2050387	0.042	0.2068434	0.042	0.20826874	0.042
14	0.0798417	0.2795	0.0810613	0.2795	0.08216438	0.2795
15	0.1415492	0.2155	0.1431106	0.2155	0.14430939	0.2155
16	0.1210127	0.1535	0.1267734	0.1535	0.13213372	0.1535

TABLE V
OPTIMAL DOCRS SETTINGS CONSIDERING A 10% DG CAPACITY RESOLUTION

Relay	Bus: 6, 7		Bus: 9, 12		Bus: 8, 11	
	Capacity 1: 5MVA	Capacity 2: 5MVA	Capacity 1: 5MVA	Capacity 2: 5MVA	Capacity 1: 5MVA	Capacity 2: 5MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.1349083	0.378	0.1555739	0.378	0.1485945	0.378
2	0.1437619	0.158	0.1488576	0.158	0.1711466	0.158
3	0.10682369	0.3365	0.1079575	0.3365	0.1146364	0.3365
4	0.17940245	0.0375	0.1767492	0.0375	0.190367	0.0375
5	0.14563463	0.3165	0.1483251	0.3165	0.1621554	0.3165
6	0.1103525	0.0845	0.1713097	0.0845	0.1391487	0.0845
7	0.1443666	0.4925	0.1456054	0.4925	0.1559872	0.4925
8	0.13063592	0.1025	0.1758456	0.1025	0.1546941	0.1025
9	0.12281901	0.2785	0.1494303	0.2785	0.1396022	0.2785
10	0.1529295	0.1195	0.1598099	0.1195	0.1905274	0.1195
11	0.14194303	0.2945	0.1475065	0.2945	0.1598306	0.2945
12	0.12789229	0.236	0.1563854	0.236	0.148828	0.236
13	0.21354815	0.042	0.2194908	0.042	0.2388257	0.042
14	0.08457326	0.2795	0.08792	0.2795	0.0891604	0.2795
15	0.14891671	0.2155	0.1558427	0.2155	0.1741584	0.2155
16	0.11440139	0.1535	0.1526254	0.1535	0.1401397	0.1535

at the same locations will require changes in the TDS settings to guarantee optimality. As can be seen all relays will experience a change in their settings with changes in installed DG capacity. Thus, for every additional DG installation utility operators will have to modify the settings of all relays. More important is the feasibility of the obtained settings. In order to highlight this Table II presents the number of constraint violations obtained considering changes in installed DG sizes with fixed relay settings. In other words, if the relay settings are planned considering a fixed DG size of 5 MVA at buses 6 and 7, DG sizes below that amount will result in 263 violations. Higher violations are even obtained for the other two scenarios. Thus, if the utility decides to plan the settings based on only the maximum planned DG capacities violations will occur. A possible solution to avoid this is to change the relays settings but this will require the utility operators to frequently change the settings across the whole system. To avoid any constraint violation as well as frequent changes in relay settings, the proposed method is applied and the results are given in the next section.

B. Optimal DOCRs Settings—Case 2 for the IEEE 14-Bus System

This section presents the settings of DOCRs considering possible combinations of DG capacities up to the planned amount. The same scenarios presented in Section IV-A are analyzed considering the proposed approach. Table V presents the optimal relay settings considering a maximum planned DG capacity of 5 MVA. By applying those optimal settings to the 3 and 4 MVA scenarios, it was found out that the number of violations is equal to zero. Thus, the proposed approach is capable of planning for one set of relay settings which can satisfy future growth in DG penetration. As can be seen in all tables, the pick-up current settings are fixed. In contrast to case 1, the optimal settings obtained for case 2 do not require modifications when DG installed sizes vary between zero and the planned maximum DG capacity. It is worthy to note that by comparing the results presented in Table V with the results presented in Section IV-A, a noticeable increase in the optimal TDS values is observed. Consequently, this will result in an increase in relay operating time, as the pick-up current settings are constant. The influence on the operating time will be highlighted in the next section.

C. Optimal DOCRs Settings—Cases 1 and 2 for the IEEE Radial 13-Bus Test System

The method is further tested on the IEEE 13-bus test system given in Fig. 2. It is worthy to note that radial systems are typically protected by OCRs or fuses. The addition of DG will result in a bidirectional flow of fault current. Thus, the protection system, in this paper, has been modified and certain

TABLE VI
OPTIMAL DOCRS SETTINGS FOR DG UNITS AT BUSES 4 AND 9 CONSIDERING A FIXED DG SIZE

Relay	DG at bus: 4, 9					
	Size 1: 0.5MVA	Size 2: 0.5MVA	Size 1: 1MVA	Size 2: 1MVA	Size 1: 2MVA	Size 2: 2MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.0553341	1.395	0.05	1.395	0.05	1.395
2	0.05	0.59	0.05	0.59	0.05	0.59
3	0.0801718	0.338	0.166929	0.338	0.24074241	0.338
4	0.05	1.285	0.05	1.285	0.05	1.285
5	0.0629586	0.33	0.1304533	0.33	0.18533417	0.33
6	0.060548	1.41	0.0653121	1.41	0.07065215	1.41
7	0.05	1.72	0.05	1.72	0.05	1.72
8	0.0628433	1.285	0.0720558	1.285	0.08328813	1.285
9	0.0700191	0.315	0.1272569	0.315	0.16713788	0.315
10	0.05	0.6675	0.05	0.6675	0.05	0.6675
11	0.1021773	0.335	0.1973092	0.335	0.27316966	0.335
12	0.05	1.015	0.05	1.015	0.05	1.015
13	0.0842345	0.33	0.1598422	0.33	0.21666818	0.33
14	0.0632595	1.085	0.0673226	1.085	0.07230968	1.085
15	0.05	1.33	0.05	1.33	0.05	1.33
16	0.05	1.415	0.05	1.415	0.05	1.415

TABLE VII
OPTIMAL DOCRS SETTINGS CONSIDERING A 10% DG CAPACITY RESOLUTION

Relay	Bus 4 and 9	
	Capacity 1 2MW	Capacity 2 2MW
	TDS,[s]	Ip,[p.u]
1	0.062275	1.395
2	0.05	0.59
3	0.2407424	0.338
4	0.05	1.285
5	0.1853342	0.33
6	0.0706521	1.41
7	0.05	1.72
8	0.0832881	1.285
9	0.1671379	0.315
10	0.05	0.6675
11	0.2731697	0.335
12	0.05	1.015
13	0.2166682	0.33
14	0.0723097	1.085
15	0.05	1.33
16	0.05	1.415

sections of the test system, depending on the DG location, are protected with DOCRs. For example, adding a DG at bus 4 will require relays between nodes 1 and 4 to be directional. On the other hand, relays between nodes 2 and 6 will not require any modification since the fault current in this section will flow in one direction. Fig. 2 presents the overall protection system for the modified IEEE 13-bus test system (all DOCRs are marked in red). Two DG units are connected at buses 4 and 9 where the relay settings are optimized considering fixed DG sizes of 0.5, 1, and 2 MVA.

The optimal relay settings will vary depending on the size of DG to be considered. Similarly, the obtained settings might not be feasible for all possible DG combinations. For example, if the relays are optimally set considering a fixed DG size of 2 MVA (settings provided in Table VI), the number of possible violations considering a 10% DG capacity resolution would equal 77. Table VII presents one set of optimal settings that considers all possible DG sizes below a maximum planned DG capacity of 2 MVA. To clarify, using such relay settings guarantees proper protection coordination for DG sizes up to 2 MVA.

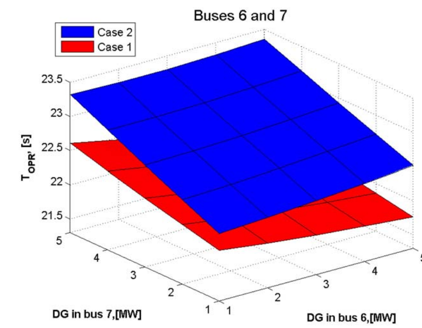

Fig. 4. Operating times for cases 1 and 2 with DG units located at buses 6 and 7 for the IEEE 14-bus system.

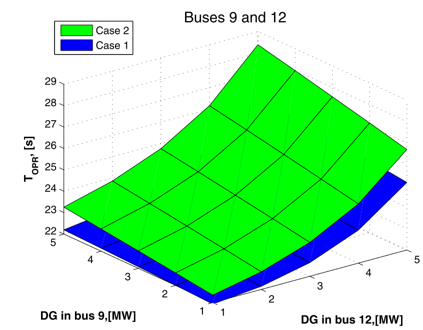

Fig. 5. Operating times for cases 1 and 2 with DG units located at buses 9 and 12 for the IEEE 14-bus system.

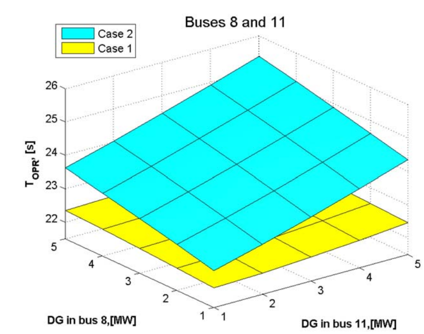

Fig. 6. Operating times for cases 1 and 2 with DG units located at buses 8 and 11 for the IEEE 14-bus system.

V. INFLUENCE OF THE PROPOSED APPROACH ON THE OPERATING TIME OF DOCRS

The benefits of the proposed formulation are highlighted in Section IV. However, in order to provide a comparative study Section V is devoted to examine the influence of the proposed approach on the relay operating time. Figs. 4–7 present the total operating time of all the primary and back-up relays for each possible combination of planned DG units. The operating time is calculated according to (2) defined in Section II.

Plots presented in Figs. 4–7 reveal the influence of the proposed approach on the total operating time of relays in a system. The total operating time presented in Figs. 4–7 is the sum of primary and back-up relays as given in (3). For each presented scenario the total operating time for case 2 is always higher than for case 1. The maximum relative increase in the total operating time for the presented scenarios are 5.5% (buses 6 and 7 for the IEEE 14-bus system),

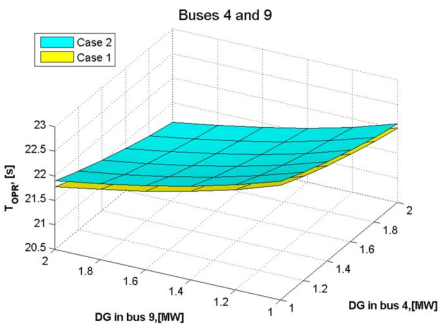

Fig. 7. Operating times for cases 1 and 2 with DG units located at buses 4 and 9 for the IEEE 13-bus test system.

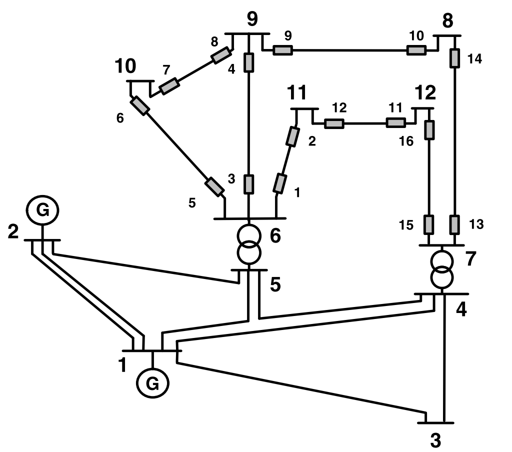

Fig. 8. Possible locations of FCL for the IEEE 14-bus system.

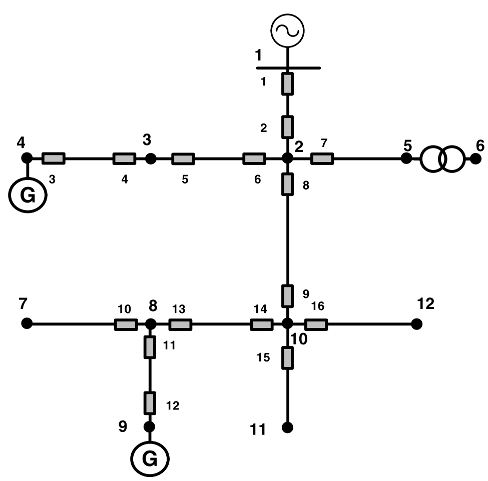

Fig. 9. Possible locations of FCL for the IEEE 13-bus test system.

9.3% (buses 9 and 12 for the IEEE 14-bus system), 12% (buses 8 and 11 for the IEEE 14-bus system), and 1.5% (buses 4 and 9 for the IEEE 13-bus test system). The presented results show that there is a tradeoff between utilizing one set of settings and relay operating time. The difference in the relay operating time will vary depending on the maximum DG capacity and thus the above figures can be useful for utility planners in the decision making process. Furthermore, the next section provides a possible solution that can mitigate the operating time increase caused by the proposed approach.

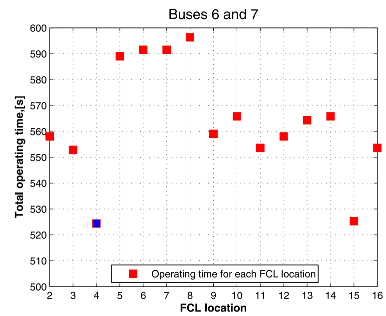

Fig. 10. Total DOCRs operating time as a function of FCL location for the IEEE 14-bus system and DG installed at buses 6 and 7.

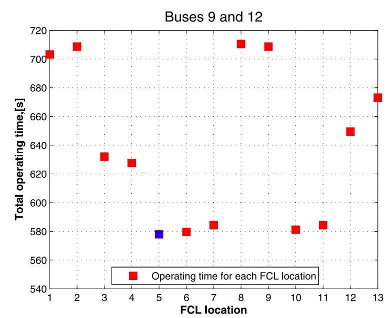

Fig. 11. Total DOCRs operating time as a function of FCL location for the IEEE 14-bus system and DG installed at buses 9 and 12.

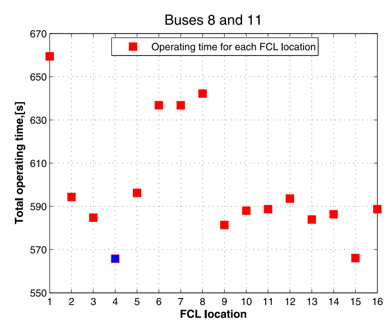

Fig. 12. Total DOCRs operating time as a function of FCL location for the IEEE 14-bus system and DG installed at buses 8 and 11.

VI. Influence of the Fault Current Limiters on the DOCRs Operating Time

The simulations conducted in this section examine the influence of the FCLs on the total operating time of the relays. The presented results examine whether it is possible to reduce the total operating time of the relays considering the settings determined in case 2. All possible system locations are examined and the reactance of each FCL is set equal to 1.5 Ω for the IEEE 14-bus system and 1 Ω for the IEEE 13-bus test system. Figs. 8 and 9 present all possible FCL locations for the test systems under study. The same scenarios, presented in Section IV, are examined. Figs. 10–13 present the total relay operating time considering all possible FCL locations for the systems under study. It is worthy to note that for each possible FCL location load flow analysis was conducted and voltage levels across all buses are determined and checked with [21].

The proposed formulation presented in Section II is applied to determine the total operating time T_{OPR} (primary and back-up relays) obtained for each DG set considering various

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

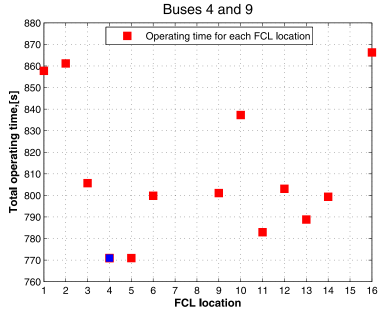

Fig. 13. Total DOCRs operating time as a function of FCL location for the IEEE 13-bus test system and DG installed at buses 4 and 9.

TABLE VIII
OPTIMAL DOCRS SETTINGS FOR SCENARIOS WITH DG UNITS INSTALLED AT BUSES 6 AND 7, 9 AND 12, AND 8 AND 11 AND A PREINSTALLED FCL FOR THE IEEE 14-BUS SYSTEM

Relay	Bus: 6, 7		Bus: 9, 12		Bus: 8, 11	
	FCL in line 6-9		FCL in line 6-10		FCL in line 6-9	
	Capacity 1: 5MVA	Capacity 2: 5MVA	Capacity 1: 5MVA	Capacity 2: 5MVA	Capacity 1: 5MVA	Capacity 2: 5MVA
	Optimal Settings		Optimal Settings		Optimal Settings	
	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]	TDS,[s]	Ip,[p.u]
1	0.1308416	0.378	0.1563254	0.378	0.1471362	0.378
2	0.1344155	0.158	0.1496261	0.158	0.1570474	0.158
3	0.1047128	0.3365	0.0974788	0.3365	0.1257798	0.3365
4	0.1752122	0.0375	0.1696766	0.0375	0.1443263	0.0375
5	0.1422822	0.3165	0.1499907	0.3165	0.1433665	0.3165
6	0.1169506	0.0845	0.1735938	0.0845	0.1255903	0.0845
7	0.1290255	0.4925	0.146004	0.4925	0.1490393	0.4925
8	0.1270627	0.1025	0.1774143	0.1025	0.1512851	0.1025
9	0.1267882	0.2785	0.1512159	0.2785	0.1327512	0.2785
10	0.1456178	0.1195	0.1600143	0.1195	0.1820927	0.1195
11	0.1305583	0.2945	0.1480579	0.2945	0.1502875	0.2945
12	0.121204	0.236	0.1574023	0.236	0.1468163	0.236
13	0.208744	0.042	0.2108587	0.042	0.2618316	0.042
14	0.0830953	0.2795	0.0941226	0.2795	0.0736489	0.2795
15	0.1442903	0.2155	0.1558933	0.2155	0.1657227	0.2155
16	0.1198604	0.1535	0.1551257	0.1535	0.1296311	0.1535

FCL locations. T_{OPR} for each particular DG set is summed and presented in Figs. 10–13.

As can be seen for the case of the IEEE 14-bus system where DGs are planned to be installed at buses 6–8 and 11 the optimum solution is to locate an FCL in lines 6–9. Similarly, it can be seen that lines 6–10 is the best location for FCL considering buses 9 and 12 to be the candidate DG locations. It should be noted that not all FCL locations provide feasible solutions, as seen in Fig. 10 location 1 is not among the possible FCL locations. Tables VIII and IX present the optimal relay settings corresponding to the optimal FCL locations for each set of DG locations. The provided settings guarantee proper coordination for DG units installed at the candidate locations up to the capacity of 5 MVA (for the IEEE 14-bus system) and 2 MVA (for the IEEE 13-bus test system). In order to highlight the effectiveness of the FCL addition, Figs. 14–17 provide a comparative analysis of the total relay operating time with and without FCL. For the IEEE 13-bus system, as seen in Fig. 13, the optimal location for the FCL is either location 4 or 5.

The impact of the FCL is highlighted in Figs. 14–17. It is worthy to note that the overall operating time presented in Fig. 10 (labeled in blue) corresponds to the summation of all the operating times presented in Fig. 14 (red plane). In other words multiple optimization problems are executed considering different DG size combinations where the optimal total operating times (including primary and back-up relays) for each DG set are summed and presented in Figs. 10–13. The results show that the FCL can significantly reduce the total

TABLE IX
OPTIMAL DOCRS SETTINGS FOR SCENARIOS WITH DG UNITS INSTALLED AT BUSES 4 AND 9 AND WITH A PREINSTALLED FCL FOR THE IEEE 13-BUS TEST SYSTEM

Relay	Bus 4 and 9	
	Capacity 1 2MW	Capacity 2 2MW
	TDS,[s]	Ip,[p.u]
1	0.053743	1.395
2	0.05	0.59
3	0.207351	0.338
4	0.05	1.285
5	0.160925	0.33
6	0.056213	1.41
7	0.05	1.72
8	0.077768	1.285
9	0.142991	0.315
10	0.05	0.6675
11	0.249807	0.335
12	0.05	1.015
13	0.193126	0.33
14	0.069857	1.085
15	0.05	1.33
16	0.05	1.415

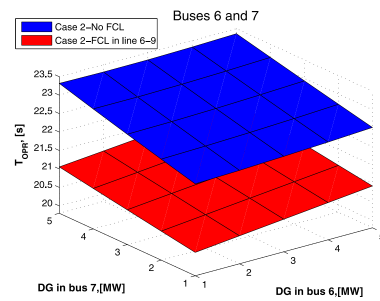

Fig. 14. Operating times for case 2 with and without FCL, with DG units located at buses 6 and 7 for the IEEE 14-bus system.

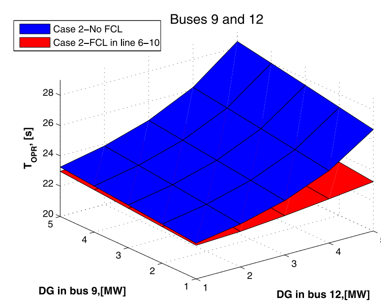

Fig. 15. Operating times for case 2 with and without FCL, with DG units located at buses 9 and 12 for the IEEE 14-bus system.

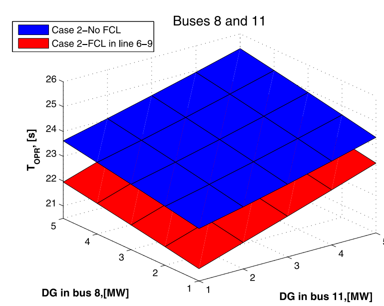

Fig. 16. Operating times for case 2 with and without FCL, with DG units located at buses 8 and 11 for the IEEE 14-bus system.

relay operating time for all scenarios under study. By planning the FCL location and by including additional constraints in the protection coordination problem, the utility planner can determine one optimal set of relay settings that guarantees proper coordination up to the planned DG capacity while

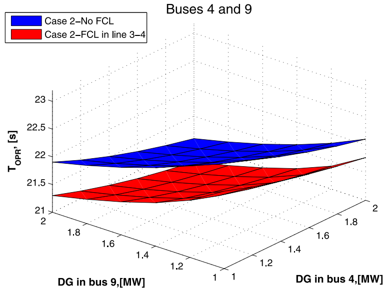

Fig. 17. Operating times for case 2 with and without FCL, with DG units located at buses 4 and 9 for the IEEE 13-bus test system.

minimizing the total operating time. To conclude, the main advantages of the proposed method are as follows.

1) The protection system settings do not need to be changed with varying DG penetration.
2) Since the settings determined are valid for DG capacities up to the planned value, the coordination of the protection system will be preserved during DG outage conditions.

VII. Conclusion

This paper proposes an approach for planning the settings of protective relays considering distribution system planning with DG. The results show that as the DG penetration increases with time possible violation in protection coordination can occur requiring frequent changes in relay settings. The proposed method avoids this problem by incorporating constraints that can guarantee protection coordination for DG capacities up to the maximum planned value (and not just for the rated value). By utilizing the proposed method and optimally allocating a FCL, one set of relay settings can be planned that can guarantee protection coordination up to the planned DG capacity while minimizing the overall relay operating time.

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