Protection of Microgrids Using Differential Relays

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***Abstract*— A microgrid provides economical and reliable power to customers by integrating distributed resources more effectively. Islanded operation enables a continuous power supply for loads during a major grid disturbance. Reliability of a microgrid can be further increased by forming a mesh configuration. However, the protection of mesh microgrids is a challenging task. In this paper, protection schemes are discussed using current differential protection of a microgrid. 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 considered in proposing the protection solutions. Relay setting criterion and current transformer (CT) selection guidelines are also discussed. The results are verified using MATLAB calculations and PSCAD simulations.**

***Index Terms*— Microgrid protection, Fault isolation, Differential relays, Current transformers**

I. Introduction

A MICROGRID integrates distributed energy resources to provide reliable, environment 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 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 can be bi-directional due to DG connections at different locations or its mesh configuration. This will create new challenges for the protection. In a microgrid, most of the sources are connected through power electronic converters [6]. For example, the dc power is generated by using the sources such as fuel cells, micro turbines, or photovoltaic cells, converters are utilized to alter 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.

In this paper, 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. It is shown that a safe and a reliable operation of a microgrid can be accomplished by using the proposed protection strategies.

II. Protection Strategies

Protection strategies are proposed for a microgrid to achieve a safe and a reliable operation thereby minimizing identified issues. The proposed protection scheme (PS) should detect any abnormal condition in the microgrid and it should isolate the smallest possible portion thus allowing rest of the system to continue operation. The PS should also allow the microgrid to operate either in grid connected or islanded modes of operation providing appropriate safety to customers and equipment. Consider the microgrid shown in Fig. 1. The microgrid is connected to the utility grid through a step up transformer. It has a partly mesh 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.

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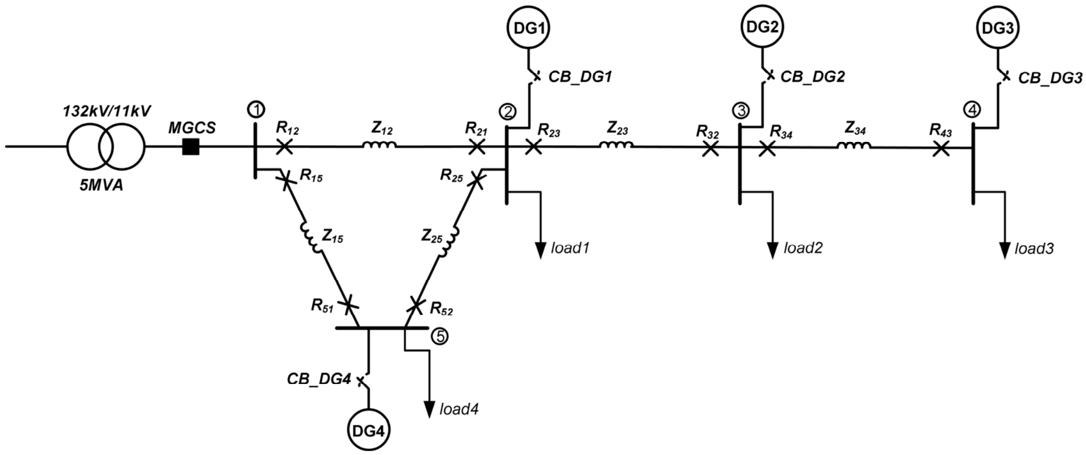

Fig.1. Schematic diagram of the microgrid.

Protection of the microgrid is discussed under different subgroups such as feeder, bus and DG. 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.

A. FeederProtection

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 outside faults. 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. 2 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 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.

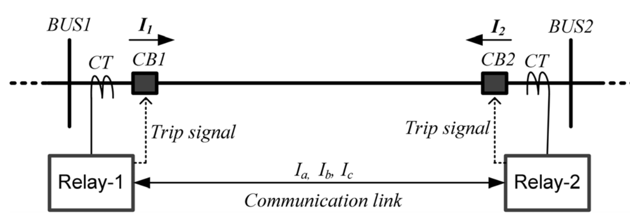

Fig. 2. Differential feeder protection for microgrid

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 (1) and (2) respectively.

$$I_{diff} = |I_1 + I_2| \quad (1)$$

$$I_{bias} = \frac{|I_1| + |I_2|}{2} \quad (2)$$

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. 3. 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. 3, 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 (3) or (4) is satisfied.

$$|I_{bias}| < I_{bias1} \quad and \quad |I_{diff}| > K_1 \cdot |I_{bias}| + I_{diff1} \quad (3)$$

$$|I_{bias}| >= I_{bias1} \; and \; |I_{diff}| > K_2 |I_{bias}| - (K_2 - K_1) I_{bias1} + I_{diff1} \quad (4)$$

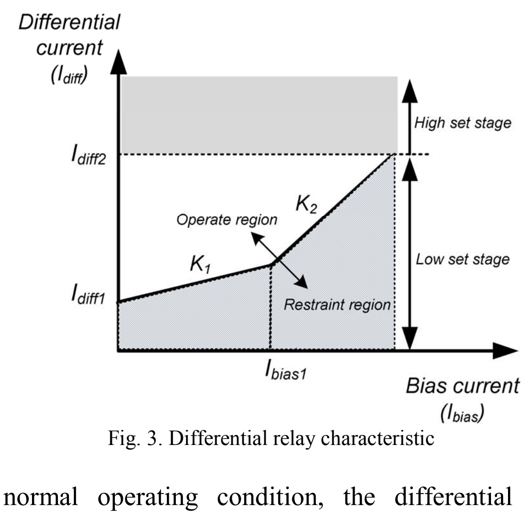

Fig. 3. Differential relay characteristic

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 [13]. 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.

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. 4. 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.

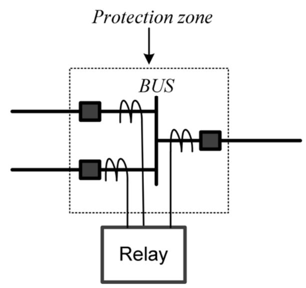

Fig. 4. Differential bus protection

C. 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.

D. The Need of Communication

A communication link between feeder end relays is a key requirement in current differential protection scheme. Therefore, a reliable communication channel is required. Relay to relay communication can be performed using a hard wire connection, power line carrier, microwave, fiber optic or Ethernet connection. However, with the deployment of smart system technologies, communication channels will be readily available for the future microgrids.

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.

E. 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 behaviour 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 (5) [14].

$$V_x > I_S \times (R_S + X_L + Z_B) \tag{5}$$

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 (6).

$$V_x > I_S \times (R_S + X_L + Z_B) \times \left[1 + \frac{X}{R}\right] \tag{6}$$

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 [14]. 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 [14]. 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%.

III. Microgrid Protection Studies

Consider the microgrid system shown in Fig. 1. The parameters of the microgrid are given in Table I. 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 II.

TABLE I : SYSTEM PARAMETERS

System parameter	Value
Voltage	11 kV L-L rms
Frequency	50 HZ
Transformer power rating	5MVA
Transformer impedance	$(0.05 + j\,2.1677)\ \Omega$
Each feeder impedance	$(0.94 + j\,2.5447)\ \Omega$
Each load impedance	$(100 + j\,75)\ \Omega$
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 II : 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 (6) 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 (6) gives,

$$V_x > 42.25 \times (0.15 + 0 + 0.25 + 0.02) \times [1 + 1.3]$$

$$V_x < 40.81V$$

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. 3 are selected based on the fault behaviour 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. 5. 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.

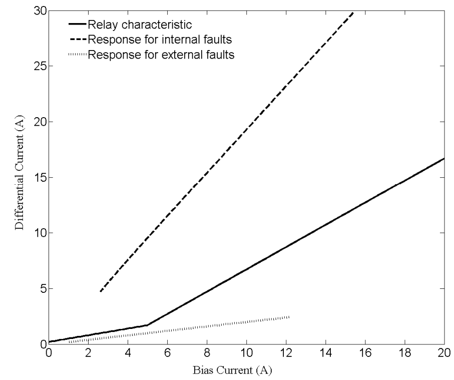

Fig. 5. Relays R_{12} and R_{21} response for microgrid faults.

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. 6. It is clear that these relays detect only internal faults distinguishing from external faults.

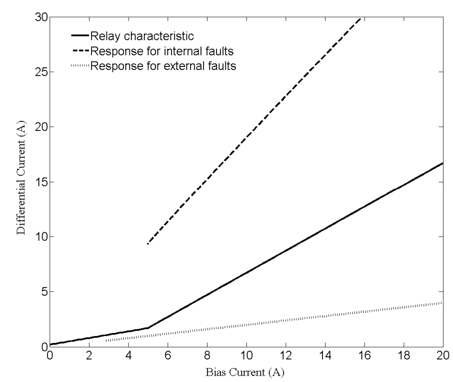

Fig. 6. Relays R_{23} and R_{32} response for microgrid faults

The simulation results obtained from PSCAD for a single line to ground fault between BUS-2 and BUS-5 are shown in Figs. 7 and 8. 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. 7 shows the variation of differential and bias currents during the fault while relay response for this fault is shown in Fig. 8. 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.

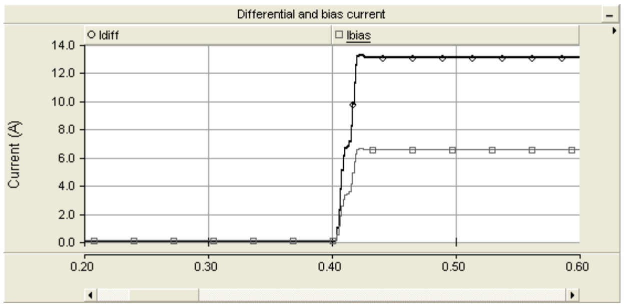

Fig.7. The variation of differential and bias current.

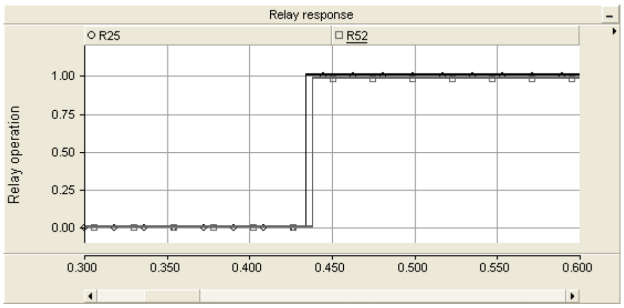

Fig. 8. The relay response for a fault between BUS-2 and BUS-5

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. 9. 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.

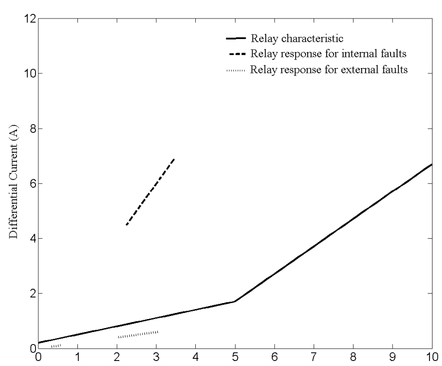

Fig. 9. Relays R_{12} and R_{21} response for faults in islanded microgrid.

IV. Conclusions

In this paper, 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.

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