Protection coordination for a distribution system in the presence of distributed generation

Muhammad YOUSAF*, Tahir MAHMOOD
Department of Electrical Engineering, University of Engineering and Technology Taxila, Taxila, Pakistan

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Abstract: This paper proposes an effective strategy to overcome the impacts on coordination among protection devices due to distributed generator (DG) integration. Increased fault current magnitude and changes in power flow directions are the major impacts imposed by DGs on a typical distribution system. The recloser-fuse coordination is much influenced upon the integration of DGs. The proposed approach presents the rehabilitation of recloser-fuse coordination for post-DG integration effects using the directional properties of a recloser. The simulation results show that coordination among protection devices can be regained using fast operation of the recloser to design a fuse saving scheme in the scenario of temporary fault occurrence. The designed scheme also works satisfactorily for the isolation of a permanently faulted section of the feeder. This technique is verified by simulation results performed on a real 11-kV radial distribution feeder for different fault locations and DG sizes.

Key words: Protection coordination, distribution generation, directional recloser, relays, fuses, distribution systems

1. Introduction

Typical distribution systems were designed to operate with radial configuration in which power flows from the source towards the connected customers, so the protection coordination of the radial system is very simple in nature. The distribution system contains protection devices, e.g., fuses, reclosers, relays, and circuit breakers. These protective devices are coordinated in such a way to interrupt the unidirectional flow of the fault current from the source end towards the fault point [1,2].

However, keeping in view the global concerns of the environment and to meet the load growth, distribution power planners have paid great attention to distributed generation [3,4].

Upon integration of the distributed generation with a distribution system, the configuration for power flow for a conventional network is changed from a unidirectional to multidirectional system. However, it is very important to know the margin required for the preservation of the protection coordination when a distributed generator (DG) is being integrated into a power system. The distributed system protection is to be reviewed after the integration of DGs [2,5–7].

In [8], researchers tried to solve the miscoordination problem caused by DG integration by formulating it as a mixed integer programming problem for directional overcurrent relays. A mathematical problem was first developed and a differential evolution algorithm was used to solve the miscoordination problem. However, the differential evolution method contains much complication to be used for a large distribution feeder. It was also

*Correspondence: engryousaf47@yahoo.com
suggested by the researchers that after integrating each distribution unit, the existing protection coordination must be checked in order to identify the impacts of adding DGs to the power system.

In [9], the authors used a new relay setting technique for the changed power generation and distribution in the power system to solve the miscoordination problem. In [10], the miscoordination problem was resolved by dividing the whole power system into different zones and installing a circuit breaker for each zone. However, this approach faced problems of limitation for the case where a very large distribution feeder was used as a test system.

In [11], researchers performed research on reducing the contribution of DGs to the short-circuit current level by using the concept of a fault current limiter, but it resulted in some disadvantages such as power dissipation across the fault current limiter as it is continuously connected to the power system. This power loss was much reduced by using a superconducting fault current limiter (SFCL) by the authors since the SFCL has zero resistance during normal operation of the power system and its resistance goes on increasing due to the increased fault current. The major disadvantage of using SFCLs is that they are very costly and thus are being used by some developed countries [12,13].

In power distribution systems, about 75%-80% of faults are temporary in nature. These faults can be categorized as self-clearing faults [14]. A directional recloser can be used for the clearance of upstream and downstream momentary faults in coordination with other protective devices of a distribution system. The proposed approach will considerably reduce the duration of sustained interruptions. The proposed scheme is used to establish the proper coordination among the fuses and recloser to eradicate the impacts of DG integration on protection coordination. The designed scheme considers all the parameters of real 11-kV distribution feeders.

2. Algorithm for the proposed approach

The proposed approach has been implemented on a particular radial distribution feeder having DGs and different protection components. The procedural steps followed for the proposed algorithm are shown in Figure 1.

When a DG is being installed at a distribution feeder, after its integration the conventional protection scheme of the hosting feeder is checked to assure whether the DG has changed the protection coordination of the feeder. If there was no change in protection coordination there is no need for reconstruction of the feeder protection coordination. However, there may be a very rare case where the traditional coordination is retained. Mostly, it is lost due to fault current contribution by DGs [15].

I) Calculate the $I_{f_{\text{min}}}$ and $I_{f_{\text{max}}}$ for the hosted feeder. In order to calculate $I_{f_{\text{min}}}$, the impact of DGs is neglected and calculations are performed without DG integration, whereas $I_{f_{\text{max}}}$ is calculated after integration of DGs.

II) $I_{f_{\text{min}}}$ and $I_{f_{\text{max}}}$ will give an idea about the current variation for the penetration of DGs into the distribution system.

III) The characteristics curves of all the coordinated protection devices are plotted.

IV) When a DG is integrated downstream of the recloser and there is fault downstream of the recloser, $I_{\text{recloser}}$ will be less as compared to the $I_{\text{fuse}}$ in the faulted section.

V) The next step is to reexamine the fast operation of the recloser in order to ensure the operation of the recloser before the melting of the fuse for a fuse saving scheme.
VI) The recloser fast operation curve will be shifted downward by a factor of the ratio of $I_{\text{recloser}}$ and $I_{\text{fuse}}$. It will ensure that the proper coordination is being established between the fuse and recloser. The new setting obtained from the newly constructed characteristics curve is implemented on the recloser.

VII) Size of the fuses can also be updated to establish proper coordination among protection devices.

VIII) Revise recloser and fuses’ time-current curves (TCCs) according to changed parameters for coordination for different protection devices.
Fuse-relay coordination is checked for the hosting and neighboring feeder and confirmation of its preservation is to be ensured.

The algorithm can be repeated to regain the proper coordination among the different protection devices.

3. Case study

In order to perform a comprehensive case study on the effectiveness of the designed scheme on a real distribution system, data of a practical 11-kV distribution feeder were used. This distribution feeder, the Panian radial distribution feeder, has 168 nodes starting from the 132-kV Haripur grid station.

It has a total length of about 98.9 km and a total load of 8425 kVA, where 4625 kVA of load is connected upstream of the recloser while 3800 kVA is downstream of the recloser. All protection device settings for the pickup currents are usually taken as 1.25 times the full load current.

In order to establish proper coordination among the protection devices, the difference among the primary and backup protection devices must always be greater than 200–300 ms. A single-line diagram constructed in MS VISIO is shown in Figure 2, while Figure 3 represents the single-line diagram in the Electrical Transient Analysis Program (ETAP).

![Figure 2. Single-line diagram of an 11-kV distribution feeder (case study).](image)

The recloser is located at the middle of the feeder because the integration of two DGs will not cause the momentary interruption for a temporary fault occurrence for the case where the recloser is at the start of the feeder.

Keeping in view the complexity of this lengthy distribution feeder, the feeder under study has been reduced from 168 nodes to only 38 nodes by summing the loads on respective laterals and associated sublaterals to the corresponding node. Practically, it was found that reduction of the case study feeder from a complex shape to a simple one did not affect the overall results of load flow and protection and protection coordination [3,16].
3.1. All possible zones of protection

A zone of power system protection is the part of the circuit that is disconnected only when an electrical fault occurs in that part of the power system, preserving the continuity of supply to the healthy sections. The radial distribution feeder has been divided into 40 zones of protection as shown in Table 1. Each zone has a primary protection as well as a backup protection device.

Each protection zone is named after the name of the protection device being installed. To make it easy to understand, each protection device was named for its corresponding node number and each bus bar was also named after the node number.

Protection of the 11-kV distribution feeder was designed to operate in conventional protection coordination order during faulty conditions. In the absence of DGs, the protection devices have to control the flow of fault current from the grid source point towards the fault point. Thus, a very limited number of protection devices have to operate for the fault isolation, which may be fuses, reclosers, and feeder relay.

Since the recloser is installed to clear the temporary fault, it must be properly coordinated with fuses. However, in the case of multiple numbers of DG integrations, each reclose and fuse will experience a different level of fault as compared to a DG-less environment for which they are being installed and coordinated. The cause for the miscoordination problem among protective devices is explained for a mid-feeder recloser in which DG1 is connected downstream and DG2 is connected upstream of the recloser.

In this distribution feeder, each zone contains a lateral fuse, which is coordinated with the recloser and can be operated according to a fuse saving scheme for temporary fault occurrence.

All the parameter data about the size of the conductor (DOG conductor denoted by ‘D’ in Figure 2), transmission line parameters, and DG sizes and their locations were given in [2].
Table 1. All possible protection zones with primary and backup protection devices.

<table>
<thead>
<tr>
<th>Protection zone</th>
<th>Primary protection devices</th>
<th>Backup protection device</th>
<th>Protection zone</th>
<th>Primary protection device</th>
<th>Backup protection device</th>
</tr>
</thead>
<tbody>
<tr>
<td>Feeder relay zone</td>
<td>Feeder relay</td>
<td>Incoming feeder protection</td>
<td>Fuse 19 zone</td>
<td>Fuse 19</td>
<td>Feeder, relay</td>
</tr>
<tr>
<td>Recloser zone</td>
<td>Recloser</td>
<td>Feeder relay</td>
<td>Fuse 20 zone</td>
<td>Fuse 20</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 1 zone</td>
<td>Fuse 1</td>
<td>Feeder relay</td>
<td>Fuse 21 zone</td>
<td>Fuse 21</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 2 zone</td>
<td>Fuse 2</td>
<td>Feeder relay</td>
<td>Fuse 22 zone</td>
<td>Fuse 22</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 3 zone</td>
<td>Fuse 3</td>
<td>Feeder relay</td>
<td>Fuse 23 zone</td>
<td>Fuse 23</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 4 zone</td>
<td>Fuse 4</td>
<td>Feeder relay</td>
<td>Fuse 24 zone</td>
<td>Fuse 24</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 5 zone</td>
<td>Fuse 5</td>
<td>Feeder relay</td>
<td>Fuse 25 zone</td>
<td>Fuse 25</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 6 zone</td>
<td>Fuse 6</td>
<td>Feeder relay</td>
<td>Fuse 26 zone</td>
<td>Fuse 26</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 7 zone</td>
<td>Fuse 7</td>
<td>Feeder relay</td>
<td>Fuse 27 zone</td>
<td>Fuse 27</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 8 zone</td>
<td>Fuse 8</td>
<td>Feeder relay</td>
<td>Fuse 28 zone</td>
<td>Fuse 28</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 9 zone</td>
<td>Fuse 9</td>
<td>Feeder relay</td>
<td>Fuse 29 zone</td>
<td>Fuse 29</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 10 zone</td>
<td>Fuse 10</td>
<td>Feeder relay</td>
<td>Fuse 30 zone</td>
<td>Fuse 30</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 11 zone</td>
<td>Fuse 11</td>
<td>Feeder relay</td>
<td>Fuse 31 zone</td>
<td>Fuse 31</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 12 zone</td>
<td>Fuse 12</td>
<td>Feeder relay</td>
<td>Fuse 32 zone</td>
<td>Fuse 32</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 13 zone</td>
<td>Fuse 13</td>
<td>Feeder relay</td>
<td>Fuse 33 zone</td>
<td>Fuse 33</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 14 zone</td>
<td>Fuse 14</td>
<td>Feeder relay</td>
<td>Fuse 34 zone</td>
<td>Fuse 34</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 15 zone</td>
<td>Fuse 15</td>
<td>Feeder relay</td>
<td>Fuse 35 zone</td>
<td>Fuse 35</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 16 zone</td>
<td>Fuse 16</td>
<td>Feeder relay</td>
<td>Fuse 36 zone</td>
<td>Fuse 36</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 17 zone</td>
<td>Fuse 17</td>
<td>Feeder relay</td>
<td>Fuse 37 zone</td>
<td>Fuse 37</td>
<td>Recloser, relay</td>
</tr>
<tr>
<td>Fuse 18 zone</td>
<td>Fuse 18</td>
<td>Feeder relay</td>
<td>Fuse 38 zone</td>
<td>Fuse 38</td>
<td>Recloser, relay</td>
</tr>
</tbody>
</table>

4. DGs and protection coordination

In order to reduce the real power loss and to make the node voltage stay within acceptable limits, two DGs have been inserted at two different nodes. DG1, having a size of about 3.722 MVA, was connected to node number 30, while DG2, with size of 2.28 MVA, was connected to node number 14 [3]. After the integration of DGs with the distribution feeder, the power loss was much reduced from 605.5 kW to 39.7 kW. At the same time, the voltage profile was much improved with 16% reduction in total voltage drop [3]. However, DG integration caused a very serious problem for protection coordination for the distribution feeder. When DGs are placed on the circuit, the objective is to isolate the faulted point fed by a number of sources.

The simulation results obtained show a miscoordination between the protection devices. The sequence of operation of protection devices is listed below in Table 2 in the presence of DGs for a few zones of protection.

Table 2. Sequence of operation of the devices in the presence of DGs.

<table>
<thead>
<tr>
<th>Faulted zone</th>
<th>Fault type</th>
<th>Status of power sources</th>
<th>Sequence of operation of protection devices</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuse 1 zone</td>
<td>L-G</td>
<td>ON ON ON</td>
<td>Fuse 1 Recloser Feeder relay Relay DG2 Relay DG1</td>
</tr>
<tr>
<td>Fuse 10 zone</td>
<td>L-G</td>
<td>ON ON ON</td>
<td>Recloser Fuse 1 Relay DG2 Feeder relay Relay DG1</td>
</tr>
<tr>
<td>Fuse 20 zone</td>
<td>L-G</td>
<td>ON ON ON</td>
<td>Fuse 20 Recloser Relay DG2 Relay DG1 Feeder relay</td>
</tr>
<tr>
<td>Fuse 30 zone</td>
<td>L-G</td>
<td>ON ON ON</td>
<td>Fuse 30 Recloser Relay DG1 Relay DG2 Feeder relay</td>
</tr>
<tr>
<td>Fuse 38 zone</td>
<td>L-G</td>
<td>ON ON ON</td>
<td>Recloser Fuse 38 Relay DG1 Relay DG2 Feeder relay</td>
</tr>
</tbody>
</table>
Simulation results show that in some cases the fuse was blown out before the operation of the recloser, which is a false tripping sequence as the recloser setting was designed to operate earlier than the fuse (fuse saving scheme) in order to remove the temporary faults by deenergizing the faulted section and again energizing.

In the case of a line to ground (L-G) fault in the fuse 1 zone, fuse 1 is tripped before the recloser. This false tripping can be explained with characteristics equations and TCCs of the protection devices.

Now the fault current for a fault in the distribution system is contributed by three fault current sources that are from the main distribution feeder, DG1, and DG2. In order to interrupt the fault current from the main distribution feeder, the correct tripping device is the main feeder relay, which initiates the operation of the associated MV circuit breaker. If the fault occurs in the relay zone, the DG1 contribution toward the fault current (I_f) can be terminated by the DG1 protection system. While DG2’s contribution can be ended by recloser operation. If the fault is in the recloser zone, the main distribution station and DG1 contribution can be controlled by recloser tripping, while that of DG2 can be controlled with the DG2 protection system.

5. Renovation of protection coordination

When the DGs are integrated, it starts to contribute toward fault current. For the same fault at the same location, fault current magnitude increases, causing a miscoordination among the traditional protection coordination. Table 2 shows that in most of the cases, a miscoordination occurs among the protection devices. The results indicate that the original system loses selectivity after the DGs’ insertion. The reason for this is explained in the next sections.

5.1. Mathematical modeling

The recloser fault current (I_{reclouser}) is always less than the corresponding lateral fuse current (I_{fuse}) because it follows these two cases:

a) If the fault is downstream of the recloser, then

\[ I_{fuse} = I_{reclouser} + I_{DG1}, \]

where \( I_{reclouser} = I_{grid} + I_{DG2} \).

b) If the fault is upstream of the recloser, then

\[ I_{fuse} = I_{reclouser} + I_{DG2} + I_{grid}. \]

These equations show that fault current is always higher for a fuse in the presence of DGs so the fuse is operated before the recloser tripping causing a false tripping. The recloser follows the following equation [17,18]:

\[ t_{op}(I) = TDS \left( \frac{A}{(I_{pick-up})^p} - 1 \right) + B \].

When the \( I_{reclouser}/I_{fuse} \) factor is multiplied by the time dial setting (TDS) in Eq. (3), the characteristics curve of the recloser will shift down, resulting in new coordination between the fuse and recloser.
5.2. Protection coordination constraints

For typical overcurrent protection coordination, the following constraints are to be met for proper coordination [18–20].

i. The first constraint to be met is the equipment overload constraint.

\[ I_{\text{pickup}} \leq I_{\text{spec}} \quad (4) \]

This constraint satisfies the condition for each protection device of not being overloaded under any circumstances. Thus, the pickup value of each protection device must be less than the maximum value for which it is designed. In this way, it will be able to perform its function properly.

ii. There should be a difference between the operating times of upstream and downstream protection devices in order to satisfy the specified time margin.

\[ T_{\text{up}}(I_f) - T_{\text{down}}(I_f) \geq t_{\text{margin}} \quad (5) \]

Here, \( T_{\text{up}}(I_f) \) shows the operating time of upstream devices under faulty conditions and \( T_{\text{down}}(I_f) \) indicates the operating time of downstream devices under faulty conditions, and the difference of these time constraints should be within some margin, which is usually greater than 100 ms.

iii. The recloser operating time in the fast mode must always be less than the minimum melting time (MMT) for the respective fuse in order to design the fuse saving scheme.

\[ T_{\text{RF}}(I_R) - MMT_f(I_{\text{Fuse}}) \leq 0 \quad (6) \]

Meanwhile, the difference between recloser fast operating time \( T_{\text{RF}}(I_R) \) and the MMT of the fuse must be negative. It will cause deenergizing of the fault by fast operation of the recloser and try to self-clear it. This will save interruption caused by fuse melting in the case of temporary fault occurrence.

5.3. Plotting of TCCs

The TCC represents the sequence and time of operation of the protection devices. The fuse TCC consists of two curves. The lower curve is the MMT while the upper is called total clearing time (TCT). The TCC for the cases mentioned in Table 2 is shown below in Figure 4.

For perfect coordination between the fuse and recloser, the recloser fast operation TCC should be lower than the respective fuse MMT curve while the recloser delayed operation curve must be above the fuse TCT curve. This will result in recloser tripping in the fast mode of operation before the fuse starts to melt, giving the momentary fault a possibility of self-clearing [15,21].

However, in the case of permanent fault occurrence, the fuse melts to operate before the recloser trips in the slow mode of operation. The relay TCCs of the main feeder relay and DGs’ protection relays lies above all the fuses’ and reclosers’ curves, giving backup protection if the primary protection devices fail in successful operation.
5.4. Designing of protection coordination scheme

Since after the addition of DGs, the power flow is changed from unidirectional to multidirectional, the requirement is to trip the flow of multidirectional fault current. In this scenario, a directional protection scheme becomes the suitable choice to resolve the selectivity problem of the distribution system. Since the fuses are located at the beginning of each lateral in which the flow of the fault current is unidirectional, fuses do not need any directional property. Since fuses do not possess a directional nature, if fuses are to be designed for directional protection, they are to be replaced by the recloser.

The fault current through the feeder relay is still unidirectional, so there is no need for a directional property of this relay. Since the recloser is subjected to a multidirectional fault current, it must possess a directional nature. In order to possess a directional nature, the recloser must have two settings. One setting is to be designed for the downstream fault location and other is designed for the upstream fault location.

In the above designed scenario, the total load connected downstream of the recloser is 3800 kVA so the pickup current for this downstream setting is 249 A while for the upstream setting of the recloser, the pickup current setting is 303 A.

Since DG2 is located upstream of the recloser at node 14, its protection relay should have a setting slower than the downstream setting of recloser. This will result in tripping of the recloser for a fault in its zone before DG2 protection operates. This will resolve the selectivity problem recloser and DG2 protection system.

For DG1, which is located at node 30, its protection setting should be slower than the upstream setting...
of the recloser so that it results in recloser tripping for a fault in the feeder relay zone. In order to coordinate fuses on the upstream side of the recloser, they should operate faster than recloser delayed operation in order to isolate the fault zone for the case of a permanent fault. The fuse on the lateral downstream of the recloser must operate before the operation of the DG1 protection system.

If the generator is to be connected to the sublateral of the distribution feeder, then the lateral fuse can be replaced with a directional recloser that allows interruption of fault current in both cases when the fault is located upstream and downstream of the lateral recloser. After isolation of the faulted section, the recloser initiates the reclosing process for restoration of supply to the healthy section. Using the above mentioned scheme, protection coordination was restored among the protection devices.

5.5. Implementation of the proposed scheme

If there is a fault in the relay zone, the fault current contribution from the distribution system was interrupted by the feeder relay. The fault current from DG1 will be interrupted by the recloser and DG1 protection will be its backup protection. The fault current contribution from DG2 will be interrupted by the DG2 protection system. In these circumstances, all the tripping decisions are correct.

Now if the fault location is downstream of the recloser (recloser zone), then fault current coming from the distribution system and DG2 is interrupted by the recloser and feeder relay and the DG2 protection system will work on its backup. The contribution of DG1 towards the fault current will be terminated by the DG1 protection system. Figure 5 shows the fault current level through the recloser and fuse for a L-G fault on each node.

![Figure 5. Fault current calculation for recloser and fuse for an L-G fault on each node.](image)

After the penetration of DGs in the distribution feeder, the fault current level and direction of fault current flow changes for both recloser and fuses. Thus, the TCCs of the recloser and relays should be revised and fuse size should be updated. The multiplication of the lowest value of \( I_R/I_F \) with the recloser curve will lower the whole curve and protection coordination will be checked again. If the fault location is in, for example, the zone of Fuse 20, then fault current contribution from all sources will be interrupted by recloser opening and DG1 protection relay. If the fault was temporary, then deenergizing and energizing the fault will result in fault removal. However, if the fault still persists after the recloser opening in the fast mode of operation, then this permanent fault can also be removed by the associated fusing protection device, i.e. Fuse 20. If this operation
is unsuccessful in removal of the fault, then recloser tripping in slow mode of operation will work as backup protection. The protection system of DG1 will also work as a backup protection device.

6. Impact of DG size on protection coordination

To illustrate the effect of DG size on protection coordination, the above proposed approach has been examined for different sizes of the DGs connected to the distribution system. As the fault current contribution increases with the increase in DG size, so the time of operation of different protection devices decreases with increase in DG size [22,23].

The simulation for fault current contribution of different sources and their effects on protection coordination are depicted in Table 3. The simulations are carried out for a line-to-ground fault on node 20 downstream of the recloser. The fault current contribution of each source and operating time of each protection device are listed in Table 3.

Table 3. Fault current contribution and time of operation for a fault downstream the recloser.

<table>
<thead>
<tr>
<th>DG size (MVA)</th>
<th>Fault current contribution (A)</th>
<th>Operating time of various protection devices (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>DG1</td>
<td>DG2</td>
<td>DS</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>270</td>
</tr>
<tr>
<td>3</td>
<td>2</td>
<td>201</td>
</tr>
<tr>
<td>4</td>
<td>3</td>
<td>167</td>
</tr>
<tr>
<td>5</td>
<td>4</td>
<td>145</td>
</tr>
<tr>
<td>6</td>
<td>5</td>
<td>133</td>
</tr>
</tbody>
</table>

It is concluded from the results that as the rating of DGs increases, their contribution towards fault current increases while that of the distribution substation (DS) decreases at the same time. The simulation results also depict that operating time of the main feeder relay is always greater than that of the recloser and DG2 relay. This will result in a recloser lockout operation for a recloser downstream fault before tripping of the feeder relay’s circuit breaker CB1. DG1 relay is required to operate before the recloser delayed operation so that before locking out the recloser the fault is completely deenergized in order to give it a chance of self-clearing. These results prove that protection coordination among these devices survives increased DG size and multiple DG integrations for a fault downstream of the recloser.

Figure 6 is the graphical representation of the fault current contribution by each source while Figure 7 presents a graphical picture of the time of operation of different protection devices with variations in DG size.

The same analysis can be performed for a fault upstream of the main recloser. Now an L-G fault is located in the feeder relay zone upstream of the recloser at node 17. The results of fault current contribution from each source and the operating time of each device are shown in Table 4 and results are graphically represented in Figures 8 and 9.

These results depict that temporary fault eradication needs tripping of all the fault current sources so that contribution towards the fault current is terminated. This will result in temporary fault removal. However, a permanent fault needs the lockout operation of the recloser along with isolation of other fault current sources. Simulation results for faults other than L-G show that this approach works properly for any type of fault occurrence.
Figure 6. Fault current contribution for an L-G fault downstream of the reclose at node 20.

Figure 7. Time of operation for different protection devices with different DG sizes with an L-G fault at node 20.

Figure 8. Fault current contribution for a fault upstream of the reclose at node 17.

Figure 9. Time of operation for different protection devices with different DG sizes with an L-G fault at node 17.

Table 4. Fault current contribution and time of operation for a fault upstream of the recloser.

<table>
<thead>
<tr>
<th>DG size (MVA)</th>
<th>Fault current contribution (A)</th>
<th>Operating time of various protection devices (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>DG1</td>
<td>DG2</td>
</tr>
<tr>
<td>2</td>
<td>337</td>
<td>710</td>
</tr>
<tr>
<td>3</td>
<td>261</td>
<td>746</td>
</tr>
<tr>
<td>4</td>
<td>222</td>
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<td>5</td>
<td>197</td>
<td>836</td>
</tr>
<tr>
<td>6</td>
<td>178</td>
<td>880</td>
</tr>
</tbody>
</table>

However, the protection coordination is needed to be checked after each insertion of a new DG or change in the size of any existing DG. The selectivity problem can be resolved using the above proposed curve-fitting approach.
7. Conclusion
This paper illustrates the impacts of distributed generation integration on the protection coordination for radial distribution networks. The proposed approach for restoration of protection coordination mainly focuses on temporary fault removal without melting the fuse. It has been observed from simulation results that the selectivity problem of the protection devices can be addressed using the curve-fitting technique. The integration of multiple DGs with the distribution feeder needs the utilization of a directional property of the recloser along with updating the fuse sizes and relay settings. The methodology is validated for a real radial distribution feeder. The simulation results verify the proper functioning of this technique for different fault locations and DG sizes. Thus, proper coordination among different protection devices can be restored to eradicate the impacts of post-DG integration on distribution network protection.

References


