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Microgrid protection with conventional and adaptive protection schemes

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Introduction

Microgrid is considered as the building block for the future smart grids, therefore a properly designed microgrid is essential for the proper functioning of the entire smart grid. Microgrid has many definitions but in general it is a well-designed local distribution system of electricity which facilitates the local integration of many small-scale renewable energy sources and energy storage systems to meet the local energy demand of consumers in a smart, secure, efficient, controlled, protected and managed environment. Unlike the traditional distribution systems of electricity, microgrids can operate in islanded mode when the main grid is disconnected due to faults. The islanded mode operation of microgrid will enhance the reliability level of existing distribution system if some sections of distribution networks are planned as microgrids. However, the islanded mode operation of microgrid has many challenges and one important challenge is related to the design of protection scheme. This chapter addresses the issues related to protection schemes in microgrid, gives an overview of the existing and new requirements of protection schemes and analyses the potential of the existing and adaptive protection schemes of microgrid.

19.1 Microgrid protection issues

Microgrid protection issues can be classified into two broad categories depending on its operational modes [1]: (1) Microgrid protection issues in grid-connected mode (2) Microgrid protection issues in islanded mode.

For the grid-connected mode of microgrid the faults inside microgrid as well as faults outside microgrid are considered. In the grid-connected mode protection schemes of microgrids should not operate unnecessarily for faults outside the microgrid for example faults upstream of the circuit breaker (CB) at point of common coupling (PCC). All faults insides the microgrid should be detected and selectively isolated for minimum interruption to other parts. During external faults at the main grid, microgrid should be able to disconnect quickly to protect its loads and start operating in islanded mode and as soon as the external fault is removed it should be reconnected to the main grid. The external faults at the main grid could be close-in faults or other far-end faults resulting in the loss of mains, hence both types of faults should be differentiated. In the grid-connected mode fault contribution from both the main grid and microgrid sources is considered. If microgrid has the majority of synchronous generator-based distributed energy resources (DERs), then fault contribution from the main grid could be reduced and overcurrent relays may experience selectivity issues like more time to issue a trip command. On the other hand, if the majority of converter-based DERs are connected inside the microgrid, then it will not have significant issues during the grid-connected mode since fault contribution from the converter-based DERs could be limited to twice the rated current capacity or even less depending on converter settings or rating.

For the islanded mode of operation the faults inside the microgrid are only considered and fault contribution from local DERs and energy storage systems is taken into account. Microgrid protection should detect and isolated the faults selectively even in islanded mode of operation. During island operation, for example in low-voltage (LV) microgrids, large fault currents from the upstream power system grid are not available. In addition, a large share from the DER units in LV microgrids will be inverter-based with low fault currents. Therefore, traditional one-directional protection schemes, assuming large difference between fault and load currents, are not applicable during island operation. These traditional protection methods could also have slower fault clearing time and reduced sensitivity and selectivity. This means that the system reliability is expected to decrease if the protection schemes are not adapted [2]. For these reasons, conventional over-current (OC) protection based of fuses and one setting group will not be able to guarantee selectivity during different types of possible faults. Therefore, LV network conventional protection will not be compatible with island operated LV microgrids and new protection schemes with adaptivity must be created. On the other hand, new LV microgrid protection scheme needs to be economical and simple [3], [4]. For medium-voltage (MV) microgrids after isolation from the utility grid, local DERs are the only fault current sources in the electric island and the fault current level depends on the types, sizes and locations of the DER. However, it is generally lower than the fault current from the utility grid [5]. The reduced fault current contributions from microgrid DERs require revised protection settings with the reduced pickup or threshold values of currents for islanded mode or protection schemes based on other protection principles like differential current [6], symmetrical components and residual current based [7], voltage based [8], harmonic content based [9] or suitable combination of them should be employed to detect and clear the fault in islanded mode. An adaptive protection scheme [10] using high speed communication links and numerical directional overcurrent protection relays could also be a suitable protection scheme to change protection settings adaptively according to grid-connected mode or islanded mode operations.

In the creation of new protection system for microgrids, multiple issues need to be taken into account, like

- The number of zones for protection,
- Operation speed specifications for the different operation modes and configurations of microgrid and
- Protection methods for microgrid normal grid-connected and islanded operation [4].

The created microgrid protection system also needs to be compatible with the microgrid operation and control solutions. Some key issues related to the LV microgrid protection are briefly reviewed based on [11] from which more detailed information can be found. The extent and number of microgrid protection zones will determine the required number of protective devices (PDs) for microgrid protection. However, the protection system simultaneously needs to fulfil the customer requirements and be economically feasible [4].

The essential structural choices will define the operation speed needs and principles for the protection of LV microgrid and correspondingly the operation speed requirements will determine some of the structural choices required to fulfil the operation speed needs. Main reasons for the operation speed requirements of LV microgrid protection are stability and customer sensitivity. The stability needs to be maintained after fast disturbances like after islanding due to fault in the upstream network during normal grid-connected operation or after fault in LV microgrid during islanded operation. One important issue related to the operation principles of LV microgrid protection is the fault behaviour of the converter-based DER units. The fault behaviour needs to be compatible with the developed microgrid protection scheme [4].

As stated in [12], the microgrid protection issues cannot be solved without a complete understanding about microgrid dynamics before, during and after islanding or fault. Related to this, for example, directly connected rotating generators or motors are very sensitive from the stability viewpoint in voltage dips caused by faults during microgrid island operation, and so they may endanger the stability of the microgrid. Therefore, if directly connected rotating machines are connected to microgrid, protection should operate rapidly during all kind of faults. For example, if microgrid customers have fuses with high nominal currents, there can be a risk that customer protection may operate too slowly during island operation due to small fault currents and that may lead to instability after clearance of the fault [4].

In cases where overcurrent based protection is utilized during island operation, the protection and control functions of IEDs in microgrids may need real-time information about network topology, the status of DER units (on or off), the state of charge of storage systems, and also number and size of loads connected to the microgrid. These conditions have to be updated and checked continuously in order to guarantee that protection settings are suitable for the actual configuration [3], [4].

Based on the above and as mentioned in [12], the high-speed operation of the protection devices is very crucial for a reliable operation of the microgrid protection system. Utilization of high-speed telecommunication is expected to be an essential part of future smart grid protection systems to achieve fast and selective protection both in grid connected and islanded modes of operation. The same communication protocols and standards used in HV / MV network can be applied directly to the LV microgrids. However, due to the smaller scale of LV microgrids, the costs of protection devices must also be lower than the cost of devices used in the HV/MV network [4].

One important issue, which is required to enable stable transition from the normal grid-connected operation to island operation, is coordination of IED protection settings with DER unit fault-ride-through (FRT) requirements (especially low-voltage-ride-through, LVRT). In order to avoid unwanted tripping, faulty lines must be disconnected first by the protection system and after that the DER units should be disconnected according to their FRT or LVRT functionality. Rapid protection operation is needed especially if there are many protection zones. Therefore, communication-based protection methods and schemes are often required to achieve selectivity [13]. Some further discussion about issues related to the protection of microgrids can be also found in [2], [4].

19.1.1 DER unit fault behaviour and effect on microgrid protection

In the future proper co-ordination between distributed generation (DG) unit grid codes and distribution network protection schemes will be increasingly important during the both grid-connected and islanded operation of microgrids. The operation time settings of short-circuit and earth-fault protection must be selective with DER unit fault-ride-through settings during normal operation**.** In MV network short-circuit protection operation time delays have traditionally been dependent on fault-current magnitude or measured impedance with fixed time delays or inverse time curves. In the future, MV networks will be increasingly divided into multiple protection zones in order to improve supply reliability. Therefore, short-circuit protection operation times may become too long if high-speed communication based and e.g. IEC 61850 GOOSE signals-based interlocking/blocking schemes are not utilized. On the other hand, the communication may fail or is not available and therefore also grid code compatible protection schemes which are not based on high-speed communication are needed in the future at least as a back-up for communication-based schemes.

Regarding the fault behaviour required from DER units during faults, it is important to ensure that the fault behaviour is compatible with the developed LV microgrid protection scheme and considers also the including FRT needs. This means that when the protection for an island operated microgrid is determined, one of the most important considerations is related to the fault current contribution of the converter-based DER units [4], [14].

Fault behaviour and fault current feeding capability of a DER unit is also highly dependent on the type of the DER unit. For example, a synchronous generator is usually able to feed prolonged fault current (about 200 to 400% of nominal current). An induction generator, in the initial stage, feeds almost as big a fault current as a synchronous generator, but the feeding is reduced quickly. Fault current fed by the inverter-connected generating unit is typically limited to 1.2 - 1.3 p.u. and highly dependent on the control system and control principles as well as grid code requirements regarding fault-ride-through and reactive current feeding requirements.

During normal grid-connected operation of microgrid with different types of DER units the grid codes can require FRT capability from the DER units in terms of frequency (f), rate-of-change-of-frequency (df/dt), voltage (U) and voltage support. Traditionally, in grid-connected operation, larger DER units have more FRT and frequency as well as voltage support related requirements in the grid codes. For example, regarding voltage support the FRT capability of DER units is defined with a voltage-against-time-profile (LVRT curve). In addition, also additional voltage support by capacitive/reactive, positive sequence, current injection during faults is required from MV and HV network connected converter- / doubly-fed-induction-generator (DFIG) -based DER units during grid-connected operation. Synchronous generator DER units naturally provide a voltage support during faults by feeding reactive current. Required dynamic response of the reactive current feeding is usually also defined in the grid codes for the converter-based DER units. However, LVRT capability and additional reactive current feeding of the converter-based DER units, like wind turbines, is not just a control issue. It also requires suitable technology to be applied in the DC-link of the converter, like for example, DC-link chopper or supercapacitor and crowbar possibly as a back-up.

Most grid codes for the grid-connected operation of DER units do not include any special requirements for the supply of negative sequence current. In synchronous generators, the negative sequence current is fed naturally and there are no effective measures to influence it. In contrast, with voltage source converters (VSCs) it is possible to individually control positive and negative sequence quantities. The main reason for the minimization of negative sequence current has been the impact of asymmetrical voltages on the DER unit (e.g. wind turbine) without considering the impact of it on the network voltages or network protection. The negative sequence may be controlled to mitigate twice the fundamental frequency oscillations appearing in the converter/inverter DC-link during asymmetrical faults. Therefore, in many applications the negative sequence component injection has been reduced partially or fully. However, full negative sequence current reduction control also reduces the line-to-line (2-phase) short circuit current to the level of the load current or even to zero which means that it may prevent the correct operation of network protection in 2-phase short-circuit faults. To overcome this problem, extensions to grid code have been proposed, which would require DG to inject a clearly defined level of negative sequence current. This is also a requirement already in Germany. From the network voltages point of view the effect of negative sequence fault current feeding during asymmetrical faults is beneficial because it reduces the negative sequence voltage, improves the voltage phase symmetry and reduces the overvoltages in the healthy phases during 2-phase short-circuits. However, negative sequence current injection will limit the control capability of the DG in the positive sequence. It can be expected that the future grid codes will increasingly specify requirements for asymmetrical / imbalanced negative sequence current injection during asymmetrical faults.

Usually the control mode change of one or more DER units connected to the distribution network is required after changing from the normal grid-connected operation to island mode. Traditionally, this means that under normal operation the DER unit uses active(P)/reactive(Q) power control and after islanding the control mode is changed to voltage(U)/frequency(f) control (or voltage/speed control). However, control schemes which do not require changing after transition to / from island operation have also been proposed. For example, in [15], an enhanced control strategy was proposed which improves the performance of a DER unit under network faults and transient disturbances, in a multi-unit microgrid setting. The proposed control strategy does not require the detection of the mode of operation and switching between different controllers (for grid-connected and islanded) modes, and it enables the adopted DER units to ride through network faults, irrespective of whether they take place within the host microgrid or impact the upstream grid [15].

LVRT, high voltage ride-through (HVRT) as well as f and df/dt related FRT capabilities are required during LV microgrid island operation also from the small-scale DER units which typically is not the case during grid-connected operation. Typically, in grid-connected operation the small-scale DER units, like PV units, are only required to support frequency stability during over-frequency situations by their active power-frequency (Pf) -droop control. From the island operated LV microgrid protection viewpoint, it is important to know exactly how the converter-based DER units behave during the faults and what kind of fault current (active, reactive, positive sequence, negative sequence etc.) they will feed. Therefore, so called 'microgrid grid codes' for island operated networks are necessary for the development of future smart grid protection solutions to reduce complexity and to avoid the need for too many case specific alternatives [4], [14].

Based on the simulations done in [14], the increased reactive power feeding with the converter-based DER units, was found to be beneficial for the possible overcurrent-based protection in LV microgrid. However, it did not significantly reduce the usability of undervoltage-based protection either due to resistive characteristics of LV lines. On the other hand, the reactive power feeding during the fault did not significantly reduce the magnitude of the voltage dip, i.e. support microgrid voltage during the fault. In the end, the excessive reactive power feeding of the converter-based DER units during the fault in island operated LV microgrid was not justified based on the simulations in [14]. Therefore, it was suggested that during faults in LV island operated microgrid the fault current fed by the converter-based DER units is recommended to be active instead of reactive if possible. In addition, the control of the converters during possible faults was not recommended to change due to the increased possibility of instabilities after fault clearance.

19.1.2 Example – Microgrid transition to islanded operation

In following, the example from [16] is used to define the protection needs (functions, time selectivity) when intentional island operation and especially successful transition to island operation is considered.

From island operation perspective (in addition to grid code FRT requirements from DG units during the normal grid-connected operation) it is required that the wind farm (green) in Fig. 19.1 as well as DER ① and ② have sufficient FRT capabilities. Figure 19.1 shows possible intended islands and MV feeder short-circuit protection at CB1-CB4 which is assumed to be directional like the earth-fault protection. In the following, the time selectivity issues (Figure 19.2) are discussed, with different fault scenarios (faults A-E in Figure 19.1), regarding successful transition to island operation.

In Figure 19.2 protection time selectivity issues, general time delay setting principles and the role of high-speed communication is shown when a) islanding is not allowed and b) islanding is possible. Figure 19.2 also illustrates the role of high-speed communication based interlockings/blockings (as well as transfer trip-based islanding detection) in the reliable and selective operation of future distribution networks with many sequential protection zones and the possibility for intended island operation. In Figures 19.1 and 19.2 the idea is that the possible operation principles of directional short-circuit protection in forward direction can be

1) Directional overcurrent protection with fixed time delay (and high-stage / low-stage settings)
2) Distance protection with fixed time delay (in forward direction)

Similarly, in Figures 19.1 and 19.2 the possible operation principles of directional protection in the reverse direction (for intentional islanding) can be

1) Under-voltage with fixed time delay (and high-stage / low-stage settings) AND current direction detection in the reverse direction. Function pick-up/start is only based on undervoltage (i.e. not in overcurrent, because fault current levels of inverter-based DER units can be fairly low as discussed in previous chapters)
2) Distance protection with fixed time delay (in the reverse direction)

From Figures 19.1 and 19.2 it can be seen that selectivity problems are possible if communication based interlockings / blockings for example are NOT used (Figure 19.2a)), because coordination between LVRT curve of DG units (defined by grid codes) and required time differences between CB2 and CB3 in forward direction may be hard to achieve. This naturally depends on the number of consecutive protection zones and the allowed time difference between the operation time delays of CB2 and CB3.

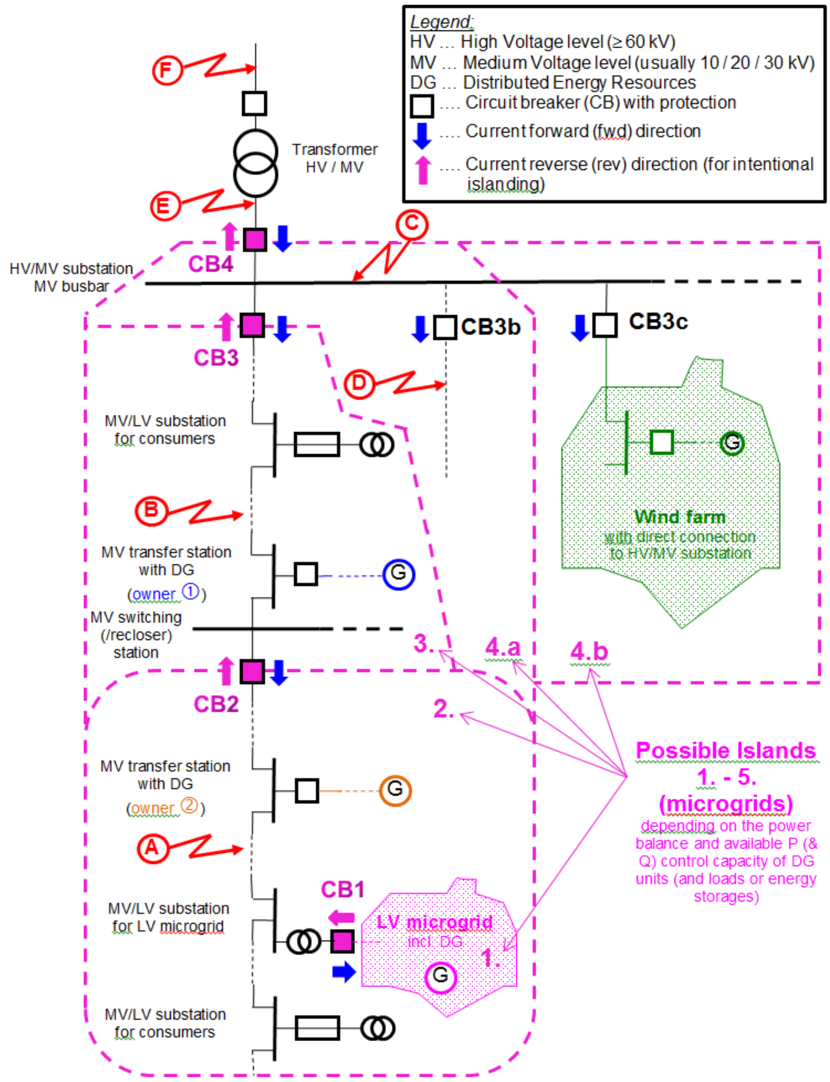


Figure 19.1. Possible intended islands 1.-4. b (see also Figure 19.2). [16]

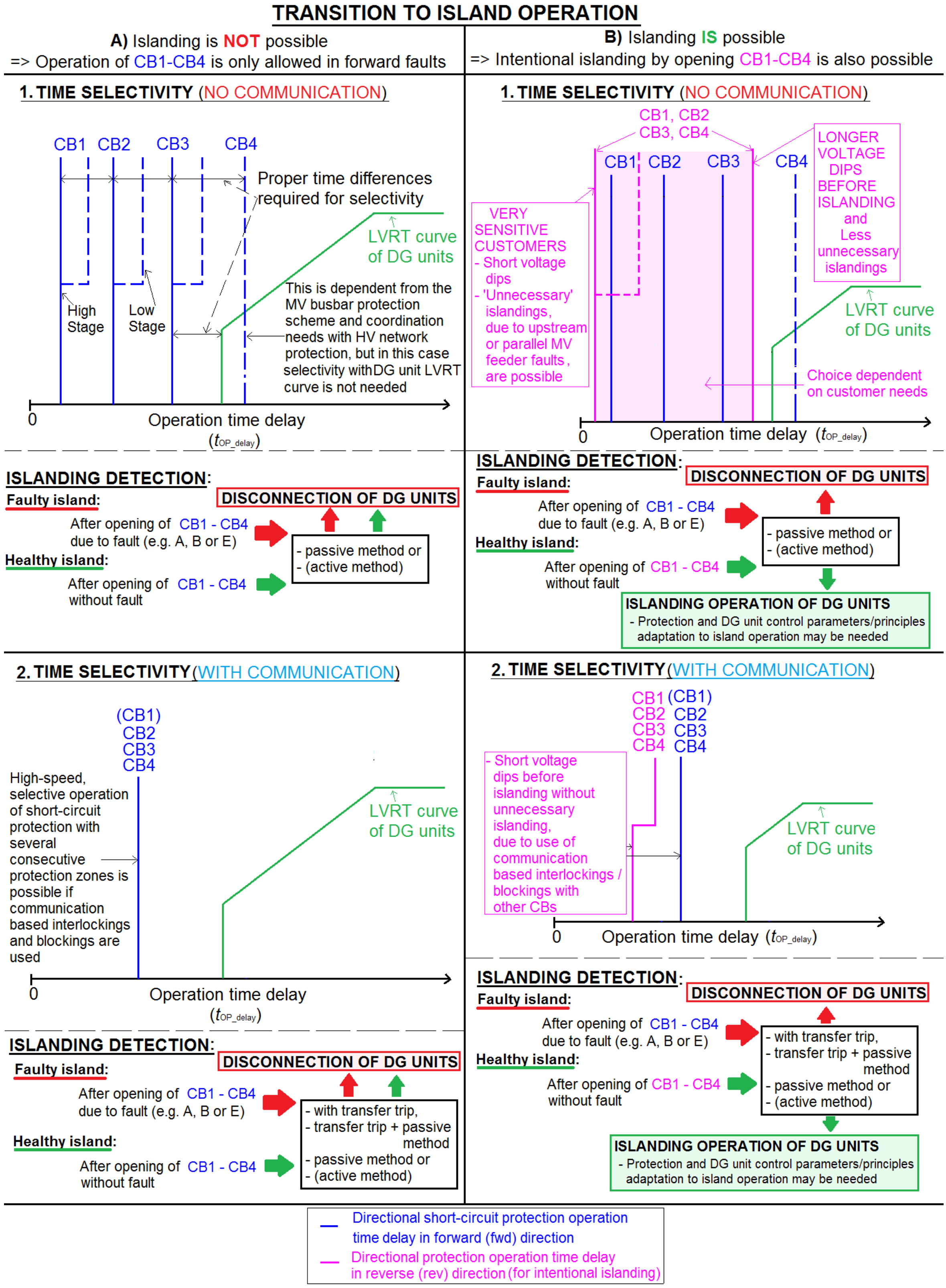


Figure 19.2. Protection time selectivity issues, setting principles and the role of high-speed communication when a) islanding is NOT allowed and b) islanding IS possible (see also Figure 19.1). [16]

Transition to intentional island operation IS only possible (Figure 19.2b)) if active and reactive power unbalance at CB1, CB2, CB3 or CB4 is small enough (or enough, rapidly controllable active and reactive power units exist in the possible island (1.-4.b in Figure 19.1) before the protection start/operation of CB1-CB4 in the reverse direction). If this is not the case transition to island operation should not be allowed. Here it is worth mentioning that the recent grid codes enable / support transition to intentional island operation because of the *P/f*-droop control requirements of DER units during over-frequency situations (under-frequency based load shedding schemes could have similar kind of effect) and possibly also due to voltage control (Q/U-control) requirements.

In the above discussion and in Figure 19.2, only short-circuit protection has been considered, but naturally also earth-fault protection principles and settings must be proper during both normal and island operation. Therefore, it should be noted here that after opening CB2, CB3 or CB4, the MV network neutral earthing method may change e.g. from compensated to isolated and MV feeder IEDs earth-fault protection settings and protection principles also needs to adapt to these changes.

In the following, the protection operation principles during different faults A-E in the example network shown in Figure 19.1 are described. It is assumed that high-speed communication is available/possible, and islanding IS possible (Figure 19.2b) using time selectivity (with communication) if power generation and consumption are close to each other behind the possible island connection point CB.

<u>In case of fault A in Figure 19.1 (see also Figure 19.2):</u>

- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - If active and reactive power unbalance at CB1 is small enough (i.e. stable transition to island operation is possible) as stated above
    - CB1 could also send signals to the LV microgrid DER units to change their control mode etc. after operation
- CB2 will operate in forward direction
    - CB2 sends simultaneously interlocking signal to CB3 (and CB4) to prevent their false operation and
    - CB2 can also send a communication-based transfer trip (faulty island) disconnection signal to DER unit ②

Wind farm and DER unit ① will remain connected according to the LVRT curve of DG units (Figure 19.2).

<u>In case of fault B in Figure 19.1 (see also Figure 19.2):</u>

- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - If active and reactive power unbalance at CB1 is small enough
    - CB1 could also send signals to the LV microgrid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - If active and reactive power unbalance at CB2 is small enough
    - CB2 could also send signal to DER unit ② to change the control mode etc. after operation
- CB3 will operate in forward direction
    - CB3 sends simultaneously interlocking signal to CB4 to prevent false operation and
    - CB3 can also send a communication-based transfer trip (faulty island) disconnection signal to DER unit ①

Wind farm will remain connected according to the LVRT curve (Figure 19.2).

<u>In case of fault C in Figure 19.1 (see also Figure 19.2):</u>

- MV busbar fault
- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - If active and reactive power unbalance at CB1 is small enough
    - CB1 could also send signals to the LV microgrid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - If active and reactive power unbalance at CB2 is small enough
    - CB2 could also send a signal to DER unit ② to change the control mode etc. after operation
- CB3 may also operate in reverse direction and disconnect either part of the MV feeder (beginning of the feeder, 3. in Figure 19.1) OR the whole MV feeder (2. &3. in Figure 19.1) to island operation
    - Depending on the active and reactive power unbalance at CB3 and CB2
    - Co-ordination with islanding of part of MV feeder by opening CB2 may be beneficial/required

- CB3 could also send a signal to DER unit ① (AND/OR DER unit ② depending on the power balance situation) to change control mode etc. or to disconnect
- CB4 will operate in forward direction.

The wind farm will be disconnected according to LVRT curve (Figure 19.2). Also, directional short-circuit protection in the reverse direction could be included in CB3c in order to disconnect the wind farm more rapidly in case of busbar faults like fault C (Figure 19.1). However, in case of upstream faults (like fault E and F in Figure 19.1) this reverse direction protection at CB3c should be blocked by communication to enable fault-ride-through support from the wind farm according to grid codes (e.g. LVRT curve).

In case of fault D in Figure 19.1 (see also Figure 19.2):

- Parallel MV feeder fault
- CB3b will operate in forward direction (Figure 19.1) and simultaneously send the interlocking signal to other CBs (e.g.) to avoid unnecessary islandings and to ensure selectivity

DER units ① and ② as well as the wind farm will remain connected according to the LVRT curve (Figure 19.2).

In case of fault E in Figure 19.1 (see also Figure 19.2):

- HV/MV transformer fault => intentional islanding can take place
    - Possible indication about intentional islanding possibility from HV/MV transformer protection IED to MV feeder IEDs
- CB1 will operate in reverse direction and disconnect the LV microgrid intentionally from the utility network
    - If active and reactive power unbalance at CB1 is small enough
    - CB1 could also send signals to the LV micro-grid DER units to change their control mode etc. after operation
- CB2 may also operate in reverse direction and disconnect part of the MV feeder intentionally from the utility network to island operation
    - If active and reactive power unbalance at CB2 is small enough
    - CB2 could also send a signal to DER unit ② to change the control mode etc.
- CB3 may also operate in reverse direction and disconnect either part of the MV feeder (beginning of the feeder, 3. in Figure 19.1) OR the whole MV feeder (2. &3. in Figure 19.1) to island operation
    - Depending on the active and reactive power unbalance at CB3 and CB2
    - Co-ordination with islanding of part of MV feeder by opening CB2 may be beneficial/required
    - CB3 could also send a signal to DG unit ① (AND/OR DER unit ② depending on the power balance situation) to change the control mode etc. or to disconnect
- Alternatively, CB4 may also operate in reverse direction and disconnect
    1) All MV feeders (4.b in Figure 19.1) to island operation
    2) Some of the MV feeders (e.g. (4.a in Figure 19.1)) to island operation
        - Simultaneously the disconnection signal from CB4 is send to MV feeder CBs (e.g. (CB3c in Figure 19.1)) which cannot be included into intentional island
        - Wind farm remains connected according to the LVRT curve (Figure 19.2) unless disconnection signal to CB3c (Figure 19.1) is send by CB4
    - This intentional island scheme is somewhat more complex due to the increased number of possible island sizes
    - Size of the island depends on the active and reactive power unbalance at CB4, CB3 and CB2 and
        - Needs (central) co-ordination with islanding of part of or whole MV feeder by opening CB3 or CB2
        - Signals to DER unit ① and ② to change the control mode etc. after operation or to disconnect will be sent based on the planned island size (which depends from the power balance situation before fault C)

In case of fault F in Figure 19.1 (see also Figure 19.2):

- HV network fault => intentional islanding should not take place (if there is an alternative HV network supply route available), MV and LV network connected DER units should ride-through HV network faults and possibly also support the HV network according to grid code requirements (for example by reactive power injection)
    - Possible indication about HV network fault could be sent from the HV/MV transformer protection IED to MV feeder IEDs to indicate that in this case intentional islanding is not possible/allowed

- Instead FRT and HV network support of DER units is preferred
  - However, if very sensitive customers (sensitive to voltage dips) are connected to MV or LV network then similar actions could take place as described above for the other faults.

19.2 Protection requirements

The traditional protection scheme requirements include sensitivity, selectivity, and reliability. However, the capability of microgrid to work in islanded mode demands the additional requirement of adaptivity for the protection scheme. Moreover, microgrid transition from the islanded mode to the grid-connected mode or even from the isolated mode to the islanded mode require re-synchronization function in order to avoid wrong protection tripping during transition periods. Since, the transitions from the grid-connected to the islanded mode and vice versa are mainly dependent on the connection and disconnection status of microgrid switches/breakers, therefore selection of proper switching technology is also important. In this section, the existing and new protection requirements of microgrid are discussed.

19.2.1 Sensitivity

Sensitivity is one of the essential requirements of a protection scheme. Any protection scheme should be sensitive enough to sense and detect the abnormality or fault in the power system components and respond to clear the fault as soon as possible. Sensitivity can be defined as “the ability of the protection system to detect even the smallest faults within the protected zone” [17]. Sensitivity is related to the minimum pickup or threshold value of measured or sensed quantity which is by some margin above or below the boundary of normal operating value. Different protection methods have different sensitivity levels depending on operational characteristics or settings and the magnitude of electrical or physical quantity on which protection scheme is working. Fuses for example are the traditional and simple overcurrent protection devices which depend on the magnitude of current flowing through the fusible element which blows or melts due to thermal effects produced by the current. Fuses are both sensing and interrupting devices with inverse operational characteristics, which means less time of fusing operation at high magnitude of current and more time of fusing operation at low or minimum magnitude of current flowing through the fusible element. The operational characteristics of fuses greatly depend on the material of fusible element through which electric current flows during the fault. Therefore, operational charactricitcs of fuses can be changed only by changing the material of fusible element, but once fuse type is selected and installed the operational characteristics can no longer be changed, this makes fuse a non-resetable device. Different types of fuses have different time-current characteristics and therefore different levels of operating sensitivities. The other protection device working on overcurrent principle is the overcurent relay. The sensitivity of definite time overcurrent relay depends on its capability or settings to detect the lowest possible magnitude of current flowing through the circuit during a fault. Usually, the lowest possible magnitude of current is observed in case of single-line to ground (SLG) short circuit fault with high fault impedance and the maximum current is observed during three-phase (LLL) short circuit fault. In conventional radial distribution systems with power flow in one direction, overcurrent protection schemes for the detection of SLG faults need to be more sensitive in comparison with overcurrent protection schemes for the detection of three-phase faults. However, with the increasing connection of small-scale DER units particularly the converter-based DERs result in very reduced three-phase fault current levels which greatly affect the sensitivities of existing overcurrent relays and both definite-time and inverse-time overcurrent relays may experience the blinding of overcurrent protection. The blinding of protection scheme occurs when a fault exists but the protection scheme is unable to detect the fault due to wrong or less sensitive settings. Moreover, transient events like starting of motor loads, the energization of transformers and switching of capacitor banks may affect the sensitivity of overcurrent protection and result in wrong or unnecessary trips due to more sensitive settings. Additional filtering, signal processing algorithms or even changed protection philosophies or functions can be employed to avoid these situations. Microgrids require different levels of sensitivities in overcurrent protection schemes to differentiate between faults in the grid-connected and islanded mode of operation. In the grid-connected mode less sensitive settings are required in order to avoid the unnecessary trips of protection schemes and in the islanded mode more sensitive settings are necessary in order to avoid the blinding of protection scheme. Other protection functions based on the measurement of voltage, frequency or impedance may have different levels of sensitivities in different operational modes and different fault categories and these functions should be carefully selected and configured. For example, the measurement of fault resistance (R_F) coverage is used as a means of evaluating sensitivty of directional overcurrent, distance and differential protections for SLG faults [17].

19.2.2 Selectivity

Selectivity or coordination is an important requirement of the traditional protection system which ensures that only the section of power system close to the fault is isolated and the minimum portion of power system is interrupted. For a complete selective or a coordinated protection scheme primary protection operates first after fault detection inside the protection zone and backup protection operates only after primary protection fails to detect and isolate the fault after a predetermined time delay. For definite time OC relays definite time based coordination is done which starts for example from the extreme load end of the feeder towards the source side of the feeder or substation. It means for faults at the extreme end of the feeder on the load side, OC relay near the load operates first and then a coordination interval of 0.2 s or so is used between each upstream OC relay towards the substation end for the backup protection of downstream relays. Usually fast acting relays and breakers or instantaneous adjustable devices like miniature circuit breaker (MCB) or moulded case circuit breakers (MCCB) are used on the load side for short circuit protection. If due to any problem, load side primary protection fails, the first upstream relay near the load will operate as backup after a coordination interval of 0.2 s, the same is valid for all subsequent upstream faults. This definite time based coordination is commonly used for three-phase faults in radial distribution feeders. Definite time relay coordination is simple, independent of fault current magnitude and it provides complete coordination as long as each relay is able to detect the fault. The only drawback for definite time coordination is longer tripping times for faults near the source or substation side of the feeder. The inverse-time OC relays, commonly known as inverse definite minimum time (IDMT) relays have operating times which are inversely proportional to the magnitude of current, the higher the fault current magnitude, the faster the IDMT relay operates. The IDMT relays have several families of inverse characteristic curves with different degrees of inversity like standard inverse, very inverse and extremely inverse characteristics. For a given pickup current above the minimum pickup value and an identical time-dial setting, an extremely inverse IDMT relay operates faster than a very inverse relay and a very inverse relay operates faster than the standard inverse. The IDMT relays with an inverse or very inverse characteristics are most commonly used types and ideally the relays with the same inverse characteristics are used throughout the system [18]. The IDMT relays operate faster for faults near the source or substation and slower for faults away from the substation. Compared with the coordination of definite time relays, the coordination of IDMT relays is much complicated and a time intensive job, however it all depends on the method used. The general methods used for the coordination of IDMT relays include trial and error, curve fitting and optimization techniques using different algorithms [19]. In traditional radial distribution systems with power flow in one direction the coordination of OC relays may not be affected, however when considerable amount of DERs are connected the coordination is either altered or completely lost depending on the capacity, type and location of DERs [20] [21]. For microgrids with nearly 100% DER supply with the majority of the converter-based DERs, the loss of protection coordination will result in the reduced security of supply to consumers due to the disconnection of large portions which is not in line with the very fundamental purpose of microgrids. Therefore, microgrid protection must be coordinated in both the grid-connected and islanded mode of operation. This could be done by the separate coordination study and settings of grid-connected and islanded mode protections or by providing sources of high fault current also in islanded mode. A case study of protection coordination in the grid-connected and islanded mode of microgrid using definite-time and inverse-time OC relays is presented in Section 19.3 for further understanding about selectivity issues.

19.2.3 Reliability

Reliability is the ability of protection scheme to operate correctly and it is usually defined in terms of dependability and security of relay operations. Dependability is defined as the measure of certainty that protection relay will operate and trip for all faults for which it is designed and security is the measure of certainty that protection relay will not operate and trip incorrectly. Traditionally, protection schemes have been designed to provide high dependability at some degree of compromise of security which may increase the false operations of protection schemes resulting in the unwanted trippings of power system elements. Traditional large interconnected power systems provide some degree of redundancy due to many alternative paths of power flow and therefore the loss of a generator or a line (n-1 criterion) due to a false trip is less objectionable in comparison with the sustained fault which may damage the faulty component [17][22] [23]. But, the false trips of a distribution line due to the unsecure protection scheme in radial, grid-connected microgrids is less acceptable because it may jeopardize the stability of microgrid. The false trips of breaker at microgrid connection point to the main grid may result in unwanted islanding, increased re-synchronization operations for the restoration of grid-connected operations, unwarranted outage to non-priority loads and microgrid exposure to power quality problems [24][25]. In islanded mode of operation, a false trip of a grid-forming generator may result in complete blackout due to consequent tripping of grid-following generators. The reliability of modern multifunction numerical relays using communication links is not only dependent on hardware and software based failures but also on the dependability and security of the communication system. In order to analyse the dependability and security of protection scheme different fault trees can be used. Fault tree analysis is a useful tool for the comparison of relative reliability of protection schemes. The construction of a fault tree starts with the identification of component failures which may cause a failure to trip (a dependability problem) or an unwanted trip (a security problem). The AND, OR or other gates are used to represent the combinations of failure rates. The idea behind using the OR gate is that any of several failures can cause the protection scheme to fail, whereas, the AND gate expresses the idea that all component failures happen simultaneously to cause a protection scheme to fail. Various combinations of protection schemes using fiber-optic channels have been analysed for dependability and security using fault trees [17]. Such type of reliability analysis will be useful for protection schemes in microgrids.

19.2.4 Adaptivity

The adaptivity of microgrid protection scheme is the new requirement which is the ability of protection scheme to adapt its settings according to changing operational modes from the grid-connected to islanded mode and vice versa. An adaptive protection is defined as an on-line activity that changes the preferable response of protection device according to changing states of system or its requirements. Adaptive protection is usually automated, but some necessary human interventions can also be included. An adaptive relay is a protection device or relay that includes different setting groups, characteristics or logic functions which can be altered or changed on-line very quickly by using external signals or control commands [26]. The modern numerical relays, also called intelligent electronic devices (IEDs), not only provide various protection functions (overcurrent, over/under voltage etc.) integrated in a single physical device, but also offer various settings groups for each of the available protection functions. These setting groups can be changed in an adaptive manner using the communication link between IEDs and IEDs and circuit breakers (CBs). Adaptivity of protection scheme in microgrid is mainly required due to different magnitudes of fault current sensed by OC relays in grid-connected and islanded modes and due to the connection and disconnection of DERs. Further detailed discussion on adaptive protection is given in Section 19.4.

19.2.5 Re-synchronization

Re-synchronization is the ability of a well-planned microgrid to reconnect back to the main grid soon after the clearance of faults on the main grid side. The availability of re-synchronization means at the microgrid point of connection to the main grid is necessary for the smooth transition of microgrid from the islanded mode to the grid-connected mode. Re-synchronization is the process of connecting islanded microgrid back to the main grid after checking or measuring voltage, frequency and phase angle of both systems and closing the breaker contacts for parallel operation only if these parameters are within acceptable limits as per table 5 of IEEE Std 1547-2003 [27]. Three types of synchronization schemes have been mentioned in [28]: active, passive and open transition synchronization. In active synchronization there is a control mechanism which can be used to match voltage, frequency and phase angle of islanded microgrid to the main grid before closing the breaker contacts. Active synchronization requires collection or sensing of conditions for both the main grid and islanded microgrid and then communicating this information to the control mechanism. Passive synchronization uses traditional synchrocheck relay for closing breaker contacts if voltage, frequency and phase angle of both the main grid and islanded microgrid reach within specified limits. Passive technique also requires sensing of conditions for both the main grid and islanded microgrid, however it is slower than active synchronization. Open transition synchronization requires the disconnection of loads and DGs inside microgrid before reconnection and does not require any sensing or measurement of conditions. Both active and passive synchronization methods maintain high reliability of microgrid as no load or DG disconnection is required. The same procedure of synchronization is applicable for the reconnection of any synchronous DG, the converter-based DG or isolated zones with one or more DGs back to the large portion of islanded microgrid in islanded mode.

19.2.5.1 LV microgrid synchronized re-connection

One important issue in enabling future Smart LV Grids with island operation capability is that challenges related to the synchronized reconnection (i.e. re-synchronization) of island operated microgrid are solved. Islanded microgrid may be synchronized with utility system directly after islanding, but later the synchronism is lost due to generation and load variations inside the microgrid. This means that the voltage phase angle difference across microgrid interconnection switch or circuit-breaker will change. Microgrid re-synchronization or synchronized re-connection of microgrid means that the voltage angle difference between utility grid and microgrid needs to be minimized before reconnection. [29]

In the HV network where line reactance X is much larger than line resistance R the active power P depends mainly on load angle δ and reactive power Q depends mainly on voltage difference. This means that the active power P control directly controls the load angle δ and frequency f. Generators in HV network are typically directly connected with synchronous generators (SGs) which can be controlled, for example, during synchronization of separate power system areas. In HV network synchronism check relays have typically such settings that frequency difference over open CB needs to be less than 55 mHz and phase difference 20°–45° before CB connection [30].

On the other hand, in LV microgrids a large share of the DER units are connected through the inverter- or converter-based interfaces and microgrid synchronized re-connection can be done by the control of these DER units. In LV networks the line resistance R is much larger than the line reactance X and therefore, the active power P depends mainly on voltage difference, while the load angle δ and frequency is mainly dependent on reactive power Q. This means that one possibility to manage the phase difference across microgrid interconnection CB could be coordinated reactive power control of the DER units.

The chosen strategy is dependent on the chosen microgrid concept. In [31], it was proposed that the control of grid-forming energy storage unit (master unit) could slowly shift the microgrid frequency reference closer to the utility grid frequency before reconnection. However, for example with P/f-droop controlled DER units re-synchronization requires the coordinated control of all DER units. This coordination should be done by an external central controller, e.g. microgrid management system or controller, which manages all the DG units during the synchronization process. [32], [33]

Voltage imbalance due to asymmetrical loads and single-phase DG units affects the voltage phase difference across open microgrid interconnection CB so that the phase difference deviation can be different in phases A, B and C. This asymmetry between phases may also require to be reduced before microgrid re-synchronization.

Active components in the connection point of microgrid, such as microgrid interconnection switch, central energy storage unit and microgrid management system, are responsible for microgrid synchronized re-connection. In [34] it was proposed that synchronous island operation could be done using a reference signal with phase and frequency information to the microgrid master unit. The phase difference before re-synchronization should be within acceptable levels, e.g. less than 60° [34]. Based on [35], microgrid re-synchronizing function has to meet a more stringent requirement than the one defined by IEEE 1547 which requires that the phase difference between a microgrid and the utility grid needs to be smaller than 20° before closing the interconnection CB. In [36], LV microgrid re-synchronization was studied and different synchronized reconnection enabling functionalities were developed and simulated.

In the simulations [36] either

1. Master unit voltage phase angle or
2. Reactive power output of DG units was modified to enable synchronized reconnection and in addition also
3. Controllable single-phase loads were used in for phase asymmetry compensation at MV/LV distribution substation.

The simulation results in [36] showed that both re-synchronization functions

1) Voltage phase angle adjustment by master unit control and
2) DER unit reactive power feeding can be utilized to enable successful LV microgrid re-synchronization.

However, the voltage phase difference deviation or asymmetry between phases A, B and C across microgrid interconnection switch still existed with these re-synchronization functions. If this phase difference deviation is too large, it must be compensated before LV microgrid re-synchronization. In simulations of [36] this phase difference deviation was well corrected by the connection of resistive or capacitive single-phase loads at MV/LV distribution substation. However, quite large frequency and voltage oscillations after the connection of single-phase capacitive loads were detected when compared to the connection of purely resistive loads.

In general, the simulation results of [36] clearly showed that re-synchronization is not necessarily a significant issue with small, e.g. less than 10°, phase difference across microgrid interconnection CB when only the converter-based

DER units are connected to microgrid. Reason for this was that phase-locked-loop (PLL) component will draw grid-following / -supporting converters into phase with the utility grid frequency after re-connection. On the other hand, with directly connected synchronous generators even small phase difference across interconnection CB during re-synchronization was found to be challenging. Therefore, re-synchronization functions for minimizing phase angle difference and possibly also voltage unbalance before LV microgrid reconnection will be needed and in practice these functions should be coordinated by microgrid central controller or management system [29].

19.2.6 Circuit breaker technology

The circuit breaker (CB) technology for AC power systems has been well-developed over years and variety of CB and switching technologies are available nowadays. AC circuit breakers range from miniature circuit breakers (MCB), moulded case circuit breakers (MCCB) and air circuit breaker (ACB) for low voltage levels up to 600 V, these devices include relays and CBs combined in one physical device. For medium voltage (MV) applications mechanical CBs are available using mostly vacuum and SF6 as arc extinguishing medium and spring, pneumatic, hydraulic, and electromagnetic mechanisms for electrode separation to interrupt the circuit. Most of the MV mechanical circuit breakers operate within 3-5 cycles of supply voltage after getting trip command from protection relays. However, some efforts have been made to still decrease the time of MV mechanical circuit breaker operation by developing new breaker prototypes using combination of Thomson coil actuator and permanent magnet actuators which give one cycle interruption for the largest current duty of T100a, but it is expensive solution. The other prototype using Thomson coil actuator and spring mechanism reduced the normal trip time delay of vacuum circuit breaker (VCB) from 15 ms to 13.5-14 ms [37]. AC solid state circuit breakers (AC-SSCB) provide the faster tripping response compared with mechanical circuit breakers. AC-SSCB can be classified into two broad categories: Non-current-limiting and current limiting types. Non-current limiting AC-SSCBs are constructed using inverse parallel SCRs (Silicon controlled rectifiers) and current limiting AC-SSCBs are constructed using faster power semiconductors switches like IGBTs (insulated gate bipolar transistors) and IGCTs (integrated gate-commutated thyristors). Non-current limiting SCR based AC-SSCBs can be compatible with traditional protection coordination with downstream breakers or fuses and offer advantages like silent operations, long life and half-cycle tripping response. However, for the worst case asymmetrical fault currents of 200kA peak for 85kA rms current, SCRs should be protected by fuses. On the other hand, current limiting AC-SSCBs result in higher power losses than non-current limiting AC-SSCBs and can be problematic for the protection coordination of traditional systems even if a few of these breakers are connected in the system. Therefore, entire protection schemes need to be designed based on only current limiting AC-SSCBs, this may be well suited to microgrids with only the converter-based DERs. Current limiting AC-SSCBs have many design challenges like employing suitable snubbers, metal-oxide varistors (MOVs) and dynamic breaking resistors for energy dissipation and voltage limiting during interruption as well as capability to differentiate between a fault current and load transients to avoid false trips [38].

19.3 Conventional protections for AC microgrids

Conventional protection of microgrids is usually based on overcurrent principle using either definite time or inverse definite OC relays. In addition, voltage-based (over/under voltage) and frequency-based (over/under frequency) protections are also used for the protection of DERs, for detection of islanding situation or for load-frequency control in microgrids. However, only overcurrent protection schemes are discussed is this section.

19.3.1 Overcurrent protection (Definite-time vs Inverse time)

The most common protection scheme used in traditional distribution systems is based on overcurrent principle. Both definite-time and inverse-time (IDMT) OC relays are used in a coordinated manner so that interruption should be limited to only faulty section. For both static and microprocessor-based relays the working time of OC relays is decided based on two details: CB opening time (0.04-0.1 s) and security factor (0.12-0.22 s). In this way total time of OC relay operations is in the range of 0.2-0.4 s [18]. For definite-time OC relays only pickup current (I_P), CB opening time and security factor are required to decide the total operating time of primary and backup relays. However, for IDMT OC relays the relay operating time is decided based on different relay characteristics defined by eq.1 according to IEC 255-3 [39]:

$$t = \frac{k\,a}{(\frac{I}{I_P})^b - 1} \qquad (1)$$

where t is the relay operating time, k is the time dial setting (TDS), I is the current detected by relay, I_P is the pickup current and a, b are the constants defining relay characteristics.

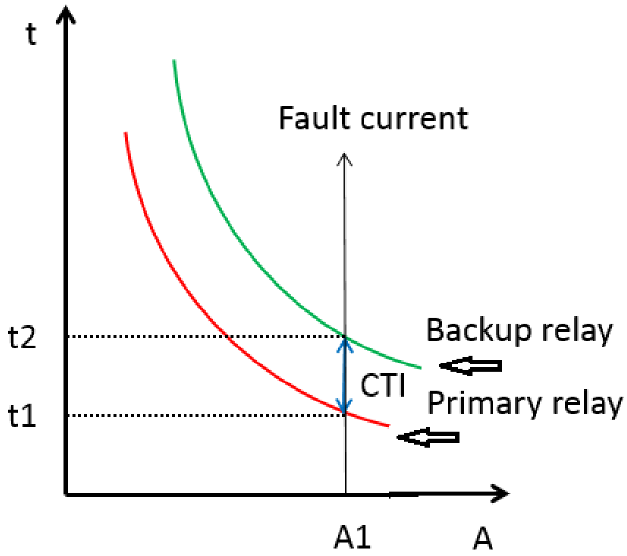


Figure 19.3 Time current characteristics curve of primary and backup inverse-time OC relays

Mainly two sets of standard inverse-time relay characteristics are applied, IEC and ANSI (in USA). Additionally, relays may include options to have some manufacturer specific characteristics or even freely programmable characteristics. It means based on types of characteristics curve (inverse, very inverse, extremely inverse etc.) different relay manufacturers may have different/additional constants for inverse-time OC relay characteristics [40] in addition to the standard IEC or ANSI constants. Generally, the settings of inverse-time OC relays should be adjusted so that there is always some coordination time interval (CTI) between primary and backup relay to ensure correct selective operation. Fig. 19.3 shows the time current characteristic curves for primary and backup inverse-time OC relays. For fault current of magnitude A1 (Fig. 19.3) primary relay will operate first at time t1 and if primary relay fails to operate than backup relay will operate at time t2 which is equal to t1+CTI. If adequate CTI (0.2-0.3 s) is not ensured, then nuisance trips may happen. For a given current, the higher the TDS is the greater the time to tripping contact closure is. Since TDS provides up and down adjustment of inverse-time OC relay characteristics and pickup current provides left and right adjustment of characteristics on the coordination plots, therefore proper CTI can be established through proper selection of TDS and I_P values [18].

The coordination practice of using definite-time characteristics or inverse-time characteristics vary between Europe/Japan and North America. In Europe and Japan it is common that primary distribution systems are operated as impedance grounded or ungrounded three-wire systems and hence no presence of single-phase laterals protected by fuses. Therefore, relay coordination can be achieved using definite-time characteristics. In North America, the usual practice is to operate grounded four-wire distribution systems with loads served by single-phase laterals protected by fuses. Therefore, coordination is done using inverse-time current characteristics which is suitable for fuse coordination [41]. However, in this section both definite-time and inverse-time coordination characteristics are used and the performance of both is compared for traditional three-phase distribution system operation without DERs, for grid-connected operation of AC microgrid with DERs and for islanded mode operation of AC microgrid with DERs and central battery energy storage system (BESS). The single-line diagrams of the grid-connected AC microgrid (Fig. 19.4) and islanded AC microgrid (Fig. 19.5) are used to verify the coordination of OC relays at CB1, CB2, CB6, CB7 and CB8 locations for three-phase short-circuit faults F1, F6 and F8 as explained in the following subsections.

The circuit breakers CB1-CB9 in Fig. 19.4 are operated by corresponding OC relays (OCR1-9) for faults in corresponding zones (zone1-9), and therefore OC relay-1 (OCR-1) means the relay at CB1 location and so on. Definite-time coordination starts from the relay OCR-8 at the extreme load end which is set to trip instantaneously after 0.04 s of the fault. OCR-7 is set to trip after 0.2 s of the fault, OCR-6 is set to trip after 0.4 s of the fault, OCR-2 is set to trip after 0.6 s of the fault and OCR-1 is set to trip after 0.8 s of the fault. The pickup current setting of each relay (OCR1-2 and OCR6-8) is set at 2.25 p.u. of maximum current a relay can experience during normal operation without DERs (Wind turbine and photovoltaic). For inverse-time current coordination, the same type of relay characteristic is chosen for all inverse-time OCRs (inverse-time OCR1-2, OCR6-8) which is very inverse characteristic with constants of relays a =13.5 and b = 1 (eq(1)). The selected values of TDS for inverse-time OCRs are 0.05, 0.15, 0.25, 0.28 and 0.29 for OCR8, OCR7, OCR6, OCR2 and OCR1 respectively, in order to ensure a proper coordination of relays. The pickup current for each inverse-time OCR is chosen to be the same as chosen for definte-time OCRs which is 2.25 p.u. of maximum current a relay can experience during normal operation without DERs. The performance of definite-time and inverse-time OCRs with regard to the speed of operation and selectivity for three different operational modes is analysed in the following subsections. It is worth here mentioning that the settings of both definitie-time and inverse-time OCRs is kept the same in all three modes to observe the issues in different modes when single-settings OCRs are used. The real-time modelling of relays and other components is done by using Matlab/Simulink and RT-Lab software of OPAL-RT.

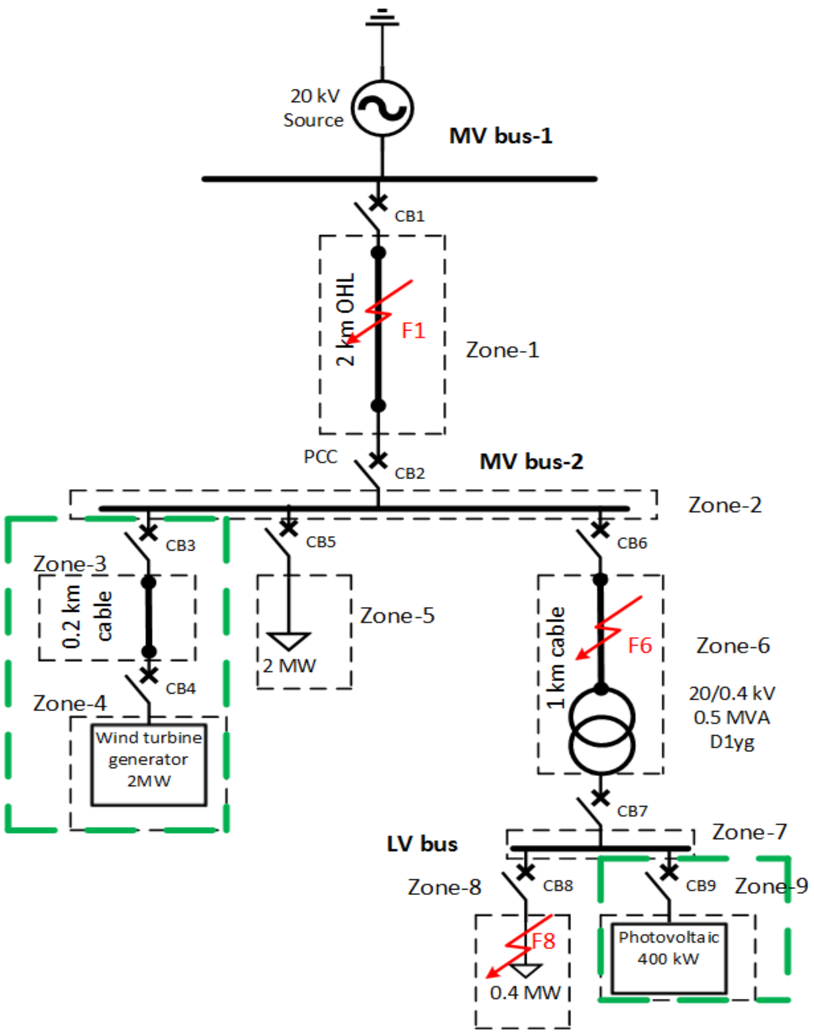


Figure 19.4 Grid-connected mode of AC Microgrid with single setting OC relay protection

19.3.1.1 Protection coordination in grid-connected mode without DERs

In this subsection, the protection coordination of definite-time OCRs and inverse-time OCRs with very inverse characteristic is analysed for the grid-connected mode of AC microgrid without DERs. It means, in this subsection the coordination of OCRs in path CB1-2-6-7-8 is observed without considering green zones in Fig. 19.4. This makes the system of Fig. 19.4 a traditional MV/LV distribution system protected by OCRs. A three-phase permanent short-circuit fault is applied separately at locations F1, F6 and F8 (R_{F1} = R_{F6} =5.001 Ohm, R_{F8} =0.001 Ohm) for a duration of 18 s (starting from 2s to 20 s in simulations) and tripping time of primary and backup OCRs was noted for both very inverse-time and definite-time characteristics. During fault F1 only tripping time of primary protection can be observed. Tab- 19.1 presents the tripping time durations (t_{op}) for primary and backup relays for the faults F1, F6 and F8. The CTI values in Tab- 19.1 (given in brackets) in columns 4 and 5 indicate the coordination time intervals between primary and backup-1 OCRs, between backup-1 and backup-2 OCRs and between backup-2 and backup-3 OCRs. Also, fault currents in per unit (p.u.) of rated current at corresponding OCRs in every fault case is given. During three-phase short-circuit fault F1, the tripping of primary inverse-time OCR1 is much faster than definite-time OCR1 because inverse-time OCR1 trips after 0.6843 s of the fault F1 whereas definite-time OCR1 trips after 0.8 s of the fault F1. During fault F6 also, primary inverse-time OCR6 trips faster in 0.0732 s compared with primary definite-time OCR6 which trips in 0.4 s. In order to observe the tripping times of backup-1 OCR2 and backup-2 OCR1 protections of primary OCR6 during fault F6, the tripping of CB6 and CB2 was disabled to simulate a breaker failures. It is observed that backup-1 inverse-time OCR2 and backup-2 inverse-time OCR1 of inverse-time OCR6 also trip faster than backup-1 definite-time OCR2 and backup-2 definite-time OCR1 of definite-time OCR6 while maintaining a good CTI of 0.2638 s between primary and backup-1 and CTI of 0.428 s between backup-1 and backup-2 during fault F6. However, during fault F8 not only the primary inverse-time OCR8 is slower than the primary definite-time OCR8, but also all backup inverse-time OCRs are slower than backup definite-time OCRs. The CTI between primary inverse-time OCR8 and backup-1 inverse-time OCR7 is 0.2757 s and CTI between backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 is 0.3062 s which are longer than the corresponding CTIs of 0.16s and 0.2 s of definite-time OCRs during fault F8. It can be observed from Tab-19.1, that backup-3 inverse-time OCR2 operates considerably slower (t_{op} =6.9592 s) than backup-3 definite-time OCR2 (t_{op} =0.6 s) due to reduced fault current of 3.45 p.u. at OCR2 during the fault F8. It is also observed that due to very low fault current (1.65 p.u.) at OCR1 during 18 s of fault F8, neither inverse-time OCR1 nor definite-time OCR1 provide backup-4 for OCR8 due to higher pickup current settings. Therefore, during fault F8 limited selective coordination only up to OCR2 is possible. In conclusion for this case, inverse-time OCRs provide faster tripping times while maintaining good coordination between primary and backup relays during faults F1 and F6. However, during fault F8 inverse-time OCRs are much slower and provide lesser coordination compared with definite-time OCRs during fault F8. So during fault F8 only definite-time OCRs provide faster tripping times and good selective coordination.

TABLE-19.1 Protection coordination in grid-connected mode without DERs (No green zones, 3,4 and 9)

Fault (duration)	Relay No.	Primary/Backup	Very inverse-time t_{op} (CTI)	Definite-time t_{op} (CTI)	Fault current at relay (p.u.)
F1 (18 s)	OCR1	Primary	0.6843	0.8	19.9
F6 (18 s)	OCR6	Primary	0.0732	0.4	159
	OCR2	Backup-1	0.337 (CTI_{6-2} = 0.2638 s)	0.6 (CTI_{6-2} = 0.2 s)	27.48
	OCR1	Backup-2	0.765 (CTI_{2-1} = 0.428 s)	0.8 (CTI_{2-1} = 0.2 s)	18.11
F8 (18 s)	OCR8	Primary	0.1368	0.04	19.72
	OCR7	Backup-1	0.4125 (CTI_{8-7} = 0.2757 s)	0.2 (CTI_{8-7} = 0.16 s)	19.72
	OCR6	Backup-2	0.7187 (CTI_{7-6} = 0.3062 s)	0.4 (CTI_{7-6} = 0.2 s)	19.05
	OCR2	Backup-3	6.9592 (CTI_{6-2} = 6.2405 s)	0.6 (CTI_{6-2} = 0.2 s)	3.45
	OCR1	Backup-4	No trip in 18 s	No trip in 18 s	1.65

19.3.1.2 Protection coordination in grid-connected mode with DERs

In this subsection, the protection coordination of definite-time OCRs and inverse-time OCRs with very inverse characteristic is analysed for the grid-connected mode of AC microgrid with the converter-based DERs. It means in this section the coordination of OCRs in path CB1-2-6-7-8 is observed with green zones of DERs (Zones 3,4 and 9) also included (Fig 19.4). This makes the section below PCC breaker CB2 in Fig 19.4 as a grid-connected AC microgrid with DERs (when CB1-2 closed) where a wind turbine DER is connected at 20 kV MV bus-2 and photovoltaic DER is connected at 0.4 kV LV bus. The main purpose of this case study is to observe how the speed and selectivity of inverse-time OCRs are affected after the connection of DERs. It should be noted here that both DERs (wind turbine and photovoltaic systems) provide FRT capability, means no trip until fault is cleared and provide 1.2 p.u. of rated current during faults when voltage is below 0.5 p.u. Fault types and durations in this case are the same as mentioned in previous subsection 19.3.1.1 and performance of inverse-time and definite-time OCRs is observed in terms of speed and selectivity. In addition to tripping times, CTI and fault currents of OCRs, DERs fault contribution and DERs terminal voltage at connection point are also noted in this case (Tab- 19.2). During fault F1 primary inverse-time OCR1 operates faster at t_{op} = 0.7068 s than primary definite-time OCR1 which operates at t_{op} = 0.8 s. However, due to reduced fault current experienced by inverse-time OCR1 in this case, its tripping time is 22.5 ms slower than it was in the previous case without DERs (Subsection 19.3.1.1). During fault F6, primary inverse-time OCR6 operates at the same time (t_{op} = 0.0732 s) as it operated during the same fault in the previous case without DERs (Subsection 19.3.1.1) even if the fault current at OCR6 has been reduced by 10 p.u.(from 159 p.u. to 149 p.u.) after the connection of DERs. However, backup-1 inverse-time OCR2 and backup-2 inverse-time OCR-1 are observed with 11 ms and 26.7 ms slower tripping responses respectively during fault F6 compared with the same fault in the previous case without DERs (Subsection 19.3.1.1) due to comparatively reduced fault currents. However, still faster tripping times and good CTI is observed for primary and backup inverse-time OCRs compared with definite-time OCRs during faults F1 and F6. During fault F8, primary inverse-time OCR8 operates slower than primary definite-time OCR8, but its tripping time is faster compared with inverse-time OCR8 in the previous case without DERs (Subsection 19.3.1.1) due to increased fault current observed at

OCR8 because some fault current contribution comes from photovoltaic DER in this case. Whereas backup-1 inverse-time OCR7, backup-2 inverse-time OCR6 and backup-3 inverse-time OCR2 are slower compared with backup-1 definite-time OCR7, backup-2 definite-time OCR6 and backup-3 definite-time OCR3 during fault F8 in this case. However, backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 have nearly the same tripping times during fault F8 in this case (Tab-19.2) compared with tripping times during the same fault in the previous case without DERs (Tab-19.1) even if the fault current seen at both OCRs is somehow reduced in this case after DER connections (Tab. 19.2). The tripping time of backup-3 inverse-time OCR2 during fault F8 has also increased from t_{op} = 6.9592 s in the previous case without DERs (Tab-19.1) to t_{op} = 8.5675 s in this case due to comparatively reduced fault current seen by OCR2 (Tab-19.2). It is also observed that due to very low fault current of 1.0851 p.u. at OCR1 during fault F8 (Tab-19.2), neither inverse-time OCR1 nor definite-time OCR1 provide backup-4 for OCR8 during fault F8 in this case with DER connections. Therefore, like the previous case (Subsection 19.3.1.1) in this case also a limited selective coordination only up to OCR2 is possible during fault F8. In conclusion for this case, inverse-time OCRs provide faster tripping times compared with definite-time OCRs while maintaining good coordination between primary and backup relays during faults F1 and F6. However, during fault F8 inverse-time OCRs are much slower and provide lesser coordination compared with definite-time OCRs during fault F8. So during fault F8 only definite-time OCRs provide faster tripping times and good selective coordination. Comparing this case with DERs to previous case without DERs, it can be said that the inclusion of DERs somehow make inverse-time OCRs slower due to reduced fault current contribution from the main grid. Some inverse-time relays e.g., OCR8 sense increased fault current due to DER connection and operate faster as compared to their operation without DERs. Definite-time OCRs show the same performance for the grid-connected mode with DERs and without DERs.

TABLE-19.2 Protection coordination in grid-connected mode with DERs (Green zones included)

Fault (duration)	Relay No.	Primary/Backup zone	Very inverse-time t_{op} (CTI)	Definite-time t_{op} (CTI)	Fault current at relay (p.u.)	DERs fault contribution
F1 (18 s)	OCR1	Primary	0.7068	0.8	14.6	$I_{F,\,pv,\,wtg} \leq 1.0$ p.u. ($U_{pv,wtg} = 0.9$ p.u.)
F6 (18 s)	OCR6	Primary	0.0732	0.4	149	$I_{F,wtg} \leq 1.04$ p.u. $I_{F,pv} \leq 1.01$ p.u. ($U_{wtg} = 0.872$ p.u.) ($U_{pv} = 0.837$ p.u.)
	OCR2	Backup-1	0.348 ($CTI_{6\text{-}2}$ =0.2748 s)	0.6 ($CTI_{6\text{-}2}$ = 0.2 s)	26.74	
	OCR1	Backup-2	0.7917 ($CTI_{2\text{-}1}$ =0.4437 s)	0.8 ($CTI_{2\text{-}1}$ = 0.2 s)	13.31	
F8 (18 s)	OCR8	Primary	0.1277	0.04	20.89	$I_{F,pv} = 1.17$ p.u., ($U_{pv} < 0.5$ p.u.) $I_{F,wtg} \leq 1.0$ p.u. ($U_{wtg} \leq 1.0$ p.u.)
	OCR7	Backup-1	0.412 ($CTI_{8\text{-}7}$ = 0.2843 s)	0.2 ($CTI_{8\text{-}7}$ = 0.16 s)	18.095	
	OCR6	Backup-2	0.7175 ($CTI_{7\text{-}6}$ = 0.3055 s)	0.4 ($CTI_{7\text{-}6}$ = 0.2 s)	17.806	
	OCR2	Backup-3	8.5675 ($CTI_{6\text{-}2}$ = 7.85 s)	0.6 ($CTI_{6\text{-}2}$ = 0.2 s)	3.215	
	OCR1	Backup-4	No trip in 18 s	No trip in 18 s	1.0851	

19.3.1.3 Protection coordination in islanded mode with DERs and BESS

In this subsection, the protection coordination of definite-time OCRs and inverse-time OCRs with very inverse characteristic is analysed for the islanded mode of AC microgrid with DERs and BESS (battery energy storage system). In this case islanding is created by opening CB2 assuming that fault F1 had happened earlier in time and OCR1 had tripped CB1 and transfer tripped CB2 within next 0.5-0.8 s. Then 2.4 MW BESS has been activated quickly as a grid-forming DER after closing CB10. An islanded AC microgrid with BESS, DERs and single-settings OCRs is shown in Fig. 19.5. It is assumed that BESS is provided with a converter of higher current rating (≥ 3 p.u.) and BESS can act as fault current source during any fault in islanded mode. Such battery converters are installed in Bronsbergen microgrid, Netherlands which have the continuous current of 290 A and provide fault current of 1100 A [42] Such fault current sources can provide fault current up to 5 s [43]. A fault current source using energy storage devices like a flywheel, a battery or ultracapacitor is proposed in [42][43] which is a modular system and multiple units can be connected in parallel to suit the local fault level. In this case it is studied that if such type of fault current source is provided at PCC then how it serves the purpose of achieving faster tripping times and maintaining protection coordination in the islanded mode.

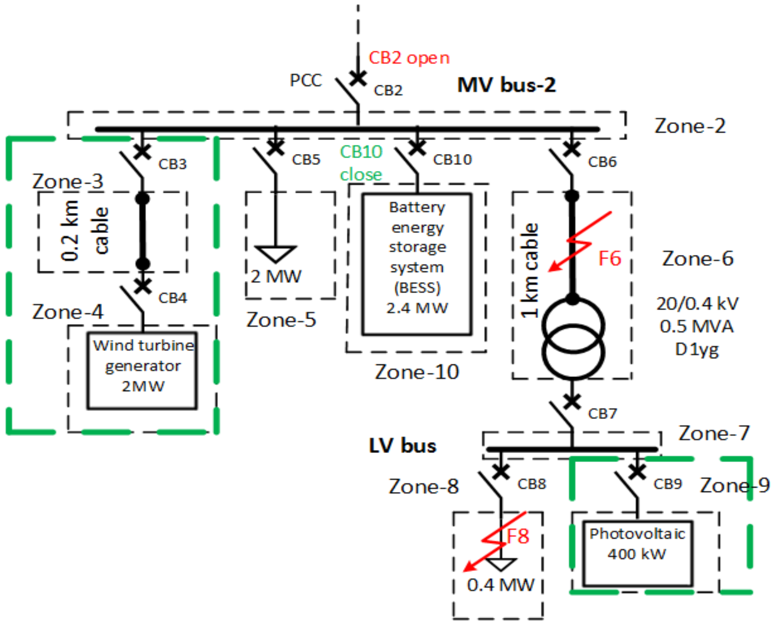


Figure 19.5 Islanded mode of AC Microgrid with single setting OC relay protection

In this subsection, the coordination of OCRs in path CB6-7-8 is observed with the green zones of DERs (Zone 3,4 and 9) and BESS zone (Zone10) included (Fig. 19.5). In this case the performance of OCRs has been observed for three-phase permanent short-circuit faults F6 and F8 (R_{F6} = 5.001 Ohm, R_{F8} = 0.001 Ohm) applied separately for a duration of 14 s (starting from 6s to 20 s) and relay tripping times are noted for different primary and backup OCRs in path CB6-7-8. All DERs and BESS have FRT capabilty during faults, and they provide fault current until the fault is cleared. During fault F6 in islanded mode, primary inverse-time OCR6 trips after 0.6163 s of fault which is 0.2163 s slower than primary definite-time OCR-6 which trips after 0.4 s of the fault F6. The OCR6 experiences 20.3 p.u. of fault current during fault F6 and all DERs including BESS provide maximum fault current contribution during this fault (Tab- 19.3). As compared to trip times in previous two grid-connected mode cases (Subsections 19.3.1.1 and 19.3.1.2), tripping time of primary inverse-time OCR6 during fault F6 in this case is 0.5431 s slower than tripping time of the same inverse-time OCR6 in previous two grid-connected cases (Tab-19.1 and 19.2). However, tripping time of primary definite-time OCR6 during fault F6 in this case is the same as in previous two grid-connected mode cases. During fault F8 in islanded mode, primary inverse-time OCR8 trips at 0.1977 s which is much slower than the tripping time of 0.04 s of primary definite-time OCR8. It means primary inverse-time OCR8 is 0.1577 s slower than primary definite-time OCR8 during fault F8 in islanded mode. Compared with trip times of primary inverse-time OCR8 in previous grid-connected mode cases (Subsections 19.3.1.1 and 19.3.1.2) tripping time of primary inverse-time OCR8 is 0.061-0.07 s slower during fault F8 in islanded mode. The tripping times of backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 are also slower than tripping times of backup-1 definite-time OCR7 and backup-2 definite-time OCR6, respectively during fault F8 in this case. Compared with the previous grid-connected case without DERs (Subsection 19.3.1.1), the tripping times of backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 are 0.3485-0.6423 s slower during fault F8 in islanded mode. When compared with the previous grid-connected case with DERs (Subsection 19.3.1.2), the tripping times of backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 in islanded mode are also 0.349-0.6435 s slower during fault F8 in islanded mode. In conclusion to this islanded mode case, primary and backup definite-time OCRs provide faster tripping times and maintain good protection coordination during faults F6 and F8 compared with primary and backup inverse-time OCRs during the same faults. The primary inverse-time OCR8 tripping time during fault F8 in islanded mode is acceptable. However, tripping times of primary inverse-time OCR6 during fault F6, and backup-1 inverse-time OCR7 and backup-2 inverse-time OCR6 during fault F8 in islanded mode are quite slow. Therefore, slower fault clearance at LV load with inverse-time OCRs can potentially damage the load if a fault current source is connected in islanded mode. Hence, for the islanded mode of operation definite-time OCRs perform better with faster tripping times and good CTI between primary and backup protection as compared to inverse-time OCRs which become slower to operate with increased CTI between primary and backup protection.

It should be noted here that in both the grid-connected mode with DERs and the islanded mode of AC microgrid (cases 19.3.1.2 and 19.3.1.3) during fault F6 if primary OCR6 trips CB6 then it should transfer trip CB7 for complete F6 fault clearance, otherwise photovoltaic DER may still feed the fault in the reverse direction. The second method is to trip photovoltaic DER after fault F6 is cleared by OCR6 by anti-islanding protection. The conventional method is to trip all DERs immediately after the fault is detected inside the microgrid. This conventional method reduces the reliability of supply to load. The other case of islanding can be the creation of islands within islanded mode after fault F6 is cleared by tripping CB6 and CB7. In this case both LV bus and MV bus-2 sections will be isolated and in this case it will be very difficult to clear the fault F8 in the islanded LV bus section with only fault contribution from photovoltaic DER. In this situation, lower adaptive trip settings will be required even for definite-time OCR8. Adaptive protection of microgrid is discussed in Section 19. 4.

TABLE-19.3 Protection coordination in islanded mode with DERs (Green zones included) and BESS as grid-forming source

Fault (duration)	Relay No.	Primary/Back up zone	Very inverse-time t_{op} (CTI)	Definite-time t_{op} (CTI)	Fault current at relay (p.u.)	DERs fault contribution
F6 (14 s)	OCR6	Primary	0.6163	0.4	20.3	$I_{F,wtg}$ = 1.2 p.u., $I_{F,pv}$ =1.17 p.u. $U_{pv, wtg}$ < 0.12 p.u. $I_{F,BESS}$ = 3.17 p.u. U_{BESS} < 0.12 p.u.
F8 (14 s)	OCR8	Primary	0.1977	0.04	13.45	$I_{F,wtg}$ = 1.2 p.u. $I_{F,pv}$ = 1.17 p.u., U_{pv} < 0.1 p.u., U_{wtg} < 0.45 p.u. $I_{F,BESS}$=1.15p.u.,U_{BESS}≤0.5 p.u.
	OCR7	Backup-1	0.761(CTI_{8-7}=0.563 s)	0.2 (CTI_{8-7} = 0.16 s)	11.25	
	OCR6	Backup-2	1.361 (CTI_{7-6} = 0.6 s)	0.4 (CTI_{7-6} = 0.2 s)	11.12	

19.4 Adaptive protection for AC microgrids

As discussed in previous sections microgrids can operate in both the grid-connected and islanded mode. For the grid-connected mode, sufficient fault current is available from the main grid in order to trip OCRs in case of any fault inside microgrid. However, in islanded mode of operation only limited fault current contribution from local DERs is available which is not sufficient for the proper operation of OCRs inside microgrid. The reduction of fault current contributions from DERs in islanded mode requires lower pickup currents for OCRs. If the OCRs designed with lower pickup values are used in both the grid-connected and islanded modes, then false operations will increase, and OCRs may even trip during switching transients and momentary overloads in the grid-connected mode. To overcome this OCR sensitivity problem two general solutions are available: (1) Connect some high fault current providing DERs inside microgrid in islanded mode and use OCRs with only grid-connected mode pickup settings in both modes (2) Use two different OCRs with different pickup settings, one for the grid-connected and other for the islanded mode. First solutions can be useful at some degree if a large number of synchronous generators are available inside microgrid. If a large number of the converter-based DERs inside microgrid are available, then the second solution is the most favourite choice. However, in order to implement different OCRs with different settings for the grid-connected and islanded modes, OCRs will need to be alternatively activated and deactivated or their logic or settings changed after knowing the present mode of operation for the correct detection of the faults and avoiding false operations. The information about microgrid mode is usually in terms of open or close status signals from circuit breakers, particularly breakers at connection point of the main grid and microgrid. The adaptive protection can be implemented with a central controller or in an autonomous/decentralized manner after getting microgrid mode information. It is obvious that communication based adaptive protections will be quick and dynamic, however delays in data transmission, reception and processing and failures of communication links also require non-communication based adaptive protections.

19.4.1 Communication-based adaptive protection

Communication-based adaptive protections can be broadly classified into two categories: (1) Centralized adaptive protections (2) Decentralized (autonomous) adaptive protections. Centralized and decentralized adaptive protections are explained separately in the following subsections.

19.4.1.1 Centralized adaptive protection

The centralized communication-based adaptive protection is the conventional approach in which centralized control architecture is used. In this method, a central controller adapts the protection settings in a coordinated manner after collecting information about the system changes at one central location. This method requires a very powerful central controller which can save, process and communicate data with other components or systems. The centralized controller reduces the computation burden on individual devices and therefore simple devices can be installed for protection and control purposes. However, this method has one drawback that if the central controller fails, it causes a complete loss of adaptive protection and hence a redundant central controller is must for increased reliability. Various communication protocols like Modbus, DNP3, IEC 60870-5-101/104, IEC 61850 support the centralized communication architecture and its implementation can be done using serial/bus communication, over PLC (power-line carrier) or via Ethernet network [51].

19.4.1.2 Decentralized adaptive protection

The decentralized communication-based adaptive protection uses distributed intelligent electronic devices (IEDs) or multi-agent systems. Each IED acts in an autonomous way after getting information from other IED to modify its active setting group. The decentralized adaptive protection reduces the burden on the central controller, however IEDs with increased data storage capacity, more computational and processing power will be needed in addition to fast and reliable communication links between IEDs. The feasibility of decentralized architecture is only possible if direct communication between IEDs is allowed by the communication protocol. Presently, the focus of industry is mainly on IEC 61850 as the standard protocol for horizontal communication between IEDs. Although a bus or Ethernet network is required to implement the decentralized architecture, but 4G/5G wireless network or PLC can be the other useful options for its implementation [51]. The IEC 61850 communication standard is getting popular for application in electric power substation automation. The IEC 61850 standard offers the possibility that IEDs of different manufacturers can interoperate or interact with each other. This standard is initially focused on communication between IEDs within single substation but can be extended for communication between various substations in the future. The IEC 61850 standard provides a set of standard model structures for data and rules defining how to exchange these data. The IEDs from different manufacturers that comply with these model definitions can then communicate, understand, and interact with each other [52]. The IEC 61850 communication standard, by one common protocol, enables the integration of several functions including protection, control, measurement, and monitoring etc. [53].

19.4.2 Review of communication-based protection schemes for AC microgrids

In the literature, several solutions have been suggested for the protection of islanded microgrids. Some main solutions are reviewed in the following.

19.4.2.1 Directional overcurrent protection

Directional overcurrent protection can be used to protect the distribution system with bi-directional current flow. One problem with the overcurrent protection is that faults closer to the source might take a longer time to clear. However, this problem can be overcome with modern microprocessor-based devices, by having shorter coordination margin, and instantaneous over-current protection. Still, there could be protection co-ordination issues because of changing fault current due to DER or change in the network configuration. An advanced solution could be adaptive directional over-current protection based on the status of the generators and networks' topology.

Adaptive Directional Overcurrent Protection

In adaptive protection, relays still carry out the protection function using local measurements. However, their settings are updated locally or remotely via communication links. Apart from the additional voltage transformer (VT) and microprocessor-based relays, this scheme may also require a central controller and a communication link to the relays; but this communication does not need to be very fast nor very reliable.

In the solution of [54], relays detect the islanding condition themselves and reconfigure their neighbours if they detect a topology change [55]. Paper [54] suggests local information utilizing adaptive protection to handle the overcurrent protection challenges in the distribution network with DG. The settings of the relays are updated based on monitoring the operating states (grid connected or island) and detected faulted section. In [54] it is proposed that the faulted section detection could be done by using time overcurrent characteristics of the protective relays. The adaptive feature was also proposed in [56] for the protection of microgrids; where directional overcurrent relays are reconfigured by a remote central unit in case of grid separation (islanding) or grid reconnection to consider for the change of short-circuit level. The central unit is constantly aware of the network topology and the connected generators [55]. Paper [57] has also presented an adaptive protection scheme for distribution networks which consists of multiple DG units. According to real-time monitoring of the state and topology of the distribution network, the active setting groups (Figure 19.6) of the protection relays are adjusted. A programmable logic application is called at central controller to perform adjustments after changes in circuit breaker (CB) status (Figure 19.6). A controller which is centralized is integrated to the substation with IEC 61850 based communications to execute the control functions. The programmable logic in this central controller (substation computer or RTU) is used to modify the settings with IEC 61131-3 compatible programming languages. The adaptive protection scheme presented in paper [57] together with microgrid control system has also been developed and adapted for a real demonstration at Hailuoto island in Finland [58].

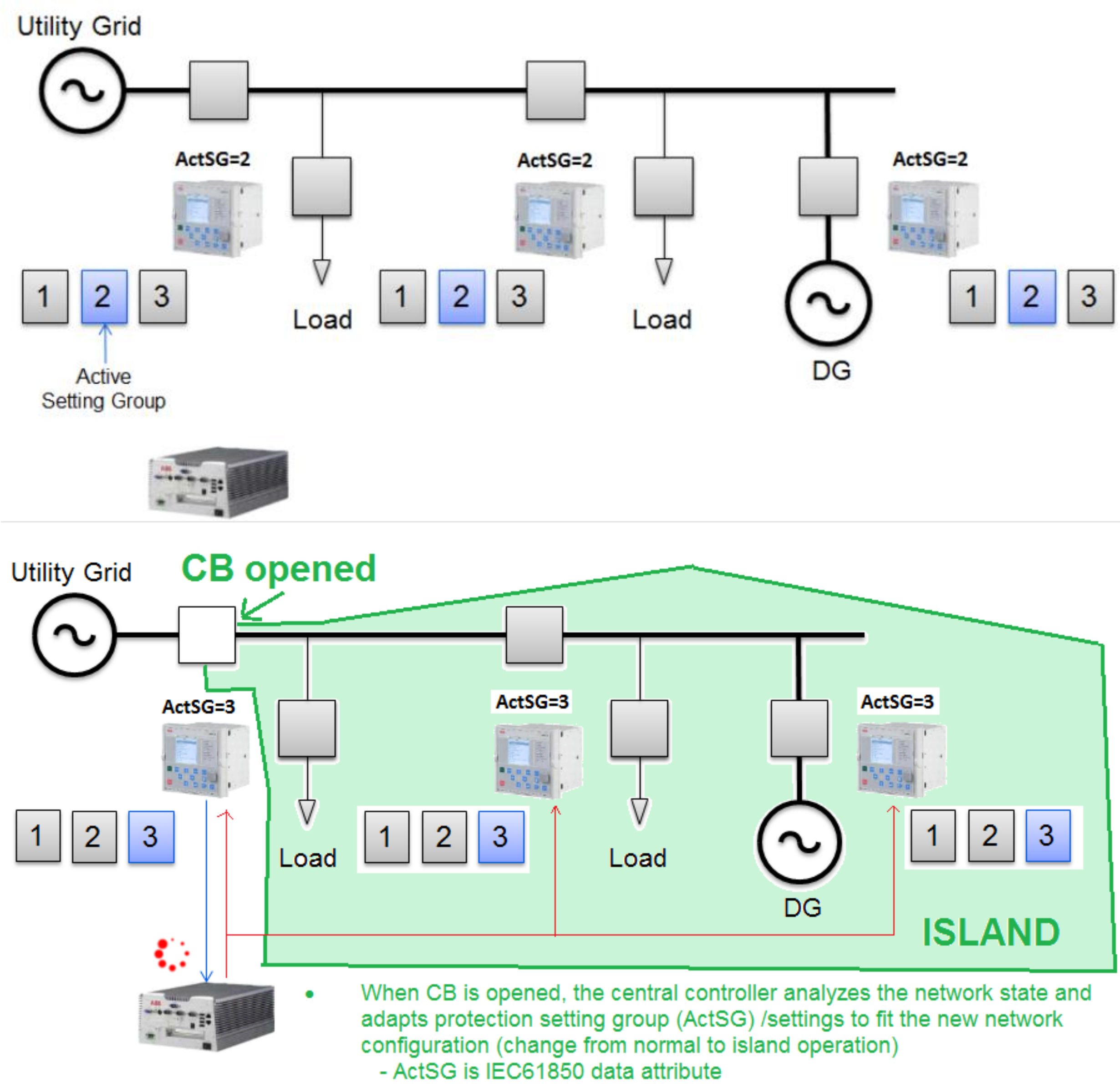


Figure 19.6. Adaptive protection by change of IED setting group.

Based on the literature, it has been stated in [59] that the major challenges related to the implementation of an adaptive protection system can be:

- The requirement for communication infrastructure
- The requirement for previous knowledge about all possible microgrid configurations
- The requirement to update or upgrade large amount of protection devices (e.g. fuses) which are currently used in the distribution networks (especially on LV network)

19.4.2.2 Current symmetrical components based protection

Protection scheme proposals based on current symmetrical components try to enhance the performance of traditional overcurrent protection [59]. For example, in [60], it was suggested that fault detection in islanded microgrids could be based on current symmetrical components. In [60] it was proposed to utilize in the event of an upstream phase-to-earth fault zero-sequence current detection (coordinated with unbalanced loads) and negative sequence current for phase-to-phase faults. In [61], a pilot instantaneous overcurrent protection scheme was briefly presented to perform instantaneous protection of a local line and remote bus-bar independent of the DG unit location. In [62], a three-level, communication-based protection selectivity scheme was proposed to be applied with voltage-restrained directional overcurrent protection. In [63], a fault current magnitude independent strategy for protection in LV microgrids with microprocessor-based overcurrent relays and directional elements, was suggested considering both operation modes (grid-connected and islanded).

19.4.2.3 Distance protection

Distance protection uses measured impedance or admittance values to detect the fault. In reference [64], it has been stated that distance protection seems to be a potential protection scheme for island operated MV networks. On the other hand, papers [65] – [67] have proposed directional inverse time-based admittance protection (Inverse Time Admittance, ITA), for grid-connected and islanded operation. This means that it can operate both in forward and reverse faults, but the reach settings should be different in forward and reverse directions. In the paper [68], comparison of distance and directional overcurrent protection was done considering only 3-phase short circuit faults. It was concluded that distance protection could selectively separate faults in MV and LV networks. Further, based on the simulations and the analysis, it was stated that overcurrent protection cannot be used if fault current levels within the island are close to the maximum load current. Based on this distance protection could be more suitable for being used in island operation. However, when also two phase and earth faults are considered the viability of distance protection must be further studied [68].

19.4.2.4 Voltage based protection schemes

Due to lack of high fault currents, it has been proposed by [69, 70] that voltages could be used for protection of an islanded microgrid. For example, paper [70] proposed a method which was based on a voltage measurement comparison: the location where the lowest voltage level is measured is tripped [55]. However, it is difficult to realize selective microgrid protection during island operation with voltage or current relays alone [71]. In [72] the same authors as in [70] also proposed to use the total harmonic distortion (THD) of voltage to enhance the protection of microgrids with the inverter-based DG units during earth faults. After detection fault type based on the variation of the fundamental frequency (50 Hz), the voltage THD seen by different feeder protection relays was analysed to determine the faulted part of the network. To prevent the challenges of previous methods related to detecting the oscillation waveform of the voltage variation, instead of voltage magnitude, [73] suggested to use only the positive sequence voltage. In [74], it was stated that a distinction between three fault types is possible by only considering the positive/direct and negative/inverse sequence voltage components, without using the zero sequence / homopolar information. Reference [75] proposed the same type of method to detect the fault and faulted network part, based on a voltage measurement at busbar and its transformation from abc coordinates to dq coordinates. In [76], the reduction in system voltage has been also used to implement an under-voltage back-up protection scheme for current differential protection.

Main problems with voltage-based methodologies during island operation, based on [59], are:

- Small differences in voltage drop seen by the relays at both ends of short lines can lead to protection maloperation, due to reduced voltage gradient
- Challenges with practical application of some of these methods and also with potentially required communication system, when large amount of DG units are present
- Solution can be highly dependent on the network architecture as well as on the defined relay protection zone related to every DG unit
- Challenges in high-impedance-fault (HIF) detection.

19.4.2.5 Current differential

In [76], line differential protection based on current measurements was chosen for the microgrid because it is non-sensitive to bidirectional power flows, changing fault current levels and amount of DG units. It is also stated that current differential protection offers the needed protection during both grid-connected and islanded operation and it is not affected by a weak infeed. This means that current line differential protection is able to detect internal faults even without having any DG units connected. The use of differential protection for microgrids with low fault current level has been suggested also in [77] – [81] to protect inverter-dominated microgrids. However, differential protection might be expensive since protective devices must be placed on every line segment of the network. Therefore, [81] proposes to form protection zones consisting of several line segments.

In addition, it is worth mentioning that the topology of the sample network i.e., schematic diagram in [76] is chosen to be very well suited for differential protection also during island operation. In general, current differential protection is not very suitable for the protection of islanded part of the distribution network having a radial topology and many protection zones (i.e. for protection of 'last' protection zones with an open end / CB).

19.4.2.6 Protection based on voltage and directional overcurrent

In [74], a microgrid protection strategy based on voltage and current measurements was proposed in addition to a voltage-based protection scheme. Also, in [82], [83], the use of voltage measurement based fault detection has been considered and a potential solution for small microgrids is presented in the form of voltage controlled overcurrent devices to enable the use of lower current threshold settings.

In addition, in references [64], [84] - [87] microgrid protection schemes based on the use of both voltage and directional overcurrent are analysed. However, these schemes are based on the utilization of high-speed communication for interlocking / blocking purposes to ensure selective operation of protection during island operation. In the following, these proposed schemes for LV and MV microgrids are presented.

19.4.3 Protection of LV AC microgrids

Different kind of protection methods and principles for microgrids have been proposed. One problem in some proposed solutions for LV microgrid protection is that their applicability is limited to microgrids with only converter-based DG units. Therefore, these solutions may overlook others e.g. requirements on the operational speed of protection to maintain the stability of LV microgrid with directly connected rotating machines after fault clearance. According to [84] key fundamental properties required from the future LV microgrid protection systems include,

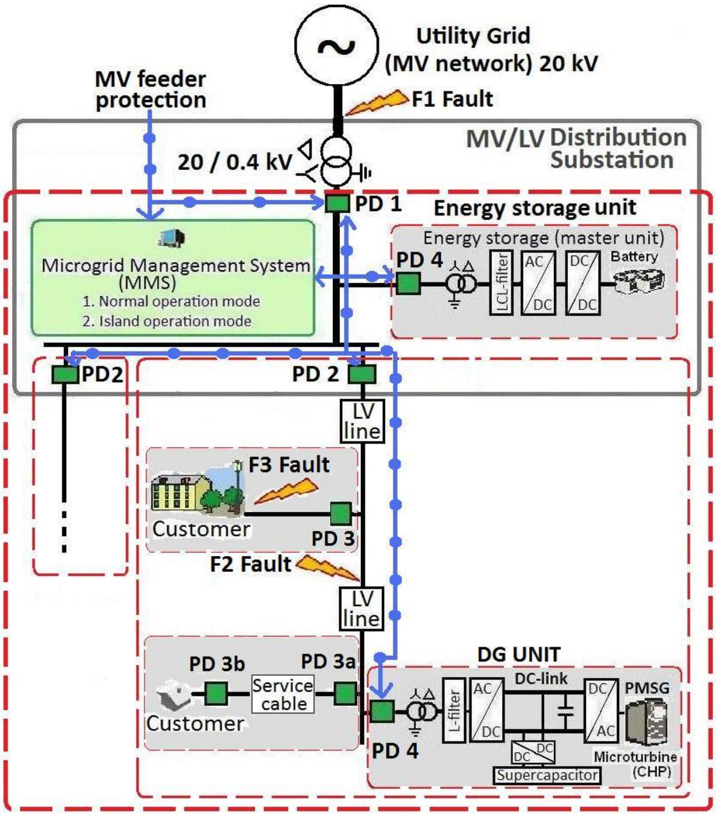
i. Adaptivity,
ii. Utilization of fast standard-based communication (IEC 61850),
iii. Fast operation in deep voltage dips due to faults to maintain stability in healthy part of LV microgrid,
iv. Fast operation to fulfil needs of very sensitive customers,
v. Selective operation in faults of every kind and
vi. Unnecessary operation of protection devices (PDs) and disconnection of DER units must be avoided.

In the following, two different proposed protection schemes for LV microgrids based on the utilization of both voltage and current (with direction detection) are shortly presented and more details can be found from the references. The main difference of the proposed protection schemes is that the first one (Proposed LV Scheme 1) relies on the extensive use of high-speed communication and the other (Proposed LV Scheme 2) is not based on the use of communication.

19.4.3.1 Proposed LV microgrid protection scheme 1

In references [84] - [87], the following scheme for the protection of LV microgrids has been proposed. The main structural choices of the proposed LV microgrid protection system are summarized in Figure 19.7 showing the type of protection devices (PD 1-4). When the measurements of active and reactive power flow between the utility grid and the LV microgrid are needed during normal operation, then also current measurements need to be included in PD 1. However, from the proposed protection system point of view the current measurement at PD 1 is not necessarily needed. Properties of the examined LV microgrid e.g. type, number and location of fault current feeding DER units made it difficult to realize selective protection for PD 2s during island operation, which is only based on current or voltage relays. Therefore, the protection algorithm of PD 2s during the island operation of LV microgrid was chosen to be multi-criteria based where both voltage and current measurements have been utilized (Figure 19.7).

The protection of PD 2s should also be able to adapt to the present network configuration as well as to the current states of the DG units during island operation. This adaptation of settings and pick-up limits of PD 2s could be realized, for example, by microgrid management system (MMS) when the microgrid configuration changes. During island operation PD 1 is changed to be ready for re-synchronization of microgrid back to the utility grid which requires that phase voltages be measured from both sides of PD 1. The protection settings of PD 2s are changed to the ones needed in island operation. To avoid the malfunction of PD 2s, the protection settings of PD 2s are not changed from normal to island operation settings before all possible transients and oscillations in voltages, currents and frequency are stabilized after transition to island operation. MMS will also send the state changed from island to normal operation signals to PD 2s and PD 4s after successful re-connection back to the utility grid. From island operated microgrid power balance viewpoint, the role of MMS is also important. For example, after fault F2 at LV feeder the MMS must immediately, after operation of LV feeder protection (PD 2), send new set point values for those DGs or DER units which still are connected to the healthy part of the microgrid or disconnect the less critical customer loads.



TYPE OF PROTECTION DEVICES (PD 1-4) NEEDED IN NORMAL AND ISLAND OPERATION OF LV MICROGRID

	NORMAL	ISLAND
PD 1	U, f	Re-syncronization
PD 2	DOC (MCB/CB/SS)	U+DOC (AM)
PD 3	OC (MCB/fuse)	OC (MCB/fuse)
PD 4	U,f	U,f

U = Phase voltages
f = Frequency
OC = Overcurrent
DOC = Directional OC
AM = Adaptive Multi-criteria

= Protection zone
= Fast data transfer for Protection (IEC 61850)
- Communication for adaptive protection
- Microgrid state changed and interlocking signals
= Protection device (PD) e.g. fuse or CB / SS

Figure 19.7. Number of protection zones and type of protection devices (PD 1-4) needed in normal and island operation of LV microgrid. [84] - [87].

During the islanded operation of a microgrid, possible oscillations due to sudden changes in the microgrid configuration need to be taken into account for the protection concept to achieve selective protection and to avoid the unnecessary tripping of protection. This could be done by using communication based interlocking signals. During islanded operation rapid communication is required for microgrid protection needs between protection devices (PD 1 and 2) as well as between master unit and DER units. MMS must also be able to communicate with all the other components and customer loads in the microgrid. Communication should preferably be based on commonly used standards like IEC 61850. Active microgrid components at the connection point of the microgrid (PD 1, master unit and MMS) are also responsible for microgrid re-synchronization. More information for example about the functions needed for LV microgrid protection in the proposed scheme as well as details about the operation curves of PDs in the proposed LV microgrid protection system during grid-connected and islanded operation can be found in [84], [85]. It is enough from the proposed LV microgrid protection system point of view that the converter-based DER units will feed 2xI_n active current (I_n is nominal current) during faults in LV microgrid for the required FRT time defined by the operation curves of different PDs.

19.4.3.2 Proposed LV microgrid protection scheme 2

In [88] and [89], strategies for the coordination of protective devices, in typical radial distribution networks with DER, were proposed. Expanding on the idea presented in [88], in [63] and [89] protection strategies based on microprocessor-based relays for LV microgrids has been proposed. One of the salient features of this protection scheme is that it does not require communications or adaptive protective devices. In addition, it is stated in [63] that the proposed scheme is to a large extent independent of the fault current magnitude, the microgrid operational mode, and the type and size of the DER, subject to the modified relay setting for the grid-connected mode of operation [88].

19.4.4 Protection of MV AC microgrids

In [88] and [90], communication-based protection methods have been suggested, which should be implementable by commercially available protection relays, for the protection of inverter-based medium-voltage (MV) microgrids. Proposed scheme also includes a backup protection method to handle the failure of the communication network. In [88] it was also stated that the suggested protection method is independent of the operation mode of the microgrid as well as of the fault current level, type, size, and location of the DER units.

19.4.4.1 Proposed MV microgrid protection scheme 1

In [91] one potential protection scheme without communication was proposed for short-circuit and earth-fault protection of an island operated medium-voltage (MV) microgrid with many protection zones. The suggested protection method was not dependent on the fault current level fed by the DER units and was compatible and selective with DG unit low-voltage-ride-through (LVRT) curves. However, the LVRT curve of the inverter- and synchronous generator-based DER units may be different. Because rotating generators typically cannot have as long fault-ride-through (FRT) / LVRT capability as the inverter-based DER units may have, and the islanded MV microgrid with synchronous generators can be divided into fewer protection zones than with inverter-based DERs. The suggested protection strategy is only for islanded microgrid operation, but there are some similarities with previously, in [92]-[95], presented short-circuit protection strategies for the grid-connected operation.

The short-circuit and earth-fault protection operation speed in the proposed scheme are not dependent on fault-current level or measured impedance. In contrast, they are based on voltage measurements from that network point (also considering the direction of the current). This means that it is easier to achieve selectivity with DER units LVRT requirements especially without fast communication and when there are many protections zones in the MV feeder. The suggested protection method could be also used as a back-up method for communication assisted strategies. It can also be mentioned that the earth-fault protection part of the proposed protection scheme is only applicable to neutral isolated MV microgrids. The main principles of this proposed protection scheme are presented broadly in Figures 19.8, 19.9 and 19.10. From [91], a more detailed descriptions with case examples can be found.

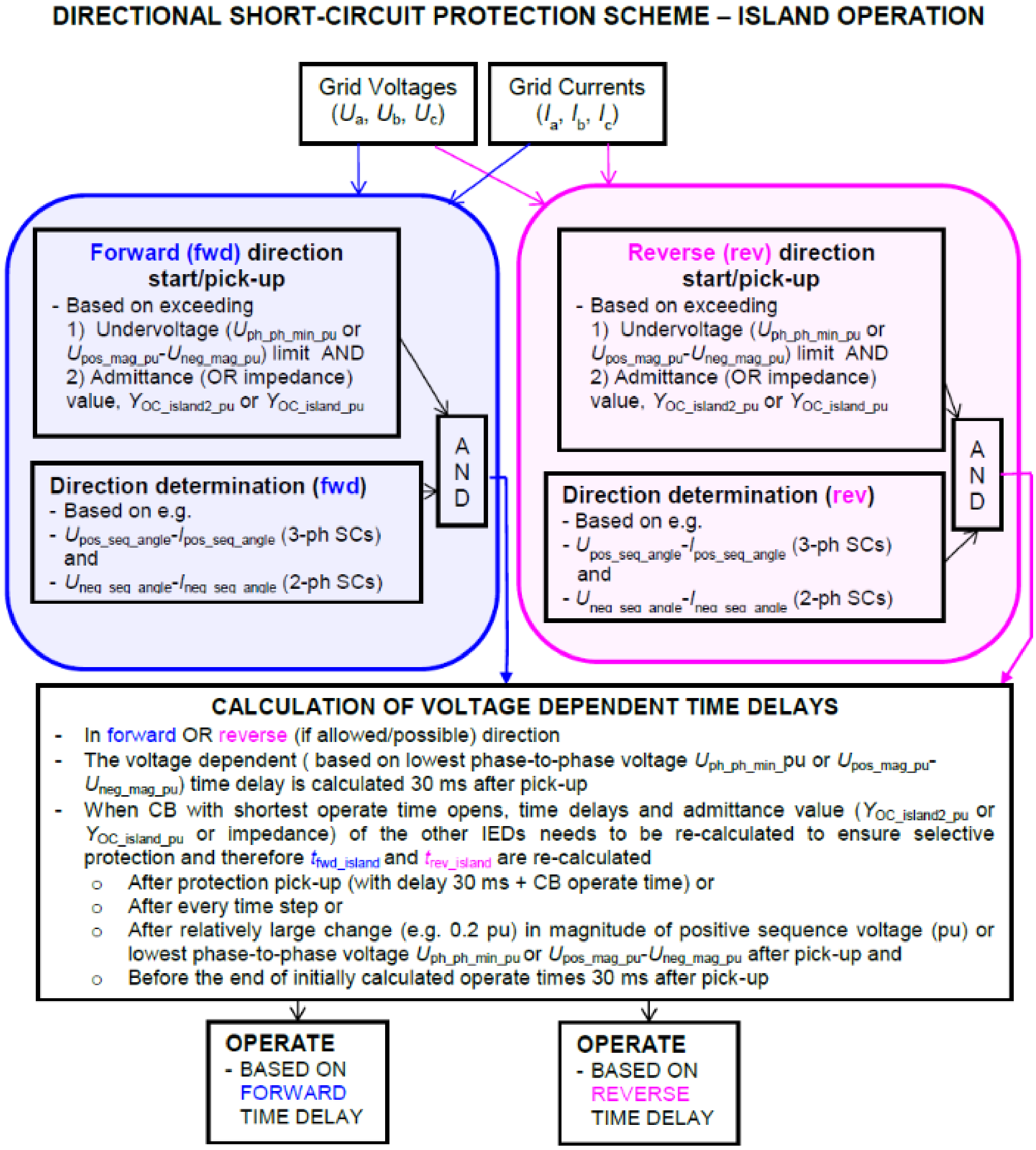


Figure 19.8. Suggested directional short-circuit protection strategy for island operated MV networks. [91]

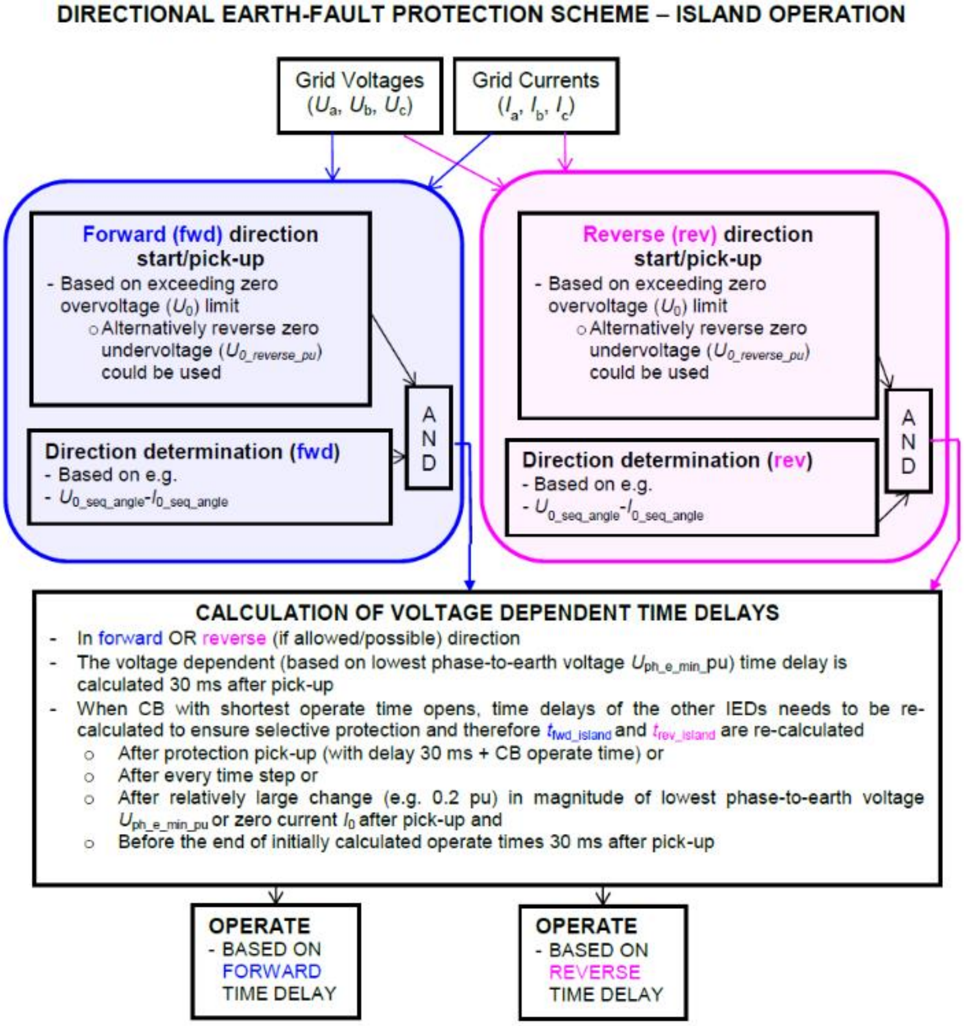


Figure 19.9. Suggested directional earth-fault protection strategy for island operated (earthing isolated) MV networks. [91]

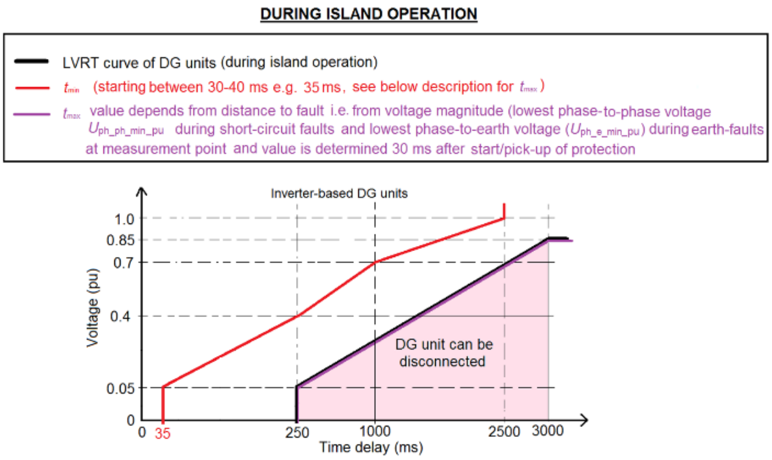


Figure 19.10. Protection voltage dependent operation time delay curve during island operation with inverter-based DG units. [91]

Table 19.4 summarizes the differences between the proposed protection strategy [91] and few other previously proposed protection methods for island operated microgrids. From Table 19.4 one can see that the key advantage of the proposed strategy (6. in Table 19.4), when compared with other previously proposed methods (1.-5. in Table 19.4), is that it is selective with DG unit LVRT curves / FRT requirements. In addition, it can be applied to microgrids with many protection zones without the requirement for fast communication.

TABLE 19.4 [91]

DIFFERENCES OF PROTECTION SCHEMES FOR ISLAND OPERATED MICROGRIDS

Protection Scheme	Sensitivity / Applicability also to microgrids with only the converter-based DER units	Selectivity of MV and LV faults	Requirement for fast communication to achieve selectivity in microgrids with DER unit FRT curves and with many protection zones
1. Directional Over-Current (DOC)	NO	NO/YES*)	YES
2. Distance	YES	YES	YES
3. Current Differential)**	YES	YES	YES
4. Voltage + DOC	YES	YES	YES
5. ITA [67], [96]	YES	YES	YES
6. Proposed Scheme [91]	YES	YES	NO

*) Case dependent, but not if only the converter-based DER units and low pick-up settings, **) Network topology dependent, not suited for microgrids with radial feeders without DER units at the end of the feeders

19.4.4.2 Enhanced MV microgrid protection scheme 1 – HIF detection included

In [91] (Subsection 19.3.8.1) a new protection strategy was suggested including short-circuit and earth-fault protection for island operated, neutral isolated MV microgrid. In [97], the MV microgrid protection strategy, with mainly OH lines and the inverter-based DER units, was enhanced so that it also included high-impedance-fault (HIF) detection (Figure 19.11). Additionally, other improvement possibilities were suggested in [97], like, DER unit high-voltage-ride-through (HVRT) curve compatibility and use of adaptive start/pick-up setting. More details can be found in [97].

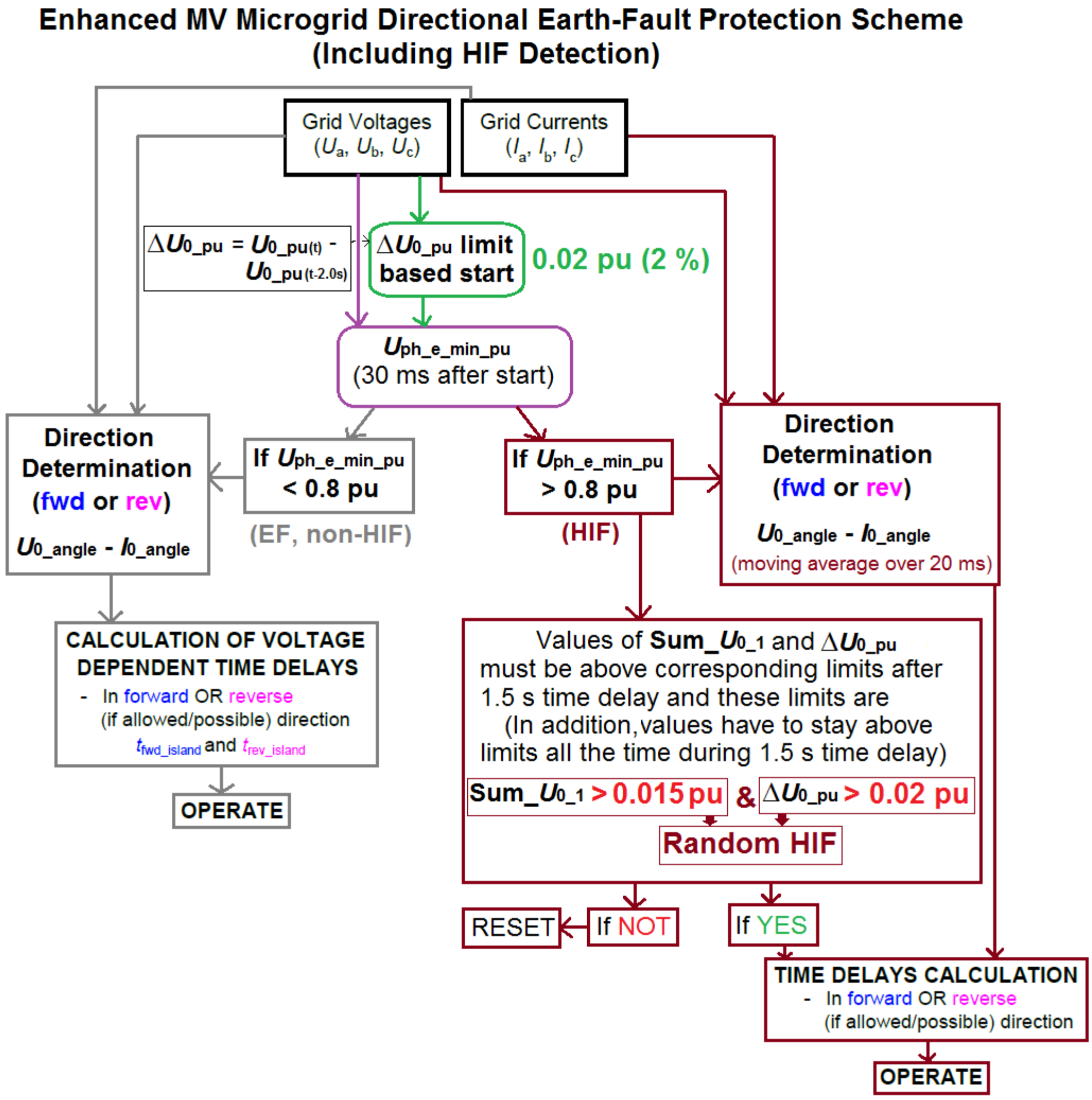


Figure 19.11. Improved MV microgrid protection strategy. [97]

19.4.5 Communication-less adaptive protection

The communication-based adaptive protections may become ineffective due to communication system failure. In this situation protection settings can not be changed according to changing network configurations. Therefore, some communication-less adaptive protections should be developed to takeover in case of communication failures. A method for knowing the present condition or state of grid operation (grid-connected or islanded) has been proposed in [98] which uses some local schemes installed near the protection devices. The proposed scheme uses the thyristor which is fired during a short waveform interval of voltage, then thyristor voltage and currents are monitored. The monitored voltage and currents are then used to calculate the grid equivalent impedance. From the value of grid equivalent impedance it is determined whether the main grid is connected or not. After determining the grid operating condition, a command is sent locally to the protection device to change its active group settings. The scheme can be used as communication-less adaptive protection scheme or can be used as a backup of communication-based schemes to provide resiliency during communication failures. However, the proposed scheme may not be effective for weak grids. The use of energy storage systems as fault current sources like batteries, flywheels, supercapacitors etc. for providing increased fault current by deactivating the fault current limiters of DERs locally or activating extra energy storage devices during the events of communication failures or cyber-attacks is proposed in [99]. However, this scheme will require over-rated converters of energy storage systems to sustain increased fault currents.

19.4.6 Islanding detection during island operation of nested microgrid

Functionalities like islanding detection should also operate during the islanded operation of (MV+MV or MV+LV) nested microgrids. In [100], islanding detection of LV network connected generation unit during nested (MV+LV) microgrid islanded operation was studied by simulations with PSCAD model from real-life smart grid pilot (Fig. 19.12). The main focus of the simulations was on the study and comparison of the usage possibilities of combined (high-speed communication based transfer trip & fault detection/direction + voltage vector shift) (Fig. 19.13) and multi-criteria (voltage total harmonic distortion U_{THD} & voltage unbalance VU) based islanding detection schemes in nested microgrid consisting only of converter-based DER units. [100]

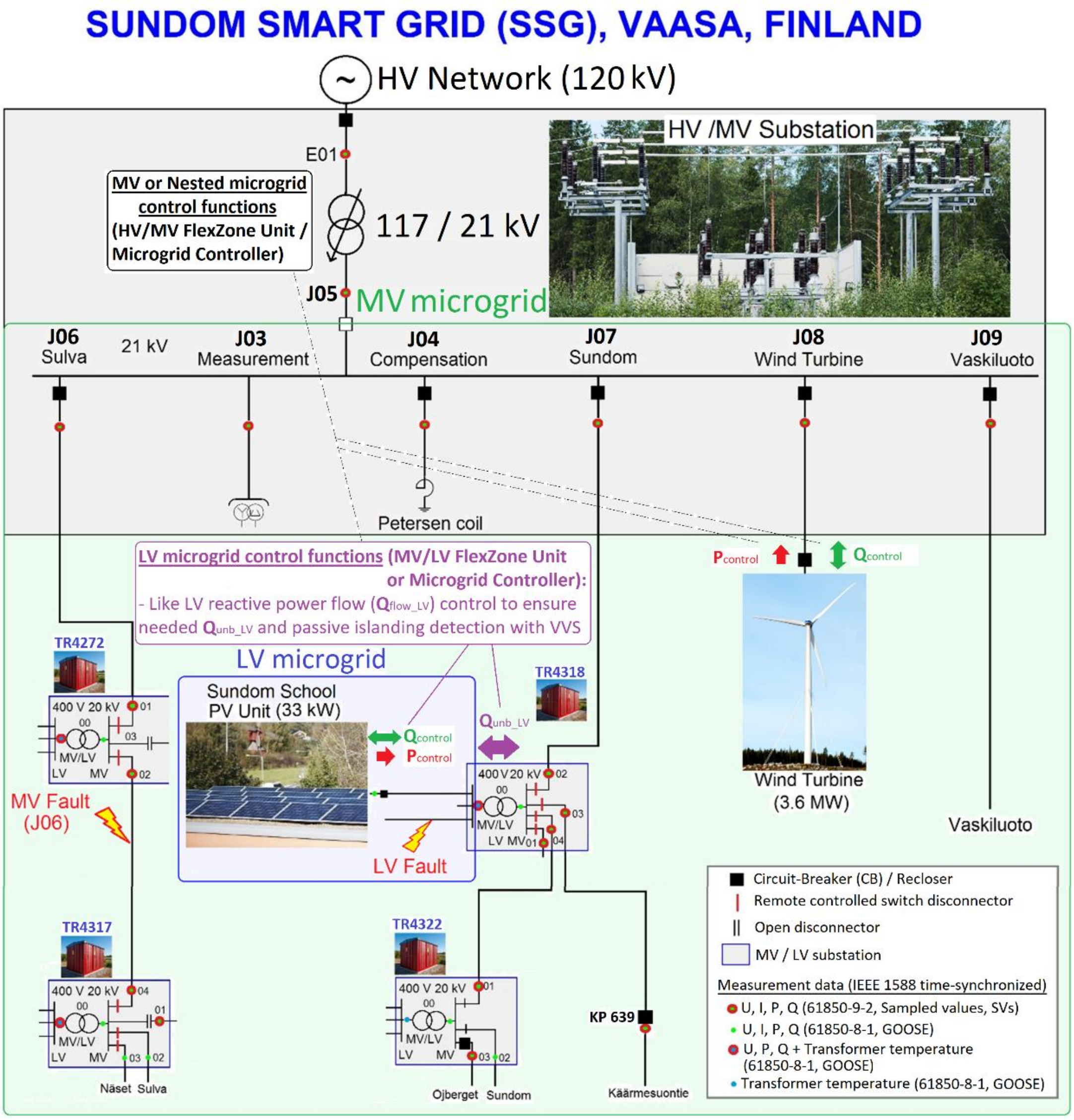


Figure 19.12. Sundom Smart Grid (SSG) to study islanding detection of LV network connected DER unit during nested (MV+LV) microgrid islanded operation. [100]

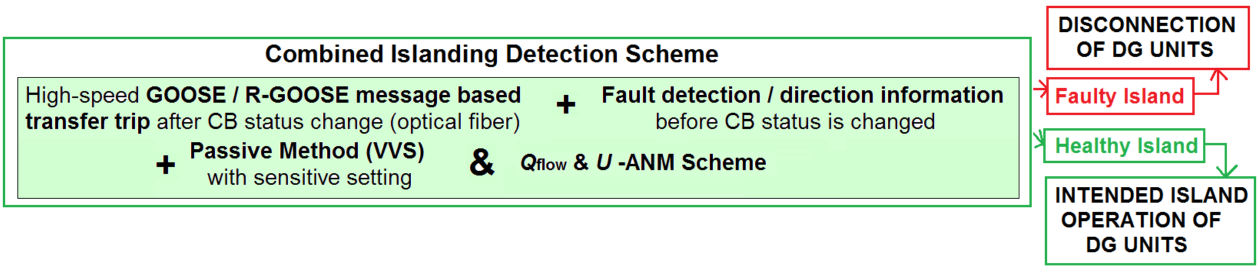


Figure 19.13. Combined islanding detection scheme. [100]

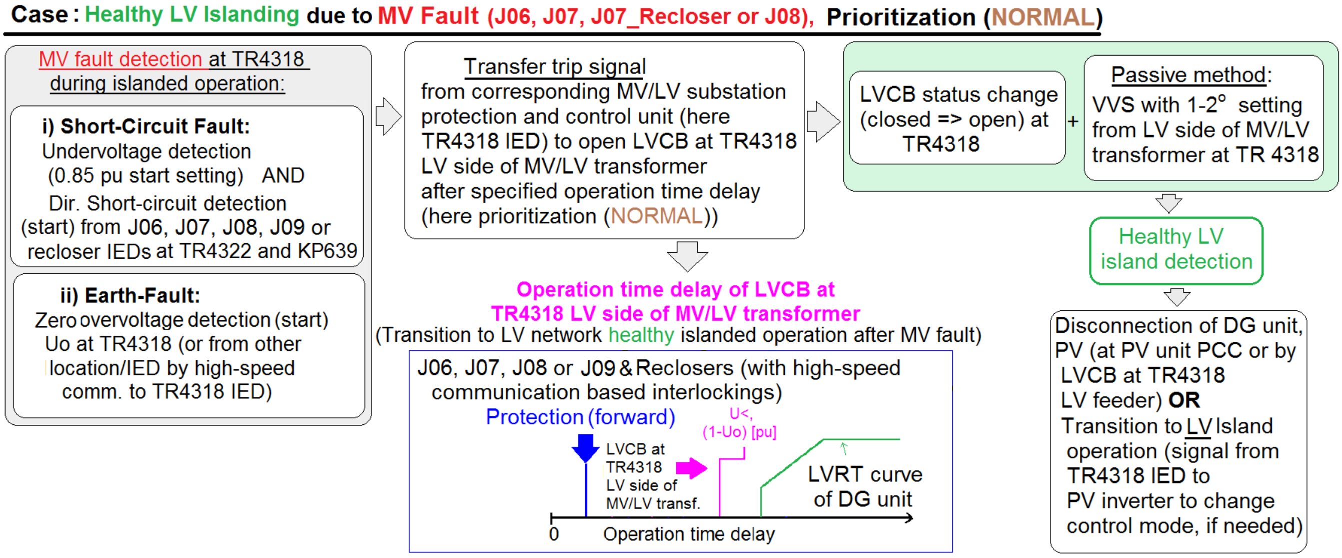


Figure 19.14. LV network DG unit (PV) primary islanding detection scheme example case (healthy LV islanding after MV fault) during islanded operation of SSG (Fig. 19.12). [100]

Based on the simulations it was concluded that combined islanding detection scheme (Fig. 19.13) seems to be very feasible for the islanding detection with LV network connected inverter-based DG units in nested (MV+LV) microgrids. However, the detection logic for faults must be adapted. In the future, nested microgrid control and protection functionality could be centralized/de-centralized in control and protection units at HV/MV and MV/LV substations. For example, the fault detection and location determination could be coordinated between these units by using high-speed communication, real-time synchronized measurements from multiple locations simultaneously as well as knowledge about the type, status and location of different DER units in order to always ensure selective islanding detection.

19.4.7 Need for microgrid grid codes

As stated in Subsection 19.1.1 from the islanded microgrid (LV or MV) protection viewpoint, the FRT capabilities and requirements as well as fault current contribution of the converter-based DER units during the faults is of importance. Microgrid grid codes for the island operated networks could 'standardize' the requirements more specifically for LV and MV microgrid by considering their typical features etc. in more detailed manner. This would also reduce complexity and the need for many case specific alternatives could be avoided. Compatibility of the DER unit FRT requirements, fault behaviour and island operated microgrid protection principles as well as operation speed requirements are naturally very critical from microgrid frequency and voltage stability viewpoint and these could be also defined as part of the microgrid grid codes.

For example, in LV microgrids the fault current fed by converter-based DER units could be required to be active and less than 2xI_n active current (I_n is nominal current) during faults in LV microgrid for the required FRT time defined by the operation curves of different PDs (Fig. 19.7, 19.15, 19.16).

On the other hand, in MV microgrids the HVRT curve during island operation for converter-based DER units could be defined in microgrid grid codes as shown in Fig. 19.17. It must be always simultaneously confirmed that the HVRT curve requirement of the DER unit, as part of the protection scheme during islanded microgrid operation, is compatible with safety regulations (e.g. touch voltages during earth-faults). Otherwise, faster MV microgrid protection schemes e.g. based on the use of high-speed communication may need to be utilized.

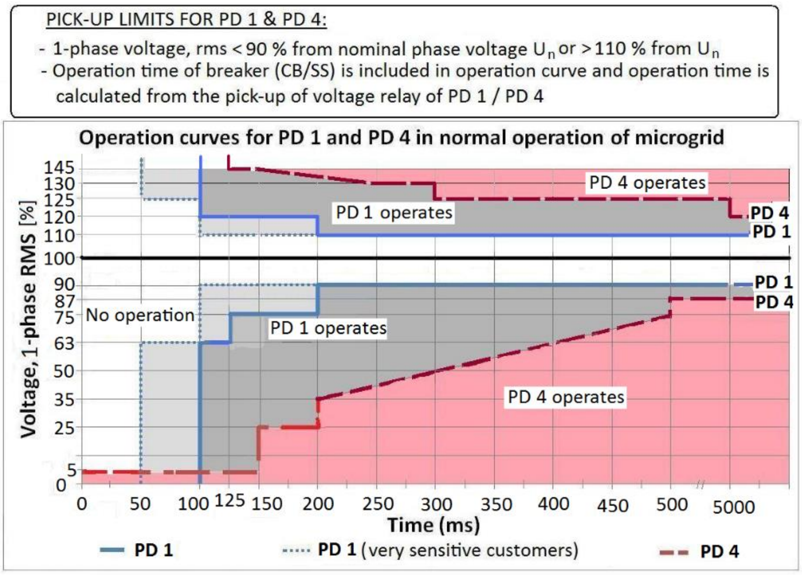


Figure 19.15. Operation curves for voltage relays (PD 1 in normal operation and PD 4 in normal and island operation) (see Fig. 19.7). [84] - [87].

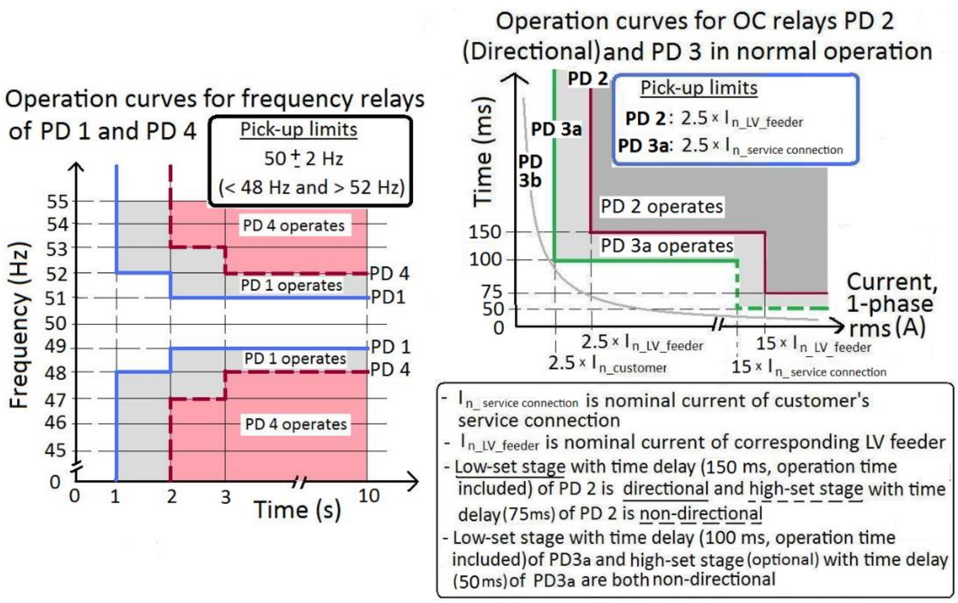


Figure 19.16. Operation curves frequency relays of PD 1 and PD 4 in normal and island operation of microgrid and operation curves for OC relays of PD 2 (directional low-set stage and non-directional high-set stage) in normal operation and PD 3 in normal and island operation (see Fig. 19.7). [84] - [87].

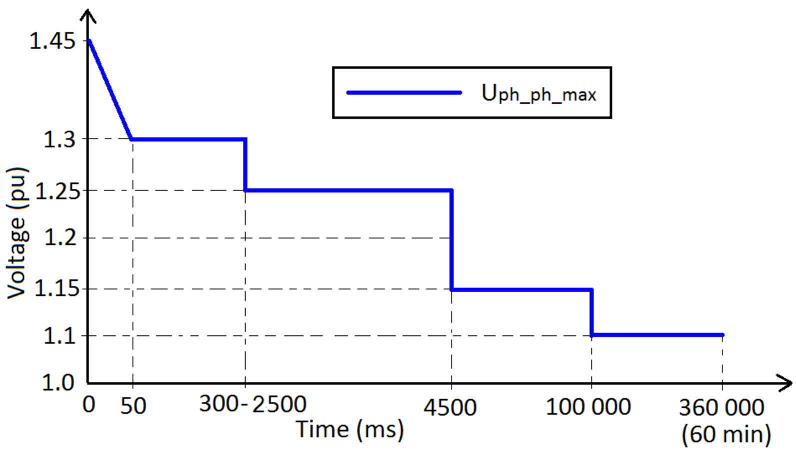


Figure 19.17. Proposed HVRT curve during MV microgrid island operation for converter-based DER units. [97]

19.5 Protection of DC microgrids

In DC microgrids, all DERs and loads are connected to a common DC bus. The DERs generating AC power (wind turbine, micro-turbine) are interfaced to the DC bus by using AC-DC converters and AC loads are interfaced by using DC-AC converters. On the other hand, all DGs generating DC power inherently (PVs, fuel cells, batteries) and DC loads are connected to the DC bus using DC-DC converters. Typically, DC microgrids are categorized into different topological configurations, like multi-terminal, zonal and DC looped. The chosen topology of DC microgrid is dependent on application, reliability level, and voltage level. Independent of the topology, there are two types of DC bus architectures i.e., (1) unipolar DC bus topology using two-level voltage source converters (VSCs) and (2) bipolar bus topology using three-level neutral-point-clamped VSCs. The DC microgrid protection schemes are typically divided into a) unit based and b) non-unit based i.e. protective device / breaker based. For example, in ships and DC homes the most typical protection scheme has been unit-based protection. A unit-based protection scheme means that protection functionality exists within the DER units and tries to either limit the DC-side fault current or drive it to zero.

The common DC bus can be interfaced to the main AC distribution grid via a bidirectional AC-DC converter. Depending on the voltage level of DC bus, DC microgrids can be classified as low voltage DC (LVDC) or medium voltage DC (MVDC) microgrids. Protective devices of DC microgrid with non-unit-based protection scheme are represented by a generic block “PD” representing protective device as these are different from conventional CBs operated by protective relays [101]. The main requirements of selectivity, sensitivity and speed of an effective AC protection system are also expected from a DC protection system. However, DC protection cannot meet all requirements of AC protection in a very straightforward way. Because in AC system sufficient protection speed is required to maintain the stability of synchronous generators while allowing a combined relay and breaker operating times for several cycles of fundamental frequency. For DC systems, in contrast, the protection system should be substantially faster because a contribution to the fault current by a voltage source converter (VSC) even for a duration of more than few milliseconds can damage the converter unless some DC fault current limiting/blocking mechanism is available to protect the converter. Additionally, DC protection should isolate the fault before the blockage of IGBT switches of the converter happens because due to the blockage of IGBTs, the converter control will be lost, and more time will be required for the post fault restoration process. The requirement to prevent IGBTs blocking imposes strict requirements for the protection of DC microgrids. The technology of DC breakers and off-the-shelf digital DC relays is at a very low advancement level. Therefore, it is common practice to trip the breakers on the AC side of all converters during a DC fault in a DC system and then the fault is isolated using DC disconnectors This approach is fast enough to protect the converter, but it is not selective because the loss of the complete DC system happens during any fault. Overcurrent protection is not the optimum selection for DC microgrid protection because the relay should be capable of differentiating between in-zone and out-of-zone well before the fault current reaches its final value. Moreover, the fault resistance also severely affects the selectivity and sensitivity of DC overcurrent relays [102]. The common method used for the location of DC fault is based on the travelling-waves principle [103] which uses a communication link to find the arrival times of fault-induced travelling waves at two ends of a line. Using the difference between two arrival times and wave propagation velocity, the location of fault can be identified. Due to the presence of noise and short lines in DC microgrids, this method faces problems. Moreover, travelling-waves relays are very costly for implementation in DC microgrids [102]. The other protection methods proposed for DC microgrids as reported in [19] include overcurrent, current derivative, directional overcurrent, distance and differential protections. The common protective/interrupting devices for DC microgrids are fuses, moulded case circuit breakers, no load switches and SSCBs [19] [101]. DC microgrids are evolving and so are DC protection systems. Until adequate DC protection devices are available the applications of DC microgrids will be limited to only special applications like avionics, automotive, marine, the international space station (ISS), spacecraft, aircraft, electronic computers, and servers in data centres.

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