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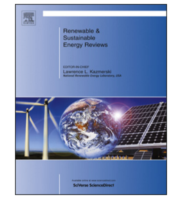

A review of coordination strategies and protection schemes for microgrids

Sachit A. Gopalan*, Victor Sreeram, Herbert H.C. Iu

School of Electrical, Electronic and Computer Engineering, The University of Western Australia, 35 Stirling Hwy, Crawley, WA 6009, Australia

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ABSTRACT

Distributed generation (DG) using renewable energy resources, is intended to reduce the impact of power generation from fossil fuels on climate change. Microgrids (MGs) represent a method of interconnecting several low voltage (LV) renewable energy sources and loads to the distribution system. Multi-microgrids (MMGs) integrate distributed generators (DGs) and MGs with medium voltage (MV) distribution systems. Protection system design for MGs pose significant challenges due to bi-directional flow from DGs as well as lower fault current levels due to the inverter connected DG sources in islanded MGs. This paper reviews the coordination strategies and protection schemes that have been proposed for MGs to address these challenges. The protection coordination strategies based on communication and time grading including their relative performance are described. The advantages and limitations of existing MG protection schemes are discussed. As most of these protection schemes apply to relatively small MGs, they may need to be extended for larger MG configurations in practical power systems. Some future directions for research in the protection system design for both MGs and MMGs are also outlined in this paper.

Contents

1. Introduction

The use of fossil fuels for large scale power generation is associated with problems such as high levels of greenhouse gas emissions, depletion of fossil fuel resources, and low energy

* Corresponding author.
E-mail addresses: gopals02@student.uwa.edu.au (S.A. Gopalan), victor.sreeram@uwa.edu.au (V. Sreeram), herbert.iu@uwa.edu.au (H.H.C. Iu).

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efficiency. These problems are partly addressed by augmenting the distribution system with distributed generators (DGs) that produce electricity from renewable energy resources such as wind, photovoltaic (PV), geothermal, and biomass. As the penetration of distributed resources increases, their direct interconnection to the distribution system becomes difficult to manage due to their intermittency. Microgrids (MGs) have been proposed as an effective way to integrate DGs with the distribution system. A low voltage (LV) MG enables the connection of multiple DG microsources and LV loads to the distribution system. It can also operate in isolation from the distribution grid [1–5].

As MGs have a limited load capacity of 10 MVA, multi-microgrids (MMGs) have been proposed to enable the supply of electric power from renewable energy sources to a larger load pocket. The MMG consists of a number of LV MGs and DGs that are connected to the distribution system at MV level. It can operate when connected to a high voltage (HV) transmission system or in standalone mode. The operation, control and architectures of the MMG have been studied in the More Microgrids Project [6,7].

Even though the connection of DGs to the distribution system brings benefits such as reduced transmission and distribution losses, lower greenhouse gas emissions, and improved power quality and reliability, it poses some challenges to protection system operation. A significant problem is the loss of coordination between overcurrent protection devices during faulted conditions due to bidirectional power flows within the distribution system. Whenever faults occur in active distribution systems, the conventional practice is to disconnect all DGs based on IEEE Standard 1547. While this approach is feasible with low penetrations of DGs, the system reliability will be adversely affected when there are a large number of DGs [1–5].

The conventional overcurrent protection scheme for the distribution system is based on high fault currents. When a fault occurs with the MG connected to the distribution system, the fault currents within the MG will be high enough for the overcurrent relays to function. However, when the MG is islanded from the distribution system, the fault currents will be significantly lower due to the limited contributions from the inverter-connected sources. The low fault current level will be insufficient to activate the overcurrent relays [1–5]. In this paper, several coordination strategies and protection schemes that have been proposed to address these issues are reviewed.

The rest of this paper is organised as follows: Section 2 describes the background information on MGs and MMGs. Section 3 reviews the current coordination strategies for protecting MGs and various protection schemes that have been proposed. Section 4 discusses the general characteristics, advantages, and disadvantages of the coordination strategies and protection schemes. Section 5 concludes the paper and presents some directions for future research.

2. Background

This section briefly describes the concepts, typical configurations, and the general advantages of MGs and MMGs to provide the background for understanding the protection schemes and coordination strategies surveyed in later sections.

2.1. Microgrids

MGs interconnect microsources, storage devices, and loads at LV level. They can either be DC or AC grids. Examples of microsources include renewable energy sources of wind, PV, and hydro as well as combined heat and power (CHP) plants. Storage devices employ technologies such as flywheels, batteries, and super-

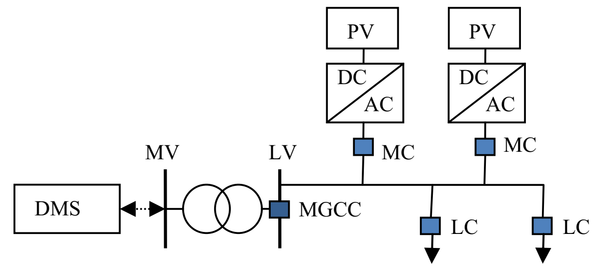

Fig. 1. Control structure for an MG that contain LCs and MCs.

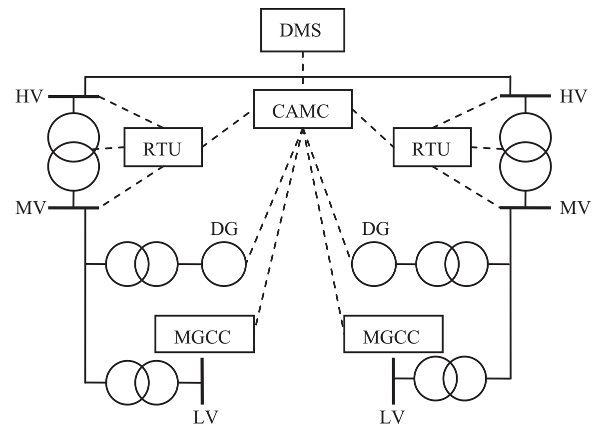

Fig. 2. Control structure for an MMG containing several LV MGs connected to the MV grid.

capacitors [3]. Power electronic interfaces are used to interconnect AC or DC DG sources, storage devices, and loads to the MG which may be either AC or DC. MGs can be used in rural and urban communities, industrial sites, and commercial areas. An unbalanced MG may be viewed from the distribution system as either a net load or a net generator even though it may consist of several generators and loads [5]. MGs can operate when either connected to the distribution system or islanded from it [4].

The control scheme for MGs proposed in [7] consists of a Distribution Management System (DMS), a Microgrid Central Controller (MGCC), Load Controllers (LCs), and Microsource Controllers (MCs) as shown in Fig. 1. The DMS establishes the rules for each controller to balance generation and load. The MGCC interacts with the LCs and MCs by acquiring data on active and reactive powers, and sending commands to balance generation and load. LCs and MCs control the power supplied to the loads and the power set points of the microsources respectively.

MGs offer several advantages over conventional distribution systems. They can be used to supply power to remote areas that are difficult to reach from the main grid. The MG can continue operation as a single aggregated unit in the islanded mode whenever power outages occur within the distribution system. CHP units in MGs can directly meet the heat and electricity requirements of customers. As the microsources use low carbon technologies, MGs can contribute to reducing global warming and climate change [1].

2.2. Multi-microgrids

MMGs consist of DGs and MGs that are connected to the MV distribution system. The large load pockets of an MMG can be divided into smaller load units served by individual MGs. The MMG can operate either connected to a HV transmission grid or in islanded mode [6,7].

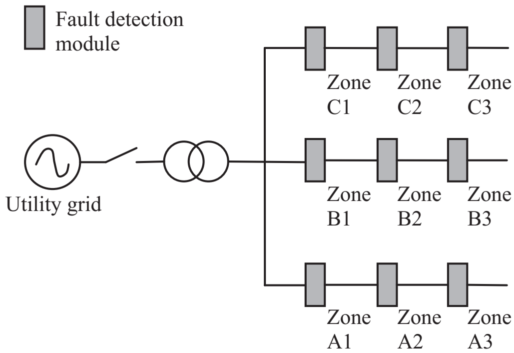

Fig. 3. MG with multiple protection zones and fault detection modules.

A hierarchical frequency control scheme for MMGs proposed in [6,7] is shown in Fig. 2. The DGs and MGs are treated as individual controllers. The remote telemetry units (RTUs) control the operation of the HV/MV substations. A Central Autonomous Management Controller (CAMC) is interfaced with a DMS similar to the one described in Section 2.1. The CAMC performs the following tasks: acquiring active and reactive power measurements from the MGCCs, DGs, and RTUs; receiving commands from the DMS for balancing generation and load; and scheduling the operation of the MGCCs, DGs and RTUs. The operation of this scheme is similar to that of Automatic Generation Control (AGC).

MMGs provide improved reliability due to the presence of several MGs. Their distributed control structure ensures greater stability and controllability [6,7].

3. Microgrid protection schemes and coordination strategies

Protection systems for islanded MGs need to consider the following factors: protecting the MV side of the MG; microsource protection; protection of distribution transformers; and neutral grounding considerations. This section reviews protection schemes and coordination strategies for both grid-connected and islanded MGs. Section 3.1 describes the protection coordination strategies and Section 3.2 the various protection schemes.

3.1. Protection coordination strategies

Strategies are needed to coordinate the operations of primary and backup protection schemes. Primary protection acts as the first line of defence against the damaging consequences of faults, whereas backup protection acts only when the primary protection fails. The strategies for protection coordination based on time grading, communications and other techniques are reviewed in the following subsections.

3.1.1. Time grading

When the primary protection fails, time grading strategies enable the backup relays to operate after varying time delays. Loix et al. [8] developed a strategy to detect and clear faults within radial MGs containing a large number of inverter-coupled energy sources. Fig. 3 shows a MG consisting of multiple protection zones that are each covered by fault detection modules. Traditional overcurrent protection is used within a given time delay to detect a fault in the grid-connected MG. If the fault is not detected within the time delay, the MG is islanded from the grid and the fault is detected using voltage measurements. The direction for each fault type is determined by the voltage and current measurements from the fault detection module. When the fault direction is known, time delays are selectively applied to each module until the fault is cleared. Adding a communication network can improve the speed of the protection system operation, though it may become vulnerable to communication failures. No experimental results have been provided for this scheme.

A protection strategy based on microprocessor relays for both the grid-connected and islanded modes was proposed in [9]. Each microprocessor relay contains modules for tripping, interface, negative-sequence directional function, three-phase protection, and also phases a, b, and c. Each phase module protects the corresponding phase of its secondary mains feeders. The three-phase protection module provides redundant protection based on zero/negative sequence detection. The protection of the MG is coordinated with a time grading technique containing directional elements for identifying forward and reverse faults. If the primary protection relay fails with this technique, downstream relays will respond one-by-one after different time delays until the fault is cleared. This scheme does not use communication or adaptive protection devices, but adapts to different fault current levels and fault types. However, it experiences relatively long fault clearing times due to the time grading technique for protection coordination.

3.1.2. Communication

In communication-based protection schemes, a central control unit is interconnected with the measurement devices and circuit breakers via communication networks. The central control unit analyses the measured voltages and currents to determine the fault location. Trip signals are then sent to nearby circuit breakers.

Sortomme et al. [10] proposed a protection scheme for phase-A-to-ground faults using digital relays and a communication system. The primary protection based on the differential scheme for each feeder segment trips the switching device on both ends of a faulted feeder. If the switching device fails to operate, a backup trip signal is sent to the adjacent relay on the same bus after a time delay. But if either the backup protection relay or communication link fails, the relays use comparative voltage protection until the system recovers. When the MG is islanded, this scheme also detects high impedance faults (HIFs) from the measured differential current. It has high reliability because of its looped configuration and can cope with communication failures. However, the placement of relays and switching devices at each end of the feeders is expensive. The errors and mismatches of the current transformers (CTs) has not been considered in this protection scheme. It also assumes technical features such as faster tripping times that are not available in state-of-the-art equipment.

A scheme proposed in [11] for radial grid-connected MG configurations uses an integrated protection and control (IPC) unit. An IPC is interconnected by an optical Ethernet communication network to the measurement devices, circuit breakers, and control units at each bus. The currents, voltages, and other electrical quantities are used by the IPC to make protection and control decisions to be sent to the circuit breakers and control units respectively. A pilot instantaneous overcurrent protection scheme for the local feeder and remote busbar is implemented. This protection scheme provides faster fault clearing times. However, communication failures and lack of available communication channels are not considered.

Nthontho et al. [12] proposed a wide-area differential protection scheme using communication links to protect a MG containing household PV systems against three-phase faults. Intelligent electronic devices (IEDs) and circuit breakers at each bus are connected to the control centre via wireless mobile broadband. The embedded sensors in the IEDs monitor the real-time current measurements and communicate this information to the control centre. The control centre executes advanced differential protection for each feeder to determine the faulted section, send trip signals to the circuit breakers at the faulted location, and apply auto-reclosing. If this primary protection fails, backup protection uses the current sensor measurements and time-stamped Global Positioning System (GPS) coordinates to locate and isolate the fault. This scheme is simple, effective, and adaptable to the dynamic behaviour of MGs. However, it has only been tested for small grid-connected PV systems. Communication failures and the optimisation of the networking technologies have not been considered in this scheme.

Li et al. [13] investigated the differential and voltage protection methods for islanded MGs using communication networks. The differential scheme was implemented at every connection point in the MG. This scheme works for both internal and external faults, operates accurately, and adapts to changes in MG configuration. However, it does not detect HIFs or provide backup protection for neighbouring feeders. It is also expensive to implement due to the placement of relays at every connection point. In the voltage based scheme, the control centre determines the fault type and location using the indicator voltage waveforms at each connection point and sends trip signals. This method accurately determines the faulted zone for large MGs that have sufficient gradient voltage dip along the feeders. However, it cannot cope with shorter feeder distances since the gradient voltage dip would be low. The calculation complexity for this method is high.

A communication-assisted protection strategy for MV MGs using microprocessors was proposed in [14]. Each microprocessor relay consists of directional, grid-connected, islanded, interface, and tripping modules. The proposed protection strategy interconnects a MG protection commander (MGPC) and the individual relays at each MG subsection via a communication network. The MGPC determines the faulted MG subsection using the fault detection and directional signals from each relay. The primary protection trip signals are sent to the circuit breakers near the faulted MG subsection. If the primary protection fails, backup trip signals are sent to the neighbouring circuit breakers after a time delay. Time grading is applied to all the circuit breakers in the faulted MG subsection if either the backup protection or communication link fails. This protection strategy can cope with different fault current levels, fault types, MG operating modes, as well as deal with different types, sizes, and locations of DGs. The fault clearing time for this strategy is faster than the scheme in [9]. Looped configurations of MGs are not considered in this scheme.

3.1.3. *Other coordination strategies*

Primary and backup protection strategies for MGs in both grid-connected and islanded modes were proposed by Nikkhajoei and Lasseter [15] without communication links or time-grading. The primary protection scheme for the single-line-to-ground fault uses differential current detection for zones upstream of the fault and zero-sequence detection for downstream zones. Negative sequence current detection is used for line-to-line faults. The main backup protection for both single-line-to-ground and line-to-line faults is I^2t. Undervoltage backup protection is also employed for the islanded MG. Three-phase faults are not considered in this protection scheme and it lacks systematic coordination. It also does not enable single phase tripping.

Salomonsson et al. [16] proposed a protection system for a radial LV direct current (DC) MG that uses primary protection schemes for the converter, battery, and feeder against pole-to-pole and pole-to-ground faults. The converter is protected by comparing the measured current derivative with a minimum threshold. Undervoltage protection is used for the DC link capacitor and overcurrent protection for the battery. For feeder protection, the measured ground currents of the converter and battery are compared against their predetermined ranges to detect the ground

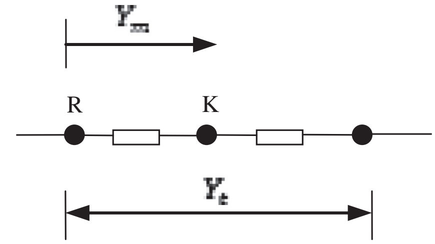

Fig. 4. Feeder segment showing the measured admittance Y_m between points R and K and total admittance Y_t.

fault. If the primary protection for the feeder fails, then the circuit breakers near the converter and battery must be opened. Fuses on the AC side provide backup protection to the converter. Low impedance ground faults are easily detected and cleared. The converter is effectively protected by using both the converter current derivative and DC link undervoltage protection. However, HIF detection within the MG is difficult due to the low ground fault currents. The protection methods are not systematically coordinated.

3.2. *Protection schemes*

In each protection scheme, relays compare the measured data such as voltages and currents against pre-determined thresholds. Trip signals are sent to the circuit breakers when these thresholds are exceeded. The protection schemes vary based on the measurements used such as voltages, currents, power, and frequency as well as the operating characteristics defining the trip thresholds. The various schemes proposed are grouped under voltage-based protection, admittance relaying, adaptive techniques, and differential zone protection in the following subsections.

3.2.1. *Voltage-based protection*

Al-Nasseri et al. [17,18] developed voltage-based schemes to protect islanded MGs containing inverter-interfaced microsources for all the fault types. The measured utility voltages undergo a series of conversions before they are used to identify the fault type and zone. In [17], the faulted zone is tripped if the disturbance voltage exceeds the threshold corresponding to the fault type. In [18], the measured voltage is transmitted via communication links between any two relays within the MG, and compared with the mean average value of the two relays to identify the faulted zone within the network. This scheme protects against both internal and external faults relative to any protective zone. However, it ignores HIFs and symmetrical faults and also does not enable single phase tripping.

3.2.2. *Admittance relaying*

The admittance relays proposed in [19] protect feeder segments of a radial MG connected to the utility network via back-to-back converters against the three-phase-to-ground fault. The feeder segment in Fig. 4 shows the measured admittance Y_m between the relay and an arbitrary point on the feeder K as well as the total admittance value Y_t. The normalised admittance Y_r is calculated in the following equation:

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

The inverse time characteristic is used to find the tripping time corresponding to Y_r in the following equation:

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

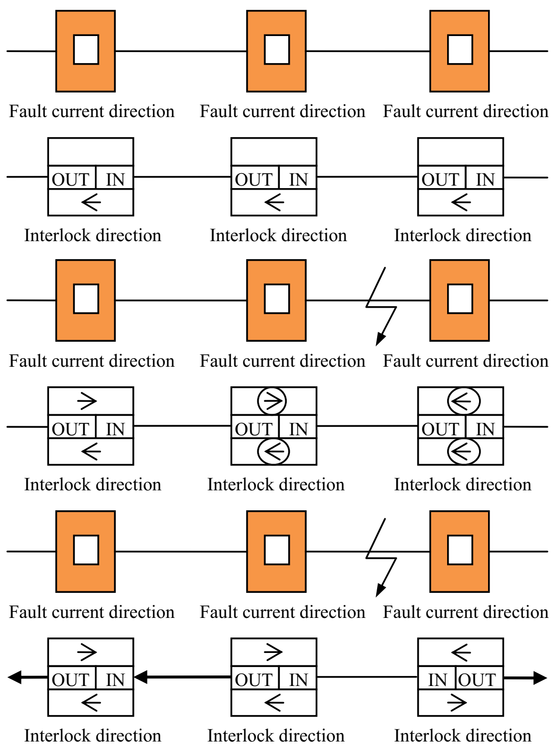

Fig. 5. Directional interlock operation of the adaptive protection scheme.

where A, ρ and k are constants. A fault occurs when the value of Y_r exceeds 1. The circuit breakers near the faulted location are tripped after a time delay t_p. Each upstream admittance relay provides backup protection to its immediate downstream relay. The admittance relay's inverse time characteristic does not use safety margins to cover protection zones. However, this scheme only works for smaller MG configurations.

3.2.3. Adaptive techniques

Adaptive protection schemes enable different MG topologies to be protected against all the fault conditions. The calculated relay settings for various topologies are stored in a database. Whenever the topology changes, the relays are updated with their new settings from the database.

An adaptive protection scheme is proposed in [20] where a MGCC is connected to directional overcurrent relays at each bus via a communication system. Off-line analysis is performed by constructing event and action tables for the circuit breaker statuses and relay settings respectively for all the MG configurations. During online operation, the MGCC monitors the MG's operating state and uses the event and action tables to configure the relays. During real-time operation, the measured current values are compared with the relay settings to detect the presence of a fault. The fault current direction is checked against the present interlock direction as shown in Fig. 5 to locate the fault. This scheme adapts to several MG configurations. Protection is provided for all fault types. The communication system speeds up the operation of the scheme. This scheme is not efficient for larger MG configurations due to excessive memory used to store large amounts of off-line analysis data. It does not protect against HIFs and the connection of new loads and DGs has not been considered.

Laaksonen [21] proposed an adaptive protection scheme for a LV MG where a communication network is connected between the MG Management System (MGMS) and the different MG components. Protection strategies for both the grid-connected and islanded modes are developed for components which include the Point of Common Coupling (PCC), LV feeders, loads, and DG units. The MGMS detects the change in MG configuration and sends the appropriate settings and pick-up limits to the protective devices for each component. This scheme protects against double phase faults. High speed communication links provide fast, selective, and reliable protection. However, the possibility of communication network failure has not been considered and the scheme does not support plug-and-play DGs.

A centralised adaptive protection scheme for a MG has been proposed by Ustun et al. [22]. The protection system interconnects a MG central protection unit (MGCPU) with all the relays at each bus and the DGs via the TCP/IP-based Ethernet communication network. In this scheme, the MGCPU receives interrupts to calculate and update the operating fault currents in the relays. When the measured currents exceed the relay operating currents, the relays near the fault send signals to the MGCPU to set their fault detection statuses. The relays that detected the fault trip the circuit breakers to isolate the fault. This scheme works well with the MG component models based on IEC 61850 and IEC 61850-7-420, but is not suitable for complex systems with changing relay connections. The dynamic behaviour of the communication network is not considered.

3.2.4. Differential zone protection

Sortomme et al. [23] proposed a differential zone protection that uses an optimum number of relays and sensors for each protection zone. Current sensors are placed on the secondary side of the transformers for each load and relays at the DG source locations. The zone relays detect a fault when the DG source currents exceed the sum of the load currents within the zone. When a fault is detected, the relays send trip signals to the DG source at the faulted zone. A genetic algorithm was used to find the optimal placement of sensors, relays, and circuit breakers to minimise the total cost. This scheme is less expensive than the differential protection in [10]. However, the operation of this scheme has not been experimentally validated.

4. Discussion

Several coordination strategies and protection schemes have been developed for MGs to meet the challenges of bidirectional power flows from DGs and lower fault current levels within islanded MGs. Table 1 summarises the advantages and disadvantages of the protection coordination strategies. The advantages and disadvantages of voltage-based, admittance, adaptive, and differential schemes are given in Table 2.

The protection coordination strategies include primary and backup protection. Most communication-based protection schemes use a central controller connected with individual relays in the MG. Communication links improve the speed of these coordination strategies. Communication failures have only been considered in some schemes [10,14]. Protection strategies using time-grading results in slower fault clearing times [8,9]. The protection strategies that do not use either communication or time-grading lack systematic coordination of primary and backup protection [15,16].

The protection schemes vary based on measurements used such as voltage, current, power, and frequency as well as operating characteristics set as thresholds. The voltage-based schemes in [17,18] work for grounded faults within islanded radial MGs. The admittance relaying scheme in [19] is useful for protecting radial MGs containing different feeder segments. Adaptive protection schemes in [20–22] are suitable for protecting different radial MG topologies. The differential zone protection scheme can protect multiple zones in the MG [23].

Table 1
Advantages and disadvantages of various coordination strategies.

Coordination strategies	Advantages	Disadvantages
Time grading [8]	Reliable scheme as it does not use communication.	Absence of communication could slow down the speed of operation. No study results have been reported to test the proposed scheme.
Microprocessor-based strategy for LV MGs [9]	Accommodates different fault levels. Does not use adaptive protection devices.	Does not use communication devices. Slower fault clearing times.
Communication-assisted digital relays [10]	Increased reliability as it accommodates looped configuration and communication failures.	Placement of relays and switching devices on each end of the feeder is expensive. CT errors and mismatches were not considered within the protection scheme. Assumes technical features not present in state-of-the-art equipment.
Integrated protection and control scheme [11]	Faster fault clearing times.	Possibility of failure or lack of availability of communication network was not considered.
Wide-area differential protection [12]	Can adapt to dynamic behaviour of MGs. Simple and effective.	Only tested for small grid-connected PV systems within MG. Does not consider the optimisation of the communication technologies or communication failures.
Communication-based protection schemes [13]	Differential protection works for internal and external faults, operates accurately, and adapts to changes in MG configuration. Voltage measurement method is able to accurately determine the faulted location provided that the MG is large and there is sufficient gradient voltage dip along the faulted feeders.	Differential protection does not detect HIFs, cannot provide backup protection to neighbouring feeders, and expensive to implement. Voltage measurement method cannot cope with reduced feeder distances due to insufficient gradient voltage dip. Voltage measurement method has high calculation complexity.
Communication-assisted microprocessor-based strategy for MV MGs [14]	Accommodates different fault current levels, MG operating modes, and type, size, and location of DG units. Faster fault clearing times.	Does not consider the looped configuration of MG.
MG protection coordination strategy [15]	Covers both primary and backup protection strategies.	Three-phase faults are not considered in the protection scheme. A systematic coordination technique was also missing from this scheme. Does not enable single phase tripping.
LV DC MG protection [16]	Low impedance ground fault are easily detected and cleared. Combination of dc link voltage and converter current derivative protects the converter more effectively.	Low ground currents make HIFs difficult to detect. No systematic coordination between the protection methods.

Table 2
Advantages and disadvantages of voltage, admittance, adaptive, and differential zone protection schemes.

Protection scheme	Advantages	Disadvantages
Voltage-based [17,18]	Able to protect against faults that are internal and external to any protection zone.	Does not consider symmetrical faults, single phase tripping, and HIFs.
Admittance relaying [19]	Each upstream relay protects their downstream relay. Relay's inverse time characteristic does not use safety margins.	Only considers a smaller MG system.
Novel adaptive protection scheme [20]	Adapts to a variety of MG configurations. Communication improves the speed of operation.	Off-line analysis data may consume large amounts of computational memory. Does not consider HIFs. Connections of new loads and DGs are not considered in this scheme.
Adaptive protection for future MGs [21]	High speed communication enables the scheme to have fast, selective, and reliable operation.	Does not consider the possibility of communication network failure. Does not consider new deployments of plug-and-play DGs.
Centralised protection scheme based on IEC 61850-7-420 [22]	Works well for the MG component models based on IEC 61850 and IEC 61850-7-420.	Does not work for complex systems with changing relay connections. Does not consider the dynamic behaviour of the communication network.
Differential zone [23]	Effective and less expensive.	No test results have been performed for the proposed scheme.

5. Conclusion

The protection of MGs presents a number of challenges. If conventional overcurrent protection devices are used, the coordination will be affected by bidirectional power flows from DGs. The fault currents from inverter-interfaced microsources in islanded MGs are too low to be detected by overcurrent protection relays. Several coordination strategies and protection schemes to address these challenges were reviewed in this paper. The communication-based coordination strategies operate faster compared to strategies that use time grading. Voltage-based schemes were found to be effective against both internal and external faults but they cannot detect symmetrical faults and HIFs. The admittance relaying scheme enables the tripping time to be dependent on the measured admittance though it only works for radial configurations. The adaptive protection schemes accommodate changes in the MG configuration and operate faster with communication networks. However, they need large amounts of memory to store the protective settings for larger configurations.

In future research, protection schemes for MGs need to consider using communication networks and microprocessors for improved speed of operation. HIF detection and differential protection could improve the sensitivity and reliability of these schemes. The protection of MMGs poses additional challenges due to bidirectional power flows from DGs and MGs as well as higher fault current levels compared to single grid-connected MGs. The existing protection philosophy in islanded MMGs is to disconnect all DGs during fault conditions. A possible future research direction is to develop flexible protection systems that allow MMGs to continue operation during fault conditions.

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