CSIRO Intelligent Grid Research Cluster- Project 7

M4: Microgrid Operation and Control Executive Summary

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Executive Summary

The cost of transmission and distribution is rising with the rapid increases in the load demand. However, the costs of distribution generation technologies are falling [1]. So from a costing point of view, it is becoming more worthwhile to increase the generation at the distribution level by connecting distributed generators (DGs) to meet the load requirement without expanding the transmission and distribution infrastructure. In addition, there are several advantages of having DGs; short construction time, lower capital costs, reduction in greenhouse gaseous emissions, reduced transmission power loss since generation is now closer to the load, improving voltage profile, enhancing reliability and diversification of energy sources [2-4].

A microgrid can be considered as an entirely DG based grid that contains both generators and loads [5]. It is usually connected to the utility grid through a single point, called the point of common coupling (PCC). To the utility grid, the microgrid behaves as a fully controllable load which at peak hours can even supply power back to the utility grid. A microgrid can operate in either (utility) grid connected mode or islanded mode [6] and can seamlessly change between these modes. The islanding occurs when the utility supply is disconnected and at least one generator in the disconnected microgrid system continues to operate. In the islanded mode, the DGs connected to the microgrid supply its loads, where a provision for load shedding exists if the load demand is higher than the total DG generation. Some of the issues in DG connected microgrids or distribution networks that need attention can be identified as bi-directional power flow, change of fault current level, islanding protection, reclosing, arc extinction and protection in the presence of current limited converters [7-9].

Most of the existing distribution systems are radial where power flows from substation to the customers in a unidirectional manner. The coordination of protective devices based on current is relatively easy in such systems. Usually overcurrent relays are employed for such distribution system protection for their simplicity and low cost [8, 10]. However, the protection of the distribution network becomes more complicated and challenging once a microgrid or several DGs are connected. With such connections, the pure radial nature of utility supply is lost [1, 11, 12]. The power flow then becomes bi-directional [7, 13]. Under such situations, the existing protection devices may not respond in the fashion for which they were initially designed [8].

The present practice is to disconnect the DGs from the network using an islanding detection method when there is a fault in the system [7, 14]. This is as per the IEEE recommended practice, standard 1547 [15]. The islanding operation with DGs is prohibited due to the restoration, personnel safety and power quality issues [12]. Therefore, the DGs need to be disconnected even for temporary faults [13].This may work satisfactorily when the penetration of DGs in a distribution system is low. However, as the penetration levels increase or in the case of micro or mini-grid, the DGs will be expected to supply power even when the supply from the utility is lost and the DGs form a small island. If protection scheme can isolate the faulted section and enable intentional power islands, system reliability can be increased [15]. Also, it will bring benefits to customers by reducing outages [9]. Therefore, the benefits of

DG installations can be maximized allowing the DGs to operate in both grid connected and islanded modes of operation, especially when the DG penetration level is high.

The fault current may change due to the presence of DGs in the network [1, 9, 16-18]. Its impact depends on the size, type, number of the DG, location of the DG [11, 19]. The system which is not designed with DGs may not work properly with existing protective devices once several DGs are connected to the system [12]. In the presence of a DG within the network, the fault current detected by a protective device located at the beginning of the feeder can be reduced due to the rise of voltage drop over the feeder section between the DG and the fault [8]. Therefore the faults previously cleared in a very short time may now require a significant time to clear. It has been shown that the reach of an overcurrent relay will reduce in the presence of a DG [20].

In the case of a microgrid, the protection system should respond to faults within the microgrid irrespective of its grid connected and islanded operation. For a fault in the utility grid, the microgrid should disconnect immediately from the PCC to maintain a continuous supply to the microgrid loads. On the other hand, the smallest possible set of faulted lines of the microgrid must be isolated for a fault within this grid. However, the short circuit levels within the islanded microgrid system may drop significantly upon disconnection from the utility [8, 10, 16].

Most of the distribution resources in the microgrid are connected through the power electronic converters which pose operational challenges [21]. For example, the dc power is generated by using the sources such as fuel cell, micro-turbine, or photovoltaic cells need converters to convert the dc power into ac power. To prevent the power electronic switches from damage, these converter interfaced DGs cannot supply currents that are much greater than the nominal load currents [22]. This creates problems during faults as sufficient current does not get injected from the converters such that the current sensing devices can reliably detect fault conditions. As a consequence, the overcurrent relays may not respond or take a long time to respond [5, 6, 22, 23]. Therefore protecting a converter dominated microgrid is a challenging technical issue under the current limited environment [24].

Most of the faults (around 80-90%) in the power system are temporary (such as conductors clashing due to strong wind, tree branch falling on the lines, animal contacts, lightning strikes, etc) and they can be successfully removed by performing reclosing [25]. Many such faults result in arcing which is sustained so long as current flows through the circuit. Therefore such faults can be successfully cleared by de-energizing the line long enough to self extinguish the arcs. Usually reclosers which open and close a few times successively, leaving a time gap between successive switch opening and closing, are used to clear such faults. This prevents any large scale power interruption that can happen if circuit breaker are used [25]. In a DG or microgrid connected distribution network, the reclosing should be performed with proper synchronization since this will join two live systems.

In the case of arc faults, sufficient time should be given to de-ionize the gas path during the recloser open condition. Otherwise the arc may reignite again and fault will not be cleared [26]. Also, if DGs are kept connected to the system during recloser open time, they can sustain the arc. The arc self-extinction action depends not only on the fault current magnitude, but also on the transient recovery voltage rate after successful arc extinction at the current zero crossing [27]. Also the arc extinction time is proportional to the arc time constant [28]. On the other hand, the fault current magnitude of an arc fault is limited by the arc resistance. Sometimes it results in difficulties of detecting the fault [29]. Therefore protection of distribution network and restoration under arc fault is nontrivial.

Once an auto recloser opens, voltage magnitude and phase of the islanded system have changed vis-à-vis those of the utility side. Therefore once the recloser closes, the voltage magnitude and phase mismatch between the systems may cause severe transient current to flow. This can damage the converters and other equipment connected to the microgrid [11]. For the converter connected DGs, the risk of damage to the DGs is low as they have their own protection [26]. In general, a DG is disconnected before the first reclosing occurs in the system. This requires that any anti-islanding protection should operate very quickly. As a result, the recloser should coordinate with the anti-islanding protection, which in itself is a challenging task [16]. A communication link can be established between the line recloser and the DG to transfer trip signal to disconnect the DG quickly [30]. An automatic synchronizing or synchronism check relay should be used at the PCC breaker while restoring the system after disconnection [31].

It has been reported that the only way to maintain the existing coordination system in the presence of arbitrary DG penetration level is to disconnect all DGs instantly in the case of a fault [1]. If the DG is not disconnected from the system at the event of a fault, the fault arc would not extinguish during an automatic recloser open time, since the source feeding the fault still remains. However, the automatic disconnection of DGs during loss of main grid supply drastically reduces the DG benefits [7]. The DG benefits can be maximized if as many DGs as possible are allowed to maintain connection for temporary faults in a high penetrative DG connected distribution network [32]. Therefore it is clear that a new protection paradigm is required to overcome this problem.

In this report, protection issues associated with disconnection of DGs are addressed in 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. Overcurrent relay based protection scheme is proposed for a converter based DG connected radial feeder to operate either in grid-connected or islanded operation, thereby 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.

1. Introduction

With the rapid increase in electrical energy demand, power utilities are seeking far more power generation capacity. However, environmental concerns make the addition of central generating stations and the erection of power transmission lines more difficult. Thus, newer technologies based on renewable distributed energy (DE) 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 in the near future. It is expected that 20% of power generation will be through renewable sources by the year 2020 [1]. However, by that time, the penetration level of DGs is expected to be higher in many countries which are seeking accelerated deployment of renewable technologies. 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 [2,6-8]. 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 [9]. This is because the protective devices may not respond in the fashion in which they were initially designed [5,10]. This change in response may be due to the change in parameters, such as source impedance, short circuit capacity level and change of fault currents and fault current directions at various locations.

The present practice is to disconnect the DGs from the network using an islanding detection method when a fault occurs [5]. This is in accordance with the stipulation of IEEE Standard 1547 [11]. The islanding operation with DGs is prohibited due to the restoration, personnel safety and power quality issues [12]. Therefore, the DGs need to be disconnected even for temporary faults [13]. The standard 1547 is formed with the assumption that the penetration level of DGs in distribution systems remains low. However, as the penetration level increases, the disconnection of these DGs drastically reduces the benefits of DGs [14]. If protection scheme can isolate the faulted section and enable intentional power islands, system reliability can be increased [15]. Moreover, this existing protection scheme will not work in the case of a microgrid in an islanded operation.

In this report, 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 even with overcurrent relays. Also the system restoration issue in the event of a temporary fault is studied. The proposals are verified through PSCAD simulation and MATLAB calculations.

2. The Protection Issues

The major protection issues associated with DG connections that will provide adequate system protection to operate DGs either in grid-connected or islanded mode are identified as:

- A smallest faulted section isolation
- 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 develop by the research team at QUT are elaborated below.

A. Smallest Faulted Section Isolation

When a fault occurs in a traditional radial network, the overcurrent relays operate in such a fashion such that the portion of the network downstream from the fault is disconnected. This causes power interruption to the customers downstream from the fault location [16]. This unnecessary customer power interruption can be minimized if DGs are allowed to supply power to customers in the unfaulted portions of a network following a fault. 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, provided that the DG capacity is sufficient to supply load power requirement in any islanded section. Also note that islanded operation is desirable in the case of permanent faults which may require several minutes or hours to clear.

A faulted section can be isolated if both upstream and downstream side protective relays respond in a DG connected radial system. Therefore directional overcurrent relays are proposed for such a network. In the grid connected mode, the upstream relay senses the fault current supplied by the utility, while the downstream relay 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 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.

As mentioned above, 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 at a particular time, the fault current level in a network changes depending on the number of DG connections. In this situation, to achieve the fault isolation, the relay settings should be changed 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 directional overcurrent 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 for 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 grid 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 [17]. Different control strategies have been proposed to improve the fault ride through capability of DGs [18,19]. 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 [11].

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 a bit higher than their 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.

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 rated power. In this case, DG benefits can be maximized for both utility and customers.

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 manually connected to the network.

DGs connected to the islanded section

There is an opportunity to form an islanded section containing some of the DGs and loads after the faulted section is isolated. The configuration of the islanded system depends on the location of the fault. In this situation, the DGs can supply the load demand of the islanded section if the total DG capacity is sufficient to match the load and therefore 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 [20-23]. The islanded operation increases the system reliability since the customers of the islanded section will be unaffected by any long-time 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 set considering the utility fault current. Therefore the relay settings should be changed by knowing the islanded configuration 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 the 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 report, 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 started based on the identification of fault direction. 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 it 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 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 reverse relay perform 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 scheme [24]. A phase mismatch however may result in unnecessary voltage and current transients that may be damaging for loads. 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 high voltage at beat frequency [25].

Let us consider the situation when the downstream relay fails to isolate the faulted section. This will cause all the DGs connected downstream to trip. Therefore even if the downstream relay is closed, the downstream circuit is dead. Therefore the upstream relay still closes live to dead reclosing. Following this, the DGs are manually reconnected.

3. Simulation Results

The radial distribution feeder shown in Fig. 1 is considered for simulation studies. The parameters of the study system are given in Table 1. The ability of protective devices to isolate the faulted section is considered when overcurrent relays are employed to protect the network. The directional overcurrent relays are selected for this application since different relay settings are required for forward and reverse directions.

Table 1: 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

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 which will provide the protection for the DG. 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 using these 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 operation 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 and operated 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, the converter will recover and start supplying power in either grid-connected or islanded mode. Otherwise, the converter-DG system 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 higher load demand in the islanded section. Two different case studies are considered to analyze the proposed protection strategies.

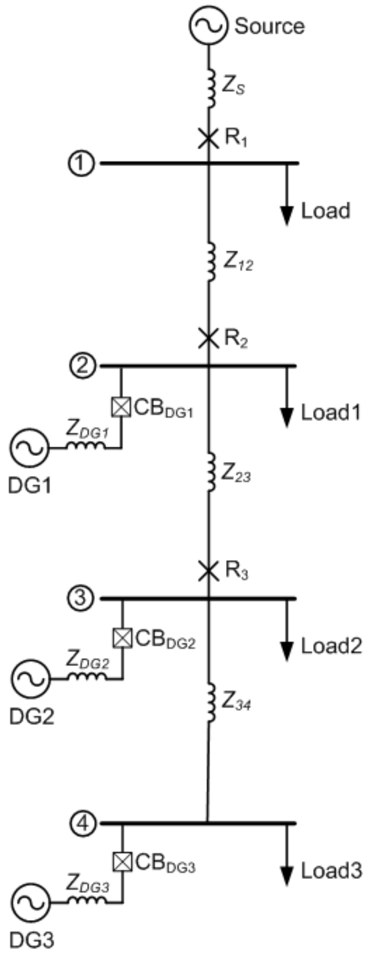

Fig.1. Radial distribution feeder with DGs and loads.

A. If DGs are neither Intermittent nor Inconsistent

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 of 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 [26] for inverse time characteristic 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 given in Table 2 are 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 3.

Table 2: Fault currents at different buses in forward direction.

Fault Type	Fault current (A)			
	BUS-1	BUS-2	BUS-3	BUS-4
SLG	5248	1359	780	546
LL	4545	1317	769	543
LLG	5285	1462	847	596
3Phase	5248	1521	888	626

Table 3: Relay setting in forward direction.

Relay	CT ratio	Pickup current (A)	Time multiplier setting (TMS)
R1	250/5	5	0.15
R2	200/5	4.5	0.1
R3	200/5	4.5	0.05

In the reverse direction, relays can be only graded considering the DG fault currents. For example, for a fault between BUS-1 and BUS-2, R_2 will see the current injected by all the three DGs, while R_3 will only see fault current injected by only two DGs. The relay setting considerations in the reverse direction are 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 trigger 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.

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 4.

Table 4: Definite time relay element settings for reverse direction.

Relay	CT ratio	Pickup current (A)	Time delay
R2	200/5	5.9	0.1
R3	200/5	3.9	0.3

The selected different relay elements in forward and reverse direction are given in Table 5. 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.

Table 5: Different relay elements to detect different faults (N.O.: No operation)

Relay	Protection type	Forward direction	Reverse direction
R1	Phase overcurrent and earth overcurrent	Inverse time and instantaneous elements	N.O.
	Sensitive earth overcurrent	Definite time element	N.O.
R2	Phase overcurrent and earth overcurrent	Inverse time and instantaneous elements	Definite time element
	Sensitive earth overcurrent	Definite time element	Definite time element
R3	Phase overcurrent and earth overcurrent	Inverse time and instantaneous elements	Definite time element
	Sensitive earth overcurrent	Definite time element	Definite time element

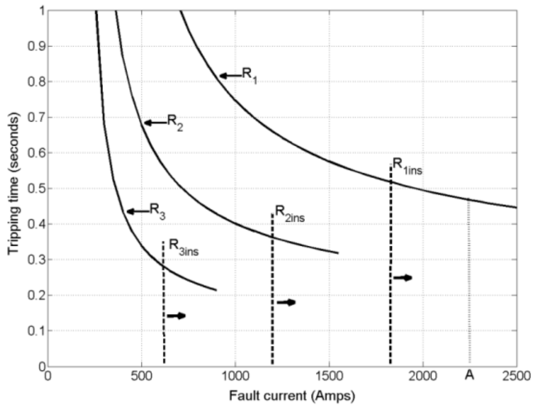

Fig.2 : Relay tripping time characteristics in forward direction.

The efficacy of employed protection scheme is simulated in PSCAD software for different fault types at different fault locations. However, several results for single line to ground (SLG) faults are given in Table 6. An 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 through PSCAD simulations and is listed in Table 6.

It can be seen that the relays employed in the system have the 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 7.

Table 6: Relay response for SLG faults at different fault locations.

Fault location	**Relay operating time (seconds) and type of relay response**		
	R_1	**R_2**	**R_3**
BUS-1 and BUS-2	0.077 Instantaneous element in forward direction	0.104 Definite time element in reverse direction	0.305 Backup operation by definite time element if R_2 fails
BUS-2 and BUS-3	0.797 Backup operation by definite time element if R_2 fails	0.429 Inverse time element in forward direction	0.305 Definite time element in reverse direction
BUS-3 and BUS-4	1.176 Backup operation by inverse time element if both R_2 and R_3 fail	0.574 Backup operation by inverse time element if R_2 fails	0.286 Inverse time element in forward direction

Table 7: System behaviour after faulted section is isolated.

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 R1 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 always 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.

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 and thereby maximizing the 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 Either Intermittent or Inconsistent

This is a realistic situation that can arise due to the intermittent and plug and play nature of the renewable sources. The DGs may be intermittent – photovoltaic solar based DGs can only supply power during day time unless they have storage devices or they are not connected all the time due to utility regulations (i.e. utility may use these DGs only to supply peak load demand requirements). Also electric vehicles may supply power during only the peak hours.

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. As mentioned earlier, the main aim of detecting a fault from downstream side is to isolate the faulted section from the network and allow DGs which are connected to unfaulted sections to operate either in grid-connected or islanded mode maintaining the electricity supply.

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 devices. In the proposed protection scheme, the relays which are graded in reverse direction know the status of each DG circuit breaker. This helps the 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 (0 or 1 to represent connectivity) 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.

The Fig. 1 is modified by adding proposed one way communication links and it is shown in Fig. 3. 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. Different system configurations can be identified depending on the DG connectivity as given in Table 8. 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. The calculated reach settings values are given in the Table 8. The rated current of each converter is assumed to be 52.5 A and the reach setting values are given without considering the CT ratio for easy understanding. As can be seen from the table, the relays R_2 and R_3 change their relay reach settings according to the 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. It is to be noted that in case of a communication failure, the relay reach setting is automatically adjusted to system configuration 8 (i.e. default settings of relays) where these relays assume that all the DGs are connected to the network. This configuration is selected to avoid nuisance tripping since DGs can feed power back to utility with the absence of several loads and maximum load current can be seen by R_2 and R_3 will be 157.5 A and 105 A respectively.

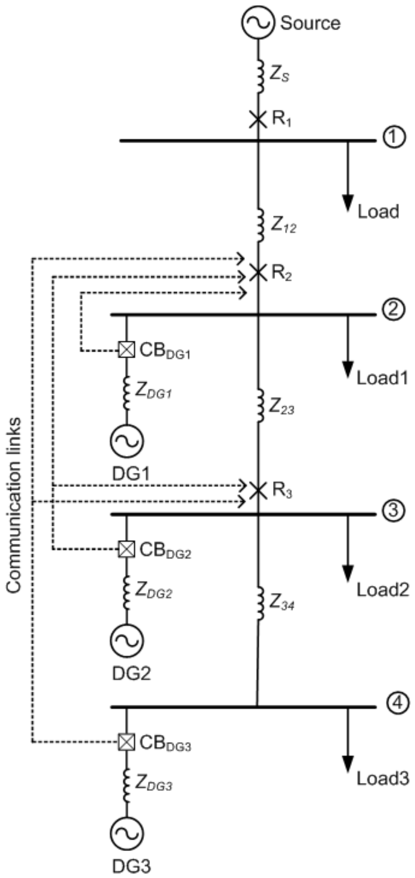

Fig. 3 DG connected radial feeder with communication links

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 9. An 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.

Table 8: Relay reach settings in reverse direction (0: Not connected, 1: connected).

System configuration	DG1	DG2	DG3	R_2 current setting	R_3 current setting
1	0	0	0	BLOCKED	BLOCKED
2	0	0	1	52.5×1.5 = 78.75	52.5×1.5 = 78.75
3	0	1	0	52.5×1.5 = 78.75	52.5×1.5 = 78.75
4	0	1	1	2×52.5×1.5 = 157.5	2×52.5×1.5 = 157.5
5	1	0	0	52.5×1.5 = 78.75	BLOCKED
6	1	0	1	2×52.5×1.5 = 157.5	52.5×1.5 = 78.75
7	1	1	0	2×52.5×1.5 = 157.5	52.5×1.5 = 78.75
8	1	1	1	3×52.5×1.5 = 236.25 Default condition	2×52.5×1.5 = 157.5 Default condition

Table 9: Relay response for different DG configurations.

System configuration	DG1	DG2	DG3	R_1 operating time	R_2 operating time	R_3 operating time
1	0	0	0	0.070	N.O.	N.O.
2	0	0	1	0.071	0.100	0.304
3	0	1	0	0.071	0.100	0.304
4	0	1	1	0.071	0.112	0.312
5	1	0	0	0.070	0.100	N.O.
6	1	0	1	0.070	0.100	N.O.
7	1	1	0	0.071	0.112	0.304
8	1	1	1	0.071	0.112	0.312

According to the results given in Table 9, it can be seen 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.

4. 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 becomes high. According to the IEEE standard 1547, 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 stipulation of immediate DG disconnections and to maximize the DG connection benefits.

In this report, 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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