Protection of distributed generation connected networks with coordination of overcurrent relays

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***Abstract-* The disconnection of distributed generators (DGs) from a distribution network for every abnormal condition drastically reduces the DG benefits and system reliability when DG penetration level is high. The DGs can be used to supply the load demand in the absence of grid supply if DGs are allowed to operate in islanded mode. In this paper, protection issues associated with disconnection of DGs are addressed in the context of a radial distribution feeder. Protection strategies are proposed to allow islanded operation and to restore the system performing auto-reclosing maintaining as many DG connections as possible. An overcurrent relay based protection scheme is proposed for a converter based DG connected radial feeder to operate either in grid-connected or islanded mode maximizing the DG benefits to customers. Moreover, an effective method is proposed to restore the system with DGs using auto-reclosers. The proposals are verified through PSCAD simulation and MATLAB calculations.**

I. Introduction

With the rapid increase in electrical energy demand, power utilities are seeking for more power generation capacity. However, environmental and right-of-way concerns make the addition of central generating stations and the erection of power transmission lines more difficult. Thus, newer technologies based on renewable energy are becoming more acceptable as alternative energy generators. This renewable energy push is starting to spread power generation over distribution networks in the form of distributed generation and will lead to a significant increase in the penetration level of distributed generation. It is expected that 20% of power generation will be through renewable sources by the year 2020 [1]. The DGs based on renewable energy sources will help in reducing greenhouse gas emissions. Moreover, these DGs can provide benefits for both utilities and consumers since they can reduce power loss, improve voltage profile and reduce transmission and distribution costs as they will be located close to customers [2, 3].

Most of the existing distribution systems are radial with unidirectional power flows from substation to customers [4]. Overcurrent protection is used for such systems because of its simplicity and low cost [1, 5]. However, once a DG or several DGs are connected within the main utility system, this pure radial nature is lost [2, 6-7]. Thus the protection of distribution networks using overcurrent protective devices becomes a challenging task due to the change in fault current levels and fault current direction [8]. This is because the protective devices may not respond in the way they were initially designed [5, 9].

According to the IEEE Standard 1547 [10], DGs should cease the connection when a fault occurs in a network. The islanding operation with DGs is prohibited due to the restoration, personnel safety and power quality issues [11]. Therefore, the DGs need to be disconnected even for temporary faults [12]. As the penetration level increases, the disconnection of these DGs drastically reduces the benefits of DGs [13]. If protection scheme can isolate the faulted section and enable intentional power islands, system reliability can be increased [14].

In this paper, the major protection issues associated with the implementation of islanded operation and system restoration in a radial distribution feeder are investigated. Solutions are proposed to avoid/minimize the identified issues without disconnecting DGs from unfaulted sections in the network. It has been shown how a fault can be isolated in a radial network containing converter interfaced DGs such that islanded operation can take place with overcurrent relay protection. Also the system restoration using auto-reclosers is studied. The proposed strategies are verified through PSCAD simulation and MATLAB calculations.

II. Protection Issues

The major protection issues associated with a DG connected network can be identified as

- Isolation of the smallest faulted section
- Fault ride-through capability of DG and DG connection/disconnection
- Islanded protection with DGs
- System restoration by performing auto-reclosing

In this study, the abovementioned protection issues are addressed assuming that all the DGs are connected to the network through converters. Furthermore, it is assumed that DGs have the ability to operate in autonomous mode if DG generation is sufficient to supply the load demand in the islanded section. The proposed solutions are elaborated below.

A. Smallest faulted section isolation

When a fault occurs in a traditional radial feeder, the overcurrent relays respond to isolate the portion of the network resulting power interruption to the customers downstream from the fault location [15]. This customer power interruption can be minimized if DGs are allowed to supply power to the unfaulted portions in the network. To achieve this goal, the smallest possible portion of the faulted section should be isolated from the network. After the fault isolation, the DGs connected to the unfaulted sections can supply power to customers either in grid-connected or islanded mode depending on system configuration after the fault. In this case, only those customers connected to the faulted section will experience a power outage, if the DG capacity is sufficient to supply load power requirement in any islanded section. Also, islanded operation is desirable in the case of permanent faults which may take several minutes or hours to restore the system.

A faulted section can be isolated, if both upstream and downstream side protective relays respond in a DG connected radial system. In the grid connected mode, the upstream relay to a fault senses the fault current supplied by the utility, while the downstream relay to the fault senses the fault current supplied by all the downstream DGs. It is to be noted that the utility can temporarily supply a fault current that is much higher than its rated current. On the other hand, converter interfaced DGs limit the maximum current that they can supply. Therefore it can be surmised that the fault current seen by a particular relay in forward direction (i.e. when a fault occurs downstream to the relay) is much higher than it can see in the reverse direction. Therefore the relays must have the ability to distinguish between forward and reverse faults. It necessitates different relay settings in forward and reverse directions. Therefore directional overcurrent relays are proposed to isolate the faulted section.

The directional relays should be graded separately in forward and reverse directions with appropriate tripping characteristics depending on the network configuration. If all the DGs in a network are connected all the time, then the DG connections will be termed as consistent. In this situation, the relays can be set calculating the fault current at different buses. However, if the DG connections are not consistent and changing with time, the fault current level changes depending on the number of DG connections. In this situation, the relay settings should be changed to achieve the fault isolation according to the available fault current level.

To change the relay settings according to present system configuration, a reliable communication method is required amongst DGs and the relays either in centralized or decentralized manner. A complete offline fault analysis should be performed for different network configurations depending on the DG connections to calculate the relay settings. The calculated settings are then stored in each relay. The relays are then responsible to select the most appropriate setting according to present system configuration. In the case of communication failure, each relay selects its default settings which are initially defined.

B. Fault ride-through capability of DGs and DG connection/disconnection

The DGs connected to the feeder should have the fault ride through capability (i.e. the ability to remain connected for a specific time period during a fault) to obtain faulted section isolation. One of the main goals of fault ride through capability is to prevent unnecessary disconnections of DGs during abnormal conditions [16]. Different control strategies have been proposed to improve the fault ride through capability of DGs [17, 18]. In the proposed protection scheme, the DGs connected to the feeder inject fault current for a defined time period (denoted by t_d) until fault is cleared by the overcurrent relays. The time period t_d can be chosen according to the protective relay requirements and DG disconnection requirements for abnormal voltages as given in IEEE standard 1547 [10].

The downstream relays can only sense the fault current coming from DGs connected to further downstream. If DGs are disconnected immediately after a fault, the relays do not have any information to detect and isolate the fault from the downstream side. Moreover, the converter connected DGs limit their output currents to a value that is twice the rated current during a fault to protect their power switches. Therefore the relay settings for reverse direction are set to detect the faults using the fault current coming from DGs. If faulted section is isolated from the rest of system within the time t_d, three types of DG status can be mainly identified depending on the DG locations.

(i) DGs connected to the utility grid

These DGs can operate in grid-connected mode after isolating the fault from the utility side (i.e. the upstream side from the fault) supplying the available power. In this case, DG benefits can be maximized for both utility and customers.

(ii) DGs connected to the faulted section

Since these DGs still supply the fault current, they can identify this condition only after the defined time period t_d elapses. Therefore the DGs connected to the faulted section will be disconnected either using the DG circuit breaker or by blocking the power semiconductor switches. If the fault is an arc fault, the disconnection of the DGs will help in arc extinction. Once the fault is cleared, the disconnected DGs need to be connected to the network.

(iii) DGs connected to the islanded section

There is an opportunity to form an islanded section containing some of the DGs and loads after faulted section is isolated. The configuration of the islanded system depends on the fault location. In this situation, the DGs can supply the load demand in the islanded section if the total DG capacity is sufficient to match the load. The DGs will have the ability to share load power while maintaining the system voltage and frequency within specified limits. There are several techniques available to control DGs in autonomous operation [19-22]. The islanded operation increases the system reliability since the customers of the islanded section will be unaffected by any long-term power interruption due to any permanent fault. If DG capacity is not sufficient to supply the load demand, DGs connected to the islanded section will be disconnected. The disconnection, however, can be avoided by defining a suitable load shedding scheme, which is not addressed here.

C. Islanded protection with DGs

If the faulted section is isolated from the network, some of the DGs may operate in islanded mode supplying the load demand. Therefore adequate protection for this islanded section must be provided. The forward settings of overcurrent relays located in islanded section will not be appropriate since they have been initially set considering the utility fault current. Therefore the relay settings should be changed by knowing the islanded status to detect faults in the islanded section. However, for a fault within the islanded section, the DGs will be disconnected after the defined time period t_d in the absence of protective relays or when the relays fail to detect a fault. Therefore the disconnection of the DGs is akin to providing backup protection for the islanded section.

D. System restoration by performing auto-reclosing

The system restoration is one of the most difficult protection issues when DGs are connected to a distribution network. In this paper, a new method for system restoration is proposed that uses auto reclosers. It has been assumed that directional overcurrent relays are connected to automatic circuit reclosers (ACRs) for system restoration. The relays issue the open or close command to ACR depending on the requirement.

In the proposed method, the faulted section restoration is commenced based on the identification of fault direction. A reclosing opportunity is given to the relay which sees the fault as forward. For example, let us assume that both forward and reverse relays have isolated the faulted section, thereby allowing the operation of an islanded section beyond the downstream relay. In this case, forward relay tries to close the ACR (live to dead reclosing) first after a pre-defined delay time period, t_r that is greater than t_d. This time period (t_r) allows the disconnection time for any DG that may be connected to the faulted section. This will also help in the self extinction of arc, if any. The downstream relay waits till upstream reclosing is successful. Only then it takes the opportunity to connect the downstream side with the upstream (utility) side.

The forward relay usually performs the live to dead reclosing since the fault section has been isolated by both upstream and downstream relays. The downstream relay, on the other hand, has to perform live to live or live to dead reclosing. If an islanded section operates successfully after the fault isolation, the downstream relay commands live to live reclosing, otherwise it performs live to dead reclosing. Usually for converter interfaced DGs, the risk of damage due to phase mismatch is low due to in-built converter protection schemes [23]. A phase mismatch however may result in unnecessary voltage and current transients. Thus, to avoid any phase mismatch when closing the ACR, each relay must have a synchronism check element. However, the control technique used in autonomous operation should be capable of maintaining the adequate system standards during the islanded mode since downstream reclosing can be only performed when two systems are fully synchronized. Immediately after the connection, DGs should switch over to grid-connected mode supplying the rated power to avoid any frequency drift which can cause over voltage at beat frequency [24].

If the downstream relay fails to isolate the faulted section, all the DGs connected downstream from the fault will be disconnected creating a dead circuit. Therefore the upstream relay still performs live to dead reclosing. Following this, disconnected DGs are manually reconnected.

III. SIMULATION STUDIES

Consider the radial distribution feeder shown in Fig. 1. The parameters of the study system are given in Table I. The ability of overcurrent relays to isolate the faulted section is considered. The directional overcurrent relays are selected for this application since different relay settings are required in forward and reverse directions. The directional overcurrent relays R_1, R_2 and R_3 are located at BUS-1, BUS-2 and BUS-3 respectively. The relays are placed just before the buses since the DG connected to that bus supply the fault current through this relay for upstream faults. Three converter interfaced DGs are connected at BUS-2 to BUS-4. Each DG is connected through a circuit breaker. The DG capacity is selected such that each DG can supply the load demand connected to its own bus since one of the goals of this study is to show the islanded operation with DGs.

The DGs limit their output current to twice the rated current during a fault in the network. However, in this case, the DGs inject the fault currents for a defined time period (t_d = 0.35 s) or until the fault isolation is achieved. Each DG has two control modes to operate depending on the present system configuration: current control and voltage control. The DGs supply the rated power in grid-connected mode operating in the current control mode. On the other hand, these DGs supply the power in the voltage control mode maintaining standard voltage and frequency limits during an islanded operation. However, in the case of a fault either in grid-connected or islanded operation, the DGs limit their output currents to twice the rated current operating in the current control mode. The faulted condition is identified by sensing the voltage drop at the converter terminal.

If the fault is cleared within 0.35 s (i.e. defined time period), the converter will recover and start supplying power in either grid-connected or islanded mode. Otherwise, the DG will be disconnected by operating its circuit breaker. It is to be noted that the DG disconnection occurs either due to the uncleared fault in the network or due to excess load demand in the islanded section. Two different case studies are considered to analyze the proposed protection strategies.

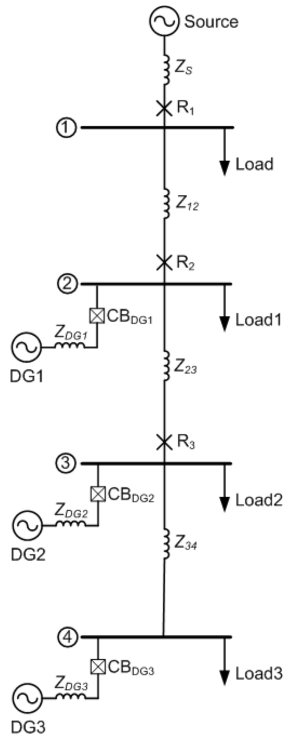

Fig. 1. Radial distribution feeder with DGs and loads.

TABLE I
SYSTEM PARAMETERS

System Quantities	Values
System frequency	50 Hz
Source voltage	11 kV rms (L-L)
Source impedance (Z_{dg})	0.39 + j 3.927 Ω
Feeder impedance (Z_{12}=Z_{23} =Z_{34}) Positive sequence Zero sequence	 0.585 + j 2.9217 0.8775 + j 4.3825
Load power	1.0 MVA, 0.8 pf
DG power rating	1.0 MVA

A. If DGs are consistent

It is assumed that all the DGs connected to the network and supplying power all the time. Therefore the fault current supplied from DGs does not change with time. In this configuration, fault analysis can be conducted to perform the relay settings considering the DG connections. As mentioned earlier, the DGs inject the same fault current (i.e., twice the rated current) during a fault in the current control mode. Therefore, the relays downstream to a fault can use the DG fault currents to detect and isolate the fault from downstream side. For example, for a fault between BUS-2 and BUS-3, the downstream relay R_3 will see the fault current supplied by DG2 and DG3.

The relay grading should be performed separately for forward and reverse directions. In forward direction, the relays are graded considering both utility and DG connections. However the fault current contribution from these current limited DGs are significantly low compared to the utility fault current. The IEC standard inverse time characteristic [25] is selected for the relays in the forward direction. Moreover, an instantaneous tripping element is added to achieve fast fault detection and isolation reducing the operating time for higher fault current levels. The maximum and minimum fault current levels at each bus is calculated and used to set the inverse time and instantaneous relay elements. Discrimination time margin of 0.3 s is maintained between two adjacent relays. Appropriate current transformer (CT) ratios are selected and then time multiplier setting (TMS) and relay setting current (i.e. pickup current) are calculated for each standard inverse time relay element. The calculated relay settings are given in Table II. In the reverse direction, relays can be only graded considering the DG fault currents and it is explained below.

As the first step, the maximum load current seen by each relay during normal operating condition is calculated in the reverse direction. It is to be noted that DGs supply the rated power (i.e. rated current) in grid-connected mode during the normal operating condition. However, in the absence of all loads in the feeder, the DGs can feed the rated current towards the utility side and this will be the maximum load current can be seen by the relays in reverse direction. Therefore none of the relays should be triggered by this level of current. Therefore, the relay setting current (pickup current) for each relay is selected above the maximum load current by keeping a safety margin.

Consider the relays R_2 and R_3 shown in Fig. 1. The definite time overcurrent relay characteristic is selected for these relays in reverse direction since the difference between maximum load current and fault current is comparably small due to the current limiting of converters. If an inverse time relay characteristic is selected as in the case of forward direction, higher fault clearing time can be experienced due to the lower fault current level since the ratio between fault current and relay setting current is small. Moreover, defining a time period for current limiting of converters will be easy since the tripping time of definite time relay characteristic is not changed.

TABLE II
RELAY SETTING IN FORWARD DIRECTION

Relay	CT ratio	Pickup current (A)	TMS
R_1	250/5	5	0.15
R_2	200/5	4.5	0.1
R_3	200/5	4.5	0.05

The maximum load current seen by R_2 (in case when all the DGs are supplying the rated power to utility in the absence of all the loads) can be calculated as 157.5 A, where 52.5 A is being the rated current of each converter. Therefore the relay R_2 is set to detect faults which have fault currents above 236.25A by maintaining a safety margin of 1.5 times the maximum load current. Similarly, the maximum load current seen by R_3 is 105A and this relay is set to detect fault currents above 157.5 A. Time delay setting of R_2 for definite time characteristic is selected as 0.1 s while it is set as 0.3 s for R_3, thereby allowing 0.2 s time discrimination margin between these two relays. Note that the same CTs are used for both forward and reverse current sensing. The selected relay settings are given in Table III.

The sensitive earth fault elements are also used to detect high resistive earth faults in addition to the normal phase and earth faults. The IEC standard inverse relay tripping time for different fault currents is shown in Fig. 2. It can be seen that relays are graded appropriately to provide backup protection for the adjacent downstream relay. The setting of instantaneous tripping element for each relay is also shown in the figure. The instantaneous current settings are shown by R_{1ins}, R_{2ins} and R_{3ins} for the three relays. For example, consider a fault at point *A* shown in Fig. 2. The fault current is 2250 A and the fault should be between BUS-1 and BUS-2 since the fault current is higher than the maximum fault current seen by R_2. Therefore, R_1 should isolate this fault from the upstream side. The standard inverse time relay element of R_1 takes 0.465 s to clear this fault. This is the disadvantage of inverse time relay element grading. The relay near to the source takes longer time to clear faults which have higher fault current levels. In this case, the problem is overcome by using the instantaneous relay element of R_1 which will clear this fault instantly. It is to be noted that in the simulation, the instantaneous elements are set to trip after a time delay of 60ms.

The efficacy of employed protection scheme is simulated in PSCAD for different fault types at different fault locations. However, several results for single line to ground (SLG) faults are presented. A SLG fault is created at the middle of the line between two buses with the fault resistance of 1.0 Ω and the relay response time is observed as listed in Table IV. It can be seen that the relays employed in the system have the

TABLE III
DEFINITE TIME RELAY ELEMENT SETTINGS IN REVERSE DIRECTION

Relay	CT ratio	Pickup current (A)	Time delay (s)
R_2	200/5	5.9	0.1
R_3	200/5	3.9	0.3

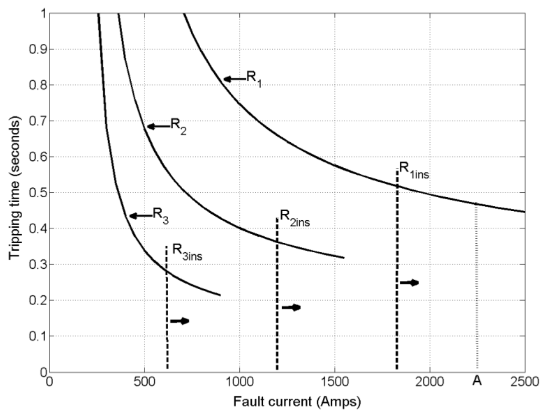

Fig. 2. Relay tripping time characteristics in forward direction.

TABLE IV

RELAY RESPONSE FOR DIFFERENT FAULT LOCATIONS

Fault location	Relay operating time (s)		
	R_1	R_2	R_3
BUS-1 and BUS-2	0.077	0.104	0.305
BUS-2 and BUS-3	0.797	0.429	0.305
BUS-3 and BUS-4	1.176	0.574	0.286

TABLE V

SYSTEM BEHAVIOR AFTER FAULTED SECTION ISOLATION

Fault location	System status after faulted section is isolated
BUS-1 and BUS-2	DG1, DG2 and DG3 supply the load demand in islanded operation beyond BUS2. The recloser associated with R_1 takes the opportunity to perform the reclosing by identifying this fault as forward. The relay R_2 waits until R_1 restores the system to synchronize the islanded section with the utility.
BUS-2 And BUS-3	DG2 and DG3 supply the load demand in the islanded section beyond BUS3. DG1 is disconnected after the defined time period and then R_2 takes the opportunity to perform reclosing as this is the forward relay to the fault. R_2 performs live to dead reclosing to make sure that all the DGs connected to the faulted section have been disconnected. R_3 waits until upstream side is restored to connect the islanded section. DG1 should be connected manually once system is restored.
BUS-3 And BUS-4	DG1 supplies the power in grid-connected mode. DG2 and DG3 are disconnected since they are connected to the faulted section. R_3 will perform reclosing. Once system is restored, DG2 and DG3 are connected manually.

ability to isolate the faulted section from the network. After the fault isolation, different system status, DG behavior and further relay actions can be identified as given in Table V. These results confirm that it is not essential to disconnect the DGs from a network if faulted section can be isolated. If fault is cleared before the faulted section isolation (i.e., temporary fault), the system can recover without disconnecting any DG, thereby maximizing the DG benefits. The fault ride through capability of DGs plays an important role to achieve the fault isolation. The system restoration is proposed using ACRs by defining a sequence of operations. This results in maximizing the DG benefits to customers while increasing the reliability of the network.

B. If DGs are not consistent

This is a realistic situation that can arise due to the intermittent and plug and play nature of the renewable sources. In this situation, the fault current seen by overcurrent relays which are located downstream to a fault will change with time depending on the number of DG connections. Therefore, it is very difficult to set these relays for a particular setting to isolate the faults. The fault current seen by upstream relays does not change significantly since fault current supplied by utility is significantly higher than the fault current supplied by current limited DGs. However the adverse effect on downstream overcurrent relays is significant.

To overcome the relay reach setting problem in reverse direction under this changing fault current environment, an adaptive type overcurrent protection scheme is proposed with the aid of communication. In the proposed protection scheme, the relays which are graded in reverse direction know the status of each DG circuit breaker. This helps relay to change the reach setting according to the present system configuration. The relay only needs to know the status of each DG circuit breaker located downstream to the relay. Based on the DG circuit breaker status, a binary signal (1 or 0 to represent connectivity and disconnectivity respectively) is transmitted to the relay. This is one way communication needed between the DGs and the relays. No fast communication scheme is required since only the change of system status is the important. It is to be noted that relay reach settings in forward direction do not change with the system configuration since the effect of current limited DGs on forward relay reach is small.

Let us add one way communication links to the system of Fig. 1. The relay R_2 will have the information of DG1, DG2 and DG3 connectivity while the relay R_3 will only have the connectivity information of DG2 and DG3. As similar to the previous study, the relay reach settings of R_2 and R_3 are calculated based on the number of DGs connected to the system considering maximum load current in normal operating condition. These calculated reach settings for different system configurations are then stored in the relays. The relays select the appropriate reach setting from the stored values according to the present system configuration.

When all the DGs connected downstream to a relay are absent, the relay is blocked in the reverse direction since there is no need to isolate the fault from the downstream side. In case of a communication failure, the relay reach setting is automatically adjusted to system default setting where these relays assume that all the DGs are connected. This configuration is selected to avoid nuisance tripping since DGs can feed power back to utility with the absence of several loads.

If the communication fails, the relays select their default settings. However, the actual network configuration may not be the same one as selected by the relays. As a result, a fault may not be detected from the downstream side. However, this failure of fault detection causes all the DGs located downstream from the fault to disconnect, failing to operate in an islanded mode. The DGs connected further upstream to the forward relay will operate in grid-connected mode. Therefore it can be seen that even if downstream relay fails to operate for a fault, the network will have adequate protection to provide a safe operation.

PSCAD simulation results for different system configurations are given in Table VI. A SLG fault is created between BUS-1 and BUS-2 with a fault resistance of 1Ω. The relay R_1 detects the fault in forward direction while the relays R_2 and R_3 detect it from the downstream side. The operating time of R_3 is obtained by simulating the case where R_2 fails to detect the fault. It can be seen from Table VI that the proposed protection scheme with the aid of overcurrent relays and communication can isolate the faulted section from both upstream and downstream side depending on the system configuration. In this analysis, the DGs are current limited and their connectivity changes with time. After successful faulted section isolation, DGs connected to unfaulted sections can operate either in grid-connected or islanded mode supplying power to customers thereby increasing the reliability. The system restoration using ACR is similar to the one explained before and it is not discussed here.

TABLE VI

RELAY OPERATING TIME FOR DIFFERENT DG CONFIGURATIONS

DG1	DG2	DG3	R1 (s)	R2 (s)	R3 (s)
0	0	0	0.070	N.O.	N.O.
0	0	1	0.071	0.100	0.304
0	1	0	0.071	0.100	0.304
0	1	1	0.071	0.112	0.312
1	0	0	0.070	0.100	N.O.
1	0	1	0.070	0.100	N.O.
1	1	0	0.071	0.112	0.304
1	1	1	0.071	0.112	0.312

0= disconnected, 1= connected, N.O.= No operation.

IV. CONCLUSIONS

The current practice of DG disconnection for every fault in a network drastically reduces the DG benefits, particularly the reliability to customers when DG penetration level is high. The network protection can be identified as one of the major reasons for these DG disconnections. Therefore, reliable protection solutions are needed to overcome the immediate DG disconnections after a fault and to maximize the DG benefits. In this paper, protection strategies are proposed to isolate the smallest portion of a faulted section allowing unfaulted sections to operate either in grid-connected or islanded mode without disconnecting DGs from the unfaulted sections.

In order to achieve this solution, both upstream and downstream protective devices are used to isolate a fault in the network. An overcurrent relay protection scheme has been proposed to isolate the faulted section depending on the DG behavior. If DGs are based on time varying sources, one way communication is used between DGs and relays to change the relay reach settings appropriately. Also, in this proposed scheme, the converters should have the ability to supply the fault current for a defined time period until relays isolate the fault. The system restoration can be then started by performing the auto reclosing. The proposed protection strategies help to maximize the DG benefits to both utility and customers maintaining as many DG connections as possible in a high penetrative DG network.

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