CSIRO Intelligent Grid Research Cluster- Project 7

Microgrid Operation and Control

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DELIVERABLE 6: Protection of Meshed Microgrids

Executive Summary

The increase in load growth can be supplied by distributed generators (DG) near to customer loads without expanding the existing network infrastructures. This is a more economical and less carbon intensive of generating power, especially through making use of renewable distributed energy sources. These small to medium size generators distributed throughout a network are known as distributed generators (DGs). There are different types of DG technologies available. Among them, combined heat and power (CHP) plants, bio-diesel generators, micro-turbines, fuel cells, wind turbines, mini-hydro power plants, solar photovoltaic arrays (PVs), DGs based on biomass, geothermal and tidal are getting more attractive.

A few or more DGs discussed above can be integrated into form a self sustained electric grid to supply local loads in the absence of the main utility grid. This small electric grid is known as a microgrid. The microgrid is capable of operating either when it is connected to the main utility grid (grid-connected mode) or it can continue operation without the presence of utility grid (islanded or autonomous mode) maintaining the power quality within the microgrid. DGs, specially based on renewable energy sources such as solar and wind can be effectively integrated into a microgrid to supply rapid load growth demand. This is one of the major advantages of forming microgrids in a distribution networks.

Appropriate protection schemes are vital to ensure personnel and equipment safety in a microgrid. To maximize the benefit of a microgrid, it should be allowed to operate either in islanded mode or grid connected mode. In order to do so, protection scheme employed in the microgrid should be capable of detecting and isolating faults in both modes of operation. There are some barriers can be identified preventing this happening with the existing protection schemes.

Overcurrent (OC) protection is usually used to protect conventional radial feeders where power flow is unidirectional. However, the power flow within a microgrid is bi-directional due to DG connections at different locations or its meshed configurations. This will create new challenges for designing appropriate protection schemes. When a microgrid operates in an islanded mode, the short circuit levels will be significantly lower compared to when it is connected to a strong utility grid. This change in fault current levels from grid-connected mode to islanded mode creates protection issues for protective devices which are designed to operate based on the fault current (i.e., overvcurrent). Therefore, the same protection setting used in grid connected mode cannot be used in islanded mode operation.

Furthermore, different fault current levels can be experienced due to intermittent nature of DG primary sources (e.g., solar photovoltaic based DGs). Therefore, the fault current level at a particular circumstance is not known and this can result in implementation of protection schemes based solely on fault current level more difficult. This is one of the major reasons why alternative protection strategies are required to ensure a safe islanded operation of a microgrid.

DGs interfaced through converters have inbuilt current limiters to protect their power switches during a fault in the system. As a result of this, these DGs cannot supply sufficient currents to trigger the protective devices which are designed based on fault currents in an islanded microgrid. Therefore protecting a converter dominated microgrid is a challenging technical issue.

The reliability of a microgrid can be increased by allowing it to form meshed configurations. However, the protection schemes proposed for radial microgrids cannot be effectively deployed in meshed microgrids. The fault current seen by each relay within the mesh configuration will not have an appreciable difference due to short line segments in the microgrid. In this circumstance, fault detection and isolation will be difficult without employing reliable communication channels.

Research Aims

The purpose of this report is to investigate the protection issues associated with microgrids and to propose new protection strategies required to overcome the identified issues. Specifically, the protection of meshed microgrids. Different protection strategies are considered that are appropriate for meshed microgrid protection. An inverse time admittance (ITA) relay is presented for microgrid protection in both grid connected and islanded modes of operation. The ITA relays are capable of detecting faults irrespective of fault current levels, thereby avoiding the requirement of communication overlay.

Furthermore, a differential protection scheme for a meshed microgrid protection is proposed based on digital current differential relays. Each local relay communicates with the remote end relay to detect an internal fault on the feeder. The proposed scheme is selective and it is not dependent on the fault current levels in the microgrid. It has been shown that a safe operation of a meshed microgrid can be enhanced in both grid connected and islanded modes of operation using proposed current differential relays with a suitable communication channel. Furthermore, current transformer selection criterion for protective relays is also discussed.

1. Introduction

A microgrid integrates distributed energy resources to provide reliable, environmentally friendly and economical power to small/medium sized urban communities or to large rural areas. A microgrid is designed to operate either in grid connected or islanded modes of operation [1]. Islanding occurs when the grid supply is disconnected during a major disturbance and distributed generators (DGs) in the disconnected section continue to supply local loads. Therefore, the islanding operation brings benefits to customers by reducing outages. However, once islanding occurs, short circuit levels may drop significantly due to the absence of strong utility grid [2-4]. Therefore, the protection system which is originally designed for high short circuit current levels will not respond for faults in islanded mode [5]. This is one of the major reasons why new protection strategies are required to ensure a safe islanding operation in a microgrid.

The power flow within a microgrid is bi-directional due to DG connections at different locations or its mesh configuration. This will create new challenges for the protection of such grids. In a microgrid, most of the sources are connected through power electronic converters [6]. For example, dc power is generated by using the sources such as fuel cells, micro turbines, or photovoltaic cells, converters are utilized to convert the dc power into ac power. These converters do not supply sufficient currents to operate current based protective devices in islanded mode because they have been designed to limit the fault current [7]. Therefore protecting a converter dominated microgrid is a challenging technical issue under the current limited environment [8-10].

Some of the DGs connected to a microgrid are intermittent in nature (e.g., solar photovoltaic based DGs). Therefore different fault current levels can be experienced in the microgrid depending on the active DG connections [11]. As a result, implementation of protection schemes based on fault current level will be further difficult.

The reliability of a microgrid can be further increased by forming a meshed configuration. However, the protection schemes proposed for radial microgrids cannot be effectively deployed in meshed microgrids [12]. The fault current seen by each relay within the mesh configuration will not have an appreciable difference due to short line segments in the microgrid. In this circumstance, fault detection and isolation will be difficult without employing reliable communication channels.

When designing an appropriate protection scheme for a microgrid, several factors should be carefully considered. The protective devices employed in microgrid should be coordinated considering reliability (correct operation), selectivity (minimum system disconnection), speed of operation (minimum fault duration), simplicity (having minimum protective equipment) and economics (maximum protection under minimum cost). These coordinated actions should be implemented fast enough to prevent personal hazards and equipment damage [9]. Generally, the protection system should consist of a primary and backup protection schemes with proper time grading between each devices. In this report, protection issues associated with microgrids are identified. Based on the identified issues, new protection strategies are proposed, specifically for a meshed microgrid.

2. Protection issues

In this section, some of the protection issues associated with microgrids are identified. These are discussed below.

(a) Fault isolation

When a fault occurs in a radial feeder, overcurrent relays operate to disconnect only the portion that is downstream from the fault, causing a power interruption to all customers downstream [16]. However, 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. Therefore the goal is to isolate the smallest possible portion of the faulted section. 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 the existing system configuration provided that the DG capacity is sufficient to supply load power requirement. In this case, only those customers connected to the faulted section will experience a power outage. Also note that islanded operation is desirable in the case of permanent faults which may require several minutes to several hours to repair.

A faulted section can be isolated if both upstream and downstream side protective relays respond in a radial feeder. 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.

Reliability of a network can be increased by forming a meshed microgrid connecting few radial lines. If faulted section is isolated successfully, the meshed configuration may allow the microgrid to maintain its grid connected operation even during a fault in the microgrid,. However, the meshed microgrid is expected to operate in islanded mode once a fault occurs in the utility grid. Providing protection for meshed microgrids to operate in both grid connected and islanded modes is more difficult than providing for a radial one.

(b) Islanded operation and protection

Islanding of a microgrid occurs when the utility supply is disconnected and DGs in the microgrid continue to supply local loads. However, this can have a number of safety issues [13]. When the islanding occurs, the generation and load capacity may not be equal and immediate control actions are required to maintain the stability.

Once islanding occurs, short circuit levels may drop significantly due to the absence of strong utility grid [2-4]. Therefore, the existing protection system (PS), which is originally designed for high short circuit current levels, will not respond for faults during islanded mode of operation. This is one of the reasons why anti-islanding protection is applied to achieve the safety of personnel and equipment of the system. However, DGs are expected to supply emergency loads in microgrid during islanded mode operation. Therefore, the implementation of an anti islanding operation every time a fault occurs reduces the reliability of the system considerably. Therefore, the islanding operation is important to ensure supply continuity to the customers.

(c) Coordination amongst protective devices

The coordination amongst protective devices based on fault current is relatively easy in unidirectional power flow networks, because the fault current reduces along the feeder [14]. However, with the connection of DGs and its meshed configuration, the microgrid permits the power flow to be bi-directional [15, 16]. This may create a number of feeder protection issues. It causes relays to under-reach or over-reach imposed by the DG location [17]. It has been shown that the reach of an overcurrent relay will reduce in the presence of a DG [18]. In addition to that, the DG can contribute by supplying short circuit currents to the neighboring faulted feeder and operating the protective device in the healthy feeder [19]. Also in the case of the islanded microgrid, the ratio between the source impedance and protected line is relatively high compared to the utility and this initiates a coordination problem since discrimination among relays is difficult [14].

When relays are present in a radial feeder, tripping time intervals between the relays should be coordinated appropriately [15]. Overcurrent relays are the simplest and widely used in protection applications. There are several types of overcurrent relays available to select from depending on the application. Inverse time relays can easily coordinate with other protective devices and they are usually employed to protect networks. Relays employed in the radial networks have both inverse time and instantaneous elements to achieve a quick response for the severe faults as well as for the coordination among relays [14]. However, with the formation of meshed configurations in networks, these overcurrent protective devices cannot be coordinated in a similar way. In meshed microgrids, there is no appreciable difference in fault current levels seen by relays due to short line segments.

(d) Current limiting of converter interfaced DGs

The fault current may change in the presence of DG connections in a network [4, 20-23]. Its impact depends on the size, type, number of the DGs, and the location of the DGs [15, 24]. Basically, three types of DGs exist with different properties: synchronous generators, induction generators and converter interface DGs [3]. Short circuit current levels vary based on the type of the generation connected [25]. Microgrids which consist of synchronous generators tend to contribute an additional fault current level in the system [24]. However generators can increase or decrease the fault current seen by protective devices depending on the location.

In a microgrid, most of the sources are connected through power electronic converters [6]. For example, the dc power generated by the sources such as fuel cell, micro turbine, or a photovoltaic is converted into ac power by power electronic converters. Due to their inbuilt current limiting feature, the converters do not supply sufficient current to operate protective devices based on current during a fault. As a result, overcurrent devices may not respond or take a long time to respond [10, 14, 26, 27]. Therefore protecting a converter dominated microgrid is a challenging technical issue [9]. If protective devices are designed to operate for low fault current levels corresponding to these current limiting converters, it may cause nuisance tripping [4, 21, 28]. Thus there is a need to assure when a microgrid operates in either grid connected or autonomous mode, the protection system is adequately fast, selective and reliable to clear the faults [22].

3. Protection Considerations in Meshed Microgrids

The main objective of this study is to design and develop efficient protection strategies to achieve safe and reliable operation of a meshed microgrid thus minimizing identified protection issues above. The proposed protection scheme should allow the microgrid to operate either in grid connected or islanded mode of operation providing appropriate safety to consumers and equipment. Different types of protection strategies are considered and they are investigated by applying them into a meshed microgrid.

3.1 Microgrid protection using inverse time admittance (ITA) relays

Overcurrent(OC) relays are sensitive to fault current levels in a network. Thus, protection of a DG connected network using OC relays is difficult without a proper communication channel. To avoid this problem, an inverse time admittance (ITA) relay has been proposed for a DG connected network to detect and isolate faults under low or changing fault current levels [29, 30]. In this section, this relay fundamentals are explained briefly. Moreover, an application of ITA relays for a meshed microgrid is discussed.

(A) Relay fundamentals

A radial distribution feeder as shown in Fig. 1 is considered to explain the ITA relay characteristics. It is assumed that the relay is located at node *R* and, node *K* is an arbitrary point on the feeder. The total admittance of the protected line segment is denoted by Y_t while the measured admittance between the nodes *R* and *K* is denoted by Y_m. Then the normalized admittance (Y_r) can be defined in terms of Y_t and Y_m as

$$Y_r = \left| \frac{Y_m}{Y_t} \right| \tag{1}$$

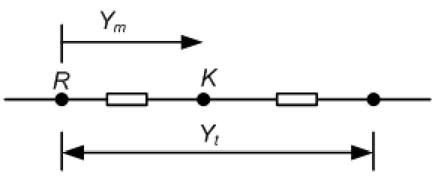

Fig. 1. A distribution feeder.

The variation of normalized admittance along a radial feeder is shown in Fig. 2 by assuming the feeder has a length of 3000m with a total feeder impedance of (0.195 + j 1.4451) Ω. It can be seen that normalized admittance decreases when measured point moves away from the relay location.

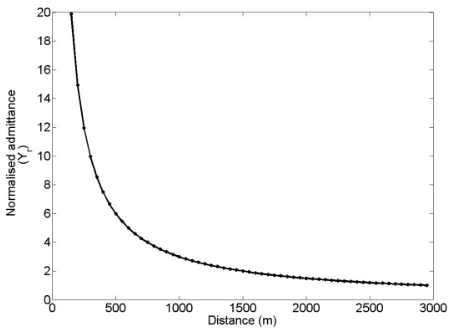

Fig. 2. The variation of normalized admittance

The change of normalized admittance along the feeder is used to obtain an inverse time tripping characteristic for the relay. The general form for the inverse time characteristic of the relay can be expressed as

$$t_p = \frac{A}{Y_r^{\rho} - 1} + k \tag{2}$$

where A, ρ and k are constants, while the tripping time is denoted by t_p. The values for these constants can be selected based on the relay location in a feeder and the protection requirements. The shape of the proposed inverse time tripping characteristic can be changed by varying the constants to obtain the required fault clearing time. When a network consists of different types of protective devices, these constants can be selected appropriately for coordination purpose. The relay tripping characteristic for A = 0.0047, ρ = 0.08 and k = 0 is shown in Fig. 3. The magnitude of the normalized admittance (i.e. Y_r) becomes higher as the fault point moves towards the relay location. As a result, the relay gives a lower tripping time for a fault near to the relay. On the other hand, higher fault clearing time can be obtained when the fault is further away from the relay location.

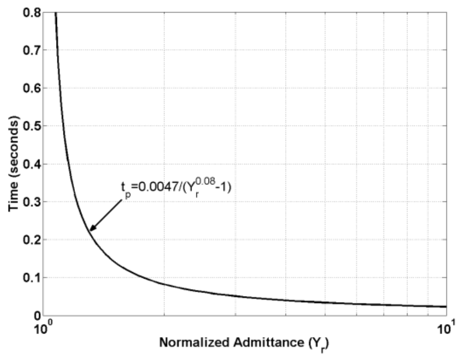

Fig. 3. Relay tripping characteristic curve

It is to be noted that the normalized admittance in (1) should be greater than 1.0 for relay tripping. This implies that the measured admittance is greater than the total admittance as shown in (3). This constraint is used by the relay algorithm to detect a faulted condition in the network. Moreover, the relay algorithm checks this constraint continuously during the faulted condition until relay issues the trip command to avoid any unnecessary tripping due to the effect of transients. The tripping time is decided depending on the calculated value of measured admittance.

$$Y_r > 1 \Rightarrow \left|\frac{Y_m}{Y_t}\right| > 1 \Rightarrow |Y_m| > |Y_t| \tag{3}$$

The ITA relay reach settings can be implemented by choosing a suitable value for the Y_t. This is totally dependent on the protection requirements such as primary and backup protections. For a particular relay, different values of Y_t can be assigned to generate a number of required zones of protection. In each zone, the relay has a unique tripping characteristic. It checks whether the measured admittance is greater than the total admittance of that particular zone before starting the relay tripping time calculation. A large coverage and minimum tripping time can be achieved by increasing the number of zones. It also leads to a good coordination amongst the relays in a feeder. Any upstream relay always provides the backup protection for the immediate downstream relay in the feeder. More details on relay hardware implementation and limitations can be found in [31].

It can be seen that the ITA relay uses both current and voltage multiples instead of only current based multiple used in overcurrent relays. As a result, an ITA relay detects faults effectively irrespective of the available fault current in the network. Therefore these relays effectively detect faults in either grid connected or islanded modes of operation.

(B) Simulation Studies using ITA relays

To demonstrate an application of ITA relays to a mesh network protection, a system shown in Fig. 4 is considered. This system has a partly meshed network containing BUS-1, BUS-2 and BUS-5. There are three DGs and three loads in this system. All the DGs are connected through voltage source converters (VSCs). Each DG in the microgrid is modeled using an ideal DC voltage source connected through a voltage source converter (VSC). In real applications, these DGs may represent solar PVs, fuel cells or battery storage. In normal operating condition, if the microgrid operates in grid connected mode, each DG supplies its rated power. On the other hand, in islanded mode, each DG shares the load power requirement operating in the frequency and voltage droop control. However, these DGs limit their output currents to twice the rated current during a fault to protect their electronic power switches in both modes.

Eight ITA relays are employed for secure and reliable operation of the system. The relay locations are shown in the figure. One of the main aims of the ITA relays is to isolate the faulted segment quickly in the event of a fault, thereby allowing unfaulted sections to operate either in grid connected or islanded mode depending on the fault location. In the case of an islanded mode operation, each DG or DGs in the islanded section can operate in autonomous mode if there is sufficient generation to supply the load demand. The system parameters are listed in Table 1. In this study, no communication between relays is considered for a simple and cost effective solution.

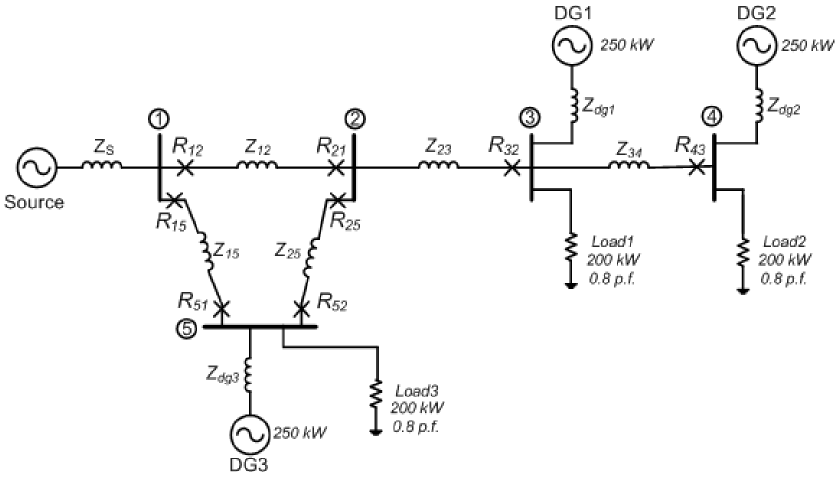

Fig. 4. Mesh network under study

Table 1 : System parameters

System parameter	Value
Voltage	11 kV L-L rms
Frequency	50 HZ
Source impedance	$(0.078 + j\ 0.7854)\ \Omega$
Each feeder impedance	$(0.585 + j\ 4.335)\ \Omega$

The relays R_{12}, R_{21}, R_{15}, R_{51}, R_{52} and R_{25} which are located in the mesh network have the directional blocking feature in which these relays only respond to forward faults. This results in proper relay coordination within the mesh network. For example, consider relay R_{15}. It protects the line segment between BUS-1 and BUS-5. Also it provides the backup protection for the line segment between BUS-5 and BUS-2. However, R_{15} is blocked for the reverse faults since R_{12} should operate for the faults between BUS-1 and BUS-2. The relays R_{12} and R_{52} cover the line segment between BUS-2 and BUS-3 in forward direction. On the other hand, the relay R_{32} has the directional feature and thus it can detect faults in either sides of BUS-3. The relay R_{43} is also a directional blocking relay which only responds for reverse faults since it is located at the end of the feeder.

Identification of primary and back up zones is essential for relay coordination and selectivity. Relay reach settings of Zone-1 and Zone-2 are selected to cover 120% and 200% of the first line length respectively. The assigned zones of protection for each relay are given in Table 2.

Table 2 : Zones of ITA relay protection

Relay	**Primary protection**	**Back up protection**
R_{12}	Up to R_{25} via BUS-2	Back up for R_{25} and R_{32}
R_{15}	Up to R_{52} via BUS-5	Back up for R_{52}
R_{51}	Up to R_{12} via BUS-1	Back up for R_{12}
R_{52}	Up to R_{21} via BUS-2	Back up for R_{21} and R_{32}
R_{25}	Up to R_{51} via BUS-5	Back up for R_{51}
R_{21}	Up to R_{15} via BUS-1	Back up for R_{15}
R_{32}	Up to R_{21} and R_{25} via BUS-2 Up to BUS-4 via R_{43}	Back up for R_{21} and R_{25}
R_{43}	Up to R_{32} via BUS-3	Back up for R_{32}

The selected constants for tripping characteristics of Zone-1 and Zone-2 are given in Table 3. The reach setting of Zone-3 is selected to cover fault resistance of 50 Ω. However, the grading of relays for Zone-3 is different to Zone-1 and Zone-2. In this system, R_{32}, R_{52}, R_{15} and R_{12} in the forward direction and R_{51}, R_{25}, R_{21}, R_{32} and R_{43} in the reverse direction should be coordinated separately. When performing the ITA relay grading in Zone-3, tripping time for forward faults should be increased, while it should be decreased for reverse faults from downstream to upstream relays in the network. The graded Zone-3 tripping characteristics of ITA relays are given in Table 4.

Table 3 : Zone characteristics of ITA relay

Zone number	*A*	*p*	*k*
Zone-1	0.0037	0.08	0.05
Zone-2	0.0037	0.1	0.1

Table 4 : Zone-3 grading of ITA relays

Relay grading for forward faults	Relay grading for reverse faults
$t_{Zone3F\_R32} = \frac{0.0037}{Y_r^{0.1}-1} + 0.3$	$t_{Zone3R\_R43} = \frac{0.0037}{Y_r^{0.1}-1} + 0.5$
$t_{Zone3F\_R12} = \frac{0.0037}{Y_r^{0.1}-1} + 0.4$	$t_{Zone3R\_R32} = \frac{0.0037}{Y_r^{0.1}-1} + 0.4$
$t_{Zone3F\_R52} = \frac{0.0037}{Y_r^{0.1}-1} + 0.4$	$t_{Zone3R\_R21} = \frac{0.0037}{Y_r^{0.1}-1} + 0.3$
$t_{Zone3F\_R15} = \frac{0.0037}{Y_r^{0.1}-1} + 0.5$	$t_{Zone3R\_R25} = \frac{0.0037}{Y_r^{0.1}-1} + 0.3$
	$t_{Zone3R\_R51} = \frac{0.0037}{Y_r^{0.1}-1} + 0.2$

The system is simulated in PSCAD. A single-line-to-ground (SLG) fault is created at different locations with different values of fault resistances at 0.2 s. The ITA relay fault clearing times and subsequent system response are listed in Table 5. In each line segment, two fault locations are considered. As can be seen from the results, the relays respond to isolate the faulted segment effectively. For example, in the event of a fault between BUS-1 and BUS-2, the relays R_{12} and R_{21} respond to isolate the faulted segment. In this case, the rest of the system operates in grid connected mode after the successful isolation of the faulted segment. Higher fault clearing time can be experienced for resistive faults due to the relay grading and infeed effect of DGs. Within the mesh configuration, fault current seen by relays are coming from different directions.

It can be seen that relays are capable of isolating the faulted section effectively. However, higher fault clearing time can be experienced for resistive faults due to the relay grading and infeed effect of DGs. Within the mesh configuration, fault current seen by relays come from different directions.

Table 5 : Fault clearing time of ITA relays

<table>
<tr><td colspan="2" rowspan="2">Fault location
(between)</td><td colspan="2">Fault clearing time of respective relay (seconds)</td></tr>
<tr><td>R_f = 0.05 Ω</td><td>R_f = 20 Ω</td></tr>
<tr><td rowspan="3">BUS-1 and BUS-2</td><td>10% from BUS-1</td><td>R_{12}=0.071,R_{21}=0.137</td><td>R_{12}=0.438,R_{21}=0.774</td></tr>
<tr><td>90% from BUS-1</td><td>R_{12}=0.137,R_{21}=0.072</td><td>R_{12}=0.443,R_{21}=0.359</td></tr>
<tr><td colspan="3">All the loads are supplied in grid connected mode without line Z_{12}</td></tr>
<tr><td rowspan="3">BUS-1 and BUS-5</td><td>10% from BUS-1</td><td>R_{15}=0.071,R_{51}=0.137</td><td>R_{15}=0.540,R_{51}=0.774</td></tr>
<tr><td>90% from BUS-1</td><td>R_{15}=0.136,R_{51}=0.073</td><td>R_{15}=0.544,R_{51}=0.251</td></tr>
<tr><td colspan="3">All loads are supplied in grid connected mode without line Z_{15}</td></tr>
<tr><td rowspan="3">BUS-2 and BUS-5</td><td>10% from BUS-2</td><td>R_{25}=0.072,R_{52}=0.137</td><td>R_{25}=0.348,R_{52}=0.445</td></tr>
<tr><td>90% from BUS-2</td><td>R_{25}=0.137,R_{52}=0.073</td><td>R_{25}=0.458,R_{52}=0.443</td></tr>
<tr><td colspan="3">All loads are supplied in grid connected mode without line Z_{25}</td></tr>
<tr><td rowspan="3">BUS-2 and BUS-3</td><td>10% from BUS-2</td><td>R_{12}=0.150,R_{52}=0.158, R_{32}=0.082</td><td>R_{12}=0.459,R_{52}=0.472
R_{32}=0.480</td></tr>
<tr><td>90% from BUS-2</td><td>R_{12}=0.410,R_{52}=0.427, R_{32}=0.075</td><td>R_{12}=0.481,R_{52}=0.494
R_{32}=0.509</td></tr>
<tr><td colspan="3">Load3 is supplied in grid connected mode while Load1 and Load2 supplied in islanded mode without line Z_{23}</td></tr>
<tr><td rowspan="3">BUS-3 and BUS-4</td><td>10% from BUS-3</td><td>R_{32}=0.074,R_{43}=0.137</td><td>R_{32}=0.345,R_{43}=0.615</td></tr>
<tr><td>90% from BUS-3</td><td>R_{32}=0.139,R_{43}=0.072</td><td>R_{32}=0.349,R_{43}=0.913</td></tr>
<tr><td colspan="3">Load1 and Load3 are supplied in grid connected mode while Load2 is supplied in islanded mode without line Z_{34}</td></tr>
</table>

3.2 Protection using Current Differential Relays

The power flow within a microgrid can be bi-directional due to DG connections at different locations or its meshed configuration. This will create new challenges for protection. Some of the DGs connected to a microgrid are intermittent in nature (e.g., solar photovoltaic based DGs). Therefore different fault current levels can be experienced in the microgrid depending on the active DG connections [11]. As a result, implementation of protection schemes based on fault current level will be made difficult further. The reliability of a microgrid can be increased by forming a meshed configuration. However, the protection schemes proposed for radial microgrids cannot be effectively deployed in meshed microgrids [12]. The fault current seen by each relay within the mesh configuration will not have an appreciable difference due to short line segments in the microgrid. In this circumstance, fault detection and isolation will be difficult without employing reliable communication channels.

In this section, protection strategies required for a microgrid are presented using current deferential relays. The protection challenges associated with bi-directional power flow, meshed configuration, changing fault current level due to intermittent nature of DGs and reduced fault current level in an islanded mode are avoided in the microgrid using the proposed protection schemes. The relay settings, communication requirements and the selection of a current transformer (CT) for a relay are also discussed.

3.2.1 Differential Protection Scheme

Consider the microgrid shown in Fig. 5. The microgrid is connected to the utility grid through a step up transformer. It has a partly meshed network containing BUS-1, BUS-2 and BUS-5. There are four loads connected to the system. The protection should be designed to incorporate both mesh and radial configurations.

Protection of the microgrid is discussed under different subgroups such as feeder, bus and DG protection. Different protection strategies are considered for each of the subgroups to provide appropriate protection. The PS has a primary and a backup protection. If primary scheme fails then the backup scheme comes into the operation appropriately. The primary PS for the microgrid is proposed with the aid of communication while backup PS is designed to operate in the event of a communication failure. The proposed PSs are discussed in the next subsections.

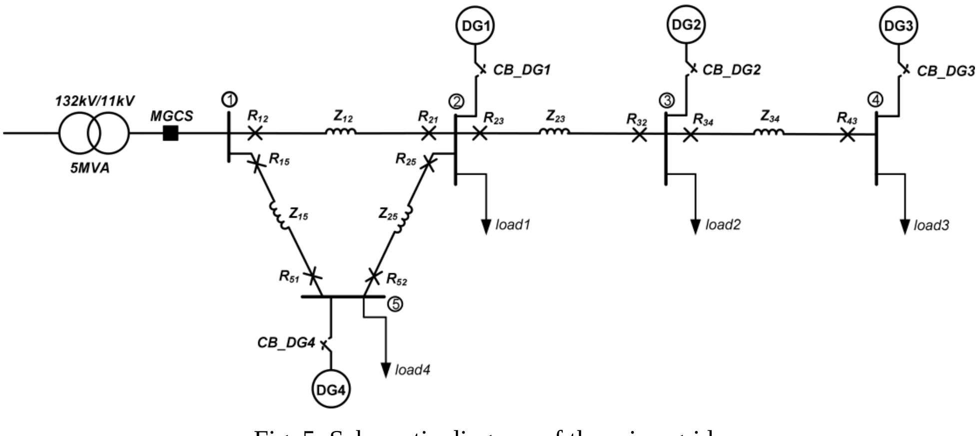

Fig. 5. Schematic diagram of the microgrid.

(A) Feeder Protection

Each feeder in the microgrid is protected using two relays which are located at the end of the feeder. In normal operating condition, current entering to a particular feeder should be equal to the current leaving from that feeder. However, this condition will not be satisfied during a fault on the feeder. Therefore, current differential protection is proposed to detect and isolate the feeder faults. The differential protection is capable of providing the protection for a specified feeder effectively while not responding to faults outside the region. The current differential protection is chosen for the microgrid since it is not sensitive to bi-directional power flow, changing fault current level and the number of DG connections. It also provides the required protection for both grid connected and islanded modes of operation. Moreover, the protection is not affected by a weak infeed where it can detect internal faults even without having any DG connected.

In the proposed current differential PS, each relay has five elements to provide the required protection. Three phase elements for each phase and two other elements for negative and zero sequence currents. The phase differential elements are responsible for providing high speed protection for faults which have high currents. The negative and zero sequence differential elements provide more sensitive earth fault protection for lower current unbalanced faults such as high impedance ground faults in a feeder. Fast operating times can be obtained using this differential protection due to the accuracy in fault detection. In addition to the differential protection elements, overcurrent and under voltage based backup protection elements are incorporated. If overcurrent based backup protection is only provided, the relays in an islanded microgrid will not sense sufficient currents to detect faults due to lower fault current levels. However, the system voltage will drop significantly since converters limit output currents during the fault. Therefore, the reduction in system voltage can be used to implement the under voltage backup protection scheme in the event of an overcurrent backup failure. However, the backup protection schemes remain blocked during the normal operating condition of differential protection and it will activate immediately, if communication failure is detected by a relay.

Fig. 6 shows the single line representation of a current differential feeder protection for the microgrid. Each relay at the end of the protected feeder is connected to its local current transformer (CT) while two relays are connected through a communication link. Two relays exchanges time synchronized phase current samples (i.e., phase currents of I_a, I_b and I_c). Each relay also calculates the negative sequence and zero sequence currents of local and remote end relay locations. The current differential elements of each relay then compare phase and calculated sequence parameters with respective remote end location quantities to identify a fault condition in the feeder. If a fault is detected (i.e., internal fault), each relay will issue a trip command to its local circuit breaker. The current differential protection is effective since it is sensitive, selective and fast. Each relay has its operating and restraint characteristics to avoid any false tripping. A more sensitive characteristic for a current differential relay can be implemented in modern digital relays where operating and restrain regions can be separated by user defined slopes.

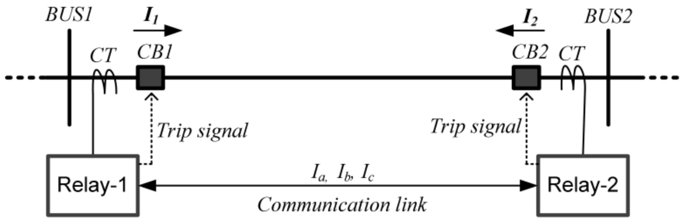

Fig. 6. Differential feeder protection for microgrid

The bias current and the differential current are the two quantities which define the relay characteristic for the operating and the restraint regions. The differential and bias currents are defined in (4) and (5) respectively.

$$I_{diff} = |I_1 + I_2| \tag{4}$$

$$I_{bias} = \frac{|I_1| + |I_2|}{2} \tag{5}$$

I_1 and I_2 are secondary CT phasor currents in each relay location. The relay may have two stages (low and high) in tripping characteristic to provide a flexible and a secure operation. Such two stage differential relay characteristic is shown in Fig. 7. The high stage of the relay is defined above a certain value of the differential current. This is a non-biased stage where the bias current is not taken into consideration when issuing the tripping command. In this high set stage, the relay shows a fast response.

The low stage is the biased stage with different user defined slopes. The relay has definite time and inverse definite minimum time (IDMT) characteristics in this region. As can be seen from the Fig. 7, the relay tripping characteristic for low set stage has two slopes. These slopes can be set by defining the percentage bias settings *K1* and *K2*. The I_{diff1} is the minimum differential current threshold (i.e., pickup current for the relay). The pickup differential current increases with the fault current increases. The current I_{bias1} should be also defined and it differentiates the two slopes. This dual slope characteristic provides a higher sensitivity during lower fault currents and improved security for higher fault currents in which CT errors are large. The relay issues the trip command when one of the following conditions given in (6) or (7) is satisfied.

$$|I_{bias}| < I_{bias1} \quad and \quad |I_{diff}| > K_1 \cdot |I_{bias}| + I_{diff1} \tag{6}$$

$$|I_{bias}| >= I_{bias1} \; and \, |I_{diff}| > K_2 \, |I_{bias}| - (K_2 - K_1) \, I_{bias1} + I_{diff1} \tag{7}$$

In normal operating condition, the differential current should be zero. However, due to the line charging, CT saturation and inaccuracies in CT mismatch, it may not equal to zero. The problem of saturation is overcome in modern numerical relays by using saturation detectors [32]. A calculation need to be carried out to determine the minimum pickup current for the relay (I_{diff1}). The setting of current differential relays should be performed lower enough to detect all types of faults on the feeder while ensuring the relays do not respond for external faults due to the CT errors and other measuring errors. The relay setting sensitivity is very important. However, the increase in sensitivity may also cause to decrease the security.

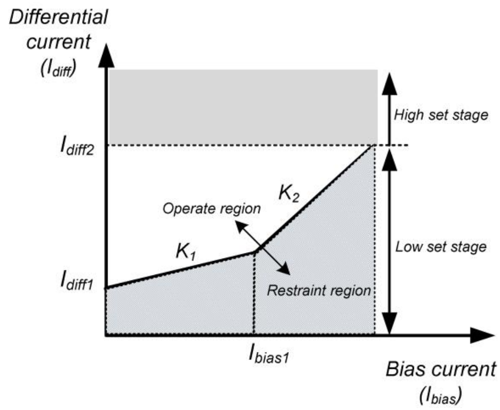

Fig. 7. Differential relay characteristic

(B) Bus Protection

Buses in the microgrid may have connected to loads, DGs and feeders. Therefore, a high speed protection is very important for a bus fault to avoid any extensive damage in the microgrid. The differential protection arrangement for a bus protection is shown in Fig. 8. The protection principle is similar to the one explained in differential feeder protection. However, in this case, the relay will issue a trip command to all the circuit breakers connected to the bus during a bus fault.

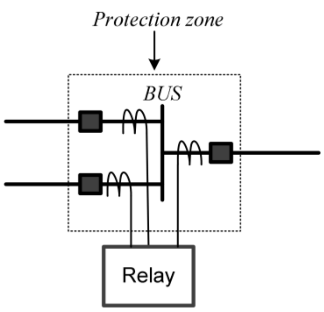

Fig. 8. Differential bus protection.

3.2.2 DG Protection

All the DGs in the microgrid should be protected from abnormal conditions. Therefore, each DG is employed with several protection elements; under voltage, reverse power flow, over voltage and synchronism check. The relay associated with these protection elements issue a trip command to DG circuit breaker once any abnormal condition is detected. The under voltage tripping is activated below a set voltage level after a defined time period. The defined time allows microgrid relays to isolate a fault and restore the system maintaining as many DG connections as possible. The reverse power flow protection activates to trip the DG when current flows towards the DG. The over voltage element responds, when the voltage at point of connection rises above a predefined limit. The synchronism check element ensures a trouble free connection to the microgrid when it is being reconnected after any disconnection. These protection schemes will ensure the DG safety.

3.2.3 The Need of Communication

A communication link between feeder end relays is a key requirement in this current differential protection scheme. Digital relays available today are programmable according to the user requirement and they facilitate for different types of communication technologies such as fibre optic and Ethernet. Therefore, the available communication technologies including leased phone lines, power line carrier (PLC), pilot wires, fibre optics, microwave, point to point radio can be used in protection implementation. However, with the deployment of smart system technologies, communication channels will be readily available for the future microgrids.The choosing an appropriate technology for a particular application depends on the several factors such as the required performance, cost, reliability, availability and bandwidth.

The current information at the remote end needs to be transferred to the local end. The digital current differential relays sample the line currents and then send them over a communication channel to the other relay. This may introduce a time delay which can be seen as a phase shift between local and remote end current samples and as a result, the relays may calculate a differential current. To avoid this problem, proper time synchronization of current phasors is required. The modern digital relays are capable of measuring the time delay and performing the compensation during the calculation. The channel based synchronization methods such as ping-pong can be used to estimate the time delay. By knowing the time delay, it is possible to align the local data with the remote end data. At the same time, the communication link should be monitored. When a failure in communication link is detected, the relays should automatically switch into their backup protection schemes.

3.2.4 CT selection Criterion for Protection

IEEE C57.13 (IEEE standard requirements for instrument transformers) and IEEE C37.11 (IEEE guide for the application of current transformers used for protective relaying purposes) provide guidelines in selecting CTs for protective relays. CT ratio (rated primary and secondary current), CT accuracy class, polarity, saturation voltage, knee point voltage, excitation characteristics and primary side voltage rating and current rating are some of the major factors should be considered when selecting a CT for a protective relay application.

The turn ratio of a CT defines the rated primary and secondary current of the CT. Usually the secondary rated current is 5A. The primary current rating of a CT is selected considering the maximum current in normal operating condition and the maximum symmetrical fault current. The selected primary current should be greater than the maximum current that the CT is expected to carry in normal operating condition and it should also be greater than one twentieth (1/20) of the maximum symmetrical fault current. The latter condition will satisfy that the secondary current of the CT will be less than 20 times the rated secondary current during the maximum fault current.

When the voltage increases in the secondary of a CT, the exciting current also increases. With the increase of secondary voltage further beyond a limit causes the magnetic saturation of the CT core due to higher flux. The CT saturation results in the increase of ratio error and distorted secondary current waveform. A particular CT behavior can be found by using its excitation curves which show the relationship between secondary voltage and the excitation current of the CT. The knee-point voltage and the saturation voltage can be found using the excitation curve in a CT. If the selected CT ratio is very low such that the secondary current of a CT exceeds 20 times the rated current during a fault, the CT may end with severe saturation. To avoid the saturation in a CT, the secondary saturation voltage (V_x) should satisfy the condition in (8) [33].

$$V_x > I_S \times (R_S + X_L + Z_B) \tag{8}$$

where I_S the ratio between the primary current and the CT turns ratio, R_S is the CT secondary resistance, X_L is the leakage reactance and Z_B is the total secondary burden which includes secondary leads and devices. Moreover, DC transients present during a fault can cause CT saturation. Depending on the time a fault occurs (i.e., a point at fault occurs in the wave), the magnitude of the DC component will change and it decays with a time constant. The saturation due to both AC and DC components can be avoided by selecting the saturation voltage of a CT according to (9).

$$V_x > I_S \times (R_S + X_L + Z_B) \times \left[1 + \frac{X}{R}\right] \tag{9}$$

where X is the primary system reactance and R is the resistance up to the fault point. It can be seen that the value of saturation depends on the X/R ratio of the system. The effect of CT saturation may be avoided by selecting appropriate CT ratios to have the saturation voltage above the value expected from AC and DC transient fault currents. Also a CT takes a finite time period to become its saturated state.

A CT used for protective relays has an accuracy rating. A letter and a CT secondary terminal voltage define the ANSI CT relaying accuracy class [33]. Most of the CTs designed for relays are covered by C and K classes. These two classes indicate that the secondary winding is uniform around the core thus leakage flux is negligible. The standard accuracy classes for C class CTs are C100, C200, C400 and C800 with standard burden of 1, 2, 4, 8 Ω respectively. The ratio error of a CT should be less than 10% for any current between 1 to 20 times secondary rated current at the standard burden or any lower standard burden [33]. For example, if a CT with C100 class is selected, the ratio current error will not exceed 10% at any current from 1 to 20 times rated secondary current (i.e., 5A) with a standard 1 Ω burden. However, if the saturation of a CT occurs then the error ratio will exceed 10%.

3.2.5 Microgrid Protection Studies

Consider the microgrid system shown in Fig. 5. The parameters of the microgrid are given in Table 6. The microgrid connection/disconnection is controlled by the microgrid control switch (MGCS). It is assumed that all the DGs are converter interfaced and the DG control is designed to enable the microgrid islanded operation during a grid disturbance. Moreover, these DGs limit their output currents to twice the rated current during a fault in the microgrid to protect their power switches.

The CT ratio for a particular CT is selected based on the maximum load current and the maximum fault current seen by the relay. To calculate the maximum load current seen by a relay, different system configurations are considered. For example, the relay R_{12} senses the maximum load current when all the DGs inject current into utility grid without any load is connected to microgrid and the feeder section between BUS-1 and BUS-5 is not in service. The maximum possible fault current seen by each relay also calculated. The CT ratio for a relay is then selected based on the criteria that the CT can deliver 20 times rated secondary current without exceeding 10% ratio error and the rated primary current to be above the maximum possible load current. The accuracy class for CTs is selected as C200. The selected CT ratio for each relay is given in Table 7.

Table 6 : System Parameters

System parameter	**Value**
Voltage	11 kV L-L rms
Frequency	50 HZ
Transformer power rating	5MVA
Transformer impedance	(0.05 + *j* 2.1677) Ω
Each feeder impedance	(0.94 + *j* 2.5447) Ω
Each load impedance	(100 + *j* 75) Ω
DG1 power rating	0.8 MVA
DG2 power rating	1.2 MVA
DG3 power rating	1.5 MVA
DG4 power rating	1.0 MVA

Table 7 : CT ratio selection

Relay	**I_{fmax} (A)**	**I_{fmax}/20 (A)**	**I_{Lmax} (A)**	**CT ratio**
R_{12}	2535	126	236	300:5
R_{21}	1478	74	236	300:5
R_{15}	2541	127	236	300:5
R_{51}	956	48	236	300:5
R_{25}	1111	56	184	200:5
R_{52}	998	50	184	200:5
R_{23}	1478	74	142	150:5
R_{32}	917	46	142	150:5
R_{34}	917	46	79	100:5
R_{43}	654	33	79	100:5

I_{fmax}-Maximum fault current
I_{Lmax}- Maximum possible load current

To show how selected CT ratios perform during a fault, the CT associated with relay R_{12} is considered. The selected CT ratio for this relay is 300:5 and CT class is C200. During the maximum fault current, the CT secondary current will be 42.25A. Now consider the voltage saturation equation in (9) to calculate the maximum allowable saturation voltage for this relay. The burden for a numerical relay is small. The parameters for this calculation are X/R=1.3, R_s=0.15 Ω, X_L=0, relay burden= 0.02 Ω, leads resistance=0.25 Ω. Substituting these values in (9) gives,

$$V_x > 42.25\times(0.15+0+0.25+0.02)\times\left[1+1.3\right]$$
$$V_x < 40.81V$$

This shows that the saturation voltage of the CT should be above the 40.81 V to avoid saturation. The selected CT is satisfied this condition. Also, it can be seen that the leads resistance can be changed by selecting different wire sizes to allow a better margin for the CT saturation if necessary.

The effect of capacitive charging current on current differential protection can be negligible since the microgrid consists of short line segments. The slope settings are selected to ensure the differential elements do not respond for external faults due to CT ratio and other measurement errors. The minimum setting for differential current is calculated allowing for errors arising from CTs. It is assumed that the CT error will not exceed 2% for currents less than the rated secondary current (i.e., 5A). The maximum error is then calculated assuming one CT to be +2% while the other CT to be -2%. Therefore, the error of 4% due to both CTs produces current of 0.2 A (5×0.04). Thus it is proposed to select the setting of I_{diff1} above 0.2 A. The other settings for the differential relay characteristic shown in Fig. 7 are selected based on the fault behavior of the microgrid and they are given below.

K_1=30%, K_2=100%, I_{bias1}=5 A, I_{diff1}=0.2 A

With the selected settings and CTs, fault response of the microgrid is investigated. Different types of faults are generated at different locations. The fault resistance is varied from 1 Ω to 20 Ω. The maximum CT ratio error of ±10% is assumed. The fault response of relays R_{12} and R_{21} for internal and external feeder faults is shown in Fig. 9. It can be seen that the response of relays for internal feeder faults are within the operating region, while for the external faults, the response lies within the restraint region.

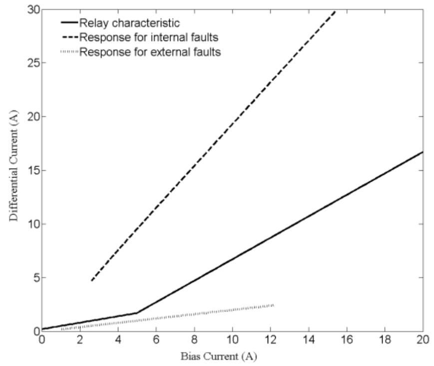

Fig. 9. Relays R_{12} and R_{21} response for microgrid faults.

The response of relays R_{23} and R_{32} which are located in radial feeder is next investigated. The fault response of relays for both internal and external faults is shown in Fig. 10. It is clear that these relays detect only internal faults distinguishing from external faults.

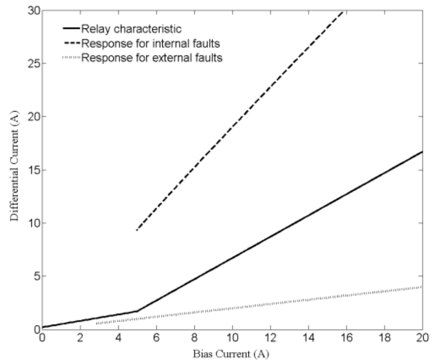

Fig. 10. Relays R_{23} and R_{32} response for microgrid faults

The simulation results obtained from PSCAD for a single line to ground fault between BUS-2 and BUS-5 are shown in Fig. 11 and Fig. 12. The fault is created at 0.4 s with a 10 Ω resistance. In this case it is assumed that 10ms communication channel delay exists for the differential relays. Fig. 11 shows the variation of differential and bias currents during the fault while relay response for this fault is shown in Fig. 12. The simulated fault in PSCAD gives 13.04 A and 6.52 A for differential and bias current respectively. In MATLAB, differential and bias current for this fault is calculated as 13.16A and 6.61A respectively. This verifies the calculated results in MATLAB with the simulation results.

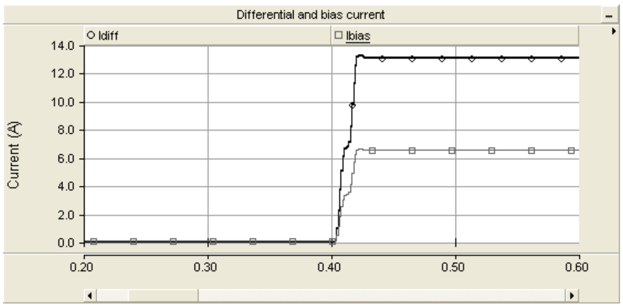

Fig. 11. The variation of differential and bias current.

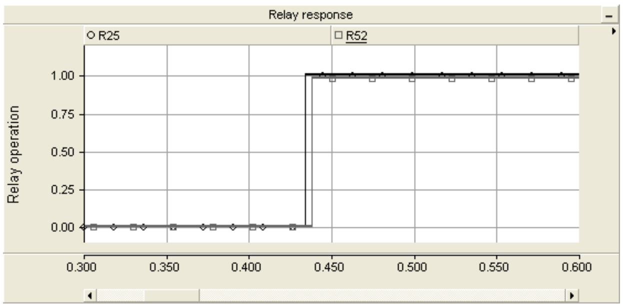

Fig. 12. The relay response for a fault between BUS-2 and BUS-5

The investigation of relay response in islanded operation is very important to ensure the relays are capable of detecting faults in the islanded microgrid. A fault is created at different locations in the microgrid. The fault resistance is varied from 0.1 Ω to 20 Ω. The response of relays R_{12} and R_{21} is shown in Fig. 13. The relay response for the faults is accurate. It can be seen that the fault current level is significantly low due to the current limiting of converters. However, the relays detect the internal faults effectively avoiding any external faults. Therefore, it can be concluded that these relays are capable of detecting faults either in grid connected or islanded modes of operation without changing any relay settings.

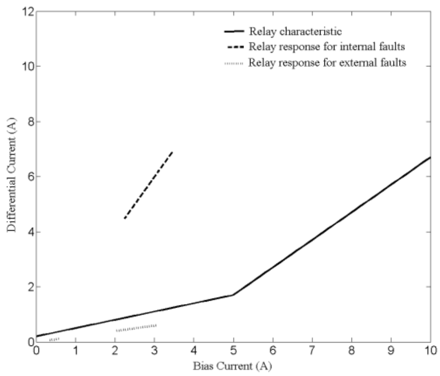

Fig. 13. Relays R_{12} and R_{21} response for faults in islanded microgrid.

In this section, a primary protection scheme for a microgrid is presented using current differential relays with the aid of a communication channel. The protection issues associated with meshed structure, microgrid islanded operation, fault detection under low fault current levels are avoided with the use of modern differential relays. Relay settings and CT selection requirements are also discussed. Results show that the proposed protection strategies can provide selectivity and high level of sensitivity for internal faults in both grid-connected and islanded modes of operation thereby allowing a safe and a reliable operation for a microgrid.

4. Conclusions

Protecion barriers for microgrid operation are identified in this research. Different protection strategies are considered to provide the appropriate protection for meshed microgrids. An inverse time admittance relay is presented to detect and isolate faults in both grid connected and islanded operation of a meshed microgrid. These relays do not require any communication overlay in the microgrid. Moreover, current differential protection scheme is proposed for a meshed microgrid using communication channels. It has been shown that the current differential protection can provide selectivity and high level of sensitivity for internal faults while discriminating from the external faults effectively. The speed of the communication and the data synchronization between the local and remote relay are very important in current differential applications. However, with the use of modern digital communication systems, a reliable and a secure protection scheme can be provided for a meshed microgrid.

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