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A Graph Theory Approach for Placing Overcurrent Relays and Reclosers for Economical Protection of Meshed Transmission Networks

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***Abstract*—Penetration of the power grid by renewable energy sources, distributed storage, and distributed generators is becoming more widespread. Increased utilization of these distributed energy resources (DERs) has given rise to additional protection concerns. With radial feeders terminating in DERs or in microgrids containing DERs, standard non-directional radial protection may be rendered useless. Moreover, coordination will first require the protection engineer to determine what combination of directional and nondirectional elements is required to properly protect the system at a reasonable cost. In this paper, a method is proposed to determine the type of protection that should be placed on each line. Further, an extreme cost constraint is assumed so that an attempt is made to protect a meshed network using only overcurrent protection devices. A method is proposed where instantaneous reclosers are placed in locations that cause the system to temporarily become radial when a fault occurs. Directional and nondirectional overcurrent (OC) relays are placed in locations that allow for standard radial coordination techniques to be utilized while the reclosers are open to clear any sustained faults. The proposed algorithm is found to effectively determine the placement of protection devices while utilizing a minimal number of directional devices. Additionally, it was shown for the IEEE 14-bus case that the proposed relay placement algorithm results in a system where relay coordination remains feasible.**

Keywords— minimum breakpoint set (MBPS), directional relay, nondirectional relay, relay coordination

I. Introduction

The complexity of the power grid is rapidly increasing with the more common use of distributed energy resources (DERs) and microgrid structures containing DERs which are capable of both delivering and absorbing energy [1, 2, 3, 4]. DERs placed at the end of a radial line intended only to deliver energy to the customer can cause issues with relays, especially if the DERs can discharge large amounts of energy upstream to the main grid [5]. If protection is not directional, in such a case, coordination of protection devices may become impossible.

As for microgrids, local area power systems may require that they be able to operate in islanded mode [6]. This forces any microgrid structure to have within it at least one DER capable of generating power. Therefore, possibly back-feeding into the main grid across the point of common coupling (PCC) between the grid and microgrid is a concern. Additionally, transmission systems are typically set up in a meshed topology and some microgrids such as remote outposts may require a meshed topology to avoid loss of service when under emergency conditions [7]. In such cases, simple non-directional inverse time overcurrent protection may not be feasible for some connections. Directional protection may be required for a portion, if not all, of the microgrid network.

For meshed transmission networks, distance relays are typically used. However, there is a substantial cost investment in utilizing distance relays versus overcurrent relays. As an example, consider the SEL series of relays shown in Table 1. The cheapest distance relay is almost 4 times more expensive than the most expensive overcurrent relay. On top of this cost, the distance relay requires the additional purchase of a voltage transformer (VT) for voltage measurements. Where the budget is limited, it would be useful to be able to use only overcurrent relays.

Table 1. SEL Relay Pricing.

Relay	Type	Cost Range	VT Req.
SEL-321	Distance	$7390-8136	Yes
SEL-551	Nondirectional OC	$910	No
SEL-851	Directional OC	$910-1872	No

In this paper, a method is proposed to protect a meshed transmission network using only overcurrent relays to reduce cost. The proposed method is initiated using the minimum breakpoint set (MBPS) algorithm detailed in [8]. First, for each line in the MBPS, instantaneous overcurrent (OC) reclosers are placed. Second, all the remote loads are identified to determine the placement of the nondirectional time overcurrent relays. Lastly, the remaining lines are assigned directional time overcurrent protection relays.

II. General Methods for Determining The Placement Protection Devices

As discussed in [9]- [10], optimal placement of protective and monitoring equipment can greatly enhance the reliability and power quality of a system. In this section, various methods for determining the placement of protective devices are discussed.

A. Optimal Relay Placement Considering Critical Clearing Times

In [10]- [11], a method for optimal placement of relays is proposed. This method takes critical clearing time into

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account. An optimization problem is constructed with the objective of minimizing the energy not supplied (ENS).

$$ENS = \sum_{j=1}^{N_c} \sum_{k=1}^{NIL} L_{kj} \times r_j \times \lambda_j \,, \tag{1}$$

where NIL is the number of isolated load points due to contingency j, N_c is the number of contingencies, L_{kj} is the curtailed load at load point due to contingency j, r_j is the average outage time due to contingency j, and λ_j is the average failure rate of contingency j. For relay coordination, the inverse definite minimum time (IDMT) characteristics are defined as

$$t = TMS\left[\frac{k}{(I/I_s)^a - 1} + c\right], \tag{2}$$

where t is the operating time for constant current I; I is the energizing current; I_s is the current tap setting; TMS is the time multiplier setting (time dial setting); and k,a,c are constants specific to the type of relay utilized. Relay coordination is constrained using

$$T_{backup} - T_{primary} \geq CTI, \tag{3}$$

where T_{backup} is the operating time of the backup relay; $T_{primary}$ is the operating time of the primary relay; and CTI is the coordination time interval assumed to be in the range of 0.3-0.4s for electromechanical relays and 0.1s-0.2s for digital relays. To aid in the reduction of ENS, [10]- [11] introduce the constraint

$$N_{sr}^{i} \leq K, \tag{4}$$

where $i = 1,...,n$; N_{sr}^{i} is the number of series relays in each branch of the graph; n is the number of branches in the graph; and K is the number of relays that can be coordinated together. Assume that there are n_k loads within zone k. Power stability within each zone k is enforced using,

$$\sum_{i=1}^{m_k} P_L^{i,k} \leq P_G^k \tag{5}$$

where m_k is the total number of loads within zone k; $P_L^{i,k}$ is the i^{th} load in zone k; and P_G^k is the total distributed generator capacitor in zone k. [10] solves this problem using particle swarm optimization (PSO).

For a further discussion of the graph theory/PSO-based algorithms introduced in [10], the reader is referred to this reference. The proposed methodology of [10]- [11] is effective for a radial system. However, it does not consider loops present in mesh systems.

B. Differential Zone Protection Scheme

A method is presented in [12] that focuses on differential protection and differentiates between the placement of sensors and relays to reduce cost. Define the total investment cost as

$$INVC = \sum_{\substack{i \\ i \neq j}} \sum_{j} D_{ij} cost_R + \sum_{i} [(D_{ii} - DG_{ii}) cost_S + \tag{6}$$

where $cost_R$ is the investment cost per relay; $cost_s$ is the investment cost per sensor; D is the protection device matrix; and DG is the diagonal distributed generation matrix. D is defined as

$$D_{ij} = \begin{cases} 1, \text{if sensor/relay device present on line } ij \\ 0, \text{if no device present on line } ij \end{cases}, \tag{7}$$

$$D_{ii} = \begin{cases} 1, \text{if sensor/relay present at bus } i \\ 0, \text{if no device present on line } i \end{cases}. \tag{8}$$

The diagonal matrix DG is defined as

$$DG_{ii} = \begin{cases} 1, \text{generation presnet at bus } i \\ 0, \text{otherwise} \end{cases}. \tag{9}$$

The sensor locations are computed as

$$S = diag(D) - DG \tag{10}$$

and the relay locations are

$$R = D - S. \tag{11}$$

The customer interruption cost is

$$CIC = \sum_{j=2}^{n} \sum_{i=1}^{j-1} \lambda_{ij} l_{ij} \left(\sum_{k=1}^{n} IC_{ijk} L_k \right), \tag{12}$$

where n is the total number of nodes, λ_{ij} is the outage rate of segment ij in failures per year/km, l_{ij} is the length of line segment ij, IC_{ijk} is the interruption cost for the load at node k due to an outage in line segment ij, and L_k is the total load at node k. The overall goal of the algorithm introduced in [12] is to solve

$$\min_{D} INVC + CIC \,, \tag{13}$$

$$\text{s.t} \quad D = diag(C) + C - diag(C). \tag{14}$$

The constraint of this optimization enforces the requirement that each bus must have a device on either its secondary side or on each line connected to it to adequately detect faults. [12] utilizes the genetic algorithm (GA) to solve (13)-(14).

One benefit of the method proposed in [12] is that it allows for a minimum number of relays to be placed within a microgrid to reduce cost. Additionally, this method does allow for application to meshed systems. However, this method requires differential protection elements to be placed throughout the system. It also requires communication with a centralized controller.

In this paper, a method is proposed which may be applied using overcurrent elements which may also be applied to mesh grids. Additionally, the proposed method requires no communication.

III. Proposed Method

For the proposed method a graph representation is utilized. Each bus is represented by a node and each line element is represented by an edge. The proposed method is summarized as follows:

1) Determine the MBPS using some algorithm (that proposed in [8] is used for the examples in this paper). Instantaneous OC reclosers are placed on each line in the MBPS.
2) Remove the MBPS from further consideration
3) Find all nodes in the graph with degree 1 (leaves)
    a. If none exist, go to Step 5.
4) For each leaf, determine whether generation is present
    a. If generation is not present, place a non-directional time OC relay on the line connected to this leaf. Remove this node from further consideration.
    b. Return to Step 3.

5) Assign all remaining lines directional time OC relays.

The algorithm is summarized in Fig. 1. The instantaneous OC reclosers should be set to open sufficiently long for the remaining radial network to clear the fault. Note that only all reclosers may not open at once if there is a fault. This will depend upon the location and magnitude of the fault. However, it is only required that the system be made radial in sufficiently close proximity to the fault in question so that lines experiencing fault level currents have the opportunity to trip.

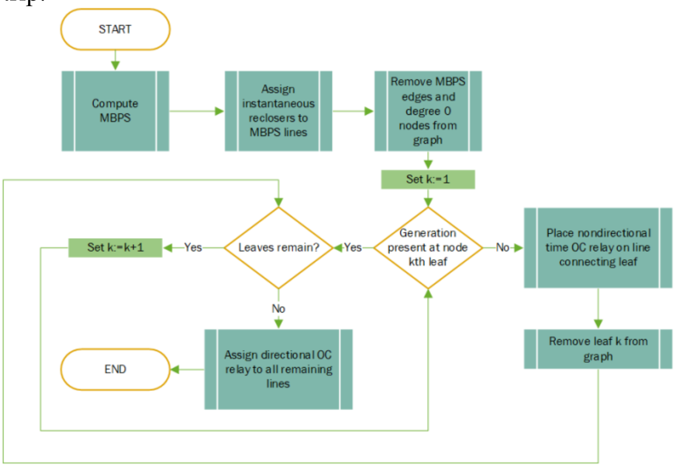

Fig. 1. Flowchart for the proposed algorithm. Note that the number of leaves may increase as the algorithm progresses.

A. Bus Fault

An unintended side effect of the proposed scheme is that if there is a fault directly at a bus, the system is guaranteed to sectionalize to clear the fault. After the first shot of the recloser, all lines directly connected to the faulted bus will trip (or on subsequent shots depending upon the current level). Then, the reclosers will close creating another fault path. This will repeat until the reclosers time out creating a sectionalized system with no loops. The exception to this phenomenon is where the fault is temporary (self-clearing).

B. Line Fault Not on MBPS Line

For a line fault not on an instantaneous recloser line, the reclosers will open when a fault occurs and the relay on the line where the fault is located will trip to clear the fault during one of the shots while the reclosers are open. Once the fault has cleared, the system will remain connected as long as the fault current is sufficient to clear the line before the final shot of the reclosers. Loops may remain in the final state.

C. Line Fault on MBPS Line

If the fault occurs on a recloser line, the reclosers will repeatedly shoot until they remain open. This will create a radial system where all lines in the MBPS are open. The system will remain connected. However, in this final state, the system will be radial assuming all reclosers experience fault-level current.

D. Oscillations

Due to all reclosers opening at once, transients may be substantial during the reclosing and clearing process. Transient stability during this process will be examined further in future work.

IV. Results

The proposed algorithm is applied to the IEEE 14-, 30-, and 57-bus test cases. In each case, the lines (edges) are classified as requiring nondirectional OC relays, directional OC relays, or instantaneous reclosers. For the IEEE-30-bus case, the thermal line limits detailed in [13] are enforced when determining the MBPS in Step 1 of the proposed method. For the remaining cases, thermal line limits are not considered.

A. IEEE 14-Bus Relay Placement Results

For the IEEE 14-bus test case, the placement of protection devices based upon the proposed algorithm is shown in Fig. 2. Note that generation is present at buses 1, 2, 3, 6, and 8. It can be seen from Fig. 2. that if all instantaneous reclosers are removed, a single radial network remains.

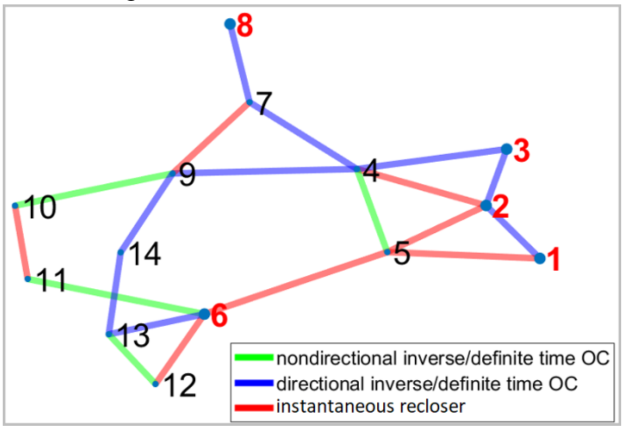

Fig. 2. Relay placement for IEEE 14-bus test case. Generator nodes are labeled with red text and larger node sizes.

B. IEEE 30-Bus Relay Placement Results

For the IEEE 30-bus test case, the placement of protection devices based upon the proposed algorithm is shown in Fig. 3. Note that generation is present at buses 1, 2, 5, 8, 11, and 13. It can be seen from Fig. 3. that if all instantaneous reclosers are removed, a single radial network remains.

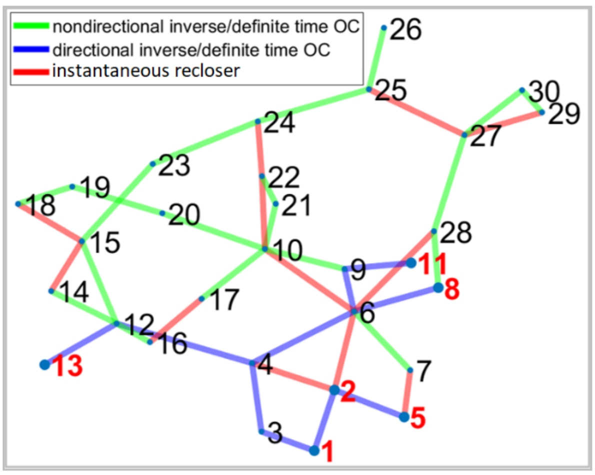

Fig. 3. Relay placement for IEEE 30-bus test case. Generator nodes are labeled with red text and larger node sizes.

C. IEEE 57-Bus Relay Placement Results

For the IEEE 57-bus test case, the placement of protection devices based on the proposed algorithm is shown in Fig. 4. Note that generation is present at buses 1, 2, 3, 6, 8, 9, and 12. It can be seen from Fig. 4. that if all instantaneous reclosers are removed, a single radial network remains.

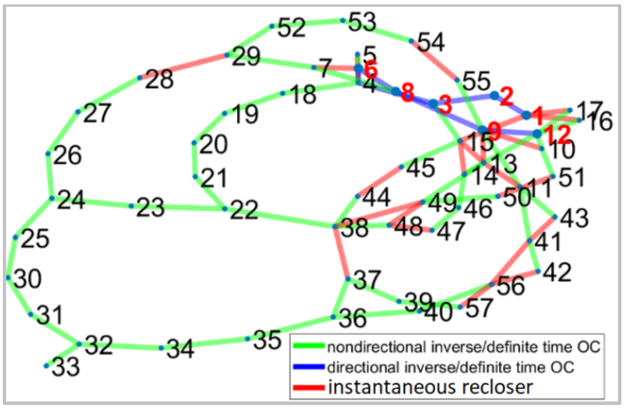

Fig. 4. Relay placement for IEEE 57-bus test case. Generator nodes are labeled with red text and larger node sizes.

D. IEEE 14-Bus Relay Coordination Results

For the IEEE 14-bus case, the optimal coordination settings were also computed using GA. A CTI (coordination time interval) of 0.25s was chosen. An optimal coordination is successfully computed for the result of Fig. 2. The results are summarized for the phase and ground settings in Table 2 and Table 3 respectively.

Table 2. IEEE 14-bus phase settings.

Location		Phase Settings			
From	To	Pickup (A)	TDS	Type	Description (US)
1	2	515.3	1.8	U4	Extremely inverse
2	1	352.5	0.1	DT	Definite time
2	3	597.5	1.9	U1	Moderately inverse
3	2	31.0	0.4	DT	Definite time
3	4	162.8	11.6	U5	Short-time inverse
4	3	150.4	0.7	DT	Definite time
4	5	40.8	4.3	U5	Short-time inverse
4	7	83.2	10.5	U5	Short-time inverse
7	4	393.0	1	DT	Definite time
7	8	83.2	2	U5	Short-time inverse
8	7	393.0	1.3	DT	Definite time
4	9	168.7	7.5	U4	Extremely inverse
9	4	30.0	1	DT	Definite time
9	10	56.6	1.6	U4	Extremely inverse
9	14	45.8	4.9	U1	Moderately inverse
14	9	68.8	1.3	DT	Definite time
13	14	68.9	5.6	U1	Moderately inverse
14	13	30.0	0.9	DT	Definite time
13	12	33.3	0.1	DT	Definite time
6	13	169.6	1.1	U4	Extremely inverse
13	6	30.0	0.6	DT	Definite time
6	11	39.5	3	U5	Short-time inverse
1	5	351	-	IT	Instantaneous
2	4	259	-	IT	Instantaneous
2	5	191	-	IT	Instantaneous
5	6	211	-	IT	Instantaneous
6	12	35	-	IT	Instantaneous
7	9	10	-	IT	Instantaneous
10	11	26	-	IT	Instantaneous

Table 3. IEEE 14-bus ground settings.

Location		Ground Settings			
From	To	Pickup (A)	TDS	Type	Description
1	2	25.4	10.2	U4	Extremely inverse
2	1	153.3	0.6	DT	Definite time
2	3	18.9	5.5	U4	Extremely inverse
3	2	6.0	0.6	DT	Definite time
3	4	5.0	5.8	U1	Moderately inverse
4	3	7.5	1	DT	Definite time
4	5	5.0	4.9	U4	Extremely inverse
4	7	68.9	7.7	U4	Extremely inverse
7	4	7.8	1.3	DT	Definite time
7	8	68.9	6.7	U4	Extremely inverse
8	7	8.0	1.9	DT	Definite time
4	9	8.4	5.9	U1	Moderately inverse
9	4	9.6	1	DT	Definite time
9	10	5.0	7.7	U4	Extremely inverse
9	14	45.8	5.4	U4	Extremely inverse
14	9	5.0	1.3	DT	Definite time
13	14	5.0	10.2	U1	Moderately inverse
14	13	5.0	1	DT	Definite time
13	12	5.0	0.3	DT	Definite time
6	13	5.0	9.4	U3	Very inverse
13	6	12.2	0.3	DT	Definite time
6	11	5.0	12.7	U2	Inverse

Example phase and ground settings for The IEEE 14-bus system are summarized in Table 2 and Table 3 respectively. U1-U5 represent the SEL inverse overtime relay curves. DT represents a definite time OC relay and IT represents an instantaneous OC relay. The relays are placed as shown in Fig. 2. Instantaneous overcurrent reclosers are placed on the lines marked in red in Fig. 2. The instantaneous relay pickup settings are set to 125% of the steady-state current for the meshed state (all reclosers closed).

The pickup settings for the inverse and overtime overcurrent relays are set to

$$\max\left(I_{SS}^{meshed}, I_{SS}^{radial}\right), \quad (15)$$

I_{SS}^{meshed} is the steady state current when the networks is in the meshed state (all reclosers closed) and I_{SS}^{radial} is the steady state current when the network is radial (all reclosers open). Note that the “reclosers” here may be either be reclosers or relays with recloser capability. In either case, operation time is set to instantaneous. The operating times for all relays, except the instantaneous relays, were delayed by the operating time of the instantaneous relays. The delay in the operating times of the time overcurrent relays allows the instantaneous relays to operate first and convert the meshed system to a radial network where a fault can be cleared by the time overcurrent relay.

V. Conclusions

The proposed method was found to accurately determine the necessary placement of protection devices for the 3 meshed grids tested. For the IEEE 30- and 57-bus test cases, the generators were in closer proximity (in terms of the number of lines/impedances separating them) so that most of the system was able to be protected using nondirectional protection. For the IEEE 14-bus case, the generators were more spread out which resulted in directional relays dominating this system (excluding the instantaneous OC reclosers). However, nondirectional relays were still able to be utilized in some sections of this system. Overall, the proposed algorithm was found to accurately determine the placement of protection devices utilizing as few directional devices as possible. The proposed methodology is recommended for cases where economical resources are exceptionally scarce. Otherwise, more expensive devices such as distance relays should be utilized.

For the IEEE 14-bus case, an optimal relay coordination was applied to the proposed relay placement. The optimal relay coordination was successfully computed showing that the proposed relay placement scheme is feasible as it relates to relay coordination.

This paper focused on the placement of directional and nondirectional relays. However, the switching associated with the triggering of multiple reclosers at once has not been examined. In future work, transient analysis will also be considered for the proposed protection scheme.

For the method proposed in this paper, it is assumed that relays are placed on each line of the system. In future work, sparce placement of relays as is discussed in [14, 15] will also be explored.

VI. Appendix: Detailed Results For IEEE 57-Bus Test Case

Due to the size of the system, additional data are provided for clarity of the results displayed in Fig. 4 for the IEEE 57-bus case.

Table 4. IEEE 57-bus results: nondirectional OC relay locations.

Nondirectional time OC relay locations		Nondirectional time OC relay locations		Nondirectional time OC relay locations	
from	to	from	to	from	to
6	5	26	24	43	11
8	7	27	26	44	38
11	9	28	27	45	15
12	10	29	7	46	14
13	12	30	25	47	46
14	13	31	30	48	38
15	3	32	31	49	13
16	12	33	32	50	49
17	12	34	32	51	10
18	4	35	34	52	29
19	18	36	35	53	52
20	19	37	36	54	53
21	20	38	22	55	9
22	21	39	37	56	40
23	22	40	36	57	39
24	23	41	11		
25	24	42	41		

Table 5. IEEE 57-bus results: directional OC relay locations.

Directional time OC relay locations		Directional time OC relay locations	
from	to	from	To
1	2	6	8
2	3	8	9
3	4	9	12
4	6		

Table 6. IEEE 57-bus results: instantaneous OC recloser locations.

Nondirectional instantaneous OC relay locations		Nondirectional instantaneous OC relay locations		Nondirectional instantaneous OC relay locations	
from	to	from	to	from	to
1	15	13	15	48	49
1	16	14	15	50	51
1	17	28	29	54	55
4	5	37	38	56	41
6	7	38	49	56	42
9	10	41	43	57	56
9	13	44	45		
11	13	47	48		

VII. Acknowledgment

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