

Low-Cost Communication-Assisted Line Protection for Multi-Inverter Based Microgrids

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Abstract—Multi-inverter microgrid systems, particularly those with loop topology, offer higher power supply reliability and robustness compared to conventional radial distribution systems. In meshed systems, communication-less protection schemes have proved to be ineffective for multi-inverter microgrids due to bidirectional power flow, and limited and controlled fault currents generated by the voltage source converters interfacing the energy source to the network. This makes communication-assisted line protection schemes preferable for such systems despite the necessity for communication means. While these protection schemes are effective, their reliability depends much on the communication availability. This requires a back-up communication path in case the main one fails bringing up the cost issue that hinders their uptake. This paper proposes a novel and low-cost line protection based on directional blocking strategy that can operate as a main as well as a back-up protection to any protection scheme using communication means between the line terminals. As the main, it requires low-bandwidth communication system. As a back-up, it would share the same communication means with the main one and use those of the healthy lines when the faulted line's fails. Thus saving the cost of back-up communication system.

Index Terms—Microgrid, inverter-interfaced distributed energy resource, protection, communication, back-up

I. INTRODUCTION

THE availability of cost effective power electronic converters has enabled the attainment of practical maturity of the conversion of renewable and clean energies, such as wind and solar, to electricity. With most of renewable energy resources locally available, their exploitation for electricity supply, to remote areas as autonomous generation systems or supply electricity to local distribution systems as distributed energy resources (DERs) has become a reality. This local availability has allowed the implementation of microgrids whereby a group of loads and distributed energy resources can be controlled as a single electrical system [1]–[4]. Integrated in the grid, microgrids can operate in grid-connected or islanded mode, which enhances their power supply reliability [3]–[7].

However, this advantage comes with technical challenges, among which the design of microgrid protection, particularly for islanded operation conditions [8]–[10]. The protection challenges are mainly due to the possibility of bidirectional power flow, and limited and controlled fault currents generated by inverters interfacing the DER to the microgrid network [8]–[12]. Bidirectional power flow renders non-directional overcurrent relays unusable while the limitation and control of fault current hinders the performance of conventional directional and distance relays [11], [12]. The latter is also challenged by short lines in medium voltage and low voltage microgrids.

A great deal of research has been undertaken on protection of islanded microgrids and new protection schemes have been proposed [3], [7], [13]–[15], [17]–[22]. However, back-up protections are not often exhaustively discussed, particularly their coordination with the primary protection.

In [22], the authors proposed a protection strategy (main and back-up for medium voltage microgrids. However, the strategy is limited to radial networks. In [13] directional overcurrent relay is proposed with the relay settings obtained from an optimisation algorithm to ensure optimal coordination between primary and back-up relays. However, it only considered synchronous distributed generators (DGs). In [14] a dual setting directional overcurrent relay is proposed with the primary protection being communication-less and the back-up being communication-assisted (low bandwidth). However, the study considers as well only synchronous DGs in islanded mode of operation. In [15] authors looked at the economic aspect of dual setting directional overcurrent relays and proposed a coordination of a mix of conventional and dual setting relays. In this study, the primary and back-up protection functionalities are integrated in a single relay programmed in two directions namely forward/primary and reverse/back-up. However, this category dual setting directional overcurrent protection schemes require prior knowledge of the system configuration [16].

Other techniques are based on inverter control to detect faults [17]–[20]. In [17] overcurrent relays are used with the coordination implemented in the inverter control whereby the current limiting strategy is modified for the inverter to adaptively inject current proportional to the distance to the fault. This strategy is only applicable to inverter-only microgrids. This limitation also applies to the protection scheme proposed in [18] whereby directional overcurrent relays are used with the IIDR controller modified to inject harmonic currents detectable by the relays. [19], [20] have proposed fault detection using inverter output signals using transient monitoring function and transient content of inverter output respectively. However, these schemes are only limited to fault detection.

Another category of protection strategies used for looped and meshed islanded microgrids is differential-based protection schemes. They have been recognised to be effective for islanded microgrids [9]–[12], [22], [23]. However, like all communication-assisted protection schemes, differential-based protection schemes have also been criticised for their high cost and reliance on communication system whose failure may compromise their correct operation.

On the other hand, however, it has also been pointed out that schemes which do not require communication infrastructure may not protect microgrids from all types of faults or may experience delays that can be prevented by communication [22], [24]. Also, it has been recognised that communication can prevent miscoordination that can happen in dual setting directional overcurrent relays between primary and back-up protections [25]. Therefore, a low cost solution to the possibility of communication failure of is essential.

One approach to this is a back-up communication means to the main one [11], [22]. The back-up communication is usually implemented using a different channel or an alternative communication path when a communication network is used. Another approach is a separate back-up protection.

To date, there is no commercially available protection relay for microgrids [12], [26]. With all the challenges previously discussed it is clear that designing an effective back-up protection is as challenging as the main one as well as the coordination between them. For example in [7], a differential current line protection is backed up with a comparative voltage strategy. This back-up protection is not as effective as the primary protection as it may isolate a larger part of the system, hence will be loss of load unnecessarily. Also, in [21], an under-voltage and overcurrent protection schemes were proposed as a back-up protection to a differential protection. However, as discussed, these back-up schemes are likely to fail in multi-inverter islanded microgrid. In [3], a differential protection for loop-based microgrids is proposed with an over-current relay as a back-up in grid-connected and in islanded modes. As previously explained, overcurrent relay in islanded mode is likely to fail in inverter-based microgrids due to low fault currents.

Modern processor based relays can integrate both the primary and back-up protection algorithms into one relay unit. This combination offers cost reduction advantage that can attract the use of such relays in distribution systems where the protection cost should be as low as possible. Despite the cost reduction advantage that may be offered by these relays, the cost of the communication channel is relatively expensive for microgrids, let alone the cost of both the primary and redundant back-up communication channels. This paper proposes a low-bandwidth line protection scheme for microgrids. It may as well serve as a back-up to any viable protection scheme using a communication means between the line terminals as it can utilise the main communication infrastructure of healthy lines when the faulted line's fails. This paper covers three-phase MV islanded microgrid systems. The paper is organised as follows: The next section describes the fault detection method and the faulted line identification. In Section III, the proposed scheme is applied to a study microgrid system to test its effectiveness through simulations. Section IV summarizes the results and the contributions of the paper.

II. PROPOSED PROTECTION STRATEGY

The proposed protection strategy is based on the following key assumptions:

- The line protection relays are available at both ends of the line.
- The relays are digital type protective relays.
- A communication channel exists between the local and remote line relays. This relays are also referred to as relay counterparts in this paper.
- Communication channels exist between neighbouring relays protecting lines connected to a common busbar (neighbouring relays around the busbar).
- In normal operating conditions, the power flowing in the line connecting the distributed generator to the loop is always from the generator to the loop. Otherwise power flow direction detection device is required.

A. Disturbance detection

In general, the occurrence of a disturbance such as a in a power system causes changes in power system parameters such as voltage and current magnitudes and the phase angles of current and voltage phasors, etc. As voltage measurement devices might not be available at each bus at distribution voltage levels, changes in current signal are investigated, particularly the phase angle as the fault currents generated by IIDERs are limited and could be inappropriate to use the magnitude for fault detection. In three-phase systems, the phase angle of positive sequence current phasor is used for simplicity and accuracy.

During steady state and normal operating conditions, positive sequence current phasor angle, remains theoretically nearly constant or changes just a little even when a small load is switched into/from the system. In practice, there are small changes but negligible. In contrast to load switching event, a fault in the system causes significant change in the angle.

Among techniques practically used for voltage/current phasor estimation in digital protective relays, discrete Fourier transform (DFT) has been the most popular, particularly recursive DFT due to its simplicity [27]–[29].

Assuming a constant input current sinusoidal signal $i(t)$ given in (1) with nominal frequency f_n and sampled at frequency $f_s = Nf_n$, a full-cycle recursive DFT can be applied to extract the fundamental current phasor of the signal samples I_n (given by (2)) as in (3) [29]:

$$i(t) = I_m \cos(2\pi f_n t + \phi) \quad (1)$$

$$I_n = I_m \cos(n\theta + \phi) \quad (2)$$

where $n = 0, 1, 2, 3, \dots$

$$\bar{I}_k = \bar{I}_{k-1} + \frac{\sqrt{2}}{N} [I_k - I_{k-N}] e^{-\frac{2\pi j}{N}} \quad (3)$$

where N is the number of samples per cycle, and $k = N + 1, N + 2, N + 3, \dots$

The cosine and sine terms of (3) can be determined as in (4) and (5) respectively:

$$\bar{I}_{Ck} = \bar{I}_{k-1} + \frac{\sqrt{2}}{N} \cos\left(\frac{2\pi j}{N}\right) [I_k - I_{k-N}] \quad (4)$$

$$\bar{I}_{Sk} = \bar{I}_{k-1} + \frac{\sqrt{2}}{N} \sin\left(\frac{2\pi j}{N}\right) [I_k - I_{k-N}] \quad (5)$$

From these terms, the fundamental phasor magnitude $\bar{I}_m$ and phase angle ϕ can be calculated:

$$\bar{I}_m = \sqrt{\bar{I}_{Ck}^2 + \bar{I}_{Sk}^2} \quad (6)$$

$$\phi = \tan^{-1} \frac{\bar{I}_{Sk}}{\bar{I}_{Ck}} \quad (7)$$

While conventional DFT offers simplicity and precision in steady state conditions, when the signal frequency is temporarily or permanently off-nominal the phasor estimation accuracy is affected when the sampling frequency is fixed and keyed to the nominal frequency. This can happen in practice since the frequency varies constantly around the nominal value in a very narrow range ± 0.5 Hz [29]. The situation is more pronounced in islanded systems, particularly in inverter-only microgrids where frequency excursions may reach ± 10 Hz [29] or the system frequency can settle to a frequency different from the nominal one. In practice however, the frequency deviation is controlled and brought back to a value close to the nominal. On the other hand, the phasor measurement units should be accurate for frequency deviation up to ± 5 Hz [29], [30].

In islanded microgrids, the system operating frequency can therefore be different from the nominal value or experience large frequency fluctuations within a large range around the nominal frequency. The analysis of the impact of the frequency deviation on phasor estimation has been studied in details in [28], [29] and it is briefly discussed in this paper in relation to the proposed protection strategy.

Considering the signal $i(t)$ in (1) with a frequency $f = f_n + \Delta f$, Expression (8) gives the relationship between the off-nominal frequency phasor estimates and the true phasors $\bar{I}_k$ and its conjugates $\bar{I}_k^*$ [28], [29]:

$$\bar{I}'_k = P \bar{I}_k e^{j \frac{2\pi \Delta f}{N f_n} k} + Q \bar{I}_k^* e^{-j \frac{2\pi (2f_n + \Delta f)}{N f_n} k} \quad (8)$$

where

$$P = \frac{\sin\left(\frac{\pi \Delta f}{f_n}\right)}{N \sin\left(\frac{\pi \Delta f}{N f_n}\right)} e^{j \frac{\pi (N-1) \Delta f}{N f_n}}$$

$$Q = \frac{\sin\left(\frac{\pi \Delta f}{f_n}\right)}{N \sin\left(\frac{\pi \Delta f}{N f_n}\right)} e^{j \frac{\pi (N-1) \Delta f}{N f_n}}$$

From phase phasor estimates, positive sequence phasor estimation of a three-phase input signal can be calculated and analysed. Applying Fortescue transform to three phase phasors $\bar{I}'_{ka}$, $\bar{I}'_{kb}$ and $\bar{I}'_{kc}$ of three phase current input samples I_{ka} , I_{kb} and I_{kc} respectively, yields:

$$\begin{bmatrix} \bar{I}'_{k0} \\ \bar{I}'_{k1} \\ \bar{I}'_{k2} \end{bmatrix} = P e^{j \frac{2\pi \Delta f}{N f_n} k} \begin{bmatrix} \bar{I}_{k0} \\ \bar{I}_{k1} \\ \bar{I}_{k2} \end{bmatrix} + Q e^{-j \frac{2\pi (2f_n + \Delta f)}{N f_n} k} \begin{bmatrix} \bar{I}_{k0}^* \\ \bar{I}_{k2}^* \\ \bar{I}_{k1}^* \end{bmatrix} \quad (9)$$

where $\bar{I}_{ka}$, $\bar{I}_{kb}$ and $\bar{I}_{kc}$ are the true phasors and $\bar{I}_{ka}^*$, $\bar{I}_{kb}^*$ and $\bar{I}_{kc}^*$ their respective conjugates.

It is important to note that the transformation from phase to sequence components has been done based on Phase A as the phase reference. It can be clearly seen from (9) that the positive sequence current phasor estimated using DFT is attenuated by time-invariant complex factor P with the negative sequence current component attenuated by time-invariant complex factor Q.

In ideal steady state conditions balanced three-phase currents do not present the negative sequence current and only P affects the accuracy of the phasor with most noticeable impact on the phase angle. The phase angle experiences an average slope corresponding to $2\pi \Delta f t$ [29]. This slope changes the true phase angle trajectory with even a very small change in frequency. For example a permanent frequency deviation of 0.0001 Hz causes a change in phase angle from 0 to 2π rad in just under three hours unless the relay is regularly reset. In such conditions, the cosine of the phase angle becomes a periodic signal with a frequency equalling to Δf . This means that to accurately measure the current/voltage phase angle using conventional recursive DFT is very challenging in practice even under slight frequency deviation.

With unbalanced currents, the negative sequence component and the coefficient Q do not affect the overall phase angle trajectory as the P coefficient does. The former affects the phase angle instantaneous values by superposing on it a second order harmonic. This harmonic can be filtered out using an average filter [29]. From the above analysis, it can be said that in steady state conditions, the slope “S” of the phase of the current phasor is directly proportional to the local frequency deviation and can be expressed as the rate of change of the phase angle over a cycle as follows:

$$S = \frac{f_n}{2\pi} (\phi_k - \phi_{k-N}) \quad (10)$$

where f_n is the nominal frequency, N the number of samples in a cycle, and ϕ_k and ϕ_{k-N} , the values of the phase angle estimates of positive sequence current from two consecutive cycles.

This means that any change in trajectory of the phase angle over a cycle can be reflected in the value of the slope of the phase angle of (10).

On the other hand, relays with identical hardware and algorithms should yield the same phasor estimates under all conditions [29]. This means that despite the loss of accuracy in phase angle estimation using conventional recursive DFT, it can still be used for protection and monitoring purposes (decision making and disturbance detection) as long as the relay's estimates are not required for control or measurements purposes that requires accurate estimates.

This paper exploits this avenue by proposing a relay co-ordination strategy using the cosine of the positive sequence current phase angle and communication channels to monitor the phase angle trajectory of relays with respect to the others

for decision-making. This coordination and associated details are discussed in the next section.

The expression in (10), in this paper, forms the basis for the detection of the occurrence of a disturbance in the system. This can be a fault or a severe switching event such as a sudden loss or connection of a generator or a large load. However, switching events as well as faults on busbar, are considered as external disturbances to the line protection scheme, which is the scope of this paper. This means that significant change in the slope of the phase angle could serve only as an alarm, signalling a potential fault in the system. It is the coordination of the relays that determines whether the disturbance detected is a fault and whether it occurred in the relay zone of protection.

Recognising that an islanded microgrid can operate at off-nominal frequency, a change in slope values may not accurately reflect a disturbance as it would if the system was operating at nominal frequency. For example if the frequency varies from 52 Hz to 48 Hz and the acceptable operating frequency range is ± 5 Hz around 50 Hz (the nominal frequency) i.e. 45 - 55 Hz, then such disturbance cannot be detected based on the change in the phase angle slope value. To detect such a disturbance, the rate of change of the slope of the phase angle (ROCOSP) over a cycle is adopted. This can be expressed as follows:

$$ROCOSP = \frac{f_n^2}{2\pi} (\phi_k - 2\phi_{k-N} + \phi_{k-2N}) \quad (11)$$

where f_n is the nominal frequency, N the number of samples in a cycle, and ϕ_k , ϕ_{k-N} and ϕ_{k-2N} are estimates of phase angle from three consecutive cycle windows.

During normal operation, regardless of the operating frequency, the average value of the ROCOSP over a cycle is zero. Any change in the local frequency or the occurrence of disturbance (transient conditions) in the microgrid causes ROCOSP to deviate significantly from zero. A threshold value for the ROCOSP can then be defined and set at any value different from zero to detect a disturbance in the microgrid. The threshold should be set at a value that allows the detection of any disturbance, even small ones to ensure high reliability of the protection scheme as the relay coordination proposed in this paper has the capability of discriminating a fault in the zone of the protection scheme from non-fault and external fault events.

It is important to note, however, that such deductions on ROCOSP are only correct when the current flow direction in a line does not change. The change in current flow direction, which is not necessarily caused by a disturbance, causes significant step change in the phase angle (close to 180°) which in turn causes significant change in phase angle slope and in the ROCOSP.

Taking the 180° phase angle difference following a certain event in the system such as a fault or a switching event, and applying (10) and (11), one can find that the associated values of the phase angle slope and ROCOSP are 25 Hz and 1250 Hz/s. These theoretical values can be obtained by a relay if

the fundamental frequency of current signal is equal to the nominal frequency. Otherwise values close to these can be considered. This is demonstrated in simulation results of the case study in Fig. 8.

Since the current flowing through the line connecting directly the IIDER to the busbar, seen by a relay at the line end close to the busbar, changes its direction only when a fault occurs between the generator and the busbar. This relay is ideal for disturbance detection in the microgrid and a fault on its own line based on ROCOSP. It is important to highlight that such a relay detects a disturbance regardless of its location in the microgrid. Such relays are, in this paper, referred to as “master relays”. The relays protecting other lines connected to the same busbar as the master relay’s line are the “slaves”. With an appropriate coordination between master relays and their respective slaves, the identification of faulted line and its isolation can be achieved. The proposed coordination is described in next section.

B. Fault detection and identification of the faulted line

Once a disturbance is detected in the system by the master relays, the directionality comparison feature is used to determine the faulted line. For example, assuming that the positive flow direction of the current is from the line to the bus, it can be determined that when a fault occurs on a line in the system both relays protecting the line will register negative directions. Equivalently, when an external fault to the line occurs, one of the relays of the pair sees a positive current flow direction. Therefore, if all relays around the busbar have the same monitoring direction (from the line to the bus or from the bus to the line) it is easier to ensure the effective comparison of the outputs of slave relays with their respective master relays and establish the fault location. Otherwise, care must be taken to ensure correct comparison of relays’ outputs.

a) *Detection of change in positive sequence current flow direction:* It has been established in the previous section how the angle of the positive sequence current can be used to estimate the rate of change of the phase angle slope, ROCOSP, for disturbance detection. The positive sequence current can also be used to detect a change in current flow direction. Directionality is considered as an essential feature for a selective microgrid protection system [11]. In transmission systems, the estimation of fault current direction has been based on the comparison of phase angles of current and the system voltage, the latter being considered as a polarizing quantity. This approach cannot be applied to distribution systems as voltage measurement devices are not often installed at each busbar and installing both voltage and current instrument transformers may be far expensive [31]. Furthermore, with the fault ride-through capability of the IIDERs, the voltage cannot be a guaranteed polarizing quantity, since it would depend on the current injected by the IIDERs than the system’s impedance. This highlights also the challenge distance relays would meet in inverter-based microgrids due to dependence on impedance measurement using voltage signal [12]. Furthermore, due to short lines in the microgrids, it cannot be guaranteed that the

traditional transmission-based angular features are effective in synchronous DG-based distribution microgrids, let alone microgrids dominated by IIDERs.

In this work, the change in fault current flow direction is estimated based on the approach of monitoring the phase angle of the current (positive sequence current phase angle for three-phase systems) reported in [32]. This approach monitors the trajectory of the phase angle with respect to “four quadrants” using the cosine function. It exploits the advantages of short lines properties whereby the effect of the line shunt parameters (capacitance and conductance) is less significant. In such a case, the line can equivalently be represented by series resistance and inductance, which means that the line current remains the same throughout the line. Similarly, in steady state conditions, the positive sequence current phasors estimated at both ends of the line will then have almost the same phase angle values. Assuming the quadrant pairs (I, IV) and (II, III) to form “two regions”, I and II respectively, when a fault occurs on the line one of the relays registers a change in current flow direction indicating a change in phase angle value from one region to another.

Based on this principle, it can be established that a relay registering a change in current flow direction equivalently registers a transition of current phase angle value from one region to another. A simple, effective and normalised way to track this trajectory is to compute the cosine of the phase angle, since the sign of the cosine value changes with the change in region. Therefore, a change in current flow direction is confirmed when the sign of the cosine value of the current phase angle changes. For simplicity, for a three-phase system, the cosine value of the positive sequence current phase angle is referred to as the cosine value. Details on this concept can be found in [32]. Such an approach, however, requires communication to ensure coordination among relays for decision making as change in flow direction itself is not a sufficient information to confirm a fault on a line unless unidirectional power flow is assumed in the considered line during normal operation. And this is not the case.

The current flow direction in the line connecting the IIDER to the busbar only changes when a fault occurs on the line. Therefore, a fault is easily detected on the master relay line when the ROCOSP value computed by the master relay exceed the threshold.

However, this simple way of detecting a fault on the line protected by master relay cannot be applied to lines protected by slave relays due to the power flow that can be in either direction during normal operation. Fortunately, based on the slave relay monitoring direction (line to busbar or busbar to line), the direction of current flowing through the line can be estimated with respect to the master relay’s line current flow direction. This is achieved by monitoring the cosine values, assuming the master relay installed with the same monitoring direction as the one of the slave. So the cosine values calculated by the slave relay and its master are of the same sign (positive or negative) if their respective current flow directions are the same. Otherwise, they are of opposite signs.

From the above deductions, it can be established that after a fault occurs on a line protected by a slave relay, the cosine values calculated by the relay and its master are of opposite signs. Naturally, the direction of the current flowing through the master relay line, during normal operation or during an external fault to the line, is always from the line to the busbar while the faulted line experiences currents flowing from the buses towards the fault point on the line. Equivalently, when one of the relays of the slave pair sees a current flowing from the line to the busbar (the case for the master relay line current), the line is healthy i.e. there is no fault on that particular line.

b) Proposed relay coordination and communication approach: As outlined in the the previous section, the coordination and communication between the microgrid relays is based on the master-slave strategy. The master relay detects the occurrence of a disturbance in the microgrid. When a disturbance is detected, the master relay sends a potential fault signal (alarm) to its respective slaves as well as the sign of the computed cosine value. Conversely, when a fault is on the master relay line, the concerned master relay sends a blocking signal. In case two or more DGs are connected to a common busbar, the blocking signal from one of the master relays overrides the disturbance signal received by the slave relays from other master relays. In such a situation, when a fault occurs on one of the DGs’ lines, only the concerned master relay registers a change in cosine value and sends a blocking signal to the slave relays, which are common to all master relays around the busbar.

Recalling that the proposed scheme is for islanded multi-inverter-based microgrids, each of the slave relays in the microgrid receives either a fault or a blocking signal from its master relay. In summary, the slave relay will receive one of the following signals from its master relay when a disturbance is detected:

- A blocking signal from the master relay
- A fault signal with the same sign of the cosine value as the master relay’s
- A fault signal with the opposite sign of the cosine value to the master relay’s

For the first two cases, the slave relay has a confirmation that a disturbance is external to its line. Therefore the relay sends in turn a blocking signal to its remote counterpart to prevent the line isolation from the remote end. On the other hand, the third case indicates a potential fault on the relay line. Therefore, if the slave relay does not receive a blocking signal from its counterpart, a fault is assumed on its line and should send a trip signal to the relevant circuit breaker.

With this relay coordination and communication approach, when the primary line protection experiences a communication channel failure between the two relays protecting the concerned line, this scheme will effectively operate using the blocking signals sent through the remaining and healthy communication channels of the healthy lines. This scheme, however, does not cover situations where any of the other line

communication channels fail at the same time as the one of the faulted line.

It may happen that there is a tapped line in the loop. In this case, the point of connection is considered as the tap point. Fig. 1 illustrates an example of such a case. In this example, Relays 1 and 4 are master relays while Relays 2 and 3 are their slaves respectively.

Three possibilities can be considered under this case.

- Load 2 is larger than Loads 1 and 3
- Load 3 is larger than Loads 1 and 2
- Load 1 is larger than Loads 2 and 3

For the first case, the prefault currents seen by Relays 2 and 3 flow from the busbars A and C to the tap point B. This is illustrated in Fig. 2. As shown in the figure, when a fault occurs on the line, there is no change in current flow directions with respect to the prefault currents.

Based on the proposed coordination principle, and assuming that the slave relays are installed with the same monitoring direction as their respective master relays, each master relay will detect the fault and send a fault signal with the cosine value sign (opposite sign due to opposite current flow direction seen by the slaves) to their respective slave relays. A potential fault is so far confirmed by each slave relay; and since there is no blocking signal from either slave relay to its counterpart, a fault on the line is confirmed and tripping signals, with a reasonable delay, will be issued by slave relays to their respective circuit breakers to isolate the line. On the other hand, for the other two cases (load at Bus A or C is the largest in the system), the prefault current flow direction seen by one of the slave relays is towards the busbar. After a fault occurrence on the line, the situation becomes consistent with the previous case a change in current flow direction is registered by either Relay 2 or Relay 3. This is illustrated in Fig. 3 with the largest load connected at Bus A.

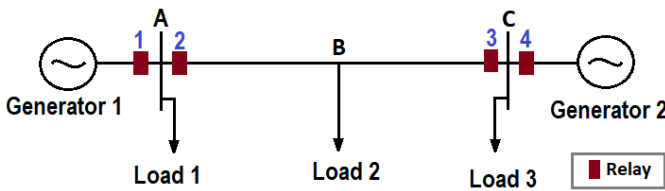


Fig. 1. Example of a case with a tapped line (tap point B)

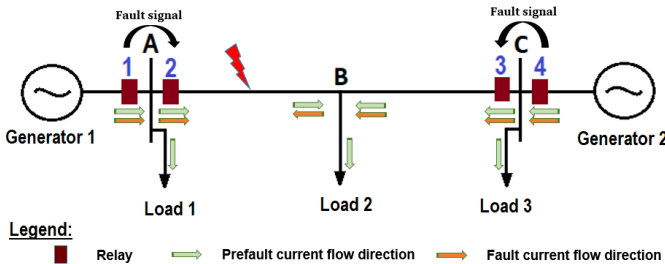


Fig. 2. Coordination of Relays with the largest load at the tap point B

As mentioned above, it may be possible that a load is connected to or disconnected from the system and leads to a change in current flow directions. For example considering the previous case (the largest load at Bus A), if an additional load (Load 4) is connected to Bus C so that the total load at Bus C becomes larger than the load at A, the slave relays (2 and 3) will register a change in current flow direction as shown in Fig. 4. However, since the slave relays are only activated by a signal from their respective master relays, there will be no operation of the protection system as there is no fault to be detected by the master relays. However, even if the switching event was severe enough to cause large ROCOSP values (detected as fault condition by master relays), it would be considered as an external disturbance and no line would be isolated. The case of a fault on the busbar is described in Section III. B. d.

Although, this study has focused on loop-based microgrids, the scheme can be extended to other topologies such as meshed topology. However, time accumulation of the communication between relays should be taken into account to ensure that the time clearance requirement is met. Also, microgrid generation mix can affect the fault clearance time as some generation technologies such as small gas turbine, internal combustion based generators, etc. generate higher fault currents than IIDGs, and the fault might be required to be cleared faster. Moreover, a microgrid can provide less constant frequency operation if gas turbine is the only type of generation, or dominates the generation mix.

III. STUDY MICROGRID AND SIMULATION RESULTS

The proposed protection scheme is tested using a model four-bus loop-based microgrid system given in Fig. 5. The general control structure of inverter interfaced generator (IIDG)

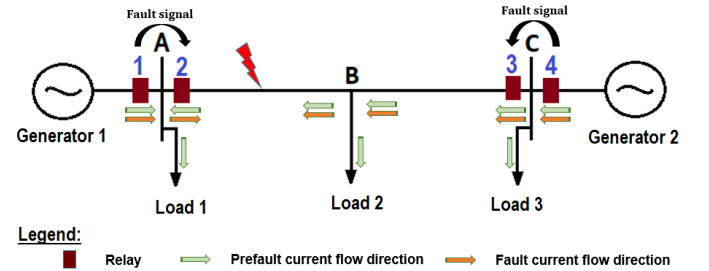


Fig. 3. Coordination of Relays with the largest load at Bus A

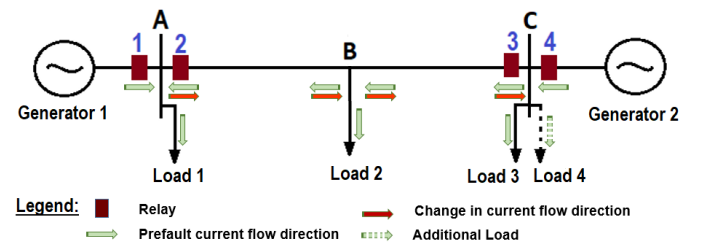


Fig. 4. Relay coordination for load switching event causing change of current flow direction sees by Relays 2 and 3

is shown in the white background of Fig. 6. The black background of the figure shows the circuit with the main elements of the IIDG including the inverter, the LC filter, and the step-up transformer. The study system was implemented and simulated in MATLAB/SIMULINK environment. The parameters of the system elements are given in Table I. Each of the IIDGs is controlled in the synchronous reference frame using PI controllers. A master-slave power sharing control strategy is adopted whereby the IIDG 1 is the master that forms the voltage and frequency of the microgrid, and share the current references i_{ref} generated by its voltage controller to the current controllers of the slave IIDGs. The current reference of each IIDG is limited to 120% of the rated current based on latched limiting strategy as one of the most popular inverter limit strategies [33]. In this study once a fault occurs, the references from the master IIDG's voltage controller are replaced by predefined current references i_{ref} chosen such that converter's power factor (PF) during fault is 0.56 lagging. Case studies with different PF values have been extensively investigated in [32].

The positive sequence current phasor angle of the fundamental frequency (50 Hz) were estimated using conventional recursive discrete Fourier transform (DFT) over a power cycle window (20 ms). This method is the basis of the proposed scheme and has been chosen as it is very well understood phasor estimation technique and prevalent in protective relays due to its immunity to harmonics, computational simplicity and efficiency [31].

Four simulation scenarios are considered: a fault on a line protected by a master relay; a fault on a line protected by slave relays; a fault on a tapped line; and a fault on a busbar. The latter case represents an external fault to the proposed scheme's protection zone. For each of all scenarios under this study, a permanent fault is initiated at time instant $t = 0.15$ s

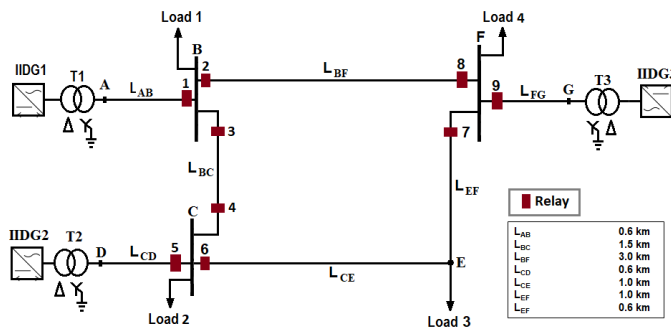


Fig. 5. Four-bus loop-based microgrid

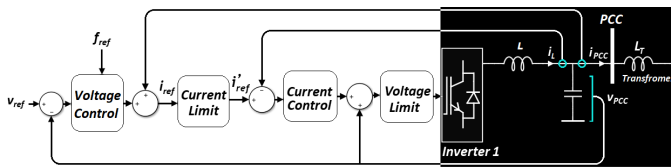


Fig. 6. IIDG control structure

TABLE I
STUDY MICROGRID PARAMETERS

IIDG Parameters			
	IIDG 1	IIDG 2	IIDG 3
Rated power (kW)	1000	1000	1000
Rated voltage (V)	260	260	260
DC bus voltage (V)	500	500	500
Fundamental frequency (Hz)	50	50	50
Switching frequency (kHz)	5	5	5
Filter inductance (mH)	0.0264	0.0264	0.0264
Filter resistance (mΩ)	0.067	0.067	0.067
Filter capacitance (mF)	2.4	2.4	2.4
Damping resistance (mΩ)	15.5	15.5	15.5
Current control proportional	0.1658	0.1658	0.1658
Current control integral	0.4199	0.4199	0.4199
Voltage control proportional	1.4965	1.4965	1.4965
Voltage control integral	0.00	0.00	0.00
Step-up Transformer Parameters			
Rated power (kVA)	1200	1200	1200
Rated primary voltage (kV)	0.260	0.260	0.260
Rated secondary voltage (kV)	20	20	20
Configuration (vector group)	D1Yg	D1Yg	D1Yg
Fundamental frequency (Hz)	50	50	50
Winding inductance (pu)	0.03	0.03	0.03
Winding resistance (pu)	0.001	0.001	0.001
Line Parameters			
Line type	Overhead		
Positive sequence parameters	Resistance (Ω/km)	Reactance (Ω/km)	Susceptance (μS/km)
	0.510	0.366	3.172
Zero sequence parameters	Resistance (Ω/km)	Reactance (Ω/km)	Susceptance (μS/km)
	0.658	1.611	1.280

with a simulation period of 0.3 s. Fig. 7 provides the IIDGs output voltages and currents during different fault types on Line L_{AB} . It can be seen that the IIDGs generate nearly balanced fault currents for unbalanced faults. This means that the configuration of the transformer interfacing the IIDG to the network has an impact on the currents supplied to the fault and the voltage waveform. The proposed scheme has been tested for all configurations during the study. The case presented in this paper considered a delta-wye configuration as it is usually used to prevent multiple sources of ground fault currents.

Simulation results for a three phase, single phase to ground fault and phase to phase faults are considered for different cases. However, it is impossible to exhaustively simulate all faults for each case in this paper. Details on the cosine method performance for the detection of change in positive sequence current flow direction in various fault and operating conditions can be found in [32].

A. Detection of disturbance occurrence in the microgrid

As described in Section II.A, the local ROCOSP is used to detect a disturbance in the microgrid and to discriminate a fault on a line protected by a master relay from a fault elsewhere in the microgrid network. To provide a clear understanding on this, a load switching event was simulated in the system on Bus B. For the simulation purposes, the system loading is shared as follows: initially, the system was simulated with Load 1 = 0.5 MW, Load 2 = 0.7 MW, Load 3 = 0.2 MW, and Load 4 =

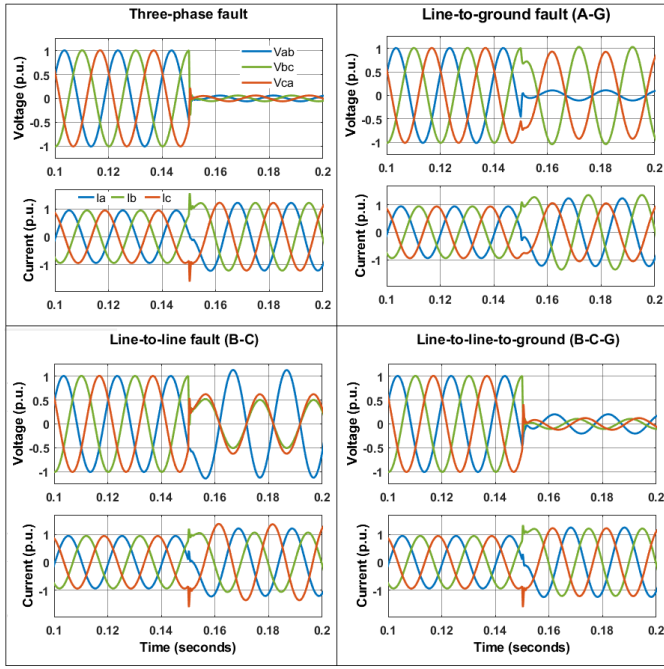


Fig. 7. IIDGs voltage and current output during different types of fault

0.2 MW. After 0.15 s, an additional load of 1.2 MW was then connected to bus B. This load is more than a third of the total system load capacity and is used to ensure that an appreciable load is used to see the effect of the event on the ROCOSP. Simulation results, as given in Fig. 8, show that the phase angle difference between phase angles measured before and during the event, the slope, and ROCOSP maximum absolute values estimated by all master relays stay relatively small (≤ 40 degrees, 6 Hz and 40 Hz/s respectively) for both 50 Hz (Fig. 8 (b), (c), (d)) and 52 Hz (Fig. 8 (f), (g), (h)) operating frequencies compared to Relay 4 that registered significantly larger maximum absolute values (close to 180 degrees, 25 Hz and greater than 1000 Hz/s respectively). Knowing that the large values estimated by Relay 4 are due to the change in current flow direction after the additional load in the system, it can be seen that simulation results are close to theoretical values previously calculated.

Furthermore, the calculation of the average values of angle difference, phase angle slope and ROCOSP over a cycle provides steady increase towards the maximum values rather than instantaneous step change from zero to the maximum value after a cycle. This means that a change in current flow direction can be detected before the values reach the maximum value. This threshold can be set at half the maximum values to ensure faster detection. In this paper, change in current flow direction in the lines protected by master relays is set at a ROCOSP value of 600 Hz/s.

On the other hand, when a fault is external to a relay line, the master relays are expected to detect the disturbance based on ROCOSP as well. However, the threshold for a fault detection is far less than that of change in current

flow direction in the master relay line. So any threshold value other than zero can be used. This is because even a severe switching event (generator disconnection or large load connection/disconnection) is discriminated by the protection scheme as an external disturbance to the scheme zone of protection. In this paper a 50 Hz threshold is set to reduce frequent false disturbance alarms.

A three-phase fault is simulated on Line L_{AB} . The loads at the buses are distributed as follows: Load 1 = 0.8 MW, Load 2 = 1.3 MW, Load 3 = 0.2 MW, and Load 4 = 0.5 MW. This is considered as the reference case in this paper. Simulation results, as presented in Fig. 9 (b), (d), and (f) provide the values local ROCOSP estimated by master relays 1, 5 and 9. It can be clearly seen that all master relays detected the disturbance occurrence in the system with Relay 1 registering the largest ROCOSP value due to the change in current flow direction in its line.

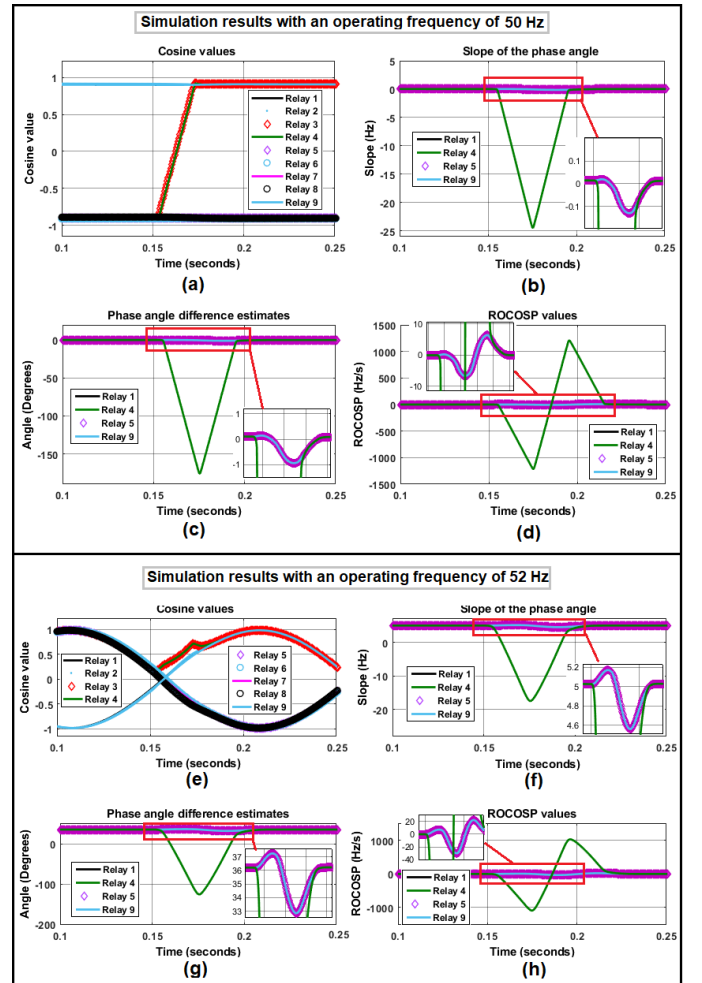


Fig. 8. Simulation results for two different operating frequencies (50 and 52 Hz) for a load switching event at Bus B causing a change in current flow direction in the line protected by Relay 4: (a & e) Cosine values computed by all relays (b & f) Phase angle difference between two consecutive cycle estimates (degrees) (c & g) The slope of the positive sequence current phasor angle (Hz) (d & h) Rate of change of the phase angle slope (ROCOSP in Hz/s)

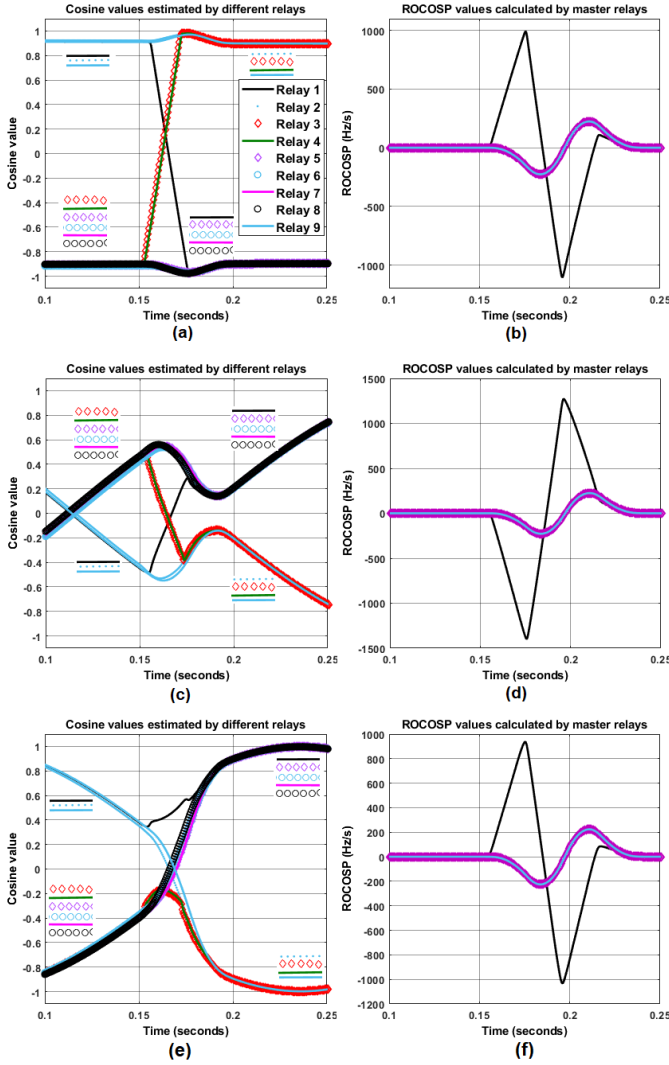


Fig. 9. Simulation results for a three-phase fault on Line L_{AB} : Cosine and ROCOSP values estimated by relays with operating frequency of (a & b) 50 Hz (c & d) 52 Hz and (e & f) 48 Hz

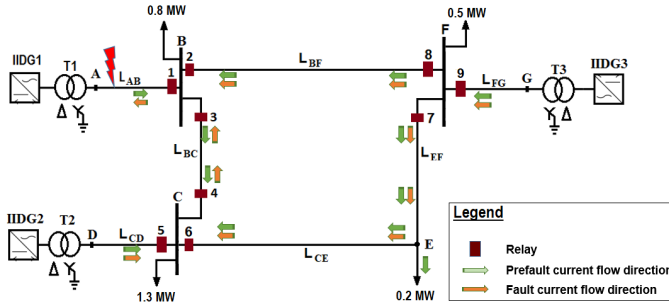


Fig. 10. Current flow direction during normal operation (green) and during a fault on line L_{AB} (Orange)

B. Identification of the faulted line

Once the disturbance is detected in the system by the master relays, the directionality feature is used to determine the faulted section. It is important to note that for the sake

of simplicity, all relays around the busbar have the same monitoring direction, from the line to the bus, under all simulation scenarios to ensure effective comparison of the cosine values signs of slave relays with their respective master relay. Otherwise, care is required to ensure correct comparison.

a) *Fault on a line protected by master relays:* The fault on Line L_{AB} discussed in the previous section represents this case. Contrary to slave relays, master relays will always see the current flowing from the DG to the busbar during normal operation. So when the current flow direction seen by a master relay changes, the fault is identified to be on the line it protects.

Taking the case of a fault on Line L_{AB} , as explained in details in the previous subsection the fault was identified on the master relay line L_{AB} . Regarding the cosine value signs by different relays as shown in Fig. 9 (a), (c), and (e), it can be clearly seen that despite the operating frequency (nominal or off-nominal), before the fault Relays 1, 2, and 9 yields cosine values with opposite sign to those of Relays 3, 4, 5, 6, 7, and 8. After the fault, Relays 1, 5, 6, 7, and 8 register cosine values with opposite signs to the ones of Relays 2, 9, 3, and 4.

By applying the proposed scheme principle as described in Section II.B.(b), the output of other relays are as follows:

- Relay 1 sends blocking signals to Relays 2 and 3, which in turn send blocking signals to their remote line relay counterparts, 8 and 4 respectively to overturn the disturbance signals received from their respective master relays 9 and 5. Thus, Lines L_{BF} and L_{BC} are kept connected.
- Relays 6 and 7 have received a fault signal with the cosine value signs from their master relays 5 and 9 respectively. The simulation results show that the cosine values of Relay 6 and its master relay 5 are the same while they are opposite for Relay 7 and its master relay 9. So Relay 6 sends a blocking signal to Relay 7 (its remote line relay counterpart) as the fault is external to their line, Line L_{CF} .

The combination of proposed relay coordination strategies has identified a fault on Line L_{AB} , since at least one relay of each of the other lines relays received a blocking signal indicating an external fault to their lines. The reflection of the results to the study system is illustrated in Fig. 10. The prefault current flow directions are based on the loading system while the fault current flow directions are derived from the simulation results.

b) *Fault on a line protected by slave relays:* A single phase to ground fault (Phase A to ground) is initiated in the middle of Line L_{BC} . The loads used are the same as those for the fault simulated previously on Line L_{AB} . The current flow directions in all lines of the system before and during the fault are shown in Fig. 12. These directions are derived from the cosine values as provided from simulation results in Fig. 11 (a) where clearly only Relay 4 registers a change in cosine value sign.

After the fault is detected by the master relays 1, 5, and 9, as shown in Fig. 11 (b), the faulted line is identified as follows:

- Relays 2, 3, 4, 6, 7, and 8 receive fault signals from their respective master relays (1, 5, and 9) along with the signs of cosine values.
- The slave relays compare the received value signs with theirs. Relays 2 and 6 output the same signs as their master relays 1 and 5 respectively, indicating an external fault to Lines L_{BF} and L_{CF} . So Relays 2 and 6 send blocking signals to Relays 8 and 7 respectively. The rest of the slave relays 3, 4, 7, and 8 register opposite cosine value signs to their master relays.

It can be seen that with exception to Relays 3 and 4, at least one of the other line relay pairs received a blocking signal. So, the Line L_{BC} protected by the pair (3,4) is identified as the faulted line to be isolated.

c) *Fault on a tapped line:* A phase to phase fault was simulated on Line L_{CF} on its part L_{EF} keeping other system parameters as in the reference case. As expected, the fault is detected by master relays using ROCOSP estimates as given in Fig. 13 (b). Also simulation results in Fig. 13 (a) show that there is no change in current flow direction in any of the lines protected by the master relays 1, 5 and 9 as illustrated in Fig. 14. Therefore, the fault is on one of the loop lines. The identification of the faulted line is as follows:

- Relays 2, 3, 4, 6, 7, and 8 receive fault signals from their respective master relays (1, 5, and 9) along with the signs of the cosine values.

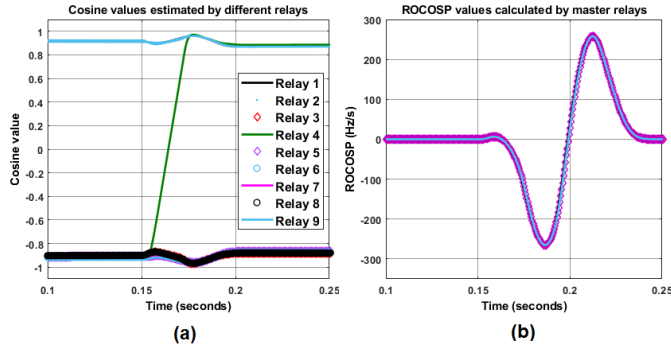


Fig. 11. Simulation results for a Phase A to ground fault on Line L_{BC} : (a) Cosine values estimated by all relays (b) ROCOSP values estimated by master relays

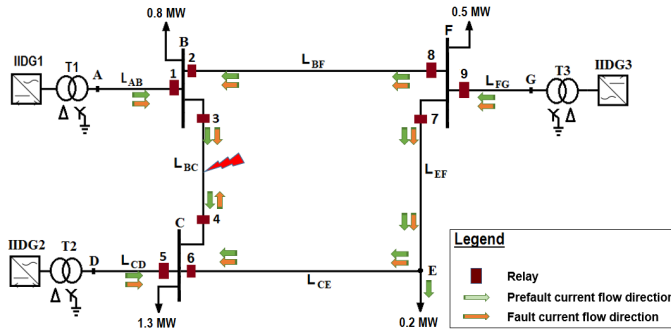


Fig. 12. Current flow direction during normal operation (green) and fault (orange) on Line L_{BC}

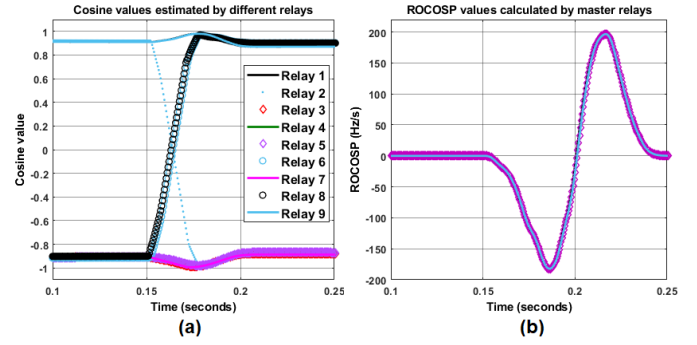


Fig. 13. Simulation results for a fault on Line L_{EF} : (a) Cosine values estimated by all relays (b) ROCOSP values estimated by master relays

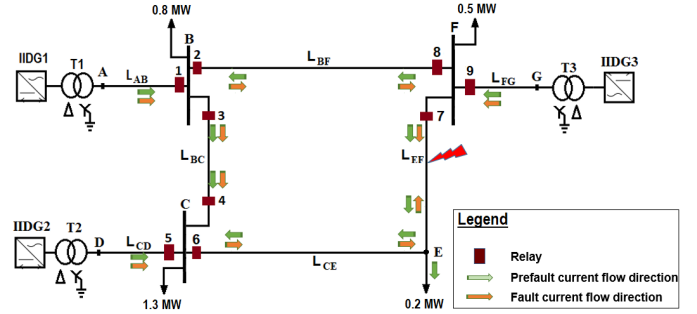


Fig. 14. Current flow direction during normal operation (green) and fault (orange) on Line L_{EF}

- The comparison of the received cosine signs from the master relays with the one of slaves shows that only Relays 4 and 8 register the same sign as their master relays. Consequently, the fault is external to Lines L_{BC} and L_{BF} . So Relays 4 and 8 send blocking signals to Relays 3 and 2 respectively.

With only Relays 6 and 7 having not received a blocking signal, the fault is confirmed on the line they are protecting, Line L_{CF} .

d) *Fault on a bus:* A fault on a bus is external to all lines. So all relays are expected to keep their lines connected as busbars are considered out of the proposed scheme's protection zone. To verify how the scheme responds to such a fault, a single phase to ground fault was initiated on Bus B with other simulation conditions kept the same as the reference case. The associated simulation results for this scenario are given in Fig. 15 (a) with the positive sequence current flow directions illustrated in Fig. 15 (c).

Under the same simulations conditions, synchronous generators with the same capacity as the IIDGs were used instead of the IIDGs. The corresponding simulation results are provided in Fig. 15 (b). These results are consistent with those in Fig. 15 (a) as expected with the only difference in cosine and ROCOSP values due to difference in fault response.

To verify the effectiveness of the proposed scheme with different type of loads and DGs, Loads 1 and 2 were changed from purely resistive loads, 0.8 MW and 1.3 MW respectively, to loads consuming both active and reactive power, 0.8 MVA

($P = 0.65$ MW and $Q = 0.45$ MVar) and 1.3 MVA ($P = 1.1$ MW and $Q = 0.7$ MVar) respectively. With a single phase to ground fault on Bus B at time instant $t = 0.35$ s (the fault time instant was changed in this case to ensure that the fault occurs when the control system is stable), simulation results with IIDGs and synchronous DGs as given in (d) and (e) parts of Fig. 15 were consistent with the ones with loads consuming only active power.

A simple discussion on this scenario's simulation results is sufficient, since the results are the same as the ones for a fault on Line L_{BC} discussed in III.B.c with one exception. The only difference is the change of current flow direction registered by both Relays 3 and 4 rather than by only Relay 4 as it is for the scenario with a fault on Line L_{BC} . Therefore the sign of the cosine value calculated by Relay 3 is of the same sign as the one of its master relay, Relay 1. This leads to Relay 3 sending a blocking signal to Relay 4 to keep the line L_{BC} connected. Consequently, no line is isolated as all lines are kept connected by their relays.

This situation is the same as the one for the load switching event shown in Fig. 8 except that the disturbance detection threshold is not reached. However, assuming that the threshold was set lower, still the relay coordination based on cosine value sign would see it as an external disturbance. This is to say that any disturbance occurring on the busbar such as generator/load connection/disconnection or a fault is effectively discriminated from a fault on a line. This clearly shows the effectiveness of the proposed scheme to external faults. Yet, this can also indicate a possibility of extending the scheme to busbar protection. However, this is out of the scope of this paper.

It is important to note that this paper is beyond proof of concept but a step forward towards testing its robustness and its implementation. The work in [32] has proven the validity of the concept and this work explores its application to different microgrid topologies. It is also important to recognise that the performance of a microgrid, particularly during faults depends on many factors such as generation technology mix, control parameters of the IIDGs' controllers, step-up transformer configuration, type of loads supplied by the microgrid, and still need to be investigated in detail as they may have impacts on the operation of the proposed protection scheme, particularly in situations with interharmonics-rich waveforms.

Considering the latter, an indication of the effect of interharmonics on the proposed protection scheme is provided. While the interharmonic voltage limits are defined based on flickers in IEEE and IEC standards, it is suggested that for issues similar to harmonics, the limits should be similar to those of harmonics, specifically, the next higher even harmonic [34]. Following this approach, [34] recognises that even harmonic current limits for systems rated 120 V to 69 kV are more complicated as they depend on the frequency and the ratio of the short-circuit to load current in the range of 0.075% (high frequency harmonic ($\geq 35^{th}$ harmonic) and low short circuit ratios (≤ 20)) and 3.75% (low frequency ($\leq 11^{th}$ harmonic) and high short circuit ratios (≥ 1000)). One would expect therefore that the interharmonic current limits in multi-inverter

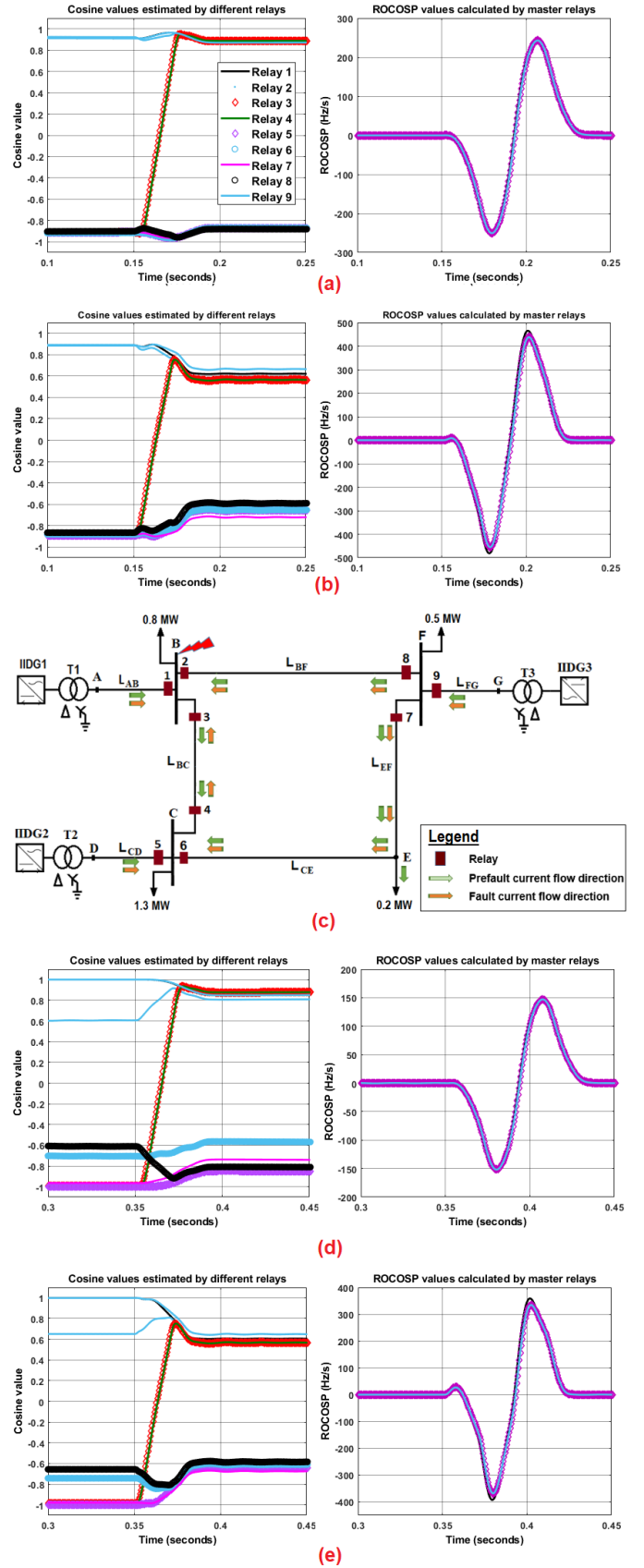


Fig. 15. Cosine and ROCOSP values for a fault on Bus B in the microgrid constituting of: (a) purely resistive loads and only IIDGs (b) purely resistive loads and only synchronous-based DGs (d) inductive loads and only IIDGs (e) inductive loads and only synchronous-based DGs (c) Illustration of current flow direction during normal (green) and fault operating conditions (orange)

microgrids to be lower than 3.75% due to low short circuit ratio in the microgrid and low frequencies due to lowpass filter in protective relays. Preliminary results have indicated that interharmonic currents below 3.75% of the line current do not affect the proposed scheme. However, in practice, this limit can be exceeded. In such a case, the effectiveness of the proposed scheme applied to the study microgrid may be compromised for interharmonic (below the 2nd harmonic) current levels roughly above 6%.

IV. CONCLUSIONS

This paper proposes a low-cost communication-assisted protection scheme using current directionality feature. As a blocking scheme, this protection strategy may as well be used as a back-up protection to any viable protection scheme using a communication means between the line terminals to save the cost of the back-up communication infrastructure as it can utilize the communication means of the healthy lines when the one for the faulted line fails. Considering the complexity that may exist in a microgrid, such as generation technology mix, control parameters of the inverters, type of loads, that may results in more complex practical situations beyond what has been reported in this work, further investigation can be undertaken as future work to ensure that the proposed protection scheme can be applied to any microgrid.

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