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Intelligent protection coordination restoration strategy for active distribution networks

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Abstract
Despite various advantages of integrating distributed generation (DG) units into distribution networks such as power loss reduction and voltage profile improvement, they may disrupt the performance of the conventional protection system due to bidirectional power flow and change of short-circuit power. With the development of multi-agent systems (MASs), intelligent protection schemes have been introduced that operate on the basis of data processing by a central controller. However, the possibility of communication failure and cyber attacks reduce reliability of these protection systems. To address this problem, this paper proposes an intelligent protection scheme that relies on peer-to-peer communication between agents in the first layer of the MAS. In the case of communication failure, the agents react to the fault condition by using the available data for similar conditions. The main advantages of the proposed scheme are reduction of number of employed agents by using only relay agents and no need for communicating with higher layers of MAS. Implementation of the proposed scheme in the ETAP simulation model of a 14 bus active distribution network shows that data exchange between relay agents properly modifies the operating time of the relays, resulting in protection coordination between main and backup protections.

1 INTRODUCTION

The electric industry is one of the main bases of economic growth and development of any country, and the generation and consumption of electrical energy is an important economic growth indicator. Accordingly, distributed generation (DG) units that use often renewable energies as the primary source have gained great attention among electrical energy producers and environmentalists [1]. By using these units, a portion of the load is locally fed. It reduces the electricity demand from the upstream grid, decreasing the power loss. Moreover, DG units allow for the autonomous operation of local electrical energy networks [2–5].

However, the integration of DG units results in some technical problems for distribution network operation. Intermittent electricity production of photovoltaic (PV) and wind turbine systems due to environmental conditions forces the distribution network operator to revise the available operation and protection schemes [6–8]. An electrical network should be designed in such a way that the electrical energy is delivered to the consumers with high reliability and low interruption. One of the main threats is the occurrence of short-circuit faults. If a short-circuit fault is not cleared immediately, it imposes irreparable damage to the electrical network. To prevent such damages, various protective devices (PDs) are installed in the systems which overcurrent relays (OCRs) are the most common PDs for distribution networks. The proper selection and setting of PDs have important roles in the increment of dependability and security of the protection system of the electrical network. The conventional protection system of the distribution network has been set according to the unidirectional power flow. However, due to changes in amplitude and direction of fault current, the increasing integration of DG units is a serious challenge for the available protection system of the distribution networks. The integration of DG units into a radial distribution network leads to the network being fed from several points. Also, the behaviour of various DG units during faults and their effects on the amplitude and direction of short-circuit current are different [9].

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The proposed measures in the literature for modifying the protection system of the distribution network in the presence of DG units can be categorized into six groups as follows:

(i) DG disconnection in the instance of fault detection [10, 11]: In the schemes of the first group, regarding the adverse effect of DG units on the operation of the protection system, they are disconnected from the distribution network during a fault condition. In [10, 11], the effects of DG disconnection on the distribution network due to transmission line faults are investigated. Also, the need for changing the network protection schemes in the presence of DG units is stated. Loss of DG production and synchronization problem for DG reconnection are the main disadvantages of this group.

(ii) Limiting the penetration level of DG units [12]: In the second group, the penetration level of DG units is kept low to decrease their effect on the protection system operation. However, this scheme prevents the distribution network from taking full advantage of these economic and clean energy sources.

(iii) Limiting the fault current using fault current limiters (FCLs) [13–16]: In the third group schemes, the FCLs are installed in various sections of the distribution lines and they insert series large impedances during a fault condition to limit the fault current; consequently, there is no need for protection setting change. Using superconducting fault current limiters (SFCLs), [13] improves the performance of the protection system. The effects of SFCL on the protection system are discussed in [14]. Ref. [15] suppresses the faulty section effect on the healthy network by using FCLs. In [16], the protection coordination between recloser and fuse is improved using FCLs. High cost and the need for determination of optimum size and location of FCLs are the main disadvantages of this group.

(iv) Network reconfiguration [17, 18]: Reconfiguration of PDs and DGs is the basis of the fourth group schemes. In [17], protection coordination between PDs is preserved in the presence of DG units by using multifunction recloser/relays and without communication links. Using digital relays, [18] implements different protection zones to preserve the protection coordination. However, high cost and complexity limit their practical implementation.

(v) Using adaptive protection system (APS) [12, 19–23]: In the fifth group schemes, using the pre-determined algorithms and calculation and prediction of all operating cases such as load change, network topology change, and intermittent power generation of renewable sources, APSs protect the distribution network. Using the SCADA system and a predefined algorithm, [12] coordinates the relays and resets the new settings on the relays online in the case of a change in the network topology and directional overcurrent relays miscoordination. In [19], the network calculations are performed using a new formulation. The new settings are then applied offline to the overcurrent relays. [20] optimizes the protection coordination between overcurrent relays using the firefly algorithm. In [21], an adaptive protection system is developed by using differential search algorithm and fuzzy logic as well as using overcurrent and distance relays. Using a mathematical programming language and interior-point optimization as well as intelligent electronic devices (IEDs), an adaptive protection scheme is presented in [22] to preserve the protection coordination between directional overcurrent relays. In [23], the appropriate settings for overcurrent relays are provided by using an adaptive method and optimization algorithms, and comparing the current angle before and after the fault occurrence to preserve the protection coordination between them. However, the need for considering all possible operating conditions increases the computational burden of this group.

(vi) Using intelligent protection system (IPS) [5, 24–30]: Recently, employment of intelligent methods in protection system has gained great attention. In an IPS, the protection system relies on the communication infrastructure and IEDs. One of the intelligent techniques is using multi-agent systems (MASs) where agents exchange the distribution network data to help the protection system. In [5], an intelligent method is presented by using the ant colony algorithm to minimize the number of errors in the protection system. Considering the relays, DGs, and equipment as the agents of the MAS and using point-to-point communication, [24] preserves the protection coordination by exchanging the network information between agents through the communication links by IEDs. Ref. [25] preserves the relay protection coordination by using a distributed MAS and IEC 61,850 generic object-oriented substation events (GOOSE) protocol as well as IEDs. An intelligent protection scheme is presented in [26] where a centralized and multi-layered MAS is in interaction with relays, DGs, and loads to preserve protection coordination. In [27], a MAS-based self-healing protection scheme is presented which is adaptable to the different network conditions. Also, using a MAS consisting of feeder, zone, breaker, and DG agents, a self-healing protection system is developed in [28]. Ref. [29] presents a protection system by using MAS and a machine learning algorithm that can coordinate and update the protection system and adapt it to the new conditions of the network. In [30], coordination of fuse-recloser in the presence of DG units is preserved by using distributed multi-agent systems. In this method, each fuse is considered as an agent and its melting time is calculated and provided to the recloser. The method of implementing communication links between agents, and number and type of agents should be correctly chosen for MAS-based protection systems to operate properly.

The intelligent protection schemes usually rely on a control centre that it decreases the reliability due to the risk of communication failure and cyber attacks. To address this problem, this paper presents a MAS-based protection system that only uses the communication between neighbour agents in the first
MAS layer. The proposed scheme only uses the relay agents. By using the shared current data among neighbour relays through peer to peer communication, the operating time of the relays is modified to restore the protection coordination. Also, in the case of communication failure, the protection system setting is adopted using the available data for similar conditions. The proposed strategy eliminates the need for a central controller and increases the protection system security.

The rest of the paper is organized as follows: Section 2 describes the effect of DG units on the protection system of the distribution network. The structure of MAS and its role in the protection system is presented in Section 3. Section 4 is dedicated to the proposed MAS-based protection system. Evaluation of the proposed technique is presented in Section 5, followed by a discussion in Section 6. Finally, Section 7 concludes the paper.

2  EFFECT OF DG INTEGRATION ON PROTECTION SYSTEM PERFORMANCE

The PDs should be able to detect and locate the fault in the shortest possible time and to isolate the faulty section from healthy ones. Moreover, the sensitivity of the protection system should be in such a way that it properly operates for short-circuit fault with minimum fault current while it does not maloperate during normal events such as a load change [31]. This section is dedicated to investigating the effect of DG units on the distribution network protection system including increment of short-circuit current and protection miscoordination.

2.1  Change of short-circuit power

In a distribution network, the short-circuit current depends on the short-circuit power of electrical energy sources. Also, the location of DG units along the feeder and distance of fault point to the sources affect the fault current. Due to the integration of the DG units, the total short-circuit power of the network increases. Also, the closer the distance of the fault point to the DG unit, the higher the short-circuit current. Since available PDs have been set in the absence of DG units, the fault current increment may degrade the performance of the PDs, resulting in life and financial losses.

2.2  Protection miscoordination

Figure 1(a) shows the single-diagram of a radial distribution network. The OCRs R1, R2, and R3 are installed along the feeder as the PDs. R3 is set based on the maximum fault current and protects the third zone of the feeder. R2 protects the zone 2 and operates as the backup protection of R3; if R3 fails to operate, R2 isolates both zones 2 and 3 with a coordination time interval (CTI) delay. Similarly, R1 operates as the main and backup protection for the zone 1 and zones 2 and 3, respectively.

2.2.1  Integration of one DG unit

If only DG3 is integrated into the feeder and fault F1 occurs inside zone 3 (Figure 1(b)), R2 and R3 currents are the same and they are injected from the main grid. Regarding the equal fault currents, these relays coordinate to operate similar to the condition of absence of DG3. However, if fault F2 occurs upstream of these relays, current of R2 and R3 is equal to the DG3 fault current contribution. In this condition, R3 operates faster than R2 while regarding the fault location, R2 and R3 are the main and backup relays, respectively, and R2 should operate faster than R3. Consequently, the protection coordination between R2 and R3 is lost.

2.2.2  Integration of multi DGs

If DG1 and DG2 are integrated into the feeder (Figure 1(c)) and a fault occurs inside zone 3, the minimum and maximum fault currents increase due to the fault current contribution of DGs. In this condition, the settings of OCRs may be required to be updated by using the new fault currents. If three DGs are integrated into the feeder (Figure 1(d)) and the previous fault condition occurs, the fault current may significantly increase. In this condition, R2 and R3 may operate simultaneously or R2 operates faster than R3 because the fault current may be inside the instantaneous trip region of the OCR characteristic curve. If a fault occurs at F2 in Figure 1(d), the current seen by R3 is the DG3 fault current while the current seen by R2 is the sum of DG2 and DG3 fault currents. It results in protection miscoordination between R2 and R3.

3  MULTI-AGENT SYSTEMS

An agent is software or hardware which is installed in some environment and can autonomously react to a change in that environment [32]. Everything out of the agent is the environment. The agents must observe or change some parts of the environment. To be observable, the agents should receive the environment data from the sensors or with the help of planning in the environment. To be alterable, the agents must be able to make a change in the environment by sending a tripping command to the switches or saving information in the databases. A multi-agent system is formed by two or several agents who cooperate to achieve the system objective. Besides, each agent achieves the local goals. Figure 2 shows a sample MAS that is implemented in the distribution network. The three-layer structure of this MAS includes relay, circuit breaker (CB), load, and DG agents. According to the definition of MAS, when a change occurs in the network, the disturbance is detected and agents collect the data from the environment. In the higher level of MAS, the hosts receive the information of agents and send them to the processing layer (control centre). The processing layer as the highest layer of MAS is responsible for organizing all the lower-level agents to make a proper collaboration.
FIGURE 1  A sample distribution network. (a) No DG unit, (b) integration of one DG unit, (c) integration of two DG units, and (d) integration of three DG units

3.1  |  Hierarchical structure

Each intelligent agent can operate in cooperation with other ones through communication links to address the protection system problems. An agent can be a sensor, a PD, a processing unit, or a database. Generally, the hierarchical structure of MAS consists of three layers. The first layer is the equipment layer that receives data from/sends data to the electrical network. The second layer is responsible for sharing and managing those data that are received from the first layer to coordinate, calculate, and process. The third layer collects, evaluates, coordinates, calculates, and processes the data received from the lower layers [33].

In agent-based protection systems, the closest layer to the electrical network is the equipment layer. This layer consists of measuring agents (MAs) such as voltage and current measuring devices, executing agents such as circuit breakers, network equipment agents such as busbar and line agents, and protection agents such as relays. The collected data by the MAs are sent to the protection agent. The protection agent determines the severity of the fault and sends data to the upper layer. The management layer receives the data from the equipment layer
and determines the type and location of the fault. Then, based on the data, the proper settings are sent to the PDs. According to the adopted decision, the management agent sends the command to the CB agent and checks whether the CB operation is properly done or not.

The evaluation results are reported to the network operator for improving the system performance. Sometimes, these results help to improve the solution management in the coordination layer. The database agent is in the third layer and is responsible for saving the collected data from the network and protection system settings. These settings are of great importance and must be always updated. According to the fault condition, the management layer selects the best group settings. An important issue in the MAS is the individual communication of each agent with the neighbouring agent and understanding its status. The status here means knowing whether the agent is healthy or not, being present in the network or not, the distance of the neighbour agent, and the information viewed by it.

3.2 Communication protocol in intelligent networks

The IEC 61,850 is commonly used as an acceptable standard communication protocol for the network communication. This standard provides a framework for communication and share of information during electrical network transition from centralized control to some decentralized capabilities. Decentralized control programs use a high-speed convergent communication. IEC 61,850-based GOOSE technology provides a convergent public communication for fast communication between two or more devices with decentralized functions in the range of 4–5 ms [33, 34]. The purpose of the IEC 61,850 for communication networks is to design infrastructure for the exchange of information between intelligent devices that differ in their manufacturers or applications. This standard supports the transfer of analog values prepared by any type of measurement transformer and by following this standard. Thus, all sensors that
have been produced over the years are accepted by this standard [35].

3.3 Centralized MAS problems

The main drawbacks of centralized protection schemes are the need for high communication capabilities with a powerful central controller and their dependence on its adopted decision. This dependency can easily cause the system to crash completely. Therefore, advanced distributed protection plans and interactive communications are required to avoid the limitations of network protection systems [36]. Decentralized methods based on the MAS can examine themselves and react based on the environmental conditions that lie ahead. Protection schemes based on information exchange principles have been discussed in the literature. However, they remained in the early development stage [33, 37].

4 PROPOSED MAS BASED PROTECTION SYSTEM

Considering the structure of MAS and problems caused by the dependence of the hierarchical structure on the central processing unit, this paper aims to propose a method for using the capabilities of MAS to make it independent of communication with higher levels and eliminate the need for presence of a central processing unit. In the proposed algorithm, the relay agents are considered as the only agent of MAS to independently modify the operating time of the relays based on the current information obtained from the network. Relay agents, by establishing a point-to-point communication with their neighbours, obtain a table of their operating time and change their behaviour pattern accordingly. The agents can act offline in the case of similar problems, and in the case of new changes, they can determine their status in accordance with the network conditions and have the correct operation.

Considering the structure of the MAS as well as the type of communication, a solution can be provided to identify the new conditions and make decisions by agents. This structure should be implemented in such a way that there is no need for the presence of central control to achieve the correct settings, and by reducing the number of agents, the increase of traffic and load of the communication network and related problems are prevented.

In the proposed method, IEDs are implemented on the digital non-directional overcurrent relays with the help of agents, thereby the problems of the conventional MAS based protection reduce. Intelligent agents with the ability of measuring and recording the information can react to changes in the network and make the proper decision. Accordingly, it is necessary for relay agents to first have their current information and performance schedule and provide them to other agents. Using the load flow and short-circuit calculations, current of each relay is determined. The relays will have a specific timing depending on their current. This means that in each current range, a certain average operating time can be considered for a relay. By modifying this period, the relays can function properly in the event of similar conditions. To be able to compare their coordination conditions with the backup relay, the relay agents must be aware of the performance status of their neighbours; so they use these timetables to check the coordination. For preserving the coordination between relay agents, the CTI is considered to be between 300 and 400 ms. If the relays maintain this operating time margin relative to each other, the main and backup relays coordinate to operate.

4.1 Proposed intelligent protection algorithm

Figure 3 shows the flowchart of the proposed algorithm which consists of seven steps as follows.

Step 1: The relay agents continuously communicate with each other on the communication platform and report their current changes to each other.

Step 2: According to the current of the relays and their specified settings for the normal operating conditions, the relays detect a fault condition when their current exceeds the threshold.

Step 3: Since the closest relay to the fault point as the main relay has the task of clearing the fault, so it is necessary to determine the backup relays according to the operating time and the data sharing between the relay agents.

Step 4: Each agent calculates the operating time of its surrounding agents based on their received currents and determines its coordination status.

Step 5: If the CTI between the two relays is within the standard time interval, the main and backup relays coordinate to operate.

Step 6: If there is no coordination between the two relays, it is necessary to prevent the backup protections from malfunctioning.

Step 7: In this step, it is necessary to check the situation. Accordingly, due to the intelligence of the equipment and based on the databases, the conditions are compared with the previous conditions. In this case, two conditions occur: offline and online operating modes.

4.1.1 Offline operating mode

For an electrical network, regarding different conditions and the presence of DGs, similar conditions may occur in the case of a fault. Therefore, it is necessary to consider these conditions in such a way that in the case of failure of the communication network, one can still expect the correct performance of the
Relay agents share their information with each other

There is no fault in the network

Current of relay is greater than threshold

A fault has occurred

Main agent specifies backup agents based on operating time

Agents calculate operating time of the neighbor agents using the received data

Relays coordinate to operate

Relays properly operate and clear the fault

Same condition is already registered in the database

Online Operating Mode

Offline Operating Mode

FIGURE 3 Flowchart of the proposed MAS based protection scheme

protection system. In this case, the agents have their own data table based on their operating time and current and how they operate in those conditions. This table is based on the settings for the neighbouring relays. Figure 4 shows the time classification for a relay agent. Based on the table and the fault current, the main relay provides a table with a specified current interval and the backup protection operating time, and according to the received information, it specifies a common point with the information stored in its database. The stored information is shown in Table 1. This table presents the current-time pattern of the backup protection that is followed based on the current. The main protection has this information, and according to its and backup protection operating times, it stores a specific pattern for itself to use as the default. Figure 5 shows the algorithm of offline operating mode. If there is no current pattern for a fault current, it is necessary to enter the online operating mode and select the appropriate performance based on the new conditions.

4.1.2 Online operating mode

The protection system is sensitized by electric current; so by monitoring the fault current on other relay agents, their incorrect operation in different conditions can be prevented. Accordingly, in the online operating mode, relay agents, according to the communication with each other, examine each other’s performance and make the correct decisions in different situations.
FIGURE 4  Classification of relay operating time based on fault current

TABLE 1  Current based timing of relay agent

| Fault current range | Operating time range |
|---------------------|---------------------|
| $I_{F0} \leq I_F < I_{F1}$ | $t_0 \leq t < t_1$ |
| $I_{F1} \leq I_F < I_{F2}$ | $t_1 \leq t < t_2$ |
| $I_{F2} \leq I_F < I_{F3}$ | $t_2 \leq t < t_3$ |
| $I_{F3} \leq I_F < I_{F4}$ | $t_3 \leq t < t_4$ |
| $I_{F4} \leq I_F < I_{F5}$ | $t_4 \leq t < t_5$ |
| $I_{F5} \leq I_F < I_{F6}$ | $t_5 \leq t < t_6$ |
| $I_{F6} \leq I_F < I_{F7}$ | $t_6 \leq t < t_7$ |
| $I_{F7} \leq I_F < I_{F8}$ | $t_7 \leq t < t_8$ |

Figure 6 shows the communication and neighbourhood table formation of relay agents. The relay agents operate based on the fault current and determine their task during the fault. Relay R2 which sees more fault current in the event of a fault informs its upstream relay that it will be responsible for the main protection in this situation. Each relay agent activates a timer to check its operating time in the event of a fault and continues to count as long as it detects the fault in the network.

The relays in an electrical network are coordinated with each other based on the maximum network fault current. By integrating the DGs, the fault current of both relays is affected. Since

the main relay has the task of clearing the fault in the shortest possible time, so the presence of DGs results in faster operation of the main relay. However, the operating time of the backup
FIGURE 6  Data sharing between agents of the main and backup relays

relay may be close to that of the main relay or it is much longer than the standard conditions.

In the proposed scheme, the relays first observe the fault current passing through each other. Once the main protection is specified, the backup relay agent will not function by default unless there is still fault current in the network after a specified time from the operating time of the main relay. In this condition, the backup relay assumes that the main relay has failed to disconnect the CB and requires to disconnect the CB associated with the backup relay. It reduces the dependence on communication. Figure 7 shows the flowchart of the online operating mode.
5 | PERFORMANCE EVALUATION

To evaluate the performance of the proposed scheme, the distribution network of Figure 8 is simulated in the ETAP environment. The study network is implemented in such a way that due to the importance of the loads on the downstream zone of the R4 relay, they should be always fed. To this end, a tie line between feeders 1 and 2 is considered, so that if feeder 2 is deenergized, the loads in the downstream zone of the R4 do not suffer from power failure and are supplied by the feeder 1. The protection system of the study network is designed in the absence of DG units. Each relay has two group settings: one
TABLE 2  
Timetable of operating time of relays R1 and R2 in the absence of DG units

| R1 current (A) | R1 operating time (ms) | R2 current (A) | R2 operating time (ms) |
|---------------|------------------------|---------------|------------------------|
| 1020 – 1223   | 1033                   | 1020 – 1223   | 168                    |
| 1224 – 1427   | 914                    | 1224 – 1427   | 135                    |
| 1428 – 1631   | 666                    | 1428 – 1631   | 112                    |
| 1632 – 1650   | 510                    | 1632 – 1650   | 96                     |

setting for the case of normal operation and the other one for the case of energizing tie line and opening circuit breaker CB3. This section investigates the performance of the proposed scheme in two operating conditions and different fault conditions at different zones in the presence of DG units. The communication structure of the agents in this design consists of the communication between the relay agents in the first protection layer. In the first protection layer design, the study network consists of four relay agents; two relays R1 and R2 on the first feeder and two relays R3 and R4 on the second feeder that are communicated to each other point to point. Four DG units can be integrated into the study distribution network; DG1 with a capacity of 10 MW, DG2 with a capacity of 10 MW, DG3 with a capacity of 5 MW, and DG4 with a capacity of 5 MW. It should be noted that setting of each relay is implemented offline in the ETAP.

5.1 Scenario 1: Normal configuration

In the normal configuration, both feeders 1 and 2 feed the loads and the tie line is deenergized. Accordingly, in the absence of DGs, R1 with the extremely inverse characteristic curve and R2 with the very inverse characteristic curve are responsible for protecting feeder 1. Also, R3 with the extremely inverse characteristic curve and R4 with the inverse characteristic curve protect feeder 2. The relevant appropriate settings are available on the relays and they coordinately operate before integration of DG units, as shown in Table 2.

In the first case, only DG1 is integrated into the study network. If a fault occurs at the main protection zone of R2, the current seen by R1 and R2 increases to 1900 A and their operating times are 374 and 81 ms, respectively. Regarding the communication between R1 and R2 agents, they investigate their currents. According to the relay operating timetable, the current of the relays is out of the fault current range in the absence of DGs. In this case, due to the unknown current pattern, it is necessary to determine the required protection pattern for those relays. The current of relays R1 and R2 is equal to each other, but this current increases compared to the case of absence of DG1. It indicates that the DG unit is located upstream of both relays. In this case, the backup relay agent does not operate and waits for clearing the fault by the main relay agent. Regarding the main relay should clear the fault in 81 ms, the backup relay waits up to 381 ms and opens its switch if the fault current persists in the network. This not only prevents the backup relay from malfunctioning in the event of a delay in the main relay operation, but also defines a new operating pattern for the protection system in this condition so that without changing its settings, it properly operates in similar conditions. In this case, the R1 table is updated as shown in Table 3. The operation of R1 and R2 is shown in Figure 9, where status of CB determines that the CB is close (0) or open (1).

In the next case, only DG2 is integrated into the network. When a fault occurs inside the protection zone of R2, the R2 current is 2490 A, resulting in the operation of CB2 in 60 ms. Also, the current seen by R1 is 1660 A. Thus, this relay clears the fault in 381 ms.

TABLE 3 Updated timetable of operating time of relay R1 in the scenario 1 in the case of integrating DG1

| R1 current (A) | R1 operating time (ms) |
|---------------|------------------------|
| 1020 – 1223   | 1033                   |
| 1224 – 1427   | 914                    |
| 1428 – 1631   | 666                    |
| 1632 – 1650   | 510                    |
| 1651 – 1900   | 381                    |

FIGURE 9  Status of CB1 and CB2 in the scenario 1 in the case of integrating DG1
TABLE 4  Updated timetable of operating time of relay R2 in the scenario 1 in the case of integrating DG2

| R2 current (A) | R2 operating time (ms) |
|---------------|------------------------|
| 1020 – 1223   | 168                    |
| 1224 – 1427   | 135                    |
| 1428 – 1631   | 112                    |
| 1632 – 1835   | 96                     |
| 1836 – 2039   | 84                     |
| 2040 – 2243   | 75                     |
| 2244 – 2447   | 67                     |
| 2448 – 2490   | 61                     |

In this paper, the CTI between the operation of main and backup protections is in the range of 300 to 400 ms. Suppose that in this condition, the communication fails; consequently, R1 and R2 fail to communicate with each other. R1 sees less current than the conditions for which the settings were made. So it interprets this change as a change in the network conditions and the integration of a DG unit between itself and its downstream relay. R2 also sees more fault current this time. This relay interprets this condition as the presence of a DG unit at its upstream. Since these relays cannot check their coordination, relay R2, which sees more fault current, clears the fault in a shorter time. In this case, R1 refers to its pattern table and according to its current, selects to operate in 381 ms. In this situation, the proposed scheme improves the network protection system operation in the case of communication failure using the previous patterns. Figure 10 shows the coordination between R1 and R2 by the proposed method.

5.2  Scenario 2: Network reconfiguration

In this scenario, the CB3 is open and the manoeuvre switch is closed; thus, only feeder 1 energizes the study network. In this condition, R1 with the extremely inverse characteristic curve, R2 with the very inverse characteristic curve, and R4 with the inverse characteristic curve protect the network. R4 has the task of protecting its main zone. Also, R2, in addition to protecting the R3 zone in its main protection zone, should operate as the backup protection of R4 and the proper CTI should be preserved between R2 and R4 operations. According to the settings on the relays, the relays coordinately operate in the absence of DG units.

In the first case of this scenario, DG1 and DG3 are integrated into the study distribution network. If a fault occurs inside the protection zone of R4, its current is 2360 A. Also, the current seen by R2 is equal to 1630 A. According to the settings of R4, this relay should clear this fault in 119 ms while relay R2 operates in 354 ms, as presented in Table 5. In the proposed scheme, first, according to the current of relays, they specify the main and backup protections. Since the protection coordination is not preserved in the new condition, the agents detect the system conditions. Based on the data in the agents’ information tables, there is no data about similar conditions. Thus, the online mode of the proposed scheme is activated. Since the main relay current is higher than the backup relay current, the operating time of the main relay is faster than that of the backup relay. In this condition, the backup relay also updates its table as Table 6 by receiving the current information of R4. According to the new changes, R2 current is 1630 A and it clears the fault in 419 ms. Figure 11 shows the operation of R2 in the new conditions.

In the next case, DG1 and DG4 are integrated into the study network. If a fault occurs between R2 and R4, the current of the
TABLE 6  Updated timetable of operating time of relays R2 and R4 in the scenario 2 in the case of integrating DG1 and DG3

| R2 current (A) | R2 operating time (ms) | R4 current (A) | R4 operating time (ms) |
|---------------|------------------------|----------------|------------------------|
| 1050 – 1079   | 650                    | 1050 – 1079    | 176                    |
| 1080 – 1214   | 559                    | 1080 – 1214    | 165                    |
| 1215 – 1349   | 489                    | 1215 – 1349    | 156                    |
| 1350 – 1484   | 435                    | 1350 – 1484    | 149                    |
| 1485 – 1619   | 391                    | 1485 – 1619    | 142                    |
| 1620 – 1754   | 419                    | 1620 – 1754    | 137                    |
| —             | —                      | 1755 – 1889    | 133                    |
| —             | —                      | 1890 – 2024    | 129                    |
| —             | —                      | 2025 – 2159    | 125                    |
| —             | —                      | 2160 – 2294    | 123                    |
| —             | —                      | 2295 – 2360    | 120                    |

TABLE 7  Updated timetable of operating time of relay R1 in the scenario 2 in the case of integrating DG1 and DG4

| R1 current (A) | R1 operating time (ms) |
|---------------|------------------------|
| 1050 – 1199   | 1730                   |
| 1200 – 1349   | 1320                   |
| 1350 – 1499   | 1040                   |
| 1500 – 1649   | 701                    |
| 1650 – 1800   | 693                    |

FIGURE 11  Status of CB2 and CB4 in the scenario 2 in the case of integrating DG1 and DG3

R4 relay is 663 A. Also, the current of R1 and R2 is the same and equal to 1500 A. The relay R4 also detects the fault condition but it sees less current than upstream relays. In this case, the relays interpret this condition as a fault between R2 and R4. According to the proposed scheme, the main and backup relays are determined; R1 is the backup protection for R2. The operating time of R4 and R2 for this fault are 216 and 401 ms, respectively, but R1 operates in 860 ms. In this case, R1 will not operate at first according to the proposed scheme, and if R2 fails, according to the new programming, R1 will update its operating table, as shown in Table 7, and clears the fault in 701 ms. Figure 12 shows the performance of R1 in the new conditions.

FIGURE 12  Status of CB1 and CB2 in the scenario 2 in the case of integrating DG1 and DG4

6  | DISCUSSION

The objective of this paper consists of developing a protection coordination restoration strategy using the MAS. Table 8 compares the features of the proposed protection strategy and some
existing MAS based protection schemes. The main features of the proposed scheme are as follows:

- Simplicity: To reduce the complexity of MAS, this paper uses few agents by employing only relay agents.
- Low cost: Due to using peer-to-peer communication and no need for communicating with higher layers of MAS, the cost of required communication infrastructure reduces.
- Generality: The proposed scheme can be used in various distribution network because it is implemented in overcurrent relays with the standard characteristic which are the most widely used protective relays in distribution networks.

7 | CONCLUSION

With the development of DG technology, the penetration level of DG units in the distribution network is increasing, which affects the short-circuit level of the network. Decreasing or increasing this level affects the performance of conventional OCRs, resulting in protection miscoordination. Unnecessary interruptions and out-of-program performance are some of the consequences of this problem. This paper investigates the effect of DG units on the short-circuit current level and protection coordination among OCRs. Then, the MAS is introduced as an effective tool to prevent protection miscoordination in the presence of DG units and network topology change. The proposed scheme evaluates the network current data by using the relay agents as the only agents of the MAS and with the help of current information obtained from other agents, modifies the operating time of the relays independently. In this method, each relay agent, by establishing a point-to-point communication with its neighbours, obtains a table of their operating time and changes its behaviour pattern accordingly. The agents can act offline in the case of similar problems, and in the case of new changes, in accordance with the network conditions, they determine their status and operate properly. Compared to the conventional MAS based protection system, the proposed scheme clearance at the lowest protection level and without the need for communicating with higher levels, which it increases response speed. Several case studies in a 14 bus distribution network verified the effectiveness of the proposed MAS based protection strategy. Development of the proposed strategy to preserve the protection coordination in the cases of the ringbus distribution network, optimizing the CTI and number and location of IEDs, and investigating the effect of existing parallel feeders can be considered as future works.

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**APPENDIX**

The protection coordination studies require the detailed relay information for different manoeuvres of the network. Accordingly, Table A1 shows this information when there is no DG unit in the network.

The central controller has full access to this table to select the appropriate value for the on-going situation of the network. Therefore, when the communication system gathered the required information showing the on-going manoeuvre, the central controller uses this table to command the relays to be updated. Of course, if the DG penetration effect is also added to this table, the number of group-settings will be increased.

However, here, the CTI calculation for different scenarios is presented. Accordingly, for the scenario in which CB1 and CB3 are close and manoeuvre switch (S) is open, the curves are obtained as follows [41]:

**R1 with extremely inverse curve:**

\[
t = \frac{80 \times TMS}{\left(\frac{I_t}{I_{pickup}}\right)^2} \quad - 1 \quad (A1)
\]

**R2 with very inverse curve:**

\[
t = \frac{13.5 \times TMS}{\left(\frac{I_t}{I_{pickup}}\right)^2} \quad - 1 \quad (A2)
\]
TABLE A1  Relay information for different scenarios of the network

| Curve Type | I\textsubscript{pickup} | TMS  |
|------------|-----------------|------|
| R1         | 1.36            | 0.44 |
| R2         | 2.04            | 0.05 |
| R3         | 1.67            | 1.38 |
| R4         | 3.34            | 0.05 |

TABLE A2  Previously designed group-settings

| Relay  | Curve type | I\textsubscript{pickup} | TMS  |
|--------|------------|-----------------|------|
| R1     | Very inverse | 0.62           | 0.68 |
| R2     | Inverse    | 1.20            | 0.17 |
| R4     | Inverse    | 1.68            | 0.05 |

R3 with extremely inverse curve:

\[ t = \frac{80 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^2 - 1}. \quad (A3) \]

R4 with inverse curve:

\[ t = \frac{0.14 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^{0.02} - 1}. \quad (A4) \]

Accordingly, the CTI is calculated as

\[ \text{CTI} = \frac{80 \times 0.44}{\left( \frac{1860}{204} \right)^2 - 1} - \frac{13.5 \times 0.05}{\left( \frac{1860}{204} \right)^2 - 1} = 0.35 \text{ s}. \quad (A5) \]

Similarly, the CTI between R3 and R4 is calculated as

\[ \text{CTI} = \frac{80 \times 1.38}{\left( \frac{3850}{250.5} \right)^2 - 1} - \frac{0.14 \times 0.05}{\left( \frac{3850}{250.5} \right)^{0.02} - 1} = 0.34 \text{ s}. \quad (A6) \]

For the scenario, where CB1 and S are close while CB3 is open, the relay characteristic curves are determined as

R1 with extremely inverse curve:

\[ t = \frac{80 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^2 - 1}. \quad (A7) \]

R2 with very inverse curve:

\[ t = \frac{13.5 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^2 - 1}. \quad (A8) \]

R4 with inverse curve:

\[ t = \frac{0.14 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^{0.02} - 1}. \quad (A13) \]

R3 with extremely inverse curve:

\[ t = \frac{80 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^2 - 1}. \quad (A3) \]

R4 with inverse curve:

\[ t = \frac{0.14 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^{0.02} - 1}. \quad (A4) \]

In this manoeuvre, the CTI between R2 and R4 is calculated as

\[ \text{CTI} = \frac{13.5 \times 0.3}{\left( \frac{1300}{146} \right)^2 - 1} - \frac{0.14 \times 0.05}{\left( \frac{1300}{145.5} \right)^{0.02} - 1} = 0.35 \text{ s}. \quad (A10) \]

Also, the CTI between R1 and R2 is calculated as

\[ \text{CTI} = \frac{80 \times 1.1}{\left( \frac{1860}{163.5} \right)^2 - 1} - \frac{13.5 \times 0.3}{\left( \frac{1860}{146} \right)^2 - 1} = 0.34 \text{ s}. \quad (A11) \]

Given the list of appropriate group-settings has previously designed to be used by the central controller, the corresponding one will be updated on the relays. For instance, for this scenario, the appropriate values are presented in Table A2.

Accordingly, for coordinating R1 and R2 relays, the following equations should be considered:

R1 with very inverse curve:

\[ t = \frac{13.5 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^2 - 1}. \quad (A12) \]

R2 with inverse curve:

\[ t = \frac{0.14 \times \text{TMS}}{\left( \frac{I_f}{I\text{\textsubscript{pickup}}} \right)^{0.02} - 1}. \quad (A13) \]
\[ \text{CTI} = \frac{13.5 \times 0.68}{(93/1323)} - 1 - \frac{0.14 \times 0.17}{(0.02 \times 120/2720)} = 0.31 \, \tau. \quad (A14) \]

Similarly, the following equations are used to coordinate R3 and R4 relays:

R3 and R4 with inverse curves:

\[ t = \frac{0.14 \times \text{TMS}}{(\frac{I_f}{I_{\text{pickup}}})^{0.02}} - 1. \quad (A15) \]

\[ \text{CTI} = \frac{0.14 \times 0.17}{(120/1670)^{0.02}} - 1 - \frac{0.14 \times 0.05}{(120/1670)^{0.02}} = 0.31 \, \tau. \quad (A16) \]