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Insight into Microgrid Protection

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***Abstract*—Microgrids consist of a combination of generation resources and load, forming an electrically sustainable entity. Although the feeder configuration, including location of circuit breakers or switches, and selection of protective devices can change from one microgrid to another, some characteristics like size of microgrid and behavior of sources feeding a fault remains similar. Due to the non-uniformity of configuration, no definite choices of protection schemes have emerged. This paper analyzes the performance of three most commonly used principles of protection - overcurrent, distance, and differential - on a microgrid topology based on three actual microgrid designs. Importance and implementation of safe islanding and resynchronization are also discussed. Though this research was done primarily for microgrids at United States military bases, the analysis and conclusions may be applied to microgrids in general.**

***Index Terms*—Fault, microgrid, power system protection, short circuit analysis.**

I. Introduction

Protection paradigm of distribution feeders in presence of distributed generation (DG) has been discussed extensively over the last decade, some seminal papers being published in early 2000 [1], [2]. Microgrid is a concept that evolved over the years to mean a self-sustained island of load and generation that safely operates either in grid-connected or islanded mode. Though some microgrids are custom-designed for prototype studies [3], [4], a practical microgrid would most likely evolve from an existing distribution feeder, changing the nature of such feeder to multi-source, while still retaining the radial network configuration - loops are avoided by switches kept open. Protection system is most likely to be affected most during this transformation. Fuses obviously become obsolete due to bi-directional fault currents. Papers over the last decade have attempted to propose different protection schemes for microgrids from directional overcurrent [5] to differential [6]–[8] to adaptive [9], [10]. There are papers that discuss the issues that challenge the design of microgrid protection [11]–[13], some assuming exclusively inverter-interfaced generation [14]. Though the issues are known for some time, due to the non-standardized nature of the microgrid topology, and the lack of functioning practical microgrids, the simulated systems used by authors have been fictitious. In addition, a comprehensive analysis of comparing different approaches of protection on a practical microgrid is still lacking. These papers focus more on the protection for faults *inside* microgrids, but do not elaborate on the the issues and solutions for faults on the utility side. This paper provides such analysis covering three traditional protection philosophies: overcurrent, differential and distance. Microgrid topology is carefully derived based on three real microgrid designs authors have analyzed.

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II. Requirements, Topology and Operating Conditions for the Analysis of Protection Schemes

A. Requirements

Following performance requirements are imposed on microgrid protection scheme:

1) detection and isolation of faults both internal and external to the microgrid, even in the event of low fault current injection,
2) immediate disconnection of microgrid for faults on the utility side, while not affecting other utility customers in case of faults inside the microgrid,
3) no chance of unintentional island with utility load outside the microgrid when utility breaker is off,
4) no possibility of inadvertent out-of-phase connection of a live microgrid with utility,
5) main and backup protection for reliable fault isolation,
6) an acceptable compromise between selectivity and speed.

The discussion about protection of microgrids in literature focuses heavily on requirements 1, 5, and 6 for internal faults, discussing overcurrent and differential schemes. When a microgrid is fed predominantly by inverter-interfaced sources and storage, external faults will remain undetectable. Even when there is a firm source like a synchronous generator in the microgrid, typically connected at secondary distribution voltage, or Low Voltage (LV), the fault contribution of microgrid at primary distribution voltage, or High Voltage (HV) for external faults may not be detectable by overcurrent relays. Differential approach of course fails to detect external faults. In light of this, requirements 2, 3, and 4 become critical.

B. Topology

Our study of three actual microgrid designs reveal the following features that can impact the protection philosophy and schemes.

1) Microgrids are supplied at HV. Load is connected to LV, typical value being 220V or 480 V three-phase. Typically, there will be a feeder section between the utility substation and microgrid, which could be feeding some loads along the way.
2) HV feeder in the microgrid can be sectionalized with breakers (buses), or simply tapped.

3) HV feeder is radial and multi-sourced, where load/source are connected at taps or at section buses through step down transformers.
4) HV feeders can be cable, overhead, or a mix of overhead and cable. Typically these are only a few miles long. Therefore, fault current discrimination is not likely to be significant for faults occurring at different locations on the feeder, especially in islanded mode.
5) It is not practical to support islanded microgrid for longer periods purely through renewables because of variability of renewable generation, and high cost of storage. Moreover, critical loads must have a firm backup. Therefore, diesel set(s), which use synchronous generators, are usually available for reliability. Such generators, as well as renewables, are rated at LV, and connect via transformers to the HV feeder. Delta on HV side is possible, meaning islanded microgrid can be ungrounded.
6) Synchronous generators will act as low impedance Thevenin sources during faults, pumping fault currents several times their load ratings. However, compared to fault contribution from utility, contribution from generators is very small.
7) Renewables, where installed, are always connected, but most existing interfacing inverters in the United States (US) are IEEE 1547.1 compliant, meaning they drop off if they sense variable voltages and/or frequency, which is typical when the utility source disconnects, or when there is fault. Steady voltage and frequency for a few minutes are needed for such inverters to auto-connect [15]. Newer inverters are 1547.8 compliant, and are made to ride through the disturbance, but they will contribute fault currents less than or equal to 110% of the converter rating. This restriction on fault currents is imposed in sub-cycle time-frame.
8) Diesel sets have inbuilt protection relay against over/under voltage, over/under frequency, and overcurrent. Overcurrent curves of these relays can coordinate with the operating characteristics of the protective devices installed in system to achieve better selectivity.
9) Recloser can be present on the distribution feeder feeding the microgrid, but may not exist inside a microgrid. This is because coordination between fuse and recloser gets difficult in a multi-source system, and even then, it would mean reclosing on a potentially live subsystem of microgrid [16].

Actual designs that were analyzed by authors are confidential. However, based on the characteristics listed above, a configuration shown in Fig. 1 is chosen to discuss protection issues and guidelines for microgrids. A tapped HV feeder is assumed, since that is a more prevalent configuration of distribution feeders in the US. However, the analysis presented in this paper covers the possibility of sectionalized feeders as well. Transformers are considered Wye grounded on HV side; if they are Delta connected, a grounding transformer will be required. Two generators are assumed at the LV side, one (G5) for overall support to counter variability of renewables in case

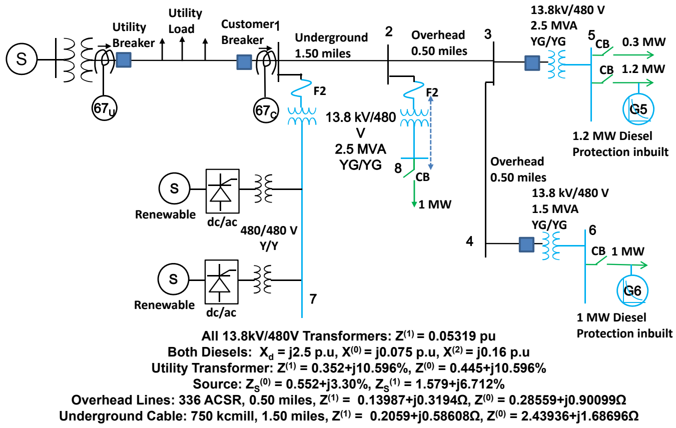


Fig. 1. Configuration of microgrid to be used for discussion and simulation.

storage is not adequate, and the other (G6) for a critical load. Thus, critical load will not only be fed when microgrid has islanded (sharing microgrid resources), but also when there is a fault on the HV part of microgrid, meaning other resources are cut off. One examples of such load is a hospital. Diesel generator parameters are taken from Cummins brochure [17]. All other system and equipment data are taken from the actual distribution system data of a utility in the southwestern USA. Transformers rated under 2.5 MVA are usually protected by fuses on the HV side. Loads and generator are controlled by Molded Case Circuit Breakers (MCCB)/ Metal Enclosed Switchgear (MESG) / Fuses, which have their own protection curves [18], [19]. It should be noted that a 1500 kW, 0.9 power factor (pf) load draws 2000 A at 480 V.

C. Operating Conditions

The operating conditions that should be supported by the proposed protection schemes are

1) grid connected mode - diesel sets are off and renewables are connected, and
2) islanded mode - diesel sets and renewables are connected.

Since renewables either disconnect or limit current contributions during faults, they will not be treated as fault sources for discussion of overcurrent based scheme. Moreover, in the grid connected mode, it is impractical to assume the diesels will be running. Therefore, that case is not considered. However, due to the fact that utility source is much stronger than diesels, it provides the lion's share of fault currents in grid connected mode. Therefore, the results reported in this paper remain valid for that case as well.

III. Analyzing the Use of Different Protection Principles for Microgrids

A. Overcurrent Protection

Before we even try to design an overcurrent based coordinated protection scheme, let us consider the obvious hindrances to this approach. It is clear that fuse $F2$ will have to coordinate with the corresponding load circuit breaker CB for faults in the LV load circuit. This is indicated by dotted magenta arrows in Fig. 1. The maximum value of the coordination range will correspond to grid connected state, and the minimum value will correspond to islanded state, with only generators contributing. This variation is typically very large due to the utility source being much stronger than the diesel sets, and can pose a potential coordination problem. Fig. 2 shows the coordination. Fault analysis was performed with Aspen® software.

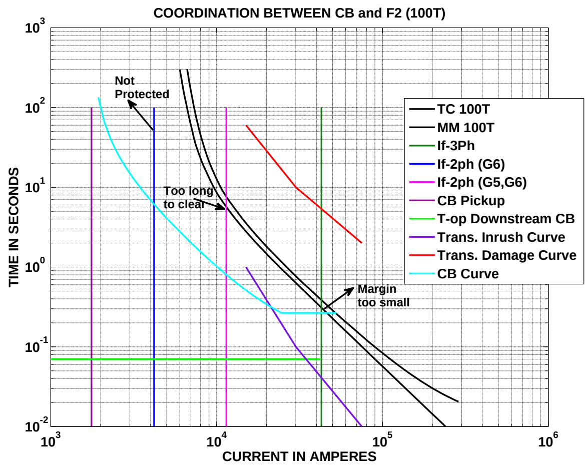


Fig. 2. Coordination of LV MECB at bus 8 and HV fuse $F2$ (100T).

Considering the 1 MW load, the load CB at bus 8 was chosen as 480 V, 1600 A Metal Enclosed Circuit Breaker (MECB) [18], [19]. The curves for the CB are given in [19]. The equations for these curves are the same as used for IEEE inverse overcurrent relays. It is reasonable to assume that this CB will coordinate with another downstream CB. If we assume a constant instantaneous time of operation of this downstream CB as 0.07 seconds [19], then the coordinated inverse curve for the MECB, and its coordination with fuse F2 (100T) [1] is shown in Fig. 2. All the curves refer to the LV side of the transformer.

Observe in Fig. 2 that the coordination margin at maximum (3-phase) current (grid connected mode) is too small. In islanded mode, fuse does not even back up the MECB when only G6 is feeding the fault. The fuse *does* back up the MECB for the minimum fault current when both G5 and G6 are feeding the fault, but the fuse will clear the fault in 7 seconds, which is a long time; the generators cannot be made to feed this fault current (their contribution more than 3 times their load current) for such a long time. This kind of situation is not surprising, because the difference between maximum and the minimum currents in the coordination range is huge.

Use of overcurrent relay instead of fuse $F2$ for better flexibility in coordination is now considered. In is case, Fig. 3 shows a general case of placement of overcurrent relays. Directional overcurrent relays 67 at buses 3 and 4 are needed to isolate buses 5 and 6 for faults on the HV side of microgrid. Now the coordination between load CB and relay RL is achieved as shown in Fig. 4 (a), though for G6 feeding alone,

[1]All fuse curves are taken from $S\&C$ Electric database

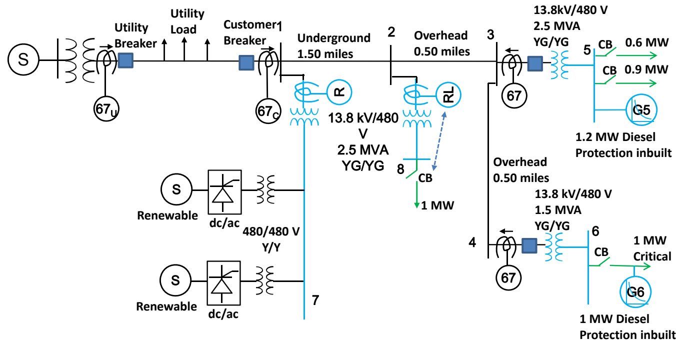
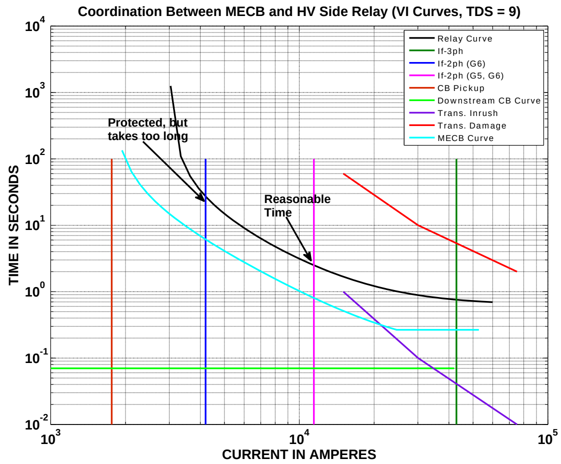


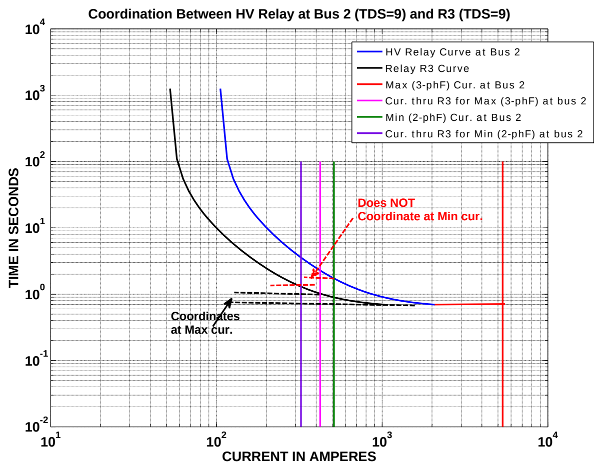
Fig. 3. Microgrid protected by overcurrent relays.

coordination margin is very large. However, Fig. 4 (b) shows that the coordination between relay RL and relay 67 at bus 3 is still a problem. For maximum current seen by relay RL, RL operates before 67 at bus 3 (denoted by $R3$ in the legend used in Fig. 4 (b)), but for minimum current, the relay 67 at bus 3 operates *before* RL. This is due to the widely different fault currents seen by these two protective devices for the same fault. Overcurrent principle is based on the assumption that the main and backup devices see the *same* fault current, so the result seen in Fig. 4 (b) is not surprising. The chosen TDS for 67 is 9 in this figure, but even with the maximum TDS of 11, this coordination was not achieved. Now, with numerical relays, a curve can probably be chosen that would enable this coordination. However, with a more complicated system, the coordination can become more difficult. This exercise at least illustrates that use of relays instead of fuses to protect transformers results in a better chance of coordination, but it is highly dependent on microgrid configuration. Of course, in a microgrid that is fed entirely by renewables and storage in islanded mode, overcurrent protection is out of question.

One characteristics of microgrid - *its small size* is also likely to create problems with overcurrent protection. For such system, it is expected that although the variation in the fault current contribution from utility can be significant, the contribution from diesels *will not vary much* for faults at different locations on the HV feeder. This makes it difficult to discriminate between primary zones of overcurrent relays. To illustrate this aspect, Fig. 5 shows the topology and relay placement in case the HV feeder is sectionalized. Each directional relay is accompanied by a breaker (not shown in the figure). As per the protection philosophy, $R1$, $R2$, and $R3$ need to be coordinated for upstream faults, and $R4$, $R5$, and $R6$ (and 67_C) for downstream faults. Though there is enough fault current discrimination for fault contribution from the utility side, the fault contribution from the diesel sets remains almost constant for faults along feeders 1-2 and 2-3. The total contribution from G5 and G6 is 639 A, 671 A, and 688 A for 3-phase faults on bus 1, 2, and 3 respectively. The values are so close (difference in the current contribution for faults on bus 2 and bus 3 is just 2.5%), that the coordination between $R1$ and $R2$ is simply not possible. Since the fault current contribution from the utility side changes substantially for faults along the feeder (7051 A and 4668 A for 3-phase faults on buses 1 and 2 respectively), and since these relays will see the *same* fault



(a)



(b)

Fig. 4. Coordination when HV side fuse $F2$ at bus 2 is replaced by an overcurrent relay RL. (a) Coordination between MECB and RL. (b) Coordination between RL and relay 67 at bus 3.

current, coordination of $R5$ and $R6$ should not be a problem. These relays will see the fault current only when the utility is connected. However, coordination of $R4$ and $R5$ is a potential problem, because when the utility source is disconnected, R4 will still be required to operate for faults on section 3-4, but it will only see the fault contribution from G5 in that case. Thus, $R4$ will see a maximum phase fault current of 4358 A, and a minimum phase fault current of 287 A. Such wide coordination range will obviously be difficult to coordinate.

B. Differential Protection

Differential protection offers a solution that is free from the uncertainty due to the connection status and location of diesel sets or renewables in the microgrid. It is also not affected by fault analysis (except for sizing CTs), and the related errors. This principle is routinely used for tapped transmission lines, a topology very much similar to the configuration of the microgrid under study. Fig. 6 illustrates the setup for differential protection. CTs should be placed to cover all taps

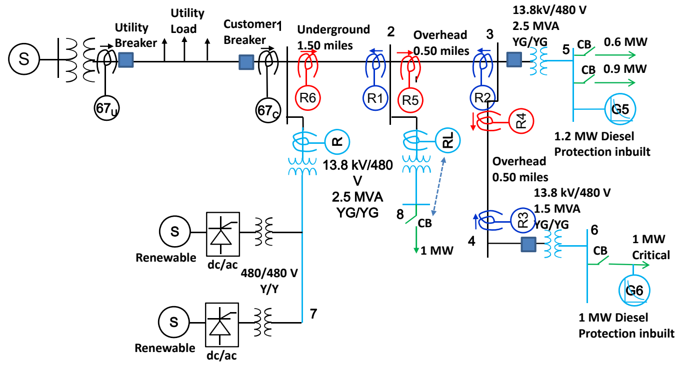


Fig. 5. Directional Overcurrent scheme for sectionalized HV feeder.

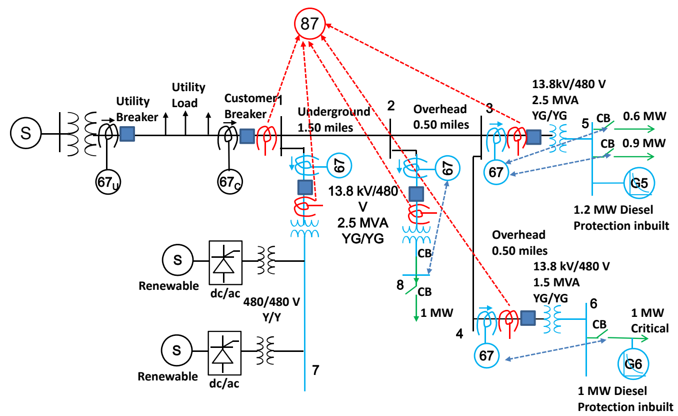


Fig. 6. Recommended differential scheme for the test system.

from the HV feeder, and fed to a differential relay (*87* in the figure). The data transfer from the CTs to the relay can be communication based, or can simply be a physical wire carrying the CT secondary currents to the relay. For microgrids of small size, wire may be a feasible option. All CTs should ideally have the same ratios. Directional overcurrent relays 67 will backup load MECBs. As per discussion in section III-A, this coordination will work in the grid connected mode, but may not coordinate for islanded mode. In that case, the generators will drop off, which will be the only indicator of fault in the LV circuit. In this very rare scenario when MECB fails to operate under islanded condition, critical load can be interrupted. Some UPS backup is necessary in this situation, so manual isolation of critical load from the faulted LV circuit can be performed. It should be mentioned here that in case of failure of differential protection on the HV feeder, generators will drop off as well. However, on the utility side, the backup is the directional relay 67_C.

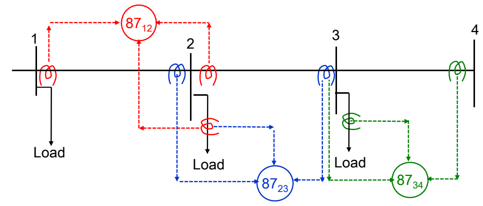


Fig. 7. Differential principle applied to sectionalized HV feeder

In case the HV feeder is sectionalized, the differential protection should be applied to each section, making sure the interconnecting bus is overlapped by the differential zones of the adjacent feeders, and load taps are accounted for (see Fig. 7). This will ensure buses are covered under differential protection.

C. Distance Protection

Distance protection also offers a solution that is free from fault calculations. However, it does not lend itself naturally to a tapped feeder. Tapped feeder, which is similar in topology to a multi-terminal line, causes the distance relays to underreach due to current infeeds [20], and can also cause blind spots [21]. Sometimes, a weak source may not even "see" a fault. It is conventional for multi-terminal lines to either be protected by a differential scheme, or a distance scheme using intertripping. For intertripping, a communication network is necessary. In light of this, for a microgrid, distance protection may not offer an advantage over differential protection. Due to the simplicity of applying differentia protection on multi-terminal configurations, it may be preferred over distance protection.

IV. Choice of Protection Scheme at Point of Common Coupling (PCC)

This is a very important part of microgrid protection that has not been discussed adequately in literature. The objectives to be achieved by this protection scheme are

1) detection and isolation of faults both internal and external to the microgrid, even in the event of low fault current injection,
2) immediate disconnection of microgrid for faults on the utility side, while not affecting other utility customers in case of faults inside the microgrid,
3) no chance of unintentional island with utility load outside the microgrid when utility breaker is off,
4) no possibility of inadvertent out-of-phase connection of a live microgrid with utility.

For faults inside the microgrid, the customer side directional relay 67_C will coordinate either with the differential relay 87 as well as with directional relays 67 (refer Fig. 6). This will ensure that microgrid faults will not affect customers beyond the PCC on the utility side, while maintaining selectivity for faults in LV and HV parts of microgrid. Utility side relay 67_U will coordinate with 67_C for faults inside microgrid. However, faults on the utility feeder can be a tricky scenario. In the test system, for a fault just outside the PCC, the fault contribution from the two generators is 639 A, but if we consider only G6, it is 236 A. Depending on how long the utility feeder is, for fault near the substation, the fault current contribution from microgrid can drop to a very low value. If microgrid is selling say, 2 MW power back to the utility, that would be a back-flow of 93 A assuming 0.9 pf. In such cases, it may be very difficult to distinguish between load and fault for faults near the utility substation. In the worst case scenario where a microgrid is fully sustained by renewables and storage, the detection of faults on utility side would be impossible with overcurrent relays.

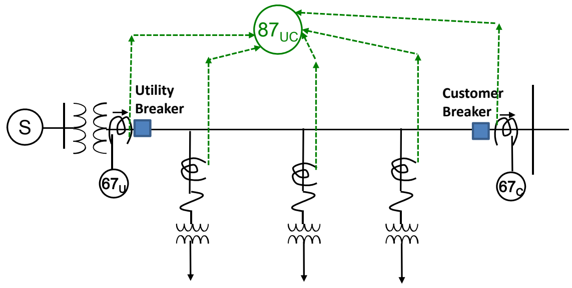


Fig. 8. Differential principle applied to utility feeder

How then, do we ensure guaranteed isolation of microgrid for faults on the utility side? A distance relay at PCC will not work due to low values of fault contribution from microgrid, as well as the tapped load feeders between the utility substation and PCC. A differential scheme to cover the feeder from substation to PCC is an option that can be explored. Of course all load taps along the feeder will have to be accounted for, as seen in Fig. 8. There is one chance, however, that may create a problem - a fault on the LV side of the load taps or on the load transformers *not* cleared by the transformer high side fuse. Though this is not likely to be a frequent event, such event would mean the 67_U will operate as backup and open the utility side breaker. However, the customer side breaker will still be on, because the fault is outside the differential zone. This means microgrid will keep feeding the fault.

In order to be absolutely sure there are no unintentional islands with/without faults, a solution would be to have a communication link between utility side and customer side breakers, where the opening of utility side breaker would automatically open the customer side breaker. If there is a recloser on the main feeder, then it has to send the opening signal to the customer side breaker. This would have to happen before the first reclose takes place. This takes care of the first three objectives cited at the beginning of this section. The last objective can be fulfilled by a check-synchronizing relay to control the closing of the customer side breaker.

V. Conclusion

This paper discusses various aspects of microgrid protection using a topology that is derived from three actual microgrid designs. The analysis and example presented in this paper shows that overcurrent schemes can be very hard to coordinate with selectivity between LV side and HV side faults due to a very large coordination range resulting from operation in grid connected mode as well as islanded mode. The lack of variation in fault current values for faults at different locations of microgrid during islanded mode creates problems with coordination of HV side relays for sectionalized feeders. Distance protection does not lend itself to the multi-terminal nature of the HV feeder, and cannot be implemented without intertripping. For sizes and configurations resembling the microgrid analyzed in this paper, differential principle appears as the most suitable option that naturally lends itself to the typical characteristics (both topological and functional) of microgrids. For most dependable and secure isolation of microgrid during fault on the utility feeder, either communication between substation breaker (or recloser) and customer side breaker is required. Check synchronizing relay to control closing of customer side breaker is also required.

VI. Future Work

With enhanced sensing, communication and computational capability, distributed controllers are being proposed for microgrid. This paper discussed the pros and cons of traditional protection schemes that use local information. Due to the fact that faults need to be cleared in less than five cycles, the local protection schemes are certainly necessary. However, future work will be focused on supervisory protection and control using global (microgrid-wide) data to achieve better reliability and selectivity.

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