Distributed Generators and Their Effects on Distribution System Protection Performance

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Abstract: The connection of distributed generators (DGs) to distribution networks greatly influences the performance and stability of such networks. Though DGs have significant economic and environmental benefits, increased penetration of DGs will impose significant technical barriers for the efficient and effective operation of bulk power systems. Increased fault current contribution and load flow changes are the major two impacts on utility systems, and these will affect existing protective relaying, especially overcurrent relays. To ensure safe and selective protection relay coordination, the impact of DGs should be taken into account when planning DG interconnection. This paper presents an introduction of distributed generators and an overview of the effects of DGs on system protection relay coordination, particularly in cases where DGs are added to a distribution feeder.

Key words: Distributed Generator (DG); Protection Coordination; Distribution Network, Overcurrent Relay.

INTRODUCTION

In the recent years the electrical power utilities are undergoing rapid restructuring process worldwide. Indeed, with deregulation, advancement in technologies and concern about the environmental impacts, competition is particularly fostered in the generation side thus allowing increased interconnection of generating units to the utility networks. These generating sources are called as distributed generators (DG) and defined as the plant which is directly connected to distribution network and is not centrally planned and dispatched. These are also called as embedded or dispersed generation units. The existing distribution networks are designed and operated in radial configuration with unidirectional power flow from centralized generating station to customers. The increase in interconnection of DG to utility networks can lead to reverse power flow violating fundamental assumption in their design. This creates complexity in operation and control of existing distribution networks and offers many technical challenges for successful introduction of DG systems. Some of the technical issues are islanding of DG, voltage regulation, protection and stability of the network (Gaonkar 2010).

A typical distribution protection system consists of fuses, relays and reclosers. An inverse overcurrent relay is usually placed at a substation where a feeder originates. Reclosers are usually installed on main feeders with fuses on laterals (Zayandehroodi *et al.*, 2010).

Reclosers are necessary in a distribution system as 80% of all faults that take place in distribution systems are temporary. It gives a temporary fault a chance to clear before allowing a fuse to blow. The coordination between fuses, reclosers and relays is well established for radial systems; however, when DG units are connected to a distribution network, the system is no longer radial, which causes a loss of coordination among network protection devices (Brahma and Girgis 2004). The extent to which a DG affects protection coordination depends on the DG's capacity, type and location (Burke 1994; Doyle 2002; Kumpulainen and Kauhaniemi 2004). The introduction of a DG into a distribution system brings about a change in the fault current level of the system and causes many problems in the protection system, such as false tripping of protective devices, protection blinding, an increase and decrease in short-circuit levels, undesirable network islanding and out-of-synchronism reclosers (Doyle 2002; Kauhaniemi and Kumpulainen 2004; Pepermans *et al.*, 2005; Fazanehrafat *et al.*, 2008; Khederzadeh *et al.*, 2010; Massoud *et al.*, 2010). However, when a fault occurs in a distribution network, it is important to quickly locate the fault by identifying either a faulty bus or a faulty line section in the network (Zayandehroodi *et al.*, 2010; Zayandehroodi *et al.*, 2010). Depending on the location of the fault with respect to the DG and the existing protection equipment, problems like bi-directionality and changes in the voltage profile can also arise. To ensure selectivity, proper coordination between relays, reclosers, fuses and other protective equipment is necessary. However, this coordination may be severely hampered if a DG is connected to a distribution system (Hussain *et al.* 2010). This paper presents an introduction of distributed generators and their effects on the relay-relay coordination in a distribution system.

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Distributed Generators:

DG refers to the notion of generating power using a set of small sized generators that produces power at low voltage levels and usually uses alternative fuel. The rating of the DG systems can vary between few kW to as high as 100 MW. The DGs are mainly designed to be connected directly to the distribution network near load centers. There are several types of DGs in the market. Some are conventional such as the diesel generators and some are new technologies such as the micro-turbines. The major DG alternatives have described briefly in the following.

2.1 Fuel cells:

A fuel cell is an electrochemical device that converts chemical energy directly into electrical energy. The fuel cell unit uses hydrogen and oxygen to perform the required chemical reaction and produce power. Fuel cells are inverter interfaced DGs, meaning the unit produces dc power that is converted to ac power via a 3-phase converter (Hirschenhofer *et al*., 1998).

2.2 Micro-turbine:

Micro-turbines are small gas fired turbines rotating at a very high rate of speed (90,000 rpm). A high rpm DC generator is used to generate dc power. The DC generator is coupled to a dc/ac power converter to produce voltages at the rated frequency (Suter 2001).

2.3 Photovoltaic cells:

Photovoltaic cells convert solar energy directly into electrical energy. Like fuel cells, the power produced is dc power and a power electronics converter is needed to interconnect with the utility grid (Joos *et al*., 2000).

2.4 Wind turbines:

The wind turbine operates by extracting kinetic energy from the wind as it passes through the rotor. The wind turbine shaft is connected either to an induction or synchronous generator. A transformer is then used to step up the output voltage to the utility grid level (Jenkins 1995).

2.5 Diesel generator:

This is the most commonly used DG now. A small synchronous generator is coupled with a reciprocating piston engine to produce ac power. They are usually operated standalone during utility power outages.

Protection coordination fundamental:

To operate a power system appropriately, the system should have a well-designed and practically-coordinated protection system. The protection requirements of a power system must take into account the following basic principles (Short 2004):

- Reliability: the ability of the protection to operate correctly.
- Speed: minimum operating time to clear a fault to avoid damage to equipment.
- Selectivity: maintaining continuity of supply by disconnecting the minimum section to isolate the fault.
- Cost**:** maximum protection at the lowest possible cost.

Because distribution systems are typically designed in a radial configuration and with only one source, they have a very simple protection system, which is usually implemented using fuses, reclosers and over-current relays. In a distribution feeder, fuses must be coordinated with the recloser installed at the beginning or middle of the feeder. The coordination means that a fuse must operate only if a permanent fault affects the feeder (fuse saving scheme). For a temporary fault, however, the recloser must rapidly open to isolate the feeder and to give the fault a chance to self-clear. If the fuse fails to operate for a permanent fault, the recloser will act as a backup by operating in its slow mode. The feeder relay will then operate if both the recloser and the fuse fail (Chaitusaney and Yokoyama 2005; Gers and Holmes 2005). Figure 1 illustrates the conventional coordination practice for the relay, recloser, and fuses in a typical distribution network.

To coordinate an overcurrent relay, as soon as a fault takes place, it is sensed by both primary and backup protection. The primary relay is the first to operate, as its operating time is less than that of the backup relay. A relay protection scheme in a simple radial feeder with 4 busbars (B1, B2, B3, and B4) is shown in Figure 2. For a fault at point F2, relay R2 is the first to operate. If the operating time of R2 is set to 0.1 second, then the relay R1 should wait for 0.1 second plus a time equal to the operating time of the circuit breaker (CB) at bus B2 plus the overshoot time of relay R1 (Paithankar and Bhide 2004). This is necessary to maintain the selectivity of the relays at B1 and B2.
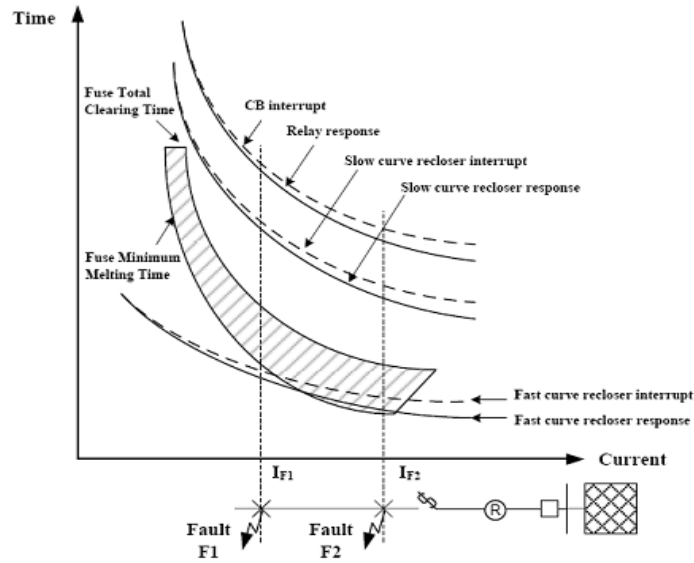
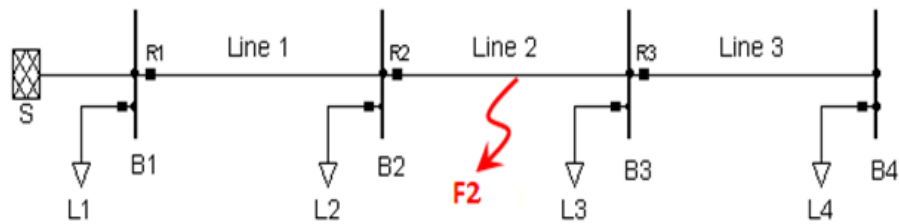**Fig. 1:** Protective device coordination.

Fig. 2: A simple radial feeder with non-directional relays.

For relay protection coordination in a ring main feeder system shown in Figure 3, it is required to maintain a power supply to all of the loads despite faults in any section. In this case, relays R1 and R8 are non-directional, whereas all other relays (R2, R3, R4, R5, R6, and R7) are directional overcurrent (OC) relays. The tripping direction of all directional relays is away from the corresponding bus.
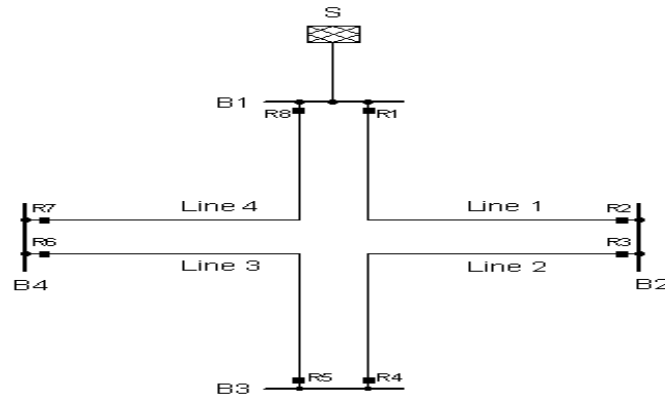
Fig. 1: A ring main feeder.

For coordination purposes, relays R2, R4, R6, and R8 will form one group, and relays R1, R3, R5, and R7 will form another. For group one, suppose the relay setting begins from relay R2. The relay operating times will be such that it obeys the following condition:

TR8 > TR6 > TR4 > TR2

For group two, if the relay setting begins from relay R7, the relay operating times will obey the following condition:

TR1 > TR3 > TR5 > TR7

The actual operating time for each relay can be determined again by considering the operating time of the preceding relay, the CB operating time associated with the preceding relay, and the overshoot time of the relay under consideration. However, the size and complexity of a distribution system normally continues to increase; therefore, it becomes more and more difficult to coordinate the relays.

Effect of dg on overcurrent relays coordination in distribution network:

Figure 4 shows a distribution network with several DG units. Depending on the placement of the DG in the feeder, different protection scenarios will arise, as described below.
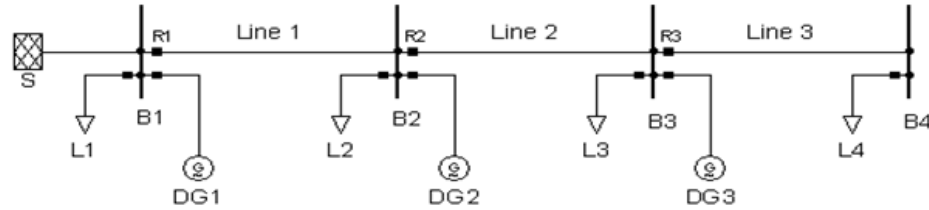

Fig. 2: Simple distribution network with three DG units.

3.1 Only DG1 is connected:

In this scenario, for a downstream fault, e.g., a fault in line 3 relays R1, R2, and R3 will see the downstream fault current, which is greater than the fault current without DG1, as shown in Figure 5. Then R3 will have to eliminate the fault with greater sensitivity because of the larger fault current. The situation will be similar for a given fault in line 2 or line 1. For an upstream fault, that is to say, a fault that occurs before busbar B1, relays R1, R2, and R3 will never see the upstream fault current and will not be activated. Meanwhile, the overcurrent relay of DG1 (R4) will sense a fault current and then separate DG1 from the utility system. Thus, the selectivity and coordination of R1, R2, and R3 will hold for downstream faults.
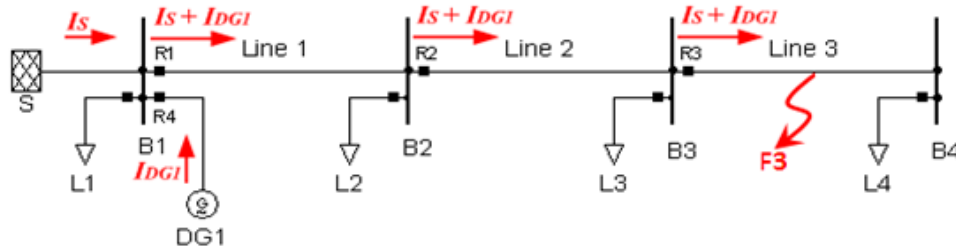

Fig. 3: Distribution network with DG1 connected and fault in line 3.

3.2 Only DG2 is connected:

This scenario considers the case when only DG2 is connected, as shown in Figure 6. Relays R1, R2, and R3 will sense downstream fault currents. The fault current sensed by R2 and R3 is greater than that without the DG, while the fault current seen by R1 is less than it was before. For a fault in line 1, relays R2 and R3 will never see the upstream fault current, while R1 will sense a downstream fault current and operate. However, the fault is not isolated because DG2 feeds fault current into this line, as shown in. When a fault occurs in line 2, if R2 does not trip, R1 cannot provide backup protection because the DG2 still feeds the fault current, as shown in Figure 5. Similarly, for a fault in line 3, relay R1 cannot provide backup protection if R3 and R2 do not trip as a primary protection. When a fault accrues before busbar B1, relay R1 will see a reversed fault current and operate when the fault current value is greater than the set value. Meanwhile, DG2 and the downstream loads will form an island.

3.3 Only DG3 is connected:

When only DG3 is connected, relays R2 and R3 will sense the downstream current for faults in line 3 and upstream current for faults in line 1. It is important to note here that for any given downstream or upstream fault,

these relays will sense the same fault current, as shown in. This result will create a conflict as these relays sense the same current for either of these faults, and it is impossible to achieve coordination with the existing scheme. Because it is required to clear only the faulted section, R3 must operate before R2 for any fault in line 3, and R2 must operate before R3 for a fault in line 1. Relays R1 and R2 cannot isolate the fault in lines 1 and 2 because the DG3 feeds the faults upstream, as shown in and Figure 10.
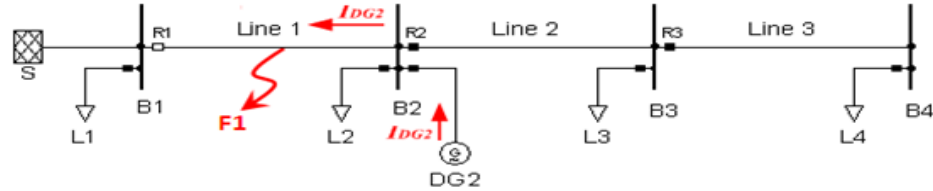
Fig. 4: Distribution network with DG2 and fault in line 1.
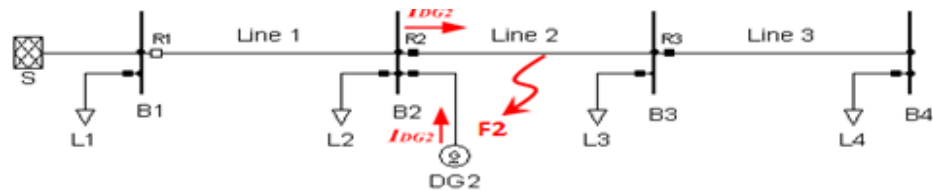
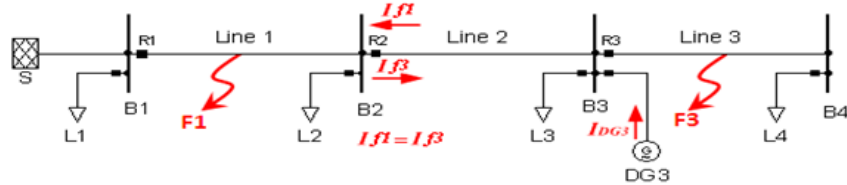**Fig. 5:** Distribution network with DG2 and fault in line 2.

Fig. 6: Distribution network with DG3 and faults in line 1 and line 3.
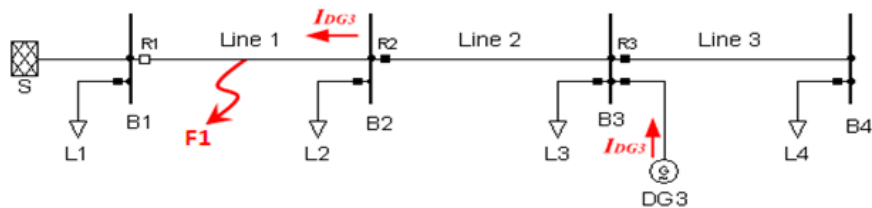

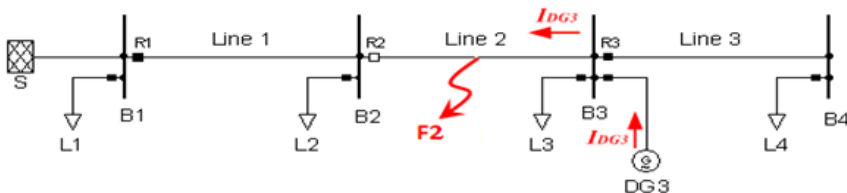**Fig. 7:** Distribution network with DG3 and fault in line 1.

Fig. 8: Distribution network with DG3 and fault in line 2.

3.4 DG1 and DG2 are connected:

For the case when DG1 and DG2 are connected in the system, the maximum and minimum currents for a fault downstream of DG2 will change. However, R3 will never sense a backflow for an upstream fault, which will require R3 and R2 to be coordinated under different current settings. As inverse relays have sufficient tap and time settings available, coordination of relays should not pose any problem. Relay R1 cannot isolate the faults in line 1 because DG2 feeds the faults upstream, as shown in
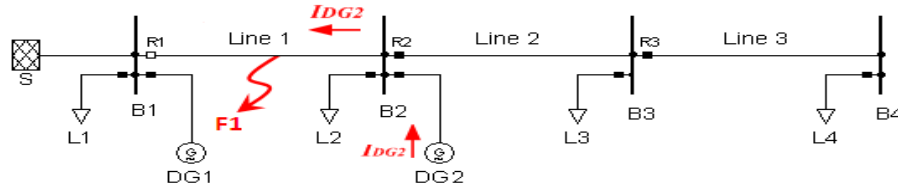Fig. 9.

Fig. 9: Distribution network with DG1 and DG2 with fault in line 1.

3.5 DG2 and DG3 are connected:

When DG2 and DG3 are connected and there is a fault in line 1, relay R1 will response to a fault in line 1, and relay R2 will see the reversed fault currents contributed by DG2 and DG3. In this case, the upstream currents are proportional to the capacities of DG2 and DG3; therefore, the corresponding operation time of R1 and R2 is related to the fault injection capabilities of DG2 and DG3. Relays R1 and R2 cannot isolate the faults in their lines because DG2 and DG3 feed the faults upstream, as shown in and Figure 13. Coordination will likely be lost.
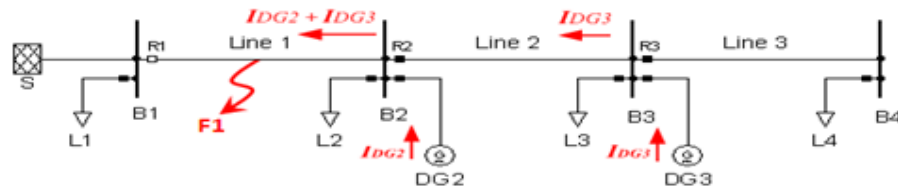

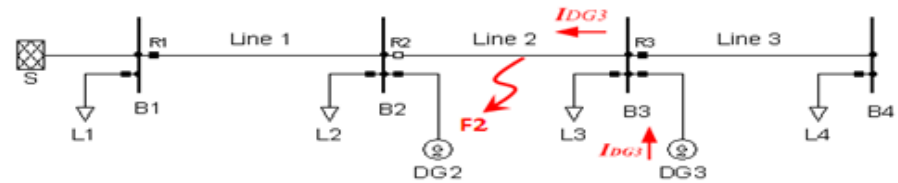**Fig. 10:** Distribution network with DG2 and DG3 with fault in line 1.

Fig. 11: Distribution network with DG2 and DG3 with fault in line 2.

3.6 Three DGs connected:

When DG1, DG2 and DG3 are connected in the system and there is a fault in line 3 (or further downstream), R3 will sense the maximum fault current, followed by R2 and R1. For a fault in line 1 or for any other lines upstream beyond line 1, R2 will sense more current than R3, as shown in and Figure 15.
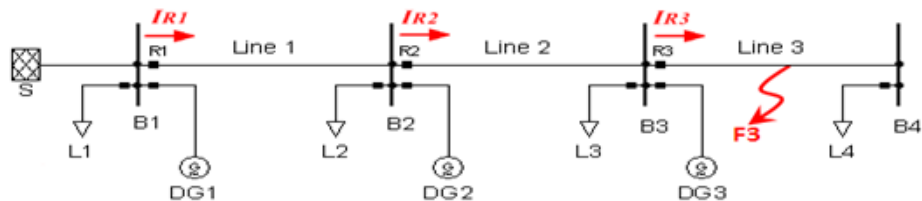

Fig. 12: Downstream fault in the distribution network with DG1, DG2, and DG3 connected.

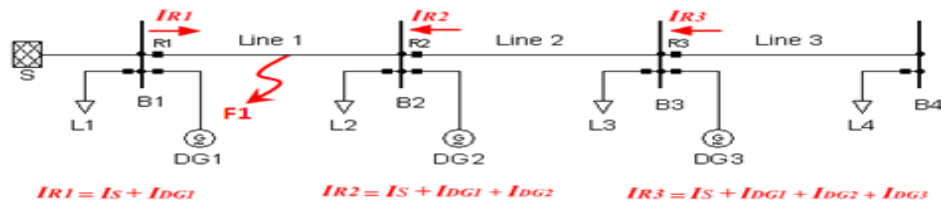$$IR1 = IS + I_{DG1} \qquad IR2 = IS + I_{DG1} + I_{DG2} \qquad IR3 = IS + I_{DG1} + I_{DG2} + I_{DG3}$$

Fig. 13: Upstream fault in the distribution network with DG1, DG2, and DG3 connected.

According to the above analysis, the coordination impact under this situation can be summarized as follows. If the coordination relay pair detects a different current for a downstream or upstream fault, there is a margin available for coordination to remain valid. If disparity in the fault currents sensed by the devices is more than the margin, coordination holds. Coordination is likely to hold if the DG fault injection is greater than the margin (Girgis and Brahma 2001).

Conclusion:

Distributed generations (DGs) are a viable alternative for developing countries where grid supply has reliability below desirable levels. Since utilities are no longer embarking on building large generating plants, DG serves as an alternative to generating energy resources. The connection of DGs to distribution networks greatly impacts the networks performance. This paper focuses on the DG's impact on the networks control and protection schemes.

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